Final Report

Analysis of Greenhouse Gas Emission Reduction Pathways for Vermont

Prepared for the Vermont Department of Environmental Protection (DEC) and the Vermont Public Service Department (PSD)

by Stockholm Environment Institute (SEI) and the Northeast States for Coordinated Air Use Management (NESCAUM)

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Acronyms

AEO	Annual Energy Outlook
ASHP	air source heat pump
BAU	business-as-usual
BEV	battery electric vehicle
BTU	British thermal units
BTM	behind the meter
CBECS	commercial buildings energy consumption survey
COBRA	Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool
COP	coefficient of performance
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EV	electric vehicle
FHWA	Federal Highway Administration
GHG	greenhouse gases
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Technologies model
GWh	gigawatt hour
GWP	global warming potential
GWSA	Global Warming Solutions Act
ISO-NE	Independent System Operator - New England
LDV	light-duty vehicle
LEAP	Low Emissions Analysis Platform
LMI	low- and moderate-income
LULUCF	land use, land-use change, and forestry
MHD	medium- and heavy-duty
$MMTCO_2e$	million metric tons of CO_2 equivalent
NESCAUM	Northeast States for Coordinated Air Use Management
PACE	Property Assessed Clean Energy
PHEV	plug-in hybrid electric vehicle
PSD	Public Service Department
RECS	residential energy consumption survey
RGGI	Regional Greenhouse Gas Initiative
RPS	renewable portfolio standard
SEDS	State Energy Data System
SEI	Stockholm Environment Institute
SIT	State Inventory and Projection Tool
UVM TRC	University of Vermont Transportation Research Center
VELCO	Vermont Electric Power Company
V2G	vehicle-to-grid
VMT	vehicle miles traveled
ZEV	zero-emission vehicle

Introduction/Background

Vermont has established greenhouse gas (GHG) reduction targets in the near-, mid-, and long-term planning horizons (2025, 2030, and 2050). Passed in 2020, Vermont's Global Warming Solutions Act (GWSA) set GHG emissions reduction targets of at least 26% below 2005 levels by 2025, 40% by 2030, and 80% by 2050 from a baseline of 1990 levels.[1] This report aims to identify the specific near- and long-term GHG mitigation actions Vermont can implement to put the state on a pathway toward achieving its GWSA GHG emissions reduction targets.

In support of this effort, Stockholm Environment Institute (SEI) conducted an integrated, regional, cross-sector energy system and an in-state sector-specific analysis to explore three unique GHG mitigation pathways that would enable Vermont to meet its 2025, 2030, and 2050 GHG reduction requirements. SEI's sector-specific modeling approach analyzed the following sectors in Vermont: electricity generation, transportation, buildings, industry, and non-energy emissions.[2] A scenarios analysis in this context provides GHG reductions relative to a Business-as-Usual (BAU) Scenario given various low- and no-carbon technology penetration pathways. Central to all scenarios in this analysis is the development of a near-zero carbon electricity grid as a necessary condition for meeting GHG reduction goals that also heavily rely on electrifying the transportation sector and more fully electrifying the residential/commercial buildings sector. In addition to the SEI analysis, the Northeast States for Coordinated Air Use Management (NESCAUM) conducted a health benefits assessment using the outputs of SEI's modeling.

The integrated, cross-sector modeling approach includes all energy generation, transportation, and energy consuming technologies, each assigned specific costs, performance characteristics, and lifetimes. The model accounts for the replacement or stock turnover of technologies through 2050 and identifies the pace of technology adoption needed to reach Vermont's emission reduction requirements. Within each sector, specific technologies are identified to reduce emissions from end uses, but the list of technologies is not exhaustive. For example, throughout the modeled years air- and ground-source heat pumps are increasingly deployed to replace heating and cooling needs previously met by fossil fuel-fired heating and cooling systems. Wherever possible, the model incorporates Vermont-specific sectoral data to better evaluate more granular impacts of policy interventions in the state. For example, historical and forecasted vehicle miles traveled (VMT) from the University of Vermont's Transportation Research Center (UVM TRC) was used in the analysis.

This GHG mitigation analysis was designed to provide Vermont with a comprehensive understanding of the needs for meeting the state's GHG reduction requirements, and to help the state better understand the implications of the necessary transition. This analysis will enable smart policy design to meet Vermont's GHG reduction requirements while strengthening the state's economy. The GHG mitigation impacts of individual states are limited by shared common source sectors in New England (i.e., electricity generation), which require regional coordination to achieve optimal GHG emissions reductions.

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[1] 10 V.S.A. §578.

[2] This analysis was developed by NESCAUM as an organization. Any views or opinions contained in this report may not necessarily reflect those of individual NESCAUM member agencies.

This report presents the methodology used to develop a BAU scenario and three mitigation scenarios that show how the state can achieve its GWSA GHG emissions targets; presents results for the three mitigation scenarios; examines the associated modeled GHG, macroeconomic, and public health impacts; provides an overview of other states' GHG mitigation approaches; and concludes with recommendations on future actions for achieving Vermont's GHG emissions reduction targets based on this analysis. The analysis is neither prescriptive nor designed to produce specific targets for low-carbon technology penetration but is instead an indicative analysis designed to show the estimated magnitude and timing of needed changes and the relative importance of major economic sectors.

Methods

a. Model and Modeling Tool Introduction

For this analysis, an integrated model of Vermont's energy system and GHG emissions was developed using the Low Emissions Analysis Platform (LEAP). LEAP is a flexible, scenario-based software planning tool for conducting energy demand and/or supply analyses, as well as for developing cost-benefit assessments and emissions projections. It offers a scalable energy accounting framework for building models that reflect historical data from detailed technology-specific end-uses through top-down energy consumption, and projecting those energy demands into the future. LEAP also offers energy supply optimization features that can be used to estimate lowest-cost solutions for meeting projected demands. Additional detailed information on the model can be found on the LEAP website.[3]

For this analysis, LEAP was used to construct a model of Vermont's energy system and GHG emissions. The Vermont model comprises a bottom-up simulation of energy demand, energy supply, and associated GHG emissions in all sectors of the economy in Vermont, as well as summary projections on non-energy GHG emissions. The model provides the basis for developing long-range mitigation scenarios; scenarios that are indicative of the level of required deployment for key technologies, and which help the state to understand the consequences of different options for reducing GHG emissions. It is an analytical tool that estimates the self-consistent impact of different choices on the energy system, often using basic (though detailed) energy, emissions, and cost accounting. The model does not prescribe a single scenario or set of directives that state policymakers should follow, but instead helps to answer policymakers' "what if?" questions by comparing costs, emissions, or other impacts across a range of different input assumptions.

The model's time period spans the years 2015 to 2050, beginning with five years of historical data before projections are applied and different scenarios diverge. Beginning in 2020, the model was used to examine four different possible scenarios: a BAU scenario in which past trends continue into the future, and three mitigation scenarios that draw on combinations of low-emission technologies and options to meet Vermont's 2025, 2030, and 2050 reduction goals.

[3] Stockholm Environment Institute. LEAP: Introduction. https://leap.sei.org/default.asp?action=introduction.

The remainder of this section describes the methods, data sources, and input assumptions used to construct the model, beginning with its core BAU scenario. Methods are arranged by major energy sectors or GHG emissions sources.

b. Business-as-Usual Scenario

Any assessment of future scenarios includes one or more "baseline" scenarios, which function as a counterfactual to other policy scenarios that are included in the assessment. In GHG mitigation analysis, the baseline scenario is often used to show the consequences of not implementing mitigation options. Without a suitable baseline to compare to, it can be difficult to express the impact of a mitigation option (or collection of mitigation options) on emissions or costs. The Vermont LEAP model includes one baseline scenario, named the BAU Scenario. The BAU Scenario is designed to show the projected annual GHG emissions under currently implemented policies and programs, implementation of regulations that are final but not yet fully implemented, and where possible, to extrapolate trends observed in recent historical data.

Many BAU assumptions depend directly on historical data. As a result, information is given in this section about major sources of historical data, how these data are arranged in the model, as well as how historical data are projected in the model's BAU Scenario.

i. Residential Fuel Use

Fundamentally, final energy consumption for residential buildings is calculated as the product of the number of households and the annual energy use per household. In the Vermont model, each of these quantities is highly disaggregated to represent several different categories of residential buildings in Vermont, while reflecting the different energy use characteristics and energy-consuming technologies found in each category. This method of accounting is commonplace in energy analysis, and is usually referred to as *activity analysis*, where final energy consumption is calculated by multiplying an activity (e.g., households), by an intensity (e.g., energy use per household), before being summed across activity categories.

Residential building types represented in the model are divided among 60 different possible building types, resulting from four different categories or tiers. Each building characteristic within each of the four categories is listed in *Table 1*.

Table 1 – Categorization of Building Types in the LEAP Model

Geography	Household Type	Tenure	Building Shell Weatherization
Urban Rural	Mobile Home Single-Family Detached Single-Family Attached Apartments of 2 - 4 Units Apartments of 5 or More Units	Owned Rented	Constructed in 2015 or Earlier Constructed in 2015 or Earlier, with Shell Retrofit Constructed after 2015

The share of all households that belong within each category is derived from U.S. Energy Information Administration's (EIA's) 2016 Residential Energy Consumption Survey (RECS).[4] Within each possible household type, energy-consuming technologies are arranged into 16 end-uses: 5 major end-uses including space heating, space cooling, water heating, cooking, refrigeration, and 11 other end-uses including lighting, dishwashing, fans, and others. Shares of each technology that are used within each end-use are derived from RECS and from Vermont's Residential Market Assessment.[5] The total number of housing units through the year 2019 is taken from the U.S. Census Bureau,[6] and is assumed to change in lockstep with the state population thereafter, holding the average household size constant. Total state population projected as the sum of county-level population forecasts, is borrowed from UVM TRC.[7] The resulting household forecast shows a gradual increase in the number of households of 0.1% per year through 2050, presented in Figure 1 disaggregated by household type.

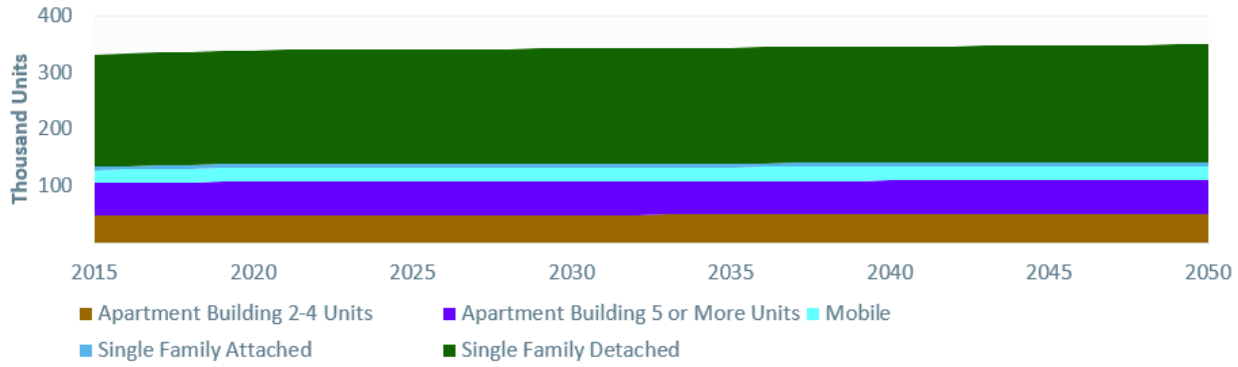
[4] U.S. Energy Information Administration (2016). 2015 Residential Energy Consumption Survey (RECS). https://www.eia.gov/consumption/residential/.

[5] NMR Group, Inc., DNV GL, Conant, D. and Energy Futures Group (2018). Vermont Multifamily Baseline On-Site Report; NMR Group, Inc., Conant, D. and Energy Futures Group (2017). Vermont Residential New Construction Baseline Study Analysis of On-Site Audits: Draft Report; NMR Group, Inc., DNV GL, Conant, D. and Energy Futures Group (2017). Vermont Single-Family Existing Homes On-Site Report.

[6] U.S. Census Bureau, Population Division (2019). Annual Estimates of Housing Units for the United States, Regions, and States: April 1, 2010, to July 1, 2019 (NST-EST2019-ANNHU). https://www.census.gov/data/tables/time-series/demo/popest/2010s-total-housing-units.html.

[7] Sullivan, Jim. "Travel Demand Forecasts and Modeling for Comprehensive Energy Plan," April 6, 2021.

Figure 1 – Vermont Household Forecast by Housing Type



Final energy demand depends on the total number of households and energy-consuming devices, as well as the annual fuel requirements per household or per device. Wood and pellet stove combustion efficiencies are informed by research undertaken by NESCAUM,[8] while annual energy requirements for all other technologies and end-uses are estimated from RECS and Vermont's Residential Market Assessment. Finally, all energy intensities (energy use per household for a given technology in a given housing category) are adjusted so that the consumption of fuel in each household in years 2015-2019 matches the consumption recorded in the State Energy Data System (SEDS).[9] Total wood consumption is not well-represented in SEDS because of the large amount of informally collected cordwood used for heating. As a result, wood and pellet consumption for historical years is adjusted to match that shown in Vermont's Residential Fuel Assessment,[10] instead of SEDS.

To project future residential energy consumption, total households are assumed to increase through 2050 at the same rate as population change. Population growth assumptions are based on projections published by the University of Vermont's Transportation Research Center.[11] As total population changes, the relative share of each household geography, type, and tenure are held constant in all years. At the same time, a number of other changes affect the mix of energy-consuming technologies and their energy intensities or efficiencies. In the BAU, these changes include expected energy savings estimated by Efficiency Vermont for water heating, cooking, and other small electrical end-uses.[12] Building shell retrofits from Efficiency Vermont[13] and Vermont Gas Systems[14] are also reflected, alongside projected building shell improvements for

[8] Rector, Lisa. "EFs for Wood Combustion," April 17, 2021. Personal communication.
[9] U.S. Vermont Department of Forests, Parks & Recreation and University of New Hampshire Survey Center (2019). Vermont Residential Fuel Assessment for the 2018-2019 Heating Season; and U.S. Energy Information Administration (2020). State Energy Data System. https://www.eia.gov/state/seds/.
[10] Vermont Department of Forests, Parks & Recreation and University of New Hampshire Survey Center (2019). Vermont Residential Fuel Assessment for the 2018-2019 Heating Season. https://fpr.vermont.gov/sites/fpr/files/Forest_and_Forestry/Wood_Biomass_Energy/Library/2019%20VT%20Residential%20Fuel%20Assessment%20Report%20FINAL.pdf.
[11] Sullivan, J. (2021). Travel Demand Forecasts and Modeling for Comprehensive Energy Plan.
[12] Efficiency Vermont (2021). Efficiency Vermont Demand Resource Plan Annual Savings by End-Use (Revised 4-17-21).
[13] Efficiency Vermont (2020). Letter to Vermont Public Utility Commission Re: Case No. 19-2956-INV - Investigation Pursuant to Act 62, Response to Commission Information Request.
[14] Vermont Gas Systems (2021). Wx Projection VGS.

new construction provided by the Vermont Public Service Department (PSD).[15] Changes to the number of heating and cooling degree-days are taken from Northeast Regional Climate Center forecasts,[16] which are assumed to decrease heating loads and increase cooling loads. Meanwhile, the mix of space conditioning technologies used within existing, retrofitted, and new households is adjusted to align with the Vermont Electric Power Company's (VELCO) heat pump forecast ("low" variant).[17] The forecast calls for a total number of new heat pumps to be introduced into Vermont's households. From this forecast, SEI estimated a total share of heating load served by heat pumps assuming that each device represented in the forecast meets an average of 40% of a household's heating needs, similar to the heating load that would be met by a single-head mini-split heat pump. The resulting heating load displaces all alternative technologies, including natural gas, oil, propane, wood, and pellet technologies, in proportion to their estimated shares in each residential building category. Displaced furnaces (natural gas, oil, and propane) are replaced with central ducted air-source heat pumps (ASHPs). Half of the remaining heating load met by heat pumps is met using two-head (ductless) mini-split ASHPs. The remainder of the heat pump load is met primarily by single-head mini-split ASHPs and a small number of ground-source heat pumps. Because central ducted and two-head mini-split ASHPs can each meet more than 40% of a home's heating needs (100% and 66%, respectively, based on guidance from Energy Futures Group[18]), this assumption results in a lower absolute number of heat pump devices in the BAU Scenario than is represented in VELCO's "low" forecast. The VELCO forecast can be extrapolated to approximately 217,000 residential heat pumps installed by 2050 based on SEI's calculations, whereas the Vermont LEAP model assumptions yield 127,000 installations.

Penetration levels and energy-consuming characteristics for all other residential technologies, unless mentioned specifically in this section, are held constant in the BAU Scenario. For these technologies and end-uses, forecasted energy demand depends solely on the number of housing units projected in each year.

Total GHG emissions are estimated by multiplying energy consumption by the appropriate emission factor for that each fuel, sector, technology, or end-use, as appropriate. Emission factors used to estimate residential GHG emissions are obtained from the Environmental Protection Agency's (EPA's) State Inventory Tool (SIT).[19]

ii. Commercial Fuel Use

Like the residential sector, final energy consumption for commercial buildings in Vermont is estimated using the activity analysis accounting practice. For the commercial sector, final energy

[15] Picotte, P. (2021). Residential New Construction Savings.
[16] Heating and cooling degree days (historical and forecast) for Vermont are taken from the Northeast Regional Climate Center. Modeled values in the future are taken from the RCP 4.5 Pathway. "Climate Data Grapher." New York Climate Change Science Clearinghouse, 2018. https://nyclimatescience.org/datagrapher/?c=Temp/state/maxt/ANN/NY/. Accessed May 25, 2021.
[17] Itron, Inc. "2020 Long-Term Electric Energy and Demand Forecast Report." Vermont Electric Power Company, September 18, 2020. Underlying data and assumption supplied by Vermont PSD in a February 16, 2021 email to SEI, "VT Statewide CCHP forecast and AC Baseline 11042019.xlsx," and Murphy, Barry. "Heat Pumps - Total Installed", email April 2, 2021.
[18] Hill, David. "Building Sector Mods," September 16, 2021.
[19] U.S. Environmental Protection Agency. State Inventory and Projection Tool, 2020. https://www.epa.gov/statelocalenergy/state-inventory-and-projection-tool.

consumption for commercial buildings is the product of commercial floorspace and the annual energy use per square foot. Unlike the residential sector, in the commercial sector no differentiation is made among commercial buildings of different types. Energy-consuming technologies are arranged into 10 end-uses: space heating, space cooling, water heating, and cooking, with 5 electric end-uses for lighting, ventilation, refrigeration, office equipment, and computing. One miscellaneous end-use is used to represent collective fuel consumption for all other smaller end-uses. Shares of floorspace that use each technology within each end-use are derived from EIA's 2012 Commercial Buildings Energy Consumption Survey (CBECS)[20] and Vermont's Business Sector Market Characterization and Assessment Study[21] (giving priority to the latter, which better represents the mix of technologies used in Vermont's commercial building stock). Separate shares are calculated for space heating and cooling technologies in four different floorspace categories. These categories represent a) buildings that were constructed prior to 2007 without any improvements made to their building shells or heating and cooling equipment; b) buildings constructed prior to 2007 with improved heating equipment; c) buildings constructed prior to 2007 with improved shell (weatherization) characteristics; and d) buildings constructed prior to 2007 with both improved heating equipment and shell characteristics, or, buildings constructed after 2007. The total amount of commercial floorspace in Vermont is estimated by multiplying New England's commercial floorspace (as estimated by EIA, provided to the modeling team by personal communication[22]) by the share of Vermont's gross domestic product among all New England states.[23]

Final energy demand depends on the number of commercial square feet occupied by a particular technology, and the energy use (or energy intensity) per square foot for that technology. For each fuel within a particular end-use, energy use per square foot is estimated from CBECS. However, many fuels are consumed by more than one different technology in a single end-use; this is especially true for space heating, where natural gas is consumed in boilers, furnaces, and packaged units. Therefore the energy intensity for each technology is calculated using both the total fuel use per square foot from CBECS, and the ratio of energy efficiencies for specific technologies used for space heating, cooling, water heating, and cooking, taken from equipment efficiency assumptions used by EIA for its National Energy Modeling System model.[24] Like in the residential sector, all energy intensities are adjusted so that the model-estimated consumption of each commercial fuel (except wood) in years 2015-2019 matches the consumption recorded in

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[20] U.S. Energy Information Administration. "Commercial Buildings Energy Consumption Survey (CBECS): User's Guide to the 2012 CBECS Public Use Microdata File," August 2016. https://www.eia.gov/consumption/commercial/data/2012/pdf/user_guide_public_use_aug2016.pdf.

[21] The Cadmus Group. "2016 Vermont Business Sector Market Characterization and Assessment Study." Vermont Public Service Department, April 30, 2017.

[22] Jarzomski, Kevin. "AEO2020 National Energy Modeling System Run Ref2020d112119a," March 29, 2021.

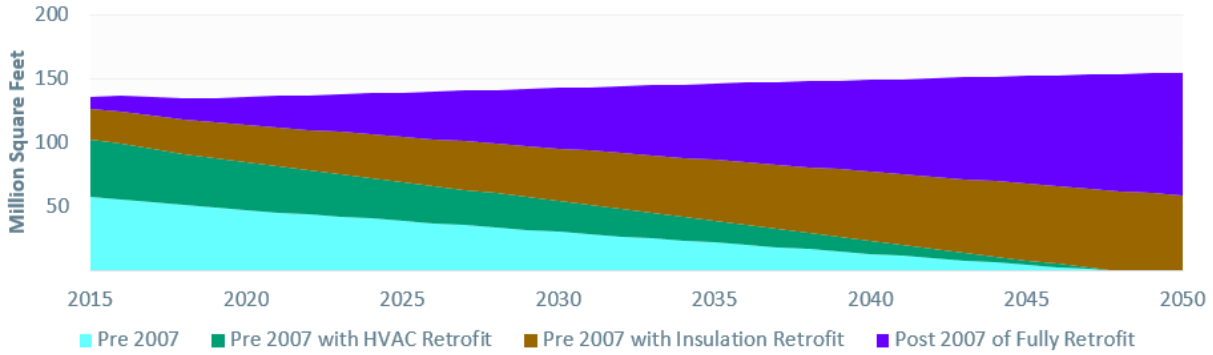
[23] U.S. Bureau of Economic Analysis. "SAGDP1 Gross Domestic Product (GDP) summary, annual by state," October 2, 2020. https://apps.bea.gov/iTable/iTable.cfm?reqid=70&step=30&isuri=1&major_area=0&area=50000&year=-1&tableid=531&category=1531&area_type=0&year_end=-1&classification=non-USindustry&state=0&statistic=-1&yearbegin=-1&unit_of_measure=levels.

[24] Navigant Consulting. "Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, Appendix A," June 2018. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf.

SEDS for Vermont.[25] Total commercial wood fuel consumption is estimated by scaling commercial wood consumption shown in SEDS by the ratio of residential wood consumption in SEDS to residential wood consumption from Vermont's Residential Fuel Assessment.[26] No wood fuel assessment exists for the commercial sector, so the modeling team assumed that a similar systematic difference might exist between SEDS and the state's own data.

To project future commercial energy consumption, total floorspace was assumed to increase at the same rate as New England's total floorspace through 2050. The increase in New England's total floorspace relied on assumptions in the Annual Energy Outlook (AEO) 2020 detailed results, which estimates both newly-added and surviving floorspace in each year.[27] Using these forecasts, the percentage of floorspace in each of the four commercial building categories, and assuming that retrofitted buildings built before 2007 are the first to retire, SEI constructed the estimate shown in Figure 2 for the number of square feet in each building category in each year.

Figure 2 – Commercial Floorspace in Each Building Category



* Building category labels refer to construction year (ex. "Pre 2007" are buildings constructed before 2007).

Among space heating technologies, the Business-as-Usual scenario reflects the number of heat pumps in the VELCO heat pump forecast ("low" variant), assuming that 10% of the devices are installed in commercial buildings.[28] SEI estimates that one representative device described in VELCO's forecast would serve 512 square feet of commercial floorspace, which is subtracted proportionally from floorspace heated by natural gas, oil, and propane heating technologies. Space cooling provided by the newly introduced heat pumps is purely additional; it does not

[25] Vermont Department of Forests, Parks & Recreation and University of New Hampshire Survey Center (2019). Vermont Residential Fuel Assessment for the 2018-2019 Heating Season; and U.S. Energy Information Administration (2020). State Energy Data System. https://www.eia.gov/state/seds/.
[26] Vermont Department of Forests, Parks & Recreation and University of New Hampshire Survey Center (2019). Vermont Residential Fuel Assessment for the 2018-2019 Heating Season. https://fpr.vermont.gov/sites/fpr/files/Forest_and_Forestry/Wood_Biomass_Energy/Library/2019%20VT%20Residential%20Fuel%20Assessment%20Report%20FINAL.pdf.
[27] Jarzomski, Kevin. "AEO2020 National Energy Modeling System Run Ref2020d112119a," March 29, 2021.
[28] Itron, Inc. "2020 Long-Term Electric Energy and Demand Forecast Report." Vermont Electric Power Company, September 18, 2020. Underlying data and assumption supplied by Vermont PSD in a February 16, 2021 email to SEI, "VT Statewide CCHP forecast and AC Baseline 11042019.xlsx," and Murphy, Barry. "Heat Pumps - Total Installed," email April 2, 2021.

displace any preexisting cooling technology. Energy savings in thermal fuels from planned Efficiency Vermont programs are represented as reductions in total fuel consumption, because their origin (whether from weatherization, technology improvement, or fuel-switching) was not specified alongside the efficiency forecast. Efficiency Vermont estimates do not distinguish propane and heating oil among thermal fuels, so SEI assumed that savings in propane comprised 75% of the thermal energy savings from the efficiency forecast, with the remainder being heating oil. Energy savings in natural gas are derived from Vermont Gas Systems' (VGS) Demand Resource Plan,[29] but like thermal fuels, these savings are included only as reductions in total fuel consumption because the origin of the reductions is not provided by VGS.

Outside of the space heating end-use, shares of technologies are generally held constant, but energy use per square foot varies according to existing forecasts provided to the modeling team. Energy intensities for oil, propane, and natural gas water heating decline at an average annual rate that achieves, and then extends, the energy savings for these fuels that are forecasted by Efficiency Vermont for 2030 provided to SEI by PSD. Electric energy intensities for ventilation, hot water, cooking, refrigeration, office equipment, and miscellaneous uses are assumed to decline at the same average annual rate used by VELCO, provided to SEI by PSD. All commercial lighting is assumed to be switched to efficient LEDs by 2050, which achieves part (though not all, and SEI does not make any further adjustments) of the lighting efficiency forecasted by VELCO.

Emission factors used to estimate commercial GHG emissions are obtained from EPA's SIT.

iii. Industrial Fuel Use

Little structural information about industrial energy consumption in Vermont was available to the modeling team. As a result, the model's representation of industrial energy use is considerably simpler than other consumption sectors.

Historical fuel consumption for the industrial sector is taken directly from the EIA's SEDS. Beginning in 2020, consumption of each fuel follows the 2019-2050 average growth rate for that fuel taken from the EIA's AEO 2020 Reference Case.[30] The Vermont PSD provided the modeling team with savings in electricity use as well as thermal fuel consumption from Efficiency Vermont forecasts, with the latter allocated proportionally among all liquid fuels consumed in the industrial sector. Efficiency in natural gas consumption is also represented, from VGS' Demand Resource Plan.[31]

Emission factors used to estimate industrial GHG emissions are obtained from EPA's SIT.

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[29] Vermont Public Utility Commission. "Order Approving 2021-2023 Demand Resource Plan for Vermont Gas Systems, Inc.," October 22, 2020.
[30] U.S. Energy Information Administration. "Annual Energy Outlook 2020," 2020. https://www.eia.gov/outlooks/aeo/.
[31] Vermont Public Utility Commission. "Order Approving 2021-2023 Demand Resource Plan for Vermont Gas Systems, Inc.," October 22, 2020.

iv. Transportation Fuel Use

Historically, the transportation sector has been the largest source of GHG emissions in Vermont, accounting for approximately 40% of gross emissions.[32] Because the majority of these GHG emissions come from on-road cars and trucks, the model contains a detailed stock turnover simulation of vehicle energy use in which energy consumption is the product of the number of vehicles, annual VMT, and fuel use per mile. Each of these quantities varies by vehicle type and age. The set of vehicle technologies represented in the model for each weight class are displayed in Table 2.

Table 2 – Categorization of On-Road Vehicle Technologies Represented in the LEAP Model

Weight Class	Vehicle Technology
Passenger Cars	Gasoline Battery Electric with 100-mile Range (EV A) Battery Electric with 200-mile Range (EV B) Battery Electric with 300-mile Range (EV C) E85 Flex Fuel Diesel Compressed Natural Gas (CNG) Gasoline Hybrid Electric Diesel Hybrid Electric Gasoline Plug-In Hybrid Electric with 10-mile Electric Range (PHEV A) Gasoline Plug-In Hybrid Electric with 40-mile Electric Range (PHEV B)
Light Trucks	Gasoline Battery Electric with 100-mile Range (EV A) Battery Electric with 200-mile Range (EV B) Battery Electric with 300-mile Range (EV C)

[32] Vermont Department of Environmental Conservation, Agency of Natural Resources. Vermont Greenhouse Gas Emissions Inventory and Forecast: 1990 – 2017. May 2021. https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2017_Final.pdf.

	E85 Flex Fuel Diesel Compressed Natural Gas (CNG) Gasoline Hybrid Electric Diesel Hybrid Electric Gasoline Plug-In Hybrid Electric with 10-mile Electric Range (PHEV A) Gasoline Plug-In Hybrid Electric with 40-mile Electric Range (PHEV B) Natural Gas Fuel Cell
Medium Duty	Gasoline Diesel Liquefied Petroleum Gas (LPG) E85 Flex Fuel Battery Electric Diesel PHEV Gasoline PHEV Natural Gas Fuel Cell
Heavy Duty	Single Unit Conventional Single Unit Liquefied Natural Gas (LNG) Single Unit Diesel PHEV Single Unit Gasoline PHEV Combination Diesel Combination LNG Combination EV Combination Natural Gas Fuel Cell

Energy consumption in each future year depends on the characteristics of remaining vehicles from prior years, as well as those of newly sold vehicles in that year. Historical vehicle stocks are estimated by combining recent vehicle registrations (from mid-2020, which for simplicity SEI interprets as registrations for the entire 2019 year) from Vermont's Department of Motor Vehicles registration database,[33] supplemented with vehicle stocks in earlier years from the U.S. Federal Highway Administration (FHWA)[34] forms MV-1 and MV-9. Additionally, numbers of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) in past years are provided by UVM TRC.[35] The vehicle categories in Table 2 are selected for their compatibility with Argonne National Laboratory's VISION 2020 model,[36] which also provided the distribution of ages at which a vehicle retires, and the age profile of vehicles in the existing fleet.

The VISION 2020 model also provided a forecast of annual new vehicle sales nationally for each technology, which reflects projections from EIA's AEO 2020 Reference Case. The modeling team downscaled this forecast to Vermont by multiplying by the ratio of vehicle stocks in Vermont to vehicle stocks nationally, calculated separately for each of the four weight classes represented in the model. SEI then adjusted the share of EV sales (both BEV and PHEV technologies) within passenger car and light truck categories, while maintaining the total light-duty vehicle (LDV) sales forecast, to achieve an EV penetration target of 35% among all LDVs by the year 2050. The modeling team selected this target for the Business-as-Usual Scenario because of its alignment with the "low" EV forecast used in VELCO's integrated resource plan.[37] In medium- and heavy-duty (MHD) vehicle classes, sales of EVs, PHEVs, and fuel cell vehicles are adjusted to reach, in aggregate, 30% of sales by 2030, consistent with the Multi-State Medium- and Heavy-Duty Zero Emission Vehicle Memorandum of Understanding.[38] Technology shares of new vehicle sales within each weight class are key input assumptions to the road transportation module, and are displayed in the following chart series.

[33] Smythe, Collin. "DMV Registration Data," March 22, 2021.
[34] Office of Highway Policy Information. "Highway Statistics 2019." U.S. Department of Transportation Federal Highway Administration, October 1, 2020. https://www.fhwa.dot.gov/policyinformation/statistics/2019/.
[35] Dowds, Jonathan. "2019 Vermont Transportation Energy Profile." The Vermont Transportation Energy Profile. UVM Transportation Research Center, November 2019.
[36] Argonne National Laboratory. VISION Model AEO 2020 Base Case, 2020. https://www.anl.gov/es/vision-model.
[37] Roberts, David. "Memorandum: Electric Vehicle Forecasts for VELCO Long Range Plan 2020 Update." VEIC, June 19, 2020.
[38] State of California, State of Colorado, State of Connecticut, District of Colombia, State of Hawaii, State of Maine, State of Maryland, et al. "Multi-State Medium- and Heavy-Duty Zero Emission Vehicle Memorandum of Understanding," July 14, 2020. https://www.nescaum.org/documents/multistate-truck-zev-governors-mou-20200714.pdf/.

Figure 3 – Passenger Car Sales Shares in BAU Scenario

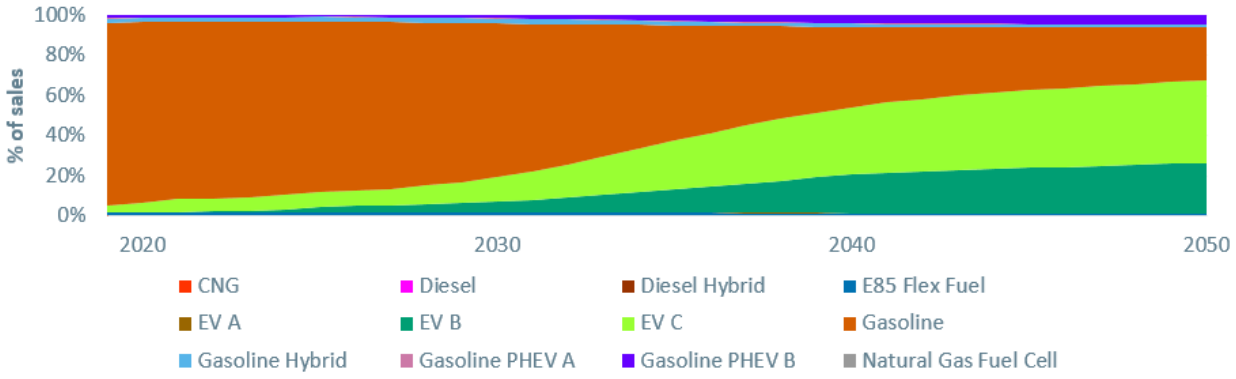


Figure 4 – Light Truck Sales Shares in BAU Scenario

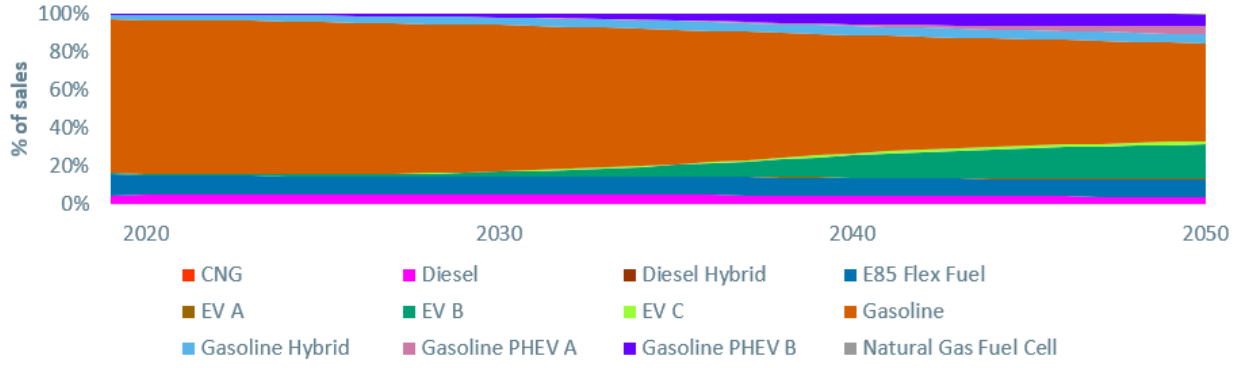


Figure 5 – Medium Duty Vehicle Sales Shares in BAU Scenario

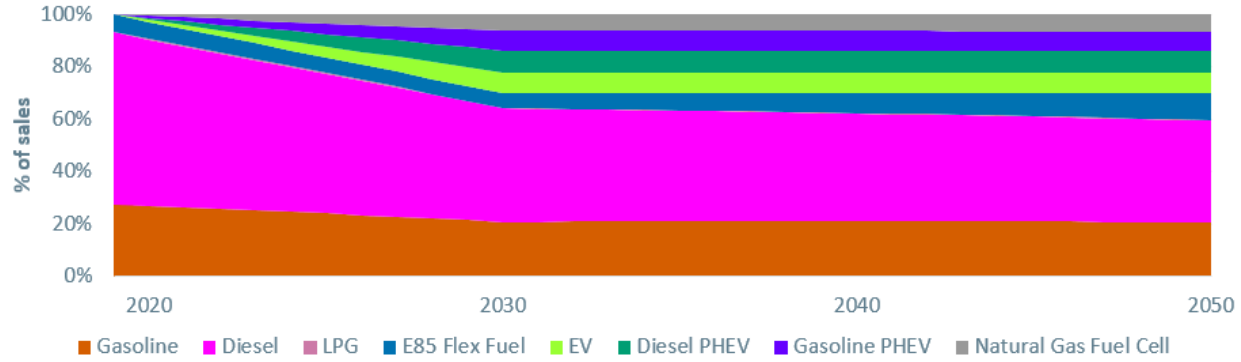
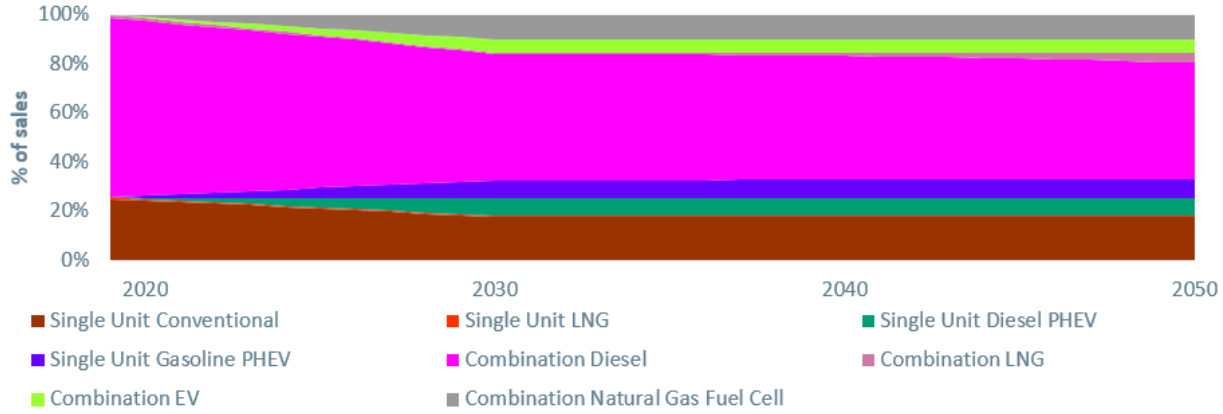


Figure 6 – Heavy Duty Vehicle Sales Shares in BAU Scenario



The annual distance traveled by vehicles of each technology is adopted from VISION 2020, and subsequently calibrated to align with Vermont's historical VMT in each vehicle class from FHWA, as reproduced by UVM TRC.[39] Future VMT is a function of vehicle sales, and SEI introduces an adjustment to align forecasted VMT decadal projections provided by UVM TRC.[40] The final ingredient in forecasting energy consumption is vehicle fuel economy, which is also extracted from VISION 2020 for vehicles sold in historical and future years.

Historical energy demand from non-road transport is estimated from SEDS. While SEDS does not provide subsectoral information within the transportation sector, this is estimated by using the share of energy consumed for air, rail, navigation, and other uses observed in the first year of the AEO 2020 Reference Case.[41] Fuel consumption in SEDS that is not assigned to non-road uses is used to calibrate historical on-road fuel economy, ensuring that total transport energy in years prior to 2020 aligns with SEDS records. In the BAU Scenario, non-road energy consumption per capita is held constant so that total non-road energy consumption grows at the rate of population increase.

Greenhouse gas emission factors for on-road vehicles come from EPA's SIT and Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model.[42]

v. Electricity Supply

Vermont participates in a regional electricity grid managed by Independent System Operator - New England (ISO-NE). Electricity consumed in Vermont may come from generators located

[39] Dowds, Jonathan. "2019 Vermont Transportation Energy Profile." The Vermont Transportation Energy Profile. UVM Transportation Research Center, November 2019.
[40] Sullivan, Jim. "Technical Memo: Vermont Statewide VMT Estimate and Forecasts." UVM Transportation Research Center, April 26, 2019.
[41] U.S. Energy Information Administration. "Annual Energy Outlook 2020," 2020. https://www.eia.gov/outlooks/aeo/.
[42] Wang, Michael, Elgowainy, Amgad, Lee, Uisung, Bafana, Adarsh, Benavides, Pahola, Burnham, Andrew, Cai, Hao, et al. Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model ® (2020 Excel). Argonne National Laboratory (ANL), Argonne, IL (United States), 2020. https://doi.org/10.11578/GREET-EXCEL-2020/DC.20200912.1.

within the state or connected to the rest of the New England grid, which has interties with neighboring grids in New Brunswick, Quebec, and New York. Vermont's electric utilities procure energy through a mix of purchasing mechanisms, which include bilateral contracts with generators, but other electricity may also be purchased from the average grid-wide resource mix, which differs from the contracted generation mix. Correctly estimating Vermont's true "consumption-based" electricity emissions[43] requires forecasting both of these; simply simulating the entire ISO-NE grid would disregard Vermont's purchase contracts, while focusing only on its purchase contracts fails to account for changes in the grid-wide mix.

Complicating this picture, in reality Vermont utilities may purchase RECs unbundled from the renewable electricity with which the REC is associated. In the extreme, utilities could retire sufficient RECs to match 100% of the electricity consumed in the state, even if the electricity was produced by combusting fossil fuels. To address this, the modeling team makes a simplifying assumption that all RECs are bundled together with their renewable megawatt-hours, and that no unbundled RECs are bought or sold by Vermont's utilities and generators. From a strictly modeling perspective, this means that Vermont's renewable electricity requirements (either its current renewable portfolio standard (RPS) or renewable targets explored in forward-looking scenarios) can only be met using the renewable content of grid electricity together with renewable energy from Vermont's purchase contracts. The model does not include any specific representation of REC trading that is separate from the production of electricity to meet Vermont's needs.

Fundamentally, the electricity sector representation within the Vermont LEAP model is a representation of the whole New England grid, downscaled to meet Vermont's electricity requirements. It includes a representation of all generating capacity across the ISO-NE region, with individual plant capacities grouped by generating technology and according to whether the plant is located inside or outside Vermont. For convenience, these technological and geographical plant groupings are called "processes" in this report. A list of the model's generating processes is provided in Table 3 (note that not all processes are used in all scenarios).

Table 3 – List of LEAP Model Generating Processes

Geographic Location	**Technology**
Vermont	Wood, Wood Waste Biomass
	Conventional Hydroelectric
	Petroleum Liquids

[43] Consumption-based emissions accounting should not be confused with lifecycle accounting or embodied emissions.

	Onshore Wind Turbine
	Landfill Gas
	Utility-Scale Solar Photovoltaic
	Batteries
	Vehicle-to-Grid Batteries
	Behind-the-Meter Photovoltaic*
	Farm and Food Waste Digestion
Remainder of ISO-NE, outside Vermont	Conventional Hydroelectric
	Hydroelectric Pumped Storage
	Petroleum Liquids
	Natural Gas Steam Turbine
	Nuclear
	Conventional Steam Coal
	Natural Gas Fired Combined Cycle
	Batteries
	Natural Gas Fired Combustion Turbine
	Natural Gas Internal Combustion Engine
	Wood, Wood Waste Biomass

	Utility-Scale Solar Photovoltaic
	Onshore Wind Turbine
	Municipal Solid Waste
	Landfill Gas
	Other Waste Biomass
	Natural Gas Fuel Cell
	Offshore Wind Turbine
	Behind-the-Meter Photovoltaic*
	All Other (primarily tire-derived fuels)
Quebec	Imports
New Brunswick	Imports
New York	Imports

* Behind-the-meter solar is treated as a supply resource in the model, and not a load reducer.

The model then simulates how that capacity may be dispatched to satisfy energy needs during a number of dispatch periods. If the grid's full capacity was available to meet Vermont's demand, then no new capacity would be required for decades, and the simulated resource mix would not reflect the true grid-wide mix. To address this, the modeling team applies a scaling multiplier to all capacities, which is equal to the ratio of Vermont's historical electricity sales with those of all New England states (about 4.7% in the most recent historical year), from SEDS.[44] In effect, this would allow the model to simulate the resource mix on the grid if all New England states followed the same demand patterns as are projected for Vermont.

Vermont's electricity consumption, however, is provided through a mix of both contracts and the system mix. As LEAP simulates electrical dispatch, it ensures that energy production for each process obeys that process' capacity limit, but after the model's capacity downscaling, this rule

[44] U.S. Energy Information Administration. "State Energy Data System," June 26, 2020. https://www.eia.gov/state/seds/.

could easily be violated for some energy purchase contracts. Addressing this means selectively uprating the model's capacity for some processes, to ensure enough capacity is available to fulfill Vermont utilities' purchase obligations. Although this was a necessary step towards accurately estimating Vermont's consumption-based electricity emissions, it (as well as the earlier scaling multiplier) does cloud the interpretation of a process' generating capacity, in the context of this model.

Existing and planned capacity for each process, in megawatts, is derived from individual power plant data in EIA Form 860,[45] supplemented with Vermont's Standard Offer Program[46] and the ISO-NE BTM Forecast.[47] Where a retirement year is scheduled in EIA-860, the retired capacity is removed from the model in that year; otherwise, plant retirements are estimated by adding assumed years of plant lifetime to a plant's commissioning year. The set of feedstock fuels and their shares consumed within each process, as well as historical electricity output and plant heat rate (efficiency) are derived from EIA Form 923.[48] To forecast future capacity additions and energy production (referred to as dispatch), LEAP uses embedded optimization software called the Next Energy Modeling system for Optimization (NEMO).[49] NEMO performs capacity expansion and dispatch calculations simultaneously and for all years in a scenario, returning the mixture of capacities and energy production that yields the lowest present cost while obeying a number of key constraints.

The first constraint is that electricity demand is satisfied. All electricity consuming end-uses are assigned a load shape that is used to allocate annual electricity requirements into 192 pseudo-hourly dispatch periods (24 hours *x* [weekend vs. weekday] *x* 4 seasons). In the BAU Scenario, demand from heat pumps is allocated according to Figure 7 based on information provided to the modeling team.[50]

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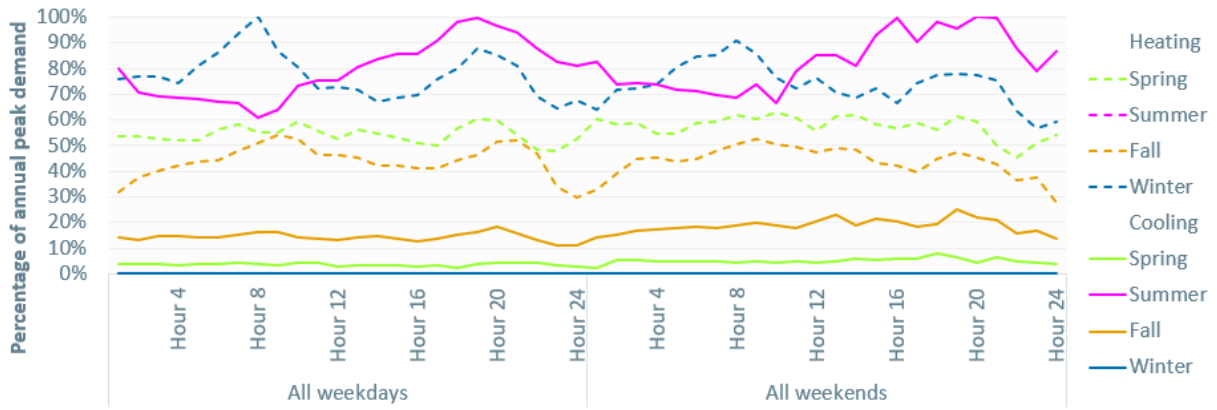
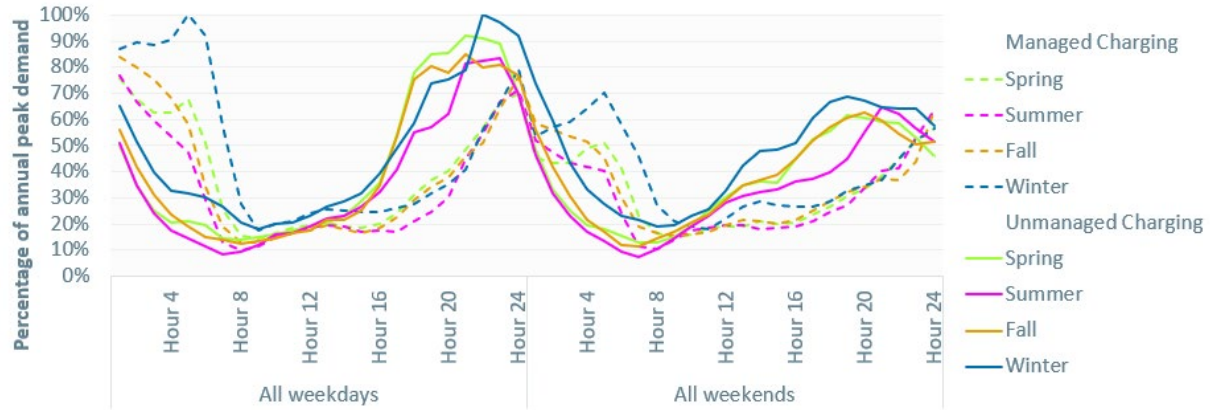
[45] U.S. Energy Information Administration. "Form EIA-860 Detailed Data," September 15, 2020. https://www.eia.gov/electricity/data/eia860/.
[46] VEPP Inc. "Standard Offer Program Developer Projects with Contracts." VEPP Inc., January 23, 2021. https://vermontstandardoffer.com/wp-content/uploads/2021/01/STANDARD-OFFER-PROJECTS-WITH-CONTRACTS-1.xlsx.
[47] ISO New England. "CELT Report: 2021-2030 Forecast Report of Capacity, Energy, Loads, and Transmission," May 1, 2021.
[48] U.S. Energy Information Administration. "Form EIA-923 Detailed Data with Previous Form Data (EIA-906/920)," February 18, 2021. https://www.eia.gov/electricity/data/eia923/.
[49] Veysey, Jason. *NEMO: Next Energy Modeling System for Optimization* (version 1.6.0), 2021.
[50] Hall, Frederick. "Load Shapes for Heat Pumps," July 21, 2021.

Figure 7 – Heat Pump Demand Profiles in the BAU Scenario



Electric vehicle charging is allocated according to Figure 8.[51] The chart includes both the unmanaged charging profile used in the BAU Scenario, as well as a managed charging profile derived from the Alternative Fuels Data Center's EVI-Pro Lite tool[52] used in later mitigation scenarios.

Figure 8 – EV Charging Profiles in the BAU Scenario



* Percentage of annual *energy demand* (not load) accounts for greater number of hours during weekdays, hence higher values.

All other electrical end-uses are assigned a load shape that is equal to the system-wide load curve for 2019, published by ISO-NE.[53] Although the system load would include vehicle charging and heat pump demand in that year, their penetration was assumed to be negligible compared to that projected in the model's scenarios. Total electricity requirements in each dispatch period are the

[51] Turk, Graham. "Load Shapes for (Managed) EV Charging," July 21, 2021.
[52] Alternative Fuels Data Center. "Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite," 2020. https://afdc.energy.gov/evi-pro-lite/load-profile/results?utf8=%E2%9C%93&load_profile%5Bstate%5D=VT&load_profile%5Burban_area%5D=Burlington&load_profile%5Bstate_name%5D=Vermont&load_profile%5Bfleet_size%.
[53] ISO New England. "System Loads in EEI Format," October 16, 2020. https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/sys-load-eei-fmt.

sum of demands from all electrical end-uses in that period, plus transmission and distribution loss, which is assumed to account for 8% of electricity generated.

Capacity that is represented in the model may be used to produce energy up to its rated availability, or capacity factor, in each dispatch period. Maximum capacity factors for non-intermittent processes were extracted from a variety of sources, including the Fifth Assessment Report,[54] the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline,[55] the International Energy Agency,[56] and the U.S. Department of Energy.[57] For intermittent or seasonal renewable energy sources, resource availability differs in each dispatch period, and is calculated from NREL's PVWatts tool,[58] the Wind Integration National Dataset,[59] and from historical hydroelectric production in EIA Form 923.[60]

The second constraint is that a minimum level of capacity adequacy is maintained. Called a reserve margin, this is the amount of additional capacity that must be installed beyond what would reliably be able to meet demand during peak times. Reserve margins are typically expressed as a percentage of peak load, and in the Vermont LEAP model, SEI calculated this value to be 10.1% based on ISO-NE's calculation method.[61,62,63] Capacity is eligible to meet the reserve margin, using qualified capacity values calculated from ISO-NE's Fifteenth Forward Capacity Auction for each process represented in the model. As capacity retires or electricity requirements (and with it, peak load) increase, the reserve margin becomes smaller, triggering the software to add new capacity, including battery storage, to maintain the margin above its required threshold. The amount of new capacity for any one process that can be added each year is itself a separate constraint, and SEI has estimated values based on the largest historical additions in the last 10 years, or based on large planned projects. No new nuclear or coal-fired capacity is permitted in the model, and a maximum of 450 MW of onshore wind may be installed in Vermont by 2050 (though the model-represented value is less, due to the downscaling procedure described earlier).

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[54] Schlömer et al. "Annex III: Technology-Specific Cost and Performance Parameters." In Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, 2014.
[55] National Renewable Energy Laboratory. "2020 Annual Technology Baseline" (version 2020), 2020. https://atb.nrel.gov/electricity/2020/index.php.
[56] International Energy Agency, and Nuclear Energy Agency. "Projected Costs of Generating Electricity: 2015 Edition." OECD, 2015.
[57] U.S. Department of Energy. "3.4 Fuel Cells." Multi-Year Research, Development, and Demonstration Plan, 2016. https://www.energy.gov/sites/prod/files/2016/06/f32/fcto_myrdd_fuel_cells_0.pdf.
[58] National Renewable Energy Laboratory. "PVWatts: Hourly PV Performance Data" (version 6.1.3), 2017. https://pvwatts.nrel.gov/pvwatts.php.
[59] Draxl, Caroline, Andrew Clifton, Bri-Mathias Hodge, and Jim McCaa. "The Wind Integration National Dataset (WIND) Toolkit." *Applied Energy* 151 (August 1, 2015): 355–66. https://doi.org/10.1016/j.apenergy.2015.03.121.
[60] U.S. Energy Information Administration. "Form EIA-923 Detailed Data with Previous Form Data (EIA-906/920)," February 18, 2021. https://www.eia.gov/electricity/data/eia923/.
[61] Wong, Peter. "Proposed Installed Capacity Requirement Related Values for the Fourteenth Forward Capacity Auction (FCA 14)." Presented at the Reliability Committee, Westborough MA, September 25, 2019.
[62] ISO New England. "Forward Capacity Auction Capacity Obligations from FCA15," February 18, 2021. https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx.
[63] SEI's calculation differs because energy efficiency and demand resources are not part of the electricity supply portion of the LEAP model and are therefore not assigned capacity values that would enter into ISO-NE's assessment of net installed capacity requirement and reserve margin.

Remaining constraints are that each process produces, at minimum, the amount of energy that would be required to fulfill existing purchase contracts, provided to the modeling team by PSD.[64] In the BAU Scenario, enough renewable electricity must be produced to meet Vermont's Tier I and II RPS, which reaches 75% of generation by 2032 and remains constant thereafter.

Like energy consumption sectors, GHG emissions associated with the electricity sector are estimated by multiplying input fuel consumption by an appropriate emission factor. Emission factors are derived using 2019 data from power plants across ISO-NE; they are calculated by aggregating total emissions for each GHG (from eGRID[65]) across all plants within each technology grouping, and dividing by total fuel consumption for the same grouping of plants (from EIA Form 923[66]). Note that these emissions factors are not guaranteed to be the same as those used by ANR to develop Vermont's GHG Inventory. In addition, the GHG Inventory's historical GHG emissions for Vermont's electricity consumption extend up to the year 2017,[67] while only the most recent electricity purchase contracts, which do not extend backwards to 2017, are represented in the model. These contracts are a key ingredient in the modeling team's assessment of consumption-based emissions, and so there is no reason that the model will faithfully reproduce historical electricity consumption emissions that are recorded in the state's GHG Inventory for years 2015-2017.

vi. Natural Gas Transmission and Distribution (Fossil Fuel Industry)

In Vermont's GHG inventory, the only fossil fuel industry activity is the transport of natural gas, through long-distance pipelines and local distribution networks. The model does not explicitly represent these pipelines, but it does account for their GHG impacts by assuming methane leakage. While the rate of gas leakage (and therefore methane emissions, because natural gas is primarily composed of methane) varies across natural gas transport infrastructure, SEI adopts an average methane emission rate per unit of natural gas delivered to consumers. The rate is calculated by dividing Vermont's historical fossil fuel industry emissions[68] by historical natural gas use for all final consumers (i.e., excluding electricity generation), and is held constant thereafter.

vii. Energy-Related GHG Emissions and Other Air Pollutants

Energy-related emissions estimates of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) are developed by multiplying the consumption of each fuel within each sector by an emission factor, appropriate for that fuel and sector (or technology) combination. Key sources of GHG emissions factors have been highlighted in each sector description. Total GHG emissions are then converted to carbon dioxide equivalent (CO_2e) using 100-year global warming

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[64] Fischer, Maria. "VT electric mix v2.xlsx," March 2021.
[65] U.S. Environmental Protection Agency. "Emissions & Generation Resource Integrated Database (EGRID) 2019," February 23, 2021. https://www.epa.gov/egrid/download-data.
[66] U.S. Energy Information Administration. "Form EIA-923 Detailed Data with Previous Form Data (EIA-906/920)," February 18, 2021. https://www.eia.gov/electricity/data/eia923/.
[67] Vermont Department of Environmental Conservation, Air Quality and Climate Division. "Vermont Greenhouse Gas Emissions Inventory and Forecast: 1990 – 2017," May 2021. https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2017_Final.pdf.
[68] Ibid.

potentials (GWPs) from the Intergovernmental Panel on Climate Change Fourth Assessment Report.[69]

Instead of CO_2, biofuels represented in the model (including biodiesel, ethanol, wood, wood pellets, wood waste solids, aviation biofuel, and biogas) emit biogenic CO_2 (CO_2B). This indicates that the carbon is of biogenic origin and is recirculated into new plant growth and soils as part of the Earth's carbon cycle, in contrast with fossil-based carbon from terrestrial carbon reservoirs. The model assigns a GWP value of zero to CO_2B, which means it is omitted from all calculations of CO_2e. The modeling team recognizes that a great deal of uncertainty is embedded in this assumption, and wishes to emphasize that both the ratio of CO_2 and CO_2B that are emitted from the combustion of biofuels, as well as the GWP value of CO_2B, are easily and freely modifiable within the model.

By assigning appropriate emission factors, fuel combustion activities are also used to estimate emissions of non-GHG air pollutants. The following table lists additional non-GHG pollutants that are represented in the model, and the extent to which they are included in each sector.

[69] Intergovernmental Panel on Climate Change, Fourth Assessment Report, September 2007, https://www.ipcc.ch/assessment-report/ar4/.

Table 4 – Non-GHG Pollutants Represented in the LEAP Model

Pollutant	Details of inclusion in model
Carbon monoxide (CO)	Included for all energy sectors and fuels
Nitrogen oxides (NO_2 or NO_x, depending on detail provided in source)	Included for all energy sectors and fuels
Sulfur dioxide (SO_2)	Included for all energy sectors and fuels
Particulate matter ($PM_{2.5}$)	Included for all energy sectors and fuels
Lead (Pb)	Included only for combustion of coal, oil, wood/wood waste, and municipal solid waste for electricity generation
Non-methane volatile organic compounds (NMVOCs)	Included for all energy sectors and fuels
Ozone (O_3)	Not included explicitly; both NO_x and NMVOC emissions included instead, which are precursors to ozone
Black carbon (BC)	Included for all liquid transport fuels, all fuels consumed in households, and all remaining wood and biomass combustion
All other toxics	Not included

Data sources for non-GHG emission factors are varied and require some judgment in cases where an emission factor for a specific fuel/sector/technology combination cannot easily be located. Major data sources include the EPA's AP-42 database,[70] eGRID,[71] Argonne National

[70] U.S. Environmental Protection Agency. "Web Factor Information Retrieval System (WebFIRE)," 2021. https://cfpub.epa.gov/webfire/.
[71] U.S. Environmental Protection Agency. "Emissions & Generation Resource Integrated Database (EGRID) 2019," February 23, 2021. https://www.epa.gov/egrid/download-data.

Laboratory's GREET software,[72] the European Environment Agency,[73] SEI's own research,[74] and NESCAUM research.[75]

viii. Non-Energy GHG Emissions: Land Use, Land-Use Change, and Forestry (LULUCF), Agriculture, Waste, Industrial Processes and Product Use

Historical non-energy GHG emissions are reproduced in the model using default data for Vermont, found in EPA's SIT.[76] In most cases, these default data yielded a close reproduction of Vermont's historical non-energy emissions. Where they did not (manure management and agricultural soils, both subsectors within agriculture), SEI introduced a calibration factor to align with the state's published GHG inventory[77] at the time of model construction, which covers historical emissions through the year 2016. In addition, SEI was directed to adjust total agriculture emissions in the year 2020 and beyond based on emerging research by Energy Futures Group and Cadmus' Carbon Budget Report (unpublished, forthcoming), which reduced the agriculture sector's emissions by approximately 50% compared to historical GHG Inventory values. Finally, the same forthcoming report proposes an adjustment to the historical LULUCF carbon sink, reducing the magnitude of the sink by approximately 50% compared with historical values shown in Vermont's GHG Inventory.

ix. Cross-Cutting Cost Assumptions

As a rule, cost information is included within the model for devices, sectors, or end-uses that are affected by different assumptions in different scenarios. For example, the penetration of different vehicle technologies changes from one scenario to the next, whereas (as the reader will see in the following sections) no separate scenario assumptions are made for water transport. An accurate cost comparison between any two scenarios would require information about the costs of different on-road vehicles, but not information about the costs of different boats. This level of detail in the model is sufficient for developing cost comparisons among scenarios, but not sufficient for estimating the cost of a single scenario (perhaps relative to an earlier reference year).

In this report, costs that are specific to individual mitigation options are listed in Section c), but other cost assumptions are used in several mitigation options, and form part of the bedrock data

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[72] Wang, Michael, Elgowainy, Amgad, Lee, Uisung, Bafana, Adarsh, Benavides, Pahola, Burnham, Andrew, Cai, Hao, et al. Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model ® (2020 Excel). Argonne National Laboratory (ANL), Argonne, IL (United States), 2020. https://doi.org/10.11578/GREET-EXCEL-2020/DC.20200912.1.

[73] European Environment Agency. "EMEP/EEA Air Pollutant Emission Inventory Guidebook - 2019." Collection - old style, 2019. https://www.eea.europa.eu/themes/air/air-pollution-sources-1/emep-eea-air-pollutant-emission-inventory-guidebook/emep.

[74] Stockholm Environment Institute. "Energy Sector Emissions Factors for Use in LEAP-IBC," September 11, 2019. https://www.energycommunity.org/documents/Combustion_EFs_LEAP_IBC.xlsx.

[75] Rector, Lisa. "EFs for Wood Combustion," April 17, 2021.

[76] U.S. Environmental Protection Agency. State Inventory and Projection Tool, 2020. https://www.epa.gov/statelocalenergy/state-inventory-and-projection-tool.

[77] Air Quality and Climate Division. "Vermont Greenhouse Gas Emissions Inventory and Forecast: Brief, 1990 – 2016." Vermont Department of Environmental Conservation, January 2020. https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_and_Forecast_1990-2016.pdf.

assumptions within the model. These "cross-cutting" cost assumptions are introduced in this section, alongside other information about the structure of the model and its BAU Scenario.

Fuel supply costs are an important part of the model's cost accounting. The model includes bottom-up modeling of electricity costs, while other fuels (whose production is not explicitly represented in the model) are assigned costs per unit of fuel consumed anywhere in the model. These costs are termed *delivered* because they are assumed to include all upstream production and transport costs. Figures 9 and 10 show the delivered cost assumptions used in the model for major fuels, merging historical data with projections.

Figure 9 – Delivered Costs for Major Biofuels

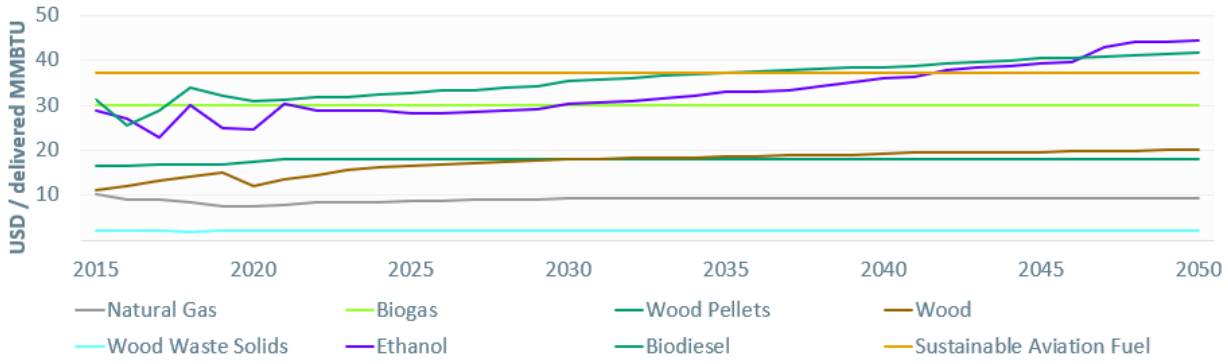
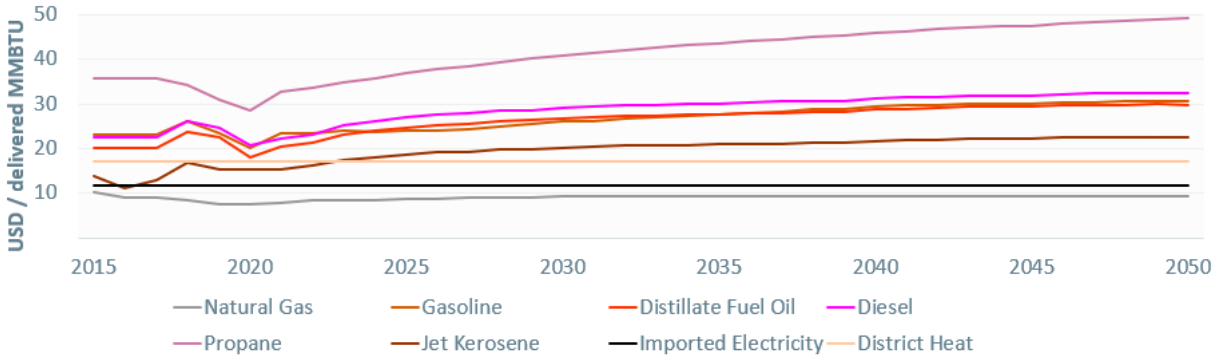


Figure 10 – Delivered Costs for Major Fossil Fuels, District Heat and Imported Electricity

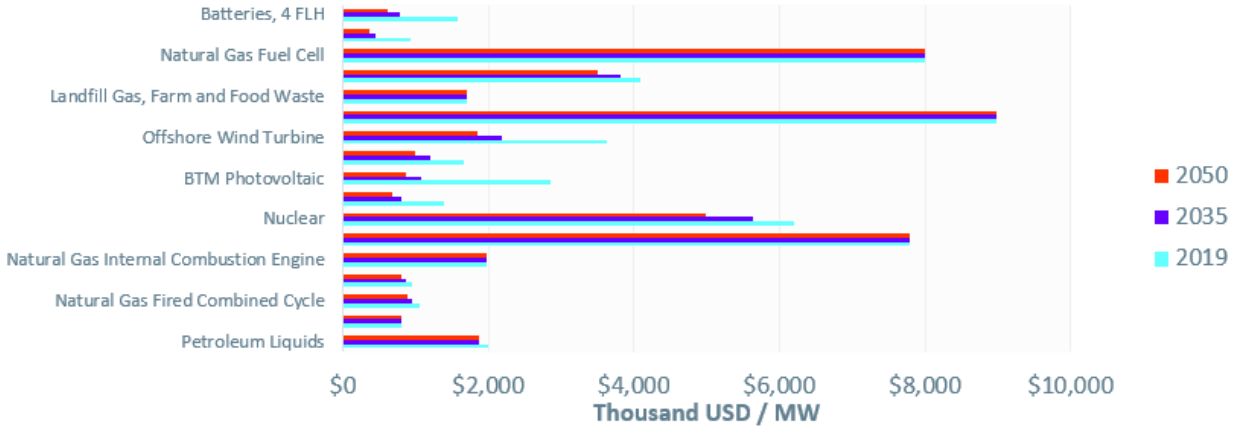


Where possible, Vermont-specific fuel costs are used for wood, wood pellets, diesel, gasoline, distillate fuel oil, and propane. For a full accounting of sources used to develop historical and forecasted fuel supply costs, please see *Appendix A: Table A.1 – Historical and Forecasted Fuel Supply Costs by Source.*

Electricity pricing is endogenous in the model and depends on the mix of power plants and plant dispatch. Each technology is assigned unitized operation and maintenance (O&M) costs, as well as capital costs that are amortized over the expected number of years of plant operation, using the model-wide discount rate as the average cost of capital. All capital costs assume overnight construction and include interconnection costs. Figure 11 shows examples of capital costs for

major electric generating technologies in the model, including future costs where capital costs are expected to decline over time. An annual system-wide $84 per kilowatt of peak load is included based on an assumption by PSD[78] to cover transmission and distribution system maintenance and upgrades. For a full accounting of sources used to develop historical and forecasted electricity supply costs, please see *Appendix A, Table A.2: Electricity Supply Costs by Data Source and Technology*.

Figure 11 – Electric Generation Capital Cost Assumptions



* FLH indicates full-load hours, the number of hours a battery may discharge energy at its rated output.

Wherever specified in the model, all costs are expressed in real 2019 US dollars, and present values of future costs are discounted to the 2019 monetary year at a rate of 2% per year.

c. GHG Mitigation Options and Scenarios

Vermont's GWSA requires that GHG emissions be reduced 26% below 2005 levels by 2025, then 40% by 2030 and 80% by 2050 from a baseline of 1990 levels.[79] Meeting these targets means gross annual GHG emissions – GHG emissions excluding any reductions afforded by the LULUCF carbon sink – cannot exceed those shown in Table 5.

[78] McIlvennie, Claire. "T&D Supply Curve," August 26, 2021.
[79] Vermont General Assembly. Vermont Global Warming Solutions Act of 2020, Pub. L. No. H.688 (2020). https://legislature.vermont.gov/Documents/2020/Docs/ACTS/ACT153/ACT153%20As%20Enacted.pdf.

Table 5 – Vermont's GHG Emission Targets

Year	GHG Target	Gross GHG Target [$MMTCO_2e/yr$]
2025	26%-below-2005	7.38
2030	40%-below-1990	5.18
2050	80%-below-1990	1.73

To achieve these targets, actions need to be taken in all key sectors within the state, including buildings, transportation, industry, electricity generation, and non-energy sectors. For this analysis, the modeling team explored over 20 energy-related GHG mitigation options, plus additional variations of these mitigation options that consider different technology penetration levels or timing. In the non-energy sectors, existing estimates of mitigation potentials were also included. Each mitigation option can be characterized by a) its cost; b) its energy or emissions performance; and c) its saturation, or how much of the measure is introduced, and on what schedule. In the following series of tables, each of these three important assumptions are detailed for each low-carbon technology or mitigation action. Additional information about the BAU Scenario is included where necessary to facilitate comparison of each mitigation action with the model's baseline.

Tables 6.1-6.21 – Technology/Resource Saturation, Performance, and Cost Assumptions

6.1 – Residential Building Shell Improvements	
Saturation	• 120,000 retrofits by 2030 based on "Weatherization at Scale" initiative provided to SEI by EFG,[80] 243,000 retrofits by 2050, aligned with 10,770 retrofits/year by 2040 based on Efficiency Vermont (EVT) "High Scenario" weatherization forecast[81] and Vermont Gas Systems (VGS) forecast[82] provided to SEI by PSD.
BAU Scenario Saturation	• 86,700 cumulative residential retrofits by 2050, aligned with 2,435 retrofits/year reached by 2040 from EVT "Low Scenario" weatherization forecast and VGS forecast. • Includes multi-family, single-family, and low-income retrofits.

[80] Hill, David. "Revised Residential Retrofits EFG 9_20_21.xlsx," September 20, 2021.
[81] Efficiency Vermont. "Letter to Vermont Public Utility Commission Re: Case No. 19-2956-INV – Investigation Pursuant to Act 62, Response to Commission Information Request," August 21, 2020.
[82] Vermont Gas Systems. "Wx Projection VGS," 2021.

Performance	• Weatherizations result in average *useful energy* savings (from reduced air leakage, etc.) of 20% and 38%, for single- and multi-family households respectively, assumed based on PSD input.[83]
Cost	• Average weatherization retrofit cost $7,405 per single-family household, $6,000 per apartment of 2-4 units, $3,000 per apartment of 5+ units, based on PSD.[84]

6.2 – Heat Pumps for Residential Space Conditioning	
Saturation	• **Variant 1:** By 2040, high-efficiency air- and ground-source heat pumps (ASHPs and GSHPs) supply 80% of home heating needs. • **Variant 2:** Heat pumps meet 70% of home heating needs by 2045.
BAU Scenario Saturation	• Approximately 127,000 heat pumps deployed by 2050 (mix of ducted, single- and two-head mini-splits with total heating load equivalent to 90% that of VELCO "medium" forecast, allocated to residential buildings). • Residential heat pumps are 89% air-source, remainder ground-source. • Centrally-ducted ASHPs provide 100% of displaced heat load provided by gas, oil and propane furnaces. Single- and two-head heat pumps displace remaining heating technologies, providing 40% and 66% of displaced heating load, respectively.
Performance	• Single-head and ducted ASHP coefficient of performance (COP) of 2.6, two-head ASHP COP of 2.3, GSHP COP of 4.5.[85]
Cost	• Single- and two-head ASHP installed cost of $6,100 and $7,000 respectively, lasting 15 years with annual maintenance of $72.50.[86] • Ducted ASHP installed cost of $8,500, lasting 18 years with annual maintenance of $72.50.[87] • GSHP installed cost of $17,050, lasting 14 years with annual maintenance of $75.

[83] Poor, TJ. "RE: Presentation on Updated Reference Case," May 28, 2021.
[84] Vermont Public Service Department. "Reported Comprehensive Retrofit Data - 2018," 2021.
[85] Navigant Consulting. "Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, Appendix A," June 2018. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf.
[86] Ibid.
[87] Hill, David. "Building Sector Mods," September 16, 2021.

6.3 – Heat Pumps for Commercial Space Conditioning	
Saturation	• **Variant 1:** By 2040, air-source heat pumps heat 80% of commercial floorspace. • **Variant 2:** Heat pumps meet 70% commercial heating needs by 2045.
BAU Scenario Saturation	• Approximately 24,000 heat pumps deployed by 2050 (with total heating load equivalent to 10% that of VELCO "medium" forecast, allocated to commercial buildings). • Commercial heat pumps from VELCO forecast are entirely air-source. • Commercial ASHPs provide 100% of displaced heat load provided by gas, oil and propane boilers.
Performance	• Average energy consumption per device 2,085 kWh/year (heating mode) and 146 kWh/year (cooling mode).[88] • Commercial heat pumps consume 16-27 kBTU/ft^2, depending on building shell.
Cost	• Commercial heat pump serving 3000 ft^2 installed cost of $7,550, lasting 21 years with annual maintenance of $310.[89]

6.4 – Advanced Wood Heating	
Saturation	• **Variant 1:** By 2045, advanced pellet boilers replace 20% of residential and commercial propane and oil boilers. • **Variant 2:** By 2045, advanced pellet boilers replace 25% of residential and 30% of commercial propane and oil boilers. • For existing buildings (classified as households built after 2015 and commercial floorspace added after 2007), pellet boilers displace only 90% of alternative heating technologies.
BAU Scenario Saturation	• No advanced pellet boilers.
Performance	• Advanced pellet boilers are 86% efficient.[90]

[88] Itron, Inc. "2020 Long-Term Electric Energy and Demand Forecast Report." Vermont Electric Power Company, September 18, 2020.
[89] Navigant Consulting. "Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, Appendix A," June 2018. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf.
[90] Efficiency Vermont. "Technical Reference Manual (TRM): Measure Savings Algorithms and Cost Assumptions," December 31, 2018.

	• In commercial sector, this translates into 76-95 kBTU/ft^2, depending on building shell.
Cost	• Residential pellet boiler installed cost of $20,000, lasting 20 years with annual maintenance of $250.[91] • Commercial pellet boiler installed cost of $65,000, lasting 20 years with annual maintenance of $250, per 6900 ft^2 commercial space.[92]

6.5 – Commercial District Heating	
Saturation	• In 2027, McNeil generating station captures 170,000 MMBTU/year waste heat for commercial sector use, based on input from EFG. • Additional dedicated wood waste heat plants are added in 2030, 2035 and two in 2040, each producing 170,000 MMBTU/year.
BAU Scenario Saturation	• No district heating.
Performance	• Dedicated heat production is 86% efficient (assuming the same as advanced pellet boilers), neglecting distribution loss.[93]
Cost	• Heat delivered through district heating network costs $17/MMBTU, assumed to include the full cost of heat production, capture and transport.

6.6 – Heat Pumps for Water Heating	
Saturation	• By 2035, hot water heat pumps (HWHPs) meet all household and commercial water heating needs previously met by fossil fuels.
BAU Scenario Saturation	• 0.2%-6.5% of household water heating needs met by heat pumps, depending on building type, no change over time. • No commercial hot water heat pumps.

https://puc.vermont.gov/sites/psbnew/files/doc_library/Vermont%20TRM%20Savings%20Verification%202018%20Version_FINAL.pdf.

[91] Ibid.

[92] Perchlik, Andrew. "RE: AWH," October 8, 2021.

[93] Efficiency Vermont. "Technical Reference Manual (TRM): Measure Savings Algorithms and Cost Assumptions," December 31, 2018. https://puc.vermont.gov/sites/psbnew/files/doc_library/Vermont%20TRM%20Savings%20Verification%202018%20Version_FINAL.pdf.

Performance	• High-efficiency residential hot water heat pump COP of 3.55.[94] • Commercial hot water heat pumps consume 4.9 kBTU/ft^2, reaching 4.3 kBTU/ft^2 by 2050.
Cost	• Residential high-efficiency HWHP installed cost of $2,475, lasting 13 years with annual maintenance of $20. • Commercial HWHP serving 11,695 ft^2 installed cost of $50,950, lasting 15 years with annual maintenance of $100.[95]

6.7 – Clean Cooking	
Saturation	• By 2035, electricity replaces fossil fuels for cooking in residential and commercial buildings.
BAU Scenario Saturation	• Electric stoves and ovens in 48%-100% of households, depending on building type. • 41% of commercial space uses electric cooking appliances. • Little or no change over time.
Performance	• Households consume 186-584 kWh/year, depending on building type.[96] • On average, commercial buildings consume 0.8 kWh/ft^2, reaching 0.5 kWh/ft^2 by 2050.
Cost	• Equipment cost differences among cooking appliances assumed to be negligible.

6.8 – Phasing Out Internal Combustion Engines	
Saturation	• **Variant 1:** By 2033, all sales of new on-road vehicles are BEVs. • **Variant 2:** All sales of new on-road vehicles are BEVs by 2040. • For LDVs, BEVs are divided among 100-, 200- and 300-mile ranges.
BAU Scenario Saturation	• Sales remain modest: by 2050, only 41% of LDV sales and 7.5% of MHD vehicle sales are BEVs. • Based on VELCO "low" EV forecast, electrifying 35% of LDVs by 2050.

[94] Navigant Consulting. "Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, Appendix A," June 2018. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf.
[95] Ibid.
[96] Navigant Consulting. "Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, Appendix A," June 2018. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf.

Performance	• Effective fuel economy taken from VISION 2020.[97]
Cost	• Costs from VISION 2020, with declining EV purchase price and charging infrastructure costs from Cadmus.[98]

6.9 – E15 Ethanol in Transport	
Saturation	• By 2040, ethanol blend in all motor gasoline reaches 15%-by-volume (E15).
BAU Scenario Saturation	• Ethanol constitutes 10.2%-by-volume in motor gasoline, rising to 12.1% in 2050.
Performance	• Ethanol emits biogenic carbon dioxide, which is assigned a GWP of zero.
Cost	• Ethanol for blending costs $25.10/MMBTU in 2019, rising to $44.90/MMBTU in 2050. Pure gasoline costs $23.80/MMBTU in 2019, rising to $30.90/MMBTU in 2050. • Existing equipment assumed to operate using E15 without additional cost.

6.10 – VMT Reductions	
Saturation	• Measure encompasses urban densification, traffic demand management, active transportation and shifting to public transport. • By 2050, annual VMT are reduced by 10% across all vehicle classes and technologies.
BAU Scenario Saturation	Annual mileage for each weight class is: • 13,852 for passenger cars • 15,300 for light trucks • 22,451-36,829 for MDVs • 21,016-98,228 for HDVs
Performance	• No change to fuel economy.

[97] Argonne National Lab. VISION Model AEO 2020 Base Case, 2020. https://www.anl.gov/es/vision-model.
[98] Morrison, Geoff. "RE: [EXT] Transportation Sector Mods," September 17, 2021.

Cost	• 10% VMT reductions assumed to be achievable for $250 million/year, estimated by Cadmus.[99]

6.11 – B20 Biodiesel and Heating Oil	
Saturation	• By 2050, biodiesel blend in industrial and transport diesel and building heating oil reaches 20%-by-volume (B20).
BAU Scenario Saturation	• Industry and transport consume 4.0%-by-volume biodiesel blend, rising to 7.5% by 2050. • No biodiesel blending within heating oil.
Performance	• Biodiesel emits biogenic CO_2, which is assigned a GWP of zero.
Cost	• Pure biodiesel costs $32.40/MMBTU in 2019, rising to $42.20/MMBTU in 2050. Diesel costs $24.90/MMBTU in 2019, rising to $32.90/MMBTU in 2050. • Existing equipment assumed to operate using B20 without additional cost.

6.12 – B100 Biodiesel Heating Oil	
Saturation	• By 2040, building heating oil reaches 100% biodiesel (B100).
BAU Scenario Saturation	• Industry and transport consume 4.0%-by-volume biodiesel blend, rising to 7.5% by 2050. • No biodiesel blending within heating oil.
Performance	• Biodiesel emits biogenic CO_2, which is assigned a GWP of zero.
Cost	• Capability to burn B100 requires upgrade cost of $1,045 per oil boiler or furnace, annualized over equipment's lifetime. • Same fuel costs as other biodiesel scenarios.

[99] Morrison, Geoff. "RE: [EXT] Transportation Sector Mods," September 17, 2021.

6.13 – B100 Biodiesel in Industry	
Saturation	• By 2040, industrial diesel consumption reaches 100% biodiesel (B100).
BAU Scenario Saturation	• Industry and transport consume 4.0%-by-volume biodiesel blend, rising to 7.5% by 2050
Performance	• Biodiesel emits biogenic CO_2, which is assigned a GWP of zero.
Cost	• Same fuel costs as other biodiesel scenarios. • No additional costs are included.

6.14 – B100 Biodiesel in Heavy Transport	
Saturation	• By 2040, diesel consumption for heavy-duty transport reaches 100% biodiesel (B100).
BAU Scenario Saturation	• Industry and transport consume 4.0%-by-volume biodiesel blend, rising to 7.5% by 2050
Performance	• Biodiesel emits biogenic CO_2, which is assigned a GWP of zero.
Cost	• Same fuel costs as other biodiesel scenarios. • Capability to burn B100 costs $15,000 more per vehicle than conventional diesel engines.[100]

6.15 – Sustainable Aviation Fuel	
Saturation	• By 2050, drop-in biofuels displace 50% of jet kerosene.
BAU Scenario Saturation	• No drop-in biofuels - jet kerosene meets 96% of aviation energy demand (remainder is aviation gasoline for small engines).

[100] Huwyler, Colin. "Cost of Retrofitting HVD Vehicles, Personal Communication with Optimus Technologies," 2021.

Performance	• Sustainable aviation fuel emits biogenic CO_2, which is assigned a GWP of zero.
Cost	• Drop-in aviation biofuel costs $37.30/MMBTU, while jet kerosene costs $15.40/MMBTU in 2019, rising to $22.50/MMBTU in 2050. • Existing aircraft assumed to operate using drop-in fuels without additional cost.

6.16 – Renewable Gas in Industry	
Saturation	• 10%/20%/80% of (fossil) natural gas consumed for industrial uses is displaced by renewable natural gas (RNG) or biogas by 2025/2030/2050, respectively.
BAU Scenario Saturation	• RNG not consumed in industry.
Performance	• RNG emits biogenic CO_2, which is assigned a GWP of zero.
Cost	• RNG costs $30/MMBTU, while natural gas costs $7.63/MMBTU in 2019, rising to $9.43/MMBTU in 2050. • Existing equipment assumed to operate using RNG without equipment additional cost.

6.17 – Renewable Gas in Buildings	
Saturation	• **Variant 1:** 5%/15%/25% of (fossil) natural gas consumed for residential and commercial building uses is displaced by RNG by 2025/2030/2050, respectively. • **Variant 2:** 10%/20%/80% of (fossil) natural gas consumed for residential and commercial building uses is displaced by RNG by 2025/2030/2050, respectively.
BAU Scenario Saturation	• RNG not consumed in buildings.
Performance	• RNG emits biogenic CO_2, which is assigned a GWP of zero.
Cost	• Same costs as other RNG scenarios. • Existing equipment assumed to operate using RNG without equipment additional cost.

6.18 – Renewable Electricity	
Saturation	• **Variant 1:** From 2032 to 2041, Renewable Energy Standard increases to 100%, affecting the mix of capacity (MW) and energy (MWh). • Existing Hydro-Quebec import contract is renewed after 2038. • **Variant 2:** Over twice as much behind-the-meter solar capacity as Variant 1.
BAU Scenario Saturation	• Vermont's existing Renewable Energy Standard is met in each year, reaching 75% by 2032 (no change thereafter). • Existing Hydro-Quebec import contract ends after 2038.
Performance	• Average electric production efficiency, emissions intensity is calculated internally within the model based on performance characteristics of each electric generation technology.
Cost	• Cost is calculated internally within the model based on capital, operation & maintenance, and fuel cost assumptions for electric generation technologies.

6.19 – Reduced Hydro-Quebec Imports	
Saturation	• Existing Hydro-Quebec import contract ends in 2030.
BAU Scenario Saturation	• Existing Hydro-Quebec import contract ends after 2038.
Performance	• Vermont imports 1.22 TWh/year from Hydro-Quebec during contract period. • Any other Hydro-Quebec energy in New England outside of contract is counted as part of the remainder of ISO-NE system mix. • Electricity from Hydro-Quebec is eligible to meet Vermont's Renewable Energy Standard.
Cost	• Cost is calculated internally within the model based on capital, operation & maintenance, and fuel cost assumptions for electric generation technologies without Hydro-Quebec. • Imported electricity assumed to cost $40/MWh.

6.20 – Managed EV Charging	
Saturation	• **Variant 1:** By 2040, 50% of all EVs (including PHEVs) are charged slowly while plugged in, resulting in a flatter load profile. • **Variant 2:** By 2040, 80% of all EVs (including PHEVs) participate in managed charging.
BAU Scenario Saturation	• All EVs charge as fast as possible while plugged in, which results in charging load peaking at 21:00 on weekdays during winter.[101] See this report's Methods section for these charging profiles displayed graphically.
Performance	• Managed charging load curve from EVI-Pro Lite, peaks at 01:00 on weekdays during winter, generally with more charging occurring overnight.[102] • No other changes to EV performance.
Cost	• No additional costs are assumed.

6.21 – Vehicle-to-Grid (V2G) Battery Storage	
Saturation	• By 2040, 15% of light-duty mid- and high-range BEVs (generally >150 miles per charge) participate in V2G discharging.
BAU Scenario Saturation	• No V2G.
Performance	• Each participating EV treated as a 10-kW battery storing 68 kWh, maintaining 70% minimum charge.[103] • Availability of V2G batteries estimated from (unmanaged) EV charging profile, indicating when vehicles are plugged in.
Cost	• Additional $5,000 per participating EV for V2G-capable charging station, based on communication with Green Mountain Power.[104]

[101] Turk, Graham. "Load Shapes for Heat Pumps & (Managed) EV Charging," July 21, 2021.
[102] Alternative Fuels Data Center. "Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite," 2020. https://afdc.energy.gov/evi-pro-lite/load-profile/results?utf8=%E2%9C%93&load_profile%5Bstate%5D=VT&load_profile%5Burban_area%5D=Burlington&load_profile%5Bstate_name%5D=Vermont&load_profile%5Bfleet_size%.
[103] Steward, Darlene. "Critical Elements of Vehicle-to-Grid (V2G) Economics." National Renewable Energy Laboratory, September 2017.
[104] Turk, Graham. "Load Shapes for Heat Pumps & (Managed) EV Charging," July 21, 2021.

To reach the level of abatement required, all non-energy mitigation options were included first. These are detailed in *Appendix B, Table B.1 – Summary of Low- and Zero-Carbon Technologies in Key Sectors of the Mitigation Scenarios.* The remaining abatement is provided by layering the discrete energy-sector mitigation options described above into combined scenarios, until the GWSA targets were satisfied.[105] SEI repeated this process three times to develop three separate GWSA-compliant mitigation scenarios, each time using a different mix of mitigation options.

i. Mitigation Scenarios

One central GHG mitigation scenario and two sub-scenarios were developed, to evaluate three different pathways with which the state would meet its GHG reduction goals. All scenarios describe a future that is markedly different than today, and different from the BAU Scenario.

- The **Central Mitigation Scenario** is the model's core mitigation pathway. It is composed of mitigation options that the modeling team felt represented a balanced portfolio of the low-carbon options explored, but also respecting the high level of abatement required to satisfy GWSA targets.
- The **Biofuel Emphasis Mitigation Scenario** builds on the Central Mitigation Scenario but relies on electrification to a lesser extent, or, to the same extent but in a later year. To make up the needed mitigation, the scenario relies more on biofuels.
- The **Local Electricity Resources Mitigation Scenario** also builds on the Central Mitigation Scenario but considers a different portfolio of clean electricity resources with less reliance on Hydro Quebec imports. In particular, these include resources that Vermont can provide itself such as behind-the-meter (BTM) solar or V2G-ready EV batteries, improving the state's energy security and self-sufficiency.

Ingredients for each of these pathways are taken from the options or option variants described in Tables 6.1–6.21. The following matrix indicates which of the measures belong within each mitigation scenario, using a checkmark. Where the modeling team explored more than one variant of an option, the appropriate variant is indicated as either variant one or two (V1 or V2, respectively).

[105] To reduce the number of scenario iterations to reach the targets, SEI tolerated an overshoot of the mitigation targets by up to 2% in 2025, 2030, and 2050.

Table 7 – Technologies and Resources Selected for Each Mitigation Scenario

Mitigation Option	Central	Biofuel Emphasis	Local Electricity Resources
Residential Building Shell Improvements	✓	✓	✓
Heat Pump Water Heating	✓	✓	✓
Heat Pump Residential Space Conditioning	V1	V2	V1
Heat Pump Commercial Space Conditioning	V1	V2	V1
Advanced Wood Heating	V1	V2	V1
Commercial District Heating	✓	✓	
Clean Cooking	✓	✓	✓
Renewable Gas in Buildings	V1	V2	V1
Renewable Gas in Industry	✓	✓	✓
Phasing Out Internal Combustion Engines	V1	V2	V1
E15 in Transport	✓	✓	✓
B20 in Transport and Heating Oil	✓	✓*	✓
B100 in Industry	✓	✓	✓
B100 in Heating Oil		✓	
B100 in Heavy-Duty Transport		✓	
VMT Reductions	✓	✓	✓
Sustainable Aviation Fuel	✓	✓	✓
Renewable Electricity	V1	V1	V2
Reduced Hydro Quebec Imports			✓
Managed EV Charging	V1	V1	V2
V2G Battery Storage			✓
All non-energy mitigation options	✓	✓	✓

** B20 in heavy transport and heating oil is superseded in this scenario by B100 measures.*

For a sector-by-sector summary of the low-carbon technology deployment in each scenario, please see *Appendix B: Table B.1 – Table B.1 – Summary of Low- and Zero-Carbon Technologies in Key Sectors of the Mitigation Scenarios.*

d. Health Benefits Analysis

NESCAUM calculated sector specific changes in mass $PM_{2.5}$, NO_x, NMVOC, and SO_2 emissions between the BAU and each of the mitigation scenarios based on results from the LEAP modeling. The calculated percent change in emissions was then input into EPA's Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA),[106] version 4. COBRA uses a simplified air quality model, the Source Receptor (S-R) Matrix, to estimate changes in

[106] U.S. Environmental Protection Agency. CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), 2021. https://www.epa.gov/cobra.

total annual ambient concentrations of $PM_{2.5}$, including the formation of secondary $PM_{2.5}$ from precursor pollutants. COBRA then estimates the avoided incidences of hospitalization for cardiovascular and respiratory illness, premature death, and emergency room visits, based on information from peer-reviewed literature. COBRA estimates a high and a low reduction in adverse health outcomes based on high and low incidence values in the peer-reviewed literature. COBRA then multiplies the change in incidence for each health outcome by a monetary value specific to that outcome (e.g., the average cost of going to the emergency room for asthma symptoms or the cost of a lost workday) to determine the monetized health impacts. In the results section, both the high and the low estimates are reported.

In COBRA, two discount rates can be used: 3% and 7%. For this analysis, NESCAUM used a 3% discount rate since that was closest to the 2% discount rate SEI used in the LEAP modeling. Changes in population are also an input to COBRA and for this, NESCAUM used the population growth projections used by SEI in the LEAP analysis and published by UVM TRC.

Results

a. Business-as-Usual Scenario

Results for the BAU Scenario show an extrapolation of historical data and recent trends affecting Vermont's emissions, alongside pre-existing forecasts in key emitting sectors described in the Methods section of this report. Here, BAU Scenario results are provided in some detail, to provide an overview of the state's major emitting sectors, now and where they may be headed without significant climate action. This detail – in fuel consumption and GHG emission sources – is not typically included in results for each mitigation scenario, presented later.

Figure 12 shows an overview of GHG emissions by sector in the BAU Scenario from 2015 to 2050, including all energy sectors (in solid color) and non-energy sectors (hatched pattern). Net emissions, including "negative" emissions estimated from the LULUCF sink, are shown using a dashed line, while gross emissions are displayed using a solid line. In the figure, the black dots represent Vermont's GHG targets for 2025, 2030, and 2050, gross of carbon sequestration from the LULUCF sector. The chart shows that the 2025 emission target is met even in the BAU Scenario - Vermont's target is 7.38 million metric tons of CO_2-equivalent ($MMTCO_2e$), and gross BAU emissions fall slightly below this for all sectors combined. This result should be interpreted cautiously (see Findings and Discussion section for more).

Gross emissions in the BAU Scenario decline from 8.51 $MMTCO_2e$ in 2015[107] to 6.52 million $MMTCO_2e$ by 2050, shown by the solid black line in Figure 12. This is largely due to transportation sector GHG reductions from improved fuel economy and vehicle electrification, and the adjustment made to agricultural emissions for years 2020 and beyond. Emissions from commercial, agricultural, and residential sources also decrease in the BAU Scenario, but to a much lesser extent than transportation-related GHG emissions. In other sectors, GHG emissions

[107] Calculated GHG emissions in 2015 may differ slightly from those in Vermont's latest GHG Inventory, published in 2021 and containing emissions through the year 2017. Reasons for these discrepancies have been partially covered in the earlier discussion of electricity consumption emissions. Discrepancies are also due to differences in historical waste sector emissions presented in GHG inventories published in 2020 and 2021.

increase or remain approximately constant, but not enough to offset the reductions in GHG emissions realized from the transportation, commercial, agricultural, and residential sectors.

While gross GHG emissions decrease in the BAU Scenario between 2015 and 2050, net GHG emissions are sensitive to the carbon sequestration potential of land and forests. Figure 12 shows that if the LULUCF sink declines to 0.4 $MMTCO_2e$ of sequestration by 2050 (an uncertain value that is also challenging to monitor and verify), Vermont's net emissions would increase over time.

Figure 12 – BAU Scenario: GHG Emissions by Sector through 2050 for Vermont

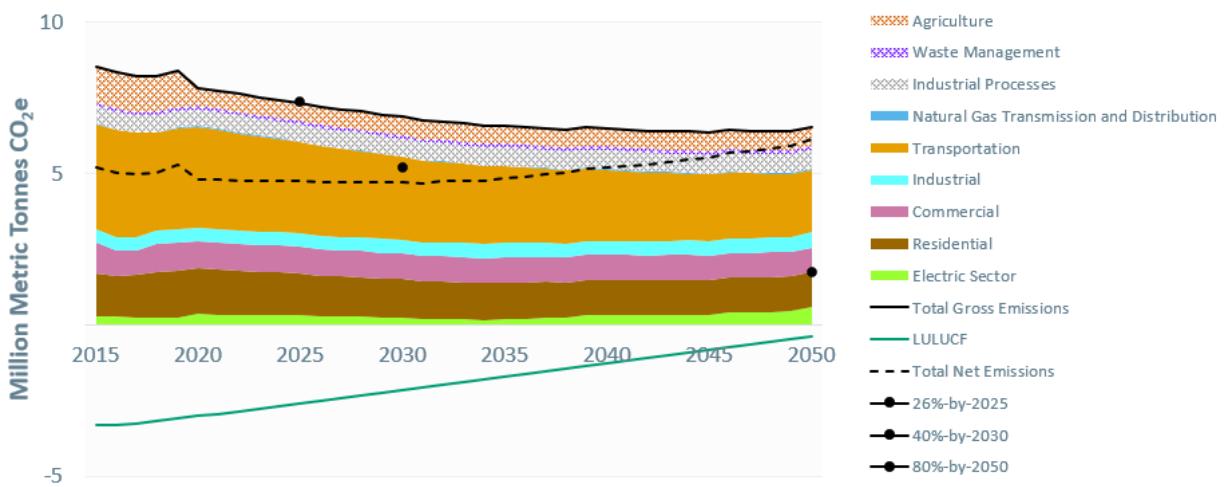


Figure 13 shows both the state's projected electricity requirements and projected resource mix, in gigawatt-hours (GWh), by technology. For the purposes of the chart, energy produced from in-state and out-of-state resources has been grouped (explaining the presence of offshore wind in Vermont's resource mix). In this scenario, electricity generation from BTM solar, onshore wind, offshore wind, and natural gas sources increase between 2020 and 2050. All other generation sources, including solid waste, landfill gas, hydro, and nuclear, gradually decline while utility-scale solar generation remains constant through 2050. Total electricity generation increases from 6,010 GWh in 2020 to 7,520 GWh in 2050 in the BAU Scenario. Hydro and nuclear power generation are shown in dark blue wedges. Hydropower decreases by 74% between 2020 and 2050, while nuclear energy is phased out entirely, albeit in the final scenario year resulting from power plant retirement assumptions made in the model. At the same time, offshore wind increases from 0.01 thousand GWh in 2020 to 1.1 thousand GWh in 2050. Onshore wind more than doubles from 0.67 thousand GWh to 1.66 thousand GWh in 2050. The largest increase is seen in BTM solar generation, which increases from 0.58 GWh to 2.12 GWh, more than tripling over the 30-year period.

Figure 13 – BAU Scenario: Electricity Requirements and Resource Mix

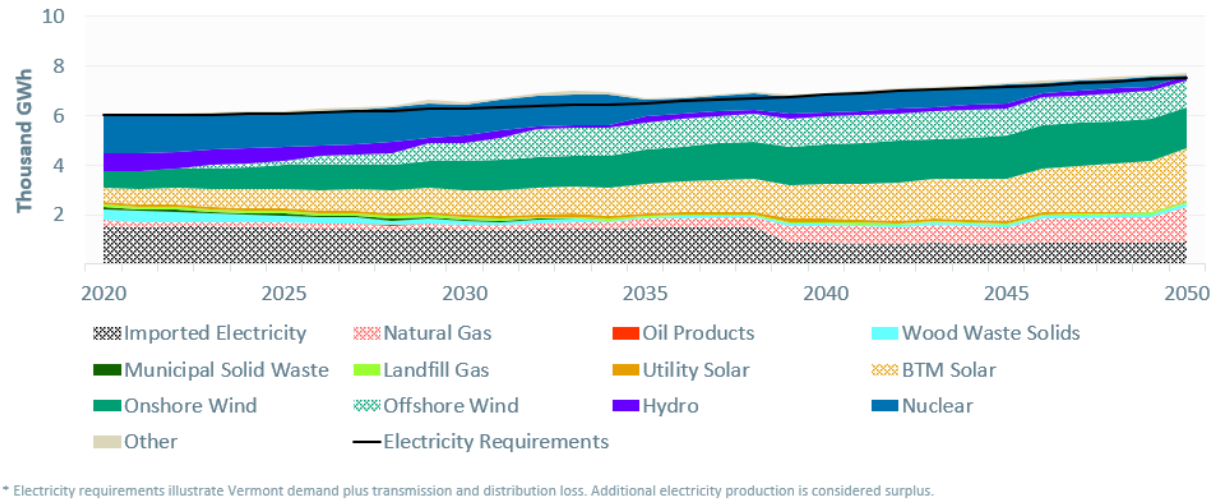
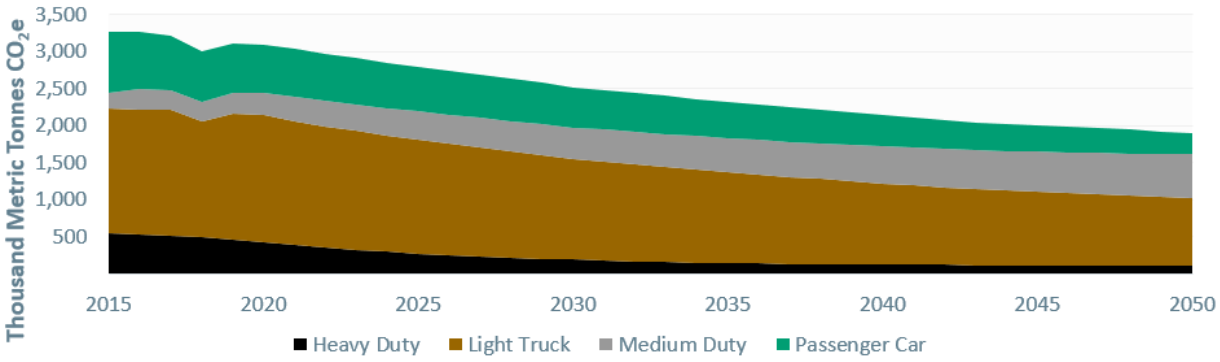


Figure 14 depicts GHG emissions from the on-road transportation sector through 2050. The chart shows *direct* emissions from fuel combustion, which do not include *indirect* emissions from activity in this sector, such as from electricity production (these emissions are tracked elsewhere). In the BAU Scenario, total on-road transportation sector GHG emissions decline 23% and 44% relative to 2015 levels in 2030 and 2050, respectively. The greatest absolute reduction in on-road transportation sector emissions in the BAU Scenario comes from the light truck segment, declining over 46% from 1.69 $MMTCO_2e$ in 2015 to 0.91 $MMTCO_2e$ in 2050. In contrast, GHG emissions from medium-duty vehicles increase 135% between 2015 and 2050 as the number of vehicles within this market segment more than triples.

Declining on-road transportation-related GHG emissions in the BAU Scenario result from reductions in the total energy demand from on-road transportation between 2015 and 2050. Energy demand declines from 45.94 trillion British thermal units (BTU) in 2015 to 36.1 trillion BTU in 2030 (a 21% decrease) and to 29.87 trillion BTU in 2050 (a 35% decrease). This is largely due to assumed increases in EVs in the baseline case from VELCO's low electrification scenario, which are more energy efficient than internal combustion engine vehicles. Fuel economy improves among unelectrified vehicles while annual distance traveled per vehicle remains constant, reducing overall fuel consumption and GHG emissions.

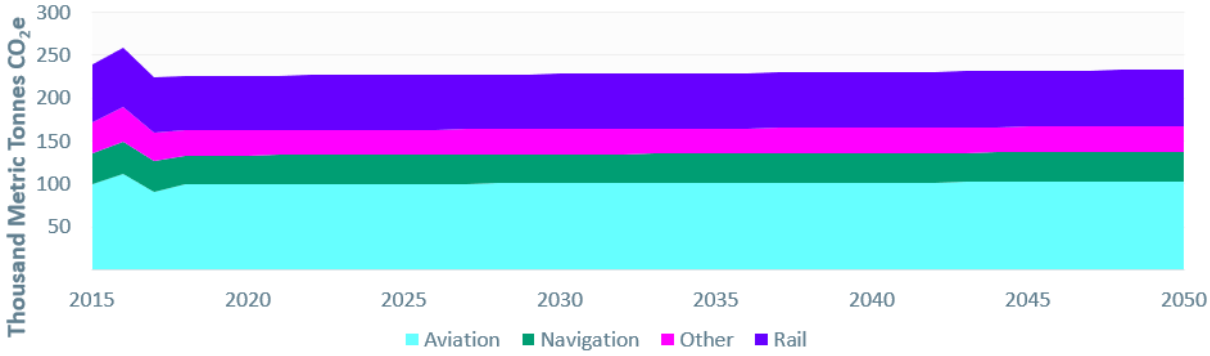
Energy demand for diesel fuel in on-road transportation declines 39% by 2030 and 49% by 2050, from 2015 levels. Meanwhile, gasoline demand declines 20% by 2030 and 45% by 2050. Electricity demand for on-road transportation increases from negligible quantities in 2015 to eventually comprise 12.6% of all energy consumed for road transport activities by 2050.

Figure 14 – BAU Scenario: On-Road Transportation Sector GHG Emissions through 2050



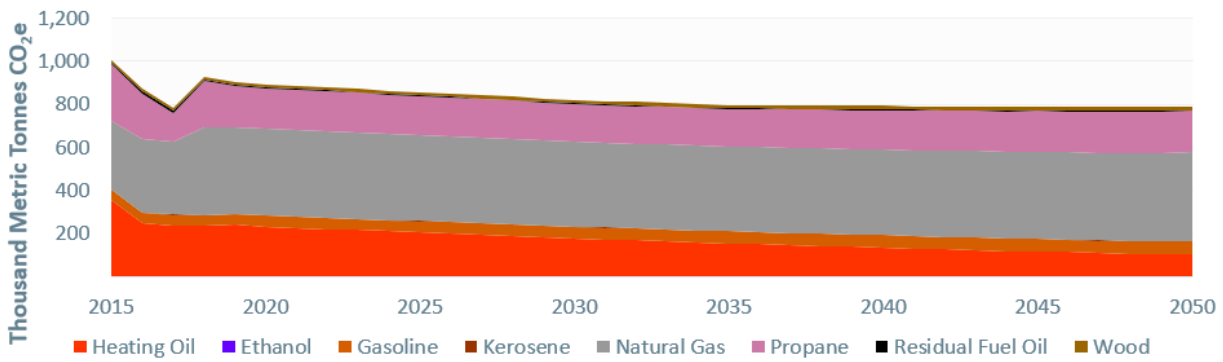
Non-road transportation includes aviation, ships and waterborne vessels, locomotives, and other forms of transport, including pipelines and military use. Because future energy demand for these subsectors is estimated by holding energy use per capita fixed, BAU Scenario demand depends only on Vermont's population, which is projected to change little. A small reduction in GHG emissions from non-road transportation is observed, due to increasing shares of biodiesel and ethanol blended into diesel and gasoline consumed in these subsectors.

Figure 15 – BAU Scenario: Non-Road Transportation Sector GHG Emissions through 2050



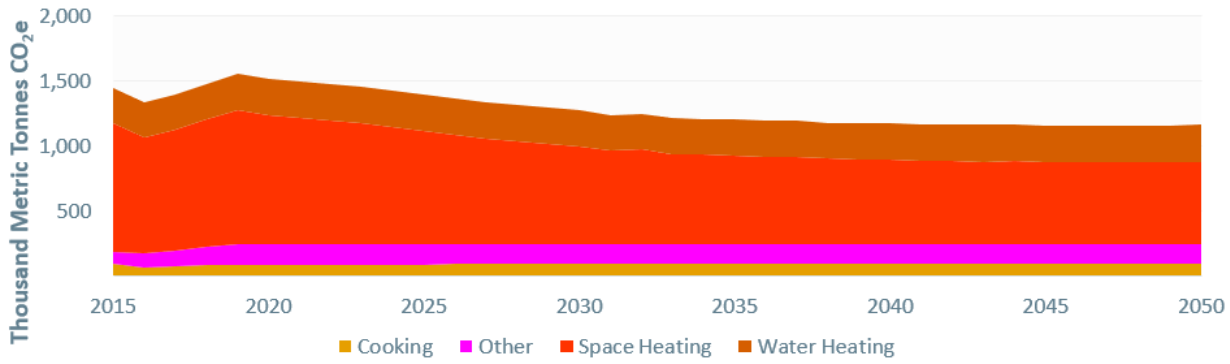
In the BAU Scenario, total energy demand from commercial buildings decreases from 24.5 trillion BTU in 2050 to 22.5 trillion BTU (a decrease of 8.2%) in 2030 and to 22.6 trillion BTU (a decrease of 7.7%) in 2050. Heating oil consumption decreases by nearly 70% from 2015 to 2050, with much of this demand replaced by natural gas. Combustion of other fuel types such as gasoline (consumed for miscellaneous purposes for some commercial activities) and wood gradually increases in the BAU Scenario. Total GHG emissions from commercial buildings decrease from 1.01 $MMTCO_2e$ in 2015 to 0.82 $MMTCO_2e$ (a decrease of 18.5%) in 2030 and 0.79 $MMTCO_2e$ (a decrease of 21.5%) in 2050.

Figure 16 – BAU Scenario: Commercial Buildings Sector GHG Emissions through 2050



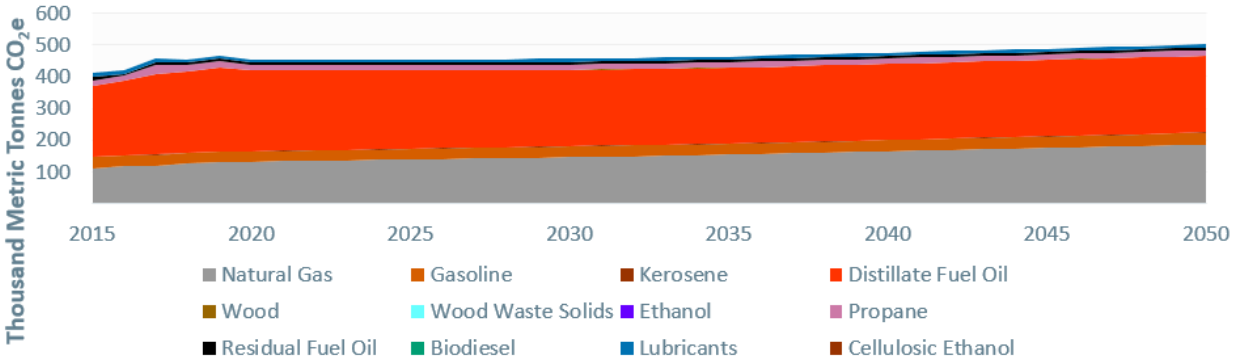
In residential buildings, energy demand for space heating decreases 20.7% and 30.5% from 2015 levels by 2030 and 2050, respectively, while energy demand for other end uses remains mostly unchanged through 2050. Increasing shares of heating oil, propane, and wood for space heating are gradually replaced by electricity for air- and ground-source heat pumps in the model. Overall GHG emissions from residential buildings decline from nearly 1.45 $MMTCO_2e$ in 2015 to 1.27 $MMTCO_2e$ (12.4% lower than 2015) in 2030 and to 1.16 $MMTCO_2e$ (19.5% lower than 2015) in 2050.

Figure 17 – BAU Scenario: Residential Buildings Sector GHG Emissions through 2050



Total energy demand from the industry sector gradually increases from 16.16 trillion BTU in 2015 to 16.75 trillion BTU in 2050. GHG emissions from the sector also increase, though not as quickly as overall demand. The difference in the rate of increase is attributed to growing shares of natural gas and biodiesel, both of which generate fewer GHG emissions than diesel, which accounted for the majority of industrial energy demand in 2015.

Figure 18 – BAU Scenario: Industry Sector GHG Emissions through 2050



b. GHG Mitigation Scenarios

This section explores the results from each of the three mitigation scenarios, occasionally introducing additional BAU Scenario results if they provide context for mitigation scenario results. The section begins with an overview of energy demand before moving through each major sector and concluding with emissions and mitigation costs.

i. Economy-Wide Energy Demand

In the Central and Local Electricity Resources Mitigation Scenarios, final energy demand shifts away from natural gas and oil products to electricity and renewables. In 2020, final energy demand is 11.4% natural gas, 12.1% renewables and biomass, 15% electricity, and 61.5% oil products. In 2030, final energy demand for the two scenarios is 8.5% natural gas, 11.4% renewables and biomass, 28.9% electricity, and 51.3% oil products. Finally, in 2050 more than half of final energy demand is electricity, 3% natural gas, and 12% renewables and biomass.

Final energy demand (in trillion BTU) by fuel type for the Central Mitigation Scenario is shown in the right-hand graph in Figure 19. The decline in use of oil products from 2015 to 2050 can be seen in the red wedge and the increase in electricity demand is shown in the green wedge. Natural gas can be seen to decline to nearly zero by 2050.

Figure 19 – Energy Demand in the Central Mitigation Scenario

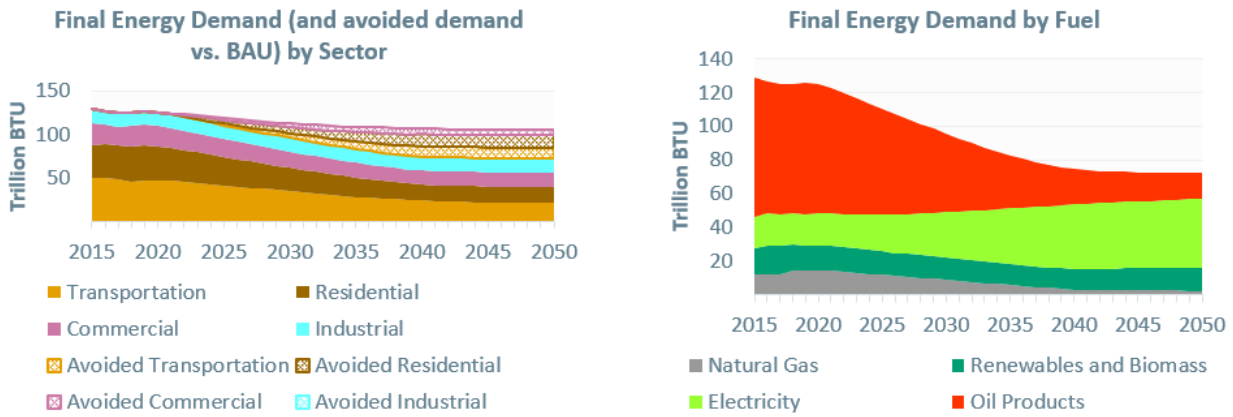
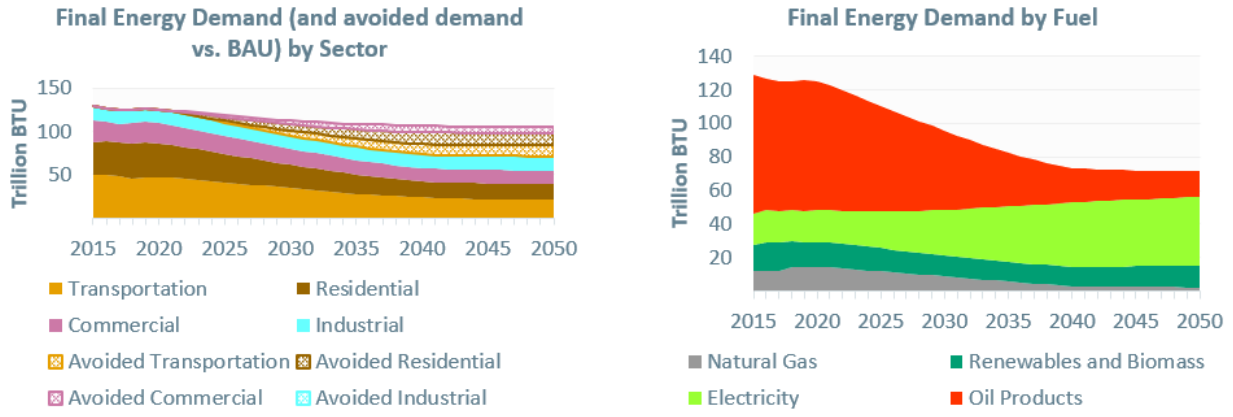


Figure 19 also shows final energy demand by sector (the left-hand graph in the figure). There is substantial reduction in transportation-related energy demand as the fleet of light-, medium-, and heavy-duty vehicles is shifted away from gasoline and diesel-powered engines to electric motors. Similarly, the residential sector sees substantial energy demand reductions between 2015 and 2050 as space heating, hot water heating, and other appliances are shifted from wood heat, natural gas, oil, and other petroleum products to heat pumps and other electrification technologies.

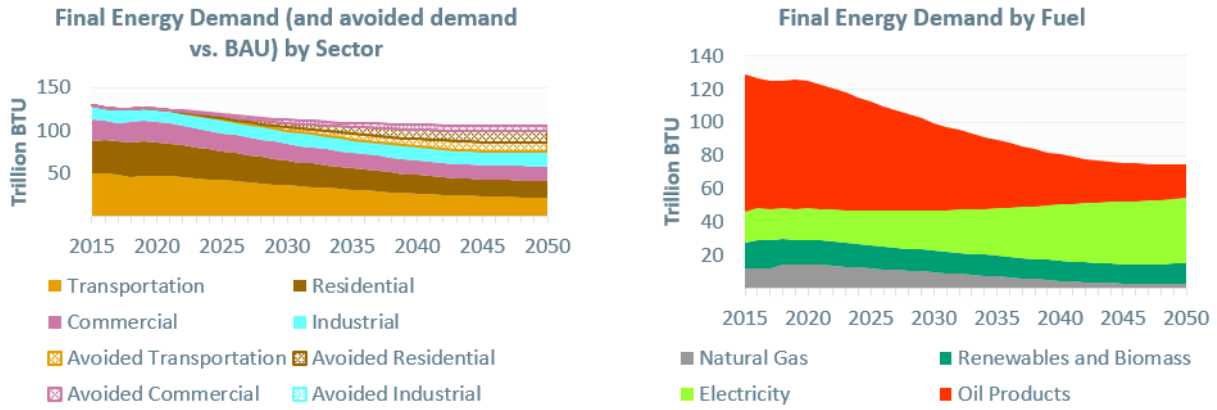
Figure 20 shows energy demand in the Local Electricity Resources Mitigation Scenario. The left-hand graph shows final energy demand by sector and the right-hand graph shows final energy demand by fuel. From a final energy demand perspective, the main difference between the two scenarios is that the Central Mitigation Scenario includes the district heating measure in the commercial sector, which is not included in the Local Electricity Resources Mitigation Scenario. As a result, commercial sector heating-related fuel consumption is lower in the Central Mitigation Scenario than in the Local Electricity Resources Mitigation Scenario.

Figure 20 – Energy Demand in the Local Electricity Resources Mitigation Scenario



In the Biofuel Emphasis Mitigation Scenario shown in Figure 21, final energy demand shifts to 9% natural gas, 12.4% renewables and biomass, 25.2% electricity, and 53.4% oil products in 2030 and to 3.7% natural gas, 13.8% renewables and biomass, 54.8% electricity, and 27.7% oil products in 2050. Final energy demand by sector is shown in the left-hand graph and final energy demand by fuel in the right-hand graph for the Biofuel Emphasis Mitigation Scenario.

Figure 21 – Energy Demand in the Biofuel Emphasis Mitigation Scenario



ii. Residential Fuel Use

The Central and Local Electricity Resources Mitigation Scenarios both avoid 7.1 and 14.2 trillion BTU in total energy demand from residential buildings by 2030 and 2050 relative to the BAU Scenario in those years, respectively. The Biofuel Emphasis Mitigation Scenario avoids 5.3 and 12.9 trillion BTU in total energy demand from residential buildings by 2030 and 2050 relative to the BAU Scenario, respectively.

Diving deeper into the Central Mitigation Scenario reveals insight into the source of these energy savings. As the dominant energy-consuming end-use, space heating measures are also responsible for the largest energy reductions. The introduction of heat pumps is the single most impactful mitigation option in the residential sector because it displaces other space heating fuels with electricity, which is consumed much more efficiently that alternatives. The following two charts show the total number of residential heat pumps in the Central Mitigation Scenario (alongside the BAU Scenario penetration), and the resulting energy impacts measured as increased consumption of electricity and decreased consumption of other fuels, relative to BAU.

Figure 22 – Residential Heat Pumps, by Type, Added in the Central Mitigation Scenario Across All Household Types

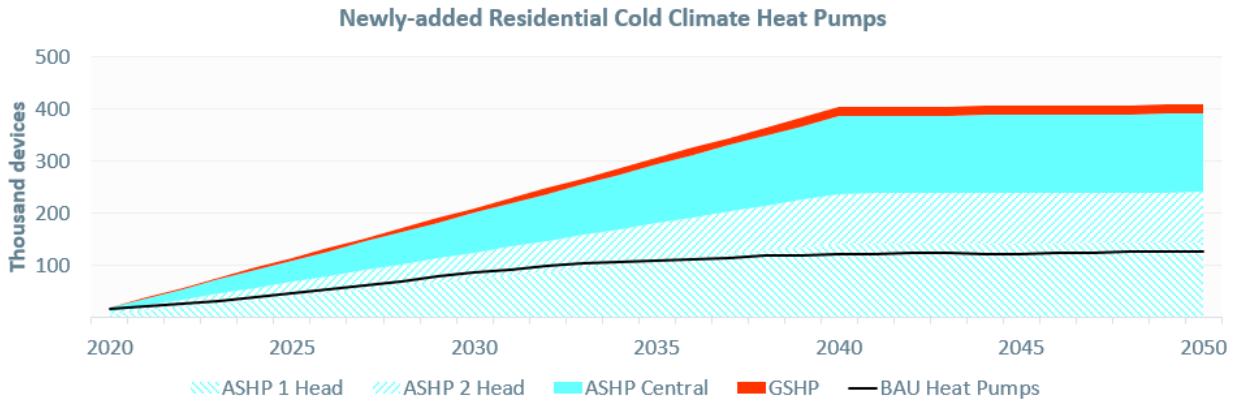
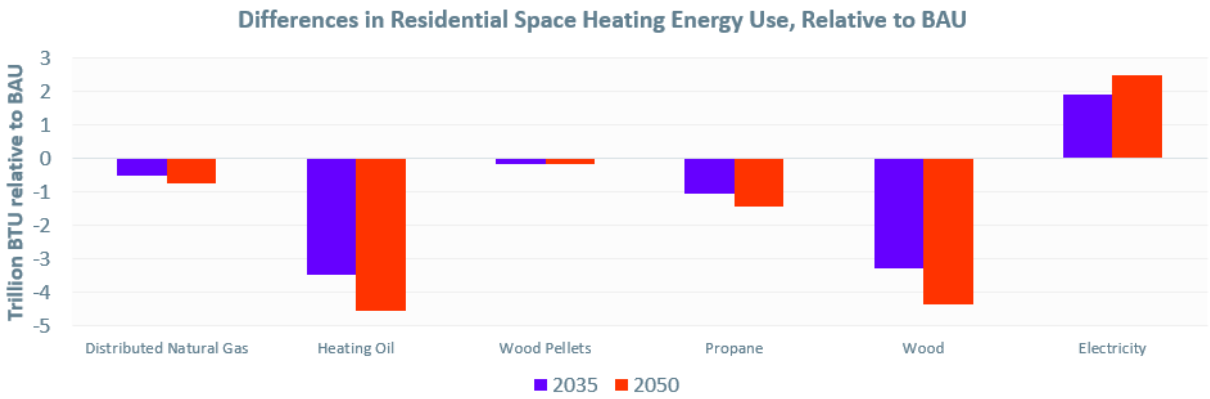


Figure 23 – Changes in Residential Energy Consumption by Fuel, for the Central Mitigation Scenario Relative to BAU Scenario



Demand reductions are distributed among housing types, with single family detached homes shouldering almost all of the reduction in rural areas but sharing the reduction with apartment buildings in urban areas. In urban areas, electricity displaces predominantly heating oil and gas, but propane and wood consumption are also curtailed by electrification of rural buildings. Figures 24 and 25 show these trends graphically for urban homes, and rural homes are depicted in Figures 26 and 27.

Figure 24 – Residential Energy Demand and Avoided Demand Relative to BAU Scenario, in the Central Mitigation Scenario in 2050, by Urban Household Type

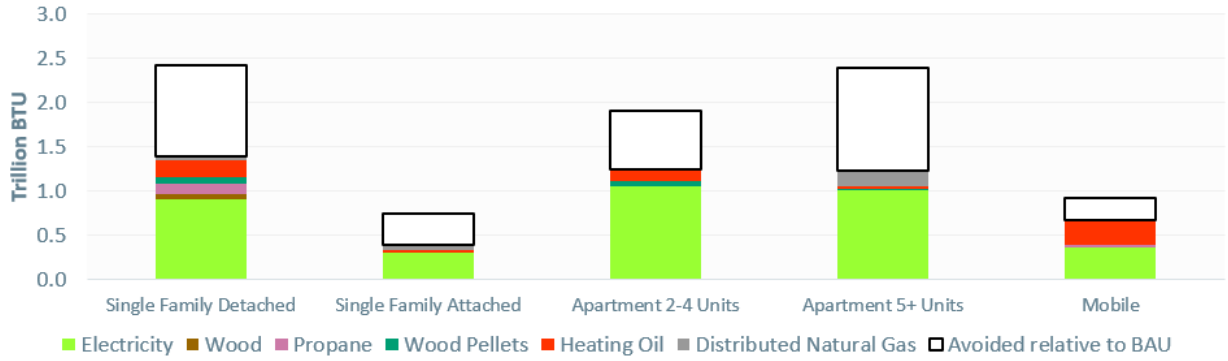


Figure 25 – Final Energy Demand in Urban Households by Fuel, for Central Mitigation Scenario

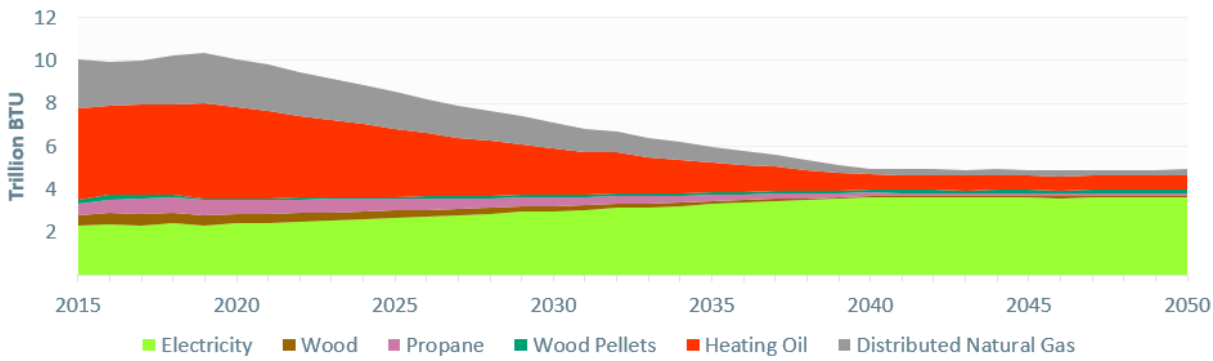


Figure 26 – Residential Energy Demand and Avoided Demand Relative to BAU Scenario, in the Central Mitigation Scenario in 2050, by Rural Household Type

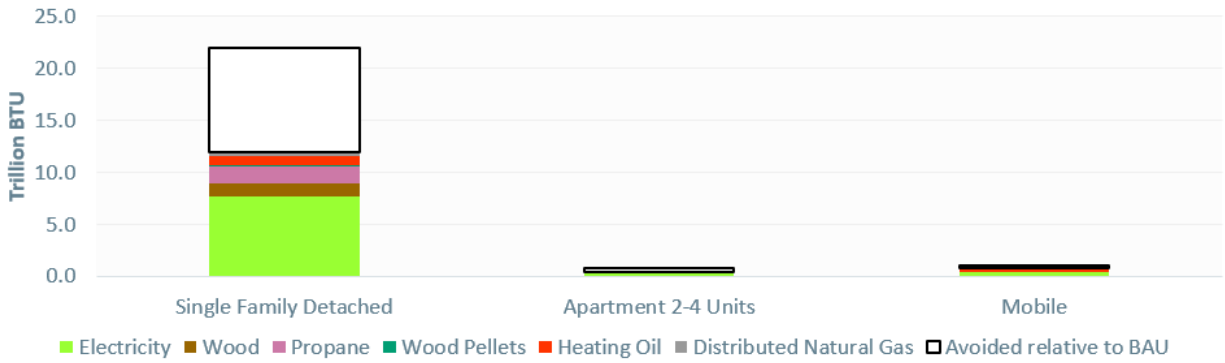
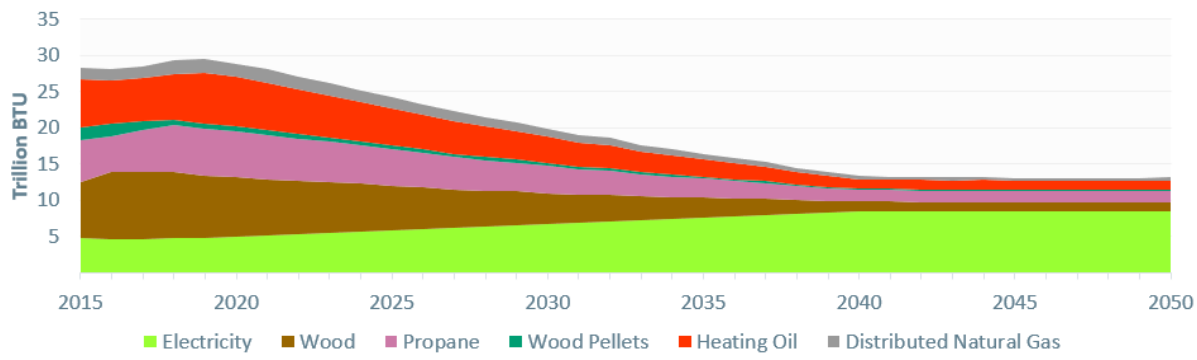


Figure 27 – Final Energy Demand in Rural Households by Fuel, for Central Mitigation Scenario



Direct GHG emissions from residential buildings are reduced by 0.48 $MMTCO_2e$ by 2030 and 0.91 $MMTCO_2e$ by 2050 in the Central and Local Electricity Resources Mitigation Scenarios compared to the BAU Scenario. In the Biofuel Emphasis Mitigation Scenario, GHG emissions from residential buildings decline by 0.53 $MMTCO_2e$ by 2030 and 1.03 $MMTCO_2e$ by 2050, relative to the BAU Scenario.

iii. Commercial Fuel Use

The Central and Local Electricity Resources Mitigation Scenarios both avoid 4.5 and 7.4 trillion BTU in total energy demand from commercial buildings by 2030 and 2050 relative to the BAU Scenario, respectively. The Biofuel Emphasis Mitigation Scenario avoids 3.5 and 7.1 trillion BTU in total energy demand from commercial buildings by 2030 and 2050 relative to the BAU Scenario, respectively.

Like for the residential sector, looking deeper into the Central Mitigation Scenario reveals insight into the source of these energy savings. Though not as aggressively deployed in the commercial sector as in households, heat pumps are an important mitigation option in the commercial sector because they displace other space heating fuels with electricity. Advanced wood heating and district heat also curb the BAU Scenario consumption of fossil fuels. The following two charts show the total number of commercial heat pumps in the Central Mitigation Scenario, and the energy impacts of all commercial mitigation options in that scenario, relative to BAU.

Figure 28 – Commercial Heat Pumps Added in the Central Mitigation Scenario

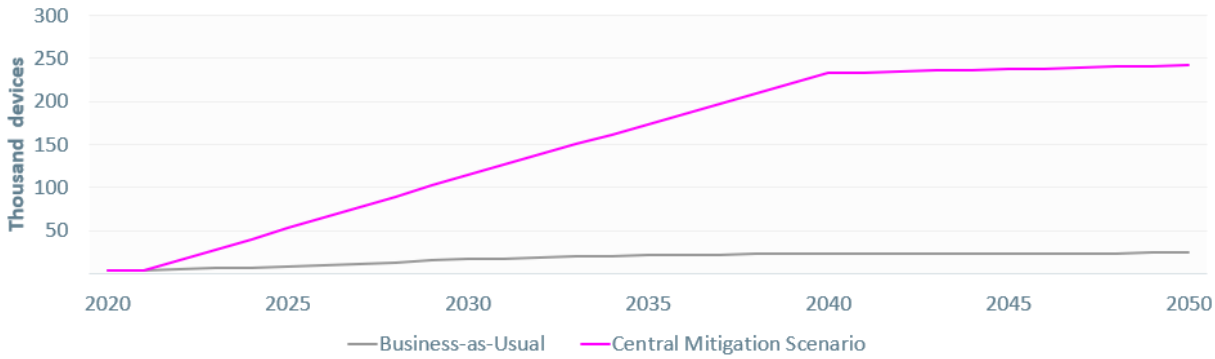
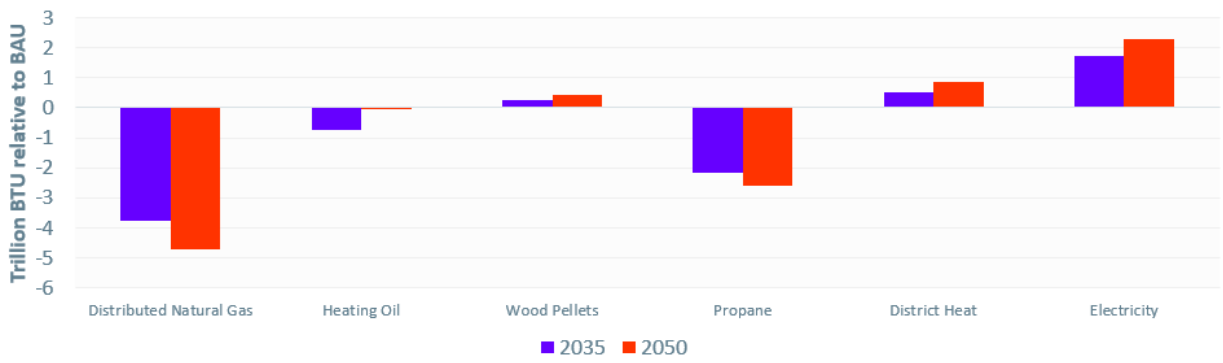


Figure 29 – Changes in Commercial Energy Consumption by Fuel, for the Central Mitigation Scenario Relative to BAU Scenario



Demand reductions are distributed among commercial end-uses, but the largest absolute reductions are within space heating, where electricity district heat and wood pellets predominantly displace gas and propane use. Figures 30 and 31 show these trends graphically.

Figure 30 – Commercial Energy Demand and Avoided Demand Relative to BAU Scenario, in the Central Mitigation Scenario in 2050

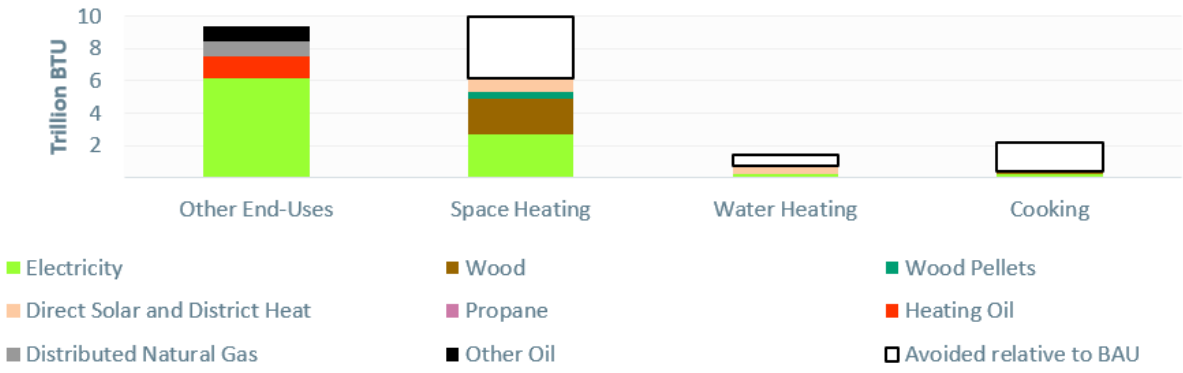
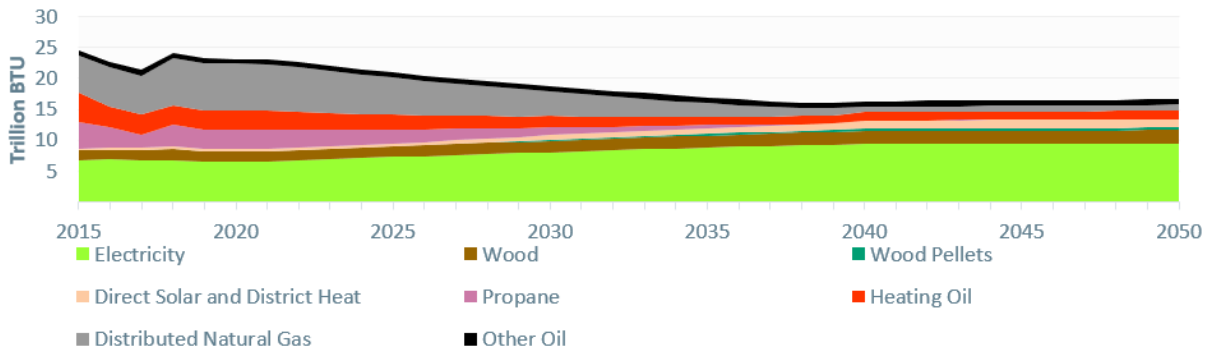


Figure 31 – Final Energy Demand in Commercial Sector, for Central Mitigation Scenario

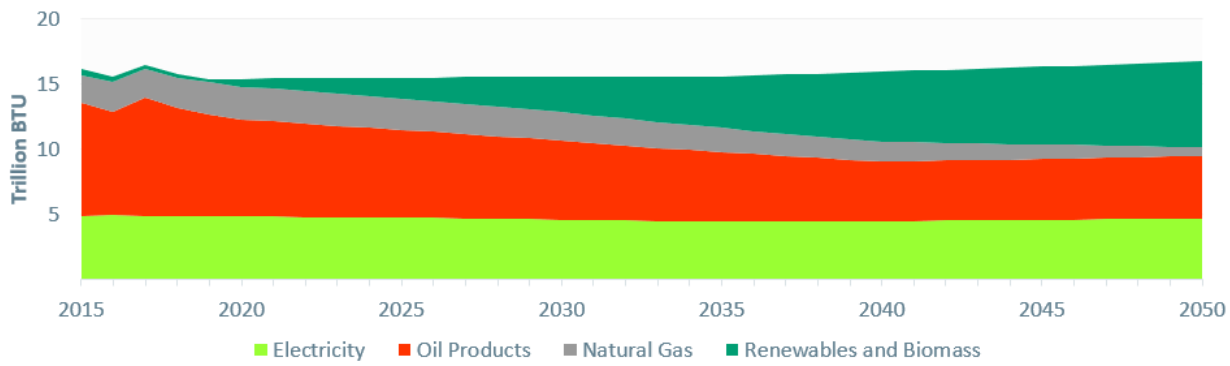


In all three mitigation scenarios, GHG emissions from commercial buildings are reduced between 0.38-0.43 $MMTCO_2e$ (a decrease of 44%-52%) by 2030 and between 0.61-0.7 $MMTCO_2e$ (a decrease of 75%-86%) by 2050, relative to the BAU Scenario.

iv. Industrial Fuel Use

In all three mitigation scenarios, GHG emissions from the industry sector are reduced 32.6% by 2030 and 78% by 2050 relative to the BAU Scenario. These reductions arise from the industry sector's partial substitution of fossil natural gas with biogas, and total substitution of diesel with biodiesel, as depicted in Figure 32. Some consumption of other oil products remains.

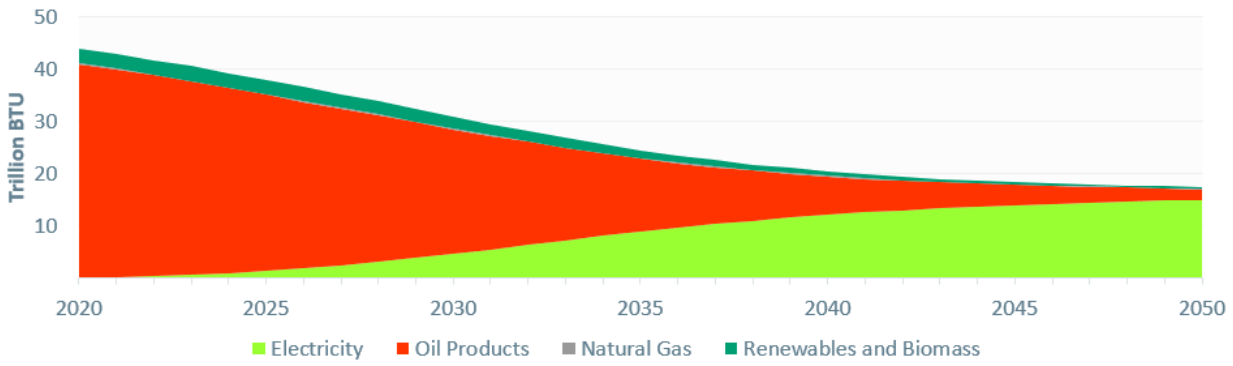
Figure 32 – Industrial Energy Demand by Fuel Group in All Mitigation Scenarios



v. Transportation Fuel Use

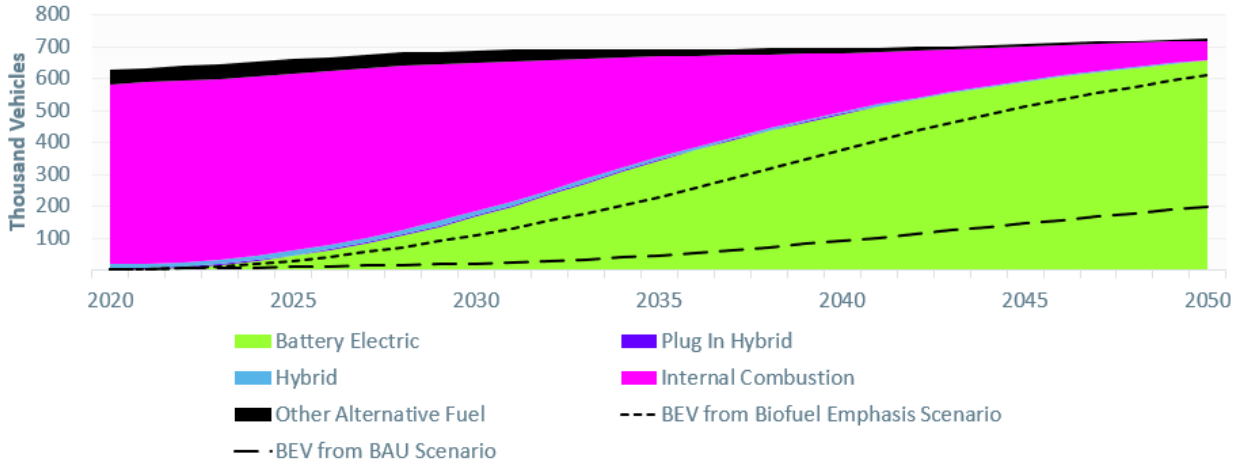
In the Central and Local Electricity Resources Mitigation Scenarios, total energy demand from the transportation sector (on- and off-road) declines from 49.5 trillion BTU in 2015 to 34.1 trillion BTU in 2030 (a decrease of 31%) and to 20.8 trillion BTU in 2050 (a decrease of 57.9%). In comparison, total energy demand from the transportation sector declines to 35.7 trillion BTU in 2030, (27.8%) and 21.5 trillion BTU in 2050 (56.5%) in the Biofuel Emphasis Mitigation Scenario. In the Central, Biofuel Emphasis, and Local Electricity Resources Mitigation Scenarios 5.3, 3.7, and 5.3 trillion BTU in energy demand from transportation are avoided by 2030 and 12.4, 11.7, and 12.4 trillion BTU in energy demand from transportation are avoided by 2050, respectively, compared to the BAU Scenario. The reduction in energy demand is almost entirely due to the large-scale electrification of the on-road vehicle fleet, seen in all mitigation scenarios. To give an example of the scale of this transition, on-road energy demand is shown in Figure 33 for the Central Mitigation Scenario.

Figure 33 – On-Road Energy Demand by Fuel in the Central Mitigation Scenario



On-road vehicle stocks by technology are displayed in Figure 34. The chart displays the total number of on-road vehicles each year for the Central Mitigation Scenario. For reference, the chart also overlays BEV stocks from both the BAU Scenario and Biofuel Emphasis Mitigation Scenario, which are distinguished as dashed lines. BEVs are singled out for comparison because they (as opposed to PHEVs) are the dominant EV technology in the model.

Figure 34 – Vehicle Stocks in the Central and Biofuel Emphasis Mitigation Scenarios by Technology



BEVs reach 91% of all vehicles by 2050 in the Central Mitigation Scenario. BEVs reach 84% of all vehicles by 2050 in the Biofuel Emphasis Mitigation Scenario.

In the Central and Local Electricity Resources Mitigation Scenarios, BEVs make up greater than 91% of all LDVs in 2050, compared to 30% in the BAU scenario (or, 35% when including PHEVs, to align with the VELCO low electrification forecast for LDVs). In the Biofuel Emphasis Mitigation Scenario, BEVs make up roughly 85% of all LDVs in 2050.

In the Central and Local Electricity Resources Mitigation Scenarios, MHD BEVs and PHEVs combined account for 86% of the MHD vehicle population, compared to just 21% in the BAU Scenario. In the Biofuel Emphasis Mitigation Scenario, BEVs and PHEVs account for 79% of MHD vehicles in 2050. In the Central and Local Electricity Resources Mitigation Scenarios, the

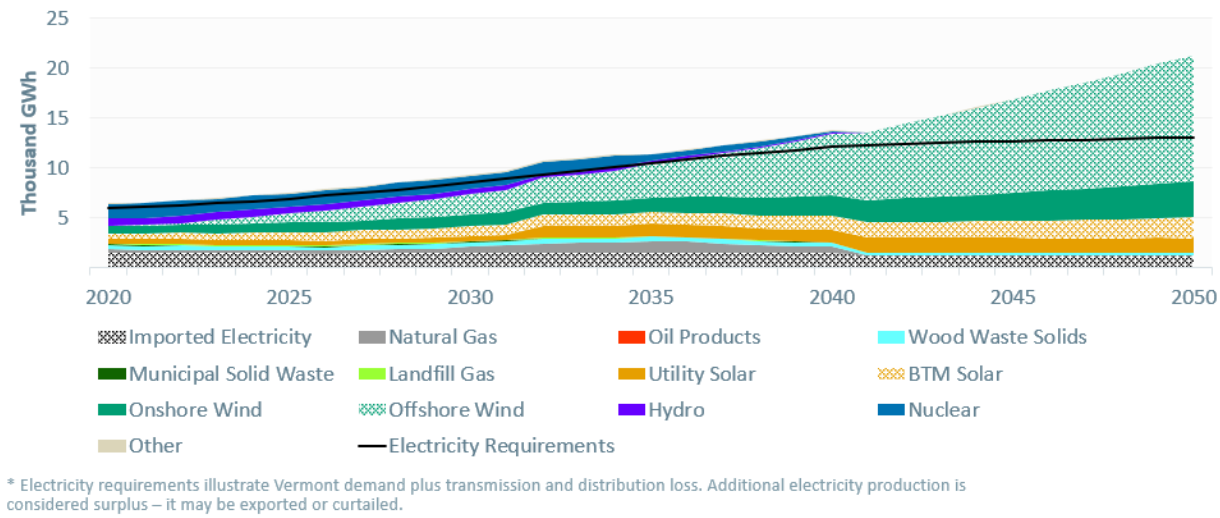
diesel-powered MHD vehicle population declines from 25,220 in 2020 to 6,640 in 2050, equivalent to a 74% reduction. Diesel-powered MHD vehicle stock declines to 9,820 in 2050, equivalent to a 61% reduction.

vi. Electricity Supply

In all three mitigation scenarios, electricity used by the state is fully renewable in all years after 2040, as renewable energy sources fully scale. Figures 35-37 depict the electricity mix in the three mitigation scenarios.

A characteristic shared by all mitigation scenarios and shown in Figures 35-37 is that electric supply in later years exceeds Vermont's annual electricity needs. Although the model makes no assumptions about whether this surplus energy would be exported, wasted, or curtailed production, it arises because of the non-dispatchable nature of wind and solar resources. Large quantities of renewable energy are needed to satisfy the 100% renewable requirement for electricity consumed in the state, especially as end-use electrification ramps up, and producing that energy requires substantial renewable generating capacity. But the model assumes that energy is generated whenever the wind or solar resource is available, regardless of demand. Some of this excess energy is absorbed and released by grid-connected battery storage (including V2G connectivity, in the Local Electricity Resources Scenario), but not enough to completely balance energy generation with demand on an annual basis. The model does not automatically invoke demand response measures or reallocate electricity demand away from the forecasted peak, which means that demand must be met in each modeled dispatch period, as specified by exogenous load profiles for each electric device.

Figure 35 – Electricity Mix in the Central Mitigation Scenario



* Electricity requirements illustrate Vermont demand plus transmission and distribution loss. Additional electricity production is considered surplus – it may be exported or curtailed.

In the Biofuel Emphasis Mitigation Scenario, as in the Central Mitigation Scenario, natural gas and nuclear energy phase out in 2040. In this scenario, BTM solar and utility solar play a smaller role in decarbonizing electricity in the years 2030 to 2040. However, renewables, such as on- and offshore wind and BTM and utility solar, generate nearly all electricity in 2050 as in the Central Mitigation Scenario.

Figure 36 – Electricity Mix in the Biofuel Emphasis Mitigation Scenario

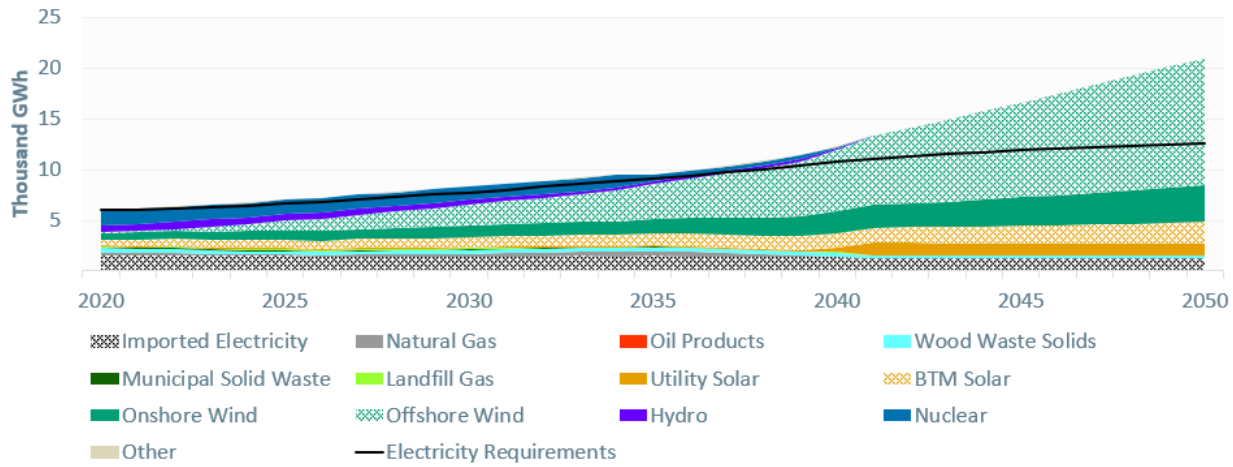
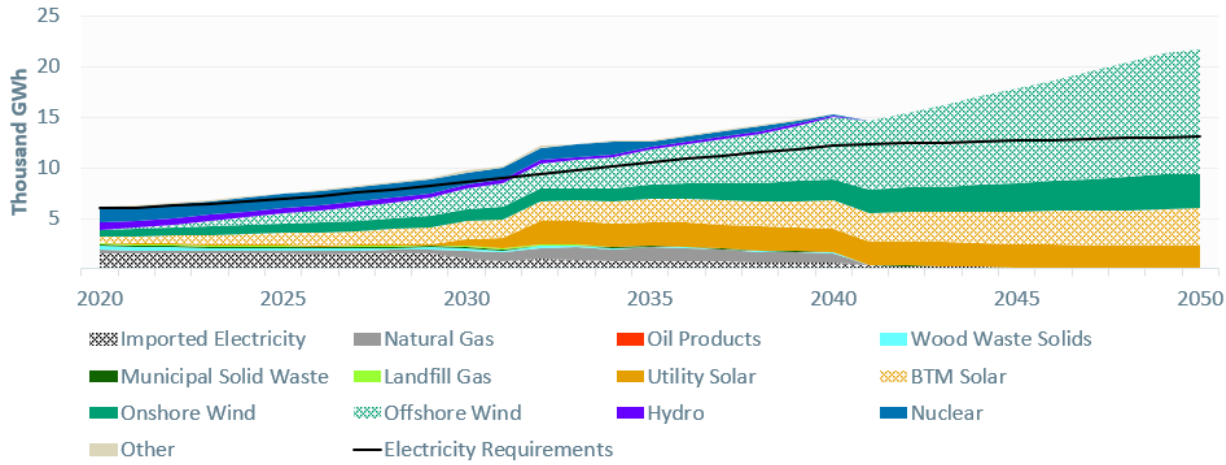


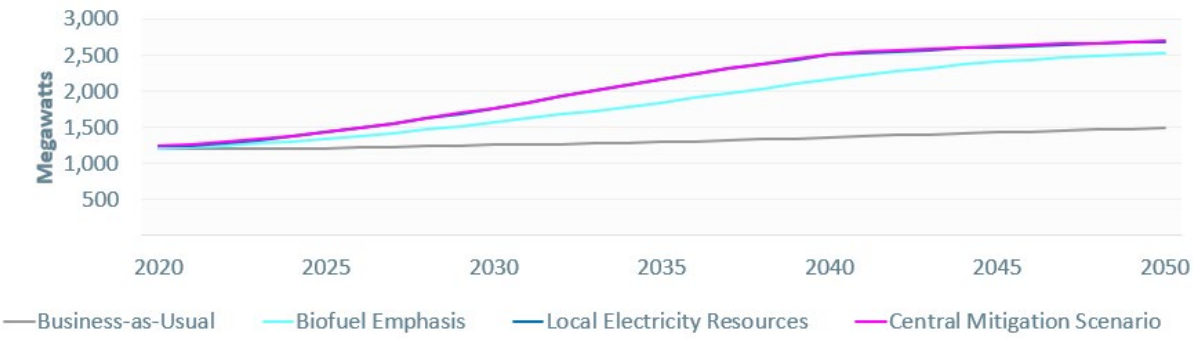
Figure 37 shows the electricity mix in the Local Electricity Resources Mitigation Scenario. In this scenario, BTM solar generates a significantly larger share of electricity by 2030 than in either the Biofuel Emphasis or Central Mitigation Scenarios.

Figure 37 – Electricity Mix in the Local Electricity Resources Mitigation Scenario



Because the model does not automatically reallocate electricity demand away from the forecasted peak, as electricity requirements grow, so too does system-wide peak load. The evolution of peak load, in both timing and in magnitude, is driven by new electric technologies like heat pumps and EVs that require energy during fixed periods. Figure 38 provides an overview of peak system load in each scenario.

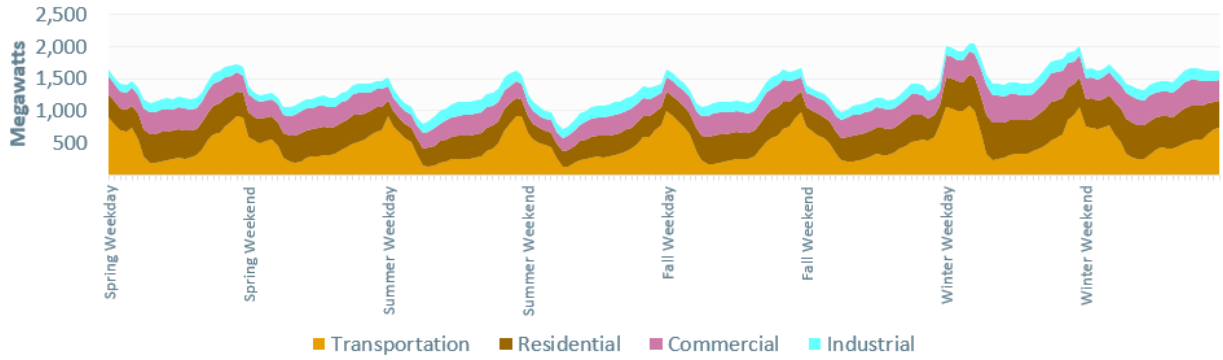
Figure 38 – Peak System Load through 2050



Electric load calculated in LEAP is gross of BTM solar, which is treated as a supply resource, and not as a load reducer.

Load growth is significant; to understand which sectors are responsible for the growth in peak system load, SEI examined the electricity demands from each sector, in each of the model's dispatch periods, for the final year of the scenario period.

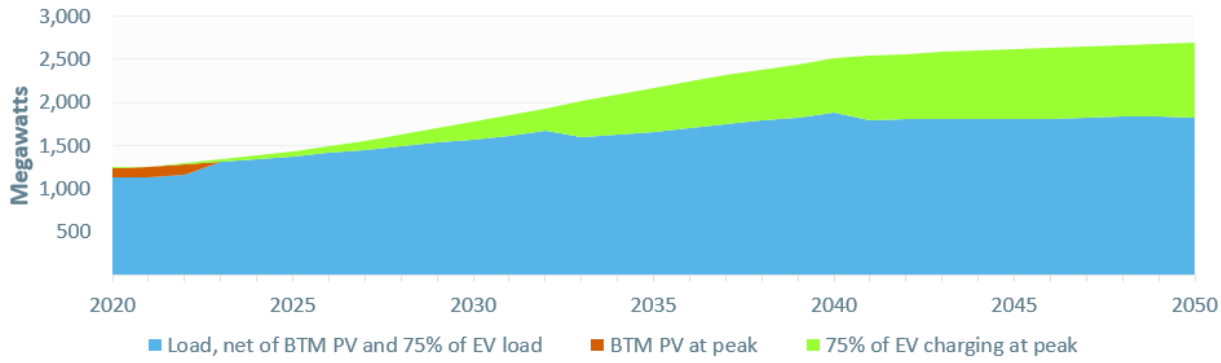
Figure 39 – Contributions to Electric Load by Sector in the Central Mitigation Scenario in 2050



Contributions are shown for each of the model's 192 dispatch periods, though for brevity, only the names of 24-hour groupings of dispatch periods are shown on the chart's abscissa.

Whereas current electricity demand patterns tend to peak during hot summer afternoons, by 2050 under the Central Mitigation Scenarios, these peaks would move to winter nights. This happens because of the overlapping requirements for electrified heating (peaking in winter) and EV charging (peaking during nighttime), in a scenario with significant penetration of EVs and heat pumps. For additional insight into peak load, PSD requested that SEI develop an auxiliary assessment of peak load that a) removes any expected BTM solar production, and b) subtracts three quarters of anticipated EV charging demand. The resulting figure is included below, for the Central Mitigation Scenario – note that BTM solar production only affects the calculation of net load early in the scenario, after which peak load occurs outside the hours of solar energy production.

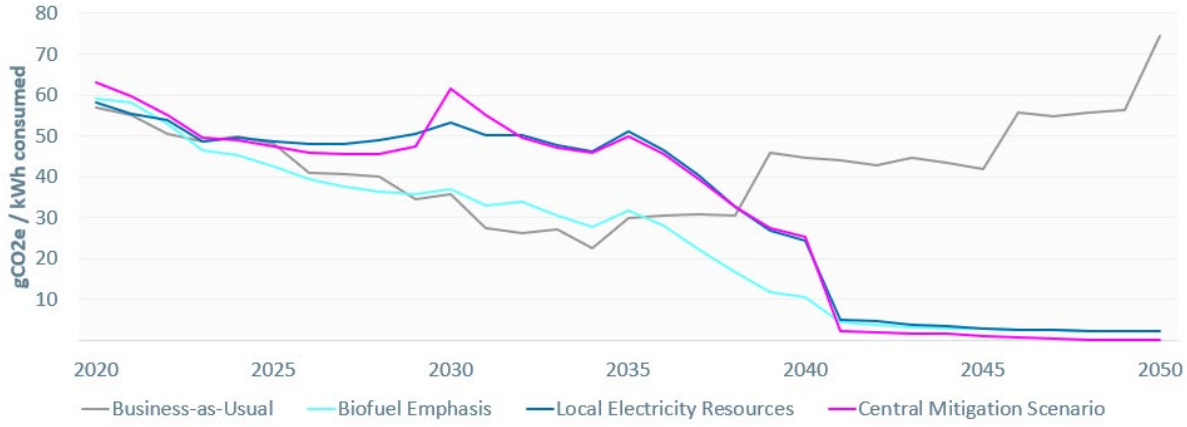
Figure 40 – Adjusted Net Peak Load in the Central Mitigation Scenario



The chart nets BTM solar production and 75% of EV charging demand (uprated for transmissions and distribution losses) at the time that peak load occurs.

As a result of the fast pace of electrification in the Central and Local Electricity Resources Mitigation Scenarios, absolute GHG emissions from electric consumption increase through 2035 in those scenarios before falling sharply in time to meet these scenarios' 100% renewable target. In fact, all mitigation scenarios exhibit higher absolute emissions than the BAU Scenario before approximately 2040. Measuring emissions using the GHG *intensity* of electricity (Figure 41) reveals more nuance, showing that all mitigation scenarios converge to less than 3 gCO_2e/kWh after 2040, whereas the BAU Scenario's GHG intensity begins to rise past 50 gCO_2e/kWh as natural gas-fired generation grows in the scenario's final decade.

Figure 41 – GHG Emissions Intensity of Electricity Consumed in Vermont



* "Proportional Reductions" shows GWSA targets applied to each sector individually. Proportional emissions for residential, commercial and industrial sectors cannot be disaggregated because they are combined in 1990 GHG inventory.

c. Economy-Wide Emissions

All three mitigation pathways follow a similar emissions trajectory, exceeding the 2025 target by similar amounts before achieving the 2030 and 2050 emissions goals. The following two charts show aggregate emissions, and a snapshot of where these emissions come from in the final scenario year.

Figure 42 – Gross (excluded LULUCF) GHG Emissions by Mitigation Scenario, with GWSA targets

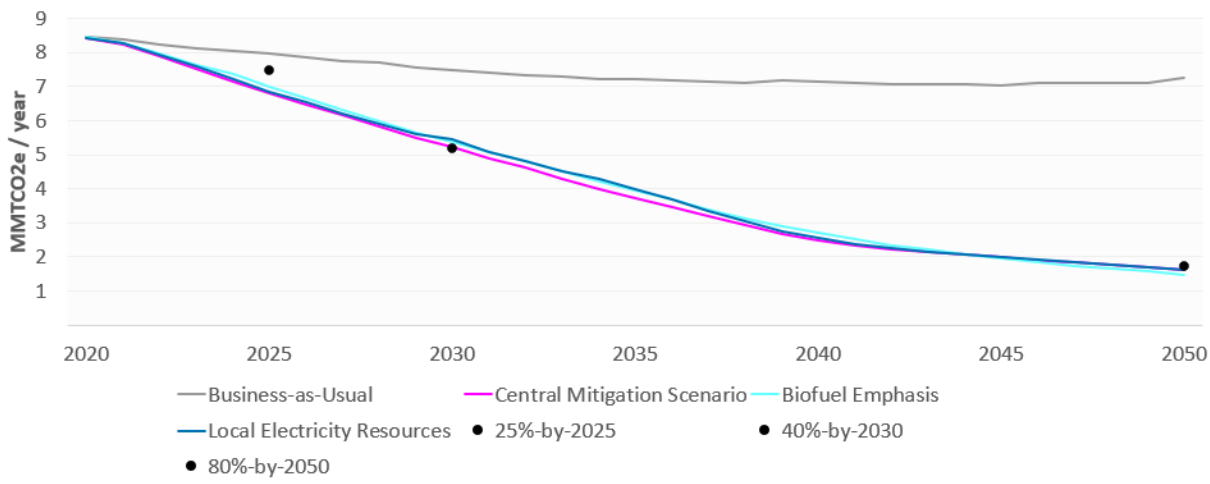
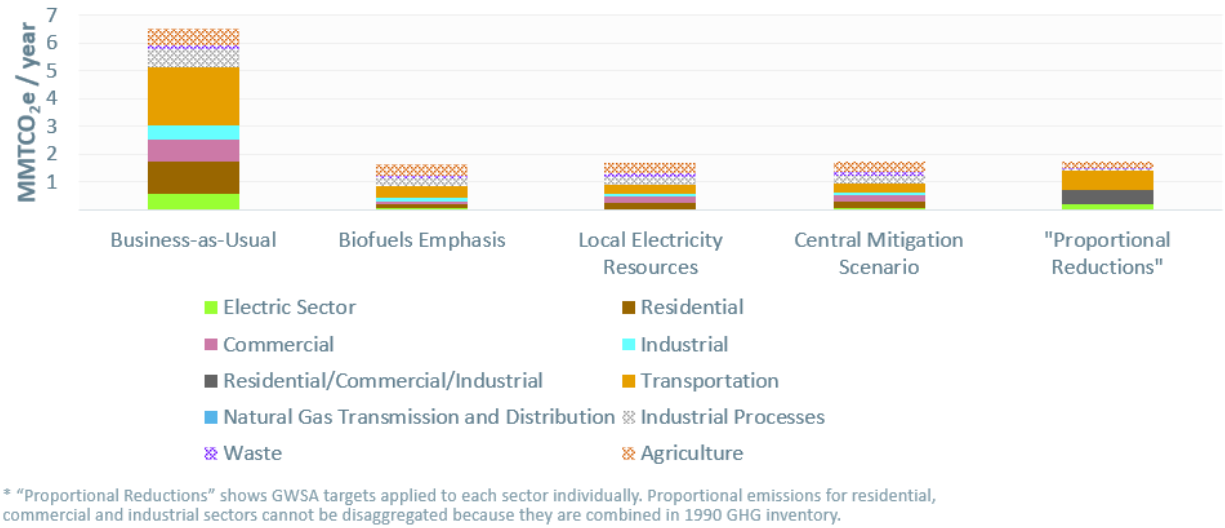


Figure 43 – Gross GHG Emissions in 2050 for Each Mitigation Scenario and BAU, Alongside the Emissions that Would Remain if Each Sector Reduced Emissions by the Same Proportion ("proportional reductions" applying GWSA targets to each sector individually)[108]

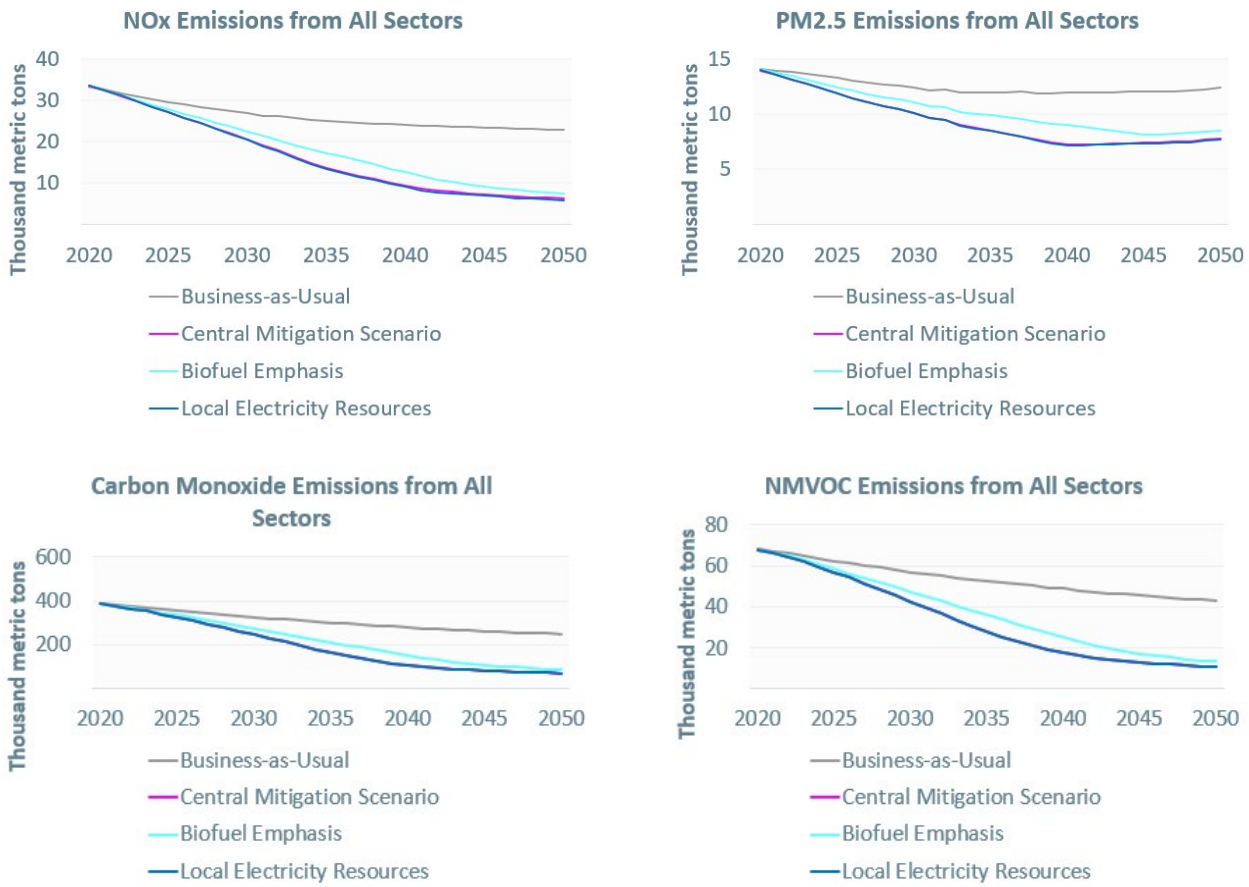


The emission reductions come from all sectors, with transportation and agriculture remaining the largest emitters in the year 2050 for all mitigation scenarios. Non-energy GHG emissions from agriculture, industrial processes and product use, and waste together comprise nearly half of the remaining GHGs emitted in Vermont in the year 2050. Compared to a future in which emissions from all sectors were abated proportionally, the mitigation scenarios presented in this analysis tend towards deeper cuts from the transportation sector, with shallower reductions included from the non-energy sectors.

[108] Proportional emissions for residential, commercial, and industrial sectors cannot be disaggregated because they are combined in 1990 GHG inventory.

All three GHG mitigation scenarios also achieve significant reductions in non-GHG pollutants, including $PM_{2.5}$, NO_x, NMVOCs, carbon monoxide, sulfur dioxide, black carbon, and lead through 2050 relative to the BAU Scenario. Cumulative reductions of these pollutants in the three GHG mitigation scenarios are equivalent to roughly 3,500 to 4,600 thousand metric tons compared to the BAU Scenario with the greatest overall reductions produced by the Central Mitigation Scenario. This scenario achieves reductions of 28%, 32%, and 31% for $PM_{2.5}$, NO_x, and NMVOCs through 2050, respectively, compared to the BAU Scenario. Non-GHG emissions reductions are not much lower for Biofuel Emphasis and Local Electricity Resources Mitigation Scenarios.

Figure 44 – Emissions of Other Pollutants in Mitigation Scenarios vs. BAU Scenario

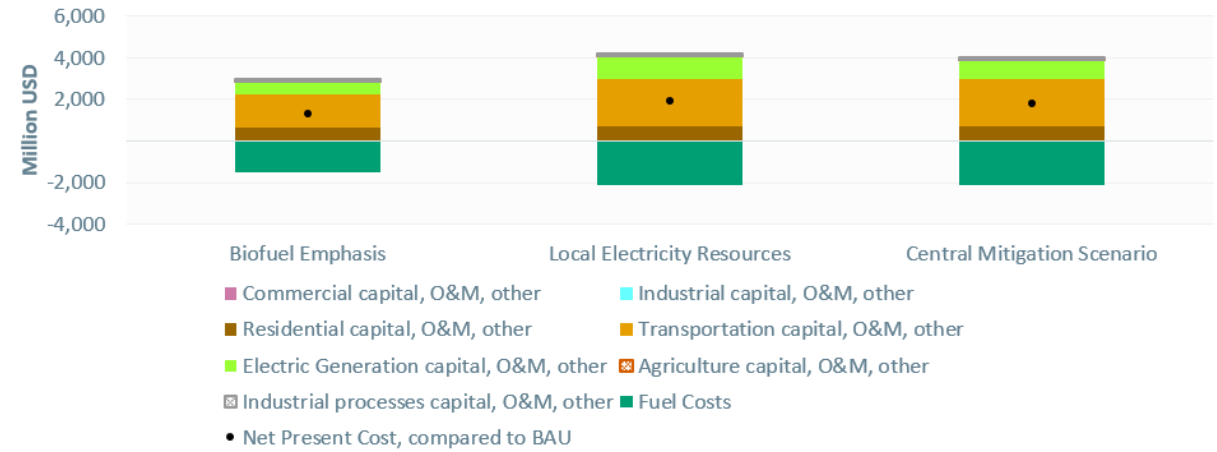


d. Cost of Mitigation

The Vermont LEAP model provides an engineering-based assessment of costs, or savings, which occur in one scenario relative to another. Its scenarios are helpful for evaluating the total costs that must be paid by adding up all cost inputs and displaying them self-consistently, but not who must pay them, nor how they may be financed. These questions should be considered carefully by policymakers as they enact incentives, rules, and legislation that are designed to unlock the mitigation potential estimated by this analysis.

In Figure 45, the costs of each mitigation scenario are shown relative to the BAU Scenario, where positive values indicate an added cost beyond the BAU, and negative values indicate a cost savings. Cost differences among scenarios years 2020 through 2030[109] are discounted back to 2019, and summed within each major cost category: capital, operations and maintenance, fuel costs, and other costs. When the cumulative, discounted cost for each cost category is summed, the result is the net present value of each mitigation scenario compared to BAU. The net present value (or cost, as is the case for positive values in Figure 45) is indicated by a solid black dot overlaid on each of the three bar charts. The Central and Local Electricity Mitigation Scenarios have a total estimated net present cost just below $2 billion, relative to the BAU. The Biofuel Emphasis Mitigation Scenario has an estimated net present cost of approximately $1.3 billion, relative to the BAU.

Figure 45 – Cumulative Discounted Cost of Mitigation Scenarios through 2030, Relative to BAU Scenario

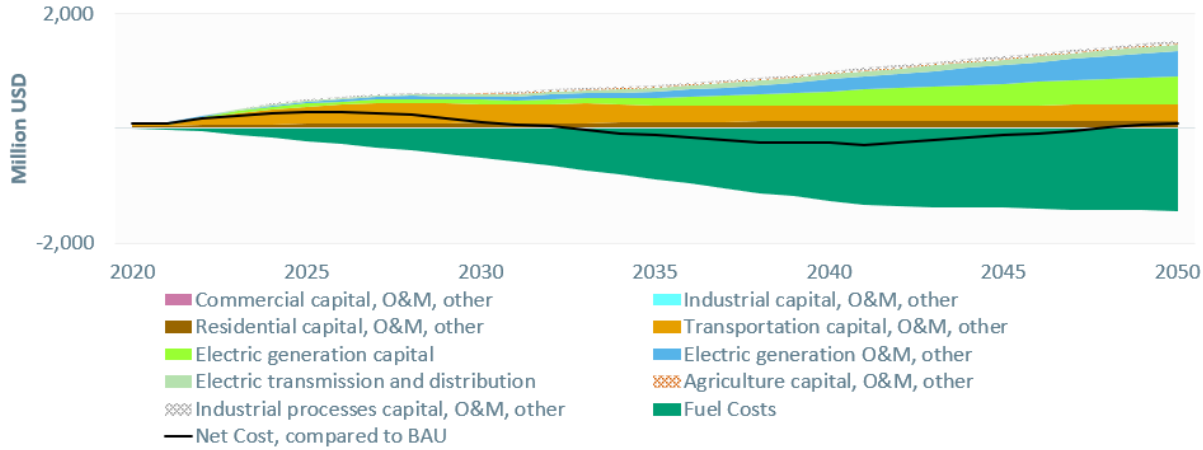


* Negative values indicate cost savings in a mitigation scenario, relative to BAU. A 2% discount rate is used for NPV calculations. Gross of all federal or state purchase incentives.

Fuel savings are incurred in each scenario relative to BAU, and while they are significant, they are not enough to offset the added costs found in each mitigation scenario. In each of the three mitigation scenarios, transportation-related costs (which include vehicle purchase costs, EV charging infrastructure, and costs associated with VMT reductions) make up the largest fraction of total costs. The second largest source of added cost comes from capital investment for the electricity sector, though from a present-value perspective these are attenuated because they tend to occur later. An assessment of costs over time for the Central Mitigation Scenario confirms this (see Figure 46), showing new annual investment needs every year for the next decade (the solid black line in the chart). In the decade after that, annual savings generally outweigh annual costs.

[109] The net present value of each scenario is estimated only for the near- and medium-term time horizon in the model. Although the full scenario time horizon extends through 2030, stakeholders reviewing intermediate modeling results observed that costs are especially uncertain more than a decade out and felt it would be inappropriate to show them as part of the synthesis in Figure 45.

Figure 46 – Real Mitigation Costs (positive values) or Savings (negative values) in Each Year, by Source, for the Central Mitigation Scenario Relative to the BAU Scenario



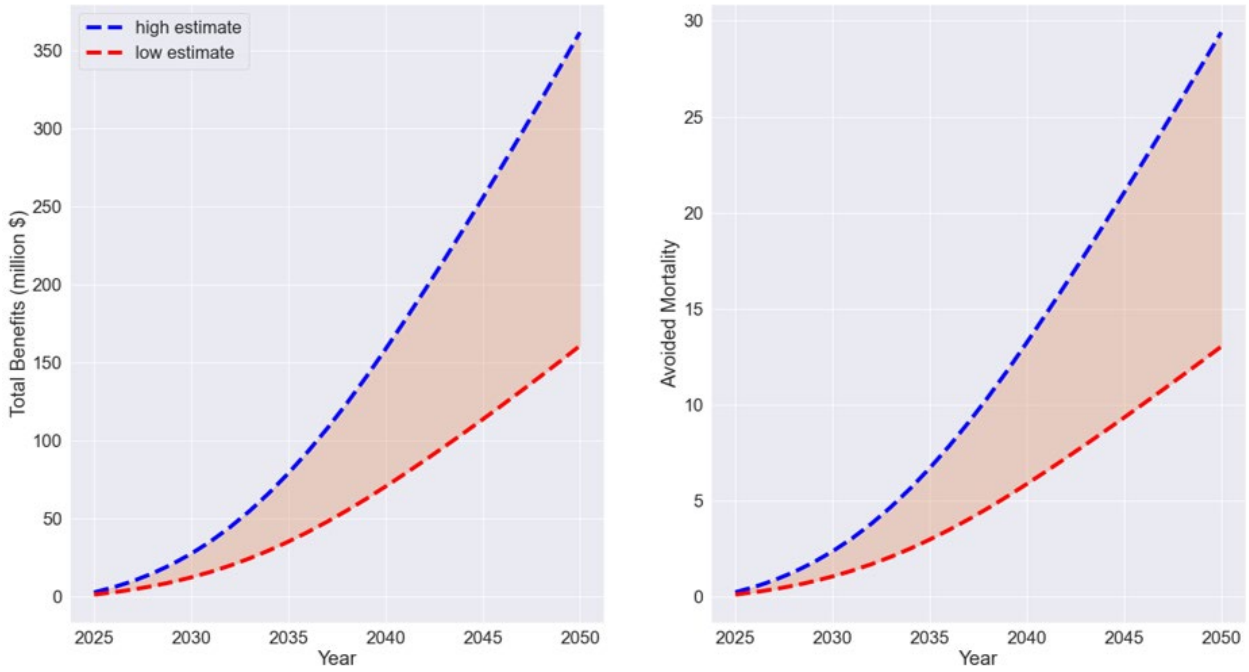
* Negative values indicate cost savings in the mitigation scenario, relative to BAU. Costs are real 2019 USD. Gross of all federal or state purchase incentives.

The modeling team recognizes that the cost assessment presented above gives an incomplete picture of the benefits, or impacts, associated with mitigation action under each scenario. Costs that are included in the model's input assumptions represent only those that are tangible and easily-monetizable: purchasing equipment, procuring fuel, paying labor costs for installation and maintenance, et cetera. But they ignore other forms of value, such as job creation, human and ecosystem health (although a separate component of this analysis does attempt to measure human health benefits), and importantly, the value of avoiding climate change, as embodied in a social cost of carbon. As a result, costs presented in Figure 46 should not be interpreted as reasons *not to act* to mitigate GHG emissions but should instead inform the reader of the relative differences in costs among the three mitigation scenarios.

e. COBRA Public Health Impacts Analysis

COBRA modeling for the Central Mitigation and Local Electricity Resources Scenarios yielded cumulative savings of $161 to $362 million between 2025 and 2050 (results for the two scenarios were virtually the same). The monetized benefits accrue because of the prevention of 13 to 29 premature deaths between 2025 and 2050 and a reduction in hospitalizations and emergency room visits. The left-hand graph in Figure 47 shows cumulative total benefits in millions of dollars for each calendar year between 2025 and 2050 and avoided mortality on the right for the same years. The high estimate is based on studies showing a higher incidence in mortality and hospitalizations at a given concentration of criteria air pollutants and the low estimate is based on studies showing a lower incidence of mortality and hospitalizations for a given concentration of criteria air pollutants. Health benefits increase over time as $PM_{2.5}$, SO_2, NO_x, and NMVOC are reduced from fuel switching, efficiency improvements, and reductions in combustion.

Figure 47 – Cumulative Total Benefits and Avoided Mortality, Mitigation Pathway



Cumulative benefits in the Biofuel Emphasis Mitigation Scenario were $126 to $284 million dollars between 2025 and 2050. The lower cumulative benefits in this scenario are due to higher $PM_{2.5}$, NO_x, and NMVOC as compared to the Central and Local Electricity Resources Mitigation Scenarios. Figure 44 showed differences in criteria air pollutant emissions reductions for the three mitigation scenarios. $PM_{2.5,}$ which is the largest driver of adverse health effects, is higher in the Biofuels Emphasis scenario because more residential woodstoves are retained than in the other two mitigation scenarios, which have higher levels of heating electrification. For NMVOCs, the main difference between the Biofuels Emphasis and the other two mitigation scenarios is greater gasoline consumption, due to lower levels of vehicle electrification. Residential woodstoves also play a secondary role in higher NMVOC emissions. For NO_x, the increased emissions in the Biofuels Emphasis scenario arises from lower vehicle electrification levels, in this case spread among a number of technologies in different vehicle classes that would otherwise have been displaced by more electric vehicles. For SO_2, the largest difference comes from households, again, with relatively higher wood stove penetration as well as oil furnaces.

f. Additional Environmental Benefits

In addition to health benefits associated with reductions in $PM_{2.5}$, NO_x, NMVOC, and SO_2, there are environmental benefits associated with reducing criteria air pollutants. These include reduced acidic deposition (acid rain) and improved visibility.

EPA conducts a periodic review of the secondary NAAQS for oxides of nitrogen and sulfur. In these reviews, EPA assesses the impact of oxides of nitrogen and sulfur in the ambient air, and their associated transformation products, such as deposited nitrogen and sulfur. The reviews

evaluate how emissions and deposition contribute to ecological effects.[110] Information from EPA's 2011 Policy Assessment is summarized below.

The combustion of fuels releases reactive oxidized nitrogen compounds into the air in both gaseous and particulate forms. The main reactive oxidized nitrogen compounds are nitric oxide (NO), nitrogen dioxide (NO_2), nitric acid (HNO_3), peroxyacetyl nitrate (PAN), nitrous acid (HONO), organic nitrates, and particulate nitrate (NO_3). Oxides of sulfur (SO_x) are defined as the sum of SO_2 and particulate sulfate (SO_4), which represent virtually all of the oxidized sulfur mass in the atmosphere.

Deposition of oxides of nitrogen and sulfur result in acidification of water bodies and terrestrial ecosystems. Soil that has been acidified often leaches into freshwater bodies and thus deposition onto land can impact the acidity of lakes and streams. Inorganic acids such as nitric acid and sulfuric acid deposited on soils can also enhance the mobility of toxic aluminum ions into water bodies, which can be lethal to aquatic biota. Deposition has been observed to alter sulfate and nitrate concentrations in surface waters, surface water pH, and dissolved toxic aluminum ions, among other impacts. These changes can result in the loss of acid-sensitive biological species such as salmonids, and disrupt the food web, causing alteration to the diet, breeding distribution, and reproduction of certain species of birds, such as goldeneye ducks and loons.

Deposited sulfates also enhance bacterial formation of methylated mercury in wetlands and water bodies. Methylated mercury is highly neurotoxic, and can bioaccumulate at higher trophic levels, such as in large predatory fish, as well as in birds and mammals, including humans, that eat fish.

In addition, ecosystems are highly sensitive to the acid neutralizing capacity of streams and lakes. When the neutralizing capacity of the water drops, the fitness of sensitive species such as brook trout begins to decline. With substantial declines, large declines in the health of fish populations have been observed. Moreover, acidification of lakes and streams can result in significant loss in economic value, according to EPA's Policy Assessment.

Acidification of forests has been shown to cause decreased growth and increased susceptibility to disease and injury in sensitive tree species, including red spruce and sugar maple. Forests of the Green Mountains of Vermont, the Adirondack Mountains of New York, and the White Mountains of New Hampshire are among the most sensitive to acidifying deposition. Economic studies cited in the EPA Policy Assessment suggest that avoiding significant declines in the health of spruce and sugar maple forests may be worth billions of dollars to residents of the eastern U.S.

In addition to acidification of water bodies and terrestrial ecosystems, criteria air pollutant emissions contribute to regional haze. Small particles, such as those formed from NO_x, SO_2, and woodsmoke, can scatter and absorb light, limiting the distance that one can see and obscuring color and clarity. Visibility can often be reduced over large regions, and is therefore called regional haze. Haze makes the outline of a skyline or a natural vista difficult to see. Regional haze is both a summertime and wintertime issue. Sulfur dioxide historically was the largest

[110] U.S. Environmental Protection Agency, "Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur," February 2011.

contributor to haze in the eastern U.S. through the formation of sulfates, but oxides of nitrogen are becoming increasingly important as SO_2 emissions from coal-fired power plants have significantly decreased in recent years. Oxides of nitrogen are converted to nitrates that are more thermally stable during the winter, and are becoming a relatively greater contributor to regional haze during this season. Secondary formation of particulate enhanced by the presence of NO_x is also a contributor in the summertime. While regional visibility has improved in recent years, regional haze has at times over the past decade reduced visibility in national parks and wilderness areas in the eastern U.S. from an average of 90 miles down to 15-25 miles.

The environmental benefits of reducing NO_x, SO_2, and primary particulate emissions in the three mitigation scenarios analyzed in the Vermont LEAP analysis have not been quantified in this study. However, a general discussion of the environmental impact of these reductions on the environment is relevant here because the analysis shows reductions of up to 80% in emissions relative the BAU by 2050. Reductions of this magnitude manifesting in lower sulfates, nitrates, and other particulates will substantially improve aquatic and terrestrial ecosystem pH, ecosystem health, and visibility in the region.

Findings and Discussion for Vermont LEAP and Health Benefits Analyses

The findings from the Vermont LEAP analysis are as follows:

- The three GHG mitigation scenarios analyzed differ in the implementation rates of some mitigation measures and combinations of mitigation measures. In general, however, all scenarios share common features in order to achieve Vermont's 2030 and 2050 GHG emissions reduction targets, such as relying upon deep decarbonization of the electricity sector coupled with extensive electrification of the buildings and transportation sectors.
- In all three mitigation scenarios, forecasted GHG emission reductions exceed the abatement necessary to achieve Vermont's GWSA requirement of 26% from 1990 levels by 2025. The model also illustrates that it may be possible to meet the 2025 goal under BAU conditions, but this outcome should be interpreted cautiously. The year 2025 is approaching quickly, and recent trends have had a large impact on the state's energy system and GHG emissions (most notably, the COVID-19 pandemic and eventual economic recovery). These changes are generally too recent to be captured in the historical data on which this analysis is founded, and the BAU modeling assumes the continuation of trends in the first half of the decade – trends that may already have been disrupted.
- The scenario analysis shows the GHG targets for 2030 and 2050 can be met using different mixes of technologies and fuels.
- The 2030 target is an ambitious target that requires immediate and increased introduction of GHG reducing technologies such as heat pumps and EVs. Given the slow vehicle fleet turnover rates and retirement of household heating and other systems, technology introduction needs to begin immediately and ramp up quickly.
- The 2050 target is achievable but requires substantial reductions from all sectors. The three mitigation scenarios converge given the need to achieve substantial reductions from all sectors. Non-energy sectors comprise almost half of the remaining emissions in 2050

for all mitigation scenarios, which points to the importance of exploring these sectors further and developing practices to monitor the effectiveness of large carbon sinks like agricultural soils.

- The analysis assumes that a supply of biofuels, including biogas, biodiesel for transport or heating oil, ethanol, and even wood and pellets, will be available to meet the state's needs, and at the cost prescribed in the model's assumptions. However, market availability of biofuels to meet the demand in each scenario has not been evaluated.
- Dynamic load flexibility will be important for the smooth integration of intermittent and seasonal renewable electricity sources. The modeling assumes some grid- and vehicle-based battery energy storage but does not fully explore technical approaches for including dispatchable energy demand that reallocate electricity demand away from peak times.
- The introduction of electrification in all sectors will increase peak electricity load and thus complementary policies are needed to ensure that peak loads are managed. These policies could be in the form of time of use rates, incentives or requirements for additional storage, or other policies and approaches.
- In the three mitigation scenarios, there is over-production of electricity due to the need to provide 100% renewable electricity during all dispatch periods. A resource mix that is completely renewable is qualitatively different than one that is not, even if it achieves 95% or more renewable penetration. This poses a challenge and an opportunity for the regional electrical grid. If built, large amounts of generation capacity could be put to productive use when generation exceeds demand. Demand response or additional energy storage could also be deployed to reduce the gap between supply and demand, during periods of high renewable production but low electricity demand.
- Mitigation costs in different sectors show a mild tendency to concentrate in different periods of the scenario timeline. For example, transport system investment must happen relatively quickly in order to affect a slowly turning over transport fleet, whereas the largest investments in electricity production happen towards the final decade, leading up to the achievement of 100% renewable electricity.
- The cumulative health benefits associated with the Central and Local Electricity Resources Mitigation Scenarios were estimated to be between $161 to $363 million dollars between 2025 and 2050. Cumulative health benefits of $126 to $284 million dollars were estimated for the Biofuel Emphasis Mitigation Scenario for the same time period.
- The environmental benefits of reducing emissions of NO_x, SO_2, and primary particulates could provide substantial monetary savings by reducing ecosystem acidification and regional haze. These potential benefits have not been monetized in this study.

a. GHG Mitigation Strategies in the Northeast States

This subsection describes, by sector, the individual GHG mitigation strategies deployed by Connecticut, Maine, Massachusetts, New Jersey, New York, and Rhode Island. For a more comprehensive list of mitigation strategies in these northeast states, please see *Appendix C: Table C.1 – Sector-Specific Mitigation Strategies in the Northeast States.*

i. Electricity Generation Sector

GHG mitigation strategies within the electricity generation sector consist of two primary actions: 1) increasing renewable energy resources and storage development and 2) reducing energy demand through grid modernization and deployment of smart management technologies to optimize the flexibility of distributed energy resources (DERs).

Across the northeastern region, states are seeking to increase the procurement and development of zero carbon electricity generation sources connected to the regional electricity system operated by New England ISO. States are using RPSs to require increasing procurements of zero carbon sources, including offshore wind, solar, and battery storage. In addition, states are looking to retain existing zero carbon electricity generation from nuclear power plants and develop near-term plans to replace nuclear generation with renewable sources like wind and solar.

Grid modernization and energy demand management is the other primary strategy for reducing emissions from this sector. States seek to replace inefficient heating and cooling technologies with renewable thermal technologies and optimize flexibility of these and other DERs to reduce energy demand, increase development of cost-effective microgrids, and implement community solar programs with a focus on low- and moderate-income (LMI) households.

Lastly, some states are exploring additional innovative approaches to accelerate decarbonization of the electricity generation sector. Massachusetts' Clean Peak Standard seeks to provide incentives to clean energy technologies that can supply electricity or reduce demand during seasonal peak demand periods.[111] New Jersey is exploring rules that limit CO_2 emissions from electric generating units. States plan to utilize green banks to provide innovative financing and low-interest loans to support in-state clean energy projects.

ii. Transportation Sector

Strategies for reducing transportation sector GHG emissions revolve around replacing all classes of internal combustion engine vehicles with EVs and reducing overall VMT. States currently utilize a menu of strategies to accelerate EV deployment, such as providing purchase incentives for light-, medium-, and heavy-duty EVs, expanding Level 2 and DC fast charging infrastructure, and developing time-of-use rates and demand charge relief programs to improve economics of EV charging. Most of the northeastern states provide purchase incentives for light-duty passenger EVs, and both Massachusetts and New York provide purchase incentives for MHD vehicles. Furthermore, many states utilize Volkswagen Settlement, Congestion Mitigation and Air Quality Improvement, Diesel Emissions Reduction Act, and other federal and state funding programs to incentivize the purchase of electric trucks and buses.

In addition to electrifying vehicles, adopting California's low- and zero-emission vehicle (LEV and ZEV) standards through Section 177 of the Clean Air Act is an important tool for continuing to realize emissions reductions from all classes of on-road vehicles. Several states are adopting California's Advanced Clean Truck, Low-NO_x Omnibus, and Advanced Clean Fleets rules to

[111] Clean Peak Energy Standard. Emerging Technology Division, Massachusetts Department of Energy Resources. Accessible at https://www.mass.gov/clean-peak-energy-standard.

lower emissions from trucks and buses. States in the region will be seeking to adopt California's Advanced Clean Cars II regulation once finalized by California. In addition, states are leading by example by setting targets for electrifying state-owned and operated fleets.

Advancing state and local initiatives that slow annual VMT growth, such as implementation of transit-oriented development, supporting mixed use-use development, increasing employee options to work from home, and expanding public transportation (bus and rail) and micro-mobility options such as bicycles can lead to greater GHG reductions from the transportation sector. Some states seek to increase the use of renewable biofuels for transportation as well.

iii. Buildings Sector (Commercial and Residential)

The primary strategies for reducing emissions from commercial and residential buildings are enacting increasingly energy efficient state and municipal building codes, improving building insulation shell efficiency (weatherization), and replacing inefficient heating and cooling appliances with renewable thermal technologies such as heat pumps and heat pump water heaters. Some northeast states offer financial incentives toward the installation of these and other energy efficient appliances, while others have implemented Property Assessed Clean Energy (PACE) programs to help finance the deployment of these technologies. Specific to nonresidential buildings, state governments are expanding their efforts to benchmark energy consumption and associated GHG emissions in state-owned and -leased buildings and set targets for reducing energy consumption and emissions from these buildings.

In addition, states seek to transition away from oil, natural gas, and propane heating in new construction by implementing renewable fuels standards and phasing out incentives for fossil fuel equipment such as natural gas boilers. Adopting progressive building codes that align or surpass the International Energy Conservation Code will increase the energy efficiency of all buildings.

iv. Industry Sector

Within the industry sector, building energy audits and benchmarking, commitments to energy efficiency upgrades, and DER deployment are the key strategies for reducing emissions. Some states are developing voluntary incentive programs for industries to reduce the carbon intensity of their operations, install combined heat and power systems, and capture waste heat for reuse.

v. Non-Energy Emissions

Across the northeast region, states are exploring options to increase carbon sequestration in natural and working lands. Strategies include improving forest management and conservation, reforestation, protecting and restoring inland and coastal wetlands, and supporting no net loss of forest and farmland. Massachusetts' Healthy Soils Action Plan is designed to support best management practices that protect the health of ecosystems and enhance carbon capture capacity of soils. New York seeks to produce and convert sustainable feedstocks for electricity, heat, and steam production while maximizing the energy efficiency of agricultural and working lands.

Lastly, some states are enacting policies that reduce food waste and utilize food waste as a feedstock for energy production.

b. Opportunity for Synergies with the Other Northeast States

The New England states' economies are all interconnected and as a result, the success of any market-based policy or program would likely depend upon coordination among the states. The New England states are linked by a regional electricity grid and generally move in the same direction to address climate change. That being said, individual states can enact market-based policies or programs, but these programs will be more effective when implemented by the New England states as a bloc. One such example is the Regional Greenhouse Gas Initiative (RGGI), which is a market-based effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia to cap and reduce CO_2 emissions from the electric generation sector. Regional Greenhouse Gas Initiative carbon allowance auctions have generated over $4.3 billion in proceeds that participating states have used to invest in energy efficiency, renewable energy deployment, GHG abatement, and direct electricity bill assistance.

All New England states have enacted an RPS that requires electricity suppliers to deploy increasing amounts of clean and renewable energy to meet electricity demand. As such, the New England states should continue to coordinate efforts to decarbonize the regional electricity generation mix, and this includes developing a shared approach to harvesting biomass for energy generation. Studies have found that clearing forests to grow biomass results in additional GHG emissions that take decades to recoup. Vermont and the other New England states must ensure that biomass harvested for energy generation is grown sustainably on previously cleared land, such as under-utilized farmland, in order to avoid new GHG emissions.

Conclusion

All three GHG mitigation scenarios enable Vermont to achieve its 2030 and 2050 GHG reduction targets using known technologies and resources. Each scenario relies heavily on deep decarbonization of the electricity grid coupled with electrification of end-use energy consumption, with particular respect to commercial and residential buildings and transportation sectors. Rapid deployment of low-carbon and zero-carbon technologies, such as BEVs and ASHPs at scale, is critical to achieving GHG emissions reductions. Policies being developed and adopted in other states can provide a model for Vermont as it designs programs to reach the state's GHG targets.

Appendix A: Key Sources of Cost Data

Table A.1 – Historical and Forecasted Fuel Supply Costs by Source

Source	Fuel Type(s)
Historical Costs	
U.S. Energy Information Administration (2021), SEDS 2019 Updates	Natural gas; nuclear; jet kerosene
Vermont Fuel Survey Memo, NMR Group, Inc. (2016)	Wood; wood pellets
U.S. Energy Information Administration. Form EIA-63C, Monthly Densified Biomass Fuel Report, March 18, 2021	Wood waste pellets
Argonne National Laboratory, VISION Model AEO 2020 Base Case	Ethanol; biodiesel
Vermont Public Service Department. Retail Prices of Heating Fuels (2021)	Diesel; gasoline; distillate fuel oil; propane
Evolved Energy Research. *Massachusetts 2050 Decarbonization Roadmap*	Biogas
Forecasted Costs	
New Hampshire Office of Strategic Initiatives, Fuel Prices (2021)	Wood
New Hampshire Office of Strategic Initiatives, Wood Pellet Pricing Survey (2019)	Wood pellets
U.S. Energy Information Administration, AEO 2021	Natural gas; nuclear; other oil; asphalt and road oil; lubricants; all varieties of coal for power generation; kerosene; gasoline; diesel; distillate fuel oil; propane; residual fuel oil
Argonne National Laboratory, VISION Model AEO 2020 Base Case	Ethanol; biodiesel; compressed natural gas
Vermont Public Service Department, Retail Prices of Heating Fuels (2021)	Kerosene
U.S. Energy Information Administration (2021), SEDS 2019 Updates	Other oil; asphalt and road oil; lubricants; residual fuel oil; all varieties of coal for power generation

Other Assumptions	
Fuel costs assumed to be zero	Other biomass liquids; black liquor; sludge waste; tire-derived fuels; municipal solid waste; landfill gas; solar; wind; hydro

Table A.2 – Electricity Supply Costs by Data Source and Technology

Electric Generation Cost Type	Source of Cost Data	Technology
Capital Costs (current, and where available, forecasted)	U.S. Energy Information Administration. "Assumptions to the Annual Energy Outlook 2015," September 2015. https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2015).pdf.	Petroleum Liquids; Municipal Solid Waste
	U.S. Energy Information Administration. "Assumptions to the Annual Energy Outlook 2020: Electricity Market Module," January 2020. http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.	Landfill Gas; Natural Gas Internal Combustion Engine; Natural Gas Steam Turbine; Other Natural Gas (fuel cell)
	National Renewable Energy Laboratory. 2020 Annual Technology Baseline (version 2020). National Renewable Energy Laboratory, 2020. https://atb.nrel.gov/electricity/2020/index.php.	Batteries; Conventional Steam Coal; Conventional Hydroelectric; Natural Gas Fired Combined Cycle; Natural Gas Fired Combustion Turbine; Nuclear; Onshore Wind; Offshore Wind; Solar Photovoltaic; BTM Photovoltaic (distinguished as "distributed residential solar PV" in source); Wood, Wood Waste, Biomass
Fixed Operation and Maintenance Costs, Variable Operation and Maintenance Costs	U.S. Energy Information Administration. "Assumptions to the Annual Energy Outlook 2015," September 2015. https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2015).pdf.	Municipal Solid Waste
	U.S. Energy Information Administration. "Assumptions to the Annual Energy Outlook 2020: Electricity Market Module," January 2020. http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.	Petroleum Liquids; Landfill Gas; Natural Gas Internal Combustion Engine; Natural Gas Steam Turbine; Other Natural Gas (fuel cell)
	National Renewable Energy Laboratory. 2020 Annual Technology Baseline (version 2020). National Renewable Energy Laboratory, 2020. https://atb.nrel.gov/electricity/2020/index.php.	Batteries; Conventional Steam Coal; Conventional Hydroelectric; Natural Gas Fired Combined Cycle; Natural Gas Fired Combustion Turbine; Nuclear; Onshore Wind; Offshore Wind; Solar Photovoltaic; BTM Photovoltaic (distinguished as "distributed residential solar PV" in source); Wood, Wood Waste, Biomass

Appendix B: Technologies Deployed in BAU Scenario and GHG Mitigation Scenarios

Table B.1 – Summary of Low- and Zero-Carbon Technologies in Key Sectors of the Mitigation Scenarios

Sector	Low- and Zero-Carbon Technologies & Resources	Low- and Zero-Carbon Technology and Resource Splits			
		BAU Scenario	Central Mitigation Scenario	Biofuel Emphasis Mitigation Scenario	Local Electricity Resources Mitigation Scenario
Electricity Generation	Solar; wind	Existing renewable energy standard is met each year, reaching 75% by 2032; existing Hydro-Quebec import contract ends after 2038	From 2032-2041, the renewable energy standard increases to 100%; existing Hydro-Quebec import contract is renewed after 2038	From 2032-2041, the renewable energy standard increases to 100%; existing Hydro-Quebec import contract is renewed after 2038	Over twice as much BTM solar capacity is brought online compared to the Central Mitigation Scenario; Hydro-Quebec import contract ends in 2030

Sector	Subsector	Low- and Zero-Carbon Technologies & Resources	Low- and Zero-Carbon Technology and Resource Splits			
			BAU Scenario	Central Mitigation Scenario	Biofuel Emphasis Mitigation Scenario	Local Electricity Resources Mitigation Scenario
Buildings	Residential/ Commercial	High-efficiency air- and ground-source heat pumps; heat pump water heaters; electric stoves and ovens; B20 biodiesel; B100 biodiesel; renewable natural gas; building shell improvements; advanced pellet boilers	0.2%-6.5% of household water needs met by heat pumps and no commercial heat pump water heaters; approximately 240,000 heat pumps deployed by 2050, 90% of which are in households, 89% of residential heat pumps are air-source, and one household heat pump displaces 40% of alternative heating technologies; electric	By 2035, heat pump water heaters meet all water heating needs; by 2040, high-efficiency air- and ground-source heat pumps supply 80% of home heating needs, air-source heat pumps heat 80% of commercial floorspace; by 2035, electricity replaces fossil fuels for cooking; 5%/15%/25% of natural gas consumed for building uses is displaced by	By 2035, heat pump water heaters meet all water heating needs; heat pumps meet 70% of home and commercial heating needs by 2045; by 2035, electricity replaces fossil fuels for cooking; residential heat pumps proportionally displace all alternative heating technologies, commercial heat pumps proportionally displace all gas, oil,	By 2035, heat pump water heaters meet all household and commercial water heating needs; by 2035, electricity replaces fossil fuels for cooking; by 2040, high-efficiency air- and ground-source heat pumps supply 80% of home heating needs, air-source heat pumps heat 80% of commercial floorspace; 5%/15%/25% of natural gas consumed for building

			stoves and ovens in 48%-100% of households; 41% of commercial space uses electric cooking appliances; renewable natural gas not consumed in buildings; no biodiesel blending in heating oil; 2,430 residential retrofits/year by 2040	renewable natural gas by 2025/2030/2050; by 2050, biodiesel blend in building heating oil reaches 20%-by-volume (B20); 10,770 residential retrofits/year reached by 2040; by 2045, advanced pellet boilers replace 20% of residential and commercial propane and oil boilers	propane boilers; 10%/20%/80% of natural gas consumed for building uses is displaced by renewable natural gas by 2025/2030/2050; by 2040, building heating oil reaches 100% biodiesel (B100); 10,770 residential retrofits/year reached by 2040; by 2045, advanced pellet boilers replace 25% of residential and 30% of commercial propane and oil boilers; for existing buildings (classified as housing stock built after 2015 and commercial floorspace after 2007), pellet boilers displace only 90% of the alternative	uses is displaced by renewable natural gas; by 2050, biodiesel blend in industrial and transport diesel, building heating oil reaches 20%-by-volume (B20); 10,770 residential retrofits/year reached by 2040; by 2045, advanced pellet boilers replace 20% of residential and commercial propane and oil boilers

Sector	Subsector	Low- and Zero-Carbon Technologies & Resources	Low- and Zero-Carbon Technology and Resource Splits			
			BAU Scenario	Central Mitigation Scenario	Biofuel Emphasis Mitigation Scenario	Local Electricity Resources Mitigation Scenario
Industry	Process Energy	B20 biodiesel; B100 biodiesel; renewable natural gas	Industry consumes 4.0%-by-volume biodiesel blend, rising to 7.5% in 2050; renewable natural gas not consumed in industry	10%/20%/80% of natural gas consumed for industrial uses is displaced by renewable natural gas by 2025/2030/2050	10%/20%/80% of natural gas consumed for industrial uses is displaced by renewable natural gas by 2025/2030/2050; by 2040, industrial diesel consumption reaches 100% biodiesel (B100)	10%/20%/80% of natural gas consumed for industrial uses is displaced by renewable natural gas by 2025/2030/2050

Sector	Subsector	Low- and Zero-Carbon Technologies & Resources	Low- and Zero-Carbon Technology and Resource Splits			
			BAU Scenario	Central Mitigation Scenario	Biofuel Emphasis Mitigation Scenario	Local Electricity Resources Mitigation Scenario
Transportation	On-Road (Light-, Medium-, and Heavy-Duty Vehicles)	BEVs; V2G battery storage; B20 biodiesel; B100 biodiesel; E15 ethanol	By 2050, only 41% of LDV sales and 7.5% of MHD vehicle sales are BEVs; all EVs charge as fast as possible while plugged in; no V2G; transport consumes 4.0%-by-volume biodiesel blend, rising to 7.5% by 2050; ethanol constitutes 10.2%-by-volume in motor gasoline, rising to 12.1% 2050	By 2033, all sales of new on-road vehicles are BEVs; by 2040, 50% of charging for all EVs (including plug-in hybrids) is managed to flatten load profiles; by 2050, biodiesel blend in transport diesel reaches 20%-by-volume (B20); by 2040, ethanol blend in all motor gasoline reaches 15%-by-volume (E15)	By 2040, all sales of new on-road vehicles are BEVs; by 2040, 50% of charging for all EVs (including plug-in hybrids) is managed to flatten load profiles; diesel consumption for 2025 and later vintage vehicles used in heavy-duty road transport reaches 100% biodiesel (B100) by 2040; by 2040, ethanol blend in all motor gasoline reaches 15%-by-volume (E15)	By 2033, all sales of new on-road vehicles are BEVs; by 2040, 80% of charging for all EVs (including plug-in hybrids) is managed to flatten load profiles; by 2040, 15% of light-duty mid- and high-range BEVs (generally >150 miles per charge) participate in V2G discharging; by 2040 ethanol blend in all motor gasoline reaches 15%-by-volume (E15); by 2050, biodiesel blend in transport diesel reaches 20%-by-volume (B20)
	Off-Road, Aviation, Rail	Drop-in biofuels	No drop-in biofuels - jet kerosene meets 96% of aviation energy demand		By 2050, drop-in biofuels displace 50% of jet kerosene	

Sector	Subsector	Low- and Zero-Carbon Technologies & Resources	Low- and Zero-Carbon Technology and Resource Splits			
			BAU Scenario	Central Mitigation Scenario	Biofuel Emphasis Mitigation Scenario	Local Electricity Resources Mitigation Scenario
Non-energy GHG	Agriculture	Agricultural soil carbon sequestration reaches -985,571 $MTCO_2e$/year by 2050; dietary changes reduce enteric fermentation methane (CH_4) by 30% in 2025, compared to historical values; digesters reduce manure management CH_4 by 40% in 2025, compared to historical values				
	Industrial	Emissions from ozone-depleting substances decline to 164,590 $MTCO_2e$/year by 2029, followed by continued declining trend of -4.9%/year				

	Processes and Product Use	
	Land Use, Land Use Change, Forestry	No change in land use, land use change, and forestry carbon sink projection
	Waste	By 2050, 50% reduction in CH_4 is achievable from wastewater gas flaring

Appendix C: GHG Mitigation Strategies in the Northeast States

Table C.1 – Sector-Specific Mitigation Strategies in the Northeast States

	Residential Buildings	Commercial Buildings	Industry	Transportation	Electric Generation	Non-Energy
Connecticut	Prioritize building envelope improvements and expand access to thermal energy-efficiency measures through innovative financing options for all income levels; ensure building codes are continuously aligned with the most recent International Energy Conservation Code standards; develop sustainable funding mechanisms to incentivize replacement of fossil-fuel space and water heating with efficient renewable thermal technologies; and incentivize installation of renewable thermal technologies in new construction.	Develop sustainable funding mechanisms to incentivize replacement of fossil-fuel space and water heating with efficient renewable thermal technologies; incentivize installation of renewable thermal technologies in new construction; develop sustainable funding mechanisms to incentivize replacement of fossil-fuel space and water heating with efficient renewable thermal technologies; and incentivize installation of renewable thermal technologies in new construction.		Maintain adherence to California LEV & ZEV requirements. Implement price signals to incentivize EV adoption and reduce electric system impacts; expand EV charging network; develop a state fleet transportation Lead by Example program that sets annual emission reduction targets and enables increasing adoption of ZEVs. Implement transit-oriented development projects that adopt state policies and local zoning regulations that support walkable, mixed-use, and sustainable urban and suburban development in areas served by transit; and encourage, incentivize, and support alternative modes and active transportation that reduce single-occupant vehicle driving. Implement a multi-state cap-and-invest program that sets a limit on transportation sector emissions and reinvests program proceeds in	Reduce 1-2 million MWh by replacing inefficient heating/cooling technologies with renewable thermal technologies; and invest in electric energy efficiency measures in state buildings. Meet the RPS target of 40% by 2030 with an aim to reduce the carbon intensity of the RPS; add 40-90 MW of residential BTM renewable energy resources per year; deploy at least 50 MW per year commercial distributed solar and 10 MW per year of fuel cells; implement a shared clean energy program deploying at least 25 MW per year with a focus on LMI customers; maintain in-state zero-carbon nuclear generation and develop a long-term zero-carbon replacement strategy equivalent to 2,100 MW; and exercise procurement authority for zero-carbon energy through competitive bidding prices. Increase adoption of smart-management	Evaluate usable models to reliably monitor and report on negative carbon emissions related to working and natural lands; evaluate approaches and best practices for siting of renewable and non-renewable energy infrastructure to avoid loss of forests, farmland and other sensitive lands; explore option of statewide "no-net-loss of forest" policy; increase adaptation and resilience of forests through keeping forests as forests and support actions to maintain un-fragmented forests; increase mitigation of GHGs in forests; protect and enhance the ecosystem services value of wetlands using sound science and adaptive management strategies by incorporating new and emerging science and technologies, identifying and conserving ecosystems vulnerable to climate change, monitoring climate impacts, and developing habitat suitability models; reduce conversion of prime and important farmland soils, active

				measures that reduce emissions; and implement user-based transportation fees - market mechanisms to reduce traffic congestion and improve efficiency of travel for all drivers.	technologies to optimize the flexibility of distributed energy resources.	agricultural land, forest land, and other soil landscapes; increase the adoption of on-farm energy production and reduce on farm energy usage; improve soil health practices on all landscapes and off farms. Implement the Short-Lived Climate Pollutants (SLCPs) reduction strategies as outlined in the U.S. Climate Alliance SLCP Challenge to Action Roadmap.
Maine	**Residential Buildings**	**Commercial Buildings**	**Industry**	**Transportation**	**Electric Generation**	**Non-Energy**
	Install at least 100,000 new heat pumps by 2025, ensuring that by 2030, 130,000 homes are using between 1-2 heat pumps and an additional 115,000 homes are using a whole-home heat-pump system. Install at least 15,000 new heat pumps in income-eligible households by 2025; and implement Maine Appliance Standards requirements by 2022. Double the current pace of home weatherization so that at least 17,500 additional homes and businesses are weatherized by 2025, including at least 1,000 low-income units	By 2024, develop a long-term plan to phase in modern, energy-efficient building codes to reach net-zero carbon emissions for new construction by 2035; and enhance existing training on building codes and expand these programs to support ongoing education of contractors and code-enforcement officials. Develop and enhance innovation support, incentives, building codes, and marketing programs to increase the use of efficient and climate-friendly Maine forest products, including mass	Launch an Industrial Task Force to collaboratively partner with industry and stakeholders to consider innovations and incentives to manage industrial emissions through 2030 and reduce total emissions by 2050. Analyze policies, including the potential for long-term contracts, needed to advance new highly efficient combined heat and power production facilities that achieve significant net GHG reductions.	Achieve emissions-reduction goals by putting 41,000 light-duty EVs on the road in Maine by 2025 and 219,000 by 2030; by 2022, develop a statewide EV Roadmap to identify necessary policies, programs, and regulatory changes needed to meet the state's EV and transportation emissions reduction goals; by 2022, create policies, incentives, and pilot programs to encourage the adoption of electric, hybrid, and alternative-fuel MHD vehicles, public transportation, school buses, and ferries. Continue to support	Achieve by 2030 an electricity grid where 80% of Maine's usage comes from renewable generation; set achievable targets for cost-effective deployment of technologies such as offshore wind, distributed generation, and energy storage, and outline the policies, including opportunities for pilot initiatives, necessary to achieve these results. Establish a comprehensive stakeholder process in 2021 to examine the transformation of Maine's electricity sector and facilitate other recommendations of the	Support the ability of Maine's natural resource economies to adapt to climate change impacts; and grow Maine's forest-products industry through bio product innovation, supporting economic growth and sustainable forest management and preservation of working lands. Increase the amount of food consumed in Maine from state food producers from 10% to 20% by 2025 and 30% by 2030 through local food system development. Increase by 2030 the total acreage of conserved lands

	per year; and weatherize at least 35,000 homes and businesses by 2030.	timber and wood fiber insulation. Use procurement rules and coordinated planning efforts for the state government to promote high-efficiency lighting, heating, and cooling; climate-friendly construction materials; and renewable energy use for reduced operating costs and emissions reductions. The state will produce a Lead by Example plan for state government by February 2021; and enhance grant and loan programs to support efficiency and renewable energy programs in municipal, tribal, school, and public-housing construction and improvements. Provide recognition programs for those projects making outstanding efforts Investigate options for establishing a Renewable Fuels Standard (RFS) for heating fuels.		increased federal fuel-efficiency standards; significantly increase, by 2024, freight industry participation in EPA's SmartWay program; increase, by 2024, local biofuel and biodiesel production and use in Maine transportation sectors, especially heavy-duty vehicles (assuming Maine biofuels production becomes viable); and establish a time-limited incentive program, targeted to LMI drivers, to encourage drivers to upgrade to higher-efficiency vehicles in the near term. Reduce LDV VMT over time, achieving 10% reductions by 2025 and 20% by 2030; reduce heavy-duty VMT by 4% by 2030; deploy high-speed broadband to 95% of homes by 2025 and 99% by 2030; by 2024, establish state coordination, strengthen land-use policies, and use state grant programs to encourage development that supports the reduction of VMT; increase public transportation funding to the national median of $5 per capita by 2024; and relaunch GO Maine to significantly increase shared public commuting	Maine Climate Council.	in the state to 30% through voluntary, focused purchases of land and working forest or farm conservation easements. Additional targets should be identified in 2021, in partnership with stakeholders, to develop specific sub-goals for these conserved lands for Maine's forest cover, agriculture lands, and coastal areas; focus conservation on high biodiversity areas to support land and water connectivity and ecosystem health; revise scoring criteria for state conservation funding to incorporate climate mitigation and resiliency goals; and develop policies by 2022 to ensure renewable energy project siting is streamlined and transparent while seeking to minimize impacts on natural and working lands and engaging key stakeholders. The Maine Department of Environmental Protection will conduct a comprehensive, statewide inventory of carbon stocks on land and in coastal areas (including blue carbon) by 2023 to provide baseline estimates for state carbon sequestration,

				options by 2022.		allowing monitoring of sequestration over time to meet the state's carbon neutrality goal; establish by 2021 a stakeholder process to develop a voluntary, incentive-based forest carbon program (practice and/or inventory based) for woodland owners of 10 to 10,000 acres and forest practitioners; and engage in regional discussions to consider multistate carbon programs that could support Maine's working lands and natural resource industries, and state carbon neutrality goals. Increase technical service provider capacity by 2024 to deliver data, expert guidance, and support for climate solutions to communities, farmers, loggers, and foresters at the Maine Department of Agriculture, Conservation and Forestry, Maine Forest Service, Department of Inland Fisheries and Wildlife, the Department of Marine Resources, and the University of Maine; launch the Coastal and Marine Information Exchange by 2024. Establish a "coordinating hub" with state and non-state partners for key climate change research

						and monitoring work to facilitate statewide collaboration by 2024; create the framework and begin pilot for a coordinated, comprehensive monitoring system by 2024; incorporate climate research and climate change-related technologies into Maine's research and development priorities such as those developed by the Maine Innovation Economy Advisory Board and the Maine Technology Institute. Adopt hydrofluorocarbons phase-down regulations in 2021 to be implemented by 2022.
Massachusetts	**Residential Buildings**	**Commercial Buildings**	**Industry**	**Transportation**	**Electric Generation**	**Non-Energy**
	Present a new high-performance stretch energy code to the Board of Building Regulation and Standards in 2021 that allows for Green Communities to opt in starting in 2022 and will become mandatory and effective statewide no later than January 1, 2028; eliminate Mass Save® incentives for fossil fuel equipment in new construction in 2022 and align incentives with a	Present a new high-performance stretch energy code to the Board of Building Regulation and Standards in 2021 that allows for Green Communities to opt in starting in 2022 and will become mandatory and effective statewide no later than January 1, 2028; eliminate Mass Save® incentives for fossil fuel equipment in new construction in 2022 and align incentives with a		Cap Transportation Sector Emissions and Invest in Clean Transportation Solutions (e.g., TCI-P); and develop a LCFS no later than 2026. Adopt and implement the California Advanced Clean Cars II Standard (all new LDV sales must be 100% ZEV by 2035) by the end of the year in which the standard is finalized by California; adopt and implement the	Continue to ensure all existing procurements for renewable energy and transmission are completed on-time; and ensure compliance with existing portfolio standards and emissions regulations. In coordination with other New England states, the Commonwealth is actively working to ensure that the states are served by a regional electricity system	Explore creating and funding an expanded suite of incentive-based programs designed to achieve no net-loss of forest and farmland; and continue to protect and restore inland and coastal wetlands. Implement and incentivize best management practices identified in the Healthy Soils Action Plan and the Resilient Lands Initiative; and commission additional

	high-performance building code including incentives for Passive House construction; and support establishing state appliance standards by statute. Phase out incentives for fossil fuel heating systems as soon as possible, limiting fossil fuel heating system incentives in the 2022-2024 Three Year Plan, and ending all fossil fuel heating system incentives by the end of 2024; increase electrification through Mass Save® programs through air source and ground source heat pump incentives and consumer education in 2022-2024; expand access to energy efficiency and clean heating for LMI renters and homeowners in EJ communities through targeted community-based incentives and outreach programs, and increased funding for pre-weatherization barriers; enhance MassCEC funding to support continued market development for building decarbonization; and refine and enhance workforce development programs related to building decarbonization and will investigate the	high-performance building code including incentives for Passive House construction; and support establishing state appliance standards by statute. DOER will work to support similar action at the federal level. Phase out incentives for fossil fuel heating systems as soon as possible, limiting fossil fuel heating system incentives in the 2022-2024 Three Year Plan, and ending all fossil fuel heating system incentives by the end of 2024; increase electrification through Mass Save® programs through air source and ground source heat pump incentives and consumer education in 2022-2024; expand access to energy efficiency and clean heating for LMI renters and homeowners in EJ communities through targeted community-based incentives and outreach programs, and increased funding for pre-weatherization barriers; enhance MassCEC funding to support continued market development for building decarbonization; and refine and enhance workforce development programs related to		ZEV purchase mandates of the California Advanced Clean Trucks rule by Dec. 31, 2021 and the Advanced Clean Fleets rule by the end of the year in which the rule is finalized by California; and work with 16 other jurisdictions pursuant to the Zero Emission Medium- and Heavy-Duty Vehicle Memorandum of Understanding and Action Plan to provide a framework for achieving 30% of all new truck and bus sales by 2030 and 100% by 2050. Explore providing MOR-EV rebates at point of sale in 2021; investigate development of a LMI consumer program for ZEVs; and develop a heavy-duty ZEV incentive program in 2021. Explore a utility-based residential charging incentive program; address how to improve DCFC financial viability through pilot projects and seeking to resolve alter current punitive rate structures; analyze and propose potential revisions to rate structures (e.g., demand charges) that may represent barriers to public charging; and explore and support time-varying rates	operator and planner that is a fully committed partner in their decarbonization efforts; and continue working with other New England states to coordinate procurement and programming for new and existing clean energy resources. Complete a review of current attribute markets (including RPS, solar carve-outs, APS, and CPS) to ensure those programs continue to support "on pace" clean energy deployment in a strategic, cost-effective way; and in its scheduled program reviews of the CES and CES-E in 2021, MassDEP will assess program levels in light of the anticipated need for regional clean energy resource deployment, including MLPs in each program after taking into account, as may be relevant, their size and structure as well as their existing programs, contractual obligations, and asset ownership. Develop a mechanism to support the minting of RECs from solar systems in previously eligible SREC I and II programs; work with electric utilities to support detailed planning for the	forest carbon sequestration research, building upon the land use analysis in the 2050 Roadmap, to assess the long-term impacts of sustainable forest management practices. Continue exploring opportunities to incentivize the regional use of harvested wood in long-lived products, such as cross laminated timber and wood-based building insulation. Continue working with states and stakeholders across the Northeast to develop the measurement, accounting, and market frameworks necessary to support development of a regional carbon sequestration offset market by the end of 2025; convene an inter-agency Carbon Sequestration Task Force beginning in 2021; and update the statewide biogenic emissions inventory as needed to support and track verified carbon sequestration. Implement regulation limiting the sale of HFCs and support Kigali Compliant policies at the state, regional, and federal level; and explore additional regulations to minimize sulfur

	need for air source heat pump certification and workforce training. Convene a Commission and Task Force on Clean Heat by May 2021; develop and implement by 2023 a long-term declining emissions cap on heating fuels following consultation in 2021 with the Commission and Task Force on Clean Heat regarding the cap structure and levels consistent with meeting or exceeding GWSA required emissions reduction levels; and propose, by 2023, statutory, regulatory, and financing mechanisms needed to ensure the development of reliable and affordable clean heat solutions for the Commonwealth's buildings. Promote, through the Alternative Portfolio Standard, conversion of oil to biofuels; and encourage MassSave® Program administrators to implement a residential program design. Increase electrification of the thermal sector by providing program incentives for air source heat pumps for heating through MassSave®.	building decarbonization and investigate the need for air source heat pump certification and workforce training. Convene a Commission and Task Force on Clean Heat by May 2021; develop and implement by 2023 a long-term declining emissions cap on heating fuels following consultation in 2021 with the Commission and Task Force on Clean Heat regarding the cap structure and levels consistent with meeting or exceeding GWSA required emissions reduction levels; and propose, by 2023, statutory, regulatory, and financing mechanisms needed to ensure the development of reliable and affordable clean heat solutions for buildings. Explore possible ways to strengthen building codes to drive additional efficiency in new buildings; increase weatherization measures to improve building shell efficiencies and promote technologies targeted at winter gas savings through the MassSave® gas efficiency programs; and promote high efficiency building construction, such as passive house standards,		and active demand response programs, including as part of demand response programs in the next MassSave® Three-Year Plan (2022-2024). Explore options to incentivize or require reductions to single-occupancy vehicle commuting, targeting a 15% reduction in average commuted VMT per employee by 2030; and continue to encourage and incentivize a broad range of Smart Growth policies. Increase the deployment of EVs and charging infrastructure; and support development of liquid renewable fuels to provide alternative transportation fuels.	integration of distributed energy resources to ease system operations, help to reduce barriers from interconnection, and pilot innovative grid flexibility technologies; plan for ground mounted solar development to ensure best land management practices that protect critical Massachusetts species and ecosystems, while MassCEC works to identify market mechanisms to incentivize alternative siting; and facilitate a path to market for an additional 2 GW of new distributed clean generation between 2025 and 2030. Continue to support development of the offshore wind workforce, build local supply chains, ensure adequate port infrastructure, and advance research and innovation; work with BOEM and regional stakeholders to identify new lease areas, coordinate project schedules, and support an efficient, on-pace federal permitting process; and commence planning to procure, construct, and interconnect an additional 6 GW of offshore wind through to Massachusetts between 2030 and 2040.	hexafluoride (SF_6). Ensure best practices are in place around waste, wastewater, and agricultural emissions; require tighter emissions standards and increased efficiency standards based on the latest technology if Municipal Waste Combustors seek to modify or rebuild facilities.

	Educate consumers about the benefits of energy efficiency and create a market incentive for consumers to invest in energy efficiency improvements through a Home Energy Scorecard Program; and address the split incentive between landlords and renters for investments in energy efficiency.	to further reduce energy demand from the thermal sector.			Investigate policies and programs that support cost-effective clean resources that are available in winter to provide both cost and emission benefits to customers; and consider policies to support distributed resources, including distributed solar development after the SMART program concludes, to continue lowering costs while providing benefits to ratepayers. Implement policies and programs, including the Clean Peak Standard, that incentivize energy conservation during peak periods; develop policies to align new demand from the charging of EVs and heating/cooling with the production of clean, low-cost energy; include cost-effective demand reduction and additional energy efficiency initiatives in energy efficiency programs and plans; and utilize Green Communities and Leading By Example programs to continue to make state and municipal infrastructure clean and efficient. Promote cost effective microgrids to provide greater overall grid resiliency and reduce	

					transmission and distribution costs from building out the grid to meet new demand; and review existing and possible new policies to support new technologies, including energy storage, which can align supply and demand and provide grid flexibility.	
New Jersey	**Residential Buildings**	**Commercial Buildings**	**Industry**	**Transportation**	**Electric Generation**	**Non-Energy**
	Establish a clearinghouse for home energy and health and safety programs targeted to low-income households; advocate for net zero carbon buildings in new construction in the upcoming 2024 International Code Council code change hearings; adopt more stringent appliance standards; expand and accelerate the current statewide net zero carbon homes incentive programs for both new construction and existing homes; develop EV-ready and demand response-ready building codes for new multi-unit dwellings and commercial construction; and incentivize transition to electrified heat pumps, hot water heaters, and other appliances. Prioritize near-term	Advocate for net zero carbon buildings in new construction in the upcoming 2024 International Code Council code change hearings; establish transparent benchmarking and energy labeling; establish mechanisms to increase building efficiency in existing buildings; build state-funded projects and buildings to a high performance standard; improve energy efficiency in, and retrofit state buildings to a high performance standard; adopt more stringent appliance standards; electrify state facilities; partner w/private industry to establish electrified building demonstration projects; study and develop mechanisms and regulations to support net zero carbon new	Develop facility-wide energy audits, benchmarking, and commitments to energy efficiency upgrades and practices; investigate opportunities to reduce industrial CO_2 emissions through regulations; expand distributed renewable energy (New Jersey Department of Environmental Protection estimates that 29,800 acres of rooftop and non-impervious land area are available at industrial facilities to host approximately 10 GW of solar capacity—enough to power up to 1 million homes—these emissions reductions would be accounted for in the electric generation sector); upgrade diesel vehicle and equipment fleet to reduce onsite emissions of fine particulate and black	Support the deployment of 330,000 light-duty ZEVs on-road by 2025; deploy EVSE throughout the state; provide EV purchase and EVSE incentives to encourage adoption of EVs; roll over the state's LDV fleet to ZEVs; continue to improve NJ TRANSIT's environmental performance; partner with industry to develop incentives to electrify MHD vehicles; explore the adoption of alternative transportation fuels; electrify diesel-powered transportation and equipment at ports and airports; and support a diesel truck buy-out program. Pilot alternative rate design to manage EV charging and encourage customer-controlled	100% Clean Power by 2050: meet the 50% RPS by 2030 and explore possible regulatory structures to enable transition to 100% clean energy by 2050; ensure at least 75% of electricity demand is met by carbon-free renewable generation by 2050 and set interim goals; routinely model scenarios and pathways to achieve 100% clean energy generation by 2050 with consideration for least-cost options; update interconnection processes to address increasing distributed energy resources and EV charging; develop mechanisms to compensate distributed energy resources for their full value stack at the regional and federal level; develop low cost loans or financing for distributed	Expand education and outreach efforts about climate friendly agricultural practices; develop a statewide carbon sequestration plan that establishes a 2030 and 2050 target for both blue carbon and terrestrial carbon sequestration; develop and adopt minimum forest cover objectives for land development, including requirements for forest stand delineations and implementation of forest conservation plans; develop a conservation program for privately held woodlands and forests; expand the Urban and Community Forestry program by increasing accreditation for all municipalities and boards of education; provide additional incentives and technical tools to assist

	conversion of buildings relying on propane and heating oil (starting no later than 2021); mandate energy audits in state buildings and encourage/incentivize energy audits in county and municipal buildings; adopt new construction new zero carbon goals for commercial and residential buildings.	construction; incentivize transition to electrified heat pumps, hot water heaters, and other appliances; develop a transition plan to a fully electrified building sector. Prioritize near-term conversion of buildings relying on propane and heating oil (starting no later than 2021); mandate energy audits in state buildings and encourage/incentivize energy audits in county and municipal buildings; adopt new construction and zero carbon goals for commercial and residential buildings.	carbon.	demand flexibility. Incentivize work-from-home programs and flexible work weeks in order to reduce single occupancy vehicle trips; transition to complete electrification of the state government fleet.	energy resources; coordinate permitting and siting processes for renewable energy development; explore rules to limit CO_2 emissions from electric generating units. Develop 7,500 MW of offshore wind generation by 2035; retain existing carbon-free resources, including the state's three nuclear power plants. Maximize local (on-site or remotely sited) solar development and distributed energy resources by 2050; continue to grow NJ's community solar program; transition to a successor solar incentive program; develop programs to increase the deployment of solar thermal technologies; develop mechanisms for achieving 600 MW of energy storage by 2021 and 2,000 of energy storage by 2030. Decarbonize and Modernize NJ's Energy System: require utilities to establish Integrated Distribution Plans to expand and enhance the location and amount of distributed energy resources and EV charging on the electric distribution	communities in forestry management and climate friendly agricultural practices; monitor sequestration results of current pilot blue carbon projects and utilize data to inform future project selection criteria. Adopt regulations to implement requirements of the Food Waste Recycling and Waste-to-Energy Production Act; promote the development of food waste processing facilities and the development of markets and best practices for sectors of the economy generating food waste; promote and support energy recovery efforts from wastewater treatment operations; reduce methane emissions from natural gas distribution systems through an aggressive transition away from the use of fossil fuels in the transportation, buildings, electric generation, and industrial sectors; implement regulations that phase-out the use of high GWP halogenated products, while requiring enhanced leak detection and end of life recycling; implement programs and policies that prioritize utility efforts to upgrade or, where practical, retire leaking

					system; support bi-directional grid power flow and modernize interconnection standards; assess integration of Volt/Var Control; instruct utilities to propose and adopt non-wires solutions; exercise regulatory jurisdiction to review and approve the need for transmission projects. Encourage and support municipalities to establish and enact Community Energy Plans; establish a NJ Green Bank to provide innovative financing and low-cost loans to support in-state clean energy projects and technology development.	natural gas distribution infrastructure and expand the use of leak detection capabilities to identify, prioritize, and replace leaking equipment to reduce methane leaks; pursue regulations that require expedited replacement or retirement of the most polluting off-road diesel equipment to reduce fine particulate (and black carbon) emissions.
New York	**Residential Buildings**	**Commercial Buildings**	**Industry**	**Transportation**	**Electric Generation**	**Non-Energy**
	Identify energy efficiency measures that can be installed in existing buildings (envelope, heating, ventilation, air conditioning, lighting, etc.) and provide loans and direct payments to buy down the cost of installed energy efficiency measures; develop combined heat and power incentives, solar electric incentives, solar thermal incentives, bioenergy incentives, building commissioning,	Require all private buildings greater than 50,000 square feet or public buildings greater than 10,000 square feet to publicly report their annual energy and water benchmarking scores; achieve 20% improvement in energy efficiency in state buildings.	Establish voluntary incentive programs to reduce the carbon intensity of industrial operations through waste heat capture and reuse, installation of combined heat and power systems, adoption of electrified advanced process technologies, and application of renewable energy systems and fuels.	Maintain and increase vehicle efficiency standards; provide vehicle incentives and disincentives; provide fleet incentives and disincentives; explore alternative fuel-related measures and infrastructure - LCFS; commuter and traveler assistance; increase telecommuting; establish congestion pricing; expand transit; identify priority growth centers; expand transit-oriented	Extend and expand NY's existing RPS to require procurement of additional renewables. Increase RPS and incentives for grid-based renewable generation: (1) set specific standards and fees for interconnecting renewable energy resources into the grid, (2) establish renewable energy development zones that allow for concentration of transmission grid upgrades to efficiently deliver	Produce/convert sustainable feedstock for electricity, heat, steam production, and liquid/gaseous biofuels; maximize waste reduction, recycling, and composting; develop integrated farm management planning and application; conserve open space, agricultural lands, and wetlands; increase on-farm energy efficiency and production of renewable energy; and promote forest restoration, urban forestry, and reforestation.

	benchmarking, and upgrades; aggressively update and consistently enforce the State Energy Code, and provisions of the Uniform Fire Prevention and Building Code; local municipalities adopt a state-set stretch code; develop a performance-based international model energy code by 2021, which New York could adopt by 2023; review the energy efficiency performance standards for products that are not federally preempted every five years and update them as needed.			development; and increase location efficient land use.	renewable power to end-user consumers, and (3) establish specific regional siting policies for technologies such as offshore wind distribution system upgrades. Consider establishing a low-carbon portfolio standard, which would require all providers of electricity to obtain a portion of the electricity they sell from low-carbon energy sources; and explore a cap-and-invest program, which would be implemented on a regional basis and could include the power sector and other sectors within its coverage.	
Rhode Island	**Residential Buildings**	**Commercial Buildings**	**Industry**	**Transportation**	**Electric Generation**	**Non-Energy**
	Mature the renewable thermal market; and electrification of 70%-80% of residential heating.	Innovate with state energy efficiency codes and standards; conduct a municipal energy use baseline and develop a plan to reduce public sector energy consumption; seek PACE designation for the community; electrify 70%-80% of commercial heating.	Improve combined heat and power market.	Achieve 2% reduction in VMT by 2035 and 10% by 2050; improve fuel efficiency and reduce vehicle emissions; expand use of biofuels; promote alternative fuel and EVs; replace end-of-life municipal-owned vehicles with high fuel efficiency and/or EVs; adopt zoning and land use policies that preserve open space and promote compact growth; achieve 75% of on-road VMT by EVs by 2050 and electrify ~97% of rail transport.	Continue electric and natural gas least-cost procurement; expand least-cost procurement to unregulated fuels; expand the Renewable Energy Standard; expand renewable energy procurement; continue to participate in RGGI; adopt zoning and siting standards for renewable energy projects; modernize the grid; address natural gas leaks; reduce soft costs of renewable energy; address high and volatile regional energy costs;	Adopt a “no net-loss of forests” policy.

					increase utility-scale renewable energy with 67% renewable installed capacity and 72% carbon-free generation by 2035 and 98% renewable installed capacity and 99% carbon-free generation by 2050.	