Final Vermont Greenhouse Gas Inventory and Reference Case Projections, 1990-2030

Center for Climate Strategies
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Executive Summary

The Center for Climate Strategies (CCS) prepared this report under contract to the Vermont Department of Environmental Conservation (VTDEC). The report contains an inventory and forecast of the State's greenhouse gas (GHG) emissions from 1990 to 2030.

Vermont's (VT) anthropogenic GHG emissions and sinks (carbon storage) were estimated for the period from 1990 to 2030. Historical GHG emission estimates (1990 through 2005) were developed using a set of generally accepted principles and guidelines for State GHG emissions estimates (both historical and forecasted), with adjustments by CCS as needed to provide Vermont-specific data and inputs as possible. The initial reference case projections (2006-2030) are based on a compilation of various existing projections of electricity generation, fuel use, and other GHG emitting activities, along with a set of transparent assumptions.

Table ES-1 provides a summary of Vermont historical (1990, 2000, and 2005) and reference case projection (2010, 2020, and 2030) GHG emissions. Although the transportation and residential, commercial, and industrial (RCI) sectors historically have accounted for about 70% of Vermont's total gross GHG emissions, future emissions associated with the electricity supply sector could increase significantly. Vermont currently has a contract with a nuclear power plant (Entergy - Vermont Yankee) and a hydro electric plant (Hydro Quebec) that together supply two-thirds of Vermont's electricity. Vermont Yankee's license ends in 2012 and its contracts with Hydro Quebec phase out from 2012 through 2020. Thus, it is difficult to estimate GHG emissions for 2012 through 2030 because of the uncertainty with how Vermont will fill its electricity supply gap over this time period.

For the purpose of this initial analysis, we have estimated emissions separately for a "high-emission" and a "low-emission" scenario. Both scenarios have the same emissions from 1990 through 2011. However, after 2011 the high-emission scenario assumes that Vermont will purchase electricity from the New England power system to fill its electricity supply gap, and the low-emission scenario assumes that Vermont will fill its electricity supply gap with electricity generated from a fuel mix that is similar in GHG emissions to its historical fuel mix. The Vermont Department of Public Service's (DPS) forecast for electricity demand was used for both scenarios. In addition, VT DPS has estimated the benefits associated with implementing new demand-side management (DSM) programs starting in 2006. For this initial analysis, the benefits associated with implementing new DSM programs were also estimated for each of the two scenarios. Table ES-1 shows the emissions for both the high- and low-emission scenarios with and without new DSM programs for the electricity supply sector. Implementation of new DSM programs starting in 2006 could lower emissions associated with the low-emissions scenario by about 45% by 2020 and 49% by 2030. Implementation of new DSM programs starting in 2006 could lower emissions associated with the high-emissions scenario by about 18% by 2020 and 23% by 2030.

The reference case projections include the effect of Vermont's adoption of California's light-duty vehicle GHG standards, adopted by Vermont in 2005. The reductions from this program can be seen separately in Table ES-1 for gasoline and diesel light-duty vehicles.

Table ES-1. Vermont Historical and Reference Case GHG Emissions, by Sector[a]

(Million Metric Tons CO_2e)	1990	2000	2005	2010	2020	2030	Explanatory Notes for Projections
Electricity Consumption (High-Emission Scenario, No New DSM)	**1.09**	**0.43**	**0.64**	**1.02**	**3.63**	**4.12**	See electric sector assumptions
Electricity Consumption (Low-Emission Scenario, No New DSM)	**1.09**	**0.43**	**0.64**	**1.02**	**1.44**	**1.91**	in Appendix A
Electricity Consumption (High-Emission Scenario, With New DSM)	**1.09**	**0.43**	**0.64**	**0.78**	**2.98**	**3.18**	
Electricity Consumption (Low-Emission Scenario, With New DSM)	**1.09**	**0.43**	**0.64**	**0.78**	**0.79**	**0.97**	
Coal	0	0	0	0	0	0	
Natural Gas	0.047	0.018	0	0	0	0	
Oil	0.014	0.058	0.011	0	0	0	
Wood (CH_4 and N_2O)	0.003	0.009	0.009	0.009	0.005	0.005	
Net Imported Electricity	1.03	0.06	0.06	0	0	0	
System Purchases (High-Emissions Scenario, No New DSM)	0	0.29	0.56	1.01	3.63	4.12	
System Purchases (High-Emissions Scenario, With New DSM)	0	0.29	0.56	0.77	2.97	3.18	
Historical Mix (Low-Emissions Scenario, No New DSM)	0	0.29	0.56	1.01	1.44	1.91	
Historical Mix (Low-Emissions Scenario, With New DSM)	0	0.29	0.56	0.77	0.79	0.97	
Residential/Commercial/Industrial (RCI) Fuel Use	**2.43**	**2.88**	**2.71**	**2.62**	**2.66**	**2.72**	
Coal	0.02	0.003	0.003	0.003	0.003	0.003	Based on US DOE regional projections
Natural Gas	0.31	0.5	0.44	0.46	0.53	0.61	Based on US DOE regional projections
Oil	2.06	2.34	2.24	2.12	2.1	2.07	Based on US DOE regional projections
Wood (CH_4 and N_2O)	0.05	0.04	0.03	0.03	0.03	0.03	Based on US DOE regional projections
Transportation	**3.22**	**3.88**	**4.02**	**4.01**	**3.52**	**3.64**	
Motor Gasoline (not including CA standards)	2.67	3.25	3.15	3.16	3.46	3.78	Based on VTrans VMT projections
CA Standards reductions--gasoline	0	0	0	-0.07	-0.90	-1.19	
Diesel (not including CA standards)	0.45	0.54	0.67	0.70	0.75	0.83	Based on VTrans VMT projections
CA Standards reductions--diesel	0	0	0	0	-0.05	-0.07	
Natural Gas, LPG, other	0.03	0.02	0.02	0.03	0.03	0.03	Based on US DOE regional projections
Jet Fuel and Aviation Gasoline	0.08	0.07	0.17	0.2	0.24	0.26	Based on VTrans aircraft operations projections
Fossil Fuel Industry	**0.01**	**0.01**	**0.014**	**0.02**	**0.02**	**0.03**	
Natural Gas Transmission	0.01	0.01	0.01	0.02	0.02	0.03	Based on historic trends
Natural Gas Distribution	0.011	0.011	0.013	0.015	0.02	0.027	Based on VT DPS growth estimate

Table ES-1. Vermont Historical and Reference Case GHG Emissions, by Sector[a] (Continued)

(Million Metric Tons CO_2e)	1990	2000	2005	2010	2020	2030	Explanatory Notes for Projections
Industrial Processes	**0.12**	**0.39**	**0.44**	**0.53**	**0.78**	**1.24**	
ODS Substitutes	0	0.16	0.28	0.41	0.7	1.17	US EPA 2004 ODS cost study report
Electric Utilities (SF6)	0.05	0.03	0.02	0.02	0.01	0.01	Based on US EPA national projections
Semiconductor Manufacturing (HFC, PFC, and SF6)	0.07	0.17	0.11	0.07	0.04	0.03	Ditto
Limestone and Dolomite Use	0	0.02	0.02	0.02	0.02	0.02	Based on VT manufacturing employment growth
Soda Ash	0.01	0.01	0.01	0.01	0.01	0.01	Based on 2004 and 2009 projections for US production
Waste Management	**0.24**	**0.31**	**0.29**	**0.28**	**0.25**	**0.23**	
Solid Waste Management	0.18	0.25	0.22	0.21	0.17	0.15	Primarily based on population
Wastewater Management	0.06	0.06	0.07	0.07	0.07	0.08	Based on population
Agriculture	**1.02**	**0.96**	**0.96**	**0.94**	**0.92**	**0.9**	
Enteric Fermentation	0.52	0.5	0.48	0.47	0.46	0.44	USDA livestock projections
Manure Management	0.13	0.14	0.14	0.13	0.13	0.12	USDA livestock projections
Agricultural Soils	0.38	0.32	0.34	0.34	0.34	0.34	Held constant at 2002 levels
Total Gross Emissions (High-Emission Scenario, No New DSM)	**8.14**	**8.87**	**9.07**	**9.42**	**11.78**	**12.87**	
increase relative to 1990		*9%*	*11%*	*16%*	*45%*	*58%*	
Total Gross Emissions (Low-Emission Scenario, No New DSM)	**8.14**	**8.87**	**9.07**	**9.42**	**9.6**	**10.66**	
increase relative to 1990		*9%*	*11%*	*16%*	*18%*	*31%*	
Total Gross Emissions (High-Emission Scenario, With New DSM)	**8.14**	**8.87**	**9.07**	**9.18**	**11.13**	**11.93**	
increase relative to 1990		*9%*	*11%*	*13%*	*37%*	*47%*	
Total Gross Emissions (Low-Emission Scenario, With New DSM)	**8.14**	**8.87**	**9.07**	**9.18**	**8.95**	**9.72**	
increase relative to 1990		*9%*	*11%*	*13%*	*10%*	*19%*	
Forestry and Land Use	**-9.7**	**-9.7**	**-9.7**	**-9.7**	**-9.7**	**-9.7**	Emissions held constant at 2004 levels
Agricultural Soils	**-0.19**	**-0.19**	**-0.19**	**-0.19**	**-0.19**	**-0.19**	Emissions held constant at 1997 levels
Net Emissions (High-Emission Scenario, No New DSM)	**-1.72**	**-1**	**-0.79**	**-0.44**	**1.92**	**3.01**	
Net Emissions (Low-Emission Scenario, No New DSM)	**-1.72**	**-1**	**-0.79**	**-0.44**	**-0.27**	**0.8**	
Net Emissions (High-Emission Scenario, With New DSM)	**-1.72**	**-1**	**-0.79**	**-0.68**	**1.27**	**2.07**	
Net Emissions (Low-Emission Scenario, With New DSM)	**-1.72**	**-1**	**-0.79**	**-0.68**	**-0.92**	**-0.14**	

[a] Totals may not equal exact sum of subtotals shown in this table due to independent rounding.

In 2005, activities in Vermont accounted for approximately 9.1 million metric tons (MMt) of *gross*[1] carbon dioxide equivalent (CO_2e) emissions, an amount equal to 0.13% of total US gross GHG emissions. Vermont's gross GHG emissions are rising at a somewhat slower rate than the nation as a whole (gross emissions exclude carbon sinks, such as forests). Vermont's gross GHG emissions increased by 11% from 1990 to 2004, while national emissions rose by 16% during this period.

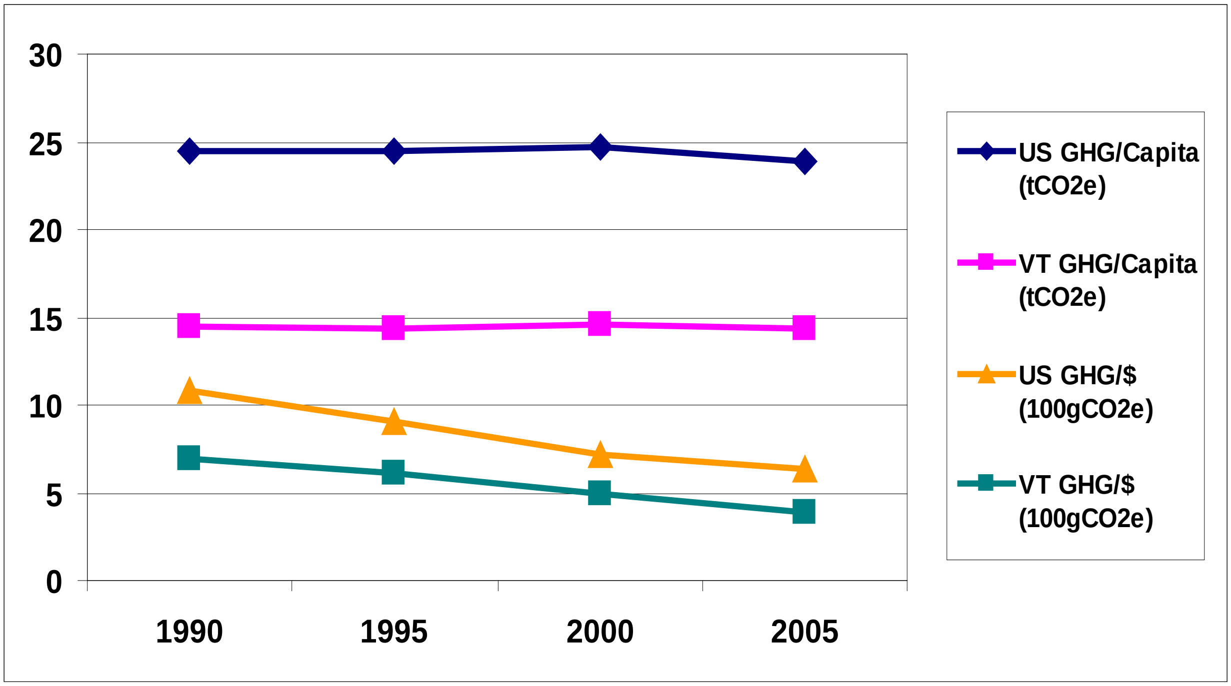
For 1990 through 2011, Vermont's net GHG emissions are negative – in other words, the GHG emissions removed from the atmosphere due to forestry and other land uses (i.e., carbon sinks) were estimated to be greater than the GHG emissions associated with electricity consumption and emissions associated with the RCI, transportation, and other sectors in Vermont. For 2012 through 2030, Vermont's net GHG emissions exceed its carbon sinks under both the low- and the high-emission scenarios without new DSM programs. However, the forecast suggests that new DSM programs could result in carbon sinks continuing to exceed emissions under the high-emission scenario through 2020 and under the low-emission scenario through 2030.

Figure ES-1 illustrates the State's emissions per capita and per unit of economic output. On a per capita basis, Vermonters emit about 15 metric tons (Mt) of CO_2e, which is 40% lower than the national average of 25 MtCO_2e. Like the nation as a whole, per capita emissions have remained fairly flat, while economic growth exceeded emissions growth throughout the 1990-2004 period. During the 1990s, emissions per unit of gross product dropped by 40% nationally, and by 44% in Vermont.

As illustrated in Figure ES-2 and shown numerically in Table ES-1, under the reference case projections, Vermont's gross GHG emissions continue to grow. By 2030, total gross emissions for all categories are projected to climb to 10.7 MMtCO_2e (31% above 1990 levels) under the low-emission scenario, and to about 12.9 MMtCO_2e (58% above 1990 levels) under the high-emission scenario without new DSM programs being implemented starting in 2006. As shown in Figure ES-3, the electric sector is projected to contribute significantly to emissions growth in both the low-emission and high-emission scenarios.

[1] Excluding GHG emissions removed due to forestry and other land uses.

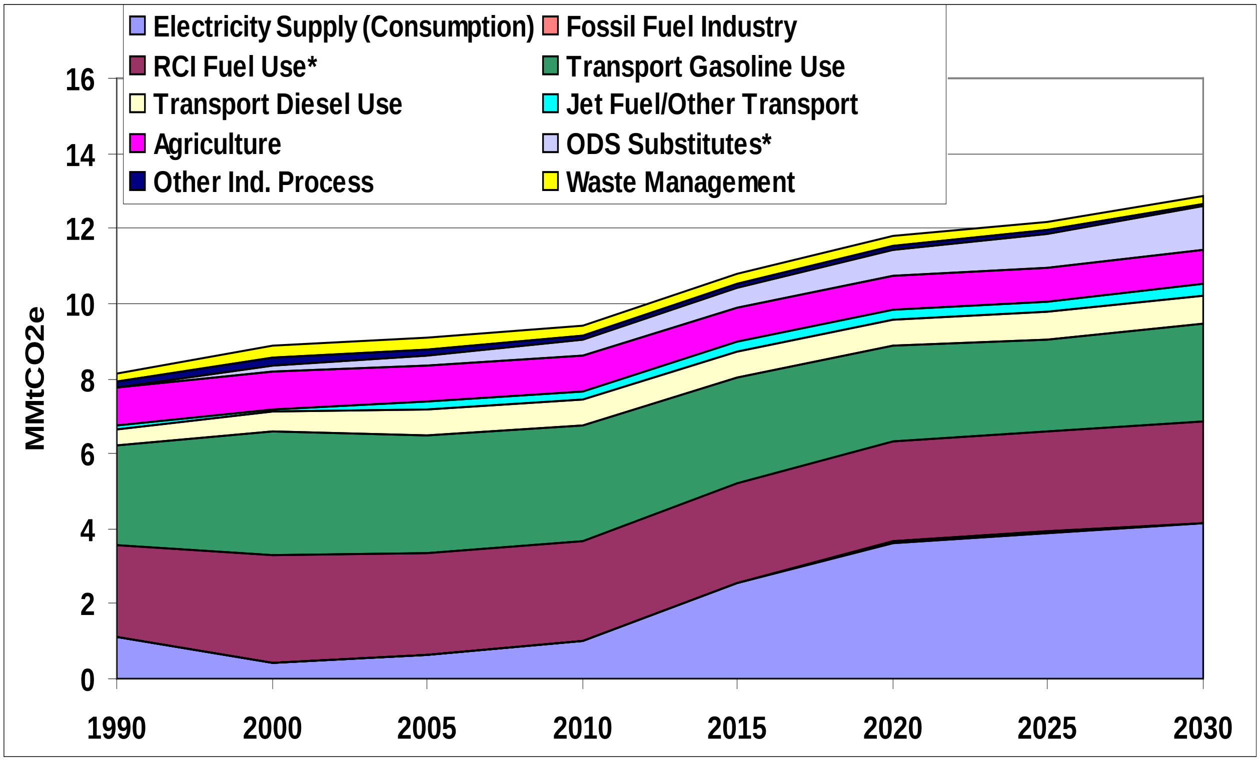
Figure ES-1. Historical Vermont and US Gross GHG Emissions, Per Capita and Per Unit Gross Product



Some data gaps exist in this analysis, particularly for the reference case projections. Key tasks include developing a better understanding of the electricity generation sources that will be used to meet Vermont loads (in collaboration with State utilities). In addition, review and revision of key emissions drivers (such as electricity and transportation fuel use growth rates) could be needed, as these are major determinants of Vermont's future GHG emissions.

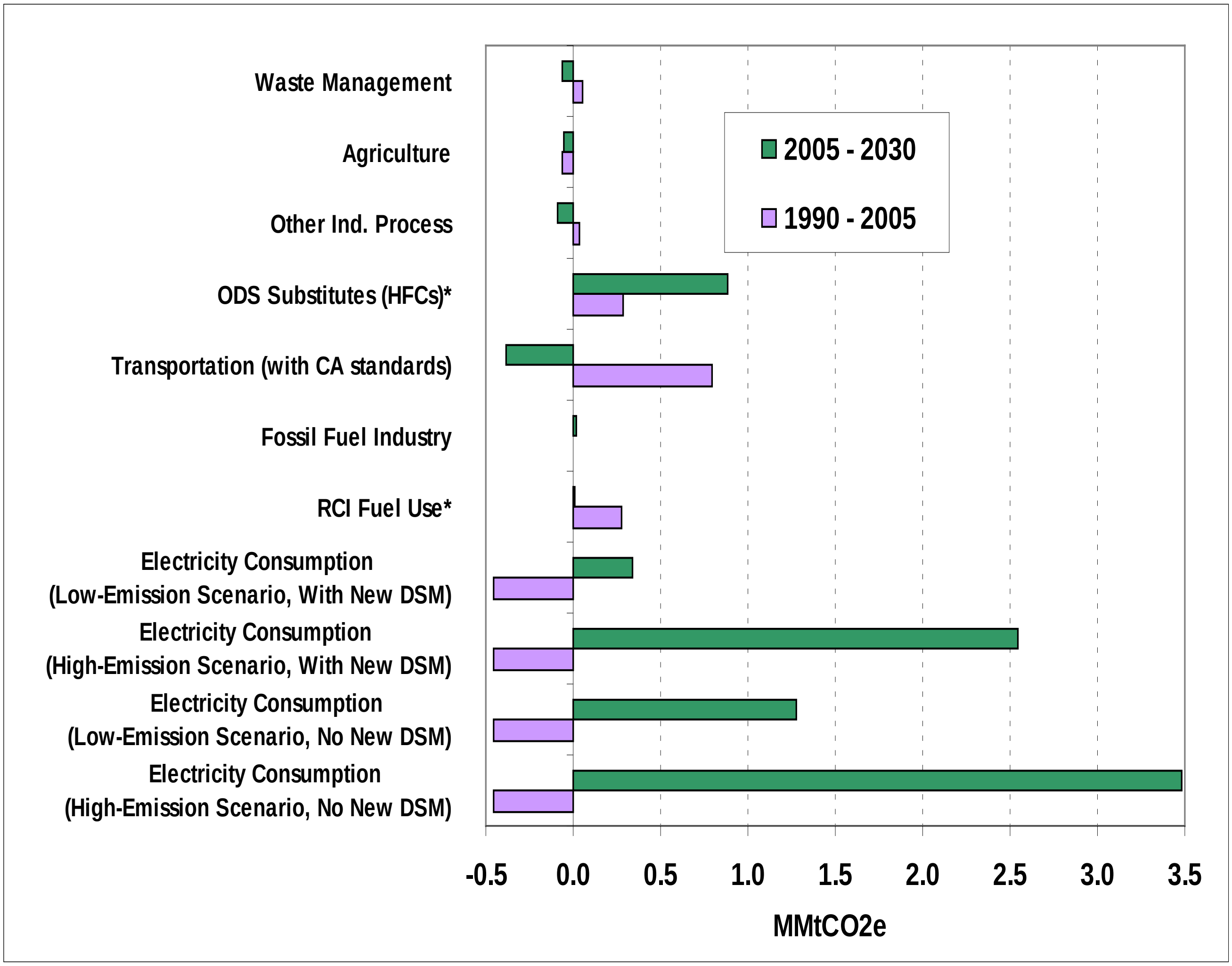
Emissions of aerosols, particularly "black carbon" (BC) from fossil fuel combustion, could have significant climate impacts through their effects on radiative forcing. Estimates of these aerosol emissions on a CO_2e basis were developed for Vermont based on 2002 and 2018 emissions data from the Mid-Atlantic – Northeast Visibility Union (MANE-VU) regional planning organization and other sources. The results for current (2002) levels of BC emissions were a total of 0.65 $MMtCO_2$e, which is the mid-point of a range of estimated emissions (0.4 – 0.9 $MMtCO_2$e. Based on an assessment of the primary contributors, it is estimated that BC emissions will decrease substantially by 2018 after new federal engine and fuel standards take effect in the onroad and nonroad diesel engine sectors (decrease of about 0.24 $MMtCO_2$e/yr). Details of this analysis are presented in Appendix I to this report. These estimates are not incorporated into the totals shown in Table ES-1 because a global warming potential (GWP) for BC has not yet been assigned by the Intergovernmental Panel on Climate Change (IPCC).

Figure ES-2. Vermont Gross GHG Emissions by Sector, 1990-2030: Historical and Projected (Electricity Supply High-Emission Scenario)



* RCI – direct fuel use in residential, commercial, and industrial sectors. ODS – ozone depleting substance.

Figure ES-3. Sector Contributions to Growth in Vermont Gross Emissions, 1990-2030: Reference Case Projections (MMtCO2e Basis)



* RCI – direct fuel use in residential, commercial, and industrial sectors. ODS – ozone depleting substance. HFCs – hydrofluorocarbons.

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Acronyms and Key Terms

AEO2006 – EIA's Annual Energy Outlook 2006

BC – Black Carbon*

BOD – Biochemical Oxygen Demand

BTU – British Thermal Unit

CCS – Center for Climate Strategies

CFCs – chlorofluorocarbons*

CH_4 – Methane*

CO_2 – Carbon Dioxide*

CO_2e – Carbon Dioxide Equivalent*

CVPS – Central Vermont Public Service

DPS – Vermont Department of Public Service

DSM – Demand-side Management

EC – Elemental Carbon*

EIA – US DOE Energy Information Administration

EIIP – Emissions Inventory Improvement Program (US EPA)

FHWA – Federal Highway Administration

FIA – Forest Inventory & Analysis

FORCARB – USFS Forest Carbon Model

GCCC-PG – Governor's Commission on Climate Change and Plenary Group

GHG – Greenhouse Gases*

GWh – Gigawatt-hour

GWP - Global Warming Potential*

HFCs – Hydrofluorocarbons*

HPMS – Highway Performance Monitoring System

IPCC – Intergovernmental Panel on Climate Change*

IPPs – Independent Power Producers

ISO-NE – Independent Service Operator for New England

KWh – Kilowatt-hour

LFGTE – Landfill Gas Collection System and Landfill-Gas-to-Energy

LMOP – Landfill Methane Outreach Program

LNG – Liquefied Natural Gas

LPG – Liquefied Petroleum Gas

MANE-VU – Mid-Atlantic – Northeast Visibility Union

MMt – Million Metric Tons

MMBTU – Million British Thermal Units

MSW – Municipal Solid Waste

Mt - Metric ton (equivalent to 1.102 short tons)

MTBE – Methyl Tertiary Butyl Ether

MWh – Megawatt-hour

N_2O – Nitrous Oxide*

NASS – National Agricultural Statistics Service

NMVOC – non-methane volatile organic compounds*

O_3 – Ozone*

OC – Organic Carbon*

ODS – Ozone-Depleting Substances*

OPS – US Office of Pipeline Safety

PM – Particulate Matter*

PM_{10} – PM with an aerodynamic diameter of less than 10 micrometers

PFCs – Perfluorocarbons*

RCI – Residential, Commercial, and Industrial

REC – Renewable Energy Credit

SED – State Energy Data

SF_6 – Sulfur Hexafluoride*

SGIT – State Greenhouse Gas Inventory Tool

Sinks – Removals of carbon from the atmosphere, with the carbon stored in forests, soils, landfills, wood structures, or other biomass-related products.

T&D – Transmission and Distribution

TWh – Terawatt-hours

US EPA – United States Environmental Protection Agency

USDA – United States Department of Agriculture

US DOE – United States Department of Energy

USFS – United States Forest Service

USGS – United States Geological Survey

VGS – Vermont Gas Systems, Inc.

VMT – Vehicle Miles Traveled

VT – Vermont

VTDEC – Vermont Department of Environmental Conservation

VTrans – Vermont Agency of Transportation

W/m^2 – Watts per Square Meter

* - See Appendix J for more information.

Acknowledgements

We appreciate all of the time and assistance provided by numerous contacts throughout Vermont, as well as in neighboring States, and at federal agencies. Thanks go to in particular the staff at several Vermont State agencies for their inputs, and in particular to Jeff Merrell, Harold Garabedian, and Jeff Wennberg of the Vermont Department of Environmental Conservation who provided key guidance for this analytical effort. In addition, thanks also go to the Vermont Department of Public Service, Vermont Agency of Transportation, and other Vermont State agencies that provided key data and guidance for developing the emission and reference case projection scenarios for the electricity supply and transportation sectors.

Summary of Preliminary Findings

Introduction

The Center for Climate Strategies (CCS) prepared this report under contract to the Vermont Department of Environmental Conservation (VTDEC). This report presents initial estimates of base year and projected Vermont (VT) anthropogenic greenhouse gas (GHG) emissions and sinks (carbon storage) for the period from 1990 to 2030. These estimates are intended to assist the State, the Governor's Commission on Climate Change and Plenary Group (GCCC-PG), and technical work groups (TWGs) with an initial, comprehensive understanding of current and possible future GHG emissions for Vermont, and, thereby, to inform the analysis and design of GHG mitigation strategies.

Historical GHG emissions estimates (1990 through 2005)[2] were developed using a set of generally accepted principles and guidelines for State GHG emissions inventories, as described in the "Approach" section below, relying to the extent possible on Vermont-specific data and inputs. The initial reference case projections (2006-2030) are based on a compilation of various existing projections of electricity generation, fuel use, and other GHG-emitting activities, along with a set of simple, transparent assumptions described in the appendices of this report. These estimates should be viewed as preliminary input to the GCCC-PG process and are subject to revisions as better data are identified.

This report covers the six gases included in the US Greenhouse Gas Inventory: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Emissions of these GHGs are presented using a common metric, CO_2 equivalence (CO_2e), which indicates the relative contribution of each gas to global average radiative forcing on a Global Warming Potential- (GWP-) 100-year weighted basis. The final appendix to this report provides a more complete discussion of GHGs and GWPs. As stated in the Executive Summary, CCS also added emission estimates for black carbon (BC) based on 2002 and 2018 data from the Mid-Atlantic – Northeast Visibility Union (MANE-VU) regional planning organization. Black carbon is an aerosol species with a positive climate forcing potential (i.e., the potential to warm the atmosphere, as GHGs do).

Emissions of conventional air pollutants, such as non-methane volatile organic compounds (NMVOC), nitrogen oxides (NOx), and sulfur dioxide (SO_2), also affect climate both directly (through ozone (O_3) and sulfate aerosol production) and indirectly through their influence on CH_4 lifetime. However, due to their short atmospheric lifetimes and heterogeneous distributions, O_3 and sulfate are not included in international climate policy instruments such as the Kyoto protocol. Also, O_3 and sulfate are strongly coupled through tropospheric photochemistry and emission source types (primarily fossil-fuel burning).[3] The influence of this O_3–sulfate interaction on climate has not yet been characterized or quantified. Therefore, these emissions are not included in this inventory.

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[2] The last year of available historical data varies by sector; ranging from 2000 to 2005.
[3] Unger, N., Shindell, D., Koch, D., Streets, D., "Air pollution radiative forcing from specific emissions sectors at 2030: prototype for a new IPCC bar chart", http://pubs.giss.nasa.gov/docs/notyet/submitted_Unger_etal.pdf.

It is important to note that the preliminary emissions estimates reflect the *GHG emissions associated with the electricity sources used to meet* Vermont*'s demands,* corresponding to a consumption-based approach to emissions accounting (see "Approach" section below). Another way to look at electricity emissions is to consider the *GHG emissions produced by electricity generation facilities in the State.* This report covers both methods of accounting for emissions, but for consistency, all total results are reported as *consumption-based.*

Vermont Greenhouse Gas Emissions: Sources and Trends

Table 1 provides a summary of GHG emissions estimated for Vermont by sector for the years 1990, 2000, 2005, 2010, 2020, and 2030. In the sections below, we discuss GHG emission sources (positive, or *gross*, emissions) and sinks (removal of emissions, or negative emissions) separately in order to identify trends, projections, and uncertainties clearly for each. These sections provide a summary of the historical emissions (1990 through 2005) followed by a summary of the reference-case projection-year emissions (2006 through 2030) and key uncertainties. We also provide an overview of the general methodology, principals, and guidelines followed for preparing the inventories. Appendices A through H provide the detailed methods, data sources, and assumptions for each GHG sector.

Based on the historical emissions provided in Table 1, the transportation and residential, commercial, and industrial (RCI) sectors together have accounted for about 70% of Vermont's total gross GHG emissions from 1990 through 2005. However, future emissions associated with the electricity supply sector could increase significantly depending on how Vermont decides to fill its looming electricity supply gap that is expected to begin in 2012 when its existing contracts with a nuclear power plant (Entergy - Vermont Yankee) and a hydro electric plant (Hydro Quebec) begin to phase out.

For the purpose of this initial analysis, we have estimated emissions separately for a "high-emission" and a "low-emission" scenario. Both scenarios have the same emissions from 1990 through 2011. However, after 2011 the high-emission scenario assumes that Vermont will purchase electricity from the New England power system to fill its electricity supply gap, and the low-emission scenario assumes that Vermont will fill its electricity supply gap with electricity generated from a fuel mix that is similar in GHG emissions to its historical fuel mix. The Vermont Department of Public Service's (DPS) forecast for electricity demand was used for both scenarios. In addition, VT DPS has estimated the benefits associated with implementing new demand-side management (DSM) programs starting in 2006. For this initial analysis, the benefits associated with implementing new DSM programs were also estimated for each of the two scenarios. Table 1 shows the emissions for both the high- and low-emission scenarios with and without new DSM programs for the electricity supply sector. Implementation of new DSM programs starting in 2006 could lower emissions associated with the low-emissions scenario by about 45% by 2020 and 49% by 2030. Implementation of new DSM programs starting in 2006 could lower emissions associated with the high-emissions scenario by about 18% by 2020 and 23% by 2030.

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Electricity Consumption (Low-Emission Scenario, No New DSM)	**1.09**	**0.43**	**0.64**	**1.02**	**1.44**	**1.91**	in Appendix A
Electricity Consumption (High-Emission Scenario, With New DSM)	**1.09**	**0.43**	**0.64**	**0.78**	**2.98**	**3.18**	
Electricity Consumption (Low-Emission Scenario, With New DSM)	**1.09**	**0.43**	**0.64**	**0.78**	**0.79**	**0.97**	
Coal	0	0	0	0	0	0	
Natural Gas	0.047	0.018	0	0	0	0	
Oil	0.014	0.058	0.011	0	0	0	
Wood (CH_4 and N_2O)	0.003	0.009	0.009	0.009	0.005	0.005	
Net Imported Electricity	1.03	0.06	0.06	0	0	0	
System Purchases (High-Emissions Scenario, No New DSM)	0	0.29	0.56	1.01	3.63	4.12	
System Purchases (High-Emissions Scenario, With New DSM)	0	0.29	0.56	0.77	2.97	3.18	
Historical Mix (Low-Emissions Scenario, No New DSM)	0	0.29	0.56	1.01	1.44	1.91	
Historical Mix (Low-Emissions Scenario, With New DSM)	0	0.29	0.56	0.77	0.79	0.97	
Residential/Commercial/Industrial (RCI) Fuel Use	**2.43**	**2.88**	**2.71**	**2.62**	**2.66**	**2.72**	
Coal	0.02	0.003	0.003	0.003	0.003	0.003	Based on US DOE regional projections
Natural Gas	0.31	0.5	0.44	0.46	0.53	0.61	Based on US DOE regional projections
Oil	2.06	2.34	2.24	2.12	2.1	2.07	Based on US DOE regional projections
Wood (CH_4 and N_2O)	0.05	0.04	0.03	0.03	0.03	0.03	Based on US DOE regional projections
Transportation	**3.22**	**3.88**	**4.02**	**4.01**	**3.52**	**3.64**	
Motor Gasoline (not including CA standards)	2.67	3.25	3.15	3.16	3.46	3.78	Based on VTrans VMT projections
CA Standards reductions--gasoline	0	0	0	-0.07	-0.9	-1.19	
Diesel (not including CA standards)	0.45	0.54	0.67	0.70	0.75	0.83	Based on VTrans VMT projections
CA Standards reductions--diesel	0	0	0	0	-0.05	-0.07	
Natural Gas, LPG, other	0.03	0.02	0.02	0.03	0.03	0.03	Based on US DOE regional projections
Jet Fuel and Aviation Gasoline	0.08	0.07	0.17	0.2	0.24	0.26	Based on VTrans aircraft operations projections
Fossil Fuel Industry	**0.01**	**0.01**	**0.014**	**0.02**	**0.02**	**0.03**	
Natural Gas Transmission	0.01	0.01	0.01	0.02	0.02	0.03	Based on historic trends
Natural Gas Distribution	0.011	0.011	0.013	0.015	0.02	0.027	Based on VT DPS growth estimate

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ODS Substitutes	0	0.16	0.28	0.41	0.7	1.17	US EPA 2004 ODS cost study report
Electric Utilities (SF6)	0.05	0.03	0.02	0.02	0.01	0.01	Based on US EPA national projections
Semiconductor Manufacturing (HFC, PFC, and SF6)	0.07	0.17	0.11	0.07	0.04	0.03	Ditto
Limestone and Dolomite Use	0	0.02	0.02	0.02	0.02	0.02	Based on VT manufacturing employment growth
Soda Ash	0.01	0.01	0.01	0.01	0.01	0.01	Based on 2004 and 2009 projections for US production
Waste Management	**0.24**	**0.31**	**0.29**	**0.28**	**0.25**	**0.23**	
Solid Waste Management	0.18	0.25	0.22	0.21	0.17	0.15	Primarily based on population
Wastewater Management	0.06	0.06	0.07	0.07	0.07	0.08	Based on population
Agriculture	**1.02**	**0.96**	**0.96**	**0.94**	**0.92**	**0.9**	
Enteric Fermentation	0.52	0.5	0.48	0.47	0.46	0.44	USDA livestock projections
Manure Management	0.13	0.14	0.14	0.13	0.13	0.12	USDA livestock projections
Agricultural Soils	0.38	0.32	0.34	0.34	0.34	0.34	Held constant at 2002 levels
Total Gross Emissions (High-Emission Scenario, No New DSM)	**8.14**	**8.87**	**9.07**	**9.42**	**11.78**	**12.87**	
increase relative to 1990		*9%*	*11%*	*16%*	*45%*	*58%*	
Total Gross Emissions (Low-Emission Scenario, No New DSM)	**8.14**	**8.87**	**9.07**	**9.42**	**9.6**	**10.66**	
increase relative to 1990		*9%*	*11%*	*16%*	*18%*	*31%*	
Total Gross Emissions (High-Emission Scenario, With New DSM)	**8.14**	**8.87**	**9.07**	**9.18**	**11.13**	**11.93**	
increase relative to 1990		*9%*	*11%*	*13%*	*37%*	*47%*	
Total Gross Emissions (Low-Emission Scenario, With New DSM)	**8.14**	**8.87**	**9.07**	**9.18**	**8.95**	**9.72**	
increase relative to 1990		*9%*	*11%*	*13%*	*10%*	*19%*	
Forestry and Land Use	**-9.7**	**-9.7**	**-9.7**	**-9.7**	**-9.7**	**-9.7**	Emissions held constant at 2004 levels
Agricultural Soils	**-0.19**	**-0.19**	**-0.19**	**-0.19**	**-0.19**	**-0.19**	Emissions held constant at 1997 levels
Net Emissions (High-Emission Scenario, No New DSM)	**-1.72**	**-1**	**-0.79**	**-0.44**	**1.92**	**3.01**	
Net Emissions (Low-Emission Scenario, No New DSM)	**-1.72**	**-1**	**-0.79**	**-0.44**	**-0.27**	**0.8**	
Net Emissions (High-Emission Scenario, With New DSM)	**-1.72**	**-1**	**-0.79**	**-0.68**	**1.27**	**2.07**	
Net Emissions (Low-Emission Scenario, With New DSM)	**-1.72**	**-1**	**-0.79**	**-0.68**	**-0.92**	**-0.14**	

[a] Totals may not equal exact sum of subtotals shown in this table due to independent rounding.

The reference case projections include the effect of Vermont's adoption of California's light-duty vehicle GHG standards. The reductions from this program are itemized in Table 1.

For 1990 through 2011, Vermont's net GHG emissions are negative – in other words, the GHG emissions removed from the atmosphere by forests, soils, and other land uses (i.e., carbon sinks) were estimated to be greater than the GHG emissions generated in the State from fossil fuel combustion and other activities. For 2012 through 2030, Vermont's net GHG emissions exceed its carbon sinks under both the low- and the high-emission scenarios without new DSM programs. However, the forecast suggests that new DSM programs could result in carbon sinks continuing to exceed emissions under the high-emission scenario through 2020 and under the low-emission scenario through 2030. Details on the methods and data sources used to construct these draft estimates for the forestry sector are provided in Appendix H.

Appendix I provides information on 2002 and 2018 black carbon (BC) estimates for Vermont. CCS estimated that BC emissions in 2002 ranged from 0.4 to 0.9 million metric tons (MMt) on a carbon dioxide equivalent (CO_2e) basis, with a mid-point of 0.65 $MMtCO_2e$. A range is estimated based on the uncertainty in the global modeling analyses that serve as the basis for converting BC mass emissions into their CO_2e. Emissions in key contributing sectors are expected to drop by about 0.24 $MMtCO_2e$/yr (mid-range estimate) by 2018 as a result of new engine and fuel standards affecting onroad and nonroad diesel engines. Since the IPCC has not yet assigned a GWP for BC, CCS has excluded these estimates from the GHG summary shown in Table 1.

Historical Emissions

Overview

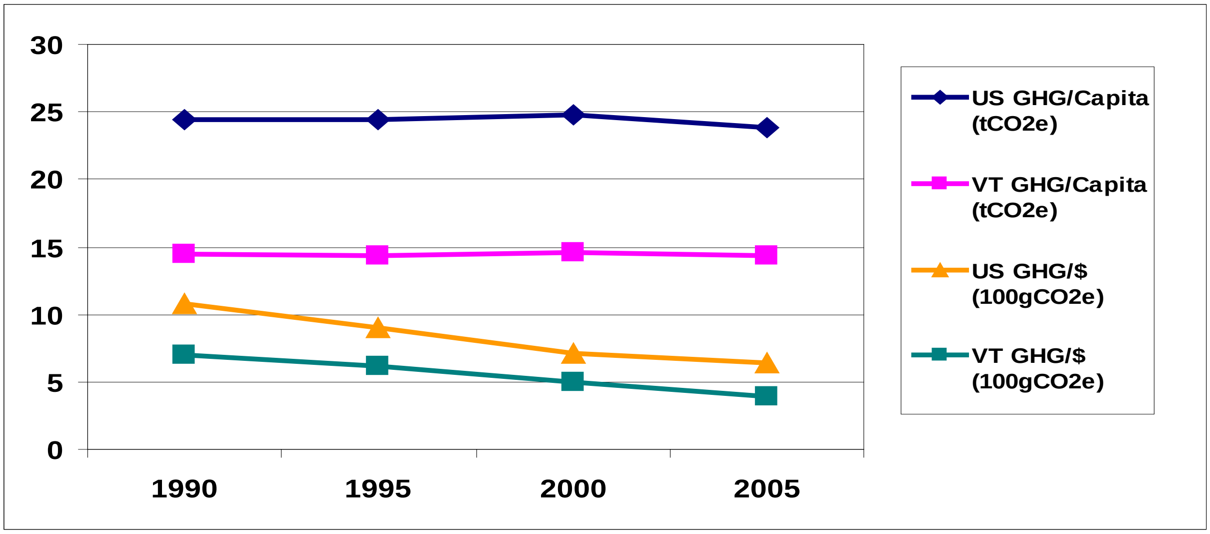
Preliminary analyses suggest that in 2005, activities in Vermont accounted for approximately 9.1 $MMtCO_2e$ of gross GHG emissions, an amount equal to 0.13% of total US GHG emissions.[4] Vermont's *gross* GHG emissions are rising at a somewhat slower rate than the nation as a whole.[5] Vermont's gross GHG emissions increased by 11% from 1990 to 2004, while national emissions rose by 16% during this period.

On a per capita basis, Vermonters emit about 15 metric tons (Mt) of CO_2e, which is 40% lower than the national average of 25 $MtCO_2e$. Figure 1 illustrates the State's emissions per capita and per unit of economic output. It also shows that like the nation as a whole, per capita emissions have remained fairly flat, while economic growth exceeded emissions growth throughout the 1990-2004 period. From 1990 to 2004, emissions per unit of gross product dropped by 40% nationally, and by 44% in Vermont.

[4] United States emissions estimates are drawn from US EPA 2006. *Inventory of US Greenhouse gas Emissions and Sinks:1990-2004*.

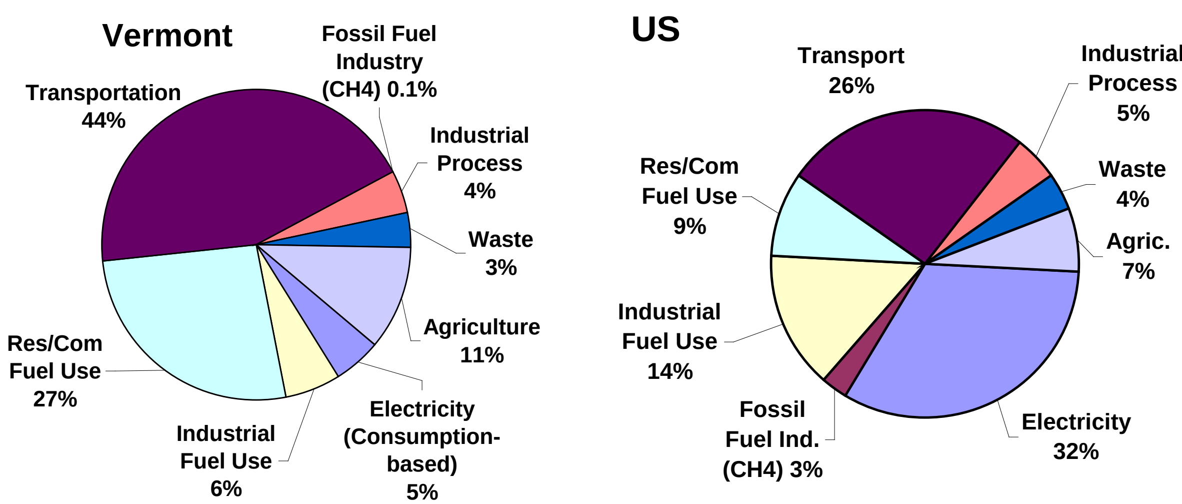
[5] *Gross* emissions estimates only include those sources with positive emissions. Carbon sequestration in soils and vegetation is included in *net* emissions estimates. All emissions reported in this section for Vermont reflect consumption-based accounting (including emissions associated with electricity generated in-state and imported electricity). On a national basis, little difference exists between *production-based* and *consumption-based* accounting for GHG emissions because net electricity imports are less than 1% of national electricity generation.

Figure 1. Historical Vermont and US Gross GHG Emissions, Per Capita and Per Unit Gross Product



Transportation and use of fossil fuels – natural gas, oil products, and coal -- in the RCI sectors historically have been the State's principal GHG emissions sources. In 2000, the combustion of fossil fuels by the transportation and RCI sectors accounted for 44% and 33%, respectively, of Vermont's *gross* GHG emissions, as shown in Figure 2. For the transportation sector, onroad gasoline and diesel consumption have been the major sources of GHG emissions. For the RCI sectors, consumption of petroleum has been the major source of historical GHG emissions. The relative contribution of agricultural emissions (CH_4 and N_2O emissions from manure management, fertilizer use, and livestock) is slightly higher in Vermont (11%) than in the nation as a whole (7%). This is a result of more agricultural activity in Vermont as compared to the US on average.

Figure 2. Gross GHG Emissions by Sector, 2000, Vermont and US



Vermont electricity demand historically has been met by a mix of generation capacity that has produced low GHG emissions. As a result, emissions associated with the electricity supply sector are significantly lower than the nation as a whole, with emissions ranging from as high as 13% of total gross GHG emissions in 1990 to as low as 5% of total gross GHG emissions in 2000. As discussed in the next section, the emissions profile may change significantly after 2012 when Vermont's contract with Entergy (Vermont Yankee; nuclear) ends and its contracts with Hydro Quebec (hydro) begin to phase out from 2012 through 2020.

Industrial process emissions comprise almost 4% of total gross GHG emissions in 2000, but these emissions are rising rapidly due to the increasing use of HFC as substitutes for ozone-depleting chlorofluorocarbons.[6] Other industrial process emissions result from CO_2 released during soda ash, limestone, and dolomite use. Landfills and wastewater management facilities produce CH_4 and N_2O emissions accounting for 3% of the State's emissions in 2000; slightly less than the US as a whole.

Vermont's forests are estimated to be net sinks for GHG emissions and, with forested lands accounting for about 78% of the State, these sequestered, or negative emissions exceed GHG emissions produced by other State activities from 1990 through 2005. Due to uncertainties in projecting the future levels of sequestration in the State's forests, the projected sinks were held constant at current levels.

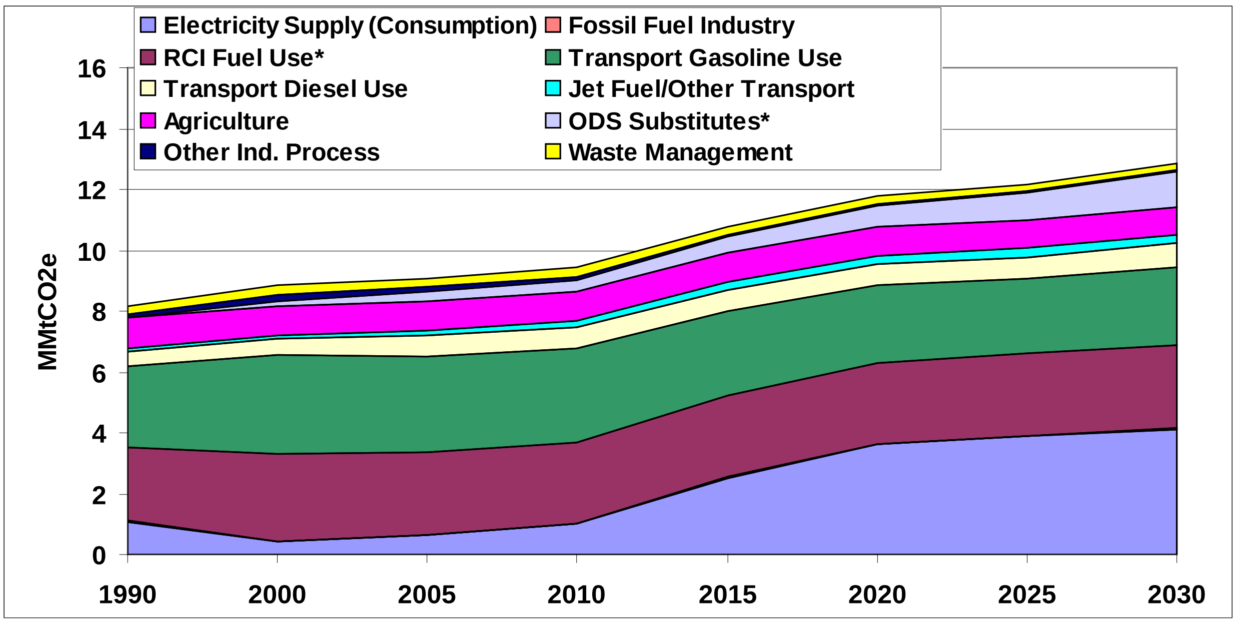
Reference Case Projections

Relying on a variety of sources for projections of electricity and fuel use, as noted below and in the appendices of this report, we developed a simple reference case projection of GHG emissions

[6] Chlorofluorocarbons (CFCs) are also potent GHGs; however they are not included in these GHG estimates, since they are addressed through the Montreal Protocol. See final Appendix (Appendix J).

through 2030. As illustrated in Figure 3 and shown numerically in Table 1, under the reference case projections for both the high- and low-emission scenarios, Vermont's gross GHG emissions increased by 11% from 1990 to 2005. However, this trend is expected to change over the next 25 years where emissions are projected to increase (from 2005 through 2030) by about 18% (an increase of 1.6 $MMtCO_2e$) under the low-emission scenario and by about 42% (an increase of 3.8 $MMtCO_2e$) under the high-emission scenario without new DSM programs. Emissions are projected to increase (from 2005 through 2030) by about 7% (an increase of 0.7 $MMtCO_2e$) under the low-emission scenario and by about 32% (an increase of 2.9 $MMtCO_2e$) under the high-emission scenario with new DSM programs.

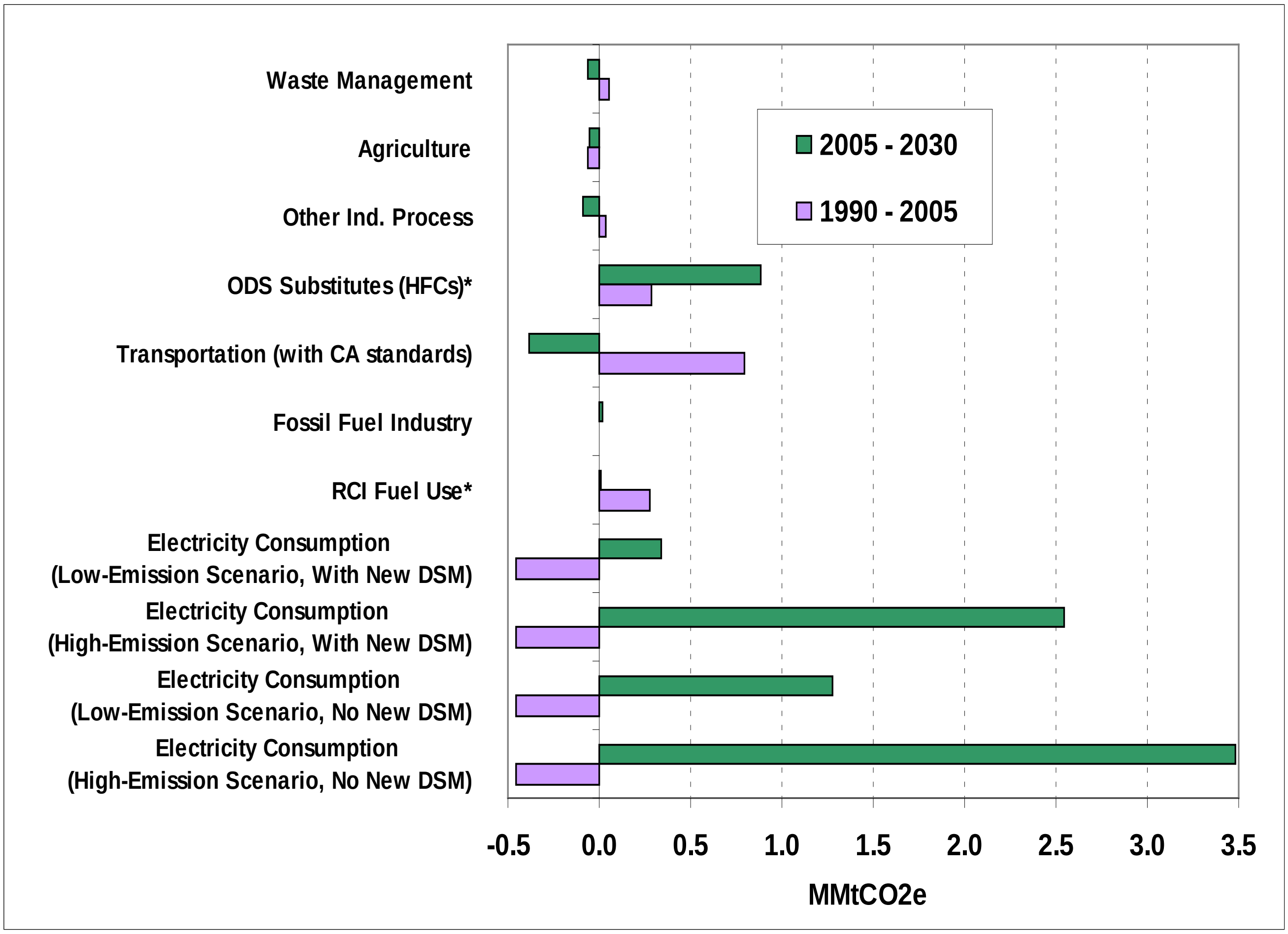
Figure 3. Vermont Gross GHG Emissions by Sector, 1990-2030: Historical and Projected (Electricity Supply High-Emission Scenario)



* RCI – direct fuel use in residential, commercial, and industrial sectors. ODS – ozone depleting substance.

As shown in Figure 4, the electricity supply sector is projected to be the major contributor to future growth in emissions, followed by significant growth in the use of substitutes for ozone depleting substances (ODS) in the industrial processes sector. Growth in emissions associated with the transmission and distribution of natural gas in the fossil fuel production sector, and fuel use by the RCI sectors are projected to have relatively low growth. The contribution of ODS substitutes to total gross GHG emissions is projected to increase from about 5% in 2005 to about 7.3% by 2030. The contributions of the RCI sectors to total gross GHG emissions is projected decline from about 30% in 2005 to about 20% by 2030, primarily due to the projected increase in emissions associated with the electricity supply sector and ODS substitutes.

Figure 4. Sector Contributions to Growth in Vermont Gross Emissions, 1990-2030: Historic and Reference Case Projections (MMtCO2e Basis)



* RCI – direct fuel use in residential, commercial, and industrial sectors. ODS – ozone depleting substance. HFCs – hydrofluorocarbons.

A Closer Look at the Two Major Sources: Transportation and Electricity Supply

As shown in Figure 2, GHG emissions from transportation fuel use have risen steadily since 1990 at an average rate of slightly over 1.1% annually. Gasoline-powered vehicles account for about 82% of total transportation GHG emissions in 1990, 78% in 2005, and are projected to decrease from 77% to about 70% of total transportation emissions between 2010 and 2030. The decrease in the portion of transportation emissions attributed to gasoline consumptions between 2010 and 2020 is due to the adoption of California's light-duty vehicle GHG standards. Diesel vehicles account for another 13% of total transportation GHG emissions in 1990, and are projected to increase from 17% to about 20% of total transportation emissions between 2010 and 2030. Although the California light-duty vehicle GHG standards also affect diesel vehicles, the diesel sector is dominated by heavy-duty vehicles, so the impact of the California program on diesel transportation emissions is less significant than the impact on gasoline emissions. Air travel accounted for roughly 2.4% of total transportation emissions in 1990, 4.3% in 2005, and is projected to increase from 4.9% of total emissions in 2010 to 7.2% of total emissions by 2030.

Natural gas and liquefied petroleum gas (LPG) vehicles and lubricants (e.g., automotive oil and grease) account for the remaining transportation sector emissions.

As the result of Vermont's increase in vehicle miles traveled (VMT) during the 1990s, gasoline use has grown at rate of 1.4% annually. Meanwhile, diesel use has risen 2.7% annually, suggesting an even more rapid growth in freight movement within or through the State.

As shown in Figure 2, electricity use accounted for about 5% of Vermont's gross GHG emissions in 2000 (about 0.43 MMtCO_2e), which is much lower than the national share of emissions from electricity consumption (32%).[7] In total (across the RCI sectors), Vermont has a much lower per capita use of electricity than the US as a whole [9,170 kilowatt-hour (kWh) per person per year compared to 12,000 kWh nationally based on 2004 data].[8,9] Overall, total electricity consumption in Vermont increased at an average annual rate of 1.34% from 1990 to 2000, and about 0.9% from 2000 through 2005. From 1990 to 2000, emissions increased by 18%, but then declined by about 6% from 2000 to 2005. Many factors influence a State's per capita electricity consumption, including the impact of weather on demand for cooling and heating, the size and type of industries in the State, and the type and efficiency of equipment in use in the residential, commercial and industrial sectors. The decline in Vermont's emissions from 2000 to 2005 is most likely associated with a decline in manufacturing activity, implementation of DSM programs, and a higher reliance on electricity supply generated from fuels that have low GHG emissions profiles.

Vermont's future emissions associated with the electricity supply sector could increase significantly. Vermont currently has a contract with a nuclear power plant (Vermont Yankee) and a hydro electric plant (Hydro Quebec) that together supply two-thirds of Vermont's electricity. Vermont Yankee's license ends in 2012 and Vermont's contracts with Hydro Quebec end from 2012 through 2020. Thus, it is difficult to estimate GHG emissions for 2012 through 2030 because of the uncertainty with how Vermont will fill its electricity supply gap over this time period. For the purpose of this initial analysis, we have estimated emissions separately for a "high-emission" and a "low-emission" scenario. Both scenarios have the same emissions from 1990 through 2011.

After 2011 the high-emission scenario assumes that Vermont will purchase electricity from the New England power system to fill its electricity supply gap, and the low-emission scenario assumes that Vermont will fill its electricity supply gap with electricity generated from a fuel mix that is similar in GHG emissions to its historical fuel mix. For the low-emission scenario, GHG emissions are projected to increase from about 0.64 MMtCO_2e in 2005 to 1.9 MMtCO_2e in 2030 (a 200% overall increase in emissions). Based on Vermont DPS forecasts, new DSM programs implemented starting in 2006 through 2030 could lower emissions for the low-

[7] Unlike for Vermont, for the US as a whole, there is relatively little difference between the emissions from electricity use and emissions from electricity production, as the US imports only about 1% of its electricity, and exports far less.

[8] Population data for 2004 (626,549 people) from Vermont Department of Public Health, Agency of Human Services' website at http://healthvermont.gov/research/intercensal/TABLE1.XLS. Electricity purchases (including line losses) for 2004 (5,748 GWh) from Vermont DPS. Vermont data for 2004 were used for comparison to US per capita data available for 2004.

[9] Census Bureau for US population, Energy Information Administration (EIA) for electricity sales.

emission scenario by about 39% in 2015, 45% in 2020, and 50% in 2030. For the high-emission scenario, GHG emissions are projected to increase from about 0.64 $MMtCO_2e$ in 2005 to 4.1 $MMtCO_2e$ in 2030 (a 548% overall increase in emissions). Implementation of new DSM programs starting in 2006 (based on Vermont DPS forecasts) could lower emissions associated with the high-emission scenario by 20% over the forecast period (i.e., 2006 to 2030). Appendix A provides further details on the data source, methods, and key assumptions applied to estimate emissions for the high and low emissions scenarios.[10]

It is important to note that these preliminary electricity emissions estimates reflect the *GHG emissions associated with the electricity sources used to meet Vermont's demands*, corresponding to a consumption-based approach to emissions accounting (see "Approach" section). Another way to look at electricity emissions is to consider the *GHG emissions produced by electricity generation facilities in the State.* [11]

While we estimate both the emissions from electricity production and consumption, unless otherwise indicated, tables, figures, and totals in this report reflect electricity consumption emissions. The consumption-based approach can better reflect the emissions (and emissions reductions) associated with activities occurring in the State, particularly with respect to electricity use (and efficiency improvements), and is particularly useful for policy-making. Under this approach, emissions associated with electricity exported to other States would need to be covered in those States' accounts in order to avoid double counting or exclusions.

Key Uncertainties and Next Steps

Some data gaps exist in this inventory, and particularly in the reference case projections. Key tasks, among others, include developing a better understanding of (1) the electricity generation sources and associated GHG emissions profile that will fulfill future Vermont loads, and (2) review and revision of key drivers such as the RCI fuel use and the transportation fuel use growth rates that will be major determinants of Vermont's future GHG emissions (See Table 2). These growth rates are driven by uncertain economic, demographic, and land use trends (including growth patterns and transportation system impacts), all of which deserve closer review and discussion.

Perhaps the variable with the most important implications for GHG emissions is the emissions profile associated with the generation sources (in-state and out-of-state) that will fill Vermont's energy supply gap from 2012 through 2030. GHG emissions can vary significantly depending on whether Vermont will fill its future demand for electricity based on its historical fuel mix or based on purchases from the New England power system. The assumptions on VMT and air travel growth also have large impacts on the GHG emission growth in the State. Finally

[10] Appendix A refers to the high-emission scenario without and with new DSM programs as Scenarios 1 and 2, respectively. The low-emission scenario without and with new DSM programs is referred to as Scenarios 3 and 4, respectively.
[11] Estimating the emissions associated with electricity use requires an understanding of the electricity sources (both in-state and out-of-state) used by utilities to meet consumer demand. The current estimate reflects some very simple assumptions described in Appendix A.

uncertainty remains on estimates for historic GHG sinks from forestry, and projections for these emissions will greatly impact the net GHG emissions attributed to Vermont.

Table 2. Key Annual Growth Rates for Vermont, Historical and Projected

	1990-2005	2005-2030	Sources
Population	0.77%	0.57%	Data 1990-2005 from Vermont Department of Public Health. Data for 2005-2030 from US Census Bureau.
Employment **Goods** **Services**	 -2.66% 1.22%	 0.08% 1.40%	Vermont Department of Labor, based on analysis by the US Bureau of Labor Statistics. Projections data cover the years 2005-2012; the annual growth rates for 2013-2030 are based on those for the years 2005-2012.
Electricity Sales	1.3%	1.5%	Based on historical and forecast data (that include line losses) provided by Vermont DPS.
Vehicle Miles Traveled	2.1%	1.2% - 1.4%	Vehicle miles traveled (VMT) projections provided by VTDEC based on historical growth curves for road types from Vermont Agency of Transportation (VTrans); 1.3% per year between 2002 and 2009, 1.4% per year for 2009-2012, and 1.2% per year for 2012-2018. Annual VMT growth rate for 2012-2018 assumed to continue through 2030. VMT projections adjusted to account for improvements in fuel efficiency taken from EIA's *Annual Energy Outlook* (AEO2006). Fuel consumption growth rates; 0.7% per year for gasoline and 1.0% per year for diesel between 2002 and 2030.

Approach

The primary goal of compiling the inventories and reference case projections presented in this document is to provide the State of Vermont with a general understanding of Vermont's historical, current, and projected (expected) GHG emissions. The following explains the general methodology and the general principles and guidelines followed during development of these GHG inventories for Vermont.

General Methodology

We prepared this analysis in close consultation with Vermont agencies, in particular, with the VTDEC staff. The overall goal of this effort is to provide simple and straightforward estimates, with an emphasis on robustness, consistency, and transparency. As a result, we rely on reference forecasts from best available State and regional sources where possible. Where reliable existing forecasts are lacking, we use straightforward spreadsheet analysis and constant growth-rate extrapolations of historical trends rather than complex modeling.

In most cases, we follow the same approach to emissions accounting for historical inventories used by the US EPA in its national GHG emissions inventory[12] and its guidelines for States.[13] These inventory guidelines were developed based on the guidelines from the IPCC, the international organization responsible for developing coordinated methods for national GHG inventories.[14] The inventory methods provide flexibility to account for local conditions. The key sources of activity and projection data are shown in Table 3. Table 3 also provides the descriptions of the data provided by each source and the uses of each data set in this analysis.

General Principles and Guidelines

A key part of this effort involves the establishment and use of a set of generally accepted accounting principles for evaluation of historical and projected GHG emissions, as follows:

- **Transparency:** We report data sources, methods, and key assumptions to allow open review and opportunities for additional revisions later based on input from others. In addition, we will report key uncertainties where they exist.

- **Consistency:** To the extent possible, the inventory and projections were designed to be externally consistent with current or likely future systems for State and national GHG emission reporting. We have used the US EPA tools for State inventories and projections as a starting point. These initial estimates were then augmented and/or revised as needed to conform with State-based inventory and base-case projection needs. For consistency in making reference case projections, we define reference case actions for the purposes of projections as those *currently in place or reasonably expected over the time period of analysis*.

- **Comprehensive Coverage of Gases, Sectors, State Activities, and Time Periods.** This analysis aims to comprehensively cover GHG emissions associated with activities in Vermont. It covers all six GHGs covered by US and other national inventories: CO_2, CH_4, N_2O, SF_6, HFCs, PFCs, and BC. The inventory estimates are for the year 1990, with subsequent years included up to most recently available data (typically 2002 to 2005), with projections to 2010 and 2030.

- **Priority of Significant Emissions Sources:** In general, activities with relatively small emissions levels may not be reported with the same level of detail as other activities.

- **Priority of Existing State and Local Data Sources:** In gathering data and in cases where data sources conflicted, we placed highest priority on local and State data and analyses, followed by regional sources, with national data or simplified assumptions such as constant linear extrapolation of trends used as defaults where necessary.

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[12] US EPA, Feb 2005. *Draft Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003.* http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

[13] http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateInventoryGuidance.html.

[14] http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

Table 3. Key Sources for Vermont Data, Inventory Methods, and Growth Rates

Source	Information provided	Use of Information in this Analysis
US EPA State Greenhouse Gas Inventory Tool (SGIT)	US EPA SGIT is a collection of linked spreadsheets designed to help users develop State GHG inventories for 1990-2005. US EPA SGIT contains default data for each State for most of the information required for an inventory. The SGIT methods are based on the methods provided in the Volume VIII document series published by the Emissions Inventory Improvement Program (EIIP) (http://www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html)	Where not indicated otherwise, SGIT is used to calculate emissions from residential, commercial, and industrial (RCI) fuel combustion, industrial processes, agriculture and forestry, and waste. We use SGIT emission factors [CO_2, CH_4 and N_2O per British thermal unit (BTU) consumed] to calculate energy use emissions. The default data are updated with the most recent published data available from the data sources (e.g., default data are added if available for 2003-2005 and pre-2003 data are revised to reflect revisions provided by the default data sources.
US DOE Energy Information Administration (EIA) State Energy Data (SED)	EIA SED source provides energy use data in each State, annually to 2003.	EIA SED is the source for most energy use data. We also use the more recent data for electricity and natural gas consumption (including natural gas for vehicle fuel) from EIA website for years after 2003. Emission factors from US EPA SGIT are used to calculate energy-related emissions.
US DOE Energy Information Administration Annual Energy Outlook 2006 (AEO2006)	EIA AEO2006 projects energy supply and demand for the US from 2005 to 2030. Energy consumption is estimated on a regional basis. Vermont is included in the New England Census region (MA, ME, NH, RI, and VT)	AEO2006 projections of transportation fuel efficiency used to adjust projected VMT for future year transportation CO_2 estimates.
US Department of Transportation (DOT), Office of Pipeline Safety (OPS)	Natural gas transmission pipeline mileage, and distribution pipeline mileage and number of services for 1990 – 2005.	Emissions for distribution system projected at annual growth rate of 3% from VT DPS. Emissions for transmission system projected at annual growth rate of 1% based on historical trends.
US EPA Landfill Methane Outreach Program (LMOP)	LMOP provides landfill waste-in-place data.	Waste-in-place data (along with additional data from VTDEC) used to estimate annual disposal rate, which was used with SGIT to estimate emissions from solid waste.
US Forest Service	Data on forest carbon stocks for multiple years.	Data are used to calculate CO_2 flux over time (terrestrial CO_2 sequestration in forested areas).
USDA National Agricultural Statistics Service (NASS)	USDA NASS provides data on crops and livestock.	Crop production data used to estimate agricultural residue and agricultural soil emissions; livestock population data used to estimate manure and enteric fermentation emissions
VT Agency of Transportation	Historical and projected vehicle miles traveled (VMT)	Historical vehicle miles traveled (VMT) used to estimate CH_4 and N_2O emissions for gasoline and diesel onroad vehicles. Projected VMT used to estimate future year emissions for gasoline and diesel onroad vehicles.

- **Use of Consumption-Based Emissions Estimates:** To the extent possible, we estimated emissions that are caused by activities that occur in Vermont. For example, we reported emissions associated with the electricity consumed in Vermont. The rationale for this method of reporting is that it can more accurately reflect the impact of State based policy strategies such as energy efficiency on overall GHG emissions, and it resolves double-counting and exclusion problems with multi emissions issues. This approach can differ from how inventories are compiled, for example, on an in-state production basis, in particular for electricity.

For electricity, we estimate, in addition to the emissions due to fuels combusted at electricity plants in the State, the emissions related to electricity *consumed* in Vermont. This entails accounting for the electricity sources used by Vermont utilities to meet consumer demands. As we refine this analysis, we may also attempt to estimate other sectoral emissions on a consumption basis, such as accounting for emissions from transportation fuel used in Vermont, but purchased out-of-state. In some cases this can require venturing into the relatively complex terrain of life-cycle analysis. In general, we recommend considering a consumption-based approach where it will significantly improve the estimation of the emissions impact of potential mitigation strategies. For example re-use, recycling, and source reduction can lead to emission reductions resulting from lower energy requirements for material production (such as paper, cardboard, and aluminum), even though production of those materials, and emissions associated with materials production, may not occur within the State.

Some data gaps exist in this analysis, particularly for the reference case projections. Key tasks include developing a better understanding of the electricity generation sources that will be used to meet Vermont loads (in collaboration with State utilities), and review and revision of key emissions drivers (such as electricity and transportation fuel use growth rates) that will be major determinants of Vermont's future GHG emissions.

Details on the methods and data sources used to construct the inventories and forecasts for each source sector are provided in the following appendices:

- Appendix A. Electricity Use and Supply;
- Appendix B. Residential, Commercial, and Industrial (RCI) Fossil Fuel Combustion;
- Appendix C. Transportation Energy Use;
- Appendix D. Industrial Processes;
- Appendix E. Fossil Fuel Industries;
- Appendix F. Agriculture;
- Appendix G. Waste Management; and
- Appendix H. Forestry.

Appendix I contains a discussion of the inventory and forecast for BC. Appendix J provides additional background information from the US EPA on GHGs and GWP values.

Appendix A. Electricity Use and Supply

Overview

Vermont's demand for electricity has experienced moderate growth from 1992 through 2005, mostly driven by population and economic growth in the State. Vermont's total electricity demand increased by 0.6% per year from 1992 through 2005, and increased by 7.8% overall during this 13-year period. Vermont has been a net importer of electricity. Based on electricity sales forecasts prepared by the Vermont Department of Public Service (DPS), Vermont's demand for electricity is estimated to increase at an average annual rate of about 1.36% from 2006 through 2026. For this 20-year period, the DPS estimates that implementation of new demand-side management (DSM) programs (beyond existing programs) could significantly decrease Vermont's electricity demand to about 0.30% annually.

Greenhouse gas (GHG) emissions associated with electricity produced in-state and imported electricity together accounted for about 0.64 million metric tons (MMt) on a carbon dioxide equivalent (CO_2e) basis, or about 7% of Vermont's gross GHG emissions in 2005. Emissions associated with the electricity sector are low relative to other categories in Vermont because of the State's use of hydroelectric and nuclear power; these resources are not significant[15] sources of GHG emissions. In 2004, Vermont emitted approximately 0.00012 metric tons of CO_2 ($MtCO_2$) per megawatt-hour (MWh) from electricity generation, which is significantly less than the national average of 0.65 $MtCO_2$/MWh.[16]

From 1992 through 2005, hydroelectric and nuclear power together met from 67% to 82% of Vermont's demand for electricity depending on the year. In addition, Vermont has benefited from the supply of electricity generated by renewable resources (including wood and wind) accounting for 2.7% of its total electricity purchases in 1992 and increasing to 6.3% of total purchases in 2005. Electricity generated by fossil fuels (i.e., coal, oil, and natural gas) and electricity purchased from the Independent Service Operator for New England (ISO-NE) system accounted for 21% of total electricity purchases in 1992, increased to a high of 27% of total purchases in 1998, and declined to a low of about 12% of total purchases in 1999. In 2005, electricity generated from fossil fuels and the ISO-NE system accounted for 19% of total purchases.

A key issue with the reference case projections for Vermont is the resource mix that will be used to meet future electricity demand. The operating license for the Entergy - Vermont Yankee nuclear power plant (that has supplied about one-third of Vermont's energy) expires in 2012. In addition, contracts with Hydro Quebec (which have supplied another one-third of Vermont's energy) will phase out from 2012 through 2020. Thus, these uncertainties present a challenge in estimating GHG emissions associated with the electricity sector through 2030.

As with any emissions inventory, it is necessary to consider the fact that some GHG emissions arise from consumption of electricity that is produced outside the State, since Vermont currently imports roughly half its electricity. This appendix provides information with regard to these

[15] Although construction emissions, hydroelectric reservoir methane emissions, and nuclear fuel cycle emissions are not strictly zero.
[16] EPA GHG Inventory.

indirect emissions by examining electricity-related emissions from both a production and a consumption basis.

The Vermont DPS provided the annual amount of electricity purchased by each of the 21 utilities in Vermont for 1992 through 2005. This information was used to identify the fuels used to generate electricity along with assumptions on heat rates, combustion efficiencies, and emission factors to estimate emissions for the inventory and reference case projections. The DPS' forecast for electricity demand for the period covering 2006 through 2026, and assumptions about future generation mix, were used to estimate GHG emissions for the reference case projections. The average annual growth rate for 2016 through 2026 was used to extend the electricity sales forecast to 2030.

Electricity Consumption

At about 9,170 kilowatt-hour (kWh) per person per year (2004 data), Vermont has relatively low electricity consumption per capita.[17] By way of comparison, the per capita consumption for the US was about 12,000 kWh per person per year.[18] Many factors influence a State's per capita electricity consumption, including the impact of weather on demand for cooling and heating, the size and type of industries in the State, and the type and efficiency of equipment in use in the residential, commercial and industrial sectors.

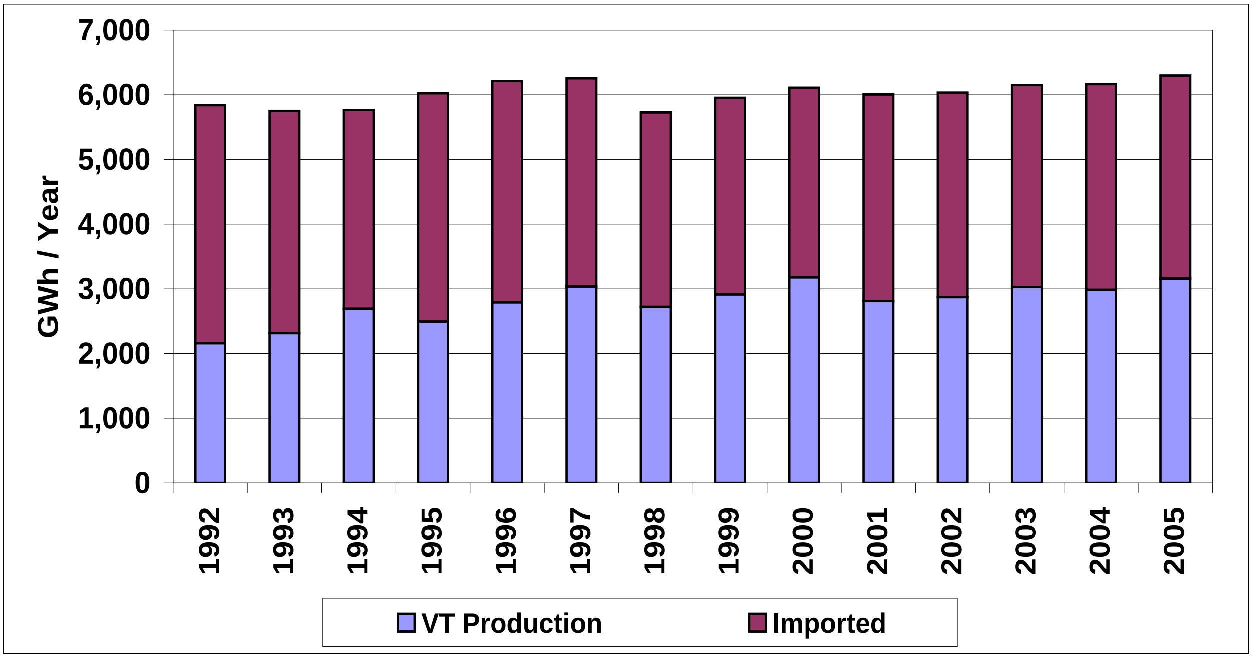
Figure A1 shows the total amount of electricity purchased by Vermont's 21 utilities, as well as electricity generated in-state and imported from other States, for 1992 through 2005. Vermont's total electricity demand was 5,841 gigawatt-hours (GWh) in 1992 and increased to 6,298 GWh in 2005. Vermont's total electricity demand increased by 0.6% per year from 1992 through 2005, with an overall increase of 7.8% over the 13-year period. Vermont has been a net importer of electricity over this 13-year period. In-state generation of electricity met 36% of Vermont's total energy demand in 1992 but has increased to account for 48% of total demand in 2005. Vermont imported electricity to meet 64% of its total demand in 1992, but its reliance on imported electricity declined to about 52% of total demand in 2005.

As shown in Table A1, electricity sales in Vermont have generally increased from 1990 through 2004. Overall, total electricity consumption increased at an average annual rate of 1.34% from 1990 to 2000, 0.89% from 2000 through 2005, and 1.14% over the 15-year period (1990 through 2005). During this period, residential sector consumption declined slightly at an average annual rate of -0.05% from 1990 through 2000, increased by an average annual rate of 1.47% from 2000 through 2005, and increased by 0.46% annually over the 15-year period. Vermont's population increased by an average annual rate of 0.79% from 1990 through 2000, 0.72% from 2000 through 2005, and by 0.77% from 1990 through 2005. Commercial sector electricity use grew by an average of 2.49% per year from 1990 through 2000, 1.39% from 2000 through 2005, and 2.12% over the 15-year period. Industrial sector electricity use grew by an average of 1.73% per

[17] Population data for 2004 (626,549 people) from Vermont Department of Public Health, Agency of Human Services' website at http://healthvermont.gov/research/intercensal/TABLE1.XLS. Electricity purchases (including line losses) for 2004 (5,748 GWh) from Vermont DPS. Vermont data for 2004 were used for comparison to US per capita data available for 2004.
[18] Census Bureau for US population, Energy Information Administration (EIA) for electricity sales.

year from 1990 through 2000, declined by an annual average rate of -0.4% from 2000 through 2005, and increased by an average annual rate of 1.02% overall for the 15-year period.

Figure A1. Electricity Purchased by Vermont Utilities (1992-2005)



Source: Vermont DPS.
Notes: Values shown in this figure include electricity associated with line losses. Data for 1990 and 1991 not available.

Table A1. Vermont Electricity Annual Average Growth Rates by Sector, Historic and Projected

	Historic			Projected	
Sector	**1990-2000**	**2000-2005**	**1990-2005**	**2006-2026**	**2026-2030**
Residential	-0.05%	1.47%	0.46%	NA	NA
Commercial	2.49%	1.39%	2.12%	NA	NA
Industrial	1.73%	-0.40%	1.02%	NA	NA
Other	0.26%	-1.25%	-0.25%	NA	NA
Total	1.34%	0.89%	1.14%	1.36%	1.16%

Source: For historic data, Vermont DPS, *Draft Update to the 2005 Vermont Electric Plan*, Table 3-2, page 38, October 20, 2006. For projections, Vermont DPS forecast.
Notes: Projected sales by sector not available (NA). Projected total sales based on Vermont DPS forecast of energy sales without new demand-side management (DSM) programs being implemented beginning in 2006. The "Other" category has historically accounted for 1% or less of total electricity sales; for the forecast this category is combined with the commercial sector.

Vermont's electric demand by end-use sector parallels the national average, but differs significantly from the New England average. For 2005, the residential, commercial, and industrial sectors accounted for 37%, 35%, and 28% of retail electricity sales, respectively.[19] This distribution of electricity use by sector is close to the overall 15-year average for the residential, commercial, and industrial sectors which is 38%, 33%, and 29% of retail electricity sales, respectively. The "Other" miscellaneous category (see Table A1) covers electricity use for street lighting and farms, which has accounted for 1% of electricity sales annually from 1990 through 2005.

Table A2 shows electricity purchases by Vermont's 21 utilities by energy source for 2005. As shown in Table A2, Vermont currently has large contracts with both Entergy (Vermont Yankee) and Hydro Quebec. These two resources comprise nearly two-thirds of Vermont's energy supply commitments. In addition to these sources, Vermont utilities also purchase their energy wholesale from ISO-NE, and from gas, oil and other renewable electricity generators.

Table A2. Vermont's Electric Utilities by Energy Source (MWh) 2005

Utility	Nuclear	Gas	Oil	System A*	System B*	Hydro	Hydro Quebec	Renewables	Total
Barton	0	0	3	4,357	0	4,154	8,575	459	17,548
BED	0	208	267	254,643	500	11,189	0	129,948	396,756
CVPS	1,365,675		51,469	3,133	60,000	251,467	718,767	67	2,450,578
Enosburg	0	5	3	6,137	0	5,228	9,879	3,228	24,480
GMP	816,990	10,315	19,853	291,612	10,000	190,586	680,984	88,798	2,109,138
Hardwick		622	304	33,384	0	4,704	0	4,108	43,121
Hyde Park	0	0	0	3,785	0	374	2,305	6,687	13,150
Jacksonville	0	0	0	5,695	0	179	0	173	6,047
Johnson	0	0	0	16,072	0	495	0	478	17,045
Ludlow	0	896	438	35,712	0	1,451	9,229	5,359	53,086
Lyndonville	0	477	295	48,058	0	6,605	18,084	8,487	82,005
Morrisville	11,412	421	202	10,132	0	9,806	15,989	7,011	54,972
Northfield	0	7	0	14,337	0	875	8,912	5,064	29,195
Orleans	0	0	0	10,021	0	452	4,256	437	15,165
Readsboro	0	0	0	2,519	0	75	0	72	2,666
Rochester	0	0	0	21	0	200	1,996	193	2,410
Stowe	0	1,934	961	41,315	0	2,154	20,794	8,254	75,413
Swanton	0	418	202	2,666	0	46,614	0	9,576	59,476
VEC	79,579	0	0	20,024	0	14,776	225,830	180,982	521,190
VT Marble	0	0	960	179,111	0	52,803	12,130	6,475	251,479
WEC	0	8	0	19,784	15,204	5,027	15,259	17,847	73,128
Total	**2,273,656**	**15,311**	**74,957**	**1,002,516**	**85,704**	**609,212**	**1,752,988**	**483,702**	**6,298,046**

Source: Vermont DPS, *Utility Facts*, October 2006.
*"System A" represents system energy purchased by utilities and "System B" represents power associated with the sale of Renewable Energy Credits (RECs).

[19] Vermont DPS, *Utility Facts*, October 2006.

Electricity Generation In Vermont

Table A3 shows the ten largest generators of electricity in Vermont. As previously discussed, Vermont electricity generators have a relatively clean GHG emissions profile because electricity generators in Vermont use either nuclear power, hydroelectric power, or wood as a fuel source. The largest generator is Entergy - Vermont Yankee, a nuclear power plant that accounts for about one-third of the electricity consumed in Vermont. Both J. C. McNeil and Ryegate burn wood to generate electricity, but may periodically use oil or natural gas to supplement their operations depending on the availability of wood.

Table A3. Ten Largest Plants by Generating Capability, 2004

Plant	Energy Sources	Operating Company	Net Summer Capability (MW)
Vermont Yankee*	Nuclear	Entergy Nuclear Vermont Yankee	506
J. C. McNeil	Petroleum, Gas, Wood	Burlington City of	52
Bellows Falls	Hydroelectric	US Gen New England Inc.	49
Wilder	Hydroelectric	US Gen New England Inc.	41
Harriman	Hydroelectric	US Gen New England Inc.	40
Berlin 5	Petroleum	Green Mountain Power Corp.	35
Vernon	Hydroelectric	US Gen New England Inc.	24
Sheldon Springs Hydroelectric	Hydroelectric	Sheldon Vermont Hydro Co., Inc.	24
Burlington GT	Petroleum	Burlington City of	20
Ryegate Power Station	Wood	Ryegate Associates	20

Source: EIA State Energy Profiles.
* For Vermont Yankee, Vermont owns 55% or 278 MW of the 206 MW capability. In 2005, Vermont Yankee completed an uprate increasing its capability to 210 MW; however, Vermont's share remains at 278 MW or about 46% of the post-uprate capability.

Methods for Calculating Historical GHG Emissions (1990 – 2005)

For Vermont, we used a contract-based approach for calculating GHG emissions. This approach involves knowing the amount (in GWh's) of electricity that each of Vermont's utilities purchased each year, and the fuel mix associated with the purchases. Assumptions on heat rates were then used to convert the GWh's of electricity purchased by fuel type to a heat input basis (i.e., British thermal units or Btu's) that can be applied with combustion efficiencies and emission factors to calculate emissions. The following presents the methods applied to estimate GHG emissions associated with electricity produced in-state (i.e., production-based emissions) and methods applied to estimate GHG emissions associated with electricity produced outside of Vermont and imported to fill demand. The emissions associated with the estimates for production and imported electricity are summed to estimate consumption-based emissions.

Note that electricity purchases by Vermont utilities were not available for 1990 and 1991. Based on discussions with Vermont DPS, there were no major changes in the types of purchases that Vermont utilities made during the period covering 1990 through 1992 except that Ryegate (a wood-fired generator) did not come on-line until 1992. Therefore, for this initial analysis, Vermont utility purchases for 1992 were used as a surrogate for estimating emissions for 1990 and 1991 except that purchases from Ryegate were excluded from the fuel mix for 1990 and 1991.

Production-Based Emissions (1990-2005)

Figure A2 shows total purchases of electricity by Vermont utilities from Vermont generators for 1992 through 2005. As shown in this figure, the fuel mix associated with purchases of electricity generated in Vermont is dominated by nuclear and hydroelectric power. The "Other Resources" category is broken out in detail in Figure A3. As shown in Figure A3, electricity generated by renewable resources (i.e., wood and wind) account for the majority of the remaining (i.e., other than nuclear and hydroelectric power – not shown in Figure A3) in-state purchases. Thus, production-based carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) emissions were calculated based on the in-state purchases of electricity generated using coal, oil, and natural gas. Emissions of N_2O and CH_4 were also calculated based on the in-state purchases of electricity generated using wood.[20] Methane emissions associated with the combustion of landfill gas are included in the inventory for the waste sector (see Appendix G).

The emission factors for calculating emissions are on a heat input basis. Therefore, heat rates were used to convert the amount of electricity purchased (GWh of heat output) to a heat input basis (as Btu's). Table A4 shows the heat rates used for each fuel type and year, and the combustion efficiencies used to estimate CO_2 emissions for coal, natural gas, and oil. The CO_2, N_2O, and CH_4 emission factors provided in the Emission Inventory Improvement Guidance (EIIP) for combustion sources were used to calculate emissions.[21]

Figure A4 shows the production-based emissions associated with in-state generation of electricity for 1990 through 2005. Emissions range from a low of 0.017 $MMtCO_2e$ from 1993 through 1995 to as high as 0.085 $MMtCO_2e$ in 2000. The emissions vary significantly depending on the fuel mix used to generate electricity over this 15-year period, and is highly sensitive to the fuel mix used at particular plants. Specifically, emissions from natural gas only occur during the years when McNeil used natural gas to produce electricity. For McNeil, in 2005, emissions associated with the use of natural gas are nearly zero based on the generation data obtained from VT DPS. However, the VT DEC Air Division's annual registration data indicates that McNeil combusted approximately 34 million cubic feet of natural gas in 2005, which is about half of the 67 million cubic feet that McNeil used in 2004. The VT DEC data suggests that emissions associated with McNeil should be higher than the emissions calculated from VT DPS generation data. This issue could not be resolved during preparation of the inventory.

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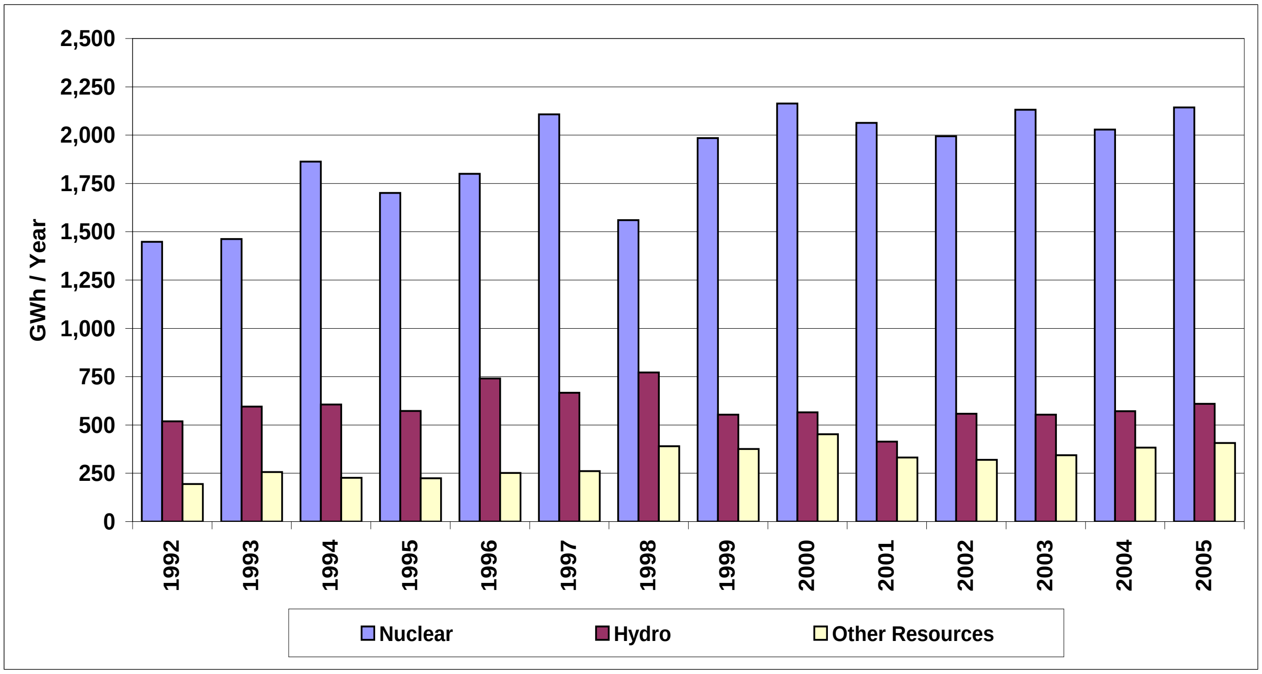
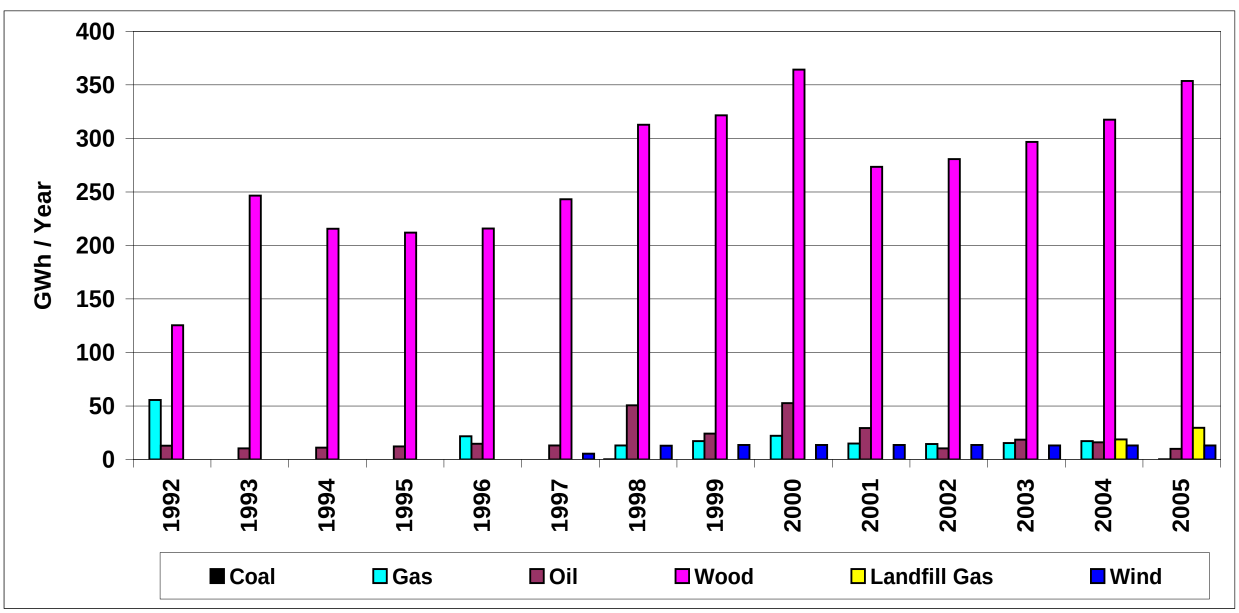
[20] Emissions from wood combustion include only N_2O and CH_4. Carbon dioxide emissions from biomass are assumed to be "net zero" consistent with US EPA and IPCC methodologies, and any net loss of carbon stocks due to biomass fuel use should be picked up in the land use and forestry analysis.
[21] *EIIP*, *Volume VIII*: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004, and Chapter 2 "Methods for Estimating Methane and Nitrous Oxide Emissions from Stationary Combustion", August 2004.

Figure A2. Utility Own-Load Purchases of Electricity Generated by Nuclear, Hydroelectric, and Other Resources in Vermont (1992-2005)



Source: Vermont DPS.

Figure A3. Utility Own-Load Purchases of Electricity Generated from Other Resources (Fuels) in Vermont (1992-2005)



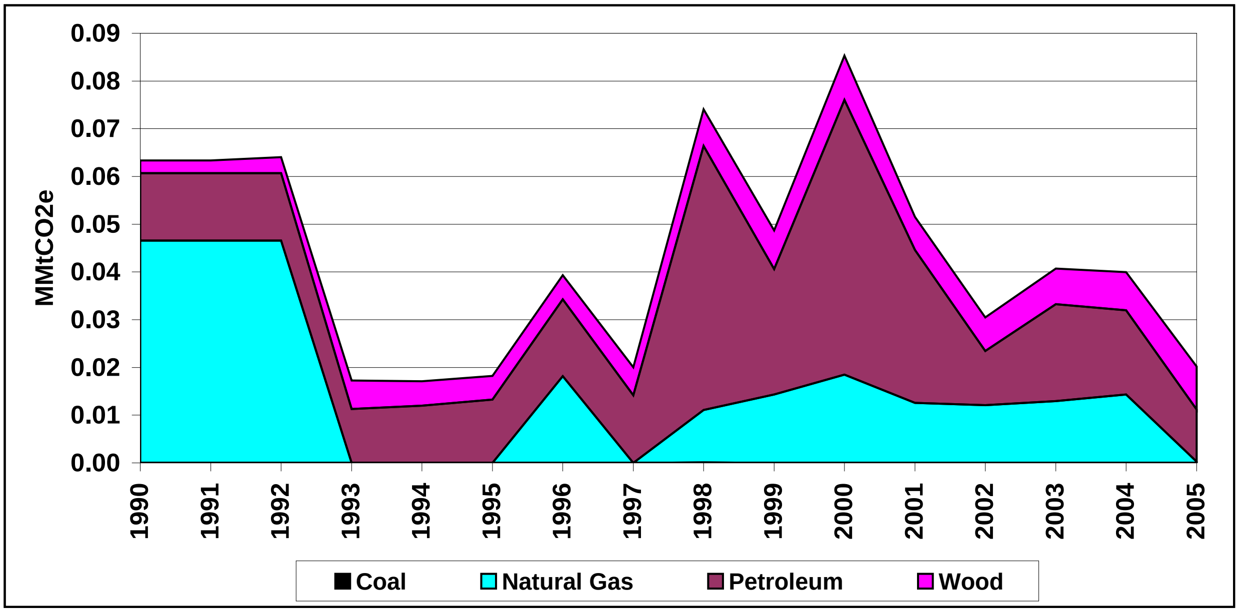
Source: Vermont DPS.
Notes: A small amount of electricity was purchased from a coal-fired generator only in 1998, but the amount of electricity purchased is too small to be seen on this graph due to scale effects.

Table A4. Heat Rates and Combustion Efficiencies Assumed for In-State and Imported Electricity Generation

Fuel	Btu / kilowatt-hour	Reference for Heat Rates	Combustion Efficiencies*
In-State Electricity Generation			
Coal	10,820	The Ludlow and Jacksonville utilities purchased a small amount of electricity (125 MWh) generated by coal in Vermont in 1998 only. Heat rates for the generator were not available. Used year-specific heat rates for Merrimack in NH for 1996-2000 from e-GRID; 5-year average used for 1990-1995 and 2001-2005.	99.0%
Natural Gas	15,919	Based on heat rates for McNeil which is the only generator in Vermont that uses natural gas.	99.5%
Oil	15,000	Vermont DPS (based on heat rates for peaking oil units in Vermont that are old and do not burn as clean as newer units).	99.0%
Wood			
McNeil	15,919	Heat rates for McNeil for 1996-2000 from eGrid. Heat rates for 1990-1995 and 2001-2005 based on 5-year average of 1996-2000 data from eGRID.	
Ryegate	12,543	Heat rates for Ryegate for 1996-2000 from eGrid. Heat rates for 1990-1995 and 2001-2005 based on 5-year average of 1996-2000 data from eGRID.	
Imported Electricity Generation			
Coal	10,820	Electricity purchased from Merrimack (a coal-fired generator) in NH. Heat rates based on year-specific values for Merrimack for 1996-2000 from e-GRID; 5-year average used for 1990-1995 and 2001-2005.	99.0%
Natural Gas	15,919	Vermont utilities purchased energy from Stony Brook (a natural gas-fired generator) in MA. Heat rates based on year-specific value for Stony Brook for 2004 (the only year for which data were available in eGRID).	99.5%
Oil	15,000	Vermont DPS (based on heat rates representative of those for the ISO-NE system).	99.0%
System	7,450	Based on 5-year average of heat rates for 1996-2000 calculated from eGRID for all generators that supplied electricity to the ISO-NE system. The 5-year average was applied for all years (1990-2030).	

* Reference for combustion efficiencies for estimating CO_2 emissions for fossil fuels: Emission Inventory Improvement Program, Volume VIII: Chapter 1 *Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels*, August 2004.

Figure A4. Emissions Associated with In-State Generation of Electricity (1990-2005)



Emissions Associated with Imported Electricity

Figure A6 shows total purchases of electricity by Vermont utilities from generators outside of Vermont for 1992 through 2005. As shown in this figure, the fuel mix associated with imported electricity is dominated by hydroelectric power, which is purchased from Hydro Quebec. Vermont utilities began reliance on purchases from the ISO-NE system in 1998 to replace electricity imports generated by other resources (fuels) as well as to adjust to fluctuations in purchases from Hydro Quebec (depending on the year). The "Other Resources" category, which refers to power purchased from coal, oil, natural gas, and landfill gas is broken out in detail in Figure A7.

Carbon dioxide, N_2O, and CH_4 emissions were calculated based on the purchases of imported electricity generated using coal, oil, and natural gas and purchases of electricity from the ISO-NE system. The heat rates and combustion efficiencies shown in Table A4, and emission factors published in the EIIP guidance documents, were used to calculate emissions. During development of this analysis, information was not available to determine how to account for emissions associated with imported electricity generated by landfills. Therefore, emissions associated with imported electricity generated by landfills outside of Vermont were not estimated.

To estimate emissions associated with system purchases of electricity, it was necessary to make some simplifying assumptions on the fuel mix that generators used to supply electricity to the system as well as the heat rate to convert energy from an energy output to an energy input basis. The first step was to allocate the system purchases of electricity by Vermont utilities to the various fuel types that generate GHG emissions when combusted (i.e., excluding nuclear and hydro), under the assumption that Vermont's purchases of electricity by fuel are proportional to

ISO-NE generation by fuel. Table A5 shows the allocation of system purchases to the various fuel types based on data obtained from eGRID for the ISO-NE Power Control Area (PCA). The next step was to apply a heat rate representative of the system to convert the system purchases of electricity for each fuel type to a heat input basis. The heat rate used for this initial analysis was 7,450 Btu/kWh, which is based on the 5-year average of heat rates for 1996-2000 calculated from eGRID for all generators in the ISO-NE system. This approach was used because fuel-specific heat rates were not available for the ISO-NE system. The emission factors published in the EIIP guidance documents and combustion efficiencies shown in Table A4 were use to calculate emissions associated with each fuel type.

Table A5. Allocation of Energy Associated with System Purchases to Fuel Types

Fuel Type	1990-1996	1997	1998	1999	2000	2001-2005
Coal	31%	27%	24%	23%	27%	26%
Oil	23%	32%	37%	39%	26%	31%
Gas	15%	15%	27%	25%	34%	23%
LPG	30%	25%	2%	2%	2%	13%
Wood	0%	0%	9%	11%	11%	6%
Total	100%	100%	100%	100%	100%	100%

Notes: Actual data from eGRID for ISO-NE system used to calculate the relative proportions of fuels for 1996 through 2000. Fuel allocations for 1990 through 1995 based on allocations for 1996. Fuel allocations for 2001 through 2005 based on 5-year average of allocations for 1996 through 2000.

Figure A6. Utility Purchases of Imported Electricity Generated by Nuclear, Hydroelectric, Other Resources, and from the ISO-NE System (1992-2005)

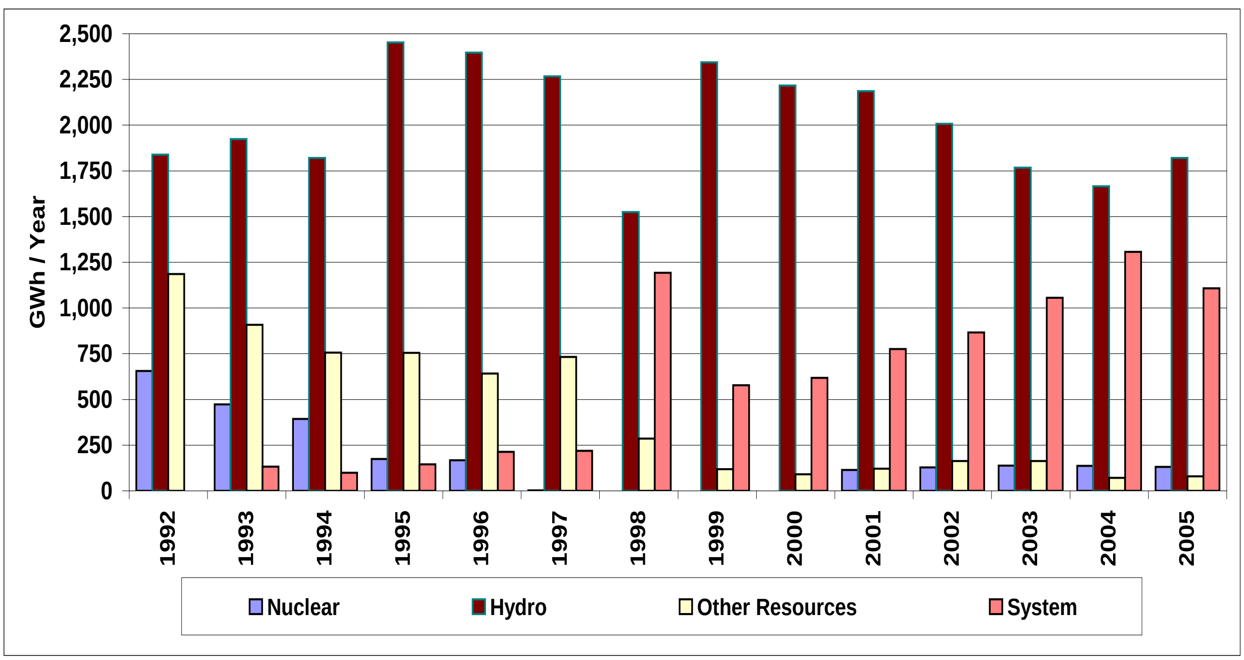


Figure A7. Utility Purchases of Imported Electricity Generated by Other Resources (1992-2005)

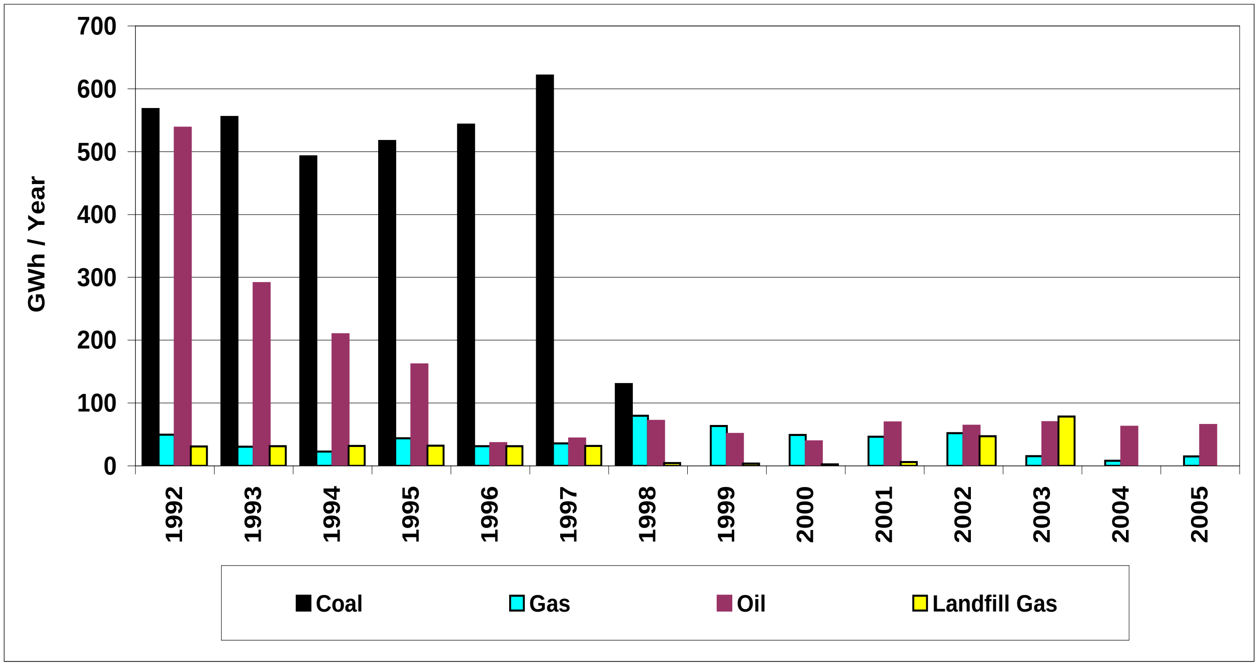


Figure A8 shows emissions associated with the generation of electricity imported into Vermont for 1990 through 2005. Emissions range from a low of about 0.4 MMtCO_2e in 1999 and 2000 to as high as 1.03 MMtCO_2e from 1990 through 1992. Similar to the historical production-based emissions, the emissions associated with imported electricity vary significantly depending on the fuel mix used to generate the electricity purchased by Vermont utilities over this 15-year period.

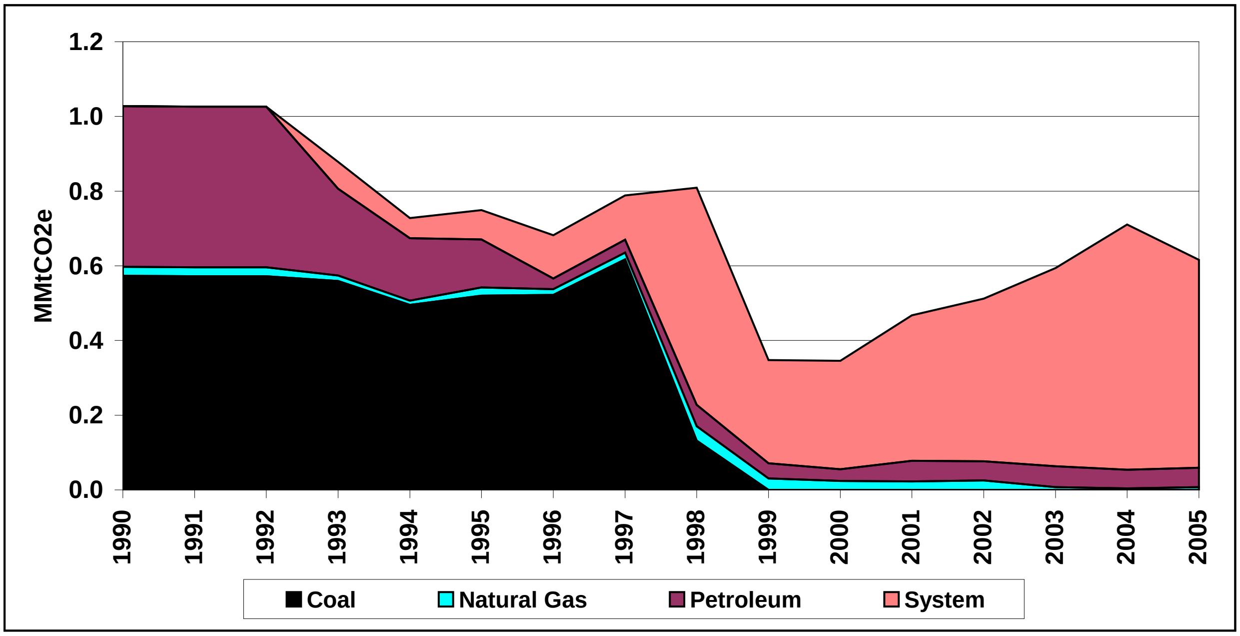
Consumption-Based Emissions (1990-2005)

Figure A9 shows the sum of production-based emissions and emissions associated with imported electricity for 1990 through 2005. Emissions range from a low of about 0.4 MMtCO_2e in 1999 and 2000 to as high as 1.09 MMtCO_2e from 1990 through 1992. From 1990 through 1998, the majority of the emissions were associated with electricity purchased on a contract basis from generators that used coal and oil. However, from 1999 through 2005, emissions were associated with purchases of electricity from the ISO-NE system. Additional research would be needed to determine the exact fuel mix used to generate the electricity purchased from the ISO-NE system in order to refine the emission estimates associated with system purchases.

Methods for Calculating Reference Case Projection Emissions (2006-2030)

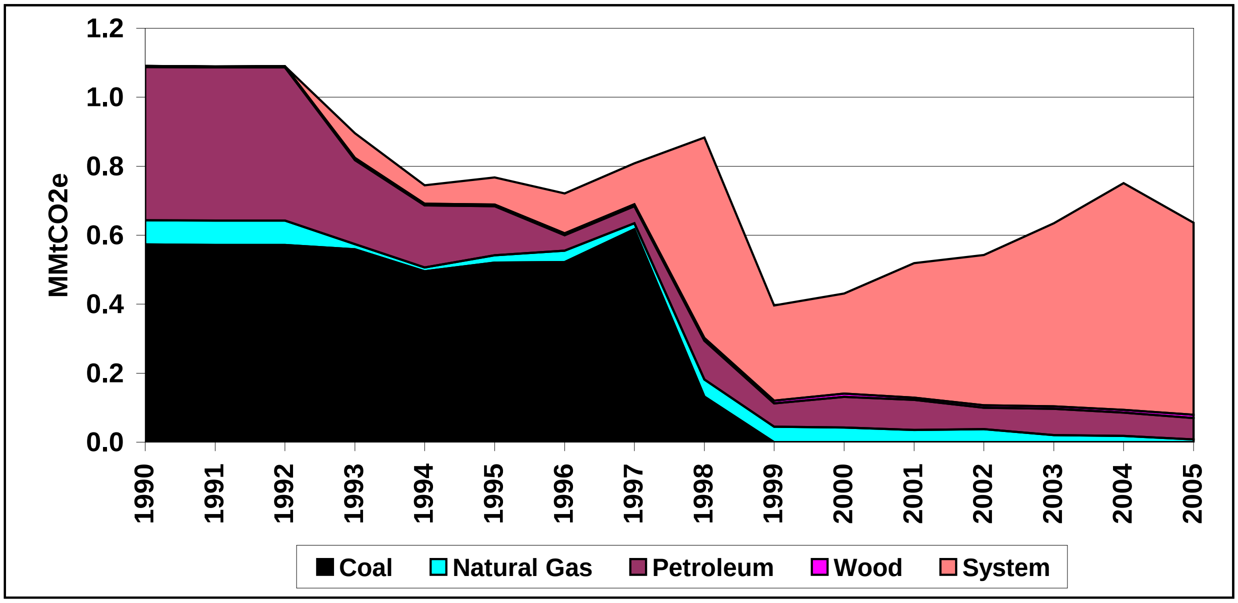
Vermont DPS has prepared two energy demand forecasts for 2006 through 2026. One forecast assumes that no new DSM programs will be implemented during the forecast period, and the second forecast assumes that new DSM programs will be implemented starting in 2006. The

Figure A8. Emissions Associated with Imported Electricity Generation (1990-2005)



Notes: Natural gas emissions are too small to be seen in this figure due to scale effects.

Figure A9. Consumption-Based Historical Electricity Supply Emissions (1990-2005)



forecasts for electricity sales from 2006 through 2026 are estimated to increase at an average annual rate of about 1.36%. The DPS forecast for this 20-year period estimates that implementation of new DSM programs beyond existing programs could lower electricity demand to about 0.30% annually. Based on discussions with DPS, the annual growth rate of DPS' forecast from 2016 through 2026 was used to extend DPS' forecast from 2026 to 2030; an annual growth rate of 1.16% was used to extend the forecast without new DSM programs, and an annual growth rate of 0.48% was used to extend the forecast with new DSM programs.

A key issue with the reference case projections for Vermont is the resource mix that will be used to meet future electricity demand. Figure A10 compares the DPS' energy forecasts to Vermont's committed resources (i.e., electricity that will be supplied under existing contracts between the State of Vermont and generators). As shown in Figure A10, a significant electricity supply gap occurs beginning in 2012. This supply gap is associated with the expiration of Vermont Yankee's operating license and contracts with Hydro Quebec that end from 2012 through 2020. As noted earlier, Vermont Yankee and Hydro Quebec currently account for about two-thirds of Vermont's energy demand. In addition, Vermont's contract with the independent power producer (IPP) Ryegate ends in 2012, and contracts with IPP hydroelectric generators end in 2020. Thus, these uncertainties present a challenge to estimating GHG emissions associated with the electricity sector through 2030 because there are various ways that the supply gap may end up being filled.

Because of the uncertainties associated with Vermont's energy future, we prepared reference case projections for the following four scenarios:

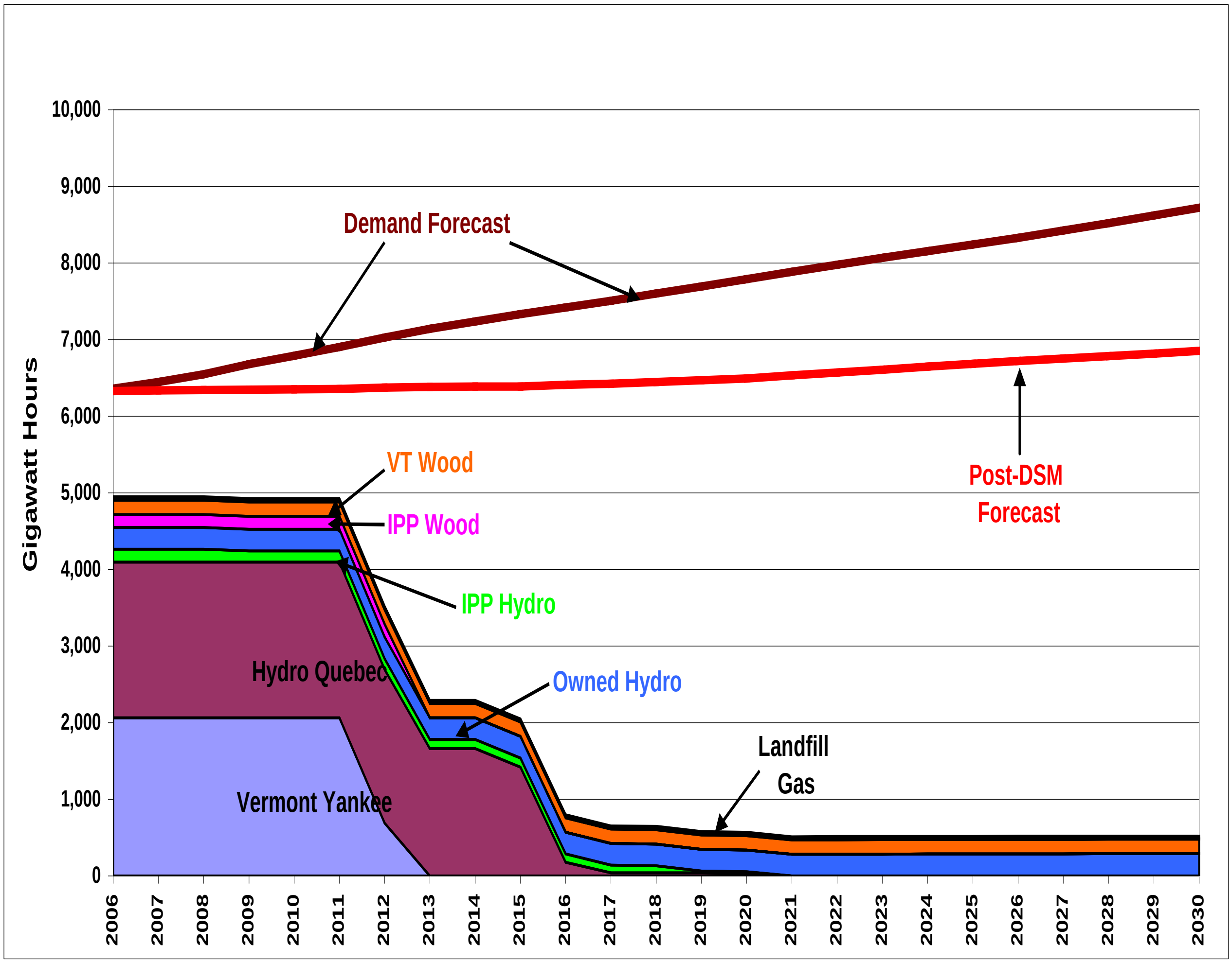
- Scenario 1: System purchases of electricity without new DSM programs (High-Emissions Scenario, No New DSM);
- Scenario 2: System purchases of electricity with new DSM programs (High-Emissions Scenario, With New DSM);
- Scenario 3: Historic mix of electricity supply resources without new DSM programs (Low-Emissions Scenario, No New DSM); and
- Scenario 4: Historic mix of electricity supply resources with new DSM programs (Low-Emissions Scenario, With New DSM).

Scenarios 1 and 2 assume that Vermont will purchase electricity from the ISO-NE system instead of contracting with generators to maintain the current fuel mix upon which its electricity purchases are based. Scenarios 1 and 2 represent the high-emission profile cases for the purpose of the reference case projections. Scenarios 3 and 4 assume that Vermont will be able to meet its future energy demands through purchases of electricity generated using resources similar to its current fuel mix. Scenarios 3 and 4 represent the low-emission profile cases for the purpose of the reference case projections. Note that Scenarios 2 and 4 differ from Scenarios 1 and 3 in that Scenarios 2 and 4 include the DPS' forecast for implementing new DSM programs starting in 2006 through 2030.

Table A6 shows the DPS energy forecast and committed resource assumptions for 2006 through 2030. Because of page width limitations, the table is broken into two parts with the first part showing energy forecasts for 2006 through 2018 and the second part showing energy forecast for

2019 through 2030. Rows 1 through 8 in Table A6 show the energy forecast assumptions associated with committed resources, and row 9 shows the total energy forecast for committed resources combined. Row 10 shows the DPS forecast without new DSM programs.

Figure A10. Vermont Energy Forecast and Committed Resources



Source: Vermont DPS, January 2007. See Table A6 for the data used to develop this graph.

Row 11 in Table A6 shows the "system purchase" energy forecast for Scenarios 1 and 2. Row 12 shows system purchases as a percentage of the DPS' energy forecast. For Scenarios 1 and 2, system purchases increase starting in 2012 when Vermont's contract with Entergy - Vermont Yankee ends and contracts with Hydro Quebec begin to phase out through 2020. The committed resources forecast also assumes that Vermont's contract with Ryegate ends in 2012 and contracts with IPPs of hydroelectric power end in 2020. Under Scenarios 1 and 2, system purchases account for 27% of the total energy demand in 2010, but rise significantly to account for 94% of total energy demand by 2030.

Table A6. Energy Forecast and Committed Resources for 2006 through 2030 (GWh / Year)

Row	Resource	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	Vermont Yankee	2,064	2,064	2,064	2,064	2,064	2,064	688	0	0	0	0	0	0
2	Hydro Quebec	2,034	2,034	2,034	2,034	2,034	2,034	2,004	1,661	1,661	1,419	179	39	39
3	IPP Hydro	168	168	168	146	146	146	146	119	119	119	108	101	95
4	VT Own Hydro	282	282	282	282	282	282	282	282	282	282	282	282	282
5	Wind	13	13	13	13	13	13	13	13	13	13	13	13	13
6	Landfill Gas	30	30	30	30	30	30	30	30	30	30	30	30	30
7	VT Wood (McNeil)	188	188	188	188	188	188	188	188	188	188	188	188	188
8	IPP Wood (Ryegate)	169	169	169	169	169	169	169	0	0	0	0	0	0
9	Committed Resources (sum of rows 1-8)	4,948	4,948	4,948	4,925	4,925	4,925	3,520	2,293	2,293	2,050	800	653	647
10	DPS Energy Forecast	6,362	6,446	6,547	6,678	6,791	6,903	7,029	7,141	7,239	7,331	7,420	7,508	7,601
11	Scenarios 1 and 2 System Purchases	1,414	1,498	1,599	1,753	1,865	1,978	3,509	4,848	4,946	5,281	6,620	6,854	6,954
12	System purchases as Percentage of DPS Energy Forecast	22%	23%	24%	26%	27%	29%	50%	68%	68%	72%	89%	91%	91%
13	Scenarios 3 and 4 Historical Fuel Mix	1,414	1,498	1,599	1,753	1,865	1,978	2,104	2,216	2,314	2,406	2,495	2,583	2,676
14	Historical Fuel Mix as Percentage of DPS Energy Forecast	22%	23%	24%	26%	27%	29%	30%	31%	32%	33%	34%	34%	35%
15	Estimated DSM Savings	33	109	202	330	439	546	655	758	852	943	1,011	1,081	1,151
16	Post DSM Forecast	6,329	6,337	6,344	6,348	6,352	6,357	6,373	6,383	6,387	6,389	6,409	6,427	6,450

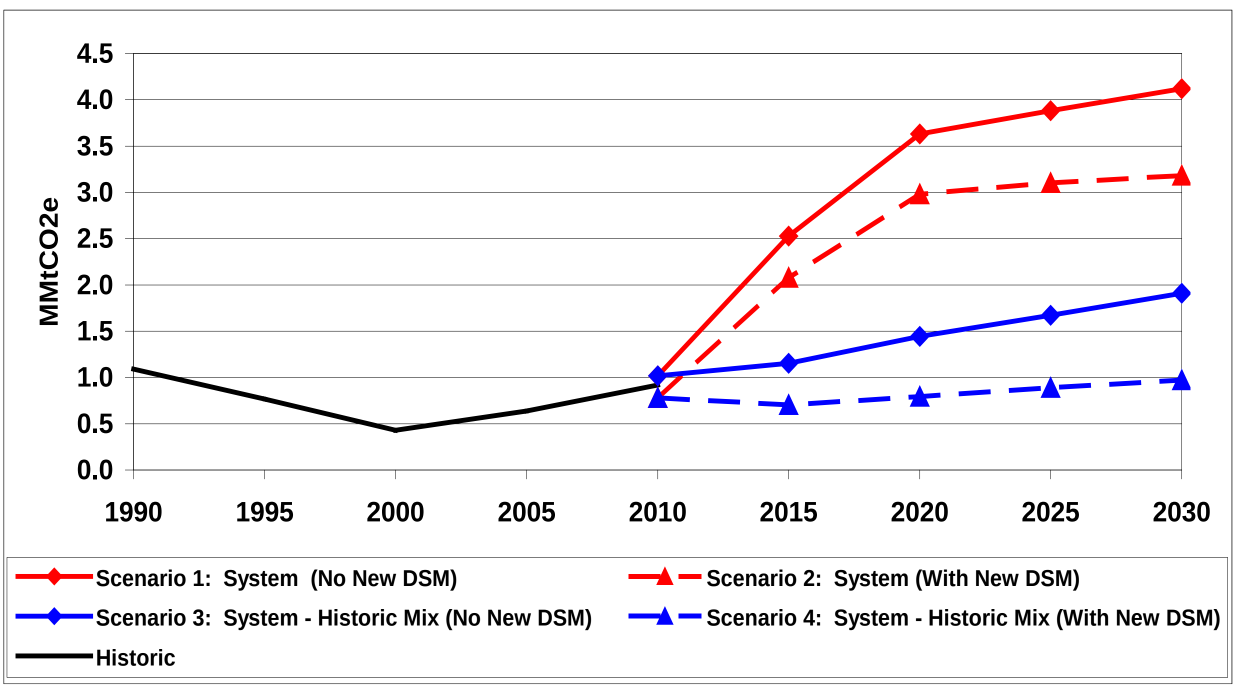
Row	Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Vermont Yankee	0	0	0	0	0	0	0	0	0	0	0	0
2	Hydro Quebec	39	33	0	0	0	0	0	0	0	0	0	0
3	IPP Hydro	26	24	0	0	0	0	0	0	0	0	0	0
4	VT Own Hydro	282	282	283	284	285	286	287	288	289	290	291	292
5	Wind	13	13	13	13	13	13	13	13	13	13	13	13
6	Landfill Gas	30	30	30	30	30	30	30	30	30	30	30	30
7	VT Wood (McNeil)	188	188	188	188	188	188	188	188	188	188	188	188
8	IPP Wood (Ryegate)	0	0	0	0	0	0	0	0	0	0	0	0
9	Committed Resources (sum of rows 1-8)	578	569	514	515	516	517	518	519	520	521	522	523
10	DPS Energy Forecast	7,694	7,792	7,885	7,976	8,068	8,155	8,242	8,327	8,424	8,522	8,621	8,721
11	Scenarios 1 and 2 System Purchases	7,116	7,223	7,372	7,461	7,552	7,639	7,724	7,809	7,904	8,001	8,099	8,198
12	System purchases as Percentage of DPS Energy Forecast	92%	93%	93%	94%	94%	94%	94%	94%	94%	94%	94%	94%
13	Scenarios 3 and 4 Historical Fuel Mix	2,769	2,867	2,960	3,051	3,143	3,230	3,317	3,402	3,499	3,597	3,696	3,796
14	Historical Fuel Mix as Percentage of DPS Energy Forecast	36%	37%	38%	38%	39%	40%	40%	41%	42%	42%	43%	44%
15	Estimated DSM Savings	1,224	1,298	1,352	1,406	1,459	1,509	1,557	1,605	1,669	1,735	1,801	1,868
16	Post DSM Forecast	6,470	6,494	6,534	6,570	6,609	6,647	6,684	6,723	6,755	6,787	6,820	6,852

As shown in Table A6, the forecast for the historical mix (Scenarios 3 and 4) is the same as for Scenarios 1 and 2 through 2011. After 2011, it was assumed that Vermont would be able to sustain energy purchases similar to the historical mix for 2009 through 2011, which amounts to a total of 4,925 GWh/year. Thus, for Scenarios 3 and 4, a total of 4,925 GWh/year was subtracted from the DPS energy forecast and the remaining energy demand was assumed to be met through purchases of electricity from the system. Under Scenarios 3 and 4, system purchases account for 27% of the total energy demand in 2010, but rise to account for 44% of total energy demand by 2030. Thus, in 2030, purchases of electricity from the system are 50% more under the system purchase scenarios than under the historical mix scenarios.

For all four scenarios, N_2O and CH_4 emissions were estimated for McNeil and Ryegate (both use wood to generate electricity), and CO_2, N_2O, and CH_4 emissions were estimated for system purchases. The heat rates and combustion efficiencies shown in Table A4, and emission factors published in the EIIP guidance documents, were use to calculate emissions for the wood generators and the fuel mix assumptions for system purchases.

Figure A11 shows the results of the emissions calculated for each of the four scenarios on a consumption basis. Emissions for all four scenarios are 0.64 $MMtCO_2e$ in 2005. From 2005 levels, emissions for Scenario 1 (system purchases with no new DSM programs) increase to 2.5 $MMtCO_2e$ in 2015, 3.6 $MMtCO_2e$ in 2020, and 4.1 $MMtCO_2e$ by 2030. Under Scenario 2, implementation of new DSM programs in 2006 lowers the Scenario 1 emissions by about 20% over the forecast period.

Figure A11. Consumption-Based GHG Inventory and Forecast for Vermont (1990-2030)



Emissions for Scenarios 3 and 4 are projected to be much lower than emissions for Scenarios 1 and 2 because the key assumption used under Scenarios 3 and 4 is that Vermont will be able to maintain a resource mix similar to its existing mix that relies heavily on nuclear and hydroelectric power. Relative to 2005 emission levels, emissions for Scenario 3 (historic mix with no new DSM programs) increase to 1.2 $MMtCO_2e$ in 2015, 1.4 $MMtCO_2e$ in 2020, and 1.9 $MMtCO_2e$ by 2030. Under Scenario 4, implementation of new DSM programs in 2006 lowers the Scenario 3 emissions by about 39% in 2015, 45% in 2020, and 50% in 2030.

Key Uncertainties

Key sources of uncertainty underlying the estimates above are as follows:

Emissions Estimates for System Purchases of Electricity: The key uncertainty with the inventory and forecast for the electricity supply sector is associated with the assumptions on the fuel mix, heat rates, and emission factors used to calculate GHG emissions associated with historical and future purchases of electricity from the ISO-NE system. Future work on the inventory and forecast should include an effort to refine the methods, data sources, and assumptions for calculating GHG emissions associated with purchases of electricity from the ISO-NE system.

Renewable Energy Credits (RECs): Vermont generators have sold RECs to out-of-state entities thus removing the renewable attributes of the power that otherwise would be available to Vermont utilities. As shown in Table A2, 85,704 MWh of power associated with the sale of RECs occurred in 2005. For the purpose of estimating emissions, assumptions would need to be made regarding whether the replacement power would or would not have renewable attributes similar to the power associated with the RECs sold to out-of-state entities. For the forecast, we have assumed that power generated using renewable resources (see committed resources in Table A6) in Vermont would be consumed in Vermont. This is a limitation of the forecast assumptions and future work should attempt to improve the forecast assumptions for renewable energy.

Historical Emissions Associated with Natural Gas Use by J.C. McNeil:
For McNeil, in 2005, emissions associated with the use of natural gas are nearly zero based on the generation data obtained from VT DPS. However, the VT DEC Air Division's annual registration data indicates that McNeil combusted approximately 34 million cubic feet of natural gas in 2005, which is about half of the 67 million cubic feet that McNeil used in 2004. The VT DEC data suggests that emissions associated with McNeil should be higher than the emissions calculated from VT DPS generation data. This issue should be investigated and resolved in future updates to the inventory for Vermont.

Appendix B. Residential, Commercial, and Industrial (RCI) Fossil Fuel Combustion

Overview

Activities in the RCI[22] sectors produce carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions when fuels are combusted to provide space heating, process heating, and other energy applications. Carbon dioxide accounts for over 98% of these emissions on a million metric tons (MMt) of CO_2 equivalent (CO_2e) basis in Vermont. In addition, since these sectors consume electricity, one can also attribute emissions associated with electricity generation to these sectors in proportion to their electricity use.[23] Direct use of oil, natural gas, coal, and wood in the RCI sectors accounted for an estimated 2.7 MMtCO_2e (30%) of total gross greenhouse gas (GHG) emissions in Vermont in 2005.[24]

Emissions and Reference Case Projections

Emissions from direct fuel use were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for RCI fossil fuel combustion.[25] The default data used in SGIT for Vermont are from United States Department of Energy (US DOE) Energy Information Administration's (EIA) *State Energy Data* (SED). The SED for Vermont were revised using the most recent data available which includes (1) the 2002 edition of SED[26] for all fuel types; (2) 2003 data that EIA released during December 2005 and August 2006 for oil, natural gas, coal, and wood;[27] and (3) 2003 and 2004 electricity consumption and natural gas consumption estimates available from the EIA's *Electric Power Annual*[28] and *Natural Gas Navigator*, respectively.[29]

[22] The industrial sector includes emissions associated with agricultural energy use and fuel used by the fossil fuel production industry.
[23] Emissions associated with the electricity supply sector (presented in Appendix A) have been allocated to each of the RCI sectors for comparison of those emissions to the fuel-consumption-based emissions presented in Appendix B. Note that this comparison is provided for information purposes and that emissions estimated for the electricity supply sector are not double-counted in the total emissions for the state. One could similarly allocate GHG emissions from natural gas transmission and distribution, other fuels production, and transport-related GHG sources to the RCI sectors based on their direct use of gas and other fuels, but we have not done so here due to the difficulty of ascribing these emissions to particular end-users. Estimates of emissions associated with the transportation sector are provided in Appendix C, and estimates of emissions associated with fossil fuel production and distribution are provided in Appendix E.
[24] Emissions estimates from wood combustion include only N_2O and CH_4. Carbon dioxide emissions from biomass combustion are assumed to be "net zero", consistent with US EPA and Intergovernmental Panel on Climate Change (IPCC) methodologies, and any net loss of carbon stocks due to biomass fuel use should be accounted for in the land use and forestry analysis.
[25] GHG emissions were calculated using SGIT, with reference to *EIIP, Volume VIII*: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004, and Chapter 2 "Methods for Estimating Methane and Nitrous Oxide Emissions from Stationary Combustion", August 2004.
[26] EIA *State Energy Data 2002*, Data through 2002, released June 30, 2006, http://www.eia.doe.gov/emeu/states/state.html?q_state_a=vt&q_state=VERMONT.
[27] EIA *State Energy Data 2003*, http://www.eia.doe.gov/emeu/states/_seds_updates.html.
[28] EIA Electric Power Annual, 2004, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.
[29] EIA Natural Gas Navigator, http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SVT_a.htm.

Note that the EIIP methods for the industrial sector exclude from CO_2 emission estimates the amount of carbon that is stored in products produced from fossil fuels for non-energy uses. For example, the methods account for carbon stored in petrochemical feedstocks, and in liquefied petroleum gases (LPG) and natural gas used as feedstocks by chemical manufacturing plants (i.e., not used as fuel), as well as carbon stored in asphalt and road oil produced from petroleum. The carbon storage assumptions for these products are explained in detail in the EIIP guidance document.[30] The fossil fuel categories for which the EIIP methods are applied in the SGIT software to account for carbon storage and for which the EIA SED contained consumption data for Vermont include the following categories: asphalt and road oil, distillate fuel, LPG, lubricants, natural gas, and residual fuel.

Reference case emissions for direct fuel combustion were estimated based on fuel consumption forecasts from EIA's *Annual Energy Outlook 2006* (AEO2006),[31] with adjustments for Vermont's projected population[32] and employment growth. Vermont employment data for the manufacturing (goods producing) and non-manufacturing (services providing) sectors were obtained from the Vermont Department of Labor.[33] New England regional employment data for the same sectors were obtained from the EIA.[34]

Table B1 shows historic and projected growth rates for electricity sales by sector. Table B2 shows historic and projected growth rates for energy use by sector and fuel type. For the residential sector, natural gas consumption is expected to increase slightly while consumption of petroleum, wood, and coal is expected to decline slightly. The rate of population growth is expected to slow between 2005 and 2030 (changing from an annual growth rate of 0.67% from 2005 through 2010 to 0.52% from 2015 through 2030) and this is reflected in the growth rates for fuel consumption.

From 2005 and 2020, the commercial sector shows a higher rate of growth in fuel consumption relative to the residential and industrial sectors. This increase is in part associated with an increase in non-manufacturing employment (1.4% annually) over this period. From 2010 to 2030, natural gas consumption by the commercial sector is projected to increase at a higher rate than for petroleum; however, the rate of consumption is expected to decline after 2015 for both of these fuels.

The industrial sector shows slight growth in the consumption of natural gas and wood, and a slight decline in the rate of consumption of petroleum from 2005 to 2020, while growth in

[30] EIIP, Volume VIII: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004.

[31] EIA Annual Energy Outlook 2006 with Projections to 2030, Energy Information Administration, Department of Energy, http://www.eia.doe.gov/oiaf/aeo/index.html.

[32] 1900-1999 population data from Vermont Department of Public Health, Agency of Human Services' website at http://healthvermont.gov/research/intercensal/TABLE1.XLS; 2000-2020 population data from U.S. Census Bureau's website at http://www.census.gov/population/projections/SummaryTabA1.xls.

[33] Vermont Department of Labor, U.I. Covered Employment & Wages (QCEW), Annual Averages, NAICS Based, 1988 – 2002 and 2002 2012, http://www.vtlmi.info/ces.cfm.

[34] EIA AEO2006 New England regional employment data obtained through special request from EIA (dated August 23, 2006).

manufacturing employment is expected to remain low (at about 0.08% annually) over this period.

These estimates of growth relative to population and employment reflect expected responses – as modeled by the EIA's National Energy Modeling System (NEMS) -- to changing fuel and electricity prices and technologies, as well as structural changes within each sector (e.g., subsectoral shares, energy use patterns).

Table B1. Electricity Sales Annual Growth Rates, Historical and Projected

	Historic			Projected	
Sector	**1990-2000**	**2000-2005**	**1990-2005**	**2006-2026**	**2026-2030**
Residential	-0.05%	1.47%	0.46%	NA	NA
Commercial	2.49%	1.39%	2.12%	NA	NA
Industrial	1.73%	-0.40%	1.02%	NA	NA
Other	0.26%	-1.25%	-0.25%	NA	NA
Total	1.34%	0.89%	1.14%	1.36%	1.16%

Source: For historic data, Vermont DPS, *Draft Update to the 2005 Vermont Electric Plan*, Table 3-2, page 38, October 20, 2006. For projections, Vermont DPS forecast.
Notes: Projected sales by sector not available (NA). Projected total sales based on Vermont DPS without new demand-side management (DSM) programs being implemented beginning in 2006. An annual average growth rate of 1.16% (based on the annual growth rate of the DPS' forecast from 2016 through 2026) was applied to extend the forecast for energy demand without new DSM programs from 2026 to 2030 (see Appendix A). The "Other" category has historically accounted for 1% or less of total electricity sales; for the forecast this category is combined with the commercial sector.

Table B2. Historic and Projected Average Annual Growth in Energy Use, by Sector and Fuel, 1990-2020

	1990-2004[a]	**2005-2010[b]**	**2010-2015[b]**	**2015-2020[b]**	**2020-2025[b]**	**2025-2030[b]**
Residential						
natural gas	2.8%	0.4%	0.7%	0.6%	0.4%	0.4%
petroleum	1.8%	-2.2%	-0.3%	-0.7%	-0.9%	-0.7%
wood	-2.7%	-0.8%	-0.7%	-0.2%	-0.4%	-0.4%
coal	-16.7%	0.0%	-0.5%	-0.5%	-0.5%	-0.4%
Commercial						
natural gas	2.2%	0.3%	2.6%	2.0%	2.2%	2.3%
petroleum	2.7%	0.6%	1.2%	0.7%	1.0%	1.1%
wood	0.9%	0.4%	1.0%	0.6%	0.9%	1.0%
coal	-13.3%	0.2%	1.0%	0.6%	0.9%	1.0%
Industrial[c]						
natural gas	3.0%	2.4%	1.4%	1.0%	1.7%	1.7%
petroleum	4.0%	-0.6%	-0.1%	-0.4%	0.2%	0.3%
wood	-4.4%	1.5%	1.3%	1.2%	1.5%	1.3%

[a] 1990-2004 figures calculated from historical consumption by sector and fuel type for Vermont.
[b] Figures for the growth periods starting with 2005 calculated from AEO2006 New England regional projections adjusted for Vermont's projected population for the residential sector, non-manufacturing employment for the commercial sector, and manufacturing employment for the industrial sector.
[c] Coal has not been used by the industrial sector since 1992 and is not anticipated to be used by Vermont industries in the future.

Results

Figures B1, B2, and B3 show historic and projected emissions for the RCI sectors from 1990 to 2020. These figures show the emissions associated with the direct consumption of fossil fuels and wood and, for comparison purposes, show the share of emissions associated with the generation of electricity consumed by each sector. Note that the emissions associated with the electricity supply sector and presented in Appendix A are not double-counted in Vermont's total statewide emissions. The electricity supply emissions are attributed to each of the RCI sectors here in Appendix B strictly for comparison to the emissions associated with the on-site consumption of fossil fuels and wood by the RCI sectors.

Electricity supply emissions for the reference case projection (i.e., 2006 through 2030), are not available. Therefore, a simple attribution of electricity supply emissions to each of the RCI sectors was based on the proportion of each sectors electricity demand to total electricity use in 2005 (i.e., 27% of total electricity supply emissions were allocated to the residential sector, 35% to the commercial sector, and 28% to the industrial sector). These proportions are typical of the historical proportions of each sector's electricity use from 1995 through 2005).[35]

As discussed in Appendix A, electricity supply emissions were estimated for two scenarios without new DSM programs being implemented from 2006 through 2030, and two scenarios with new DSM programs being implemented from 2006 through 2030. For the purposes of presentation here in Appendix B, we compare the emissions associated with the following two scenarios without new DSM programs: Scenario 1 presents electricity emissions based on purchases of electricity from the New England power system starting in 2012 to fill Vermont's electricity supply gap, and Scenario 3 presents the electricity supply emissions based on the assumption that Vermont will be able to fill its electricity supply gap (from 2012 through 2030) by maintaining a fuel mix similar to its historical fuel mix (see Appendix A for details). Thus, in Figures B1, B2, and B3, the emissions for both scenarios are the same from 1990 through 2011. Starting in 2012 through 2030, the high-emission case (Scenario 1) is shown as the entire purple area in each graph, and the purple area under the green line in each graph defines the emissions associated with the low-emission scenario (Scenario 3).

Residential Sector

Figure B1 presents the emission inventory and reference case projections for the residential sector. Figure B1 was developed from the emissions data in Table B3. Table B4a and Table B4b show the relative contributions of emissions associated with each fuel type to total residential sector emissions under the high- and low-emission scenarios for the electricity supply sector, respectively.

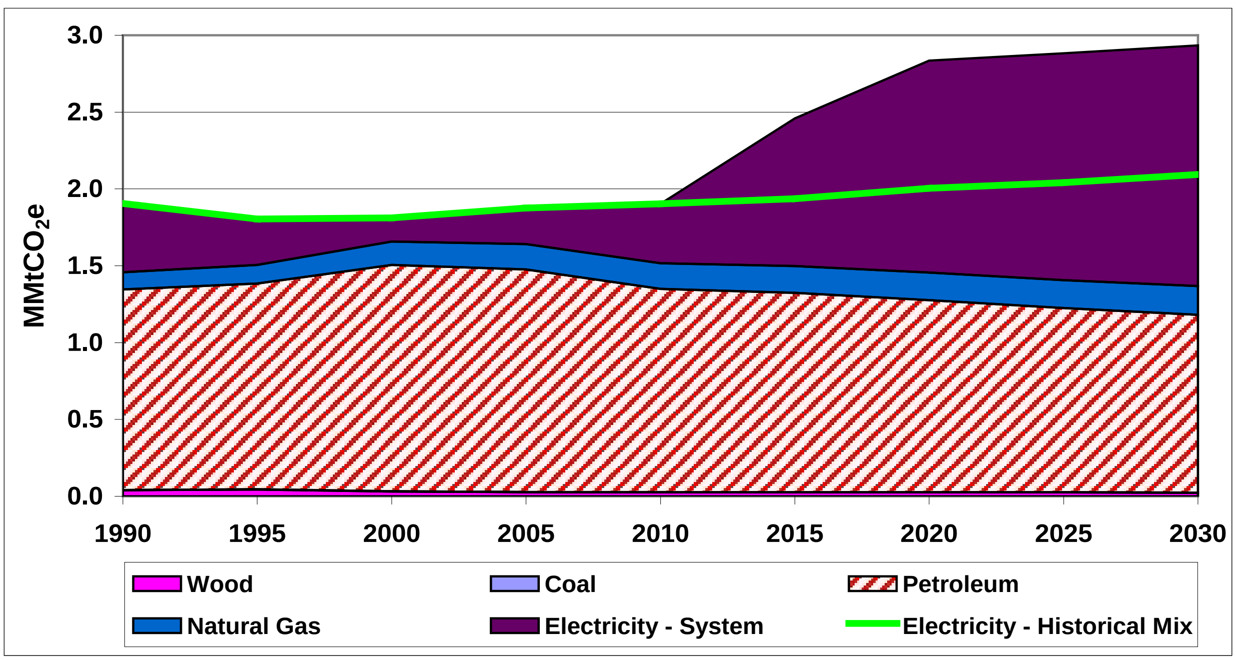
During the period from 1990 through 2010, the residential sector's share of total RCI emissions from direct fuel use and electricity use ranges from 54% in 1990, 55% to 56% (depending on the year) from 1995 through 2005, and 52% in 2010. From 2015 through 2030, the residential sector's share of total RCI emissions is projected to range from 47% in 2015 to 43% in 2030 under the electricity supply high-emission scenario, and 51% in 2015 to 45% in 2030 under the electricity supply low-emission scenario.

[35] Vermont DPS, *Draft Update to the 2005 Vermont Electric Plan*, Table 3-2, page 38, October 20, 2006.

From 1990 through 2010, petroleum consumption accounted for the largest component of the residential sector's emissions. Petroleum consumption accounted for a low of about 69% of total gross emissions in 1990 and 2010, and a high of 81% of total residential sector emissions in 2000. Electricity supply emissions accounted for a high of 23% of total residential sector emissions in 1990, a low of 9% of total residential sector emissions in 2000, and then increased to 13% of total emissions in 2005, and 20% of total emissions in 2010. Natural gas use by the residential sector was fairly constant across the 20-year period accounting for about 6% of total residential sector emissions in 1990, 8% in 2000, and 9% in 2005 through 2010. Wood consumption accounted for 2% of total emissions from 1990 through 2000 and 1% of total emissions from 2005 through 2010.

For the reference case projections, the relative proportion of each fuel type to total emissions changes depending on if the emissions are compared to the high- or low-emission scenario for the electricity supply sector. However, petroleum consumption remains as a primary source of emissions in the residential sector under both scenarios. In 2030, the contribution of emissions under the high-emission scenario for the electric supply sector is project to exceed the contribution from the residential use of petroleum.

Figure B1. Residential Sector GHG Emissions from Fuel Consumption



Source: CCS calculations based on approach described in text.
Note: Emissions associated with coal combustion are too small to be seen on this graph due to scale effects.

Table B3. Residential Sector Emissions Inventory and Reference Case Projections ($MMtCO_2e$)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	0.0002	0.0010	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Petroleum	1.31	1.34	1.47	1.45	1.32	1.30	1.25	1.20	1.16
Natural Gas	0.11	0.12	0.15	0.16	0.17	0.17	0.18	0.18	0.19
Wood	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.02	0.02
Electricity - System Purchases	0.45	0.30	0.16	0.24	0.39	0.96	1.38	1.48	1.57
Electricity - Historical Mix	0.45	0.30	0.16	0.24	0.39	0.44	0.55	0.63	0.73
Total (Including Electricity - System Purchases)	1.91	1.80	1.81	1.88	1.90	2.46	2.84	2.88	2.93
Total (Including Electricity - Historical Mix)	1.91	1.80	1.81	1.88	1.90	1.94	2.00	2.04	2.09

Source: CCS calculations based on approach described in text.

Table B4a. Residential Sector Proportions of Emissions by Fuel Type and High-Emission Electricity Supply Scenario (%)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	0.01	0.06	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Petroleum	68.5	74.2	81.3	77.2	69.5	52.8	44.1	41.6	39.4
Natural Gas	5.9	6.7	8.4	8.8	8.8	7.1	6.3	6.3	6.3
Wood	2.1	2.5	1.8	1.5	1.4	1.0	0.9	0.9	0.8
Electricity - System Purchases	23.5	16.6	8.6	12.6	20.3	39.1	48.7	51.2	53.4

Source: CCS calculations based on approach described in text.
Note: The percentages shown in this table reflect the emissions in Table B3 divided by the sum of the emissions for each RCI fuel type and the emissions associated with the high-emission scenario for the electricity supply sector (i.e., electricity – system purchases).

Table B4b. Residential Sector Proportions of Emissions by Fuel Type and Low-Emission Electricity Supply Scenario (%)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	0.01	0.06	0.02	0.02	0.02	0.02	0.02	0.02	0.01
Petroleum	68.5	74.2	81.3	77.2	69.5	67.0	62.4	58.8	55.3
Natural Gas	5.9	6.7	8.4	8.8	8.8	9.0	8.9	8.9	8.9
Wood	2.1	2.5	1.8	1.5	1.4	1.3	1.3	1.2	1.2
Electricity - Historical Mix	23.5	16.6	8.6	12.6	20.3	22.6	27.4	31.1	34.7

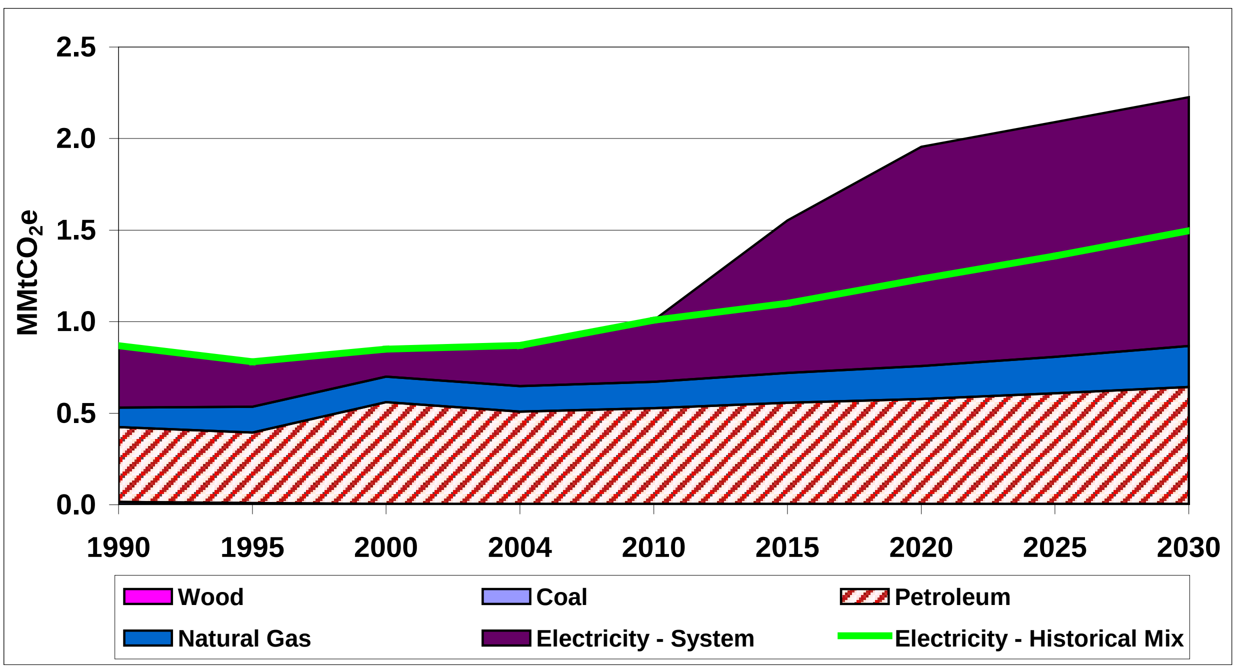
Source: CCS calculations based on approach described in text.
Note: The percentages shown in this table reflect the emissions in Table B3 divided by the sum of the emissions for each RCI fuel type and the emissions associated with the low-emission scenario for the electricity supply sector (i.e., electricity – historical mix).

Commercial Sector

Figure B2 presents the emission inventory and reference case projections for the commercial sector. Figure B2 was developed from the emissions data in Table B5. Table B6a and Table B6b show the relative contributions of emissions associated with each fuel type to total commercial sector emissions under the high- and low-emission scenarios for the electricity supply sector, respectively.

During the period from 1990 through 2010, the commercial sector's share of total RCI emissions from direct fuel use and electricity use ranges from 25% in 1990, 24% to 26% (depending on the year) from 1995 through 2005, and 28% in 2010. From 2015 through 2030, the commercial sector's share of total RCI emissions is projected to range from 30% in 2015 to 33% in 2030 under the electricity supply high-emission scenario, and 29% in 2015 to 32% in 2030 under the electricity supply low-emission scenario.

Figure B2. Commercial Sector GHG Emissions from Fuel Consumption



Source: CCS calculations based on approach described in text.
Note: Emissions associated with wood and coal combustion are too small to be seen on this graph due to scale effects.

From 1990 through 2010, petroleum consumption accounted for the largest component of the commercial sector's emissions. Petroleum consumption accounted for about 47% of total gross emissions in 1990, 49% in 1995, 65% in 2000, and then declined to 58% in 2005 and to 52% in 2010. Electricity supply emissions accounted for a high of about 39% of total commercial sector emissions in 1990, a low of about 18% of total commercial sector emissions in 2000, and then increased to about 26% of total emissions in 2005, and 33% of total emissions in 2010. Natural gas use by the commercial sector accounted for about 12% of total gross emissions in 1990, 18% in 1995, 16% from 2000 through 2005, and is projected to decline to about 14% in 2010. Wood consumption accounted for 0.2% to 0.3% of total emissions from 1990 through 2010.

For the reference case projections, the relative proportion of each fuel type to total emissions changes depending on if the emissions are compared to the high- or low-emission scenario for the electricity supply sector. However, petroleum consumption remains as a primary source of emissions in the commercial sector under both scenarios. For the high-emission scenario, petroleum consumption is projected to account for about 29% to 35% of total commercial sector emissions, electricity supply emissions are projected to account for about 54% to 61% of total emissions, and natural gas is projected to account for about 9% to 10% of total emissions. For the low-emission scenario, petroleum consumption is projected to account for about 43% to 50% of total commercial sector emissions, electricity supply emissions are projected to account for about 35% to 42% of total emissions, and natural gas is projected to account for about 15% of total emissions.

Table B5. Commercial Sector Emissions Inventory and Reference Case Projections ($MMtCO_2e$)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	0.01	0.01	0.002	0.002	0.002	0.003	0.003	0.003	0.003
Petroleum	0.41	0.39	0.56	0.51	0.52	0.55	0.57	0.60	0.64
Natural Gas	0.11	0.14	0.14	0.14	0.14	0.16	0.18	0.20	0.22
Wood	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity - System Purchases	0.34	0.25	0.15	0.22	0.34	0.83	1.20	1.28	1.36
Electricity - Historical Mix	0.34	0.25	0.15	0.22	0.34	0.38	0.48	0.55	0.63
Total (Including Electricity - System Purchases)	0.87	0.78	0.85	0.87	1.01	1.55	1.96	2.09	2.23
Total (Including Electricity - Historical Mix)	0.87	0.78	0.85	0.87	1.01	1.10	1.23	1.36	1.50

Source: CCS calculations based on approach described in text.

Table B6a. Commercial Sector Proportions of Emissions by Fuel Type and High-Emission Electricity Supply Scenario (%)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	1.7	0.8	0.3	0.3	0.2	0.2	0.1	0.1	0.1
Petroleum	46.9	49.4	65.4	58.0	52.0	35.6	29.3	28.9	28.6
Natural Gas	12.3	18.0	16.3	16.0	14.3	10.5	9.2	9.6	10.1
Wood	0.2	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Electricity - System Purchases	38.9	31.4	17.7	25.6	33.3	53.7	61.3	61.3	61.1

Source: CCS calculations based on approach described in text.
Note: The percentages shown in this table reflect the emissions in Table B5 divided by the sum of the emissions for each RCI fuel type and the emissions associated with the high-emission scenario for the electricity supply sector (i.e., electricity – system purchases).

Table B6b. Commercial Sector Proportions of Emissions by Fuel Type and Low-Emission Electricity Supply Scenario (%)

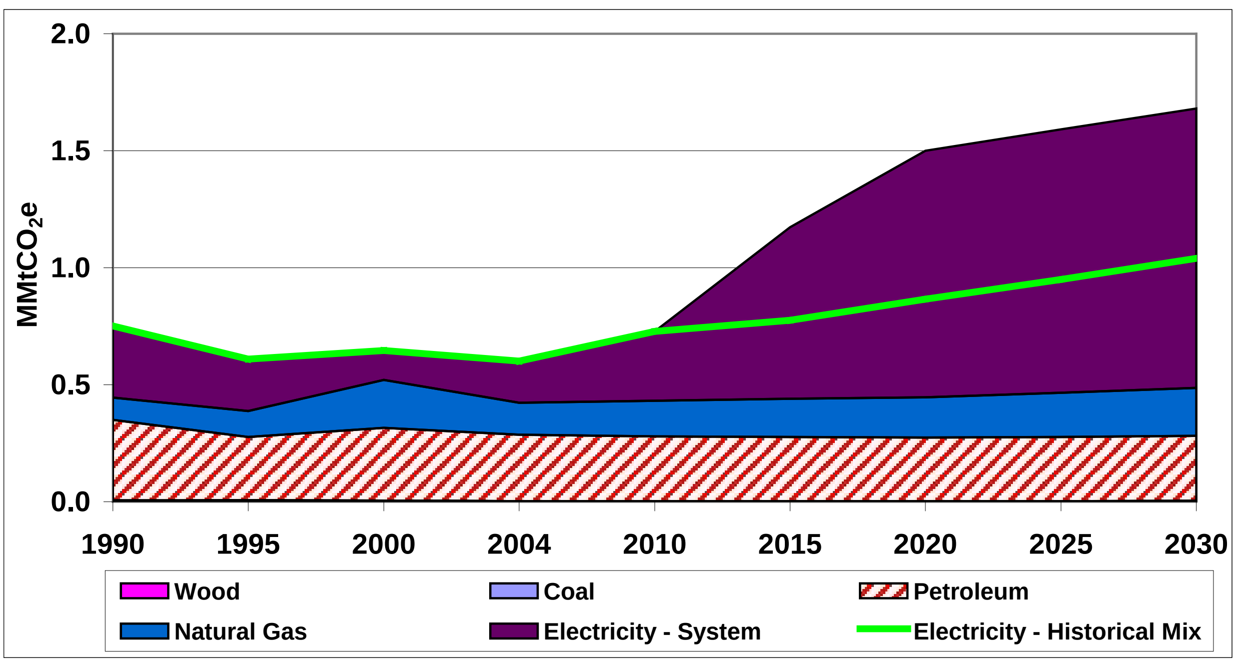
Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	1.7	0.8	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Petroleum	46.9	49.4	65.4	58.0	52.0	50.2	46.5	44.4	42.6
Natural Gas	12.3	18.0	16.3	16.0	14.3	14.8	14.5	14.7	15.0
Wood	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Electricity - Historical Mix	38.9	31.4	17.7	25.6	33.3	34.6	38.6	40.5	42.1

Source: CCS calculations based on approach described in text.
Note: The percentages shown in this table reflect the emissions in Table B5 divided by the sum of the emissions for each RCI fuel type and the emissions associated with the low-emission scenario for the electricity supply sector (i.e., electricity – historical mix).

Industrial Sector

Figure B3 presents the emission inventory and reference case projections for the industrial sector. Figure B3 was developed from the emissions data in Table B7. Table B8a and Table B8b show the relative contributions of emissions associated with each fuel type to total industrial sector emissions under the high- and low-emission scenarios for the electricity supply sector, respectively.

Figure B3. Industrial Sector GHG Emissions from Fuel Consumption



Source: CCS calculations based on approach described in text.
Note: Emissions associated with wood and coal combustion are too small to be seen on this graph due to scale effects. A small about of coal was consumed by the industrial sector from 1990 through 1992. Since 1992, Vermont's industrial sector has not burned any coal.

During the period from 1990 through 2010, the industrial sector's share of total RCI emissions from direct fuel use and electricity use ranges from 21% in 1990, 18% to 20% (depending on the year) from 1995 through 2005, and 20% in 2010. From 2015 through 2030, the industrial sector's share of total RCI emissions is projected to range from 23% in 2015 to 25% in 2030 under the electricity supply high-emission scenario, and 20% in 2015 to 22% in 2030 under the electricity supply low-emission scenario.

From 1990 through 2010, petroleum consumption accounted for the largest component of the industrial sector's emissions. Petroleum consumption accounted for about 46% of total gross emissions in 1990, 44% in 1995, 48% in 2000, then declined to 47% in 2005 and 38% in 2010. Electricity supply emissions accounted for about 41% of total industrial sector emissions in 1990, a low of 19% of total industrial sector emissions in 2000, and then increased to about 30% of total emissions in 2005, and about 41% of total emissions in 2010. Natural gas use by the industrial sector accounted for about 13% of total gross emissions in 1990, 18% in 1995, 32% in 2000, 23% in 2005, and is projected to decline to 21% in 2010. Wood consumption accounted for 0.3% to 0.9% of total emissions from 1990 through 2010.

For the reference case projections, the relative proportion of each fuel type to total emissions changes depending on if the emissions are compared to the high- or low-emission scenario for the electricity supply sector. However, petroleum consumption remains as a primary source of emissions in the industrial sector under both scenarios. For the high-emission scenario, petroleum consumption is projected to account for about 17% to 23% of total industrial sector emissions, electricity supply emissions are projected to account for about 63% to 71% of total emissions, and natural gas is projected to account for about 12% to 14% of total emissions. For the low-emission scenario, petroleum consumption is projected to account for about 27% to 35% of total industrial sector emissions, electricity supply emissions are projected to account for about 43% to 53% of total emissions, and natural gas is projected to account for about 20% to 21% of total emissions.

Table B7. Industrial Sector Emissions Inventory and Reference Case Projections ($MMtCO_2e$)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	0.003	-	-	-	-	-	-	-	-
Petroleum	0.34	0.27	0.31	0.28	0.28	0.27	0.27	0.27	0.28
Natural Gas	0.10	0.11	0.20	0.14	0.15	0.16	0.17	0.19	0.20
Wood	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Electricity - System Purchases	0.31	0.22	0.13	0.18	0.30	0.73	1.05	1.13	1.20
Electricity - Historical Mix	0.31	0.22	0.13	0.18	0.30	0.33	0.42	0.48	0.55
Total (Including Electricity - System Purchases)	0.75	0.61	0.65	0.60	0.73	1.17	1.50	1.59	1.68
Total (Including Electricity - Historical Mix)	0.75	0.61	0.65	0.60	0.73	0.78	0.87	0.95	1.04

Source: CCS calculations based on approach described in text.

Table B8a. Industrial Sector Proportions of Emissions by Fuel Type and High-Emission Electricity Supply Scenario (%)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum	45.8	44.4	48.1	47.2	38.1	23.4	18.1	17.2	16.5
Natural Gas	12.7	18.2	31.7	22.8	21.0	13.9	11.5	11.8	12.2
Wood	0.5	0.9	0.8	0.4	0.3	0.2	0.2	0.2	0.2
Electricity - System Purchases	40.7	36.5	19.3	29.6	40.6	62.5	70.2	70.8	71.1

Source: CCS calculations based on approach described in text.
Note: The percentages shown in this table reflect the emissions in Table B7 divided by the sum of the emissions for each RCI fuel type and the emissions associated with the high-emission scenario for the electricity supply sector (i.e., electricity – system purchases).

Table B8b. Industrial Sector Proportions of Emissions by Fuel Type and Low-Emission Electricity Supply Scenario (%)

Fuel Type	1990	1995	2000	2005	2010	2015	2020	2025	2030
Coal	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum	45.8	44.4	48.1	47.2	38.1	35.4	31.3	28.9	26.7
Natural Gas	12.7	18.2	31.7	22.8	21.0	21.1	20.0	19.8	19.7
Wood	0.5	0.9	0.8	0.4	0.3	0.3	0.3	0.3	0.3
Electricity - Historical Mix	40.7	36.5	19.3	29.6	40.6	43.2	48.4	51.0	53.3

Source: CCS calculations based on approach described in text.
Note: The percentages shown in this table reflect the emissions in Table B7 divided by the sum of the emissions for each RCI fuel type and the emissions associated with the low-emission scenario for the electricity supply sector (i.e., electricity – historical mix).

Key Uncertainties

Key sources of uncertainty underlying the estimates are as follows:

- Population and economic growth are the principal drivers for electricity and fuel use. The reference case projections are based on regional projections for EIA's New England modeling region scaled for Vermont population and economic growth projections. Not only are there uncertainties in the regional projections, but significant uncertainties associated with down-scaling the projections to Vermont. Future work should attempt to base projections on data specific to Vermont to the extent that the data become available.
- The forecasts for wood and biomass consumption indicate little growth in the use of this fuel in Vermont. However, due to recent increases in fuel prices, there has been an increase in the use of wood stoves and furnaces to heat residential homes. In addition, new wood stove technology (i.e., pellet stoves) is expected to burn much more efficiently than previous designs thus reducing emissions; however, emissions test data are not yet available to determine how N_2O and CH_4 emissions would change. Future work could focus on collecting data on wood burning appliance sales for Vermont to support improvements to the projections for this category.
- The projections assume no large long-term changes in relative fuel and electricity prices, as compared with current levels and US DOE projections. Price changes would influence consumption levels and encourage efficiency and/or switching among fuels.

- Growth of major industries – the energy consumption projections assume no new large energy-consuming facilities. A few large new facilities – or the decline of major industries – could significantly impact energy consumption and subsequent emissions.
- Attribution of electricity supply emissions to RCI sectors – Vermont DPS provided forecasts for total energy demand for the forecast period. As with all energy forecasts, there are considerable uncertainties in this electricity demand forecast. Moreover, disaggregated forecast information for each of the RCI sectors was not available. The method used in Appendix B to attribute electricity supply emissions to each sector is a simple extrapolation of the historical proportions of each sectors electricity use relative to total electricity use in Vermont. As a result, the overall annual growth rate for the forecast period is the same for each RCI sector. It is unlikely that the emissions for each sector will grow at exactly the same rate. Future work should include an assessment to develop annual growth rate factors for each sector.
- New DSM programs – Vermont DPS has prepared forecasts to model the potential benefits associated with implementing new DSM programs starting in 2006 that go beyond the programs that have been implemented in Vermont over the past several years. The reader is referred to the following Vermont DPS publications for details on DSM program forecasting: *Vermont Electric Plan 2005*, January 19, 2005; and *Update to the 2005 Vermont Electric Plan*, October 20, 2006. Appendix A includes scenarios for estimating the effects of new DSM programs for mitigating electricity demand for the reference case projections.

Appendix C. Transportation Energy Use

Overview

The transportation sector is the largest source of greenhouse gas (GHG) emissions in Vermont – accounting for 44% of Vermont's gross GHG emissions in 2000. Carbon dioxide (CO_2) accounted for about 96% of transportation GHG emissions. Most of the remaining GHG emissions from the transportation sector are due to nitrous oxide (N_2O) emissions from gasoline engines.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2005 were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for the sector.[36] For onroad vehicles, the CO_2 emission factors are in units of pounds (lb) per million British thermal unit (MMBtu) and the methane (CH_4) and N_2O emission factors are both in units of grams per vehicle mile traveled (VMT). Key assumptions in this analysis are listed in Table C1. The default data within SGIT were used to estimate emissions, with the most recently available fuel consumption data (2002) from the United States Department of Energy (US DOE) Energy Information Administration's (EIA) *State Energy Data* (SED) added.[37] For motor gasoline, default consumption data were replaced with consumption estimates from State tax data provided by Vermont Department of Environmental Conservation (VTDEC). The default VMT data in SGIT were replaced with State-level annual VMT from the Vermont Agency of Transportation (VTrans).[38] Vehicle mix data were provided by VTDEC; however, these data were only available for one year. Therefore, State-level VMT was allocated to vehicle types using the default vehicle mix in SGIT, based on data from Federal Highway Administration's (FHWA) Highway Statistics publication.[39]

GHG emissions from transportation are expected to grow considerably over the next 15 years due to increased demand for current modes of transportation. VMT projections supplied by VTDEC[40] suggest that VMT will grow at an average rate of 1.3% per year between 2002 and 2009, 1.4% for 2009-2012, and 1.2% for 2012-2018. We assumed that the annual VMT growth rate for 2012-2018 would continue through 2030. Vehicle-specific VMT projections provided by VTDEC were based on road type-specific growth curves from VTrans. VMT projections adjusted to account for improvements in fuel efficiency suggest fuel consumption growth rates of

[36] GHG emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 3. "Methods for Estimating Methane and Nitrous Oxide Emissions from Mobile Combustion", August 2004.

[37] Energy Information Administration, State Energy Consumption, Price, and Expenditure Estimates (SED), http://www.eia.doe.gov/emeu/states/_seds.html.

[38] Vermont Agency of Transportation, http://www.aot.state.vt.us/Planning/Documents/HighResearch/Publications/avmthist.pdf.

[39] Federal Highway Administration, Highway Statistics 2002, http://www.fhwa.dot.gov/policy/ohim/hs02/index.htm.

[40] Paul Wishinski, Air Pollution Control Division, VT DEC. DEC developed the VMT projections from historical road type growth curves from VTrans. These VMT projections were also used in the MANE-VU Inventory projection.

0.7% per year for gasoline and 1.0% per year for diesel between 2002 and 2030. Fuel efficiency projections were taken from EIA's *Annual Energy Outlook* (AEO2006).

Projections of biodiesel consumption provided by the Vermont Biofuels Association were subtracted from projected diesel consumption. Current consumption of ethanol for vehicle fuel in Vermont is very low (reported as 0 gallon by EIA). Consumption of ethanol as a blending component of gasoline is expected to increase, in part, because of the recent ban on methyl tertiary butyl ether (MTBE). However, since the sale of reformulated gasoline is not required in Vermont, the effect of this ban on ethanol consumption was assumed to be low, and was not factored into gasoline projections.

Onroad gasoline and diesel emissions were also adjusted to reflect the effects of California's light-duty vehicle GHG standards, adopted by Vermont in 2005. These standards apply to new vehicles starting with model year 2009. First, the projected fuel consumption for new vehicles without standards was estimated for light-duty vehicles by applying projected new vehicle fuel economy from AEO2006 to the estimated VMT. VMT for model year 2009 and newer vehicles was estimated for each year using the default percentage of VMT allocated to model year from SGIT, which is take from EPA's MOBILE6 model. Emissions for these vehicles without standards were then estimated by applying SGIT emission factors to the estimated fuel consumption. Emissions for the phase-in vehicles under the standards were estimated by applying the emission levels set by the standards (in CO2e-g/mi) to the estimated VMT. The emission reductions resulting from the standards were then estimated by subtracting estimated emissions from phased-in light-duty vehicle from the estimated emissions for these vehicles without the standards. Transportation emissions including and not including the effects of the CA standards are shown in Table C2 and Figures C1 and C2.

Aircraft emissions were projected using projections of general aviation and commercial aircraft operations in Vermont for 2005, 2010, 2015, and 2025 provided by VTrans.[41] Aircraft operations projections predict growth rates of 0.6% per year for general aviation and 1.7% per year for commercial operations between 2005 and 2030. While commercial aircraft consume only jet fuel, general aviation aircraft consume both jet fuel and aviation gasoline. However, State-level projection data specific to each fuel were not available. Therefore, jet fuel emissions were projected based on commercial operations forecasts, and aviation gasoline emissions were projected using the general aviation forecasts. Aircraft operations data for 2002 were not available. Therefore, jet fuel prime supplier sales volumes in Vermont for 2002-2005 from EIA[42] were used to project jet fuel consumption from 2002 to 2005. The EIA data for prime supplier sales of jet fuel in Vermont shows a large increase between 2003 and 2005 (6.5 thousand gallons per day in 2003, 42.4 thousand gallons per day in 2005). However, the resulting projected 2006 annual consumption of 15.7 million gallons is in line with 2006 jet fuel consumption data for

[41] Vermont Airport System and Policy Plan, provided by Scott Bascom, Policy and Planning Division, Vermont Agency of Transportation.
[42] Vermont Prime Supplier Sales Volumes of Petroleum Products, Energy Information Administration, http://tonto.eia.doe.gov/dnav/pet/xls/pet_cons_prim_dcu_SVT_a.xls.

Burlington International Airport.[43] For aviation gasoline, the 2005-2010 growth rate (0.87% per year) predicted by the general aviation projections was applied to 2002-2005.

Table C1. Key Assumptions and Methods for the Transportation Inventory and Projections

Vehicle Type and Pollutants	Methods
Onroad gasoline, diesel, natural gas, and liquefied petroleum gas (LPG) vehicles – CO_2	**Inventory (1990 – 2002)** US EPA SGIT and fuel consumption from EIA SED and motor gasoline tax data provided by VTDEC. **Reference Case Projections (2003 – 2020)** Gasoline and diesel fuel projected using VMT projections provided by VTDEC, adjusted by fuel efficiency improvement projections from AEO2006. Other onroad fuels projected using New England Region fuel consumption projections from EIA AEO2006 adjusted using State-to-regional ratio of population growth.
Onroad gasoline and diesel vehicles – CH_4 and N_2O	**Inventory (1990 – 2002)** US EPA SGIT, onroad vehicle CH_4 and N_2O emission factors by vehicle type and technology type within SGIT were updated to the latest factors used in the US EPA's *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003.* State total VMT replaced with VMT provided by VTrans, VMT allocated to vehicle types using data from FHWA's *Highway Statistics*. **Reference Case Projections (2003 – 2020)** VMT projections from MANE-VU onroad inventory.
Non-highway fuel consumption (jet aircraft, gasoline-fueled piston aircraft, boats, locomotives) – CO_2, CH_4 and N_2O	**Inventory (1990 – 2002)** US EPA SGIT and fuel consumption from EIA SED. **Reference Case Projections (2003 – 2020)** Aircraft projected using Vermont airport operations projections provided by VTrans (2005-2025) and EIA prime supplier sales volumes for jet fuel (2002-2005), all others projected using transportation fuel consumption projections for the New England Region from EIA AEO2006 adjusted by population.

[43] Brian Searles, Director of Aviation, Burlington International Airport estimated the 2006 consumption of jet fuel to be approximately 16 million gallons.

These assumptions combine to produce an increase of about 52% in GHG emissions from the transportation sector from 1990 to 2030. GHG emissions from onroad gasoline consumption are projected to increase by about 41%, and GHG emissions from onroad diesel consumption are expected to increase by 86% during this time period. Aviation fuel consumption is projected to increase by 243% between 1990 and 2030, with most of this growth (125%) occurring between 1990 and 2005.

Table C2. Projected Transportation Emissions With and Without CA Light-duty Vehicle GHG Standards

Emission Totals (MMTCO2e)	2005	2010	2015	2020	2025	2030
Onroad Gasoline						
Not including CA Standards	3.13	3.14	3.28	3.43	3.57	3.75
Emission Reduction from CA Standard	0.00	0.07	0.49	0.90	1.12	1.19
Including CA Standards	3.13	3.07	2.80	2.54	2.45	2.56
Onroad Diesel						
Not including CA Standards	0.66	0.69	0.71	0.74	0.77	0.82
Emission Reduction from CA Standard	0.00	0.00	0.02	0.05	0.06	0.07
Including CA Standards	0.66	0.69	0.68	0.69	0.71	0.75
Jet Fuel/Av. Gas	0.17	0.20	0.23	0.24	0.25	0.26
Boats and Ships	0.02	0.02	0.02	0.02	0.02	0.02
Rail	0.01	0.01	0.01	0.01	0.02	0.02
Other	0.02	0.03	0.03	0.03	0.03	0.03
Total Not Including CA Standards	**4.02**	**4.09**	**4.27**	**4.47**	**4.65**	**4.90**
Total Including CA Standards	**4.02**	**4.01**	**3.76**	**3.53**	**3.45**	**3.64**

Fuel consumption data from EIA includes nonroad gasoline and diesel fuel consumption in the commercial and industrial sectors. Therefore, nonroad emissions were included in the residential, commercial, and industrial (RCI) emissions in this inventory (see Appendix B). Table C3 shows how EIA divides gasoline and diesel fuel consumption between the transportation, commercial, and industrial sectors.

Table C3. EIA Classification of Gasoline and Diesel Consumption

Sector	Gasoline Consumption	Diesel Consumption
Transportation	Highway vehicles, marine	Vessel bunkering, military use, railroad, highway vehicles
Commercial	Public non-highway, miscellaneous use	Commercial use for space heating, water heating, and cooking
Industrial	Agricultural use, construction, industrial and commercial use	Industrial use, agricultural use, oil company use, off-highway vehicles

Results

Total gross GHG emissions for the transportation sector were about 3.2 million metric tons (MMt) of CO_2 equivalent (CO_2e) in 1990 (40% of total gross GHG emissions), 3.8 MMtCO_2e in 2002 (43% of total gross emissions), about 4.5 MMtCO_2e in 2020 (35% of total gross emissions), and about 4.9 MMtCO_2e in 2030 (35% of total gross emissions). As shown in Figure C2, onroad gasoline consumption accounts for the largest share of transportation GHG emissions. Emissions from onroad gasoline vehicles increased by about 18% from 1990 – 2002 to cover almost 81% of total transportation emissions in 2002. Accounting for the effects of the CA light-duty vehicle GHG standards, average annual growth in gross GHG emissions for the onroad gasoline consumption sector is projected at about -0.7% from 2002 through 2030.

GHG emissions from onroad diesel fuel consumption increased by 56% from 1990 to 2002, and by 2002 accounted for 16% of GHG emissions from the transportation sector. From 2010 through 2030, onroad diesel fuel consumption is projected to increase from about 17% to 20% of total gross GHG emissions for the transportation sector. Accounting for the effects of the CA light-duty vehicle GHG standards, average annual growth in gross GHG emissions for the onroad diesel consumption sector is projected at about 0.6% from 2002 through 2030.

Emissions from all other categories combined [air travel, boats and ships, locomotives, natural gas and liquefied petroleum gas (LPG), and oxidation of lubricants] contributed only 2% of total transportation emissions in 2002, 6.3% of total transportation emissions in 2010, and about 9% of total transportation emissions from 2020 through 2030. The jet and aviation fuel consumption sector is projected to have the most significant growth with emissions increasing at an average annual rate of about 8.2% from 2002 through 2030. The average annual growth in emissions for the rail, marine, and other categories is projected to be 2.7%, 1.2%, and 1.0%, respectively, from 2002 through 2030.

Figure C1. Transportation GHG Emissions by Fuel Not Including CA Light-Duty Vehicle GHG Standards , 1990-2030

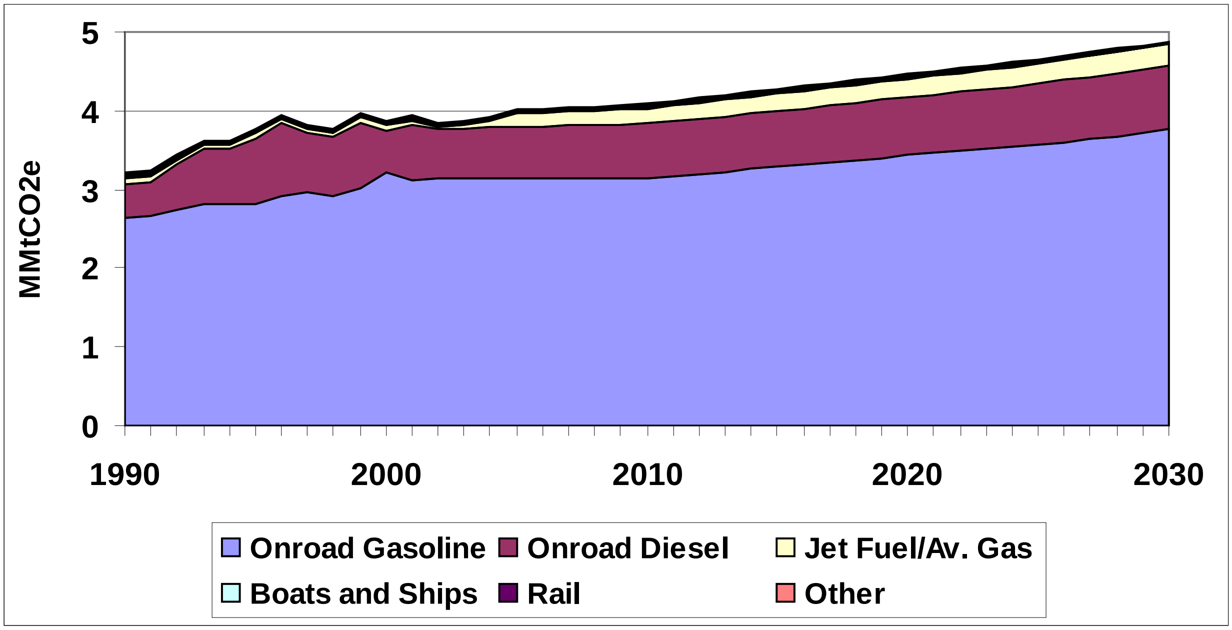
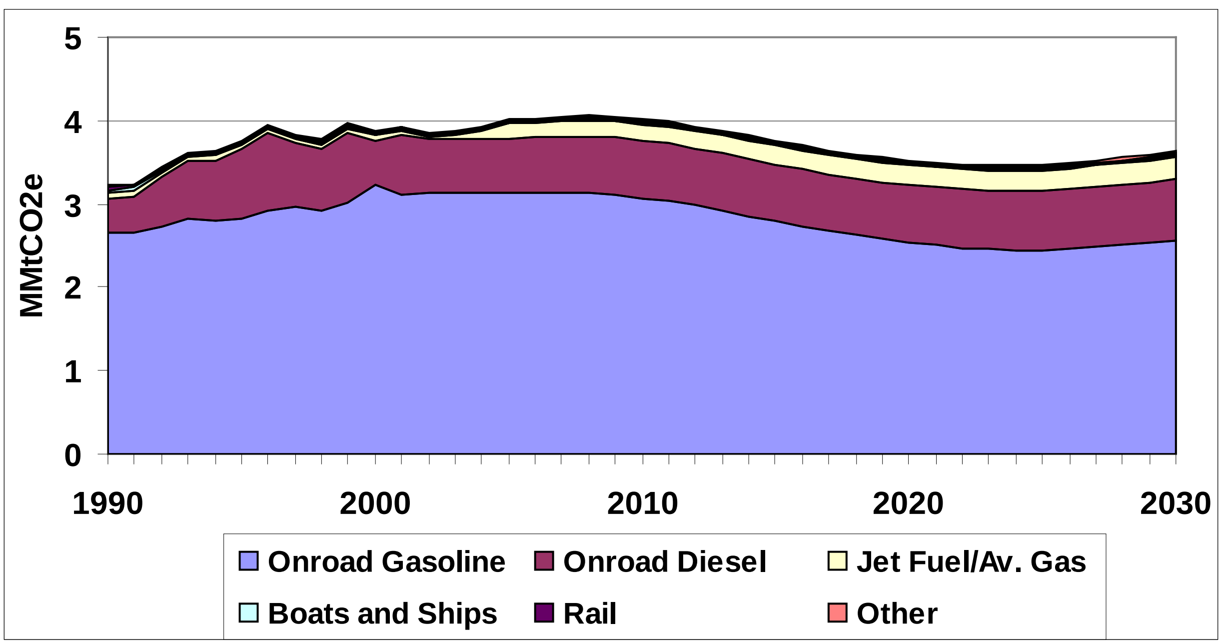


Figure C2. Transportation GHG Emissions by Fuel Including CA Light-Duty Vehicle GHG Standards, 1990-2030



Key Uncertainties

One uncertainty is the use of FHWA vehicle mix data to allocate VMT. Another uncertainty associated with VMT is the VMT projections data based on VTrans growth curves for road types. These projections are based on increases in travel on specific road types and not for specific vehicle types; therefore, possible differences in growth rates for gasoline and diesel vehicles are not captured. The VMT projections show a similar growth rate for gasoline and diesel vehicles, while the regional projections from AEO2006 predict that diesel consumption will grow at about twice the rate of gasoline.

The consumption of international bunker fuels included in jet fuel consumption from EIA is another uncertainty. There is a question as to whether fuel consumption associated with international air flights should be included in the State inventory (as much of it is actually consumed out of State/country); however, data were not available to subtract this consumption from total jet fuel estimates (note that domestic air flights would also consume much of the fuel out of State). Another uncertainty associated with aviation emissions is the use of general aviation forecasts to project aviation gasoline consumption. General aviation aircraft consume both jet fuel and aviation gasoline, but fuel specific data were not available. Emissions from aircraft are small, and, therefore, do not have a significant effect on the total transportation emissions.

Appendix D. Industrial Processes

Overview

Emissions in the industrial processes category span a wide range of activities, and reflect non-combustion sources of greenhouse gas (GHG) emissions from several industrial processes. The industrial processes that exist in Vermont, and for which emissions are estimated in this inventory, include the following:

- Carbon Dioxide (CO_2) from the consumption of limestone, dolomite, and soda ash;
- Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) from semiconductor manufacture;
- SF_6 from transformers used in electric power transmission and distribution (T&D) systems; and
- HFCs and PFCs from consumption of substitutes for ozone-depleting substances (ODS) used in cooling and refrigeration equipment.

Other industrial processes that are sources of GHG emissions but are not found in Vermont include the following:

- CO_2 from the production of cement, lime, and soda ash;
- Nitrous oxide (N_2O) from nitric and adipic acid production;
- SF_6 from magnesium production and processing;
- PFCs from aluminum production; and
- HFCs from HCFC-22 production.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2005 were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for this sector.[44] Table D1 identifies the information needed by SGIT to calculate emissions, the data sources, and the historical years for which emissions were calculated based on the availability of data. Table D2 lists the data sources, annual compounded growth rates, and years for which the reference case projections were calculated.

Results

Figures D1 and D2 show historic and projected emissions for the industrial sector from 1990 to 2020. Total gross GHG emissions were about 0.44 million metric tons (MMt) of CO_2 equivalent (CO_2e) in 2005 (4.9% of total emissions), about 0.78 $MMtCO_2e$ in 2020 (6.1% of total emissions), and about 1.2 $MMtCO_2e$ in 2030 (8.8% of total emissions) indicating that the emission may triple over this 25-year period. Emissions from this category are expected to grow

[44] GHG emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 6. "Methods for Estimating Non-Energy Greenhouse Gas Emissions from Industrial Processes", August 2004.

rapidly, as shown in Figures D1 and D2, almost entirely due to the increasing use of HFCs and PFCs in refrigeration and air conditioning equipment.

Table D1. Approach to Estimating Historical Emissions

Source Category	Time Period	Required Data for SGIT	Data Source
Limestone and Dolomite Consumption	1994 - 2002	Consumption of limestone and dolomite by industrial sector for use as flux stone and in glass manufacturing.	Minerals Yearbook, 2004: Volume I, Metals and Minerals, (http://minerals.usgs.gov/minerals/pubs/state/vt.html).
Soda Ash	1990 - 2005	Consumption of soda ash used in consumer products such as glass, soap and detergents, paper, textiles, and food. Emissions based on State's population and estimates of emissions per capita from the US EPA national GHG inventory.	Minerals Yearbook, 2004: Volume I, Metals and Minerals, (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/). For population data, see references for ODS substitutes.
ODS Substitutes	1990 - 2002	Based on State's population and estimates of emissions per capita from the US EPA national GHG inventory.	-- State 1990-1999 population from Vermont Department of Public Health, Agency of Human Services' (http://healthvermont.gov/research/intercensal/TABLE1.XLS). -- US 1990-2000 population from US Census Bureau (http://www.census.gov/popest/archives/EST90INTERCENSAL/US-EST90INT-01.html). -- State and US 2000-2005 population from US Census Bureau (http://www.census.gov/population/projections/SummaryTabA1.xls).
Semiconductor Manufacturing	1990 - 2002	State and national value of semiconductor shipments for NAICS code 334413 (Semiconductor and Related Device Manufacturing). Method uses ratio of State to national value of semiconductor shipments to estimate State proportion of national emissions.	Value of shipments from U.S Census Bureau's Economic Census (http://www.census.gov/econ/census02/). Data for State in 2002 Economic Census withheld; therefore, SGIT default values used for 1990-2002.
Electric Power T&D Systems	1990 - 2002	Emissions from 1990 to 2002 based on the national emissions per kWh and State's electricity use.	National emissions per kWh from US EPA GHG inventory (US EPA 2005 Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003).

Table D2. Approach to Estimating Projections

Source Category	Time Period	Projection Assumptions	Data Source	Annual Growth Rates (%) 2000 to 2005	2005 to 2010	2010 to 2015	2015 to 2030
Limestone and Dolomite Consumption	2003 - 2030	State manufacturing sector growth rate.	Vermont Department of Labor, U.I. Covered Employment & Wages (QCEW), Annual Averages, NAICS Based, 1988 – 2002 and 2002 2012, http://www.vtlmi.info/ces.cfm.	0.08	0.08	0.08	0.08
Soda Ash	2006 - 2030	Growth between 2004 and 2009 is projected to be about 0.5% per year for US production. Assumed growth is same for 2010 – 2030.	Minerals Yearbook, 2004: Volume I, Metals and Minerals, (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/).	0.5	0.5	0.5	0.5
ODS Substitutes	2003 - 2030	Based on national growth rate for ODS substitutes.	US EPA, 2004 ODS substitutes cost study report.	15.8	7.9	5.8	5.3
Semiconductor Manufacturing	2003 - 2030	National growth rate (based on aggregate for all stewardship program categories provided in referenced data source)	US Department of State, *US Climate Action Report*, May 2002, Washington, D.C., May 2002 (Table 5-7). (http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/SHSU5BNQ76/$File/ch5.pdf).	3.3	-6.2	-9.0	-2.8
Electric Power T&D Systems	2003 - 2030	ditto	ditto	3.3	-6.2	-9.0	-2.8

Substitutes for Ozone-Depleting Substances (ODS)

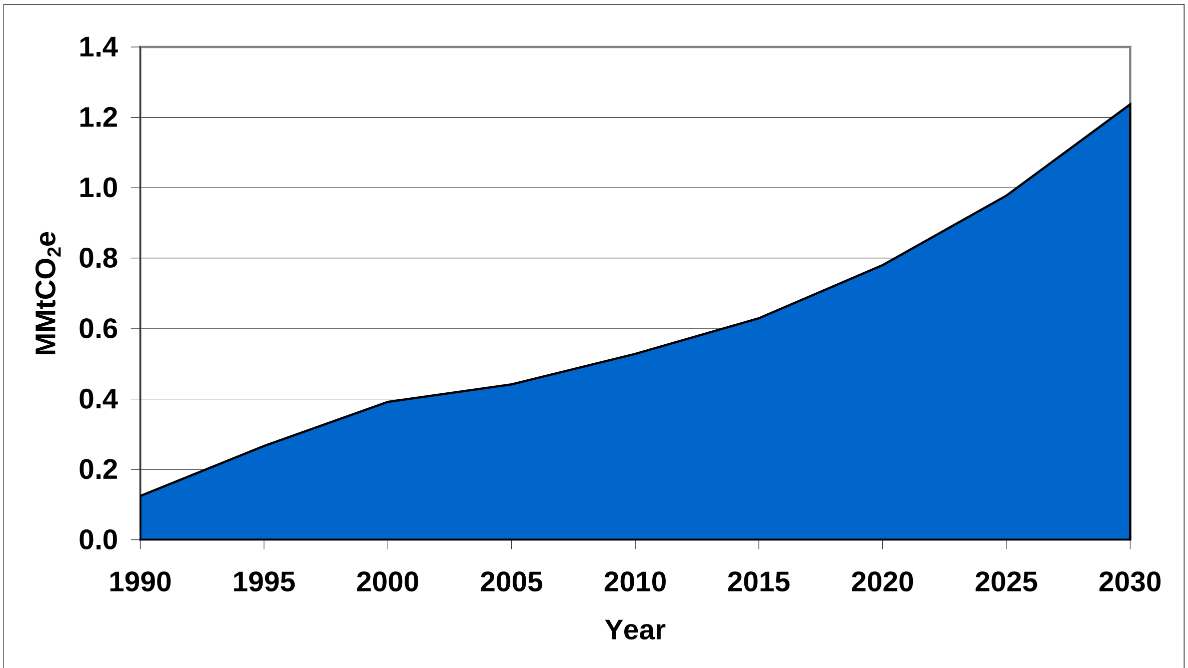
HFCs and PFCs are used as substitutes for ODS, most notably CFCs (CFCs are also potent warming gases, with global warming potentials on the order of thousands of times that of CO_2 per unit of emissions) in compliance with the *Montreal Protocol* and the *Clean Air Act Amendments of 1990*.[45] Even low amounts of HFC and PFC emissions, for example, from leaks and other releases associated with normal use of the products, can lead to high GHG emissions on a carbon-equivalent basis. The projected rate of increase for these emissions is based on

[45] As noted in EIIP Chapter 6, ODS substitutes are primarily associated with refrigeration and air conditioning, but also many other uses including as fire control agents, cleaning solvents, aerosols, foam blowing agents, and in sterilization applications. The applications, stocks, and emissions of ODS substitutes depend on technology characteristics in a range of equipment types. For the US national inventory, a detailed stock vintaging model was used to track ODS substitutes uses and emissions, but this modeling approach has not been completed at the State level.

projections for national emissions from the US EPA report referenced in Table D2. The forecast of US emissions were only available through 2020. Because of a lack of forecast information beyond 2020, the annual growth rate calculated from the forecast of US emissions for the 2015 to 2020 period was used to extend the forecast for Vermont to 2030.

Greenhouse gas-equivalent emissions from the use of ODS substitutes in Vermont were calculated using the default methods in SGIT. Emissions have increased from 0.0008 $MMtCO_2e$ in 1990 to about 0.285 $MMtCO_2e$ in 2005, and are expected to increase at an average rate of 5.8% per year from 2005 to 2030 due to increased substitutions of these gases for ODS (see dark green line in Figure D2).

Figure D1. GHG Emissions from Industrial Processes, 1990-2020

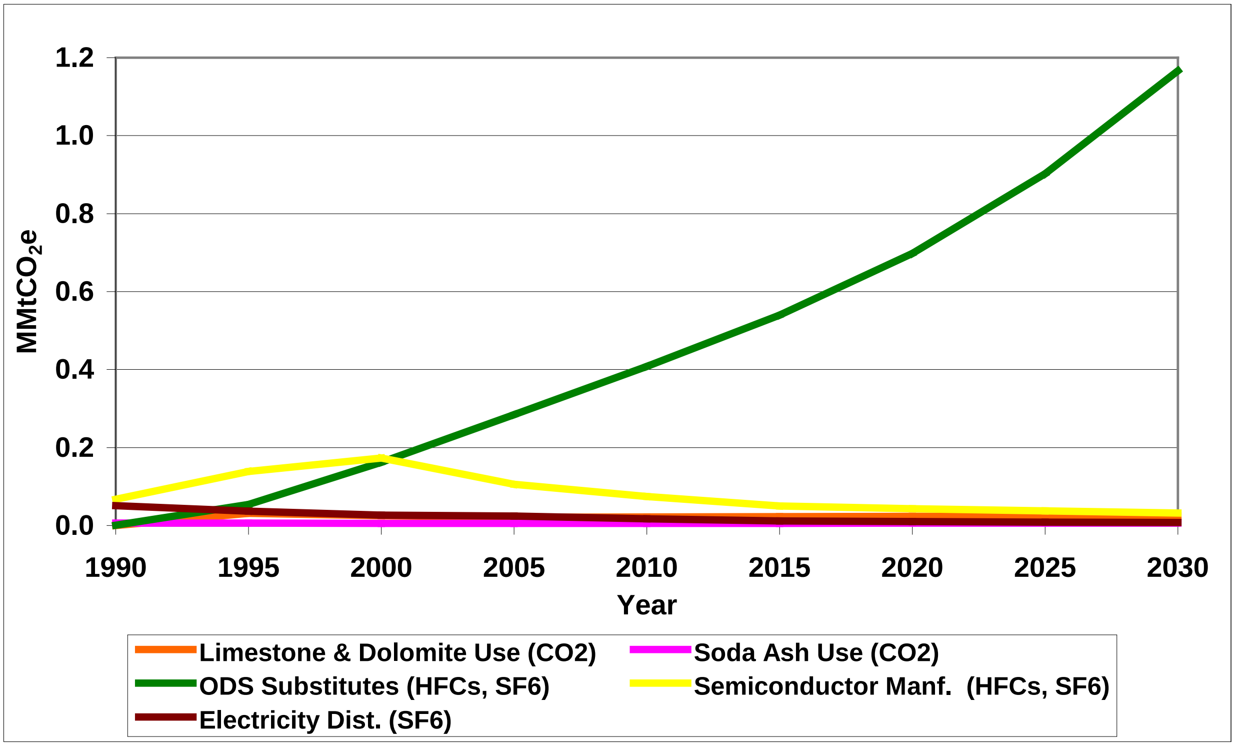


Electricity Distribution

Emissions of SF_6 from electrical equipment have experienced declines since the early nineties (see brown line in Figure D2), mostly due to voluntary action by industry. SF_6 is used as an electrical insulator and interrupter in electricity T&D systems. Emissions for Vermont from 1990 to 2002 were estimated based on the estimates of emissions per kWh from the US EPA national GHG inventory (referenced in Table D2) and Vermont's electricity consumption estimates provided in SGIT. The *US Climate Action Report* shows expected decreases in these emissions at the national level, and the same rate of decline is assumed for emissions in Vermont. The decline in SF_6 emissions in the future reflects expectations of future actions by the electric industry to reduce these emissions. The forecast of US emissions were only available through 2020. Because of a lack of forecast information beyond 2020, the annual growth rate calculated from the forecast of US emissions for the 2015 to 2020 period was used to extend the forecast for Vermont to 2030.

Relative to total industrial non-combustion process emissions, SF_6 emissions from electrical equipment are low (about 0.051 $MMtCO_2e$ in 1990, 0.025 $MMtCO_2e$ in 2005, and 0.008 $MMtCO_2e$ in 2030), and therefore, appear at the bottom of the graph because of scaling effects in Figure D2.

Figure D2. GHG Emissions from Industrial Processes, 1990-2020, by Source



Semiconductor Manufacture

Emissions of SF_6 and HFCs from the manufacture of semiconductors have experienced declines since 2000 (see yellow line in Figure D2). Emissions for Vermont from 1990 to 2002 were estimated based on the default estimates provided in SGIT, which uses the ratio of the State-to-national value of semiconductor shipments to estimate the State's proportion of national emissions from the US EPA national GHG inventory (referenced in Table D2). For Vermont, the 2002 *Economic Census* withheld information on the value of semiconductor shipments to avoid disclosing confidential information for establishments in Vermont; consequently, the default data provided in SGIT were used. The *US Climate Action Report* shows expected decreases in these emissions at the national level, and the same rate of decline is assumed for emissions in Vermont. The decline in emissions in the future reflects expectations of future actions by the semiconductor industry to reduce these emissions. Because of a lack of forecast information beyond 2020, the annual growth rate calculated from the forecast of US emissions for the 2015 to 2020 period was used to extend the forecast for Vermont to 2030.

Relative to total industrial non-combustion process emissions, emissions associated with semiconductor manufacturing are low (about 0.067 $MMtCO_2e$ in 1990, 0.106 $MMtCO_2e$ in 2005, and 0.032 $MMtCO_2e$ in 2030), and therefore, appear at the bottom of the graph because of scaling effects in Figure D2.

Soda Ash Consumption
Commercial soda ash (sodium carbonate) is used in the manufacture of many consumer products such as glass, soap and detergents, paper, textiles, and food. Carbon dioxide is also released when soda ash is consumed (see footnote 1 for reference to EIIP guidance document). SGIT estimates historical emissions (see dark pink line in Figure D2) based on the State's population and national per capita emissions from the US EPA national GHG inventory (referenced in Table D2). According to the US Geological Survey (USGS), this industry is expected to grow at an annual rate of 0.5% from 2004 through 2009 for the US as a whole. Information on growth trends for years later than 2009 was not available; therefore, the same 0.5% annual growth rate was applied for estimating emissions to 2030.

Relative to total industrial non-combustion process emissions, emissions associated with soda ash consumption are low (about 0.0061 $MMtCO_2e$ in 1990, 0.0055 $MMtCO_2e$ in 2005, and 0.0062 $MMtCO_2e$ in 2030), and therefore, appear at the bottom of the graph because of scaling effects in Figure D2.

Limestone and Dolomite Consumption
Limestone and dolomite are basic raw materials used by a wide variety of industries, including the construction, agriculture, chemical, glass manufacturing, and environmental pollution control industries, as well as in metallurgical industries such as magnesium production. For Vermont, activity in this category includes consumption of limestone and dolomite for use as flux stone and in glass manufacturing.[46] Recent historical data for Vermont were not available from the USGS; consequently, the default data provided in SGIT were used to calculate emissions for Vermont from the use of these materials (see orange line in Figure D2). The employment growth rate for Vermont's good's producing (manufacturing) sector for 2002 through 2012 (i.e., 0.08% annual) was used to project emissions from 2004 through 2030. Note that forecast data for Vermont's manufacturing sector was not available past 2012.

Relative to total industrial non-combustion process emissions, emissions associated with limestone and dolomite consumption are low (about 0.0031 $MMtCO_2e$ in1995, 0.0021 $MMtCO_2e$ in 2005 and 0.024 $MMtCO_2e$ in 2030), and therefore, appear at the bottom of the graph in Figure D2 due to scaling effects. Note that for this sector, SGIT did not contain default consumption data for Vermont for 1990 through 1993, and therefore, emissions were not estimated for these years.

[46] In accordance with EIIP Chapter 6 methods, emissions associated with the following uses of limestone and dolomite are not included in this category: (1) crushed limestone consumed for road construction or similar uses (because these uses do not result in CO_2 emissions), (2) limestone used for agricultural purposes (which is counted under the methods for the agricultural sector), and (3) limestone used in cement production (which is counted in the methods for cement production).

Key Uncertainties

Key sources of uncertainty underlying the estimates above are as follows:

- Since emissions from industrial processes are determined by the level of production and the production processes of a few key industries—and in some cases, a few key plants—there is relatively high uncertainty in the future emissions estimates for the industrial processes category as a whole. Future emissions depend on the competitiveness of Vermont manufacturers in these industries, and on the specific nature of the production processes used in Vermont.
- The projected largest source of future industrial emissions, HFCs and PFCs used in cooling applications, is subject to several uncertainties as well. First, historical emissions are based on national estimates; Vermont-specific estimates are currently unavailable. For example, the SGIT method for allocating national emissions to States does not account for climatic variations in air conditioning use. Thus, emissions for northern climates may be overstated relative to southern climates. Second, emissions through 2020 and beyond will be driven by future choices regarding mobile and stationary air conditioning technologies and the use of refrigerants in commercial applications, for which several options currently exist.
- There is also significant uncertainty in the forecast for SF_6 emission leakage from electrical transmission and distribution systems given the recent issue of electrical transmission line expansion in the state. Also, SF_6 leaks from electrical breakers / transformers in industrial applications is not known at this time. In addition, only one electricity supplier (Central Vermont Public Service) has signed onto the EPA voluntary SF_6 reduction agreement. Future work on this category should focus on obtaining better data from the electricity suppliers in Vermont.
- Greenhouse gases are emitted from several additional industrial processes that are not covered in the EIIP guidance documents, due in part to a lack of sufficient State data on non-energy uses of fossil fuels for these industrial processes. These sources include:
    - Iron and Steel Production (CO_2 and CH_4);
    - Ammonia Manufacture and Urea Application (CO_2, CH_4, N_2O);
    - Aluminum Production (CO_2);
    - Titanium Dioxide Production (CO_2);
    - Phosphoric Acid Production (CO_2);
    - CO_2 Consumption (CO_2);
    - Ferroalloy Production (CO_2);
    - Petrochemical Production (CH_4); and
    - Silicon Carbide Production (CH_4).

  The CO_2 emissions from the above CO_2 sources (other than CO_2 consumption and phosphoric acid production) result from the non-energy use of fossil fuels. Although the

US EPA estimates emissions for these industries on a national basis, US EPA has not developed methods for estimating the emissions at the State level due to data limitations. If State-level data on non-energy uses of fuels become available, future work should include an assessment of emissions for these other categories.

Appendix E. Fossil Fuel Production Industry[47]

Overview

The inventory for this subsector of energy supply consists only of methane (CH_4) emissions associated with the transmission and distribution (T&D) of natural gas in Vermont. There is no oil or natural gas production or processing or coal mining in Vermont. In 2005, emissions for this sector account for an estimated 0.014 million metric tons (MMt) of CO_2 equivalent (CO_2e) of total gross greenhouse gas (GHG) emissions in Vermont, and are estimated to increase to about 0.028 MMtCO_2e of Vermont's total gross GHG emissions by 2030.

Vermont Gas Systems, Inc. (VGS) is Vermont's only natural gas company with about 38,000 residential and commercial customers in Chittenden and Franklin counties in 2006. Natural gas supplied to Vermont is transported across Canada via the TransCanada PipeLine and enters VGS' main pipeline at Highgate, on the Vermont/Canada border. VGS' customers are served through a network of more than 650 miles of underground transmission and distribution lines.[48]

Natural Gas T&D Emissions and Reference Case Projections

Methane emissions for 1990 through 2005 were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for natural gas T&D.[49] Table E1 provides an overview of the required data, data sources, and the approach to projecting future emissions. The annual activity data for this category were obtained from the Office of Pipeline Safety (OPS).[50] The activity data was then entered into the SGIT to calculate emissions for 1990 through 2005. Methane emissions are calculated by multiplying emissions-related activity levels (e.g., miles of pipeline) by aggregate emission factors. The SGIT methods also include emission factors for estimating CH_4 emissions associated with leaks at gas storage compressor stations or liquefied natural gas (LNG) storage compressor stations; however, Vermont does not have these types of stations.

Based on information obtained from the DPS, natural gas consumption is expected to grow at a rate of about 3% to 4% per year.[51] A 3% compound annual growth rate was applied to forecast emissions for the distribution system. Information was not readily available on an annual growth rate for the transmission system in Vermont. For this analysis, it was assumed that that emissions associated with the transmission system would increase at 1% annually based on (1) the historical growth from 1990 to 2005 in the total miles of transmission pipeline in Vermont, and

[47] This category includes emissions from the production, processing and transmission of natural gas, oil and coal. Emissions are released due to energy consumption (mostly CO2) and methane release (venting or leaks) during processing and transmission.
[48] Vermont Gas Systems, Inc., http://www.vermontgas.com/.
[49] Methane emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 5. "Methods for Estimating Methane Emissions from Natural Gas and Oil Systems", March 2005.
[50] US Office of Pipeline Safety, Distribution and Transmission Annuals Data for 1990-2005, http://ops.dot.gov/stats/DT98.htm.
[51] Vermont Department of Public Service, http://publicservice.vermont.gov/natural-gas/natural-gas.html.

(2) the rate of growth in the total miles of transmission pipeline relative to the rate of growth in the number of distribution system connections.[52]

Table E1. Approach to Estimating Historical and Future Methane Emissions from Natural Transmission and Distribution

	Approach to Estimating Historical Emissions		Approach to Estimating Projections
Activity	***Required Data for SGIT***	***Data Source***	***Projection Assumptions***
Natural Gas Transmission	Miles of transmission pipeline	OPS, VGS	Transmission emissions grown 1% annually based on historical growth rates (1990 – 2005) and forecast of natural gas consumption (2005-2030). There are no gas storage compressor stations or LNG storage compressor stations in Vermont.
	Number of gas transmission compressor stations	OPS, VGS	
	Number of gas storage compressor stations	OPS, VGS	
	Number of LNG storage compressor stations	OPS, VGS	
Natural Gas Distribution	Miles of distribution pipeline	OPS, VGS	Distribution emissions grown 3% annually based on forecast of natural gas consumption (2005-2030).
	Total number of services	OPS, VGS	
	Number of unprotected steel services	OPS, VGS	
	Number of protected steel services	OPS, VGS	

Results

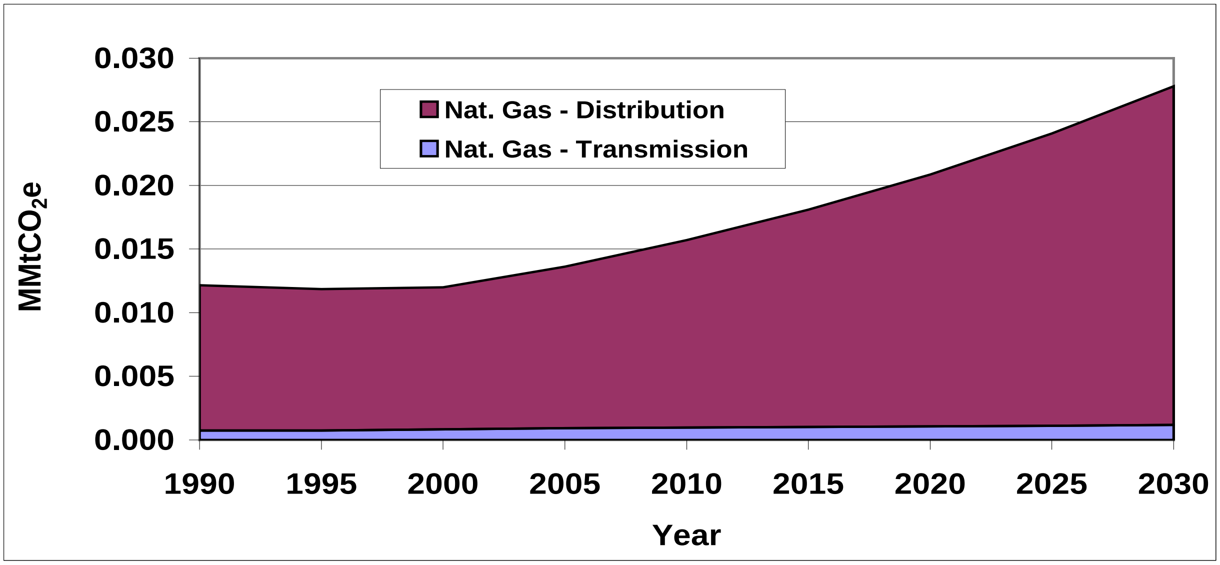
Figure E1 displays the estimated GHG emissions associated with natural gas T&D system in Vermont from 1990 to 2005, with projections to 2030. Emissions associated with this sector are estimated to be about 0.012 $MMtCO_2e$ in 1990, 0.014 $MMtCO_2e$ in 2005, and 0.028 $MMtCO_2e$ in 2030. As shown in Figure E1, CH_4 emissions associated with Vermont's distribution system have declined slightly from 1990 through early 2000. This decline in emissions is associated with VGS completely replacing cast iron and unprotected steel pipe with protected steel and plastic pipe. VGS also replaced unprotected steel service connections with protected steel service connections that helped reduce emissions.

Key Uncertainties

The main uncertainties are associated with the reference case projection assumptions. Although the growth rates for the transmission and distribution pipeline systems for the 2005 to 2030 period are similar (but slightly less than) historical growth rates from 1990 to 2005, market factors (e.g., price of natural gas relative to other available energy sources) could have a significant impact on the growth for this sector. In addition, potential emission reduction improvements to pipeline technologies and the effect of demand-side management programs have not been accounted for in the projections analysis.

[52] Based on OPS data, the number of distribution system connections grew at an annual compound rate of about 4.2% from 1990 to 2000, 3.3% from 2000 to 2005, and averaged about 3.9% over the 1990 to 2005 period. The miles of transmission pipeline grew at an annual compound rate of about 1.2% from 1990 to 2000, 2.1% from 2000 to 2005, and averaged about 1.5% over the 1990 to 2005 period.

Figure E1. Methane Emissions and Projections from the Fossil Fuel Industry



Appendix F. Agriculture

Overview
The emissions discussed in this appendix refer to non-energy methane (CH_4) and nitrous oxide (N_2O) emissions from enteric fermentation, manure management, and agricultural soils. Emissions and sinks of carbon in agricultural soils are also covered. Energy emissions (fossil fuel combustion in agricultural equipment) are included in the residential, commercial, and industrial (RCI) sector estimates (see Appendix B).

There are two livestock sources of greenhouse gas (GHG) emissions: enteric fermentation and manure management. Methane emissions from enteric fermentation are the result of normal digestive processes in ruminant and non-ruminant livestock. Microbes in the animal digestive system breakdown food and emit CH_4 as a by-product. More CH_4 is produced in ruminant livestock than in other animals because of digestive activity in the large fore-stomach to break down grasses and other high-fiber feeds. Methane and N_2O emissions from the storage and treatment of livestock manure (e.g., in compost piles or anaerobic treatment lagoons) occur as a result of manure decomposition. The environmental conditions of decomposition drive the relative magnitude of emissions. In general, the more anaerobic the conditions are, the more CH_4 is produced because decomposition is aided by CH_4 producing bacteria that thrive in oxygen-limited (or oxygen-free) anaerobic conditions. Under aerobic conditions, N_2O emissions are the dominant GHG emissions of concern. Emissions estimates from manure management are based on estimates of the volumes of manure that are stored and treated in livestock operations. Emissions from manure that is applied to agricultural soils as an amendment or deposited directly to pasture and grazing land by grazing animals are accounted for in inventories of emissions from agricultural soils.

The management of agricultural soils can result in N_2O emissions and in fluxes of carbon dioxide (CO_2) that make soils net emitters or net sinks of carbon. In general, soil amendments that add nitrogen to soils can also result in N_2O emissions. Nitrogen additions drive underlying soil nitrification and de-nitrification cycles, which produce N_2O as a by-product. The emissions estimation methodologies used in this inventory account for several sources of N_2O emissions from agricultural soils, including decomposition of crop residues, synthetic and organic fertilizer application, manure and sewage sludge application to soils, nitrogen fixation, and cultivation of histosols (high organic soils, such as wetlands or peat lands). Both direct and indirect emissions of N_2O occur from the application of manure, fertilizer, and sewage sludge to agricultural soils. Direct emissions occur at the site of application and indirect emissions occur when nitrogen leaches to groundwater or in surface runoff and is transported off-site before entering the nitrification/denitrification cycle. Methane and N_2O emissions also result when crop residues are burned. Methane emissions occur during rice cultivation; however, rice is not grown in Vermont.

The net flux of CO_2 in agricultural soils depends on the balance of carbon losses from management practices and gains from organic matter inputs to the soil. Carbon dioxide is absorbed by plants through photosynthesis and ultimately becomes the carbon source for organic matter inputs to agricultural soils. When inputs are greater than losses, the soil accumulates carbon and there is a net sink of CO_2 into agricultural soils. In addition, soil disturbance from the cultivation of histosols releases large stores of carbon from the soil to the atmosphere. Finally, the practice of adding limestone and dolomite to agricultural soils results in CO_2 emissions.

Emissions and Reference Case Projections

Methane and Nitrous Oxide

GHG emissions for 1990 through 2005 were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for the sector.[53] In general, the SGIT methodology applies emission factors developed for the US to activity data for the agriculture sector. Activity data include livestock population statistics, amounts of fertilizer applied to crops, and trends in manure management practices. This methodology is based on international guidelines developed by sector experts for preparing GHG emissions inventories.[54]

Data on crop production and the number of animals in the Vermont from 1990 to 2002 within SGIT come from the United States Department of Agriculture's (USDA) National Agriculture Statistical Service (NASS). SGIT data on fertilizer usage came from *Commercial Fertilizers*, a report from the Fertilizer Institute. The default data in SGIT accounting for the percentage of each livestock category using each type of manure management system were also used. Emissions from enteric fermentation and manure management were forecast based on projected livestock populations. The average annual growth rates for 2015-2020 were assumed to continue through 2030. Dairy cattle populations used for manure management projections were adjusted to account for Vermont's Cow Power program.[55]

Crop production data from USDA NASS were available through 2002; therefore, N_2O emissions from crop residues and N-fixation were calculated through 2002. Emissions for the other agricultural crop production categories (synthetic and organic fertilizers, agricultural residue burning) were also available through 2002. SGIT data indicate that agricultural residue burning is not a common practice in Vermont agriculture. Historical emissions from agricultural soils, based on USDA NASS data, do not show a significant positive or negative trend. Therefore, emissions for this source were held constant from 2002 through 2030.

[53] GHG emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter 8. "Methods for Estimating Greenhouse Gas Emissions from Livestock Manure Management", August 2004; Chapter 10. "Methods for Estimating Greenhouse Gas Emissions from Agricultural Soil Management", August 2004; and Chapter 11. "Methods for Estimating Greenhouse Gas Emissions from Field Burning of Agricultural Residues", August 2004.

[54] Revised 1996 1ntergovermental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories, published by the National Greenhouse Gas Inventory Program of the IPCC, available at (http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm); and Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, published in 2000 by the National Greenhouse Gas Inventory Program of the IPCC, available at: (http://www.ipcc-nggip.iges.or.jp/public/gp/english/).

[55] Dave Dunn, Central Vermont Public Service (CVPS). Vermont Cow Power Program projected dairy cattle populations: 1,000 head in 2005, 4,000 head in 2007, and 10,000 head in 2009, translating to an emission reduction of 0.008 MMtCO2e/year in 2009.

Soil Carbon

Carbon dioxide is either emitted or sequestered as a result of agricultural practices. Net carbon fluxes from agricultural soils have been estimated by researchers at the Natural Resources Ecology Laboratory at Colorado State University and are reported in the US Inventory of Greenhouse Gas Emissions and Sinks[56] and the US Agriculture and Forestry Greenhouse Gas Inventory. The estimates are based on the Intergovernmental Panel on Climate Change (IPCC) methodology for soil carbon adapted to conditions in the US. Preliminary state-level estimates of CO_2 fluxes from mineral soils and emissions from the cultivation of organic soils were reported in the US Agriculture and Forestry Greenhouse Gas Inventory.[5] Currently, these are the best available data at the state-level for this category. The inventory did not report state-level estimates of CO_2 emissions from limestone and dolomite applications; hence, this source is not included in this inventory at present.

Carbon dioxide fluxes resulting from specific management practices were reported. These practices include: conversions of cropland resulting in either higher or lower soil carbon levels; additions of manure; participation in the Federal Conservation Reserve Program (CRP); and cultivation of organic soils (with high organic carbon levels). For Vermont, Table F1 shows a summary of the latest estimates available from the USDA.[57] The latest data available are for 1997 agricultural practices. These data show that changes in agricultural practices are estimated to result in a net sink of 0.19 million metric tons (MMt) of CO_2 equivalent (CO_2e) per year (yr) in Vermont. Since data are not yet available from USDA to determine if the emissions are increasing or decreasing, the net sink of 0.19 MMtCO_2e/yr is assumed to remain constant.

Results

As shown in Figure F1, total gross emissions from agricultural sources are fairly constant at about 1 MMtCO_2e from 1990 through 2030. The projections predict a decline in emissions from these sources from 2002 to 2030, mainly due to a predicted decrease in the dairy cattle population. With the inclusion of soil carbon flux from agricultural soils (-0.19 MMtCO_2e/yr), the net agricultural sector emissions range from about 0.8 to 0.7 MMtCO_2e/yr over the forecast period.

The only standard IPCC source category missing from this report is CO_2 emissions from limestone and dolomite application. Estimates for Vermont were not available; however the USDA's national estimate for soil liming is about 9 MMtCO_2e/yr.[58]

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[56] US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004 (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006. Available at: http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

[57] US Agriculture and Forestry Greenhouse Gas Inventory: 1990-2001. Global Change Program Office, Office of the Chief Economist, US Department of Agriculture. Technical Bulletin No. 1907. 164 pp. March 2004. http://www.usda.gov/oce/global_change/gg_inventory.htm; the data are in appendix B table B-11. The table contains two separate IPCC categories: "carbon stock fluxes in mineral soils" and "cultivation of organic soils." The latter is shown in the second to last column of Table F1. The sum of the first nine columns is equivalent to the mineral soils category.

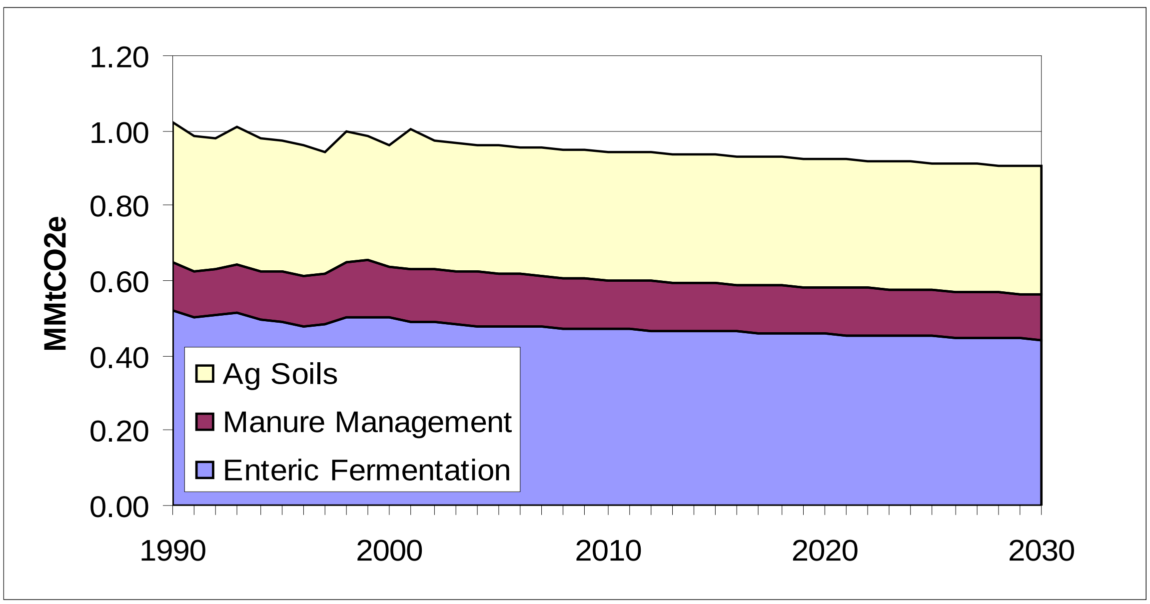
[58] US Agriculture and Forestry Greenhouse Gas Inventory: 1990-2001. Global Change Program Office, Office of the Chief Economist, US Department of Agriculture. Technical Bulletin No. 1907. 164 pp. March 2004.

Table F1. GHG Emissions from Soil Carbon Changes Due to Cultivation Practices ($MMtCO_2e$)

Changes in cropland			Changes in Hayland				Other			Total[4]
Plowout of grassland to annual cropland[1]	Cropland manage-ment	Other cropland[2]	Cropland converted to hayland[3]	Hayland manage-ment	Cropland converted to grazing land[3]	Grazing land manage-ment	CRP	Manure application	Cultivation of organic soils	Net soil carbon emissions
0.07	0.00	0.00	(0.11)	0.00	0.00	(0.04)	0.00	(0.11)	0.00	(0.19)

Based on USDA 1997 estimates. Parentheses indicate net sequestration.
[1] Losses from annual cropping systems due to plow-out of pastures, rangeland, hayland, set-aside lands, and perennial/horticultural cropland (annual cropping systems on mineral soils, e.g., corn, soybean, cotton, and wheat).
[2] Perennial/horticultural cropland and rice cultivation.
[3] Gains in soil carbon sequestration due to land conversions from annual cropland into hay or grazing land.
[4] Total does not include change in soil organic carbon storage on federal lands, including those that were previously under private ownership, and does not include carbon storage due to sewage sludge applications.

Figure F1. Gross GHG Emissions from Agriculture



Key Uncertainties

Key sources of uncertainty underlying the estimates are the projection data. State-level projections of livestock populations were not available; therefore, national projections from USDA were used to project livestock populations. However, national livestock trends may not reflect the future of livestock in Vermont.

Emissions from enteric fermentation and manure management are dependent on the estimates of animal populations and the various factors used to estimate emissions for each animal type and manure management system (i.e., emission factors which are derived from several variables including manure production levels, volatile solids content, CH_4 formation potential). Each of these factors has some level of uncertainty. Also, animal populations fluctuate throughout the year, and thus using point estimates introduces uncertainty into the average annual estimates of these populations. In addition, there is uncertainty associated with the original population survey methods employed by USDA. The largest contributors to uncertainty in emissions from manure management are the emission factors, which are derived from limited data sets.

As mentioned above, for emissions associated with changes in agricultural soil carbon levels, the only data currently available are for 1997. When newer data are released by the USDA, these should be reviewed to represent current conditions as well as to assess trends. In particular, if additional idle crop lands are returned to active cultivation prior to 2030, the current size of the CO_2 sink could be appreciably affected. As mentioned above, emission estimates for soil liming have not been developed for Vermont.

Appendix G. Waste Management

Overview

Greenhouse gas (GHG) emissions from waste management include:

- Solid waste management – methane (CH_4) emissions from landfills and waste combustion, accounting for identified CH_4 that is flared or captured for energy production;
- Solid waste combustion – CH_4, carbon dioxide (CO_2), and nitrous oxide (N_2O) emissions from the combustion of solid waste in incinerators or waste to energy plants; and
- Wastewater management – CH_4 and N_2O from municipal wastewater treatment facilities.

Inventory and Reference Case Projections

Solid Waste Management

For solid waste management, the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) and the US EPA's Landfill Methane Outreach Program (LMOP) landfills database[59] were used as a starting point to estimate emissions. Since the LMOP database does not include data covering all Vermont landfills, the Center for Climate Strategies (CCS) gathered additional data from Vermont Department of Environmental Conservation (VTDEC).[60] The data from VTDEC included waste-in-place data for additional landfill sites, their years of operation, and use of landfill gas controls. The combined EPA LMOP and VTDEC data indicate that six of the State's landfills are controlled [five with landfill gas to energy (LFGTE) plants, the other with a flare]. Two additional active landfills are uncontrolled, as are the remaining 60 or so small closed landfills throughout the State. To obtain the annual disposal needed by SGIT for each landfill, the waste-in-place was divided by the number of years of operation. This average annual disposal rate for each landfill was assumed for all years that the landfill was operating.

CCS performed three different runs of SGIT to estimate emissions from municipal solid waste (MSW) landfills: (1) uncontrolled landfills; (2) landfills with a landfill gas collection system and flare; and (3) landfills with a landfill gas collection system and LFGTE plant. SGIT produced annual estimates through 2005 for each of these landfill types. CCS then performed some post-processing of the landfill emissions to account for landfill gas controls (at LFGTE and flared sites) and to project the emissions through 2030. For the controlled landfills, CCS assumed that the overall CH_4 collection and control efficiency is 75%.[61]

CCS used the SGIT default for industrial landfills. This default is based on national data indicating that industrial landfilled waste is emplaced at approximately 7% of the rate of MSW emplacement. Since VTDEC indicated that there were only four or five old and closed paper sludge landfills in the State, CCS only included the industrial landfill emissions associated only

[59] LMOP database is available at: http://www.epa.gov/lmop/proj/index.htm. Database downloaded June 2006.
[60] David DiDomenico, VTDEC, personal communication with S. Roe, CCS, August 2006.
[61] As per EPA's AP-42 Section on Municipal Solid Waste Landfills: http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf.

with the first SGIT run noted above for MSW landfills (uncontrolled sites). No controls were assumed for industrial waste landfilling.

Solid Waste Combustion
Municipal waste combustion in Vermont ceased in the late 1990s.[62] The SGIT defaults were used to estimate emissions up through 1998 by assuming 1,000 tons per year combusted consistent with previous VTDEC assumptions. From 1999 and later years, these emissions were set to zero.

Wastewater Management
GHG emissions from municipal wastewater treatment were also estimated. Emissions were calculated using EPA's SGIT based on State population, assumed biochemical oxygen demand (BOD) and protein consumption per capita, and emission factors for N_2O and CH_4. The key SGIT default values are shown in Table G1. The only change to these defaults is the estimated fraction of Vermont's population not on septic systems. The estimate of 51% comes from VTDEC's 2005 GHG inventory documentation.[63]

For industrial wastewater emissions, SGIT provides default assumptions and emission factors for three industrial sectors: Fruits & Vegetables, Red Meat & Poultry, and Pulp & Paper. Based on the previous VTDEC GHG estimates and discussions with VTDEC staff, no significant activity occurs in the State in any of these industrial sectors. Although there was historical pulp and paper industrial activity in the Vermont; due to their relative lack of importance, CCS did not gather data to estimate these historical emissions.

Table G1. SGIT Key Default Values for Municipal Wastewater Treatment

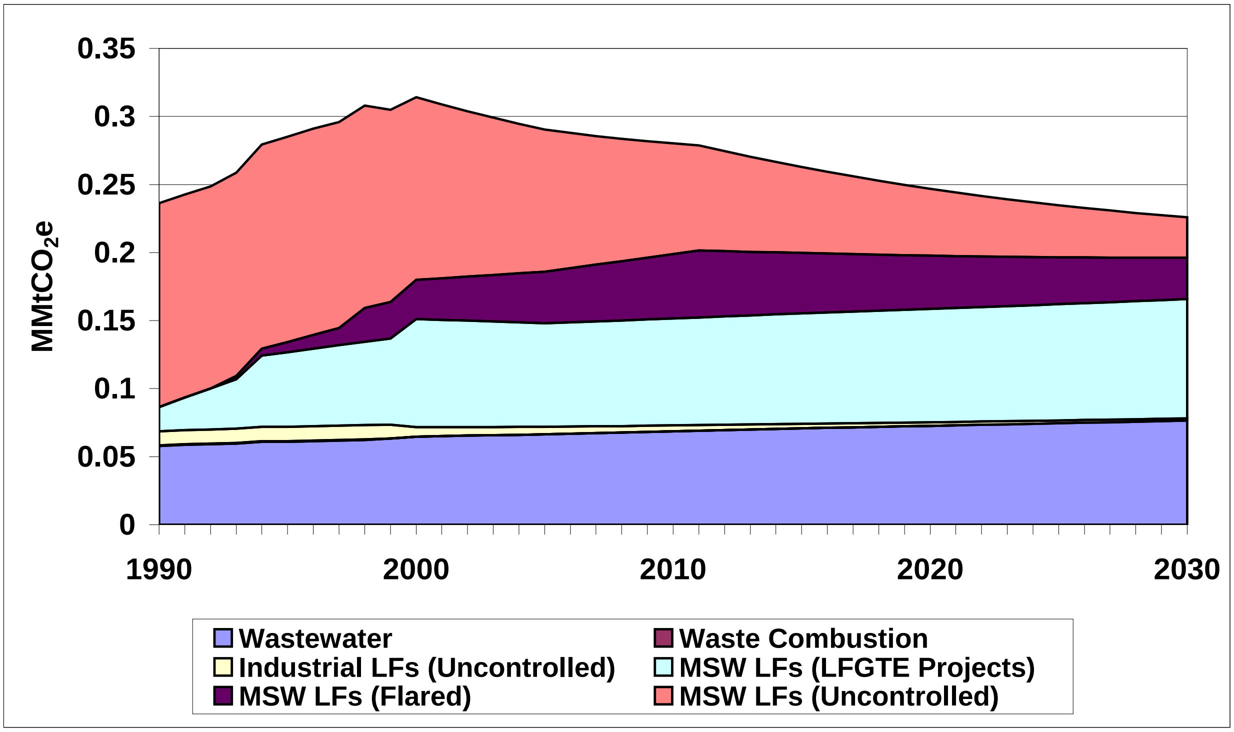
Variable	Value
BOD	0.065 kg /day-person
Amount of BOD anaerobically treated	16.25%
CH_4 emission factor	0.6 kg/kg BOD
Vermont residents not on septic	51%[a]
Water treatment N_2O emission factor	4.0 g N_2O/person-yr
Biosolids emission Factor	0.01 kg N_2O-N/kg sewage-N

[a] From VTDEC, April 2005 GHG documentation.

Results
Figure G1 shows the emission estimates for the waste management sector. Overall, the sector accounts for less than 0.31 million metric tons (MMt) of CO_2 equivalent (CO_2e) emissions per year from 1990 through 2030. Emissions were estimated to be about 0.24 MMtCO_2e in 1990, peak at about 0.31 MMtCO_2e from 1998 through 2001, and then are projected to decline to about 0.28 MMtCO_2e in 2010, 0.25 MMtCO_2e in 2020, and 0.23 MMtCO_2e by 2030.

[62] Vermont Statewide Greenhouse Gas Emissions Inventory Estimates, J. Merrell, April 2005.
[63] VTDEC's source for this estimate: Windham Regional Commission (http://www.rpc.windham.vt.us/pubs/), "Nearly half of Vermont's population is served by onsite septic systems." Based on this information, the default was adjusted to 51%.

Figure G1. Vermont GHG Emissions from Waste Management



Note: Emissions associated with waste combustion are too small to be seen on this graph.

For the reference case projections for MSW landfills with LFGTE plants, growth from the 2005 level was assumed to follow population, because these sites are those that are currently operating and controlled in Vermont (emissions from future waste placed into these landfills will also likely be controlled). This is due to Federal requirements (New Source Performance Standards and Emission Guidelines), which require landfills above a certain size to collect and control landfill gas emissions. In 2005, over 26% of total emissions for the waste management sector were associated with MSW landfills with LFGTE plants. The contribution from MSW landfills with LFGTE plants is expected to increase to about 28% by 2010, 33% by 2020, and 38% by 2030.

For the uncontrolled (primarily closed) sites, emissions were assumed to decline at an annual rate of 5% from the 1998 peak based on the age of waste in place at these sites (peak landfill gas generation begins to tail off after waste has been in place for 10-15 years. For 2005, these sites accounted for about 35% of total emissions for the waste management sector. Based on the forecast assumption for these landfills, their contribution to total emissions for the waste sector was estimated to be about 29% in 2010, 20% in 2020, and 13% in 2030.

For the one flared MSW landfill, emissions were assumed to decline after the year this site is projected to close (2011). The rate of decline for the flared site was assumed to be half of the annual rate for uncontrolled landfill sites (i.e., 2.5% annually), since the landfill is assumed to accept waste up until the closure year and the rate of landfill gas production should begin to decline following the initial years after closure. This site accounts for about 17% of total emissions for the waste sector in 2010, 16% of total emissions in 2020, and 13% of total emissions in 2030.

Emissions from industrial landfills were forecasted based on the same rate of decline as the uncontrolled MSW sites. This category accounted for about 4% of total emissions in 1990 and is projected to account for about 1% of total emissions in 2010, and less than 1% of total emissions for the waste sector from 2020 through 2030.

Combustion of MSW in Vermont was estimated for 1990 through 1998. Emissions associated with MSW combustion were estimated to be less than 0.2% of total emissions for the waste sector during the 1990 through 1998 period.

Emissions from municipal wastewater treatment were about 0.06 $MMtCO_2e$ in 1990, 0.07 $MMtCO_2e$ in 2005, and were estimated to be about 0.07 $MMtCO_2e$ in 2010, 0.07 $MMtCO_2e$ in 2020, and 0.08 $MMtCO_2e$ in 2030. Emissions were forecasted based on population growth. Emissions associated with this category are estimated to account for about 25% of total emissions for the waste sector from 1990 through 2005. Emissions are expected to increase slightly to about 28% of total waste management sector emissions by 2020 and then 34% of total emissions by 2030.

Key Uncertainties

The methods used to model landfill gas emissions do not adequately account for the points in time when controls were applied at individual sites. Hence, for landfills, the historical emissions are less certain than current emissions and future emissions (since each site that is currently controlled was modeled as always being controlled, the historic emissions estimates are lower than they should be as a result). The modeling also does not account for uncontrolled sites that will need to apply controls during the period of analysis due to triggering the requirements of the federal New Source Performance Standards/Emission Guidelines. However, CCS does not anticipate that this is an issue for Vermont landfills.

For industrial landfills, emissions were estimated using national defaults (with industrial landfill wastes buried at 7% of the rate of MSW emplacement). CCS assumed that this rate of waste emplacement occurred only as a fraction of waste emplacement at uncontrolled sites. Sources at VTDEC indicate that very little industrial waste emplacement occurred in Vermont, except for some forest products sites. Hence, CCS feels that the minimal contribution indicated from these sites in Figure G1 is accurate. Any additional industrial waste emplacement is assumed to be captured within the emplacement occurring at MSW sites.

For the wastewater sector, the key uncertainties are associated with the application of SGIT default values for the parameters listed in Table G2 (e.g., the fraction of the Vermont population on septic sewers; and the fraction of BOD that is anaerobically decomposed). The SGIT defaults for emission factors used to estimate wastewater emissions were derived from national data.

Appendix H. Forestry

Overview
Forestland emissions refer to the net carbon dioxide (CO_2) flux[64] from forested lands in Vermont, which account for about 78% of the State's land area.[65] Through photosynthesis, CO_2 is taken up by trees and plants and converted to carbon in biomass within the forests. Carbon dioxide emissions occur from respiration in live trees and decay of dead biomass. In addition, carbon is stored for long time periods when forest biomass is harvested for use in durable wood products. Carbon dioxide flux is the net balance of CO_2 removals from and emissions to the atmosphere from the processes described above. Forestlands are net CO_2 sinks for Vermont, with an estimated 9.7 million metric tons (MMt) of CO_2 equivalent (CO_2e) removed per year (see Table H1). Live trees are estimated to remove about 6.3 MMtCO2e per year (yr). Another key pool of forest carbon, harvested wood products and landfilled forestry waste, sequesters 1.7 $MMtCO_2e$/yr.

Table H1. Annual CO_2 Sequestered in Forests and Wood Products, 1983-1997

Carbon Pool		$MMtCO_2e$/yr
Live Trees		-6.3
Standing Dead Trees		-0.3
Live Understory		-0.03
Down and Dead Trees		-0.4
Forest Floor		-0.5
Soils		-0.7
Harvested Wood Products & Landfilled Forestry Waste		-1.4
	Total	**-9.7**

Emissions Inventory and Reference Case Projections
Carbon dioxide flux from forests was estimated using data on forest carbon pools from the US Forest Service (USFS).[66] The carbon pool data are taken from the Forest Carbon Model (FORCARB), which are in turn derived from the USFS Forest Inventory & Analysis (FIA) survey data. Carbon pool data for three FIA survey cycles (two time periods) were available. These included FIA surveys covering 1983, 1997, and 2004. Based on discussions with State forestry officials, CCS only used the data for the 1983-1997 period to estimate CO_2 flux, since the 2004 survey cycle data are not yet complete.[67]

For each of the forest carbon pools listed in Table H1, the annual flux estimate was determined from the increase/decrease in forest carbon between FIA cycles divided by the number of years between the cycles. The forestry sequestration estimates for Vermont are driven both by an

[64] "Flux" refers to both emissions of CO_2 to the atmosphere and removal (sinks) of CO_2 from the atmosphere.
[65] Source: *The Vermont Forest Resource Plan* 1999-2008, Vermont Department of Forests, Parks & Recreation, http://www.vtfpr.org/forplan/index.htm.
[66] Jim Smith, USFS, personal communication with S. Roe, CCS, August 24, 2006.
[67] Sandy Wilmot, Vermont Department of Forests, Parks & Recreation, personal communication with S. Roe, CCS, August 30, 2006.

increase in forested area from 1983 to 1997 (about 182,000 acres) and an increase in live tree biomass during this period (12% increase in biomass density).

In addition to the forest carbon pools, additional carbon stored as biomass is removed from the forest for either the production of durable wood products or landfilling of wood waste. An estimate of these removals was provided by the USFS.[68]

The methods used to construct the inventory for Vermont are aligned with those used to produce EPA's national inventory. Additional details on these methods can be found in Annex 3 to EPA's 2006 greenhouse gas (GHG) inventory for the US.[69] Other losses of forest carbon, such as through wildfires/prescribed burns are accounted for in the carbon pools accounting methods described above (i.e., losses of forest carbon due to large wildfires would show up in lower biomass estimates in the succeeding FIA survey).

For the 1990 and 2000 historic emission estimates as well as the reference case projections, the levels of forest CO_2 sequestration were assumed to be at the same levels as those shown in Table H1. Hence, there is no change in the estimated future sinks for 2010 through 2030.

Key Uncertainties

Key uncertainties in the current estimates of forest sinks are mainly attributable to the lack of complete data for the 2004 FIA cycle. Hence, data from the 1983-1997 time-frame were used to construct estimates of both historical and future sequestration rates. When the 2004 survey data are complete, a more up to date estimate of current sequestration can be made.

When the 2004 data are available, differences in survey methods between the different FIA cycles can drive additional uncertainty in sequestration rates. For example, surveys since 1999 include all dead trees on the plots, but data prior to that are extremely variable. This is mostly because dead trees were not timber and not the focus of data collection. Also, according to USFS, the first FIA survey missed much of the non-National Forest Service reserved lands, so these areas may need to be left out of the estimation of flux. Finally, different FIA cycles have used different forest cover definitions, which lead to differences in the estimated acreage of forests (post 1999 FIA data are based on a 5% forest cover definition as compared to the earlier 10% definition). The effect of these changes will probably be difficult for the USFS to estimate.

In order to provide a more comprehensive understanding of GHG sources/sinks from the forestry sector, CCS is conducting an assessment of methane and nitrous oxide emissions from wildfires and prescribed burns. This analysis is being conducted as part of a regional study for a group of Western States. Based on estimates for the State of Montana, where there is significant wildfire activity, the levels of methane and nitrous oxide emissions were found to be very low (<1% of the CO_2 sequestration rate). Therefore, assessment of these emissions in Vermont does not seem warranted.

[68] Jim Smith, USFS, personal communication with S. Roe, CCS, August 18, 2006.
[69] Annex 3 to EPA's 2006 report can be downloaded at: http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/RAMR6MBLNQ/$File/06_annex_Chapter3.pdf.

The estimates provided here for Vermont compare to previous sequestration estimates made by VTDEC of 11 $MMtCO_2e$/yr in 1990 and 17 $MMtCO_2e$/yr in 1997.[70] The VTDEC estimates were made using different methods based on forested area and biomass growth rates and exclude sequestration in harvested wood products and landfilled forestry waste.

[70] Vermont Statewide Greenhouse Gas Emissions Inventory Estimates, J. Merrell, VTDEC, April 2005.

Appendix I. Black Carbon Emissions

Overview

This appendix summarizes the methods, data sources, and results of the development of an inventory and forecast for black carbon (BC) emissions in Vermont. Black carbon is an aerosol (particulate matter or PM) species with positive climate forcing potential but currently without a global warming potential defined by the Intergovernmental Panel on Climate Change (IPCC) (see Appendix J for more information on BC and other aerosol species). Black carbon is synonymous with elemental carbon (EC), which is a term common to regional haze analysis. An inventory for 2002 was developed along with a forecast for 2018, based on inventory data from the Mid-Atlantic – Northeast Visibility Union (MANE-VU) regional planning organization and other sources. This appendix describes these data and methods for estimating mass emissions of BC and then transforming the mass emission estimates into CO_2 equivalents (CO_2e) in order to present the emissions within a greenhouse gas (GHG) context.

In addition to the PM inventory data from MANE-VU, PM speciation data from the United States Environmental Protection Agency's (US EPA) SPECIATE database were also used: these data include PM fractions of EC (also known as BC) and primary organic aerosols (also known as organic material or OM). These data come from ongoing work being conducted by E.H. Pechan & Associates, Inc. for EPA on updating the Version 4 of the SPECIATE database that the US EPA released to the public during January 2007.[71] As will be further described below, both BC and OM emission estimates are needed to assess the CO_2e of BC emissions.

After assembling the BC and OM emission estimates, the mass emission rates were transformed into their CO_2e estimates using information from recent global climate modeling. This transformation is described in later sections below.

Emissions and Reference Case Projections

Development of BC and OM Mass Emission Estimates

The BC and OM mass emission estimates were derived by multiplying the emissions estimates for PM with an aerodynamic diameter of less than 10 micrometers (PM_{10}) by the appropriate aerosol fraction for BC and OM. The aerosol fractions were taken from Version 4 of the SPECIATE database.

After estimating both BC and OM emissions for each source category, we summed these two aerosol species into a BC+OM estimate. The BC+OM estimate is needed for use along with the global climate modeling estimate described below. We then collapsed the inventory down to the sector level to be consistent with the gaseous portion of Vermont's GHG inventory. The mass emission results for 2002 are shown in Table I1.

[71] Version 4.0 of the SPECIATE database and report: http://www.epa.gov/ttn/chief/software/speciate/index.html#related.

Development of CO_{2e} for BC+OM Emissions

We used similar methods to those applied previously in Connecticut for converting BC mass emissions to CO_2 equivalents.[72] These methods are based on the modeling of Jacobson (2002)[73] and his updates to this work (Jacobson, 2005a).[74] Jacobson (2005a) estimated a range of 90:1 to 190:1 for the climate response effects of BC+OM emissions as compared to CO_2 carbon emissions (depending on either a 30-year or 95-year atmospheric lifetime for CO_2). It is important to note that the BC+OM emissions used by Jacobson were based on a 2:1 ratio of OM:BC (his work in these papers focused on fossil fuel BC+OM; primarily diesel combustion, which has an OM:BC ratio of 2:1 or less).

For Maine and Connecticut, ENE (2004) applied climate response factors from the earlier Jacobson work (220 and 500) to the estimated BC mass to estimate the range of CO_{2e} associated with BC emissions. Note that the analysis in the northeast was limited to BC emissions from onroad diesel exhaust. An important oversight from this work is that the climate response factors developed by Jacobson (2002, 2005a) are on the basis of CO_2 carbon (not CO_2). Therefore, in order to express the BC emissions as CO_{2e}, the climate response factors should have been adjusted upward by a factor of 3.67 to account for the molecular weight of CO_2 to carbon (44/12). In addition, Jacobson's modeling was based on total BC+OM, not just BC; hence, the sum of these two species is needed for the transformation into CO_2e.

For this inventory, we started with the 90 and 190 climate response factors adjusted to CO_2e factors of 330 and 697 to obtain a low and high estimate of CO_{2e} for each sector. An example calculation of the CO_{2e} emissions for 10 tons of PM_{10} from onroad diesel exhaust follows:

BC mass = (10 tons PM_{10}) x (0.613 ton EC/ton PM_{10}) = 6.13 short tons BC

Low estimate CO_{2e} = (6.13 tons BC) (330 tons CO_{2e}/ton BC+OM) (3 tons BC+OM/ton BC) (0.907 metric ton/ton) = 5,504 metric tons CO_{2e}

High estimate CO_{2e} = (6.13 tons BC) (697 tons CO_{2e}/ton BC+OM) (3 tons BC+OM/ton BC) (0.907 metric ton/ton) = 11,626 metric tons CO_{2e}

NOTE: The factor 3 tons BC+OM/ton BC comes directly from the modeling assumptions used by Jacobson (2002, 2005a; i.e., 2 tons of OM/ton of BC).

For source categories that had an OM:BC mass emission ratio >4.0, we zeroed out these emission estimates from the CO_{2e} estimates. The reason for this is that the net heating effects of OM are not currently well understood (overall OM is thought to have a negative climate forcing

[72] ENE, 2004. Memorandum: "Diesel Black Carbon Calculations – Reductions and Baseline" from Michael Stoddard, Environment Northeast, prepared for the Connecticut Stakeholder Dialog, Transportation Work Group, October 23, 2003.

[73] Jacobson, 2002. Jacobson, M.Z., "Control of fossil-fuel particulate black carbon and organic matter, possibly the most effective method of slowing global warming", *Journal of Geophysical Physical Research*, volume 107, No. D19, 4410, 2002.

[74] Jacobson, 2005a. Jacobson, M.Z., "Updates to 'Control of fossil-fuel particulate black carbon and organic matter, possibly the most effective method of slowing global warming", *Journal of Geophysical Research Atmospheres*, February 15, 2005.

effect or a net cooling effect). Therefore, for source categories where the PM is dominated by OM (e.g., biomass burning), the net climate response associated with these emissions is highly uncertain and potentially have a negative climate forcing potential. Further, OM:BC ratios of 4 or more are well beyond the 2:1 ratio used by Jacobson in his work.

Results

We estimate that BC mass emissions in Vermont total about 1,300 metric tons (Mt) in 2002 (see Table I1). Table I2 presents the results of the BC analysis in CO_2e. In this table both 2002 and 2018 emissions are shown. The total 2002 emissions range from about 0.4 to 0.9 million metric tons (MMt) of CO_2 equivalent (CO_2e) with a mid-range of 0.65 MMtCO_2e. In 2018 there is a drop in BC emissions to a mid-range estimate of 0.24 MMtCO_2e.

The drop in the forecasted BC emissions stems from large reductions in the onroad and nonroad diesel sectors due to new engine and fuels standards that will reduce PM emissions. The onroad diesel sector contributed 40% of the 2002 BC emissions, while in 2018 the contribution will drop to just 14%. The nonroad diesel sector (e.g., construction and agricultural equipment) contributed 46% in 2002 and although emissions drop in 2018, the sector still remains the main contributor to future emissions at 42%. The other large contributor to future year emissions is the residential, commercial, and industrial (RCI) oil combustion sector at 20%.

Miscellaneous sources such as fugitive dust from paved and unpaved roads contributed a significant amount of PM emissions (see Table I1); however the OM:BC ratio is >4 for these sources, so the BC emissions were not converted to CO_2e. RCI wood combustion is also a significant contributor of PM emissions and BC. For the residential wood combustion component (the larger component), the OM:BC ratio is again >4; however, for industrial wood combustion, the ratio is less than 4 and so the emissions were converted to CO_2e.

While the state of science in aerosol climate forcing is still developing, there is a good body of evidence supporting the net warming impacts of BC. Aerosols have a *direct* radiative forcing because they scatter and absorb solar and infrared radiation in the atmosphere. Aerosols also alter the formation and precipitation efficiency of liquid water, ice, and mixed-phase clouds, thereby causing an *indirect* radiative forcing associated with these changes in cloud properties (IPCC, 2001).[75] There are also a number of other indirect radiative effects that have been modeled (e.g., Jacobson, 2002).

The quantification of aerosol radiative forcing is more complex than the quantification of radiative forcing by GHGs because of the direct and indirect radiative forcing, and the fact that aerosol mass and particle number concentrations are highly variable in space and time. This variability is largely due to the much shorter atmospheric lifetime of aerosols compared with the important GHGs (i.e., CO_2). Spatially and temporally resolved information on the atmospheric burden and radiative properties of aerosols is needed to estimate radiative forcing.

The quantification of indirect radiative forcing by aerosols is especially difficult. In addition to the variability in aerosol concentrations, some quite complicated aerosol influences on cloud

[75] IPCC, 2001. Climate Change 2001: The Scientific Basis, Intergovernmental Panel on Climate Change, 2001.

processes must be accurately modeled. For example, the warm (liquid water) cloud indirect forcing may be divided into two components. The first indirect forcing is associated with the change in droplet concentration caused by increases in aerosol cloud condensation nuclei. The second indirect forcing is associated with the change in precipitation efficiency that results from a change in droplet number concentration. Quantification of the latter forcing necessitates understanding of a change in cloud liquid-water content and cloud amount. In addition to warm clouds, ice clouds may also be affected by aerosols.

To put the radiative forcing potential of BC in context with CO_2, the IPCC estimated the radiative forcing for a doubling of the earth's CO_2 concentration to be 3.7 watts per square meter (W/m^2). For BC, various estimates of current radiative forcing have ranged from 0.16 to 0.42 W/m^2 (IPCC, 2001). These BC estimates are for direct radiative effects only. There is a higher level of uncertainty associated with the direct radiative forcing estimates of BC compared to those of CO_2 and other GHGs. There are even higher uncertainties associated with the assessment of the indirect radiative forcing of aerosols.

Table I1. 2002 BC and OM Mass Emission Estimates

Sector	Subsector	Mass Emissions			Mass Emissions		
		PM10	BC	OM	BC	OM	BC + OM
		Short Tons			Metric Tons		
Electric Generating Units (EGUs)	Coal	0	0	0	0	0	0
	Oil	2	1	0	1	0	2
	Gas	0	0	0	0	0	0
	Other						
Non-EGU Fuel Combustion (Residential, Commercial, and Industrial)							
	Coal	158	6	9	6	9	14
	Oil	358	30	32	27	29	56
	Gas	47	0	31	0	28	28
	Other (wood)	4,183	613	3,070	556	2,787	3,344
Onroad Gasoline (Exhaust, Brake Wear, & Tire Wear)		258	32	126	29	115	144
Onroad Diesel (Exhaust, Brake Wear, & Tire Wear)		291	186	94	169	86	255
Aircraft		12	8	4	7	4	11
Railroad*		1	1	0	1	0	1
Other Energy Use	Nonroad Gas	224	18	194	16	176	192
	Nonroad Diesel	288	214	71	194	65	258
	Other Combustion**	9	0	4	0	3	3
Industrial Processes		107	6	48	6	44	49
Agriculture***		2,506	11	331	10	301	310
Waste Management	Landfills						
	Incineration						
	Open Burning	1,374	77	985	70	895	964
	Other						
Wildfires/Prescribed Burns		2	0	2	0	1	2
Miscellaneous****		42,474	219	3,658	199	3,321	3,520
Total		**52,294**	**1,423**	**8,661**	**1,291**	**7,863**	**9,154**

* Railroad includes Locomotives and Railroad Equipment Emissions.
** Other Combustion includes Motor Vehicle Fire, Structure Fire, and Aircraft/Rocket Engine Testing Emissions.
*** Agriculture includes Agricultural Burning, Agriculture/Forestry and Agriculture, Food, & Kindred Spirits Emissions.
**** Miscellaneous includes Paved/Unpaved Roads and Catastrophic/Accidental Releases Emissions.

Table I2. 2002 and 2018 BC CO_2e Emission Estimates

Sector	Subsector	2002 CO2 Equivalents (Mt) Low	2002 CO2 Equivalents (Mt) High	2002 % Contribution	2018 CO2 Equivalents (Mt) Low	2018 CO2 Equivalents (Mt) High	2018 % Contribution
Electric Generating Units (EGUs)	Coal	-	-	-	-	-	-
	Oil	1,174	2,479	0	1,057	2,232	1
	Gas	-	-	-	-	-	-
	Other			-			-
Non-EGU Fuel Combustion (Residential, Commercial, and Industrial)							
	Coal	5,687	12,012	1	6,140	12,969	4
	Oil	26,775	56,551	6	31,630	66,807	20
	Gas	5	10	0	5	10	0
	Other (wood)	7,448	15,732	2	7,565	15,978	5
Onroad Gasoline (Exhaust, Brake Wear, & Tire Wear)		12,836	27,112	3	14,760	31,174	9
Onroad Diesel (Exhaust, Brake Wear, & Tire Wear)		167,339	353,440	40	21,624	45,673	14
Aircraft		7,102	15,001	2	8,488	17,928	5
Railroad*		666	1,407	0	333	703	0
Other Energy Use	Nonroad Gas	-	-	-	-	-	-
	Nonroad Diesel	191,887	405,289	46	65,539	138,426	42
	Other Combustion**	-	-	-	-	-	-
Industrial Processes		-	-	-	-	-	-
Agriculture***		-	-	-	-	-	-
Waste Management	Landfills	-	-	-	-	-	-
	Incineration	-	-	-	-	-	-
	Open Burning	-	-	-	-	-	-
	Other	-	-	-	-	-	-
Wildfires/Prescribed Burns		-	-	-	-	-	-
Miscellaneous****		-	-	-	-	-	-
Total		**420,919**	**889,031**		**157,141**	**331,901**	
Mid-point			**654,975**			**244,521**	

* Railroad includes Locomotives and Railroad Equipment Emissions.

** Other Combustion includes Motor Vehicle Fire, Structure Fire, and Aircraft/Rocket Engine Fire & Testing Emissions.

*** Agriculture includes Agricultural Burning, Agriculture/Forestry and Agriculture, Food, & Kindred Spirits Emissions.

**** Miscellaneous includes Paved/Unpaved Roads and Catastrophic/Accidental Releases Emissions.

Appendix J. Greenhouse Gases and Global Warming Potential Values: Excerpts from the *Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2000*

Original Reference: Material for this Appendix is taken from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2000*, U.S. Environmental Protection Agency, Office of Atmospheric Programs, EPA 430-R-02-003, April 2002 (www.epa.gov/globalwarming/publications/emissions). Michael Gillenwater directed the preparation of this appendix.

Introduction

The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and removals for the years 1990 through 2000. The estimates are presented on both a full molecular mass basis and on a Global Warming Potential (GWP) weighted basis in order to show the relative contribution of each gas to global average radiative forcing.

The Intergovernmental Panel on Climate Change (IPCC) has recently updated the specific global warming potentials for most greenhouse gases in their Third Assessment Report (TAR, IPCC 2001). Although the GWPs have been updated, estimates of emissions presented in the U.S. *Inventory* continue to use the GWPs from the Second Assessment Report (SAR). The guidelines under which the *Inventory* is developed, the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) and the United Nations Framework Convention on Climate Change (UNFCCC) reporting guidelines for national inventories[76] were developed prior to the publication of the TAR. Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. This excerpt of the U.S. *Inventory* addresses in detail the differences between emission estimates using these two sets of GWPs. Overall, these revisions to GWP values do not have a significant effect on U.S. emission trends.

Additional discussion on emission trends for the United States can be found in the complete Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000.

What is Climate Change?

Climate change refers to long-term fluctuations in temperature, precipitation, wind, and other elements of the Earth's climate system. Natural processes such as solar-irradiance variations, variations in the Earth's orbital parameters, and volcanic activity can produce variations in climate. The climate system can also be influenced by changes in the concentration of various gases in the atmosphere, which affect the Earth's absorption of radiation.

The Earth naturally absorbs and reflects incoming solar radiation and emits longer wavelength terrestrial (thermal) radiation back into space. On average, the absorbed solar radiation is balanced by the outgoing terrestrial radiation emitted to space. A portion of this terrestrial radiation, though, is itself absorbed by gases in the atmosphere. The energy from this absorbed terrestrial radiation warms the Earth's surface and atmosphere, creating what is known as the "natural greenhouse effect." Without the natural heat-trapping properties of these atmospheric gases, the average surface temperature of the Earth would be about 33^{o}C lower (IPCC 2001).

Under the UNFCCC, the definition of climate change is "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in

[76] See FCCC/CP/1999/7 at <http://unfccc.int/2860.php>.

addition to natural climate variability observed over comparable time periods." Given that definition, in its Second Assessment Report of the science of climate change, the IPCC concluded that:

> *Human activities are changing the atmospheric concentrations and distributions of greenhouse gases and aerosols. These changes can produce a radiative forcing by changing either the reflection or absorption of solar radiation, or the emission and absorption of terrestrial radiation (IPCC 1996).*

Building on that conclusion, the more recent IPCC Third Assessment Report asserts that "[c]oncentrations of atmospheric greenhouse gases and their radiative forcing have continued to increase as a result of human activities" (IPCC 2001).

The IPCC went on to report that the global average surface temperature of the Earth has increased by between 0.6 ± 0.2°C over the 20th century (IPCC 2001). This value is about 0.15°C larger than that estimated by the Second Assessment Report, which reported for the period up to 1994, "owing to the relatively high temperatures of the additional years (1995 to 2000) and improved methods of processing the data" (IPCC 2001).

While the Second Assessment Report concluded, "the balance of evidence suggests that there is a discernible human influence on global climate," the Third Assessment Report states the influence of human activities on climate in even starker terms. It concludes that, "[I]n light of new evidence and taking into account the remaining uncertainties, most of the observed warming over the last 50 years is likely to have been due to the increase in greenhouse gas concentrations" (IPCC 2001).

Greenhouse Gases

Although the Earth's atmosphere consists mainly of oxygen and nitrogen, neither plays a significant role in enhancing the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide, and other trace gases in the atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 1996). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans. A gauge of these changes is called radiative forcing, which is a simple measure of changes in the energy available to the Earth-atmosphere system (IPCC 1996). Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth).

Climate change can be driven by changes in the atmospheric concentrations of a number of radiatively active gases and aerosols. We have clear evidence that human activities have affected concentrations, distributions and life cycles of these gases (IPCC 1996).

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). Because CFCs, HCFCs, and halons are stratospheric ozone depleting substances, they are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty; consequently these gases are not included in national greenhouse gas inventories. Some other fluorine containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas inventories.

There are also several gases that, although they do not have a commonly agreed upon direct radiative forcing effect, do influence the global radiation budget. These tropospheric gases—referred to as ambient air pollutants—include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and tropospheric (ground level) ozone (O_3). Tropospheric ozone is formed by two precursor pollutants, volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of ultraviolet light (sunlight). Aerosols—extremely small particles or liquid droplets—often composed of sulfur compounds, carbonaceous combustion products, crustal materials and other human induced pollutants—can affect the absorptive characteristics of the atmosphere. However, the level of scientific understanding of aerosols is still very low (IPCC 2001).

Carbon dioxide, methane, and nitrous oxide are continuously emitted to and removed from the atmosphere by natural processes on Earth. Anthropogenic activities, however, can cause additional quantities of these and other greenhouse gases to be emitted or sequestered, thereby changing their global average atmospheric concentrations. Natural activities such as respiration by plants or animals and seasonal cycles of plant growth and decay are examples of processes that only cycle carbon or nitrogen between the atmosphere and organic biomass. Such processes—except when directly or indirectly perturbed out of equilibrium by anthropogenic activities—generally do not alter average atmospheric greenhouse gas concentrations over decadal timeframes. Climatic changes resulting from anthropogenic activities, however, could have positive or negative feedback effects on these natural systems. Atmospheric concentrations of these gases, along with their rates of growth and atmospheric lifetimes, are presented in Table 10.

Table 10. Global Atmospheric Concentration (ppm Unless Otherwise Specified), Rate of Concentration Change (ppb/year) and Atmospheric Lifetime (Years) of Selected Greenhouse Gases

Atmospheric Variable	CO_2	CH_4	N_2O	SF_6[a]	CF_4[a]
Pre-industrial atmospheric concentration	278	0.700	0.270	0	40
Atmospheric concentration (1998)	365	1.745	0.314	4.2	80
Rate of concentration change[b]	1.5[c]	0.007[c]	0.0008	0.24	1.0
Atmospheric Lifetime	50-200[d]	12[e]	114[e]	3,200	>50,000

Source: IPCC (2001)
[a] Concentrations in parts per trillion (ppt) and rate of concentration change in ppt/year.
[b] Rate is calculated over the period 1990 to 1999.
[c] Rate has fluctuated between 0.9 and 2.8 ppm per year for CO_2 and between 0 and 0.013 ppm per year for CH4 over the period 1990 to 1999.
[d] No single lifetime can be defined for CO_2 because of the different rates of uptake by different removal processes.
[e] This lifetime has been defined as an “adjustment time” that takes into account the indirect effect of the gas on its own residence time.

A brief description of each greenhouse gas, its sources, and its role in the atmosphere is given below. The following section then explains the concept of Global Warming Potentials (GWPs), which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H_2O). Overall, the most abundant and dominant greenhouse gas in the atmosphere is water vapor. Water vapor is neither long-lived nor well mixed in the atmosphere, varying spatially from 0 to 2 percent (IPCC 1996). In addition, atmospheric water can exist in several physical states including gaseous, liquid, and solid. Human activities are not believed to directly affect the average global concentration of water vapor; however, the radiative forcing produced by the increased concentrations of other greenhouse gases may indirectly affect the hydrologic cycle. A warmer atmosphere has an increased water holding capacity; yet, increased concentrations of water vapor affects the formation of clouds, which can both absorb and reflect solar and terrestrial radiation. Aircraft contrails, which consist of water vapor and other aircraft emittants, are similar to clouds in their radiative forcing effects (IPCC 1999).

Carbon Dioxide (CO_2). In nature, carbon is cycled between various atmospheric, oceanic, land biotic, marine biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. In the atmosphere, carbon predominantly exists in its oxidized form as CO_2. Atmospheric carbon dioxide is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. Carbon dioxide concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 367 ppmv in 1999, a 31 percent increase (IPCC 2001). The IPCC notes that "[t]his concentration has not been exceeded during the past 420,000 years, and likely not during the past 20 million years. The rate of increase over the past century is unprecedented, at least during the past 20,000 years." The IPCC definitively states that "the present atmospheric CO_2 increase is caused by anthropogenic emissions of CO_2" (IPCC 2001). Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of carbon dioxide.

In its second assessment, the IPCC also stated that "[t]he increased amount of carbon dioxide [in the atmosphere] is leading to climate change and will produce, on average, a global warming of the Earth's surface because of its enhanced greenhouse effect—although the magnitude and significance of the effects are not fully resolved" (IPCC 1996).

Methane (CH_4). Methane is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit CH_4, as does the decomposition of municipal solid wastes. Methane is also emitted during the production and distribution of natural gas and petroleum, and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of methane have increased by about 150 percent since pre-industrial times, although the rate of increase has been declining. The IPCC has estimated that slightly more than half of the current CH_4 flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use and waste disposal (IPCC 2001).

Methane is removed from the atmosphere by reacting with the hydroxyl radical (OH) and is ultimately converted to CO_2. Minor removal processes also include reaction with Cl in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of methane reduce the concentration of OH, a feedback which may increase methane's atmospheric lifetime (IPCC 2001).

Nitrous Oxide (N_2O). Anthropogenic sources of N_2O emissions include agricultural soils, especially the use of synthetic and manure fertilizers; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater treatment and waste combustion; and biomass burning. The atmospheric concentration of nitrous oxide (N_2O) has increased by 16 percent since 1750, from a pre industrial value of about 270 ppb to 314 ppb in 1998, a concentration that has not been exceeded during the last thousand years. Nitrous oxide is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere.

Ozone (O_3). Ozone is present in both the upper stratosphere, where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere, where it is the main component of anthropogenic photochemical "smog." During the last two decades, emissions of anthropogenic chlorine and bromine-containing halocarbons, such as chlorofluorocarbons (CFCs), have depleted stratospheric ozone concentrations. This loss of ozone in the stratosphere has resulted in negative radiative forcing, representing an indirect effect of anthropogenic emissions of chlorine and bromine compounds (IPCC 1996). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover, with detection of such recovery not expected to occur much before 2010 (IPCC 2001).

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the third largest increase in direct radiative forcing since the pre-industrial era, behind CO_2 and CH_4. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds mixing with nitrogen oxides (NO_x) in the presence of sunlight. Ozone, carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_2) and particulate matter are included in the category referred to as "criteria pollutants" in the United States under the Clean Air Act and its subsequent amendments. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable.

Halocarbons, Perfluorocarbons, and Sulfur Hexafluoride (SF_6). Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine—chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), methyl chloroform, and carbon tetrachloride—and bromine—halons, methyl bromide, and hydrobromofluorocarbons (HBFCs)—result in stratospheric ozone depletion and are therefore controlled under the Montreal Protocol on Substances that Deplete the Ozone Layer. Although CFCs and HCFCs include potent global warming gases, their net radiative forcing effect on the atmosphere is reduced because they cause stratospheric ozone depletion, which is itself an important greenhouse gas in addition to shielding the Earth from harmful levels of ultraviolet radiation. Under the Montreal Protocol, the United States phased out the production and importation of halons by 1994 and of CFCs by 1996. Under the Copenhagen Amendments to the Protocol, a cap was placed on the production and importation of HCFCs by non-Article 5 countries beginning in 1996, and then followed by a complete phase-out by the year 2030. The ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC.

Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. HFCs—primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process—currently have a small aggregate radiative forcing impact; however, it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2001). PFCs and SF_6 are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium casting. Currently, the radiative forcing impact of PFCs and SF_6 is also small; however, they have a significant growth rate, extremely long atmospheric lifetimes, and are strong absorbers of infrared radiation, and therefore have the potential to influence climate far into the future (IPCC 2001).

Carbon Monoxide (CO). Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH_4 and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH_4 and tropospheric ozone. Carbon monoxide is created when carbon-containing fuels are burned incompletely. Through natural processes in the atmosphere, it is eventually oxidized to CO_2. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides (NO_x). The primary climate change effects of nitrogen oxides (i.e., NO and NO_2) are indirect and result from their role in promoting the formation of ozone in the troposphere and, to a lesser degree, lower stratosphere, where it has positive radiative forcing effects. Additionally, NO_x emissions from aircraft are also likely to decrease methane concentrations, thus having a negative radiative forcing effect (IPCC 1999). Nitrogen oxides are created from lightning, soil microbial activity, biomass burning – both natural and anthropogenic fires – fuel combustion, and, in the stratosphere, from the photo-degradation of nitrous oxide (N_2O). Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Nonmethane volatile organic compounds include compounds such as propane, butane, and ethane. These compounds participate, along with NO_x, in the formation of tropospheric ozone and other photochemical oxidants. NMVOCs are emitted primarily from transportation and industrial processes, as well as biomass burning and non-industrial consumption of organic solvents. Concentrations of NMVOCs tend to be both short-lived in the atmosphere and spatially variable.

Aerosols. Aerosols are extremely small particles or liquid droplets found in the atmosphere. They can be produced by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. They affect radiative forcing in both direct and indirect ways: directly by scattering and absorbing solar and thermal infrared radiation; and indirectly by increasing droplet counts that modify the formation, precipitation efficiency, and radiative properties of clouds. Aerosols are removed from the atmosphere relatively rapidly by precipitation. Because aerosols generally have short atmospheric lifetimes, and have concentrations and compositions that vary regionally, spatially, and temporally, their contributions to radiative forcing are difficult to quantify (IPCC 2001).

The indirect radiative forcing from aerosols is typically divided into two effects. The first effect involves decreased droplet size and increased droplet concentration resulting from an increase in airborne aerosols. The second effect involves an increase in the water content and lifetime of clouds due to the effect of reduced droplet size on precipitation efficiency (IPCC 2001). Recent research has placed a greater focus on the second indirect radiative forcing effect of aerosols.

Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulphates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning.

The net effect of aerosols is believed to produce a negative radiative forcing effect (i.e., net cooling effect on the climate), although because they are short-lived in the atmosphere—lasting days to weeks—their concentrations respond rapidly to changes in emissions. Locally, the negative radiative forcing effects of aerosols can offset the positive forcing of greenhouse gases (IPCC 1996). "However, the aerosol effects do not cancel the global-scale effects of the much longer-lived greenhouse gases, and significant climate changes can still result" (IPCC 1996).

The IPCC's Third Assessment Report notes that "the indirect radiative effect of aerosols is now understood to also encompass effects on ice and mixed-phase clouds, but the magnitude of any such indirect effect is not known, although it is likely to be positive" (IPCC 2001). Additionally, current research suggests that another constituent of aerosols, elemental carbon, may have a positive radiative forcing (Jacobson 2001). The primary anthropogenic emission sources of elemental carbon include diesel exhaust, coal combustion, and biomass burning.

Global Warming Potentials

Global Warming Potentials (GWPs) are intended as a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas. It is defined as the cumulative radiative forcing—both direct and indirect effects—integrated over a period of time from the emission of a unit mass of gas relative to some reference gas (IPCC 1996). Carbon dioxide (CO_2) was chosen as this reference gas. Direct effects occur when the gas itself is a greenhouse gas. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The relationship between gigagrams (Gg) of a gas and Tg CO_2 Eq. can be expressed as follows:

$$\text{Tg CO}_2\text{ Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1{,}000\text{ Gg}}\right) \text{where,}$$

Tg CO_2 Eq. = Teragrams of Carbon Dioxide Equivalents
Gg = Gigagrams (equivalent to a thousand metric tons)
GWP = Global Warming Potential
Tg = Teragrams

GWP values allow policy makers to compare the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of roughly ±35 percent, though some GWPs have larger uncertainty than others, especially those in which lifetimes have not yet been ascertained. In the following decision, the parties to the UNFCCC have agreed to use consistent GWPs from the IPCC Second Assessment Report (SAR), based upon a 100 year time horizon, although other time horizon values are available (see Table 11).

> *In addition to communicating emissions in units of mass, Parties may choose also to use global warming potentials (GWPs) to reflect their inventories and projections in carbon dioxide-equivalent terms, using information provided by the Intergovernmental Panel on Climate Change (IPCC) in its Second Assessment Report. Any use of GWPs should be based on the effects of the greenhouse gases over a 100-year time horizon. In addition, Parties may also use other time horizons. (FCCC/CP/1996/15/Add.1)*

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. The short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, other ambient air pollutants (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and black carbon), however, vary spatially, and consequently it is difficult to quantify their global radiative forcing impacts. GWP values are generally not attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table 11. Global Warming Potentials (GWP) and Atmospheric Lifetimes (Years) Used in the Inventory

Gas	Atmospheric Lifetime	100-year GWP[a]	20-year GWP	500-year GWP
Carbon dioxide (CO_2)	50-200	1	1	1
Methane (CH_4)[b]	12±3	21	56	6.5
Nitrous oxide (N_2O)	120	310	280	170
HFC-23	264	11,700	9,100	9,800
HFC-125	32.6	2,800	4,600	920
HFC-134a	14.6	1,300	3,400	420
HFC-143a	48.3	3,800	5,000	1,400
HFC-152a	1.5	140	460	42
HFC-227ea	36.5	2,900	4,300	950
HFC-236fa	209	6,300	5,100	4,700
HFC-4310mee	17.1	1,300	3,000	400
CF_4	50,000	6,500	4,400	10,000
C_2F_6	10,000	9,200	6,200	14,000
C_4F_{10}	2,600	7,000	4,800	10,100
C_6F_{14}	3,200	7,400	5,000	10,700
SF_6	3,200	23,900	16,300	34,900

Source: IPCC (1996). Note: More recent GWPs from the IPCC (2001) can be found at http://www.eia.doe.gov/oiaf/1605/gwp.html.
[a] GWPs used here are calculated over 100 year time horizon
[b] The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Table 12 presents direct and net (i.e., direct and indirect) GWPs for ozone-depleting substances (ODSs). Ozone-depleting substances directly absorb infrared radiation and contribute to positive radiative forcing; however, their effect as ozone-depleters also leads to a negative radiative forcing because ozone itself is a potent greenhouse gas. There is considerable uncertainty regarding this indirect effect; therefore, a range of net GWPs is provided for ozone depleting substances.

Table 12. Net 100-year Global Warming Potentials for Select Ozone Depleting Substances*

Gas	Direct	Net_{min}	Net_{max}
CFC-11	4,600	(600)	3,600
CFC-12	10,600	7,300	9,900
CFC-113	6,000	2,200	5,200
HCFC-22	1,700	1,400	1,700
HCFC-123	120	20	100
HCFC-124	620	480	590
HCFC-141b	700	(5)	570
HCFC-142b	2,400	1,900	2,300
$CHCl_3$	140	(560)	0
CCl_4	1,800	(3,900)	660
CH_3Br	5	(2,600)	(500)
Halon-1211	1,300	(24,000)	(3,600)
Halon-1301	6,900	(76,000)	(9,300)

Source: IPCC (2001)

* Because these compounds have been shown to deplete stratospheric ozone, they are typically referred to as ozone depleting substances (ODSs). However, they are also potent greenhouse gases. Recognizing the harmful effects of these compounds on the ozone layer, in 1987 many governments signed the *Montreal Protocol on Substances that Deplete the Ozone Layer* to limit the production and importation of a number of CFCs and other halogenated compounds. The United States furthered its commitment to phase-out ODSs by signing and ratifying the Copenhagen Amendments to the *Montreal Protocol* in 1992. Under these amendments, the United States committed to ending the production and importation of halons by 1994, and CFCs by 1996. The IPCC Guidelines and the UNFCCC do not include reporting instructions for estimating emissions of ODSs because their use is being phased-out under the *Montreal Protocol*. The effects of these compounds on radiative forcing are not addressed here.

The IPCC recently published its Third Assessment Report (TAR), providing the most current and comprehensive scientific assessment of climate change (IPCC 2001). Within that report, the GWPs of several gases were revised relative to the IPCC's Second Assessment Report (SAR) (IPCC 1996), and new GWPs have been calculated for an expanded set of gases. Since the SAR, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2 response function (presented in WMO 1999). The GWPs are drawn from WMO (1999) and the SAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated. Because the revised radiative forcing of CO_2 is about 12 percent lower than that in the SAR, the GWPs of the other gases relative to CO_2 tend to be larger, taking into account revisions in lifetimes. However, there were some instances in which other variables, such as the radiative efficiency or the chemical lifetime, were altered that resulted in further increases or decreases in particular GWP values. In addition, the values for radiative forcing and lifetimes have been calculated for a variety of halocarbons, which were not presented in the SAR. The changes are described in the TAR as follows:

New categories of gases include fluorinated organic molecules, many of which are ethers that are proposed as halocarbon substitutes. Some of the GWPs have larger uncertainties than that of others, particularly for those gases where detailed laboratory data on lifetimes are not yet available. The direct GWPs have been calculated relative to CO_2 using an improved calculation of the CO_2 radiative forcing, the SAR response function for a CO_2 pulse, and new values for the radiative forcing and lifetimes for a number of halocarbons.

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