Final Utah Greenhouse Gas Inventory and Reference Case Projections, 1990-2020

Center for Climate Strategies
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Executive Summary

The Center for Climate Strategies (CCS) prepared this report for the Utah Department of Environmental Quality (UDEQ) under an agreement with the Western Governors' Association. The report contains an inventory and forecast of the State's greenhouse gas (GHG) emissions from 1990 to 2020.

Utah's anthropogenic GHG emissions and sinks (carbon storage) were estimated for the period from 1990 to 2020. Historical GHG emission estimates (1990 through 2005, or most recent historical year) were developed using a set of generally-accepted principles and guidelines for state GHG emission estimates, with adjustments by CCS to provide Utah-specific data and inputs when it was possible to do so. The initial reference case emission projections (2006-2020) 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 historical (1990, 2000 and 2005) and reference case projection (2010 and 2020) GHG emissions for Utah. Activities in Utah accounted for approximately 69 million metric tons (MMt) of *gross*[1] carbon dioxide equivalent (CO_2e) emissions in 2005, an amount equal to about 1% of total U.S. gross GHG emissions. Utah's gross GHG emissions are rising at a faster rate than those of the nation as a whole (gross emissions exclude carbon sinks, such as forests). Utah's gross GHG emissions increased 40% from 1990 to 2005, while national emissions rose by only 16% during this period.

Figure ES-1 illustrates the State's emissions per capita and per unit of economic output. On a per capita basis, Utahans emit about 27 metric tons (Mt) of CO_2e annually, slightly higher than the national average of 25 $MtCO_2e$/yr. As in the nation as a whole, per capita emissions in Utah have changed relatively little (with a slight decrease in the post-2000 period), while economic growth exceeded emissions growth throughout the 1990-2005 period (leading to declining estimates of GHG emissions per unit of state product). During the 1990s, emissions per unit of gross product dropped by 40% nationally, and by 52% in Utah.

The principal source of Utah's GHG emissions is electricity use (electricity production netting out electricity exports), accounting for 37% of total State gross GHG emissions in 2005 (see Table ES-1). The next largest contributors to total gross GHG emissions are the transportation sector (25%) and the residential, commercial, and industrial fossil fuel combustion sector (18%).

As illustrated in Figure ES-2 and shown numerically in Table ES-1, under the reference case projections, Utah's gross GHG emissions continue to grow, and are projected to climb to 96.1 $MMtCO_2e$ per year by 2020, 95% above 1990 levels. As shown in Figure ES-3, emissions associated with electricity generated to meet Utah's demands is projected to be the largest contributor to future emissions growth, followed by emissions from the transportation sector. The figure shows that electricity generation will add more than 10 $MMtCO_2e$ to Utah's emissions by 2020, while the transportation sector will add almost 6 $MMtCO_2e$.

[1] Excluding GHG emissions removed due to forestry and other land uses and excluding GHG emissions associated with exported electricity.

Some data gaps exist in this analysis, particularly for the reference case projections. Key tasks include review and revision of key emissions drivers (such as electricity, fossil fuel production, and transportation fuel use growth rates) that will be major determinants of Utah's future GHG emissions. We expect that Utah's ongoing climate change action planning process will shed light on these issues.

Estimates of carbon sinks within Utah's forests and agricultural soils have also been included in this report. For forests, the current estimates are based on data from the U.S Forest Service and indicate that about 38 $MMtCO_2e$ are sequestered annually in Utah forest biomass. As described in Appendix H however, there is a significant degree of uncertainty in the size of the forest sink in Utah. The estimates presented here are believed to be at the high end of the possible range of sequestration estimates.

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 Utah based on 2002 and 2018 data from the WRAP. Estimated BC emissions for the year 2002 were a total of 4.9 $MMtCO_2e$, which is the mid-point of a range of estimated emissions (3.1 – 6.6 $MMtCO_2e$). Based on an assessment of the primary contributors, it is estimated that BC emissions will decrease substantially by 2018 after new engine and fuel standards take effect in the onroad and nonroad diesel engine sectors. 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 below because a global warming potential for BC has not yet been assigned by the Intergovernmental Panel on Climate Change (IPCC).

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

(Million Metric Tons CO_2e)	1990	2000	2005	2010	2020	Explanatory Notes for Projections
Electricity Production	**15.3**	**22.5**	**25.6**	**27.6**	**36.6**	
Coal	28.8	31.7	33.6	33.6	39.7	See electric sector assumptions in Appendix A
Natural Gas	0.05	0.6	0.4	2.3	3.1	
Oil	0.04	0.04	0.02	0.02	0.03	
Net Exported Electricity	-13.6	-9.9	-8.4	-8.4	-6.3	
Res/Comm/Non-Fossil Ind (RCI)	**14.1**	**15.7**	**12.2**	**13.7**	**16.3**	
Coal	5.1	5.1	1.4	1.5	1.6	Based on USDOE regional projections
Natural Gas	6.5	8.3	7.7	8.7	10.7	Based on USDOE regional projections
Oil	2.4	2.3	3.0	3.4	4.0	Based on USDOE regional projections
Wood (CH_4 and N_2O)	0.02	0.03	0.02	0.02	0.02	Based on USDOE regional projections
Transportation	**10.9**	**16.1**	**16.9**	**18.4**	**22.4**	
Motor Gasoline	6.5	9.1	9.4	9.8	12.0	VMT projections from UDOT
Diesel	2.1	3.5	4.3	5.2	7.1	VMT projections from UDOT
Natural Gas, LPG, other	0.1	0.3	0.4	0.5	0.7	Projected based on historical data
Jet Fuel and Aviation Gas	2.2	3.1	2.9	2.9	3.0	Aircraft operations projections from FAA
Fossil Fuel Industry	**2.5**	**3.1**	**4.1**	**4.4**	**4.6**	
Natural Gas Industry	0.8	1.8	1.9	2.1	2.4	Historical trends and USDOE regional projections
Oil Industry	0.2	0.1	0.1	0.1	0.1	
Coal Mining (Methane)	1.4	1.1	2.1	2.1	2.1	Held flat at 2004 levels
Industrial Processes	**2.2**	**2.8**	**3.7**	**4.3**	**5.8**	
Cement Manufacture	0.5	0.8	0.9	0.9	1.1	Utah manufacturing employment growth
Lime Manufacture	0.3	0.5	0.6	0.7	0.8	Utah manufacturing employment growth
Limestone and Dolomite Use	0.04	0.1	0.1	0.1	0.1	Utah manufacturing employment growth
Nitric Acid Production	0.2	0.1	0.1	0.1	0.1	Utah manufacturing employment growth
ODS Substitutes	0.002	0.6	1.1	1.6	2.7	EPA 2004 ODS cost study report
Semiconductor Manufacture	0.002	0.005	0.003	0.002	0.001	Based on national projections (USEPA)
Magnesium Production	1.0	0.7	0.9	0.9	1.1	Utah manufacturing employment growth
SF_6 from Electric Utilities	0.2	0.1	0.1	0.1	0.04	Based on national projections (USEPA)
Waste Management	**1.1**	**1.7**	**2.0**	**2.7**	**4.7**	
Solid Waste Management	0.9	1.4	1.7	2.3	4.2	Projected based on 1996-2005 trend
Wastewater Management	0.2	0.3	0.3	0.4	0.5	Projected based on population
Agriculture	**3.1**	**4.0**	**4.2**	**4.6**	**5.8**	
Manure Management	1.2	1.4	1.5	1.6	1.9	USDA livestock projections
Enteric Fermentation	0.3	0.6	0.7	0.9	1.5	USDA livestock projections
Agricultural Soils	1.6	1.8	1.7	1.8	1.9	Projected based on historical trend
Agricultural Residue Burning	0.001	0.001	0.001	0.001	0.001	No growth assumed
Total Gross Emissions	**49.3**	**65.9**	**68.8**	**75.7**	**96.1**	
increase relative to 1990		*34%*	*40%*	*54%*	*95%*	
Forestry and Land Use	**-37.8**	**-37.8**	**-37.8**	**-37.8**	**-37.8**	Historical and projected emissions held at 2004 level
Agricultural Soils	**-0.7**	**-0.7**	**-0.7**	**-0.7**	**-0.7**	Historical and projected emissions held at 1997 level
Net Emissions (incl. forestry*)	**11.5**	**28.1**	**31.0**	**37.9**	**58.3**	
increase relative to 1990		*146%*	*171%*	*231%*	*409%*	

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

Figure ES-1. Historical Utah and U.S. GHG Emissions, Per Capita and Per Unit Gross Product, 1990-2005

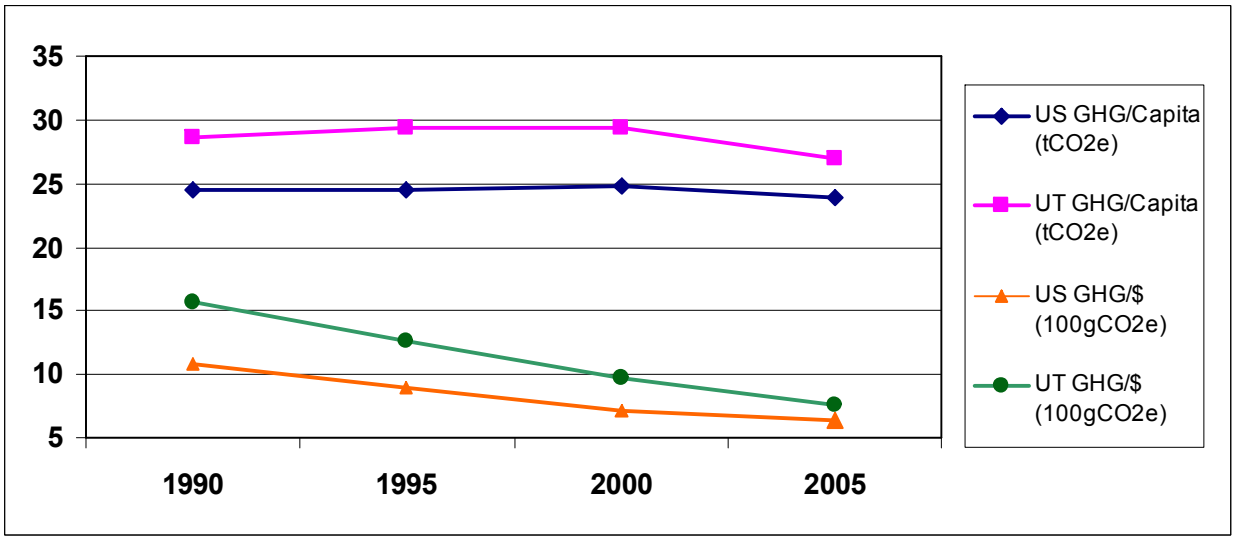


Figure ES-2. Utah Gross GHG Emissions by Sector, 1990-2020: Historical and Projected

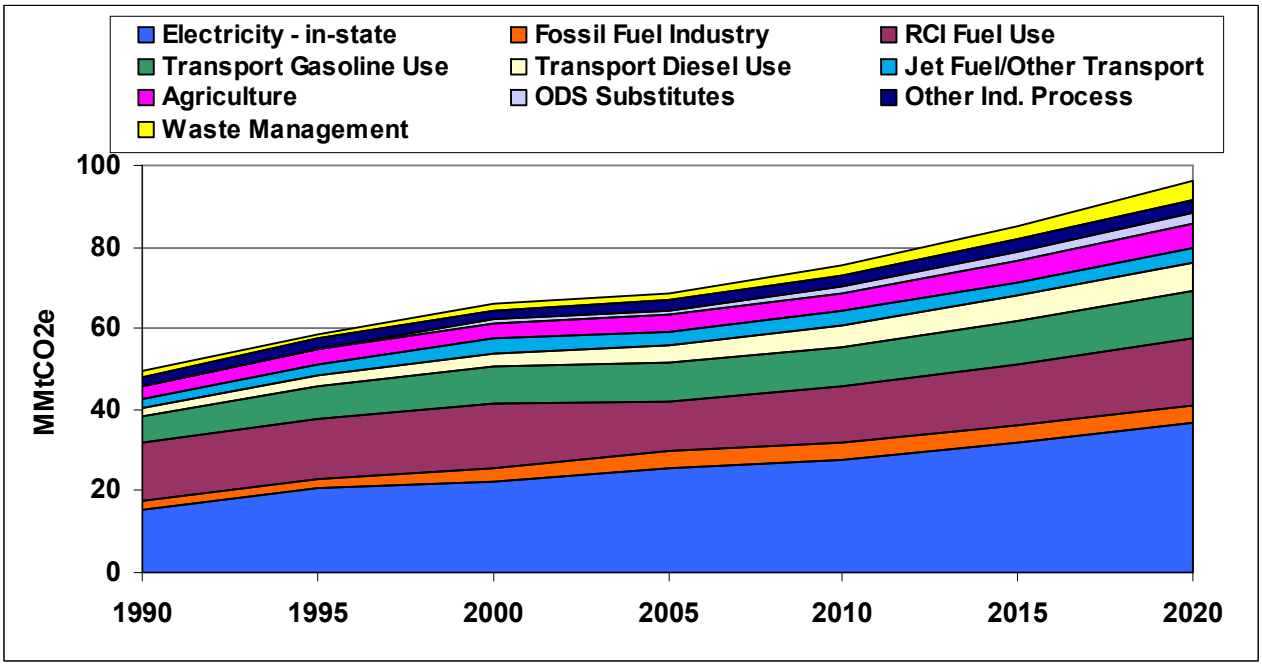
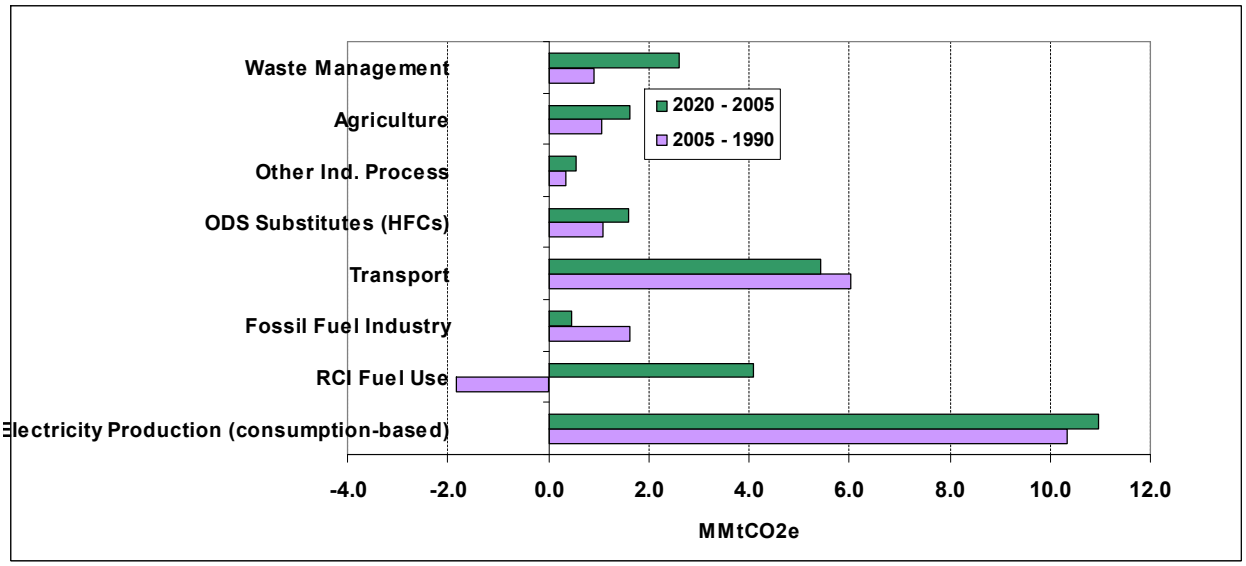


Figure ES-3. Sector Contributions to Emissions Growth in Utah, 1990-2020: Reference Case Projections



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Acronyms and Key Terms

AEO – *Annual Energy Outlook, EIA*

Ag – Agriculture

bbls – Barrels

BC – Black Carbon

Bcf – Billion Cubic Feet

BLM – United States Bureau of Land Management

BOC – Bureau of Census

BTU – British Thermal Unit

C – Carbon

$CaCO_3$ – Calcium Carbonate

CBM – Coal Bed Methane

CCS – Center for Climate Strategies

CFCs – Chlorofluorocarbons

CH_4 – Methane*

CO_2 – Carbon Dioxide*

CO_2e – Carbon Dioxide Equivalent*

CRP – Federal Conservation Reserve Program

EC – Elemental Carbon

eGRID – U.S. EPA's Emissions & Generation Resource Integrated Database

EIA – U.S. DOE Energy Information Administration

EIIP – Emissions Inventory Improvement Project (US EPA)

FIA – Forest Inventory Analysis

GHG – Greenhouse Gases*

GSP – Gross State Product

GWh – Gigawatt-hour

GWP - Global Warming Potential*

HFCs – Hydrofluorocarbons*

HNO_3 – Nitric Acid

HWP – Harvested Wood Products

IPCC – Intergovernmental Panel on Climate Change*

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

Mg – Megagrams (equivalent to one metric ton)

Mt - Metric Ton (equivalent to 1.102 short tons)

MMt – Million Metric Tons

MPO – Metropolitan Planning Organization

MSW – Municipal Solid Waste

MW – Megawatt

N – Nitrogen

N_2O – Nitrous Oxide*

NO_2 – Nitrogen Dioxide*

NAICS – North American Industry Classification System

NASS – National Agricultural Statistics Service

NO_x – Nitrogen Oxides

NSCR – Non-selective Catalytic Reduction

ODS – Ozone-Depleting Substances

OM – Organic Matter

PADD – Petroleum Administration for Defense Districts

PFCs – Perfluorocarbons*

PM – Particulate Matter

ppb – parts per billion

ppm – parts per million

ppt – parts per trillion

PSCo – Public Service Company of Utah

PV – Photovoltaic

RCI – Residential, Commercial, and Industrial

RPA – Resources Planning Act Assessment

RPS – Renewable Portfolio Standard

SAR – Second Assessment Report

SCR- Selective Catalytic Reduction

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.

TAR – Third Assessment Report

T&D – Transmission and Distribution

TWh – Terawatt-hours

UDOT – Utah Department of Transportation

UGS – Utah Geological Survey

UNFCCC – United Nations Framework Convention on Climate Change

U.S. EPA – United States Environmental Protection Agency

U.S. DOE – United States Department of Energy

USDA – United States Department of Agriculture

USFS – United States Forest Service

USGS – United States Geological Survey

UDEQ – Utah Department of Environmental Quality

UT - Utah

VMT – Vehicle-Miles Traveled

WAPA – Western Area Power Administration

WECC – Western Electricity Coordinating Council

W/m^2 – Watts per Square Meter

WMO – World Meteorological Organization*

WRAP – Western Regional Air Partnership

* - See Appendix J for more information.

Acknowledgements

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1.0 Introduction

The Center for Climate Strategies (CCS) prepared this report for the Utah Department of Environmental Quality (UDEQ) under an agreement with the Western Governors' Association. This report presents initial estimates of base year and projected Utah anthropogenic greenhouse gas (GHG) emissions and sinks for the period from 1990 to 2020. These estimates are intended to assist the State with an initial, comprehensive understanding of current and possible future GHG emissions for Utah, and, thereby, to inform future 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 Section 2, relying to the extent possible on Utah-specific data and inputs. The initial reference case projections (2006-2020) 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.

This report covers the six types of gases included in the U.S. 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-) weighted basis. The final appendix to this report provides a more complete discussion of GHGs and GWPs. Emissions of black carbon were also estimated. Black carbon (BC) is an aerosol species with a positive climate forcing potential (that is, the potential to warm the atmosphere, as GHGs do); however, black carbon currently does not have a GWP defined by the IPCC due to uncertainties in both the direct and indirect effects of BC on atmospheric processes (see Appendices I and J for more details).

It is important to note that the preliminary emission estimates reflect the *GHG emissions associated with the electricity sources used to meet Utah'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.* For many years, Utah power plants have tended to produce more electricity than is consumed in the State; emissions associated with exported electricity are excluded from the consumption-based emissions. This report covers both methods of accounting for emissions, but for consistency, all total results are reported as *consumption-based.*

[2] The last year of available historical data varies by sector; ranging from 2000 to 2005.

2.0 Utah Greenhouse Gas Emissions: Sources and Trends

Table 1 provides a summary of GHG emissions estimated for Utah by sector for the years 1990, 2000, 2005, 2010, and 2020. In the sections below, we discuss GHG emission sources (positive, or *gross*, emissions) and sinks (negative emissions) separately in order to identify trends, projections and uncertainties for each.

This next section of the report provides a summary of the historical emissions (1990 through 2005) followed by a summary of the forecasted reference-case projection-year emissions (2006 through 2020), key uncertainties, and suggested next steps. CCS also provides an overview of the general methodology, principles, and guidelines followed for preparing the inventories. Appendices A through H provide the detailed methods, data sources, and assumptions for each GHG sector.

Appendix I provides information on 2002 and 2018 BC estimates for Utah. CCS estimated that BC emissions in 2002 ranged from 3.1 – 6.6 $MMtCO_2e$ with a mid-point of 4.9 $MMtCO_2e$. 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 carbon dioxide equivalents (see Appendix I for more details). Since the IPCC has not yet assigned a global warming potential for BC, CCS has excluded these estimates from the GHG summary shown in Table 1 below. Based on an assessment of 2018 forecasted emissions for the primary BC contributors from the Western Regional Air Partnership (WRAP), it is estimated that BC emissions will decrease significantly by 2018 after new engine and fuel standards take effect in the onroad and nonroad diesel engine sectors. About 3.7 $MMtCO_2e$ was estimated for 2002 BC emissions. Emissions are expected to decrease to 0.9 $MMtCO_2e$ by 2018. Appendix I contains a detailed breakdown of emissions contribution by source sector.

Appendix J provides background information on GHGs and climate-forcing aerosols.

Table 1. Utah Historical and Reference Case GHG Emissions, by Sector[a]

(Million Metric Tons CO_2e)	1990	2000	2005	2010	2020	Explanatory Notes for Projections
Electricity Production	**15.3**	**22.5**	**25.6**	**27.6**	**36.6**	
Coal	28.8	31.7	33.6	33.6	39.7	See electric sector assumptions in Appendix A
Natural Gas	0.05	0.6	0.4	2.3	3.1	
Oil	0.04	0.04	0.02	0.02	0.03	
Net Exported Electricity	-13.6	-9.9	-8.4	-8.4	-6.3	
Res/Comm/Non-Fossil Ind (RCI)	**14.1**	**15.7**	**12.2**	**13.7**	**16.3**	
Coal	5.1	5.1	1.4	1.5	1.6	Based on USDOE regional projections
Natural Gas	6.5	8.3	7.7	8.7	10.7	Based on USDOE regional projections
Oil	2.4	2.3	3.0	3.4	4.0	Based on USDOE regional projections
Wood (CH_4 and N_2O)	0.02	0.03	0.02	0.02	0.02	Based on USDOE regional projections
Transportation	**10.9**	**16.1**	**16.9**	**18.4**	**22.4**	
Motor Gasoline	6.5	9.1	9.4	9.8	12.0	VMT projections from UDOT
Diesel	2.1	3.5	4.3	5.2	7.1	VMT projections from UDOT
Natural Gas, LPG, other	0.1	0.3	0.4	0.5	0.7	Projected based on historical data
Jet Fuel and Aviation Gas	2.2	3.1	2.9	2.9	3.0	Aircraft operations projections from FAA
Fossil Fuel Industry	**2.5**	**3.1**	**4.1**	**4.4**	**4.6**	
Natural Gas Industry	0.8	1.8	1.9	2.1	2.4	Historical trends and USDOE regional projections
Oil Industry	0.2	0.1	0.1	0.1	0.1	
Coal Mining (Methane)	1.4	1.1	2.1	2.1	2.1	Held flat at 2004 levels
Industrial Processes	**2.2**	**2.8**	**3.7**	**4.3**	**5.8**	
Cement Manufacture	0.5	0.8	0.9	0.9	1.1	Utah manufacturing employment growth
Lime Manufacture	0.3	0.5	0.6	0.7	0.8	Utah manufacturing employment growth
Limestone and Dolomite Use	0.04	0.1	0.1	0.1	0.1	Utah manufacturing employment growth
Nitric Acid Production	0.2	0.1	0.1	0.1	0.1	Utah manufacturing employment growth
ODS Substitutes	0.002	0.6	1.1	1.6	2.7	EPA 2004 ODS cost study report
Semiconductor Manufacture	0.002	0.005	0.003	0.002	0.001	Based on national projections (USEPA)
Magnesium Production	1.0	0.7	0.9	0.9	1.1	Utah manufacturing employment growth
SF_6 from Electric Utilities	0.2	0.1	0.1	0.1	0.04	Based on national projections (USEPA)
Waste Management	**1.1**	**1.7**	**2.0**	**2.7**	**4.7**	
Solid Waste Management	0.9	1.4	1.7	2.3	4.2	Projected based on 1996-2005 trend
Wastewater Management	0.2	0.3	0.3	0.4	0.5	Projected based on population
Agriculture	**3.1**	**4.0**	**4.2**	**4.6**	**5.8**	
Manure Management	1.2	1.4	1.5	1.6	1.9	USDA livestock projections
Enteric Fermentation	0.3	0.6	0.7	0.9	1.5	USDA livestock projections
Agricultural Soils	1.6	1.8	1.7	1.8	1.9	Projected based on historical trend
Agricultural Residue Burning	0.001	0.001	0.001	0.001	0.001	No growth assumed
Total Gross Emissions	**49.3**	**65.9**	**68.8**	**75.7**	**96.1**	
increase relative to 1990		*34%*	*40%*	*54%*	*95%*	
Forestry and Land Use	**-37.8**	**-37.8**	**-37.8**	**-37.8**	**-37.8**	Historical and projected emissions held at 2004 level
Agricultural Soils	**-0.7**	**-0.7**	**-0.7**	**-0.7**	**-0.7**	Historical and projected emissions held at 1997 level
Net Emissions (incl. forestry*)	**11.5**	**28.1**	**31.0**	**37.9**	**58.3**	
increase relative to 1990		*146%*	*171%*	*231%*	*409%*	

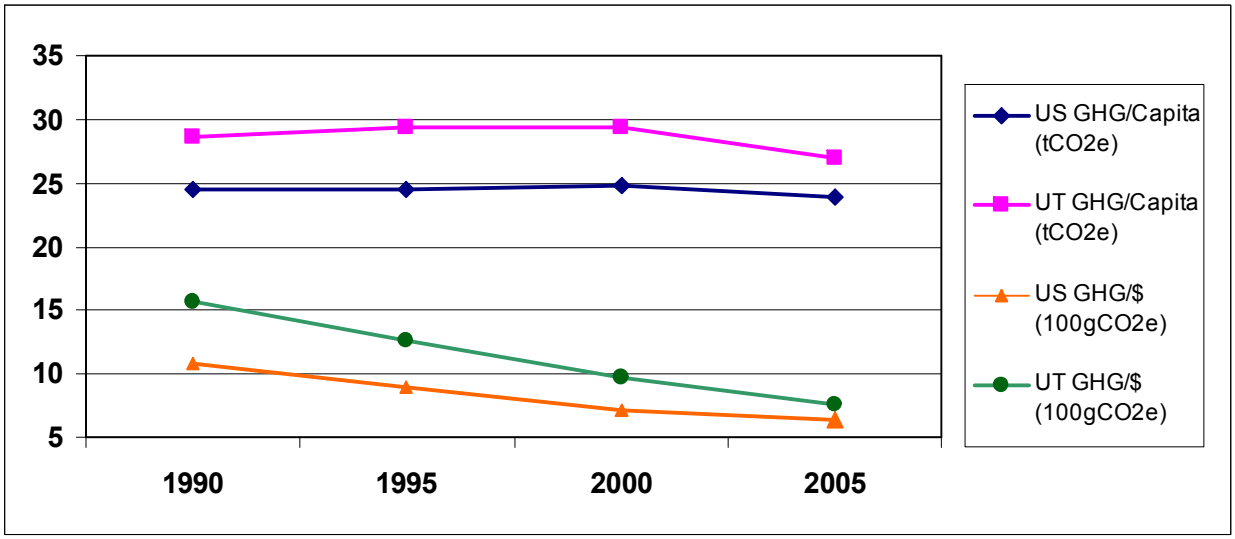
[a] Totals may not equal exact sum of subtotals shown in this table due to independent rounding. NA = not available.

2.1 Historical Emissions

Our analyses suggest that in 2005, activities in Utah accounted for approximately 68.8 million metric tons (MMt) of *gross*[3] CO_2e emissions, an amount equal to 1% of total U.S. gross GHG emissions. Utah's gross GHG emissions are rising at a faster rate than those of the nation as a whole (gross emissions exclude carbon sinks, such as forests). Utah's gross GHG emissions increased by about 40% from 1990 to 2005, while national emissions rose by 16% during the same period.

On a per capita basis, Utahns emitted about 27 metric tons (Mt) of CO_2e in 2005, slightly higher than the national average of 25 $MtCO_2e$/yr. Figure 1 illustrates the State's emissions per capita and per unit of economic output. Unlike the nation as a whole, where per capita emissions have changed relatively little, per capita emissions have dropped slightly. The figure also shows that economic growth has exceeded emissions growth in Utah throughout the 1990-2005 timeframe. From 1990 to 2005, emissions per unit of gross product dropped by 40% nationally and by 52% in Utah.

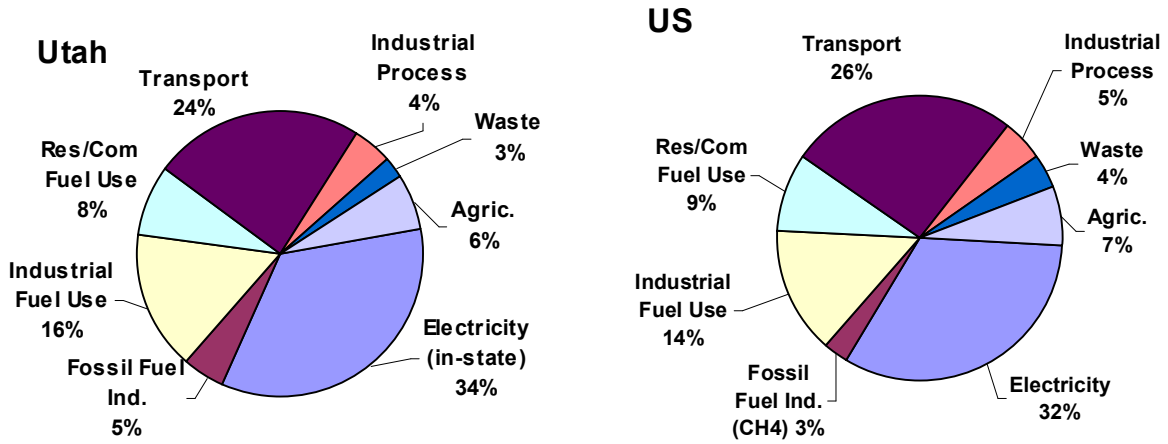
Figure 1. Utah and US Gross GHG Emissions, Per Capita and Per Unit Gross Product, 1990-2005



[3] Excluding GHG emissions removed due to forestry and other land uses and excluding GHG emissions associated with exported electricity.

Electricity use, transportation and residential/commercial/industrial (RCI) fossil fuel combustion are the State's principal GHG emissions sources. The combustion of fossil fuels for electricity generation used in-state and for transportation accounted for 61% of Utah's *gross* GHG emissions in 2005, as shown in Table 1. A comparison of Utah and U.S. emissions for 2000 is shown in Figure 2 below, which shows a 58% contribution from these two sectors. The remaining use of fossil fuels – natural gas, oil products, and coal – in the transportation and the residential, commercial, and industrial (RCI) sector, plus the emissions from fossil fuel production, constituted another 29% of total State emissions. The large drop in industrial coal combustion emissions shown in Table 1 between 2000 and 2005 is due to the shut down of the Geneva Steel plant in 2002 (see Appendix B).

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



Agriculture (CH_4 and N_2O emissions from manure management, fertilizer use, crops, livestock, and agricultural burning) accounted for 6%, and landfills and wastewater management facilities produce CH_4 and N_2O emissions accounting for 3% of the State's emissions in 2000. Industrial process emissions comprised the remaining 4% of State GHG emissions in 2000, but these emissions are rising in part due to the increasing use of HFC as substitutes for ozone-depleting chlorofluorocarbons.[4] Other industrial process emissions result from CO_2 released during soda ash, limestone, and dolomite use.

Forestry and agricultural soils in Utah are estimated to result in an annual net sink of over 38 $MMtCO_2e$ in 2005. As described in Appendix H, the forestry sink estimates should be considered conservatively high for UT.

[4] Chlorofluorocarbons (CFCs) are also potent GHGs; they are not, however, included in GHG estimates because of concerns related to implementation of the Montreal Protocol. See final Appendix (Appendix I).

The 1990 historical emission estimates are comparable to estimates previously prepared by UDEQ.[5] In the UDEQ study, the total 1990 gross emissions estimate was about 64 $MMtCO_2e$ compared to the estimate provided in Table 1 of 63 $MMtCO_2e$. Note that the emissions for electricity exports (13.6 $MMtCO_2e$) need to be added to the gross emissions total to make this comparison.

Figure 3 shows the historical and forecasted emissions for all sectors and all pollutants in CO_2e. The two largest contributing sectors to emissions growth are electricity consumption and transportation emissions. This is shown graphically in Figure 4, which shows that the electricity consumption sector will add over 10 $MMtCO_2e$/yr to Utah's emissions by 2020, while the transportation sector will add almost 6 $MMtCO_2e$/yr. This figure also shows that these two sectors have been the strongest contributors to historic emissions growth since 1990.

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

As shown in Table 1, electricity use accounted for about 37% of Utah's gross GHG emissions in 2005 (25.6 $MMtCO_2e$), which was slightly higher than the national share of emissions from electricity production (32%).[6] In total (across the residential, commercial and industrial sectors), Utah has a lower per capita use of electricity than the U.S. as a whole (10,000 kWh per person per year compared to 12,000 kWh/person-yr nationally), which means that the carbon content of electricity consumed in the state is higher than the U.S. as a whole.

It is important to note that these preliminary electricity emissions estimates reflect the *GHG emissions associated with the electricity sources used to meet Utah demands,* corresponding to a *consumption-based* approach to emissions accounting (see Section 4 Approach). Another way to look at electricity emissions is to consider the *GHG emissions produced by electricity generation facilities in the State.* Utah power plants produce more electricity than is consumed in the State – in the year 2000, for example, Utah exported 28% of the electricity produced in the State. As a result, in 2000, emissions associated with electricity consumption (22.5 $MMtCO_2e$) were much lower than those associated with electricity production (32.4 $MMtCO_2e$).[7]

While CCS estimated emissions associated with both electricity production and consumption, unless otherwise indicated, tables, figures, and totals in this report reflect electricity consumption-based 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

[5] *Utah Greenhouse Gas Inventory, 1990 and 1993*, UDEQ and the UT Department of Natural Resources, Office of Energy and Resource Planning, 1996.
[6] Unlike for Utah, for the U.S. as a whole, there is relatively little difference between the emissions from electricity use and emissions from electricity production, as the U.S. imports only about 1% of its electricity, and exports far less.
[7] 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.

would need to be covered in those States' accounts in order to avoid double-counting or exclusions. Arizona, California, Oregon, New Mexico, and Washington are currently considering such an approach. Data to account for the electricity imported into Utah were not factored into the analysis conducted for this report.

Like electricity emissions, GHG emissions from transportation fuel use have risen steadily since 1990 at an average rate of slightly over 3% annually. Gasoline-powered vehicles accounted for about 55% of transportation GHG emissions in 2005. Diesel vehicles accounted for another 25% of emissions and air travel for roughly 17%. Marine gasoline, locomotives, and other sources [natural gas and liquefied petroleum gas (LPG) vehicles and lubricants] accounted for the remaining 3% of transportation emissions. As the result of Utah's population and economic expansion and an increase in total vehicle miles traveled during the 1990s, onroad gasoline use grew by 45% between 1990 and 2005. Meanwhile, onroad diesel use more than doubled during this period, suggesting an even more rapid growth in freight movement within the State. Aviation fuel use grew by 32% from 1990-2005.

2.3 Reference Case Projections

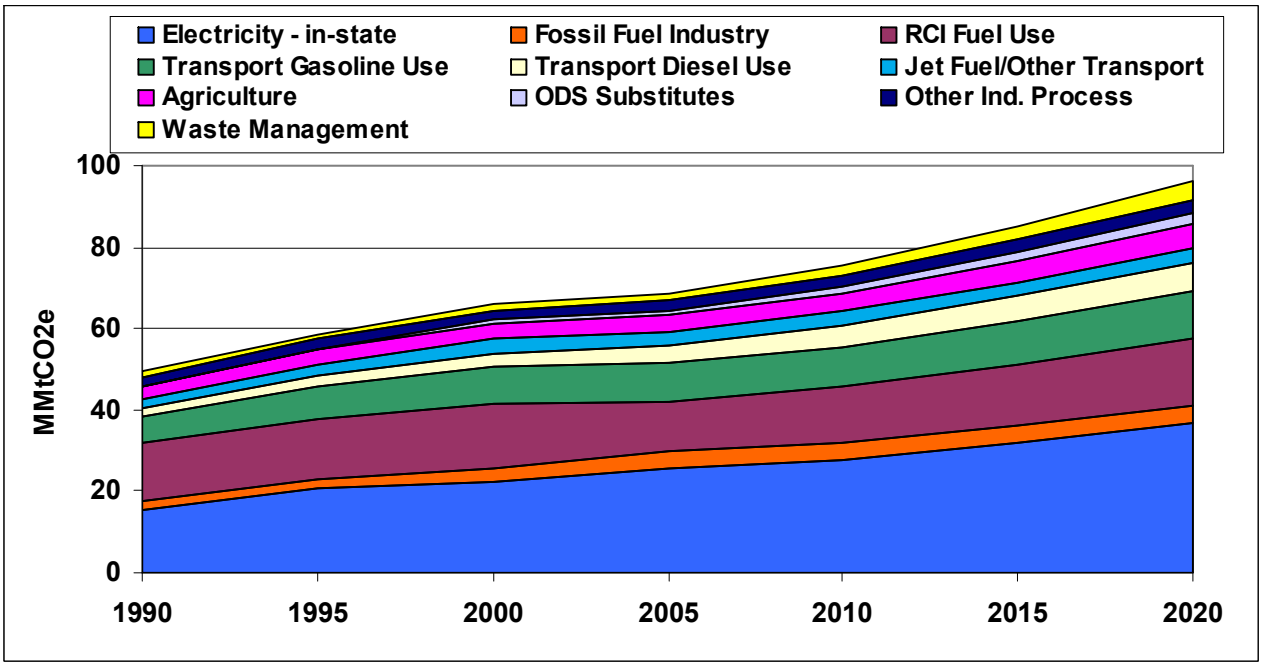
Relying on a variety of sources for projections of electricity and fuel use, as noted below and in the Appendices, we developed a simple reference case projection of GHG emissions through 2020. As illustrated in Figure 3 and shown numerically in Table 1, under the reference case projections, Utah gross GHG emissions continue to grow steadily, climbing to 98 $MMTCO_2e$ by 2020, 98% above 1990 levels. Electricity use is projected to be the largest contributor to future emissions growth, followed by the transportation sector and RCI fossil fuel use.

3.0 Key Uncertainties and Next Steps

Some data gaps exist in this inventory, and particularly in the reference case projections. Key tasks that should be performed in future updates include review and revision of key drivers, such as the electricity and transportation fuel use growth rates that will be major determinants of Utah's future GHG emissions (see Table 1). 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.

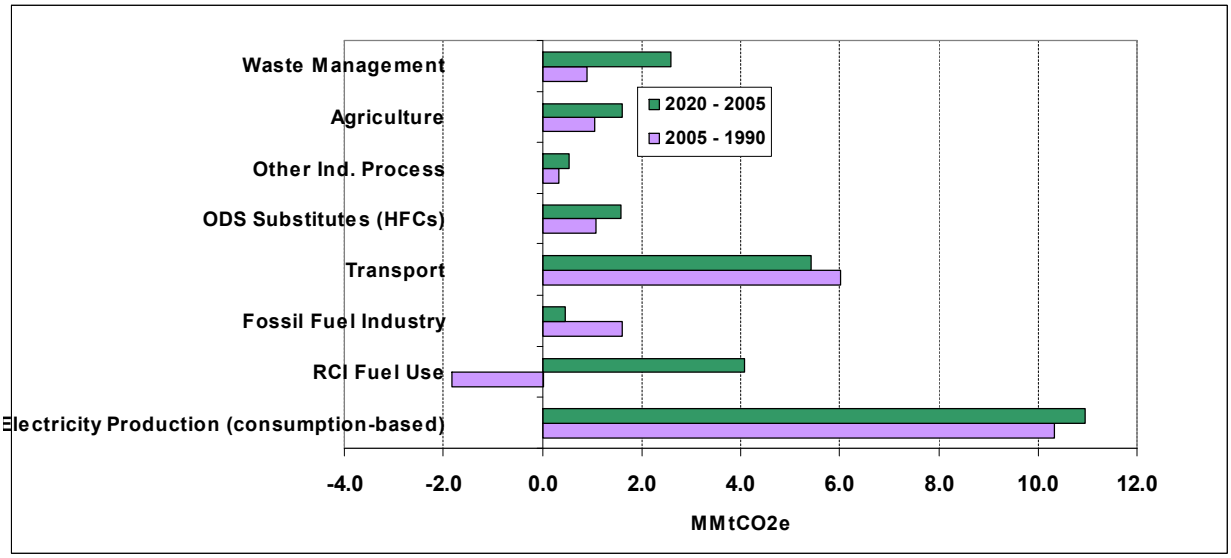
Perhaps the variable with the most important implications for GHG emissions is the type and number of power plants built in Utah between now and 2020. The assumptions on vehicle miles traveled (VMT) and air travel growth also have large impacts on the GHG emission growth in the State. Finally, uncertainty remains regarding the estimates for historic GHG sinks from forestry, and projections for these emissions will greatly affect the net GHG emissions attributed to Utah.

Figure 3. Utah Gross GHG Emissions by Sector, 1990-2020: Historical and Projected



*RCI – direct fuel use in residential, commercial and industrial sectors (excluding the fossil fuel production industry)

Figure 4. Sector Contributions to Emissions Growth in Utah, 1990-2020: Historic and Reference Case Projections



*RCI – direct fuel use in residential, commercial and industrial sectors (excluding the fossil fuel production industry)

Table 3. Key Annual Growth Rates for Utah, Historical and Projected

Key Parameter	1990-2005	2005-2020	Sources
Population	2.6%	2.1%	The Utah Governor's Office of Planning and Budget
Employment Goods Services	 2.3% 3.2%	 2.4% 1.6%	Utah Department of Workforce Services, The Utah Governor's Office of Planning and Budget
Electricity Sales	3.3%	3.3%	EIA data for 1990-2005, Rocky Mountain power for projections
Vehicle Miles Traveled	3.8%	2.3%	Utah Department of Transportation

* Population and employment projections for Utah were used together with US DOE's Annual Energy Outlook 2006 projections of changes in fuel use on a per capita and per employee, as relevant for each sector. For instance, growth in Utah's residential natural gas use is calculated as the Utah population growth times the change in per capita natural gas use for the Mountain region.

Emissions of aerosols, particularly black carbon from fossil fuel combustion, could have significant impacts in terms of radiative forcing (that is, climate impacts). Methodologies for conversion of black carbon mass estimates and projections to global warming potential involve significant uncertainty at present, but CCS has developed and used a recommended approach for estimating black carbon emissions based on methods used in other States. Current estimates suggest a CO_2e contribution of about 7% overall from BC emissions, as compared to the CO_2e contributed from the gases (4.9 MMtCO_2e from BC in 2002 compared to 66 MMtCO_2e from the six GHGs). Emissions from two primary contributing sectors (onroad and nonroad diesel combustion) are expected to decline by 2020 due to new engine and fuel standards.

4.0 Approach

The principal goal of compiling the inventories and reference case projections presented in this document is to provide the State with a general understanding of Utah'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 Utah.

4.1 General Methodology

CCS prepared this analysis in close consultation with Utah agencies, in particular, with the UDEQ 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 forecasts are lacking, we use straightforward spreadsheet analysis and linear 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 U.S. EPA in its national GHG emissions inventory[8] and its guidelines for States.[9] These inventory guidelines were developed based on the guidelines from the Intergovernmental Panel on Climate Change, the international organization responsible for developing coordinated methods for national GHG inventories.[10] The inventory methods provide flexibility to account for local conditions. The key sources of activity and projection data are shown in Table 4. Table 4 also provides the descriptions of the data provided by each source and the uses of each data set in this analysis.

4.2 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 report key uncertainties where they exist.

[8] U.S. EPA, Feb 2005. *Draft Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003.* http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.
[9] http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateInventoryGuidance.html.
[10] http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

Table 4. Key Sources for Utah Data, Inventory Methods, and Growth Rates

Source	Information provided	Use of Information in this Analysis
U.S. EPA State Greenhouse Gas Inventory Tool (SGIT)	US EPA SGIT is a collection of linked spreadsheets designed to help users develop State GHG inventories. 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 8 document series published by the Emissions Inventory Improvement Program (http://www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html)	Where not indicated otherwise, SGIT is used to calculate emissions from residential/commercial/industrial fuel combustion, industrial processes, transportation, agriculture and forestry, and waste. We use SGIT emission factors (CO_2, CH_4 and N_2O per BTU consumed) to calculate energy use emissions.
U.S. DOE Energy Information Administration (EIA) State Energy Data (SED)	EIA SED source provides energy use data in each State, annually to 2004 or in some cases 2005).	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 the EIA website for years after 2001. Emission factors from US EPA SGIT are used to calculate energy-related emissions.
U.S. DOE Energy Information Administration Annual Energy Outlook 2006 (AEO2006)	EIA AEO2006 projects energy supply and demand for the U.S. from 2005 to 2030. Energy consumption is estimated on a regional basis. Utah is included in the Mountain Census region (AZ, CO, ID, MT, NM, NV, UT, and WY)	EIA AEO2006 is used to project changes in per capita (residential) and per employee (commercial/industrial) energy consumption
American Gas Association – Gas Facts	Natural gas transmission and distribution pipeline mileage.	Pipeline mileage from Gas Facts used with SGIT to estimate natural gas transmission and distribution emissions.
UDEQ	Data on industrial source activity.	Includes information on cement, lime production, and other sources.
U.S. EPA Landfill Methane Outreach Program (LMOP)	LMOP provides landfill waste-in-place data.	Waste-in-place data used to estimate annual disposal rate, which was used with SGIT to estimate emissions from solid waste, with additional data from UDEQ staff.
U.S. Forest Service	Data on forest carbon stocks for multiple years.	Data are used to calculate carbon dioxide flux over time (terrestrial CO_2 sequestration in forested areas)
USDS National Agricultural Statistics Service (NASS)	USDA NASS provides data on crops and livestock.	Crop production data used to estimate agricultural residue and agricultural soils emissions; livestock population data used to estimate manure and enteric fermentation emissions

- **Consistency:** To the extent possible, the inventory and projections will be designed to be externally consistent with current or likely future systems for state and national GHG emission reporting. We have used the 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[11], 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 Utah. It covers all six GHGs covered by U.S. and other national inventories: CO_2, CH_4, N_2O, SF_6, HFCs, and PFCs and black carbon. 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 2020.

- **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.

- **Use of Consumption-Based Emissions Estimates:** To the extent possible, we estimated emissions that are caused by activities that occur in Utah. For example, we reported emissions associated with the electricity consumed in Utah. 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 Utah. This entails accounting for the electricity sources used by Utah utilities to meet consumer demands. If UDEQ decides to refine this analysis, they may also consider estimating other sectoral emissions on a consumption basis, such as accounting for emissions from combustion of transportation fuel used in Utah, but purchased out-of-state. In some cases this can require venturing into the relatively complex terrain of life-cycle analysis. In general, CCS recommends 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,

[11] "Reference case" refers to a projection of the current or "base year" inventory to one or more future years under business-as-usual forecast conditions (for example, existing control programs and economic growth).

cardboard, and aluminum), even though production of those materials, and emissions associated with materials production, may not occur within the State.

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 (excluding fuel used by the fossil fuel production industry).
- Appendix C. Transportation Energy Use.
- Appendix D. Industrial Processes.
- Appendix E. Fossil Fuel Industries.
- Appendix F. Agriculture.
- Appendix G. Waste Management.
- Appendix H. Forestry.

Appendix I contains a discussion of the inventory and forecast for black carbon. Appendix J provides additional background information from the U.S. EPA on greenhouse gases and global warming potential values.

Appendix A. Electricity Use and Supply

Utah's electricity demand has experienced strong growth in the last 15 years, mostly driven by population and economic growth in the State. This growth - population, economy, and electricity demand – are expected to continue for the next 15 years. Utah's electricity generation is dominated by coal resources, which have relatively high levels of GHG emissions. From 1990 to 2005, GHG emissions associated with electricity production and consumption in Utah have shown the largest growth of any sector in the State. Electric sector GHG emissions are also expected to lead growth from 2006 to 2020.

As noted earlier, one of the key questions for the State to consider is how to treat GHG emissions that result from generation of electricity that is produced in Utah to meet electricity needs in other state. In other words, should the State consider the GHG emissions associated with the State's electricity consumption or its electricity production, or some combination of the two? Since this question still needs to be resolved, this section examines electricity-related emissions from both a production and consumption basis.

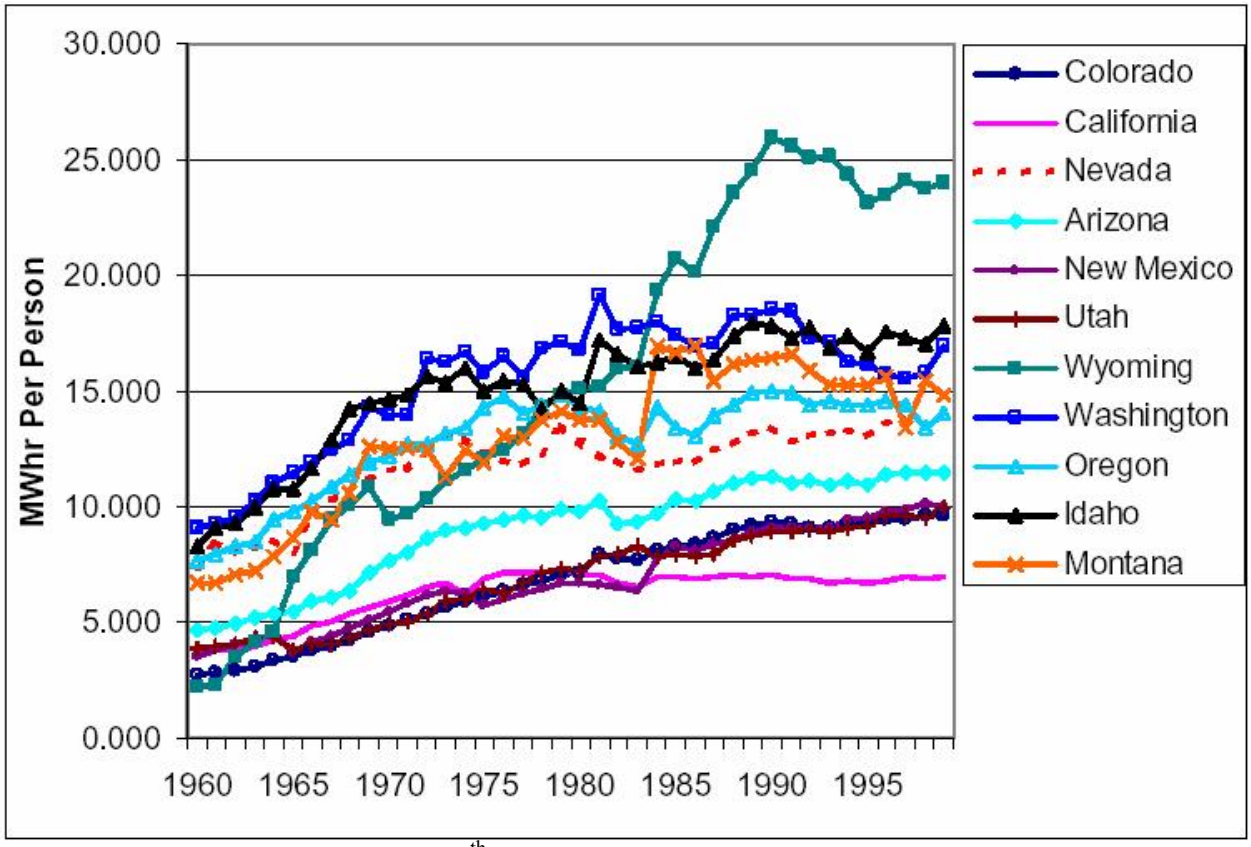
This appendix describes Utah's electricity sector in terms of net consumption and production, including the assumptions used to develop the reference case projections. It then describes Utah's electricity trade and potential approaches for allocating GHG emissions for the purpose of determining the State's inventory and reference case forecasts. Finally, key assumptions and results are summarized.

Electricity Consumption

At about 10,000 kWh/capita (2004 data), Utah has relatively low electricity consumption per capita. By way of comparison, the per capita consumption for the U.S. was about 12,000 kWh per year.[12] Figure A1 shows Utah's rank compared to other western states from 1960-1999; Utah's per capita consumption has been relatively low (2nd lowest, tied with Colorado and New Mexico). Many components influence a state's per capita electricity consumption including the impact of weather on demand for cooling and heating, the fraction of heating demand that is met by electricity rather than by natural gas or other energy sources, the size and type of industries in the State, and the type and efficiency of equipment in the residential, commercial and industrial sectors.

[12] Census bureau for U.S. population, Energy Information Administration for electricity sales.

Figure A1. Electricity Consumption per capita in Western States, 1960-1999

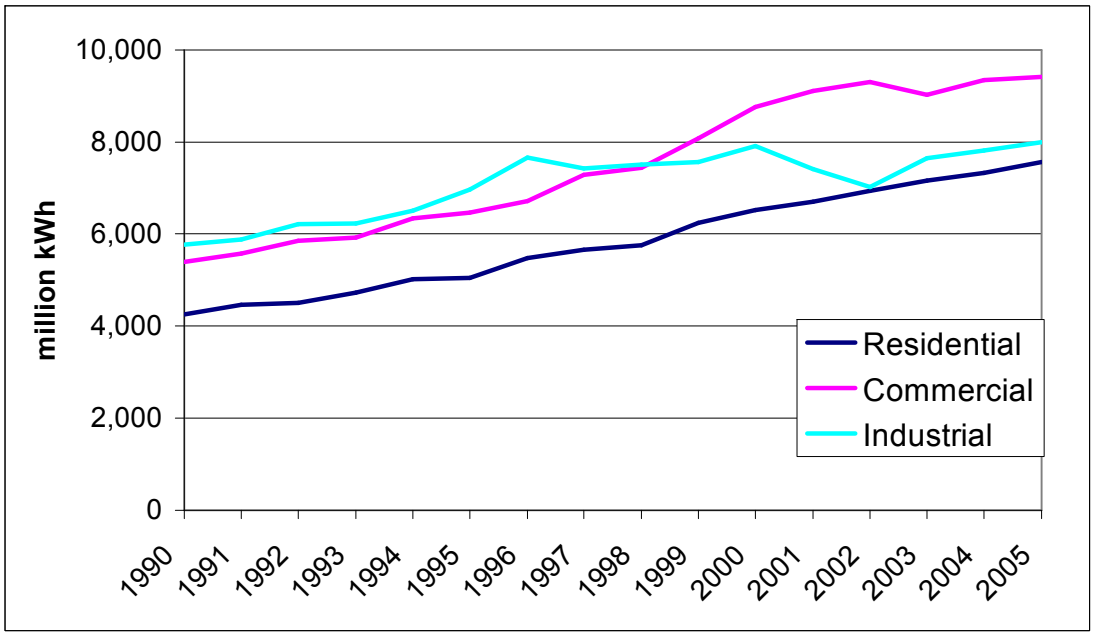


Source: Northwest Power Council, 5th Power Plan, Appendix A

As shown in Figure A2, electricity sales in the Utah have generally increased steadily from 1990 through 2005. Overall, total electricity consumption increased at an average annual rate of 3.3% from 1990 to 2005, comparable to the population growth rate of 2.6% per year.[13] During this period, the residential sector grew by an average of 3.9% per year, the commercial sector by 3.8% per year, and the industrial sector by 2.2% per year.

[13] Population from The Utah Governor's Office of Planning and Budget, Demographic and Economic Analysis (DEA), *Demographics - Data on People, Data Tables*: Provides annual population for each year for 1990 through 2006 in Excel file named "AllUPECData061114.xls".

Figure A2. Electricity Consumption by Sector in Utah, 1990-2005[14]



Source: EIA State Energy Data (1990-2002) and EIA Electric Power Annual (2003-2005).

Projections for electricity sales from 2006 through 2020 are based on the 2006 *Load Forecast* developed by Rocky Mountain Power (previously named PacifiCorp).[15] Since Rocky Mountain Power accounts for 80% of Utah's retail electricity sales, the projections from its load forecast are assumed to be representative of the whole state and have been applied to total electricity sales. Rocky Mountain Power's projected annual growth in electricity sales from 2005 through 2017 is 3.3% per year, same as the average growth from 1990-2005. Table A1 reports historic and projected annual average growth rates.

[14] Note from 1990-2002, the EIA data includes a category referred to as "other," which included lighting for public buildings, streets, and highways, interdepartmental sales, and other sales to public authorities, agricultural and irrigation sales where separately identified, electrified rail and various urban transit systems (such as automated guideway, trolley, and cable). To report total electricity in Figure A2, the sales from the "other" category are included with the commercial sector. The decision to include with commercial rather than the other sectors is based on comparing the trends of electricity sales from 2000-2002 with 2003 sales.

[15] Data from the 2006 Load Forecast for Utah were found in a powerpoint presentation from one of Pacificorp's Public Input Meeting for the 2006 Integrated Resource Plan (April 20, 2006). See http://www.utah-power.com/File/File64180.pdf. Accessed on November 14, 2006.

Table A1. Electricity Growth Rates, historic and projected

	Historic		Projections	
	1990-2000	2000-2005	2006-2010	2010-2020
Residential	4.4%	3.0%	3.4%	3.4%
Commercial	5.0%	1.5%	4.3%	4.3%
Industrial	3.2%	0.2%	2.3%	2.3%
Total	**4.2%**	**1.5%**	**3.3%**	**3.3%**

Source: Historic from EIA data, projections from Rocky Mountain Power *2006 Load Forecast.*

Electricity Generation – Utah's Power Plants

The following section provides information on GHG emissions and other activity associated with power plants *located in Utah*. Since Utah is part of the interconnected Western Electricity Coordinating Council (WECC) region – electricity generated in Utah can be exported to serve needs in other states and electricity used in Utah can be generated in plants outside the state. For this analysis, we estimate emissions on both a *production-basis* (emissions associated with electricity produced in Utah, regardless of where it is consumed) and a *consumption-basis* (emissions associated with electricity consumed in Utah). The following section describes production-based emissions while the subsequent section, *Electricity trade and the allocation of GHG emissions*, reports consumption-based emissions.

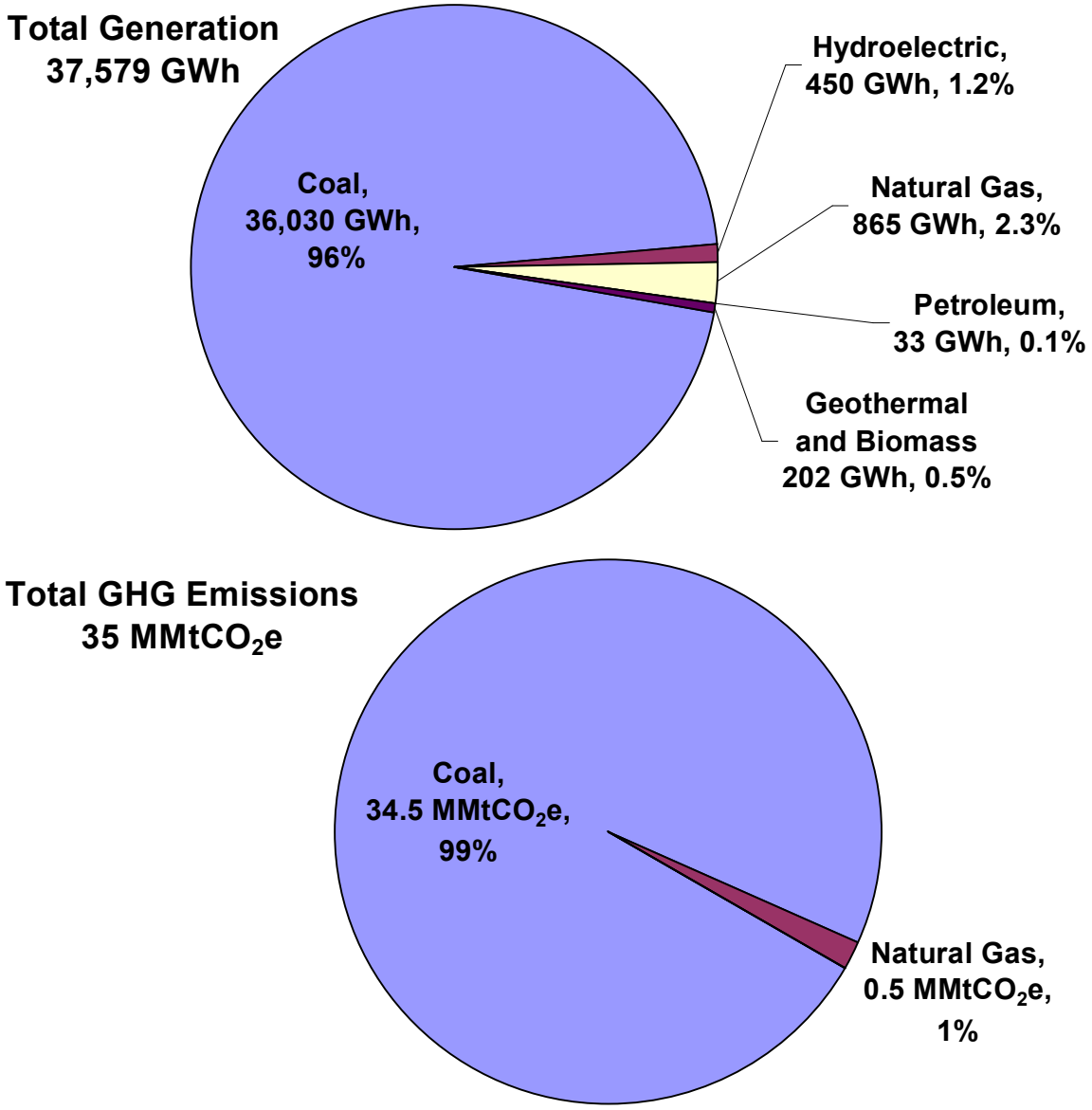
As displayed in Figure A3, coal figures prominently in electricity generation and accounts for 99% of the GHG emissions from power plants in Utah. Table A2 reports the emissions from each of the six plants in Utah with the highest emissions, plus reports the combined emissions from all remaining plants in the "other plants" category. The plant with the highest GHG emissions, Intermountain, accounts for about 40% of all Utah's GHG emissions. Intermountain is a large facility with two generator units having a combined capacity of 1900 MW. It runs primarily on coal (over 99.5% of energy consumption) but also consumes small amounts of diesel for start-up. California utilities account for about 75% of Intermountain's Generation Entitlement Shares, with Utah purchasers accounting for the remaining 25% (Utah co-ops buy 21% and Rocky Mountain Power buys 4%, the latter could send power out of state).[16] Electricity trade and GHG allocation are discussed in the section below.

We considered two sources of data in developing the historic inventory of GHG emissions from Utah power plants – EIA State Energy Data (SED), which need to be multiplied by GHG emission factors for each type of fuel consumed, and Utah Geological Survey (UGS) GHG inventory, which provides GHG emission estimates through 2002.[17] For total electric sector GHG emissions, we used the EIA's State Energy Data (SED) rather than UGS data because the EIA data cover more recent data (through 2004, in some cases 2005) and the UGS inventory was also based on EIA data. However, the UGS GHG inventory provides easily accessible data for each power plant, which would be much more difficult to extract from EIA data. Based on this information, we report both data sources but rely on the EIA data for the inventory values.

[16] Information from Intermountain Power Agency website, http://www.ipautah.com/participants.htm, accessed on December 6, 2006.
[17] http://geology.utah.gov/sep/energydata/ghgdata.htm.

To calculate total GHG emissions from electricity production in Utah, we applied SGIT emission factors to EIA's SED. For CO_2 emissions from individual plants, we used the UGS GHG inventory.

Figure A3. Electricity Generation and CO_2 Emissions from Utah Power Plants, 2004[18]



[18] The most recent data available for electricity generation is 2005, and this data was used for the GHG inventory and projections. The tables and charts in this section refer to 2004 data to be consistent and comparable with information presented in other sections of this report.

Table A2. CO_2 Emissions from Individual Utah Power Plants, 1997-2002

(Million metric tons CO2)	1997	1998	1999	2000	2001	2002
Bonanza	*2.9*	*3.2*	*3.0*	*2.8*	*3.7*	*3.8*
Carbon	*1.4*	*1.3*	*1.2*	*1.4*	*1.4*	*1.4*
Gadsby	*0.1*	*0.2*	*0.2*	*0.5*	*0.6*	*0.4*
Hunter	*8.7*	*8.5*	*8.9*	*9.1*	*8.0*	*9.0*
Huntington	*5.6*	*6.0*	*6.5*	*6.6*	*5.9*	*5.5*
Intermountain	*11.0*	*11.3*	*11.3*	*11.5*	*11.6*	*11.6*
Other Plants	*0.7*	*0.5*	*0.4*	*0.4*	*0.4*	*1.2*
Total CO2 emissions	**30.4**	**31.1**	**31.6**	**32.2**	**31.6**	**32.8**

Source: Utah Geological Survey GHG inventory for named plants (http://geology.utah.gov/sep/energydata/ghgdata.htm). Total emissions calculated from fuel use data provided by SED (US DOE Energy Information Administration).
Note: The emissions reported in the above table are CO_2 only. CH_4 and N_2O emissions were not included in the power plant data from the UGS GHG inventory.

Table A3 shows the growth in generation by fuel type between 1990 and 2004 from power plants in Utah. Overall generation grew by 16% over the 15 years, while electricity consumption grew by 60%. Based on the difference in growth rates for electricity generation and consumption in Utah, net exports have declined from about 42% of total in-state generation in 1990 to 25% in 2004. In Utah, natural gas generation has had particularly strong growth, increasing by more than 16 times from 1990 to 2004. Coal generation grew more slowly but remains the dominant source of electricity in the State. Hydro generation shows a decrease between 1990 and 2004, but the table masks the considerable year-by-year variation from this resource. In the 15-year period, hydro generation ranged from a low of 421 GWh in 2003 to a high of 1,344 GWh in 1997.

Table A3. Growth in Electricity Generation in Utah 1990-2004

	Generation (GWh)		Growth
	1990	2004	
Coal	31,519	36,030	14%
Hydroelectric	508	450	-12%
Natural Gas	54	865	1501%
biomass and waste	0	10	n/a
Geothermal	152	192	26%
Petroleum	49	33	-34%
Total	32,283	37,579	16%

Source: EIA data, generation from electric sector, including independent power producers, excludes electricity generation from industrial and commercial combined heat and power facilities

Future Generation and Emissions

Estimating future generation and GHG emissions from Utah power plants requires estimation of new power plant additions and production levels from new and existing power plants. There are, of course, large uncertainties, especially related to the timing and nature of new power plant construction.

The future mix of plants in Utah remains uncertain as the trends in type of new builds are influenced by many factors. Since 2000, new fossil-fuel plants in Utah have been natural gas-

fired; however, coal dominates the new plants that have been proposed recently in the State. Rocky Mountain Power and other private developers are also showing interest in new wind and geothermal plants. Table A4 presents data on new and proposed plants in Utah.

Individual proposed plants are not modeled in the reference case projections, but the mix of types of proposed plants are considered when developing assumptions.

Table A4. New and Proposed Power Plants in Utah

	Plant Name	Fuel	Status	Capacity MW	Estimated Annual generation GWh	Emissions $MMtCO_2e$	Notes
New plants	Current Creek	Natural gas	On-line 2005	280	981	0.4	
Proposed Plants	Blundell plant expansion	Geothermal	unknown	11	82	negligible	proposed for 2007
	Spanish Fork	wind	Power Purchase agreement	18.9	58	0.0	proposed for 2008
	Pioneer Ridge, Tooele Utah	wind	Power Purchase agreement	70	215	0.0	
	Beaver County	wind	Proposed	400	1,226	0.0	Phase I - 320 MW in 2008 Phase 2 - 80 MW in 2009
	Renaissance	geothermal	Proposed	100	745	negligible	Renaissance Energy is in early stages
	IPP 3	coal (pulverized)	Permit has been issued	900	6,701	5.5	Intermountain Power Authority, planned for 2012
	NEVCO	coal (fluidized bed)	Permit has been issued	270	2,010	1.7	planned for 2008, Nevco Energy
	Hunter 4*	coal (pulverized)	unknown	400	2,978	2.5	planned for 2012, Rocky Mountain Power
	Summit Lake Side	Natural gas, combined cycle	unknown	340	2,532	0.9	planned for 2007, Rocky Mountain Power
	Bonanza*	waste coal	unknown	86	640	0.6	Deseret Generation and Transmission

* Capacity information for Hunter4 and Bonanza was obtained from Western Resource Advocates website but permits have not been received and proposed capacity is subject to change.
Sources: Utah Energy and Mineral Statistics website[Table 6.7] (http://geology.utah.gov/sep/energydata/index.htm), personal communication with Jason Berry, State Renewable Energy Coordinator, Rusty Ruby, Utah Department of Air Quality Permits, Western Resource Advocates website (http://www.westernresourceadvocates.org/energy/coal/utah.php). Generation estimates based on capacity factors of 0.85 for base load coal, 0.4 for natural gas, and 0.35 for wind. Emissions estimates based on heat rates of 9,000 BTU/kWh of coal, 10,200 BTU/kWh for waste coal and 7,000 BTU/kWh for natural gas.

Given the many factors affecting electricity-related emissions and a diversity of assumptions by stakeholders within the electricity sector, developing a "reference case" projection for the most likely development of Utah's electricity sector is particularly challenging. Therefore, to develop an initial projection, simple assumptions were made, relying to the extent possible on widely-reviewed and accepted modeling assessments.

The reference case projections assume:

- Generation from plants in Utah grows at 3.3% per year from 2008-2010, following growth rate in electricity sales.
- Generation from plants in Utah grows at 2.5% per year from 2010 to 2015 and 2.0% from 2015 to 2020. This reflects the generation growth rate for the Rocky Mountain region in Annual Energy Outlook 2006 (AEO2006). These assumptions lead to growth of about 2200 MW of new power plant capacity by 2020.

- Generation from existing non-hydro plants is based on holding generation at 2005 levels. Generation from existing hydro-electric plants is assumed to be 816 GWh per year, the average generation from the last ten years. New plants and changes to existing plants due to plant renovations and overhauls that result in higher capacity factors are counted as new generation.
- New power plants built between 2007 and 2010 will be a mix of 80% natural gas, 15% wind, and 5% geothermal. This mix is roughly based on the mix of proposed new plants, Table A4 and information from Utah Geological Survey.[19]
- New power plants built between 2011 and 2020 will be a mix of 70% coal, 20% natural gas, 5% wind, and 5% geothermal. This mix of proposed plants is based on regional projections from the EIA AEO2006 combined with information in Table A4 on proposed new plants.

Electricity Trade and Allocation of GHG Emissions

Utah is part of the interconnected Western Electricity Coordinating Council (WECC) region - a vast and diverse area covering 1.8 million square miles and extending from Canada through Mexico, including all or portions of 14 western states. The inter-connected region allows electricity generators and consumers to buy and sell electricity across regions, taking advantage of the range of resources and markets. Electricity generated by any single plant enters the interconnected grid and may contribute to meeting demand throughout much of the region, depending on sufficient transmission capacity. Thus, it is challenging to define which emissions should be allocated to Utah, and secondly in estimating these emissions both historically and into the future. Some utilities track and report electricity sales to meet consumer demand by fuel source and plant type; however, tracing sales to individual power plants may not be possible.

In 2004, Utah had 52 entities involved in providing electricity to state customers. The State's two private utilities, Rocky Mountain Power and Strawberry Water Users Association, serve approximately 75% of the customers, and provide 80% of the electricity sales.[20] The State's 9 electric cooperatives serve 4% of the customers and account for 3% of sales. One federal, one State, and 39 municipal utilities account for the remaining 21% of customers and 16% of sales. The top 5 providers of retail electricity in the State are reported in Table A5.

In 2004, electricity demand (sales + losses[21]) in Utah was about 28,282 GWh, while electricity generation in the State was 37,579 GWh. Net exported electricity to other states accounts for the additional 9,296 GWh, but net exports generally encompass a mix of both imports and exports from the State. As mentioned above, 75% of the capacity at the Intermountain power plant is under contract with California utilities. Other power plants have contracts with out-of-state

[19] Personal communication M. Vanden Berg to CCS, December 2006.
[20] Rocky Mountain Power accounts for the vast majority of these customer and sales, with the Strawberry Water Users Association supplying only 0.041% of Utah's sales.
[21] Utah's electricity losses are assumed to be 10 percent of total generation based on information from EPA's Emission & Generation Resource Integrated database (EGRID), http://www.epa.gov/cleanenergy/egrid/index.htm. 10 percent is the average rate of losses, according to this dataset, over the period 1994-2000.

utilities and Utah utilities may own or have contracts with power plants outside of the State. Thus, electricity trade counts for a significant portion of the electric power associated with Utah.

Since almost all states are part of regional trading grids, many states that have developed GHG inventories have grappled with the problem of how to account for electric sector emissions, when electricity flows across state borders. Several approaches have been developed to allocate GHG emissions from the electricity sector to individual states for inventories.

Table A5. Retail Electricity Providers in Utah (2004)

	Ownership Type	2004 GWh
Top 5 providers of Retail Electricity, ranked by retail sales		
Rocky Mountain Power	Investor-Owned	19,732
Provo City Corp	Public	716
St George City of	Public	523
Logan City of	Public	397
Murray City of	Public	378
Total Sales, Top Five Providers		21,745
Total, all Utah		24,512

Source: Utah Energy and Mineral Statistics website [Table 5.24] (http://geology.utah.gov/sep/energydata/index.htm), based on EIA data.

In many ways the simplest approach is *production-based* – emissions from power plants within the state are included in the state's inventory. The data for this estimate are publicly available and unambiguous. However, this approach is problematic for states that import or export significant amounts of electricity. Under a production-based approach, characteristics of Utah electricity consumption would not be fully captured since only emissions from in-state generation would be considered.

An alternative is to estimate *consumption-based* or *load-based* GHG emissions, corresponding to the emissions associated with electricity consumed in the state. The load-based approach is currently being considered by states that import significant amounts of electricity, such as California, Oregon, and Washington.[22] By accounting for emissions from imported electricity, states can account for increases or decreases in fossil fuel consumed in power plants outside of the State, due to demand growth, efficiency programs, and other actions in the state. The difficulty with this approach is properly accounting for the emissions from imports and exports. Since the electricity flowing into or out of Utah is a mix of all plants generating on the inter-connected grid, it is impossible to physically track the sources of the electrons.

The approach taken in this initial inventory is a simplification of the consumption-based approach. This approach, which one could term "*Net-Consumption-based,*" estimates consumption-based emissions as in-state (production-based) emissions times the ratio of total in-

[22] See for example, the reports of the Puget Sound Climate Protection Advisory Committee (http://www.pscleanair.org/specprog/globclim/), the Oregon Governor's Advisory Group On Global Warming (http://egov.oregon.gov/ENERGY/GBLWRM/Strategy.shtml), and the California Climate Change Advisory Committee, Policy Options for Reducing Greenhouse Gas Emissions From Power Imports - Draft Consultant Report (http://www.energy.ca.gov/2005publications/CEC-600-2005-010/CEC-600-2005-010-D.PDF).

state electricity consumption to in-state generation (net of losses). This method does not account for differences in the type of electricity that is imported or exported from the State, and as such, it provides a simple method for reflecting the emissions impacts of electricity consumption in the State. The calculation also ignores "gross" imports – since Utah plants have contracts to out-of-state entities, some of the in-state electricity generation will be exported and gross imports will be greater than net imports. More sophisticated methods – for example, based on individual utility information on resources used to meet loads – can be considered for further improvements to this approach. Estimating the mix of electricity generation for the imports/export of a state is possible and several states are developing data collection approaches to do this. Washington State has developed regular fuel disclosure reporting.[23]

Summary of Assumptions and Reference Case Projections

As noted, projecting generation sources, sales, and emissions for the electric sector out to 2020 requires a number of key assumptions, including economic and demographic activity, changes in electricity-using technologies, regional markets for electricity (and competitiveness of various technologies and locations), access to transmission and distribution, the retirement of existing generation plants, the response to changing fuel prices, and the fuel/technology mix of new generation plants. The key assumptions described above are summarized in Table A6.

Figure A4 shows historical sources of electricity generation in the state by fuel source, along with projections to the year 2020 based on the assumptions described above. Based on the assumptions for new generation, coal continues to dominate new generation throughout the forecast period (2006-2020). Both natural gas and renewable energy show high growth, relative to levels in 2005. Overall electricity generation grows at 2.4% per year from 2005 to 2020.

GHG emission estimates were calculated by multiplying the energy consumption by GHG emission factors by fuel. Energy consumption for 2006 to 2020 was calculated based on changes to future generation and heat rate properties described in Table A6. The EPA SGIT software provided GHG emission factors by fuel for each state, consistent with factors used for EPA's national GHG inventory report.[24] GHG emissions from geothermal plants were estimated using a rate of 7 Mt CO_2/GWh, based on estimates from the UGS GHG inventory.[25]

Figure A5 illustrates the GHG emissions associated with the mix of electricity generation shown in Figure A4. From 2005 to 2020, the emissions from Utah electricity generation are projected to grow at 1.5% per year, lower than the growth in electricity generation, due to an increased fraction of generation from renewable energy and natural gas. As a result, the emission intensity (GHG emissions per MWh) of Utah electricity is expected to decrease from 0.91 $MtCO_2$/MWh in 2004 to 0.80 $MtCO_2$/MWh in 2020.

[23] http://www.cted.wa.gov/site/539/default.aspx
[24] SGIT http://www.epa.gov/climatechange/emissions/state_guidance.html, National GHG inventory http://www.epa.gov/climatechange/emissions/usinventoryreport.html
[25] The UGS GHG inventory estimates are based on USEPA *Inventory OF U.S. Greenhouse Gas Emissions and Sinks*, which uses an emission factor of 2.05 Tg Carbon/QBTU,

Table A6. Key Assumptions and Methods for Electricity Projections for Utah

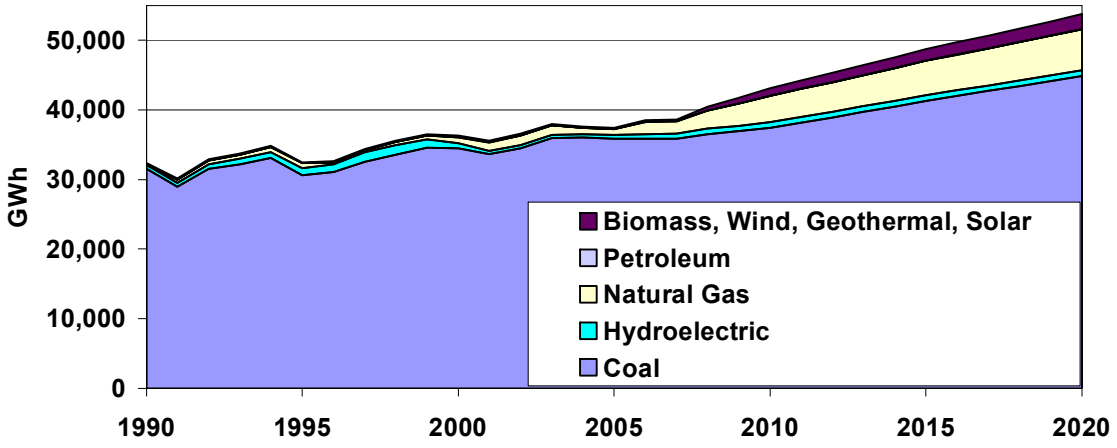
Electricity sales	Average annual growth of 3.3% from 2006 to 2020, based on growth rates in Rocky Mountain Power *2006 Load Forecast*.
Electricity generation	3.3% per year from 2006-2010, based on consumption growth and proposed plants and 2.2% per year from 2010 to 2020, based on regional growth rates in AEO2006.
Transmission and Distribution losses	10% losses are assumed, based on average statewide losses, 1994-2000, (data from the US EPA Emission & Generation Resource Integrated Database[26])
New Generation Sources (2006-2010)	The mix of new generation in this period roughly tracks the mix of proposed new plants in Utah (Table A4). 80% natural gas 15% wind 5% geothermal
New Non-Renewable Generation Sources (2010-2020)	The mix of new generation in this period is based on regional projections from the AEO2006 combined with the mix of proposed new plants in Utah (Table A4). 70% coal 20% natural gas 5% wind 5% geothermal
Heat Rates	The assumed heat rates for new gas and coal generation are 7000 Btu/kWh and 9000 Btu/kWh, respectively, based on estimates used in similar analyses.[27]
Operation of Existing Facilities	Existing non-hydro facilities are assumed to continue to operate as they were in 2005. Existing hydro facilities are assumed to generate 816 GWh per year the average generation over the period 1996-2005. Improvements in existing facilities that lead to higher capacity factor and more generation are captured under the new generation sources.

Figure A6 shows the "net-consumption-based" emissions from 1990 to 2020. Total emissions are lower than the production-based emissions due to the GHG emissions associated with net electricity exports. Consumption-based emissions increase by 2.4% per year from 2006 to 2020. The higher growth, relative to production-based emissions, results from higher growth in electricity consumption in the State compared to electricity generation. Figure A6 also shows the decreasing role of net electricity exports in Utah.

Table A7 summarizes the GHG emissions for Utah's electric sector from 1990 to 2020. During this time period, emissions are projected to increase by 49% on a production-basis and 139% on a consumption-basis.

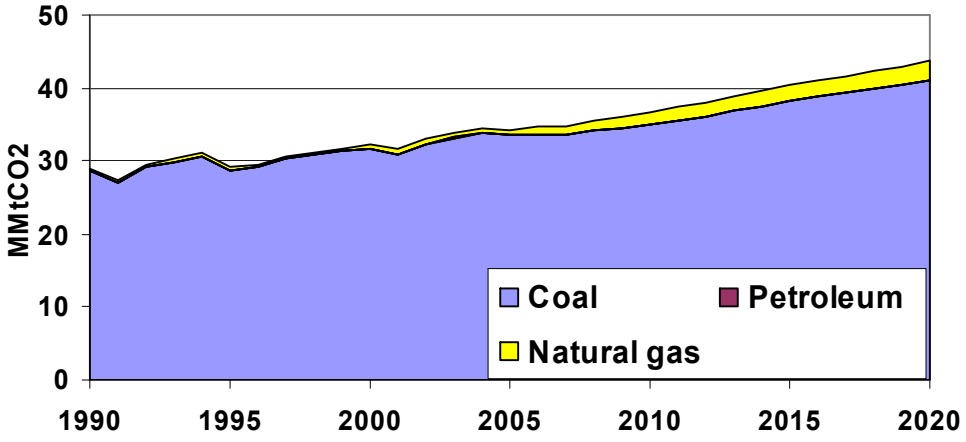
[26] http://www.epa.gov/cleanenergy/egrid/index.htm.
[27] See, for instance, the Oregon Governor's Advisory Group On Global Warming http://egov.oregon.gov/ENERGY/GBLWRM/Strategy.shtml.

Figure A4. Electricity Generated by Utah Power Plants 1990-2020



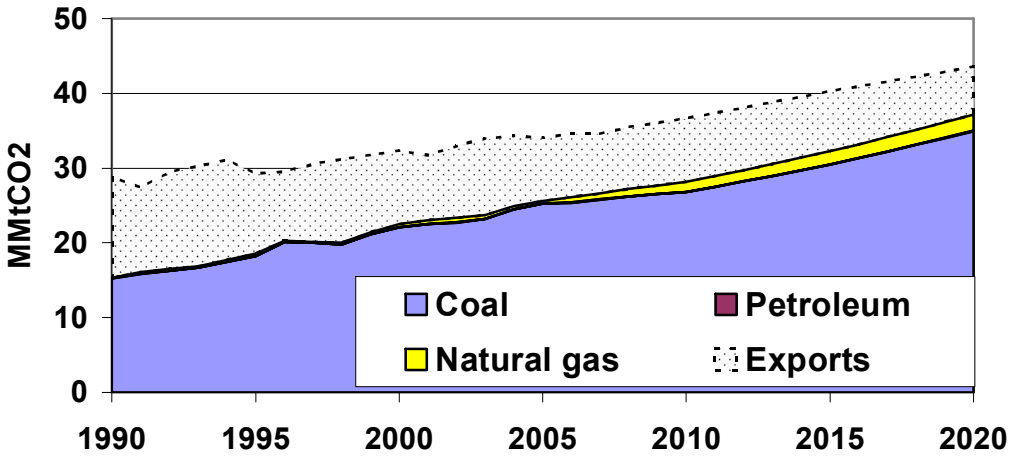
Source: 1990-2005 EIA data, 2006-2020 CCS calculations based on assumptions described above, generation from petroleum resources is too small to be visible in the chart

Figure A5. Utah CO_2 Emissions Associated with Electricity Production (Production-Basis)



Source: CCS calculations based on approach described in text.
Note: Utah's electric generation GHG emissions from petroleum sources are less than 0.05 $MMtCO_2e$ and are too small to be visible in this chart.

Figure A6. Utah CO_2 Emissions Associated with Electricity Use (Consumption-Basis), Showing Exports



Source: CCS calculations based on approach described in text.
Note: Utah's electric generation GHG emissions from petroleum sources are less than 0.05 $MMtCO_2e$ and are too small to be visible in this chart.

Table A7. Utah GHG Emissions from Electric Sector, Production and Consumption-based Estimates, 1990-2020

(Million Metric Tons CO_2e)	1990	2000	2005	2010	2020
Electricity, Production-based	**28.9**	**32.4**	**34.1**	**36.0**	**42.9**
Coal	28.8	31.7	33.6	33.6	39.7
CO_2	28.6	31.6	33.4	33.4	39.5
CH_4 and N_2O	0.1	0.2	0.2	0.2	0.2
Natural Gas	0.0	0.6	0.4	2.3	3.1
CO_2	0.0	0.6	0.4	2.3	3.1
CH_4 and N_2O	0.0	0.0	0.0	0.0	0.0
Petroleum	0.0	0.0	0.0	0.0	0.0
CO_2	0.0	0.0	0.0	0.0	0.0
CH_4 and N_2O	0.0	0.0	0.0	0.0	0.0
Biomass and Waste (CH_4 and N_2O)	0.0	0.0	0.0	0.0	0.0
Electricity Net Imports	**-13.6**	**-9.8**	**-8.4**	**-8.3**	**-6.3**
Electricity Consumption-based	**15.3**	**22.5**	**25.6**	**27.6**	**36.6**

Note: Values that are less than 0.05 $MMTCO_2e$ are listed as 0.0 in Table A7.

Comparison to Utah State GHG Inventory

The Utah Geological Survey (UGS) GHG inventory[28] provided estimates of production-based electric sector GHG emissions for 1990-2002. The production-based GHG emissions that CCS has estimated for this analysis match the UGS GHG estimates for the electric sector for all years from 1990 through 2000. The CCS values are 0.4% lower than the UGS values in 2001 and 1.1% lower than UGS in 2002. Contacts at UGS have confirmed that these small differences are due to CCS using more recent EIA data for energy consumption, which include updated values for 2001 and 2002. The 2001 and 2002 updates were not available at the time the UGS GHG inventory was completed.

[28] http://geology.utah.gov/sep/energydata/ghgdata.htm.

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

Overview

Activities in the RCI[29] 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 applications. Carbon dioxide accounts for over 99% of these emissions on a million metric tons of CO_2 equivalent ($MMtCO_2e$) basis in Utah. 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.[30] Excluding emissions associated with RCI electricity consumption, the RCI sector is the third-largest source of gross GHG emissions in Utah. Direct use of oil, natural gas, coal, and wood in the RCI sectors accounted for an estimated 12.2 $MMtCO_2e$ (18%) of gross GHG emissions in 2005.[31]

Emissions and Reference Case Projections

Emissions for direct fuel use were estimated using the U.S. EPA's SGIT software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for RCI fossil fuel combustion.[32] The default data used in SGIT for Utah are from EIA's *State Energy Data (SED)*. The SGIT default data for Utah were revised using the most recent data available, which includes:

1. 2002 SED information for all fuel types.[33]
2. 2003 SED information for coal, wood, and wood waste.[34]
3. 2004 SED information for natural gas (same data source as previous citation.
4. 2003 and 2004 SED information for petroleum (distillate oil, kerosene, and liquified petroleum gas) consumption (same data source as previous citation).
5. 2004 electricity consumption data from the EIA's *State Electricity Profiles*.[35]
6. 2005 natural gas consumption data from the EIA's *Natural Gas Navigator*.[36]

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[29] The industrial sector includes emissions associated with agricultural energy use and fuel used by the fossil fuel production industry. Emissions from energy used in the fossil fuel production industry are reported in Appendix E.
[30] 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 relatively small level of emissions from these sources.
[31] 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 U.S. EPA and 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.
[32] 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.
[33] EIA *State Energy Data 2002,* Data through 2002, released June 30, 2006, (http://www.eia.doe.gov/emeu/states/state.html?q_state_a=co&q_state=UTAH).
[34] EIA *State Energy Data 2003 revisions for all fuels and first release of 2004 information for natural gas and petroleum*, (http://www.eia.doe.gov/emeu/states/_seds_updates.html). Sources with UGS note problems with the 2004 and 2005 SED coal consumption data. These should be reviewed and revised during any updates to this inventory and forecast for Utah.
[35] EIA *Electric Power Annual 2005 - State Data Tables*, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html). Data are available for 2005 and could be used in updates to this inventory.
[36] EIA *Natural Gas Navigator* (http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SUT_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, liquefied petroleum gases (LPG), and natural gas used as feedstocks by chemical manufacturing plants (that is, 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.[37] The fossil fuel categories for which the EIIP methods are applied in the SGIT software to account for carbon storage include the following categories: asphalt and road oil, coking coal, distillate fuel, feedstocks (naphtha with a boiling range of less than 401 degrees Fahrenheit), feedstocks (other oils with boiling ranges greater than 401 degrees Fahrenheit), LPG, lubricants, miscellaneous petroleum products, natural gas, pentanes plus,[38] petroleum coke, residual fuel, still gas, and waxes. Data on annual consumption of the fuels in these categories as chemical industry feedstocks were obtained from the EIA SED.

Reference case emissions from direct fuel combustion were estimated based on fuel consumption forecasts from EIA's *Annual Energy Outlook 2006* (AEO2006),[39] with adjustments for Utah's projected population[40] and employment growth. Utah employment data for the manufacturing (goods producing) and non-manufacturing (commercial or services providing) sectors were obtained from the Governor's Office of Planning and Budget.[41] Regional employment data for the same sectors were obtained from EIA for the Mountain region.[42]

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, the rate of population growth is expected to increase by about 2.2% annually between 2004 and 2020; this demographic trend is reflected in the growth rates for residential fuel consumption. Based on the Utah Governor's Office of Planning and Budget's forecast (2005 to 2020), commercial and industrial employment are projected to increase at compound annual rates of 2.4% and 1.6%, respectively, and these growth rates are reflected in the growth rates in energy use shown in Table B2 for the two sectors. These estimates of growth relative to

[37] EIIP, Volume VIII: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004.
[38] A mixture of hydrocarbons, mostly pentanes and heavier fractions, extracted from natural gas.
[39] EIA AEO2006 with Projections to 2030, (http://www.eia.doe.gov/oiaf/aeo/index.html).
[40] Population data for 1990 through 2005 from Utah Governor's Office of Planning and Budget, Demographic and Economic Analysis (DEA), "Demographics - Data on People, Data Tables": Provides annual population for each year for 1990 through 2006 in Excel file named "AllUPECData061114.xls" (http://governor.utah.gov/dea/DataTables.html). Population forecasts for 2006 to 2020 from Utah Governor's Office of Planning and Budget, DEA Long-Term Projections, "2005 Baseline, Economic and Demographic Projections, ALL Summary Tables Combined of the Economic and Demographic Projections", from the *2006 Economic Report to the Governor*. Population forecasts provided for 2010, 2020, and 2030 in Excel file named "06SummaryTables.xls" (http://governor.utah.gov/dea/LongTerm Projections.html). Population for intermediate years calculated using the compound annual growth rate calculated from the years for which data were published (i.e., 2010, 2020, and 2030).
[41] Utah Governor's Office of Planning and Budget, DEA "Long-Term Projections, 2005 Baseline, Economic and Demographic Projections" in spreadsheet named "Employment by Major Industry" in Excel file named "06SummaryTables.xls" (http://governor.utah.gov/dea/LongTermProjections.html).
[42] AEO2006 employment projections for EIA's Mountain region obtained through special request from EIA (dated September 27, 2006).

population and employment reflect expected responses of the economy — as simulated by the EIA's National Energy Modeling System — to changing fuel and electricity prices and changing technologies, as well as to structural changes within each sector (such as shifts in subsectoral shares and in energy use patterns).

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

Sector	1990-2004[a]	2004-2020[b]
Residential	4.0%	3.4%
Commercial	5.3%	4.3%
Industrial	2.2%	2.3%
Total	**3.4%**	**3.3%**

[a] 1990-2004 compound annual growth rates calculated from Utah electricity sales by year from EIA state electricity profiles (Table 8), (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html).
[b] 2004-2020 compound annual growth rate for total for all three sectors taken from forecast for the energy supply sector (see Appendix A).

Results

Figures B1, B2, and B3 show historic and projected emissions for the RCI sectors in Utah from 1990 through 2020. These figures show the emissions associated with the direct consumption of fossil fuels and, for comparison purposes, show the share of emissions associated with the generation of electricity consumed by each sector. During the period from 1990 through 2020, the residential sector's share of total RCI emissions from direct fuel use and electricity use ranges from 25% to 30% and the commercial sector's share of total emissions ranges from 22% to 35%. The industrial sector's share of total emissions was as high as 53% in 1990, declined to 39% in 2005, and is projected to decline to 35% by 2020.

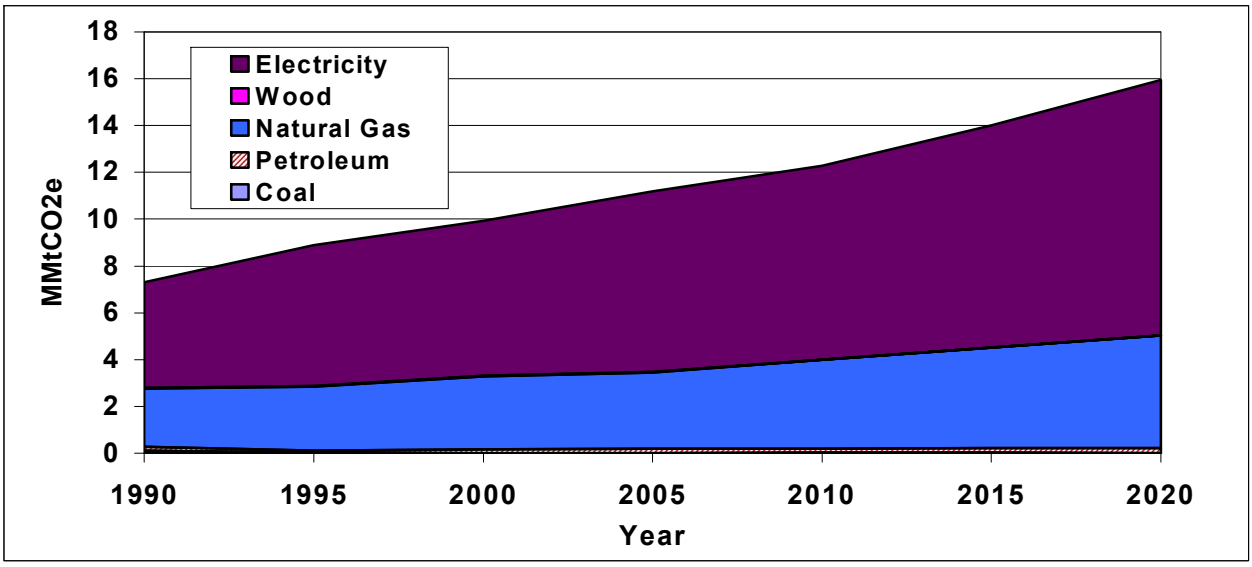
For the residential sector, emissions from electricity and direct fossil fuel use in 1990 were about 7.3 $MMtCO_2e$, and are estimated to increase to about 16 $MMtCO_2e$ by 2020. Emissions associated with the generation of electricity to meet residential energy consumption demand accounted for about 62% of total residential emissions in 1990 and are estimated to increase to 69% of total residential emissions by 2020. In 1990, natural gas consumption accounted for about 34% of total residential emissions and is estimated to account for about 30% of total residential emissions by 2020. Residential sector emissions associated with the use of coal, petroleum, and wood in 1990 were about 0.3 $MMtCO_2e$ combined, and accounted for about 4.1% of total residential emissions. By 2020, emissions associated with the consumption of these three fuels are estimated to be 0.25 $MMtCO_2e$ and to account for 1.6% of total residential sector emissions.

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

	1990-2004[a]	2005-2010[b]	2010-2015[b]	2015-2020[b]
Residential				
natural gas	1.8%	3.0%	2.6%	2.4%
petroleum	0.6%	1.6%	1.9%	1.5%
wood	-2.5%	1.5%	-0.03%	0.5%
coal	-13.5%	1.5%	-0.6%	-0.5%
Commercial				
natural gas	5.0%	2.4%	3.5%	2.8%
petroleum	0.9%	-0.4%	1.8%	1.3%
wood	1.1%	1.1%	1.0%	0.6%
coal	-10.0%	1.0%	1.0%	0.6%
Industrial				
natural gas	-1.5%	1.9%	0.6%	0.6%
petroleum	0.7%	2.9%	2.0%	1.4%
wood	2.3%	3.5%	2.4%	2.3%
coal	-9.1%	1.5%	0.3%	0.2%

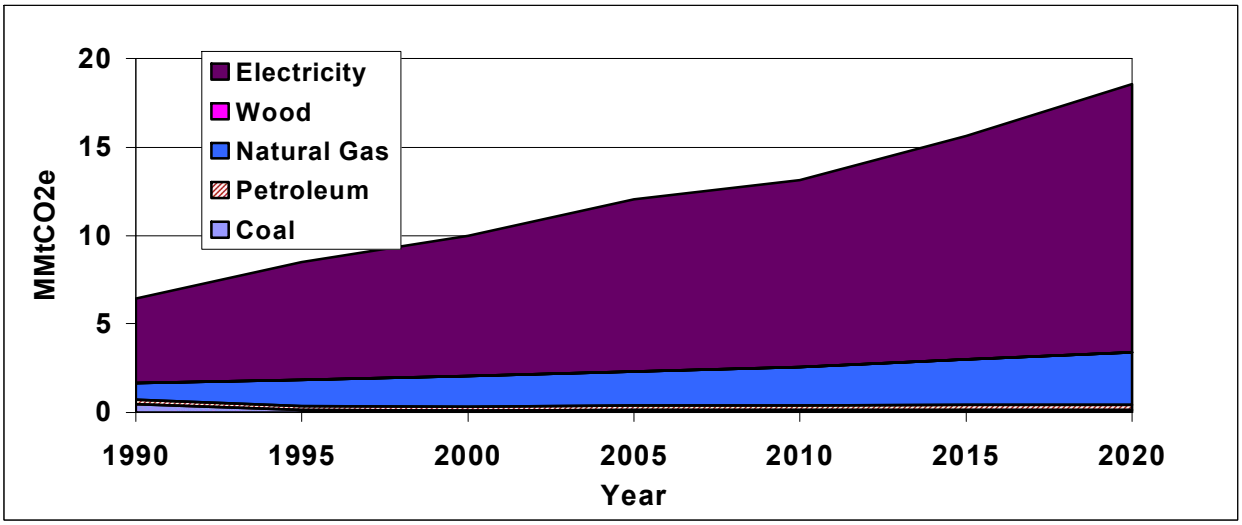
[a] Compound annual growth rates calculated from EIA SED historical consumption by sector and fuel type for Utah. Latest year for which EIA SED information was available for each fuel type is 2003 for coal and wood/wood waste, 2004 for petroleum (distillate oil, kerosene, and liquefied petroleum gas), and 2005 for natural gas. Petroleum includes distillate fuel, kerosene, and liquefied petroleum gases for all sectors plus residual oil for the commercial and industrial sectors.
[b] Figures for growth periods starting after 2004 are calculated from AEO2006 projections for EIA's Mountain region, adjusted for Utah's projected population for the residential sector, non-manufacturing employment for the commercial sector, and manufacturing employment for the industrial sector.

Figure B1. Residential Sector GHG Emissions from Fuel Consumption, 1990-2020



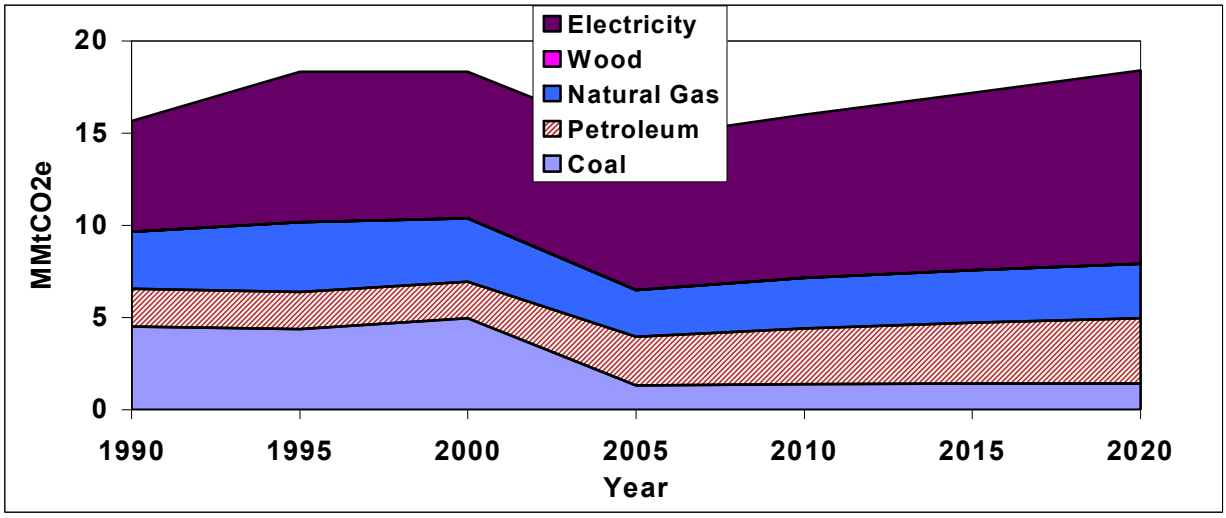
Source: CCS calculations based on approach described in text.
Note: Emissions associated with wood and coal combustion are too small to be seen on this graph.

Figure B2. Commercial Sector GHG Emissions from Fuel Consumption, 1990-2020



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.

Figure B3. Industrial Sector GHG Emissions from Fuel Consumption, 1990-2020



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

For the 15-year period 2005 to 2020, residential-sector GHG emissions associated with the use of electricity and natural gas are expected to increase at average annual rates of about 2.3% and 2.6%, respectively. Emissions associated with the use of petroleum and wood are expected to increase annually by about 1.6% and 0.5%, respectively, and emissions associated with the use of coal are expected to decline by about -0.04% annually. Total GHG emissions for this sector increase by an average of about 2.4% annually over the 15-year period.

For the commercial sector, emissions from electricity and direct fuel use in 1990 were about 6.4 $MMtCO_2e$ and are estimated to increase to about 18.6 $MMtCO_2e$ by 2020. Emissions associated

with the generation of electricity to meet commercial energy consumption demand accounted for about 75% of total commercial emissions in 1990, and are estimated to increase to about 82% of total commercial emissions by 2020. In 1990, natural gas consumption accounted for about 14.6% of total commercial emissions, and is estimated to account for about 16% of total commercial emissions by 2020. Commercial-sector emissions associated with the use of coal, petroleum, and wood in 1990 were about 0.7 $MMtCO_2e$ combined, and accounted for about 11% of total commercial emissions. For 2020, emissions associated with the consumption of these three fuels are estimated to be 0.42 $MMtCO_2e$, and to account for 2.3% of total commercial sector emissions.

For the 15-year period 2005 to 2020, commercial-sector GHG emissions associated with the use of electricity and natural gas are expected to increase at average annual rates of about 3.0% and 2.9%, respectively. Emissions associated with the use of coal, petroleum, and wood are expected to increase annually by about 0.82%, 1.0%, and 0.85%, respectively. Total GHG emissions for this sector increase by an average of about 2.9% annually over the 15-year period.

For the industrial sector, emissions in 1990 were about 15.7 $MMtCO_2e$, and are estimated to increase to about 18.4 $MMtCO_2e$ by 2020. Emissions associated with the generation of electricity to meet industrial energy consumption demand accounted for about 38% of total industrial emissions in 1990 and are estimated to increase to about 57% of total industrial emissions by 2020. In 1990, natural gas consumption accounted for about 20% of total industrial emissions and is estimated to account for about 16% of total industrial emissions by 2020. Industrial sector emissions associated with the use of coal, petroleum, and wood in 1990 were about 6.5 $MMtCO_2e$ combined and accounted for about 42% of total industrial emissions. For 2020, emissions associated with the consumption of these three fuels are estimated to be 5.0 $MMtCO_2e$ and to account for 27% of total industrial sector emissions.

For the 15-year period 2005 to 2020, industrial sector GHG emissions associated with the use of electricity and natural gas are expected to increase at average annual rates of about 1.7% and 1.0%, respectively. Emissions associated with the use of coal, petroleum, and wood are expected to increase annually by about 0.6%, 2.0%, and 2.7%, respectively. Total GHG emissions for this sector increase by an average of about 1.5% annually over the 15-year period.

Figure B3 shows a sharp decline in industrial sector GHG emissions from 2000 to 2005. This decline is primarily associated with the closure of the Geneva Steel plant in 2002 and its use of coking coal. Coking coal consumption was 22,093 billion British thermal units in 2001 and went to zero beginning in 2002, accounting for about a 75% reduction in total coal consumption.

Key Uncertainties

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

- Population and economic growth are the principal drivers for electricity and fuel use. The reference case projections are based on regional fuel consumption projections for EIA's Mountain modeling region scaled for Utah population and employment growth projections. Consequently, there are significant uncertainties associated with the projections. Future work should attempt to base projections of GHG emissions on fuel consumption estimates specific to Utah to the extent that such data become available.

- The AEO2006 projections assume no large long-term changes in relative fuel and electricity prices, relative to current price levels and to U.S. DOE projections for fuel prices. Price changes would influence consumption levels and, to the extent that price trends for competing fuels differ, may encourage switching among fuels, and thereby affect emissions estimates.
- The exception to the AES2006 assumption of no large changes in prices or fuels consumption is the AEO2006 reference case projections for industrial coal consumption. The AEO2006 model's forecast for the EIA's Mountain region assumes that new coal-to-liquids plants would be constructed near active coal mines when low-sulfur distillate prices reach high enough levels to make coal-to-liquids processing economic. Plants are assumed to be co-production plants with generation capacity of 758 MW and the capability of producing 33,200 barrels of liquid fuel per day. The technology assumed is similar to an integrated gasification combined cycle plant, first converting the coal feedstock to gas, and then subsequently converting the synthetic gas to liquid hydrocarbons using the Fisher-Tropsch process. As a result, AEO2006 projections assume a rather significant increase in coal consumption by the coal-to-liquids industrial sector starting in 2011. For the EIA's Mountain region, this sector accounts for 17.5% of total coal consumption in 2011 and 63% of total coal consumption in 2020, with an annual growth rate of 26% from 2011 to 2020.[43] This increase in coal consumption, associated with the installation of coal-to-liquids plants starting in 2011, was excluded from the industrial coal consumption forecasts for Utah because it is considered to represent technology that is beyond the "business-as-usual" assumptions associated with the reference case projections for the industrial coal consumption sector.
- As mentioned in the footnotes above, EIA fuel consumption data are now available through 2005, although UGS has noted problems with the 2004/2005 coal consumption data. Due to resource constraints, these data (available from UGS) could not be incorporated into this initial inventory effort for Utah, but should be incorporated during future updates.

[43] Coal Market Module of the National Energy Modeling System 2006, *Assumptions to the Annual Energy Outlook 2006, Coal Market Module*, Report #: DOE/EIA-0554(2006), March 2006 (http://www.eia.doe.gov/oiaf/aeo/assumption/index.html).

Appendix C. Transportation Energy Use

Overview

Transportation is one the largest GHG source sectors in Utah. The transportation sector includes light and heavy-duty (onroad) vehicles, aircraft, rail engines, and marine engines. Carbon dioxide accounts for about 96 percent of transportation GHG emissions from fuel use. Most of the remaining GHG emissions from the transportation sector are due to N_2O emissions from gasoline engines.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2002 were estimated using SGIT and the methods provided in the EIIP guidance document for the sector.[44,45] For on-road vehicles, the CO_2 emission factors are in units of lb/MMBtu and the CH_4 and N_2O emission factors are both in units of grams/VMT. Key assumptions in this analysis are listed in Table C1. The default fuel consumption data within SGIT were used to estimate emissions, with the most recently available fuel consumption data (2002) from EIA SED added.[46,47] The default VMT data in SGIT were replaced with state-level annual VMT from the Utah Department of Transportation (UDOT).[48] State-level VMT were allocated to vehicle types using the default vehicle mix data in SGIT.

Onroad vehicle gasoline and diesel emissions were projected based on VMT forecasts provided by UDOT.[49] The forecasted VMT data provided by UDOT are based on a straight-line projection of historical data (1990-2004). These VMT projections suggest that the overall state VMT will grow at an average rate of 2.3 percent per year between 2002 and 2020. These projected VMT were applied to vehicle mix fractions calculated from EIA's *Annual Energy Outlook* 2006 (AEO2006). The AEO2006 data were incorporated because they indicate significantly different VMT growth rates for certain vehicle types (e.g., 34 percent growth between 2002 and 2020 in heavy-duty gasoline vehicle VMT versus 284 percent growth in light-duty diesel truck VMT over this period). The procedure first applied the AEO2006 vehicle type-based national growth rates to 2002 Utah estimates of VMT by vehicle type. These data were then used to calculate the estimated proportion of total VMT by vehicle type in each year. Next, these proportions were

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[44] CO_2 emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 1. "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004.

[45] CH_4 and N_2O 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.

[46] Fuel consumption data for Utah are available from: http://geology.utah.gov/sep/energydata/oildata.htm (Table 3.18). However, this table is not specific to transportation, so a portion of the motor gasoline and diesel belongs in the RCI sector. Incorporation of the more recent data for jet fuel and aviation gasoline could not be incorporated into this initial inventory effort due to resource constraints; however, they are estimated to change 2020 emissions by less than 0.1 $MMtCO_2e$.

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

[48] Jerry Arnold, Utah Department of Transportation

[49] Walt Steinvorth, Transportation Planning, Utah Department of Transportation. An alternative source of VMT projections for the Salt Lake City region is the Wasatch Front Regional Council (WFRC). Projections from WFRC were not identified in time for incorporation into this analysis.

applied to the projected state-total VMT year to yield vehicle-type compound annual average growth rates.

Onroad gasoline and diesel fuel consumption was forecasted by developing a set of growth factors that adjusted the VMT projections to account for improvements in fuel efficiency. Fuel efficiency projections were taken from EIA's *Annual Energy Outlook* (AEO). These projections suggest average onroad fuel consumption growth rates of 1.5% per year for gasoline and 1.7% per year for diesel between 2002 and 2020.

Gasoline consumption estimates for 1990-2002 were adjusted by subtracting ethanol consumption. While the historical ethanol consumption suggests continued growth, projections for ethanol consumption in Utah were not available. Therefore, ethanol consumption was assumed to remain at the 2002 level in the reference case projections. Biodiesel and other biofuel consumption were not considered in this inventory because historical consumption and projection data were not available.

For the aircraft sector, emission estimates for 1990 to 2002 are based on SGIT methods and fuel consumption from EIA. Emissions were projected from 2002 to 2020 using general aviation and commercial aircraft operations for 2002 and 2020 from the Federal Aviation Administration's Terminal Area Forecast System[50] and national aircraft fuel efficiency forecasts. To estimate changes in jet fuel consumption, itinerant aircraft operations from air carrier, air taxi/commuter, and military aircraft were first summed for each year of interest. The post-2002 estimates were adjusted to reflect the projected increase in national aircraft fuel efficiency (indicated by increased number of seat miles per gallon), as reported in AEO2006. Because AEO2006 does not estimate fuel efficiency changes for general aviation aircraft, forecast changes in aviation gasoline consumption were based solely on the projected number of itinerant general aviation aircraft operations in Utah, which was obtained from the FAA source noted above. These projections resulted in compound annual growth rates of 1.6% for aviation gasoline and 1.9% for jet fuel.

For the rail and marine sectors, 1990 – 2004 estimates are based on SGIT methods and fuel consumption from EIA. For rail, the historic data show no significant positive or negative trend. The historic marine sector gasoline consumption data show growth from 1990 to 2000; however, there was no growth between 2000 and 2004. Therefore, no growth was assumed for these two sectors.

It should be noted that fuel consumption data from EIA includes nonroad gasoline and diesel fuel consumption in the commercial and industrial sectors. Emissions from these nonroad engines are included in the RCI emissions in this inventory (see Appendix B). Table C2 shows how EIA divides gasoline and diesel fuel consumption between the transportation, commercial, and industrial sectors.

Results

As shown in Figure C1, onroad gasoline consumption accounts for the largest share of transportation GHG emissions. Emissions from onroad gasoline vehicles increased by about 41%

[50] Terminal Area Forecast, Federal Aviation Administration, http://www.apo.data.faa.gov/main/taf.asp.

from 1990-2002 to cover 57% of total transportation emissions in 2002. GHG emissions from onroad diesel fuel consumption increased by 78% from 1990 to 2002, and by 2002 accounted for 23% of GHG emissions from the transportation sector. Emissions from aviation grew by 21% from 1990-2002 to cover 16% of transportation emissions in 2002. Emissions from all other categories combined (boats and ships, locomotives, natural gas and LPG, and oxidation of lubricants) contributed less than 4% of total transportation emissions in 2002.

GHG emissions from onroad gasoline consumption are projected to increase by about 27%, and emissions from onroad diesel consumption are expected to increase by 30% between 2002 and 2020. Aviation fuel consumption is projected to increase by 25% between 2002 and 2020.

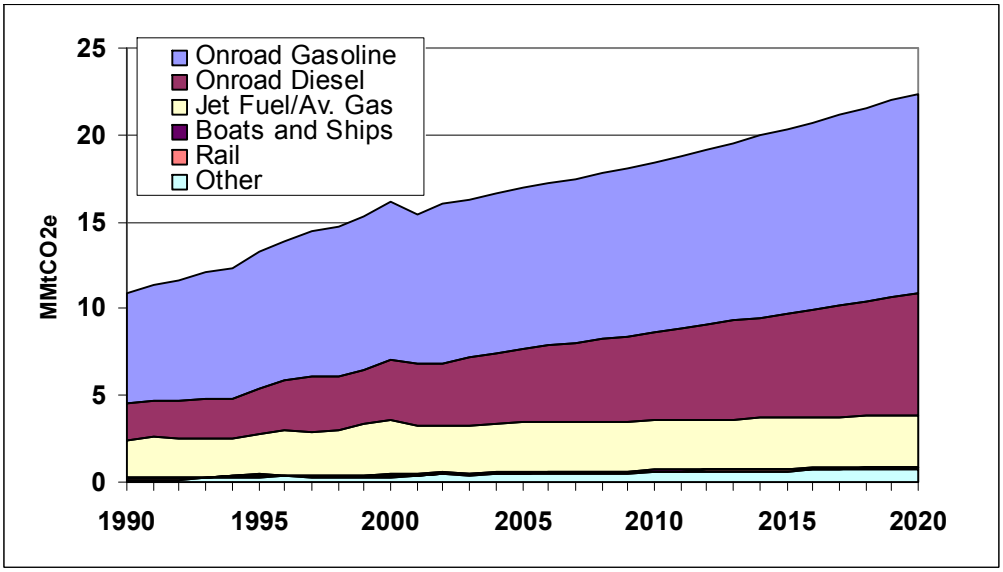
Table C1. Key Assumptions and Methods for the Transportation Inventory and Projections

Vehicle Type and Pollutants	Methods
Onroad gasoline, diesel, natural gas, and LPG vehicles – CO_2	**Inventory (1990 – 2002)** EPA SGIT and fuel consumption from EIA SED **Reference Case Projections (2003 – 2020)** Gasoline and diesel fuel projected using VMT projections provided by UDOT adjusted by fuel efficiency improvement projections from AEO2006. Other onroad fuels projected based on historical data.
Onroad gasoline and diesel vehicles – CH_4 and N_2O	**Inventory (1990 – 2002)** 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 U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003.* State total VMT replaced with VMT provided by UDOT, VMT allocated to vehicle types using default data in SGIT. **Reference Case Projections (2003 – 2020)** VMT projections from UDOT.
Non-highway fuel consumption (jet aircraft, gasoline-fueled piston aircraft, boats, locomotives) – CO_2, CH_4 and N_2O	**Inventory (1990 – 2002)** EPA SGIT and fuel consumption from EIA SED. **Reference Case Projections (2003 – 2020)** Aircraft projected using aircraft operations projections from FAA.

Table C2. 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

Figure C1. Transportation GHG Emissions by Fuel, 1990-2020



Key Uncertainties

Projections of Vehicle Miles of Travel (VMT) and Biofuels Consumption

One source of uncertainty is the future year vehicle mix, which was calculated based on national growth rates for specific vehicle types. These growth rates may not reflect vehicle-specific VMT growth rates for the state. Also, onroad gasoline and diesel growth rates may be slightly overestimated because increased consumption of biofuels between 2005 and 2020 was not taken into account (due to a lack of data).

Uncertainties in Aviation Fuel Consumption

The consumption of international bunker fuels included in jet fuel consumption from EIA is another uncertainty. This fuel consumption associated with international air flights should not be included in the state inventory (as much of it is actually consumed out of state); however, data were not available to subtract this consumption from total jet fuel estimates. 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.

Appendix D. Industrial Processes

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

- CO_2 from:
  - Production of cement and lime.
  - Consumption of limestone, dolomite, and soda ash.
- HFCs, PFCs, and SF_6 from semiconductor manufacture.
- N_2O from nitric acid production.
- SF_6 from magnesium production and processing.
- SF_6 from transformers used in electric power transmission and distribution (T&D) systems.
- 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 Utah include the following:

- N_2O from adipic acid production.
- CO_2 from soda ash production.
- PFCs from aluminum production.
- HFCs from HCFC-22 production.

Emissions and Reference Case Projections
GHG emissions for 1990 through 2005 were estimated using SGIT and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for this sector.[51] Table D1 identifies for each emissions source category the information needed for input into SGIT to calculate emissions, the data sources used for the analysis described here, and the historical years for which emissions were calculated based on the availability of data.

[51] GHG emissions were calculated using SGIT, with reference to EIIP, Volume VIII: Chapter. 6. "Methods for Estimating Non-Energy Greenhouse Gas Emissions from Industrial Processes", August 2004. Referred to as "EIIP" below.

Table D1. Approach to Estimating Historical Emissions

Source Category	Time Period	Required Data for SGIT	Data Source
Cement Manufacturing - Clinker Production	1990 - 2005	Metric tons of clinker produced each year.	Production data sources by year provided in Table D2.
Lime Manufacture	1990 - 2005	Metric tons of dolomitic lime produced each year.	Production data sources by year provided in Table D2.
Limestone and Dolomite Consumption	1990 - 2005	Metric tons of limestone and dolomite consumed.	Production data sources by year provided in Table D2.
Soda Ash Consumption	1990 - 2005	Metric tons of soda ash consumed.	Production data sources by year provided in Table D2.
Nitric Acid Production	1990 - 2005	Metric tons of nitric acid produced each year.	Production data sources by year provided in Table D2.
Magnesium Production	1990 - 2005	Metric tons of magnesium produced each year.	Production data sources by year provided in Table D2.
ODS Substitutes	1990 - 2002	Based on state's population and estimates of emissions per capita from the U.S. EPA national GHG inventory.	-- Population data for 1990 through 2005 from Utah Governor's Office of Planning and Budget, Demographic and Economic Analysis (DEA), "Demographics - Data on People, Data Tables": Annual population provided for each year for 1990 through 2006 in Excel file named "AllUPECData061114.xls" (http://governor.utah.gov/dea/DataTables.html) . -- U.S. 1990-2000 population from U.S. Census Bureau (http://www.census.gov/popest/archives/EST90INTERCENSAL/US-EST90INT-01.html). -- U.S. 2000-2005 population from U.S. 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's proportion of national emissions for 1990 - 2002.	National emissions from U.S. EPA 2005 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003" (http://www.epa.gov/climatechange/emissions/usgginv_archive.html). Value of shipments from U.S Census Bureau's "1997 Economic Census" (http://www.census.gov/econ/census02/). Note: Utah data for NAICS code 334413 withheld in 2002 Economic Census.
Electric Power T&D Systems	1990 - 2002	Emissions from 1990 to 2003 based on the national emissions per kWh and state's electricity use.	National emissions per kWh from U.S. EPA 2005 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003" (http://www.epa.gov/climatechange/emissions/usgginv_archive.html).

Table D2 identifies several industries for which the Utah Department of Environmental Quality (UDEQ), Division of Air Quality (DAQ), compiled production and consumption data for 1995,

2000, and 2005 from either its emission inventory database or by contacting plants to obtain the data. In addition, 1990 and 1993 production and consumption data were taken from a report prepared by the UDEQ/DAQ and Utah's Department of Natural Resources, Office of Energy and Resource Planning, titled, *Utah Greenhouse Gas Emissions, Estimates for 1990 and 1993* (referred to hereafter as "Utah's GHG report"). Chapter 2 of this report presents activity data and GHG emissions for 1990 and 1993 for cement and lime manufacture; limestone, dolomite, and soda ash use; and nitric acid production. The data that UDEQ/DAQ compiled for 1995, 2000, and 2005 and the 1990 and 1993 data in Utah's GHG report were in short tons. A conversion factor of 0.9072 was used to convert short tons to the metric ton values shown in Table D2. Table D3 lists the data sources used to quantify activities related to industrial process emissions, the annual compound growth rates implied by estimates of future activity used, and the years for which the reference case projections were calculated.

Results

Figures D1 and D2 show historic and projected emissions for the industrial processes sector from 1990 to 2020. Total gross GHG emissions were about 2.8 $MMTCO_2e$ in 2000 (4.3% of total gross GHG emissions), rising to about 5.8 $MMTCO_2e$ in 2020 (6.1% of total gross GHG emissions).

Emissions from the overall industrial processes category are expected to grow rapidly, as shown in Figures D1 and D2, with emissions growth primarily associated with increasing use of HFCs and PFCs in refrigeration and air conditioning equipment, and, to a lesser extent, as a result of emissions of CO_2 associated with the production of clinker for cement production, lime manufacture, and magnesium production.

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*.[52] 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. Emissions from the use of ODS substitutes in Utah were calculated using the default methods in SGIT (see dark green line in Figure D2). Emissions have increased from 0.0023 $MMtCO_2e$ in 1990 to about 0.6 $MMtCO_2e$ in 2000, and are expected to increase at an average rate of 7.8% per year from 2000 to 2020 due to increased substitutions of these gases for ODS. The projected rate of increase for these emissions is based on projections for national emissions from the US EPA report referenced in Table D3.

[52] 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. For the US national inventory, a detailed stock vintaging model was used, but this modeling approach has not been completed at the state level.

Table D2. Annual Activity Data for Industrial Processes

Process (Units) / Source	1990	1993	1995	2000	2005	Reference for 1990 and 1993 Data	Reference for 1995, 2000, and 2005 Data
Cement Clinker Production (Metric Tons of Clinker Produced)							
Ash Grove Cement Company	539,421	527,148	673,706	979,807	961,666	Utah's GHG report	UDEQ/DAQ obtained data from company
Holcim (US) Inc. (formerly Holnam)	332,332	317,883	288,880	581,664	707,562	Utah's GHG report	UDEQ/DAQ obtained data from company
Total	871,753	845,030	962,585	1,561,471	1,669,228		
Dolomitic Lime Manufacture (Metric Tons of Lime Manufactured)							
Chemical Lime Company	36,288	49,978	82,142	76,777	74,981	Utah's GHG report	UDEQ/DAQ's Emission Inventory Database; 1996 data used for 1995
Graymont Western US Inc (formerly Continental Lime)	331,128	375,808	437,707	502,004	653,854	Utah's GHG report	UDEQ/DAQ obtained data from company
Total	367,416	425,785	519,848	578,781	728,835		
Limestone Use (Metric Tons Limestone Consumed)							
Intermountain Power Service Corp	57,194	61,397	51,843	54,343	87,008	Utah's GHG report	UDEQ/DAQ obtained data from company; 1996 data used for 1995
Sunnyside Cogeneration Associates					10,295	No data available	UDEQ/DAQ's Emission Inventory Database; no data available prior to 2005
Total	57,194	61,397	51,843	54,343	97,303		
Dolomite Use (Metric Tons Dolomite Consumed)							
Geneva Steel	28,032	37,413	35,038	29,462	0	Utah's GHG report	UDEQ/DAQ's Emission Inventory Database; 1996 data used for 1995; plant closed in 2002
Nucor Steel			73,089	22,951	20,875	No data available	UDEQ/DAQ verified data with company; 1996 data used for 1995
Owens Corning			1,843	1,219	1,843	No data available	UDEQ/DAQ verified data with company
Total	28,032	37,413	109,969	53,633	22,717		
Soda Ash Consumption (Metric Tons Soda Ash Consumed)							
	454	907	3,958	6,669	8,748	Utah's GHG report; data are for one company's sales in Utah	UDEQ/DAQ obtained sales for Utah from four companies
Nitric Acid Production (Metric Tons of Nitric Acid Produced)							
Geneva Nitrogen Inc	84,715	83,170	24,254	24,615	20,671	Utah's GHG report	UDEQ/ DAQ's Emission Inventory Database; 1996 data used for 1995
Primary Magnesium Production (Metric Tons of Magnesium Produced)							
US Magnesium	34,572	34,572	39,071	28,838	35,805	CCS used average of 1995, 2000, and 2005 data for 1990 and 1993.	UDEQ/DAQ obtained data from company

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 the electricity T&D system. Emissions for Utah from 1990 to 2002 were estimated based on the estimates of emissions per kWh from the U.S. EPA GHG inventory and Utah's electricity consumption estimates provided in SGIT. The U.S. Climate Action Report shows expected decreases in these emissions at the national level, and the same rate of decline is assumed for emissions in Utah. The decline in SF_6 emissions in the future reflects expectations of future actions by the electric industry to reduce these emissions.

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 Utah 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 U.S. EPA GHG inventory (U.S. EPA 2005 *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*). The U.S. Climate Action Report shows expected decreases in these emissions at the national level, and the same rate of decline is assumed for emissions in Utah. The decline in emissions in the future reflects expectations of future actions by the semiconductor industry to reduce these emissions.

Relative to total industrial non-combustion process emissions, emissions associated with semiconductor manufacturing are low (about 0.0019 $MMtCO_2e$ in 1990 and 0.0012 $MMtCO_2e$ in 2020), and therefore, appear at the bottom of the graph because of scaling effects in Figure D2. Note that Utah has one semiconductor wafer manufacturing plant (Fairchild Semiconductor Corporation) but due to time constraints UDEQ/DAQ was unable to verify if this plant uses SF_6 and HFCs in its manufacturing processes.

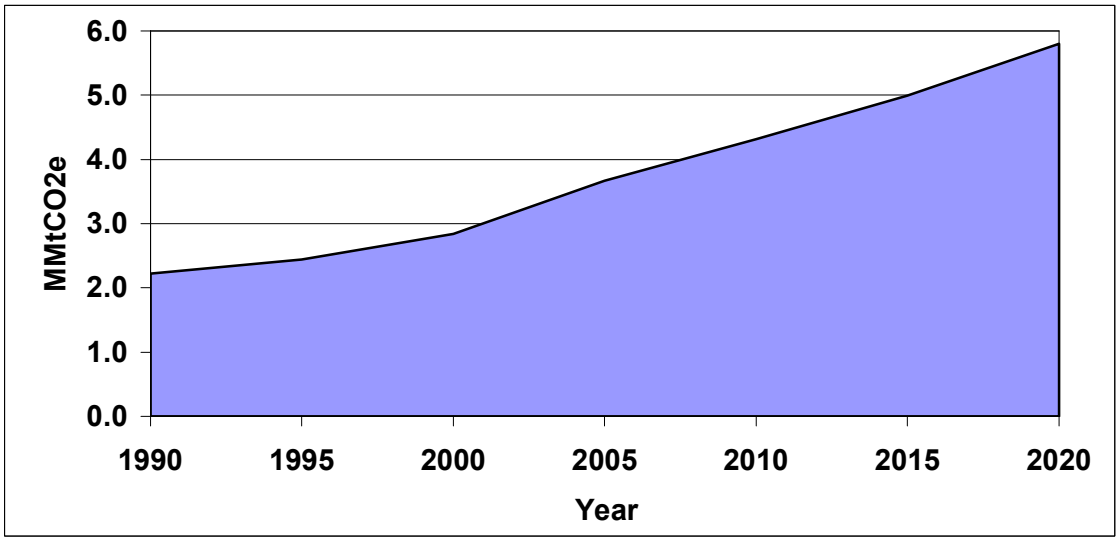
Clinker Production for Cement Manufacture
Utah has two cement plants (Ash Grove Cement Company and Holcim (US) Inc.) that produce clinker (an intermediate product from which finished Portland and masonry cement are made). Clinker production releases CO_2 when calcium carbonate ($CaCO_3$) is heated in a cement kiln to form lime (calcium oxide) and CO_2 (see footnote 1 for reference to EIIP guidance document). Emissions are calculated by multiplying annual clinker production and annual production of masonry cement by emission factors for these processes. The clinker production data for both plants were summed and entered into the SGIT to calculate GHG emissions (see black line in Figure D2). Information on masonry cement production for these two plants was not available. The growth rate for Utah's goods-producing sector was used to project emissions to 2020. As shown in Figure D2, emissions increase slightly from 2005 to 2020, reflecting an overall average annual increase of about 1.6% in growth over that time period.

Table D3. 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 2020
Cement Manufacturing - Clinker Production	2006 - 2020	Compound annual growth rate for Utah's goods-producing sector. The goods-producing sector includes employment in the natural resources and mining, construction, and manufacturing sectors.	Utah Governor's Office of Planning and Budget, DEA "Long-Term Projections, 2005 Baseline, Economic and Demographic Projections"[a]	None, actual data used for 2000 to 2005	1.8	1.5	1.5
Lime Manufacture	2006 - 2020	Ditto	Ditto	Ditto	1.8	1.5	1.5
Limestone and Dolomite Consumption	2006 - 2020	Ditto	Ditto	Ditto	1.8	1.5	1.5
Nitric Acid Production	2006 - 2020	Compound annual growth rate for Utah's manufacturing sector.	Ditto	Ditto	1.4	1.4	1.4
Magnesium Production	2006 - 2020	Ditto	Ditto	Ditto	1.4	1.4	1.4
Soda Ash Consumption	2006 - 2020	Growth between 2004 and 2009 is projected to be about 0.5% per year for U.S. production. Assumed growth is same for 2010 – 2020.	*Minerals Yearbook, 2005: Volume I, Soda Ash*, (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/soda_myb05.pdf).	Ditto	0.5	0.5	0.5
ODS Substitutes	2003 - 2020	Based on national growth rate for use of ODS substitutes.	EPA, 2004 ODS substitutes cost study report (http://www.epa.gov/ozone/snap/emissions/TMP6si9htnvca.htm).	15.8	7.9	5.8	5.3
Semiconductor Manufacturing	2003 - 2020	National growth rate (based on aggregate for all stewardship program categories provided in referenced data source)	U.S. Department of State, U.S. *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 - 2020	Ditto	Ditto	3.3	-6.2	-9.0	-2.8

[a] Employment data provided in spreadsheet named "Employment by Major Industry" in Excel file named "06SummaryTables.xls" (http://governor.utah.gov/dea/LongTermProjections.html).

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

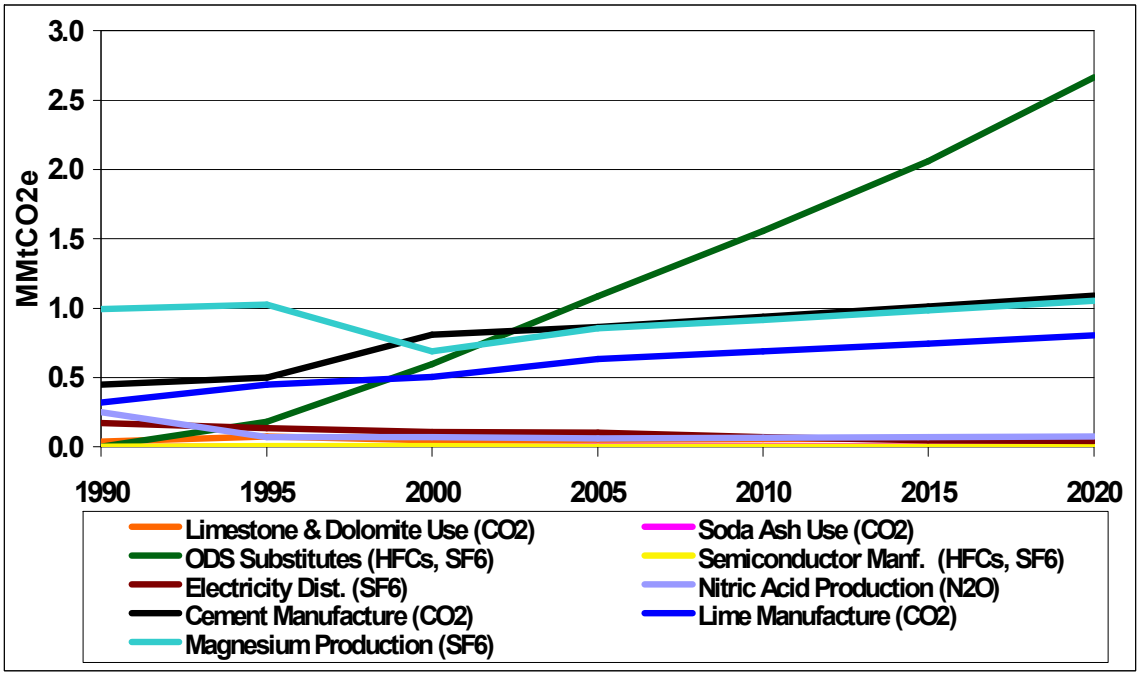


Lime Manufacture

Utah has two plants (Chemical Lime Company and Graymont Western US Inc.) that produce dolomitic lime. Lime is a manufactured product that is used in many chemical, industrial, and environmental applications including steel making, construction, pulp and paper manufacturing, and water and sewage treatment. Lime is manufactured by heating limestone (mostly $CaCO_3$) in a kiln, creating calcium oxide and CO_2. The CO_2 is driven off as a gas and is normally emitted to the atmosphere, leaving behind a product known as quicklime. Some of this quicklime undergoes slaking (combining with water), which produces hydrated lime. The consumption of lime for certain uses, specifically the production of precipitated $CaCO_3$ and refined sugar, results in the reabsorption of some airborne CO_2 (see footnote 1 for reference to EIIP guidance document).

Emissions are estimated by multiplying the amount of dolomitic lime produced by an emission factor for dolomitic lime. The dolomitic lime production data for both plants were summed and entered into the SGIT to calculate GHG emissions (see dark blue line in Figure D2). The growth rate for Utah's goods-producing sector was used to project emissions to 2020. As shown in Figure D2, emissions increase slightly from 2005 to 2020 reflecting an overall average annual increase of about 1.6% in growth over that time period.

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



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.[53] Table D2 shows the companies for which the UDEQ/DAQ obtained limestone and dolomite consumption data and for which 1990 and 1993 consumption data were available in Utah's GHG report. In developing the data for this category, the UDEQ/DAQ identified potential double-counting of limestone consumption estimates for 1990 and 1993 and, therefore, not all of the limestone consumption data in Utah's GHG report were used for this inventory.

Emissions were estimated by multiplying the total amount of limestone and the total amount of dolomite consumed in Utah for each year by emission factors in SGIT (see orange line in Figure D2). The growth rate for Utah's goods-producing sector was used to project emissions to 2020. As shown in Figure D2, emissions increase slightly from 2005 to 2020 reflecting an overall average annual increase of about 1.6% in growth over that time period. Relative to total industrial non-combustion process emissions, emissions associated with limestone and dolomite consumption are low (about 0.039 $MMtCO_2e$ in 1990 and 0.068 $MMtCO_2e$ in 2020), and therefore, appear at the bottom of the graph in Figure D2 due to scaling effects.

[53] 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).

Soda Ash Consumption
Commercial soda ash (sodium carbonate) is used in many consumer products such as glass, soap and detergents, paper, textiles, and food. CO_2 is also released when soda ash is consumed (see footnote 1 for reference to EIIP guidance document). The State of Utah estimated soda ash consumption for 1990 and 1993 based on sales data obtained from one major distributor in Utah. For 1995, 2000, and 2005, the UDEQ/DAQ obtained data from four distributors on the amount of soda ash sold in Utah to Utah customers. It is assumed that all soda ash sold in Utah to Utah customers, was consumed within the state. The amount of soda ash sold in Utah was summed and entered into the SGIT to calculate GHG emissions (see dark pink line in Figure D2).

According to the USGS, this industry is expected to grow at an annual rate of 0.5% from 2004 through 2009 for the U.S. 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 2020. Relative to total industrial non-combustion process emissions, emissions associated with soda ash consumption are low (about 0.0002 $MMtCO_2e$ in 1990 and 0.0039 $MMtCO_2e$ in 2020), and therefore, cannot be seen in the graph due to scaling effects in Figure D2.

Nitric Acid Production
Utah has one plant (Geneva Nitrogen Inc.) that produces nitric acid. The production of nitric acid (HNO_3) produces nitrous oxide (N_2O) as a by-product, via the oxidation of ammonia. Nitric acid is a raw material used primarily to make synthetic commercial fertilizer. It is also a major component in the production of adipic acid (a feedstock for nylon) and explosives. Relatively small quantities of nitric acid are also employed for stainless steel pickling, metal etching, rocket propellants, and nuclear fuel processing (see footnote 1 for reference to EIIP guidance document). The production data for the plant were entered into the SGIT to calculate GHG emissions (see purple line in Figure D2).

The SGIT uses a default emission factor of 0.008 metric tons of N_2O emissions per metric ton of nitric acid produced based on a weighted-average calculated over the different types of emissions control technologies typically employed by nitric acid plants nationwide.[54] The UDEQ/DAQ verified that the Geneva Nitrogen nitric acid plant has used and continues to use selective catalytic reduction (SCR) control technology. Therefore, the emission factor in SGIT was changed to 0.0095 metric tons of N_2O emissions per metric ton of nitric acid produced for application in the Utah case. The growth rate for Utah's manufacturing sector was used to project emissions to 2020. Though it is difficult to see in Figure D2 due to scale effects, emissions from nitric acid production in Utah increase slightly from 2005 to 2020, reflecting an overall average annual increase of about 1.4% in Utah's manufacturing sector growth over that time period. Emissions declined at an annual rate of about -9.0% from 1990 to 2005.

[54] According to Chapter 6 of the EIIP (see footnote 1 for reference to EIIP guidance document), the nitric industry controls for oxides of nitrogen through two technologies: non-selective catalytic reduction (NSCR) and SCR. Only one of these technologies, NSCR, is effective at controlling N_2O emissions in the process of controlling oxides of nitrogen emissions. NSCR technology was widely installed in nitric acid plants built between 1971 and 1977. Due to high-energy costs and associated high gas temperatures, this technology has not been popular with modern plants. Only about 20% of the current plants have NSCR technology installed. All other plants have installed SCR technology. Since 80% of the current plants have SCR technology installed and 20% have NSCR technology, the weighted-average emission factor used in the SGIT is equal to (0.0095 x 0.80) + (0.002 x 0.20) = 0.008 metric tons N_2O per metric ton of nitric acid produced.

Magnesium Production
Utah has one primary magnesium production plant (US Magnesium). According to the EIIP guidance (see footnote 1 for reference to EIIP guidance), the magnesium metal production and casting industry uses SF_6 as a cover gas to prevent the violent oxidation of molten magnesium in the presence of air. A gas mixture consisting of CO_2, air, and a small concentration of SF_6 is blown over the molten magnesium metal to induce the formation of a protective crust. Most producers of primary magnesium metal and most magnesium part casters use this technique. Sulfur dioxide was previously used for this process, but SF_6 replaced it due to the numerous health and safety risks associated with sulfur dioxide.

The UDEQ/DAQ obtained annual magnesium production data for the plant for 1995, 2000, and 2005. Information on production data for castings was not obtained due to time constraints. This category was not included in the Utah GHG report. The Center for Climate Strategies (CCS) estimated emissions for 1990 and 1993 based on the average annual magnesium production rates for 1999, 2000, and 2005. The production data for each year were entered into the SGIT to calculate GHG emissions for this plant (see turquoise line in Figure D2). The growth rate for Utah's manufacturing sector was used to project emissions to 2020. As shown in Figure D2, emissions increase slightly from 2005 to 2020, reflecting an overall average annual increase of about 1.4% in Utah's manufacturing sector growth over that time period.

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

- Data for all of the historical years could not be obtained because of time and resource constraints. The inventory can be improved upon in the future by obtaining actual production and consumption data for all of the historical years. In addition, for plants for which 1996 data were used for 1995, future work should include an effort to obtain the 1995 data for use in calculating emissions.
- Primary magnesium production data were not available for 1990 and 1993. CCS estimated production for these two years based on the average of the production data that the UDEQ/DAQ obtained for the US Magnesium plant in Utah. This approach for estimating production for 1990 and 1993 is highly uncertain. In addition, production data on castings were not obtained due to time constraints. Future work on this category should include efforts to obtain actual magnesium production and casting data from the US Magnesium plant for all historical years.
- Historical production and consumption data for 1990 and 1993 were obtained from Utah's GHG report. Due to time and resource constraints, the UDEQ/DAQ was unable to verify the production and consumption data with the companies for these years. Some potential for double counting of limestone consumption with cement and lime production in Utah's GHG report was identified and, for the purpose of this inventory and forecast effort, the limestone consumption data were not used. Future work should focus on verifying with companies the 1990 and 1993 production and consumption data in Utah's GHG report.

- 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 regarding future emissions from the industrial processes category as a whole. Future emissions depend on the competitiveness of Utah manufacturers in these industries, and the specific nature of the production processes used in Utah.
- 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; Utah-specific estimates are currently unavailable. In addition, 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.
- 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).
    - 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 Industries

This appendix reports the GHG emissions that are released during the production, processing, transmission, and distribution of fossil fuels. Known as fugitive emissions, these are methane and carbon dioxide emissions released via leakage and venting at coal mines, oil and gas fields, processing facilities, and pipelines. Nationally, fugitive emissions from natural gas systems, petroleum systems, and coal mines accounted for 2.8% of total US greenhouse gas emissions in 2004.[55] Emissions associated with energy consumed by these processes are included in Appendix B, Residential, Commercial and Industrial Sectors.

Oil and Gas Production

In 2005, Utah ranked 13th in crude oil production among U.S. states, totaling 46,000 barrels (bbls) per day and accounting for about 1% of U.S. production.[56] Proved crude oil reserves sit at 215 million barrels, which is similarly about 1% of U.S. totals. Oil production in the State peaked in 1985 at 113,000 bbls per day, and declined steadily until 2004.[57] With the discovery of the Covenant Field in 2004, Utah crude oil production experienced an upswing, but with no new discoveries in that area, production will likely start to decline in 2008 or 2009.[58] Utah has five petroleum refineries, with a combined crude oil distillation capacity of 167,350 barrels per day.[59]

Utah currently produces over two times the amount of natural gas that it consumes. For example, in 2005, Utah consumed 161 billion cubic feet (Bcf) of natural gas and produced 313 Bcf.

In 2005, Utah reported its highest natural gas production in the State's history at 313 Bcf gross production, 26% of which was attributed to coalbed methane (CBM) production.[60] Although CBM production started in 1987, it was not until 1996 that CBM accounted for more than 5% of total natural gas production in the state.[61] Currently, Utah places fifth in the nation for both CBM proved reserves and for CBM production, with total coalbed methane production for the State at about 15% of the production of each of the two leading CBM producing states, Colorado and New Mexico.[62] Utah CBM production peaked at 102 Bcf in 2002, when it accounted for 35% of total natural gas production in the State. Although overall natural gas production has been

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[55] "The US Inventory of Greenhouse Gas Emissions and Sinks", US EPA, 2005.
[56] Utah Division of Oil, Gas and Mining, Accessed at <http://ogm.utah.gov/oilgas/STATISTICS/production/annual/AOILPROD.HTM> and "Petroleum Profile: Utah", US DOE Energy Information Administration website, December 2006, Accessed at <http://tonto.eia.doe.gov/oog/info/state/ut.html>
[57] Utah Division of Oil, Gas and Mining, Accessed at <http://ogm.utah.gov/oilgas/STATISTICS/production/annual/AOILPROD.HTM>
[58] Input from Michael Vanden Berg, Utah Geological Survey. E-mail: michaelvandenberg@utah.gov
[59] "Petroleum Profile: Utah", US DOE Energy Information Administration website, December 2006, Accessed at <http://tonto.eia.doe.gov/oog/info/state/ut.html>
[60] Utah Division of Oil, Gas and Mining, Jan 2007, Accessed at < http://ogm.utah.gov/oilgas/STATISTICS/production/annual/AGASPROD.HTM > and CBM production from Utah Geological Survey, Jan 2007, accessed at < http://geology.utah.gov/sep/energydata/natgasdata.htm>
[61] Utah Division of Oil, Gas and Mining, Jan 2007, Accessed at < http://ogm.utah.gov/oilgas/STATISTICS/production/annual/AGASPROD.HTM > and CBM production from Utah Geological Survey, Jan 2007, accessed at < http://geology.utah.gov/sep/energydata/natgasdata.htm>
[62] "Natural Gas Navigator", US DOE Energy Information Administration website, December 2006, Accessed at <http://tonto.eia.doe.gov/dnav/ng/ng_enr_cbm_a_EPG0_r52_Bcf_a.htm>

increasing, CBM production has been declining at an average of 7% annually for the past three years.[63] While the production and transport systems for CBM and conventional natural gas are similar, coalbed methane development generally requires more wells to produce a comparable amount of gas. Therefore, CBM will generally have slightly higher fugitive emissions per unit of natural gas produced. These differences are accounted for in the inventory.

A potentially significant source of CO_2, is that of 'entrained' CO_2 in raw gas emerging from the ground. In some areas entrained CO_2 can be significantly above pipeline specifications, and must be separated out at gas processing facilities. A simple estimate of entrained CO_2 in Utah coal bed methane is included in the inventory and forecast.[64]

As for unconventional oil reserves, Utah has the second largest oil shale deposits of any U.S. state. While commercial oil shale production is a number of years away, high oil prices have brought renewed interest. The Utah portion of the Green River oil shale resource is estimated to be between 165 and 320 billion barrels of oil while Colorado holds approximately 1 trillion barrels, and Wyoming has about 300 billion barrels.[65] Several companies are currently researching the economics of developing this resource. Great uncertainty lies in oil price forecasts and whether high prices can be sustained over the long-term while oil shale technologies are developed. In Utah, there is currently one company, Oil Shale Exploration Company, who is researching mine and surface retort of oil shale.[66] Given the large uncertainty surrounding future production from oil shale in Utah, especially in the 2010-2020 timeframe, this analysis does not include a specific estimate for oil shale production or for total GHG emissions from this process. While a high level review of oil shale research projects has been conducted, meaningful GHG emission intensity estimates could not be provided within the time constraints of this project.

Oil and Gas Industry Emissions

Emissions of methane (CH_4) and entrained CO_2 can occur at many stages of production, processing, transmission, and distribution of oil and gas. With approximately 6700 active gas and oil wells in the State, 11 operational gas processing plants, 5 oil refineries, and over 16,000 miles of gas pipelines[67], there are significant uncertainties associated with estimates of Utah's GHG emissions from this sector. This is compounded by the fact that there are no regulatory requirements to track CO_2 or methane emissions. Therefore, estimates based on emissions measurements in Utah are not possible at this time.

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[63] Utah Division of Oil, Gas and Mining, Jan 2007, Accessed at < http://ogm.utah.gov/oilgas/STATISTICS/production/annual/AGASPROD.HTM > and CBM production from Utah Geological Survey, Jan 2007, http://geology.utah.gov/sep/energydata/natgasdata.htm

[64] A simple assumption of 2% entrained CO2 is used, based on average data from CBM well tests in the Drunkard's Wash and Whitman Park fields, as reported in Bulletin 132, "Energy, Minerals and Groundwater Resources of the Carbon and Emery Counties", Utah Geological Survey, 2003. The one exception included in this inventory is for production from the Castlegate field (<1% total CBM production), for which 10% entrained CO_2 is reported.

[65] Utah Oil Shale database, compiled by Michael D. Vanden Berg, John R. Dyni, and David E. Tabet, 2006.

[66] Based on input from Michael Vanden Berg, Utah Geological Survey. E-mail: michaelvandenberg@utah.gov.

[67] Data from EIA, Gas Facts and Utah Division of Oil, Gas and Mining, and Utah Geological Survey.

The State Greenhouse Gas Inventory Tool (SGIT), developed by the U.S. EPA, facilitates the development of a rough estimate of state-level greenhouse gas emissions.[68] Methane emission estimates are calculated by multiplying emissions-related activity levels (e.g. miles of pipeline, number of compressor stations) by aggregate industry-average emission factors. Key information sources for the activity data are the Utah Division of Oil, Gas and Mining[69], the Utah Geological Survey[70], the American Gas Association's annual publication *Gas Facts*[71], and to a lesser extent, the U.S. DOE EIA.[72] Methane emissions were estimated using SGIT, with reference to the EIIP guidance document.

Projections of methane emissions from oil and gas systems are developed based on the following key drivers:

- Natural Gas Consumption – See Appendix A, Electricity, and Appendix B, Residential, Commercial and Industrial Sector for assumptions used in projecting natural gas consumption in Utah. Based on those assumptions, Utah's natural gas consumption is projected to grow at an annual rate of about 2.6% until 2010, then, slow slightly with an annual average growth of about 2% out to 2020.
- Production – Continued growth over the next few years in both oil and gas appears likely. According to statistics from the Utah Division of Oil, Gas and Mining, the number of approved drilling permits has grown by at least a third in each of the last three years.[73] While an increase in drilling permits does not necessarily translate directly to increased production, it is an indication that growth may continue in the short term. As a simple estimate for projections, oil and total natural gas production, processing, refining and transportation rates are forecast to follow recent growth trends in the State through 2009. Actual production over this period could be significantly higher, as reflected by the strong increase in drilling permits. From 2010 to 2020, growth rates for gas production are based on regional results from U.S. DOE EIA's *Annual Energy Outlook 2006* ("U.S. DOE regional projections"), where these data are available. Oil production is forecast to decline between 2009 and 2020. Simple assumptions were made for oil refining and transport growth rates.

Table E1 provides an overview of data sources and approach used to project future emissions.

[68] 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.
[69] Utah Division of Oil, Gas, and Mining, Department of Natural Resources, Accessed at http://ogm.utah.gov.
[70] Utah Geological Survey, Jan 2007, http://geology.utah.gov.
[71] American Gas Association "Gas Facts, A Statistical Record of the Gas Industry" Referenced annual publications from 1992 to 2004.
[72] "Petroleum Navigator" and "Natural Gas Navigator", U.S. DOE Energy Information Administration website, November 2006, Accessed at http://www.eia.doe.gov.
[73] Government of Utah: Division of Oil, Gas and Mining Statistics, as of 12/1/2006. Accessed at http://www.ogm.utah.gov/oilgas/STATISTICS/permits/APDcount/apds_annual.htm.

Table E1. Approach to Estimating Historical and Projected Methane Emissions from Natural Gas and Oil Systems.

	Approach to Estimating Historical Emissions		**Approach to Estimating Projections**
Activity	***Required Data for SGIT***	***Data Source***	***Projection Assumptions***
Natural Gas Drilling and Field Production	Number wells	EIA	Emissions estimated assuming natural gas production trend continues until 2009 at 2.4% annually,[74] then follow U.S. DOE regional projections until 2020, which average 0.8% annual growth.[75]
	Miles of gathering pipeline	Gas Facts[76]	
Natural Gas Processing	Number gas processing plants	Utah Geological Survey[77]	Emissions follow trend of natural gas processing volume, which continues to grow at 4.5% annually until 2009, then follow U.S. DOE production trends to 2020, as above.[78]
Natural Gas Transmission	Miles of transmission pipeline	Gas Facts[76]	Emissions follow trend of State gas production, as above.
	Number of gas transmission compressor stations	EIIP[79]	
	Number of gas storage compressor stations	EIIP[80]	
	Number of LNG storage compressor stations	Unavailable, assumed negligible.	
Natural Gas Distribution	Miles of distribution pipeline	Gas Facts[76]	Distribution emissions follow State gas consumption trend - annual growth rate of 2.6% until 2010, and 2% per year out to 2020.[81]
	Total number of services	Gas Facts	
	Number of unprotected steel services	Ratio estimated from 2002 data[82]	

[74] Assumption based on EIA data with an average annual growth rate of 2.4% average annual growth between 2000-2005.
[75] Based on US DOE Annual Energy Outlook 2006, natural gas production projection for Rocky Mountain region. Accessed at http://www.eia.doe.gov/oiaf/aeo/supplement/sup_ogc.xls.
[76] No Gas Facts available for 1991 and 1993, so a linear relationship was assumed to extrapolate from the previous and subsequent year.
[77] Utah Geological Survey lists gas processing plants from 1997 to 2005.
[78] Growth assumption based on EIA gas processing data. Average annual growth of 9.8% in gas processing volume between 1990 and 2004.
[79] Number of gas transmission compressor stations = miles of transmission pipeline x 0.006 EIIP. Volume VIII: Chapter 5, March 2005.
[80] Number of gas storage compressor stations = miles of transmission pipeline x 0.0015 EIIP. Volume VIII: Chapter 5, March 2005.
[81] Based on US DOE regional projections and electric sector growth assumptions (see Appendix A and B).
[82] Gas Facts reported unprotected and protected steel services for 2002, but only total services for other years. Therefore the ratio of unprotected and protected steel services in 2002 was assumed to be the ratio for all other years (0.4891 for protected services and 0.0045 for unprotected services). This yields more congruent results than the EIIP guidance of using multipliers of 0.2841 for protected steel services, and 0.0879 for unprotected steel services.

	Approach to Estimating Historical Emissions		**Approach to Estimating Projections**
Activity	***Required Data for SGIT***	***Data Source***	***Projection Assumptions***
	Number of protected steel services	Ratio estimated from 2002 data[82]	
Coal Bed Methane – Entrained CO_2	Average entrained CO_2 level assumed from well tests[83]	Utah Geological Survey[84]	Emissions hold flat at 2005 levels, entrained CO_2 levels assumed constant at 2%.[85]
Oil Production	Annual production	Utah DOGM[86]	Emissions follow recent trend in State oil production, growing at 4.5% annually until 2008[87], then declining at 3.5% annually until 2020.[88]
Oil Refining	Annual amount refined	EIA[89]	Emissions projected to increase at a rate of 1.0% annually in the State.[90]
Oil Transport	Annual oil transported	Unavailable, assumed oil refined = oil transported	Emissions follow trend of State oil refining, as above.

Note that potential improvements to production, processing, and pipeline technologies resulting in GHG emissions reductions have not been accounted for in this analysis.

As noted above, this analysis also does not include a specific estimate for oil shale production. Note that any commercial development of oil shale in the region would result in increased CO_2e emissions from oil production, refining and transportation, not included in current forecasts. As production of oil from oil shale is expected to be energy (and therefore greenhouse gas) intensive, any future oil shale development could have significant GHG implications.[91]

[83] A simple assumption of 2% entrained CO2 is used, based on average data from CBM well tests in the Drunkard's Wash and Whitman Park fields, as reported in Utah Geological Survey Bulletin 132.
[84] Bulletin 132, "Energy, Minerals and Groundwater Resources of the Carbon and Emery Counties", Utah Geological Survey, 2003.
[85] With the exception of the Castlegate field, as it has measured entrained CO_2 levels of 10%, as reported in
[86] Utah Division of Oil, Gas and Mining reports annual oil production.
[87] Based on Utah Geological Survey data, annual growth exceeded 10% in 2004 and 2005 with the discovery of the Covenant Field. Continued 4.5% growth to 2008 suggested by Michael Vanden Berg, Utah Geological Survey. E-mail: michaelvandenberg@utah.gov.
[88] Following the production peak in 1985, Utah crude oil production declined at an average rate of 5.5% annually between 1990 and 2003 (until further discoveries in 2004). Decline rate of 3.5% between 2009 and 2020 suggested by Michael Vanden Berg, Utah Geological Survey. E-mail: michaelvandenberg@utah.gov.
[89] Data extracted from the Petroleum Supply Annual for each year. Refining assumed to be equal to the total input of crude oil into PADD IV times the ratio of Utah's refining capacity to PADD IV's total refining capacity. No data for 1995 and 1997, so linear relationship assumed from previous and subsequent years.
[90] Projected growth rate based on input from Michael Vanden Berg, Utah Geological Survey. E-mail: michaelvandenberg@utah.gov. Based on EIA data, crude refined in Utah grew 1.4% annually between 1990 and 2004.
[91] For indications of potential GHG emission intensity of oil shale development see "Strategic Significance of America's Oil Shale Resource", U.S. Department of Energy, March 2004. Accessed on January 20, 2007 at http://www.fossil.energy.gov/programs/reserves/npr/NPR_Oil_Shale_Program.html.

Coal Production Emissions

Methane occurs naturally in coal seams, and is typically vented during mining operations for safety reasons. Coal mine methane emissions are usually considerably higher, per unit of coal produced, from underground mining than from surface mining.

Utah's 13 operational coal mines, all of which are underground, produced 24.6 million short tons of coal in 2005.[92] As reported in this inventory, methane emissions from coal mines are as reported by the EPA, and include emissions from underground coal mines and post-mining activities.[93]

While coal mining activity fluctuated between 1990 and 2004, the average annual growth rate over this period was just under 1%.[94] During this same period, coal mining methane emissions reported by the U.S. EPA fluctuated significantly, but average growth was just over 5% annually. Fluctuations in coal mine methane emissions is likely due to a number of factors including variations in mining practices and varying methane content in the coal seams. While Utah's coal production will fluctuate from year to year, it is expected to average around 25 million short tons per year, as market conditions limit Utah coal production growth.[95] Given that coal production is projected to stay relatively flat, as a simple assumption, coal mine methane emissions are projected to hold flat at 2004 levels.

Results

Table E2 displays the estimated methane emissions from the fossil fuel industry in Utah from 1990 to 2005, with projections to 2020. Emissions from this sector grew by 65% from 1990 to 2005 but projections indicate slowing growth from this sector, with a projected increase of a further 11% between 2005 and 2020. Coal mining and the natural gas industry are the major contributors to GHG emissions, while most of the projected growth in emissions is attributed to the natural gas industry.

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[92] Utah Geological Survey, Energy and Mineral Data, accessed at http://geology.utah.gov/sep/energydata/coaldata.htm.

[93] Emissions from EPA *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004* (April 2006) http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2006.html.

[94] Utah Geological Survey, Energy and Mineral Data, accessed at http://geology.utah.gov/sep/energydata/coaldata.htm.

[95] Input from Michael Vanden Berg, Utah Geological Survey. E-mail: michaelvandenberg@utah.gov.

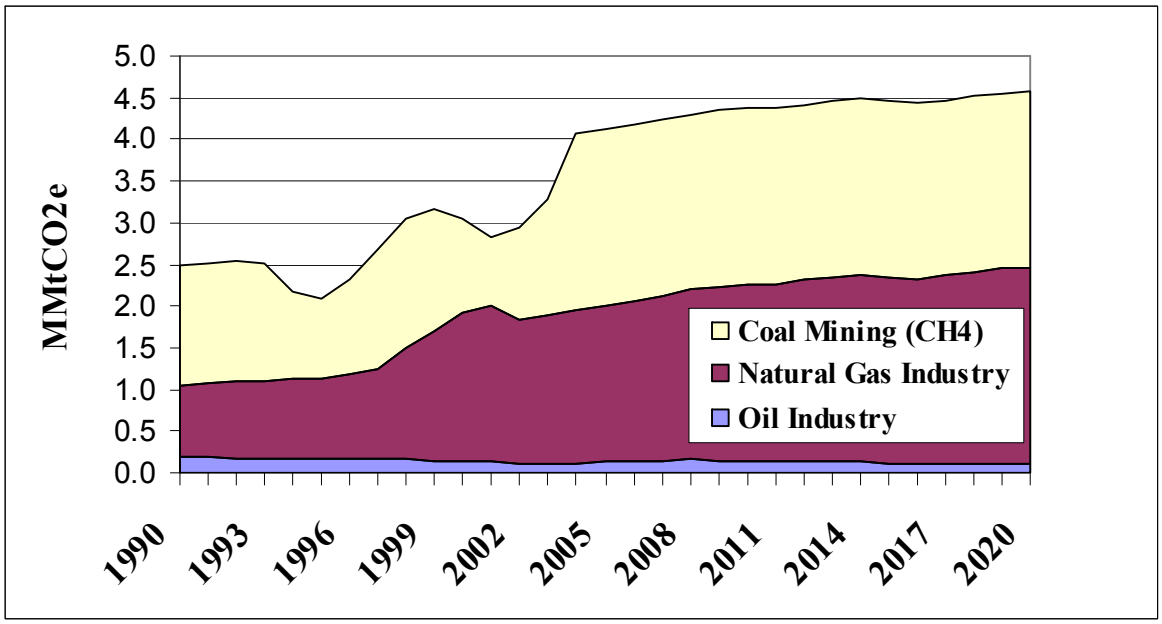
Table E2. Methane Emissions and Projections from the Fossil Fuel Industry, 1990-2020

	1990	1995	2000	2005	2010	2015	2020
Fossil Fuel Industry	**2.49**	**2.10**	**3.06**	**4.12**	**4.38**	**4.46**	**4.58**
Natural Gas Industry	0.84	0.97	1.80	1.87	2.12	2.22	2.36
Production (CH4)	0.1	0.1	0.3	0.3	0.3	0.4	0.4
Processing (CH4)	0.3	0.3	0.5	0.5	0.6	0.6	0.7
Methane Emissions (CH4)	*0.3*	*0.3*	*0.4*	*0.4*	*0.5*	*0.5*	*0.6*
Entrained Gas (CO2)	*0.0*	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Transmission (CH4)	0.2	0.2	0.2	0.6	0.7	0.7	0.7
Distribution (CH4)	0.3	0.3	0.8	0.4	0.5	0.6	0.6
Oil Industry	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Production (CH4)	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Methane Emissions (CH4)	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Refineries (CH4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Methane Emissions (CH4)	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Coal Mining (CH4)	1.4	1.0	1.1	2.1	2.1	2.1	2.1

Numbers in the above table may not appear to add exactly due to rounding.

Figure E1 displays the methane emissions from coal mining and natural gas and oil systems, on a CO_2 equivalent basis.

Figure E1. Fossil Fuel Industry Emission Trends, 1990-2020



Key Uncertainties

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

- Current levels of fugitive emissions: these are based on industry-wide averages, and until estimates are available for local facilities significant uncertainties remain.
- Projections of future production of fossil fuels: these industries are difficult to forecast with the mix of drivers: economics, resource supply, demand, and regulatory procedures. The assumptions used for the projections, projecting trends for the near-term and a combination of AEO2006 growth rates and input from State energy data specialists through 2020, do not include any significant changes in energy prices, relative to today's prices. Large price swings, resource limitations, or changes in regulations could significantly change future production and the associated GHG emissions.
- Other uncertainties include the exact amount of entrained CO_2 in current and future CBM production, any commercial oil shale production, and potential emissions-reducing improvements in oil and gas production, processing, and pipeline technologies.

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 (combustion of fossil fuels in agricultural equipment) are included in the RCI sector estimates.

There are two livestock sources of 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 because of digestive activity in the large fore-stomach. 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 aerobic conditions. Under aerobic conditions, N_2O emissions are dominant. Emissions estimates from manure management are based on manure that is stored and treated on 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 the agricultural soils emissions.

The management of agricultural soils can result in N_2O emissions and net fluxes of CO_2 causing emissions or sinks. 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 application, sewage sludge, nitrogen fixation, and histosols (high organic soils, such as wetlands or peatlands) cultivation. 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 (CO_2 from crop residue burning is not included, as it is considered to be associated with a short-term carbon cycle, unlike fossil fuels). Methane emissions occur during rice cultivation. However, rice is not grown in Utah.

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 SGIT and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for the sector.[96] In general, the SGIT methodology applies emission factors developed for the U.S. 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.[97]

The SGIT file for this category includes data on the number of animals in the state from 1990 to 2002 published by the USDA National Agriculture Statistical Service (NASS).[98] Data for 2003 through 2005 were available from NASS for diary cattle, swine, and some but not all of the beef cattle categories in SGIT. Data for poultry, sheep, goats, and horses were not available from NASS for 2003 through 2005. Because of time and resource constraints associated with forecasting individual animal populations (within the SGIT structure) for which the latest year of data varied, emissions for enteric fermentation and manure management were aggregated and projected from 2002 year emissions (the latest year for which population data were available for all animal categories) using growth factors developed from the historical trend in emissions. For Utah, the NASS does not publish historical population data for turkeys. The Utah Department of Environmental Quality (UDEQ), Division of Air Quality (DAQ) provided population data for turkeys for 1995 through 2005.

The default data in SGIT accounting for the percentage of each livestock category using each type of manure management system was used for this inventory, except that the UDEQ/DAQ provided revisions that were used to replace the default SGIT assumptions for swine, chickens, and turkeys. Default SGIT assumptions were available for 1990 through 2002. For swine, the revisions for 1995 to 2002 provided by the UDEQ/DAQ reflect the manure management system used by a commercial swine operation that began operation in Utah in 1995. The following tables show the default SGIT assumptions and UDEQ/DAQ revisions to the default assumptions for swine and chickens, which vary by year in SGIT. For turkey manure management systems, the SGIT assumed 0% for litter and 100% for range for all years from 1990 through 2002. The UDEQ/DAQ revised the turkey manure management system assumptions to 100% litter and 0% range.

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[96] 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.

[97] 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/).

[98] USDA, NASS (http://www.nass.usda.gov/Statistics_by_State/Utah/index.asp).

Swine Manure Management Assumptions for Utah

Year	Pasture	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit
UDEQ/DAQ Revisions to SGIT Default Assumptions for 1995-2002					
1995-2002	1%	0%	0%	99%	0
SGIT Default Assumptions					
1990-1992	54%	2%	13%	10%	21%
1993	44%	3%	15%	11%	27%
1994	34%	3%	18%	12%	33%
1995	23%	4%	20%	14%	38%
1996	13%	5%	23%	15%	44%
1997-2002	3%	5%	26%	17%	49%

Chicken Manure Management Assumptions for Utah

Year	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Poultry without bedding
UDEQ/DAQ Revisions to SGIT Default Assumptions				
1990-2002	75%	0%	0%	25%
SGIT Default Assumptions				
1990	50%	0%	0%	50%
1991	44%	0%	7%	49%
1992	39%	0%	13%	48%
1993	33%	0%	20%	47%
1994	28%	0%	27%	46%
1995	22%	0%	33%	44%
1996	17%	0%	40%	43%
1997	11%	0%	47%	42%
1998	6%	0%	53%	41%
1999-2002	0%	0%	60%	40%

Data on fertilizer usage came from *Commercial Fertilizers*, a report from the Fertilizer Institute. Data on crop production in Utah from 1990 to 2005 from the USDA NASS were used to calculate N_2O emissions from crop residues and crops that use nitrogen (i.e., nitrogen fixation) and CH_4 emissions from agricultural residue burning through 2005. Emissions for the other agricultural crop production categories (i.e., synthetic and organic fertilizers) were calculated through 2002.

Data were not available to estimate nitrogen released by the cultivation of histosols (i.e., the number of acres of high organic content soils). However, as discussed in the following section for soil carbon, the Natural Resources Ecology Laboratory at Colorado State University estimated zero CO_2 emissions for organic soils in Utah for 1997, suggesting that the area of cultivated high organic content soils was either very small or zero in Utah. Therefore, N_2O emissions from cultivated histosol soils were also assumed to be zero.

There is some agricultural residue burning conducted in Utah. The SGIT methodology calculates emissions by multiplying the amount (e.g., bushels or tons) of each crop produced by a series of factors. This determines the amount of crop residue produced and burned, the resultant dry

matter, and the carbon/nitrogen content of the dry matter. For Utah, the default SGIT method was used to calculate emissions because activity data in the form used in the SGIT were not readily available. Future work on this category should include an assessment to refine the SGIT default assumptions.

Table F1 shows the annual growth rates applied to estimate the reference case projections by agricultural sector. Emissions from enteric fermentation and agricultural soils were projected based on the annual growth rate in historical emissions ($MMtCO_2e$ basis) for these categories in Utah for 1990 to 2002 (1990 to 2005 for crop residues and nitrogen fixing crops). For manure management, Utah's first large commercial swine operation began operation in 1995 thus resulting in a higher annual growth rate (about 7%) than expected for the 12-year forecast period (1990 to 2002). Thus, a 5-year annual growth rate calculated from the trend in manure management emissions for the 5-year period 1997 to 2002 was used to project emissions associated with manure management practices to 2020 in Utah.

Table F1. Growth Rates Applied for the Agricultural Sector

Agricultural Category	Growth Rate	Basis for Annual Growth Rate*
Enteric Fermentation	1.4%	Historical emissions for 1990-2002.
Manure Management	4.8%	Historical emissions for 1997-2002.
Agricultural Burning	0.0%	Assumed no growth.
Agricultural Soils – Direct Emissions		
Fertilizers	-4.9%	Historical emissions for 1990-2002.
Crop Residues	-3.1%	Historical emissions for 1990-2005.
Nitrogen-Fixing Crops	1.3%	Historical emissions for 1990-2005.
Histosols	0.0%	No historical data available.
Livestock	1.8%	Historical emissions for 1990-2002.
Agricultural Soils – Indirect Emissions		
Fertilizers	-4.9%	Historical emissions for 1990-2002.
Livestock	2.6%	Historical emissions for 1990-2002.
Leaching/Runoff	1.0%	Historical emissions for 1990-2002.

* Except for manure management, compound annual growth rates shown in this table were calculated using the growth rate in historical emissions ($MMtCO_2e$ basis) from 1990 through the most recent year of data. These growth rates were applied to forecast emissions from the latest year of data to 2020. For manure management, the annual growth rate is based on the last 5 years for which historical emissions were calculated (see text for explanation).

Soil Carbon

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 U.S. Inventory of Greenhouse Gas Emissions and Sinks[99] and the U.S. Agriculture and Forestry Greenhouse Gas Inventory. The estimates are based on the IPCC methodology for soil carbon adapted to conditions in the U.S. Preliminary state-level estimates of CO_2 fluxes from mineral soils and emissions from the cultivation of organic soils were reported in the U.S. Agriculture and Forestry Greenhouse Gas Inventory.[7] 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

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

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 Utah, Table F2 shows a summary of the latest estimates available from the USDA, which are for 1997.[100] These data show that changes in agricultural practices are estimated to result in a net sink of 0.74 $MMtCO_2e$/yr in Utah. Since data are not yet available from USDA to make a determination of whether the emissions are increasing or decreasing, the net sink of 0.74 $MMtCO_2e$/yr is assumed to remain constant.

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Table F2. 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
0.29	0.00	0.00	(0.55)	(0.04)	(0.15)	0.00	(0.15)	(0.15)	0.00	(0.74)

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.

Results

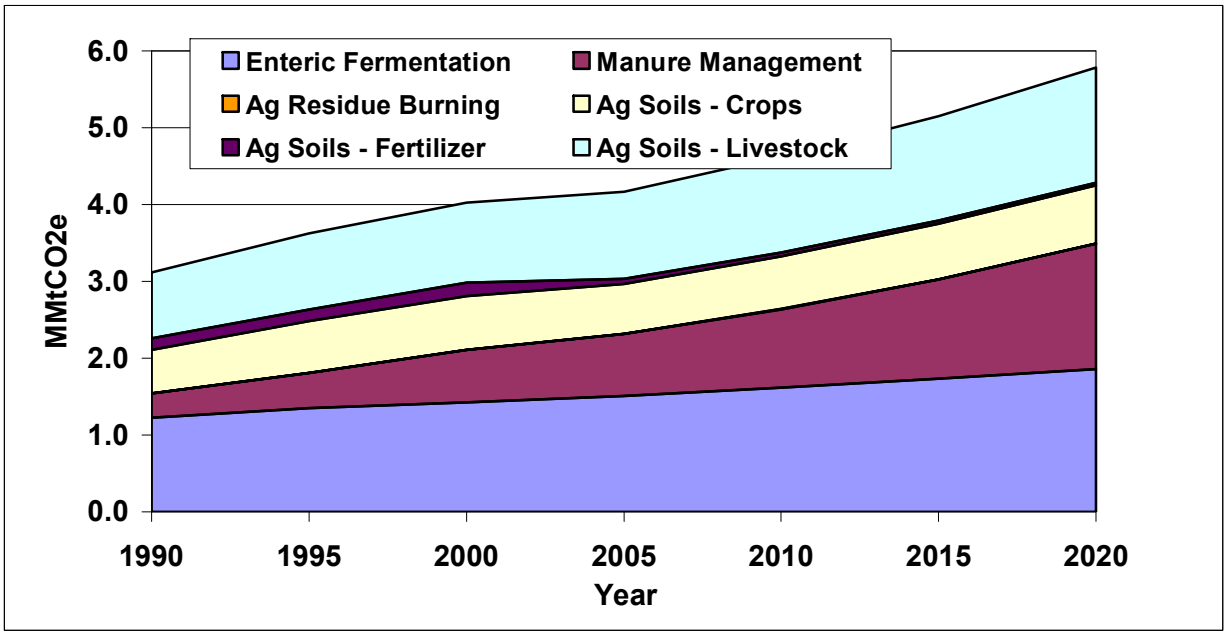
As shown in Figure F1, gross GHG emissions from agricultural sources range between about 3.1 and 5.8 $MMtCO_2e$ from 1990 through 2020, respectively. In 1990, enteric fermentation accounted for about 40% (1.2 $MMtCO_2e$) of total agricultural emissions and is estimated to account for about 32% (1.9 $MMtCO_2e$) of total agricultural emissions in 2020. The manure management category, which shows the highest rate of growth relative to the other categories, accounted for 10% (0.32 $MMtCO_2e$) of total agricultural emissions and is estimated to account for about 28% (1.6 $MMtCO_2e$) of total agricultural emissions in 2020. The agricultural soils category shows declining growth, with 1990 emissions accounting for 50% (1.6 $MMtCO_2e$) of total agricultural emissions and 2020 emissions estimated to be about 40% (2.3 $MMtCO_2e$) of total agricultural emissions. Including the CO_2 sequestration from soil carbon changes, the historic and projected emissions for the agriculture sector would range between about 2.4 and 5.0 $MMtCO_2e$/yr.

[100] U.S. Agriculture and Forestry Greenhouse Gas Inventory: 1990-2001. Global Change Program Office, Office of the Chief Economist, U.S. 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.

Agricultural burning emissions were estimated to be very small based on the SGIT activity data (<0.001 $MMtCO_2e$/yr from 1990 to 2002). This agrees with the USDA Inventory which also reports a low level of residue burning emissions (0.02 $MMtCO_2e$).

The only standard IPCC source category missing from this report is CO_2 emissions from limestone and dolomite application. Estimates for Utah were not available; however, the USDA's national estimate for soil liming is about 9 $MMtCO_2e$/yr.[7]

Figure F1. Gross GHG Emissions from Agriculture



Source: CCS calculations based on approach described in text.
Notes: Ag Soils – Crops category includes: incorporation of crop residues and nitrogen fixing crops (no cultivation of histosols estimated); emissions for agricultural residue burning are too small to be seen in this chart. Soil carbon sequestration is not shown (see Table F2).

Key Uncertainties

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, and 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, given the potential for some CRP acreage to retire and possibly return to active cultivation prior to 2020, 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 Utah.

Another contributor to the uncertainty in the emission estimates is the projection assumptions. This inventory assumes that the average annual rate of change in future year emissions will follow the historical average annual rate of change from 1990 through the most recent year of data. For example, the historical data show a decline in the use of fertilizers; however, there may be a leveling-off in fertilizer use trends due to recent efficiency gains that may be close to reaching their full technical potential.

Appendix G. Waste Management

Overview

GHG emissions from waste management include:

- Solid waste management – CH_4 emissions from municipal and industrial solid waste landfills, accounting for CH_4 that is flared or captured for energy production (this includes both open and closed landfills).
- Solid waste combustion – CH_4, CO_2, and N_2O emissions from the combustion of solid waste in incinerators or waste to energy plants.
- Wastewater management – CH_4 and N_2O from municipal and industrial wastewater (WW) treatment facilities.

Inventory and Reference Case Projections

Solid Waste Management
For solid waste management, we used the U.S. EPA SGIT and the U.S. EPA Landfill Methane Outreach Program (LMOP) landfills database[101] as starting points to estimate emissions. The LMOP data serve as input data to estimate annual waste emplacement for each landfill needed by SGIT. SGIT then estimates CH_4 generation for each landfill site. Additional post-processing outside of SGIT to account for controls is then needed to estimate CH_4 emissions.

Since the LMOP database does not include data covering all Utah landfills, CCS gathered additional data from UDEQ.[102] The data from UDEQ included 2005 emplacement, year opened, year closed, and the use of landfill gas controls. The combined EPA LMOP and UDEQ data indicate that 3 of the State's 55 landfills are controlled [2 with landfill gas to energy (LFGTE) plants; the other with a flare to December 2006, then with LFGTE]. Hence, all three were modeled in the LFGTE category (site names are Salt Lake Valley, Trans Jordan, and Wasatch Integrated). Additional information from UDEQ indicated that the ECDC site was controlled by a flare. This site was the only site modeled within the flared LF category. See the previous footnote for additional information. The remaining landfills are uncontrolled.

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. In cases where the estimated annual disposal rate was much lower than the 2005 disposal rate provide by UDEQ, the estimated disposal rate was used for each year up to 1995 and then grown annually up to the 2005 disposal rate. For one large landfill site (East Carbon), annual emplacement data were collected directly

[101] LMOP database is available at: http://www.epa.gov/lmop/proj/index.htm. Updated version of the database provided by Rachel Goldstein, Program Manager, EPA Landfill Methane Outreach Program, October 2006.
[102] Ralph Bohn and Roy Vanof, UDEQ, Division of Solid Waste, personal communications with S. Roe, CCS, November 2006. In addition to the sites mentioned in the text, Carl Nielson of UDEQ mentioned another 2 sites that were LFGTE sites: Hill Air Force Base and Kennecott Utah Copper Corporation. The first site was listed in the LMOP/UDEQ data but did not include relevant waste emplacement data, so it was not modeled. The second site did not appear in the LMOP/UDEQ data, and so was not modeled.

from the facility.[103] Both municipal and industrial wastes are disposed at this site. Since a large fraction of the industrial wastes are probably non-degradable (e.g., cement, steel), we adjusted the industrial emplacement down by 50% based strictly on engineering judgment. For several sites added by UDEQ, no waste in place estimate was available to estimate annual waste emplacement. Therefore, we used the 2005 waste acceptance data provided by UDEQ for each year in which the landfill operated.

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 LFGTE plant; and (3) landfills with landfill gas collection and a flare. SGIT produced annual estimates through 2005 for each of these landfill categories. 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 2020. For the controlled landfills, CCS assumed that the overall methane collection and control efficiency is 75%.[104] Of the methane not captured by a landfill gas collection system, it is further assumed that 10% is oxidized before being emitted to the atmosphere (consistent with the SGIT default).

Growth rates were estimated by using the historic (1995-2005) growth rates of emissions in both the controlled and uncontrolled landfill categories. The period from 1995 to 2005 was used since there were a large number of landfill closures during the period from 1990 to 1995 (which could have affected waste management practices). Hence, the post-1995 period is thought to be most representative of waste emplacement rates and subsequent emissions. For uncontrolled landfills, the annual emissions growth rate is 5.7% and for LFGTE landfills it is 8.8%. For the only site in the flared category (ECDC), the growth rate for emissions is 8.4% per year. The growth rates reflect large emplacement rates (at ECDC, emplacement rates at this site are 500,000 – 800,000 tons/year after adjusting the industrial waste component down as mentioned above). These growth rates are higher than the 1995-2005 rate of population growth in UT (about 2.5%/yr). This suggests that waste imports contribute substantially to emissions growth (although no specific information on waste imports was obtained for this study).

CCS used the SGIT default for industrial landfills. This default is based on national data indicating that industrial landfill waste is emplaced at approximately 7% of the rate of MSW emplacement. We assumed that this additional industrial waste emplacement occurs beyond that already addressed in the emplacement rates for MSW sites. Due to a lack of data, no controls were assumed for industrial waste landfill. For industrial landfills, the overall growth rate in MSW emissions from 1996 to 2005 (2.6%/yr) was used to project emissions to 2010 and 2020 (based on the assumption that industrial waste landfill will continue to grow at the same rate as MSW landfill).

Solid Waste Combustion

There is only one municipal waste combustion facility in UT and annual waste combustion data were obtained from UDEQ.[105] The available data covered the years 1995-2005, so the annual

[103] Darin Olson, East Carbon Landfill, personal communication with S. Roe, CCS, December 2006.
[104] As per EPA's AP-42 Section on Municipal Solid Waste Landfills: http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf.
[105] Roy Vanof, UDEQ, Division of Solid Waste, personal communication with S. Roe, CCS, November 2006.

waste combusted for 1990 to 1994 were assumed to be the same as 1995. SGIT defaults (emission factors, waste characteristics) were used to estimate emissions using these data. UDEQ contacts were not aware of any plans for additional plants in the future or expanded capacity at the existing plant, so emissions were held constant in the forecast years.

Although it is restricted in Utah, open burning of MSW at residential or municipal sites can also contribute GHG emissions. If data are available, future inventory work should attempt to capture this source.

Wastewater Management
GHG emissions from municipal wastewater treatment were also estimated. Emissions are calculated in 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 below.

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 discussions with UDEQ water quality, there are no pulp and paper operations in the state.[106] For the other two industrial categories, wastewater data were not readily available. Staff provided some rough estimates of current annual flows for meat & poultry processing of 3 million gallons per day and for fruit and vegetable processing an estimate of 1 million gallons per day.[6] Significant changes in both historic and future flows are not anticipated, so these flow rates were entered into SGIT to gauge the relative importance of this emissions sector and held constant over the period of analysis.

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
Utah residents not on septic	75%
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
Source: U.S. EPA State Inventory Tool – Wastewater Module; methodology and factors taken from U.S. EPA, Emission Inventory Improvement Program, Volume 8, Chapter 12, October 1999: www.epa.gov/ttn/chief/eiip/techreport/volume08/.	

Figure G1 shows the initial emission estimates for the waste management sector. Overall, the sector accounts for 2.0 $MMtCO_2e$ in 2005. By 2020, emissions are expected to grow to 4.7 $MMtCO_2e$/yr. In 2005, over 60% of the emissions were contributed by the uncontrolled landfills sector and by 2020 the contribution from these sites is expected remain at about 60%. As mentioned above, CCS modeled only the ECDC site in the flared LF category. In 2005, this site was estimated to contribute less than 4% of the waste management sector and remain about the same by 2020. Landfills with LFGTE contributed 0.26 $MMtCO_2e$ in 2005, which is less about 13% of the total for the waste management sector. The contribution from this category will increase to about 19% by 2020.

[106] Mike Herkimer, UDEQ, Division of Water Quality, personal communication with S. Roe, CCS, December 2006.

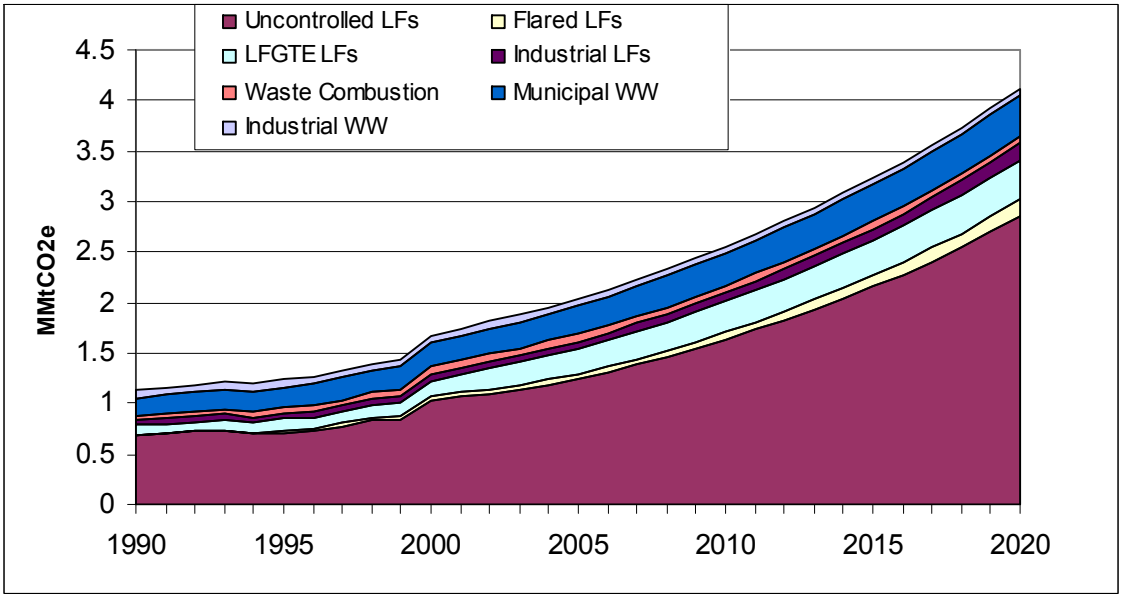
Emissions from municipal wastewater treatment were estimated to be 0.28 $MMtCO_2e$ in 2005 or about 14% of the waste management sector total. Industrial wastewater treatment was estimated to contribute less than 0.1 $MMtCO_2e$/yr or about 4% of the sector total. Contributions to total sector emissions for each of the wastewater treatment sectors are expected to drop by 2020, representing about 10% of the waste management sector emissions combined.

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 for this reason (since each site that is currently controlled was modeled as always being controlled, the historic emissions are low 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 requirements of the federal New Source Performance Standards/Emission Guidelines.

For industrial landfills, these were estimated using national defaults (7% of the rate of MSW emplacement) with a further adjustment downward of 50% to represent an assumed high amount of nondegradable waste. It could be that the waste emplacement data within the combined LMOP/UDEQ data used to model the MSW emissions already captures industrial LF emplacement and emissions. Industrial landfill emissions growth is assumed to occur at the same rate estimated for MSW growth. Hence, the industrial landfill inventory and forecast has a significant level of uncertainty and should be investigated further.

Figure G1. Utah GHG Emissions from Waste Management



Notes: LF – landfill; WW – wastewater; LFGTE – landfill gas to energy; there is only one landfill in the Flared LF category.

For the wastewater sector, the key uncertainties are associated with the application of SGIT default values for the parameters listed in Table G1 above (e.g. fraction of the UT population on septic; fraction of BOD which is anaerobically decomposed). The SGIT defaults were derived from national data.

Appendix H. Forestry

Overview

Forestland emissions refer to the net CO_2 flux[107] from forested lands in Utah, which account for about 30% of the state's land area.[108] The dominant forest type in UT is pinyon-juniper forests which make up about 58% of forested lands. Forestlands are net sinks of CO_2 in Utah. Through photosynthesis, carbon dioxide 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. CO_2 flux is the net balance of carbon dioxide removals from and emissions to the atmosphere from the processes described above.

Inventory and Reference Case Projections

For over a decade, the United State Forest Service (USFS) has been developing and refining a forest carbon modeling system for the purposes of estimating forest carbon inventories. The methodology is used to develop national forest CO_2 fluxes for the official US Inventory of Greenhouse Gas Emissions and Sinks.[109] The national estimates are compiled from state-level data. The Utah forest CO_2 flux data in this report come from the national analysis and are provided by the USFS.

The forest CO_2 flux methodology relies on input data in the form of plot level forest volume statistics from the Forest Inventory Analysis (FIA). FIA data on forest volumes are converted to values for ecosystem carbon stocks (i.e., the amount of carbon stored in forest carbon pools) using the FORCARB2 modeling system. Coefficients from FORCARB2 are applied to the plot level survey data to give estimates of C density (Mg per hectare) for a number of separate C pools.

CO_2 flux is estimated as the change in carbon mass for each carbon pool over a specified time frame. Forest volume data from at least two points in time are required. The change in carbon stocks between time intervals is estimated at the plot level for specific carbon pools (Live Tree, Standing Dead Wood, Under-story, Down & Dead Wood, Forest Floor, and Soil Organic Carbon) and divided by the number of years between inventory samples. Annual increases in carbon density reflect carbon sequestration in a specific pool; decreases in carbon density reveal CO_2 emissions or carbon transfers out of that pool (e.g., the death of a standing tree transfers carbon from the live tree to standing dead wood pool). The amount of carbon in each pool is also influenced by changes in forest area (e.g. an increase in area could lead to an increase in the associated forest carbon pools and the estimated flux). The sum of carbon stock changes for all forest carbon pools yields a total net CO_2 flux for forest ecosystems.

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[107] "Flux" refers to both emissions of CO_2 to the atmosphere and removal (sinks) of CO_2 from the atmosphere.
[108] *Utah Forest Health Report, A Baseline Assessment 1999/2001*, Utah Department of Natural Resources, Division of Forestry, Fire and State Lands, http://www.ffsl.utah.gov/health/utfor-lr.pdf, reports 16 million acres of forested lands. The total land area in UT is 54.3 million acres (http://www.50states.com/utah.htm).
[109] U.S. 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.

In preparing these estimates, USFS estimates the amount of forest carbon in different forest types as well as different carbon pools. The different forests include those in the national forest system and those that are not federally-owned (private and other public forests). USFS also provides information on forests categorized as being either woodlands (forests with low productivity) and non-woodlands (e.g. timberlands or productive forest systems).

Carbon pool data for two periods are used to estimate CO_2 flux for each pool. The data shown in Table H1 are a summary of the FIA data used to derive the carbon pool and flux estimates that are summarized in Table H2. As shown in Table H1, the current forest carbon pool estimates are derived from 2003 FIA data. The previous inventory data came from a previous FIA cycle in 1993.

Table H1. Forestry Data Used to Estimate Forest CO_2 Flux

Forest	Current Inventory Source	Past Inventory Source	Avg. Year[a]	Interval[b] (yr)	Current Forest Area (10^3 hectares)	Previous Forest Area (10^3 hectares)
Non-Woodlands	FISDB21_UT_02_2005	FISDB21_UT_01_1993	2003.0	9.6	2,470	2,182
Woodlands	FISDB21_UT_02_2005	FISDB21_UT_01_1993	2003.1	9.3	5,508	4,176
				Totals	**7,978**	**6,358**

[a] Average year for the current FIA inventory data.
[b] The number of years between the current inventory source and the past inventory source.

The data in Table H1 show an increase of 1,620 kilo-hectares (3.9 million acres) in forested area during the period of analysis (1993-2003). Over 80% of this increase occurred in woodland forests (as mentioned under key uncertainties below, some of this difference is likely driven by methodological differences in survey methods between the two FIA cycles).

Table H2 provides a summary of the size of the forest carbon pools for the final survey period and the resultant flux estimates (in units of C and CO_2) developed by the USFS.[3] A total of 38 $MMtCO_2$ is estimated to be sequestered in Utah forests each year with most of this accumulating in the forest floor and soil organic carbon pools. The live tree carbon pool sequesters about 4 $MMtCO_2$/yr. However, in the non-woodland forests (timberlands and other productive forests), a net emission (loss of carbon) is occurring for this pool in Utah's forests. Note that this analysis averages out annual fluctuations in carbon sequestration rates over an approximate 10 year time interval.

In addition to the forest carbon pools, additional carbon stored as biomass is removed from the forest for the production of durable wood products; carbon remains stored in the products pool or is transferred to landfills where much of the carbon remains stored over a long period of time. An estimated 0.2 $MMtCO_2e$ is sequestered annually in wood products; these data are based on a

USFS study from 1987 to 1997.[110] Additional details on all of the forest carbon inventory methods can be found in Annex 3 to EPA's 2006 GHG inventory for the U.S.[111]

Table H2. Forestry CO_2 Flux Estimates for Utah

Forest	Carbon Pool (MMt Carbon)					
	Live Tree	Standing Dead	Under-story	Down & Dead	Forest Floor	Soil Organic Carbon
Non-Woodlands	137	19.5	7.3	10.1	71.4	88.9
Woodlands	131	1.1	17.3	4.6	122	125
Totals	**268**	**20.7**	**24.6**	**14.7**	**193**	**214**

Forest	Carbon Pool Flux (MMt C/yr)					
	Live Tree	Standing Dead	Under-story	Down & Dead	Forest Floor	Soil Organic Carbon
Non-Woodlands	0.92	-0.03	-0.19	0.10	-0.34	-0.87
Woodlands	-2.01	-0.10	-0.52	-0.09	-3.30	-3.83
Totals	**-1.08**	**-0.13**	**-0.71**	**0.01**	**-3.64**	**-4.70**

Forest	Carbon Pool Flux (MMt CO_2/yr)					
	Live Tree	Standing Dead	Under-story	Down & Dead	Forest Floor	Soil Organic Carbon
Non-Woodlands	3.4	-0.1	-0.7	0.4	-1.2	-3.2
Woodlands	-7.4	-0.4	-1.9	-0.3	-12.1	-14.1
Totals	**-4.0**	**-0.5**	**-2.6**	**0.0**	**-13.3**	**-17.2**

Total Forest Flux =	**-37.6**
Harvested Wood Products[a] =	**-0.2**
Total Statewide Flux =	**-37.8**

NOTE: Totals may not add exactly due to rounding.
[a] Source: http://www.fs.fed.us/ne/global/pubs/books/epa/states; For Utah, HWP are estimated to sequester 0.06 MMtC during the period 1987-1997).

For the 1990 and 2000 historic emission estimates as well as the reference case projections, the forest area and carbon densities of forestlands were assumed to be at the same levels as those shown in Table H2. Hence, there is no change in the estimated future sinks for 2010 and 2020. Note that CCS is currently reviewing these estimates with the USFS and that revisions could be recommended, especially for the woodlands forest type. These revisions could result in a significant reduction in the size of the sink associated with the woodlands forests.

In order to provide a more comprehensive understanding of GHG sources/sinks from the forestry sector, CCS also developed some rough estimates of state-wide emissions for methane and nitrous oxide from wildfires and prescribed burns. A study published earlier this year in *Science*

[110] http://www.fs.fed.us/ne/global/pubs/books/epa/states. See data for Utah.
[111] 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.

indicated an increasing frequency of wildfire activity in the western U.S. driven by a longer fire season and higher temperatures.[112]

CCS used 2002 emissions data developed by the Western Regional Air Partnership (WRAP) to estimate CO_2e emissions for wildfires and prescribed burns.[113] The CO_2e from methane emissions from this study were added to an estimate of CO_2e for nitrous oxide to estimate a total CO_2e for fires (the carbon dioxide emissions from fires are captured within the carbon pool accounting methods described above). The nitrous oxide estimate was made assuming that N_2O was 1% of the emissions of nitrogen oxides (NO_x) from the WRAP study. The 1% estimate is a common rule of thumb for the N_2O content of NO_x from combustion sources.

The results for 2002 are that fires contributed about 0.4 $MMtCO_2e$ of methane and nitrous oxide from about 284,000 acres burned (269,000 acres by wildfires). About 94% of the CO_2e was contributed by CH_4. Note that this level of activity compares to over 730,000 acres burned in Utah in 1996.[114] A comparison estimate was made using emission factors from a 2001 global biomass burning study[115] and the total tons of biomass burned from the 2002 WRAP fires emissions inventory. This estimate is nearly 1.3 $MMtCO_2e$ with about equal contributions from methane and nitrous oxide on a CO_2e basis. Given the large swings in fire activity from year to year and the current lack of data for multiple years, CCS did not include these estimates in with the annual forestry flux estimates presented in the emissions summaries of this report.

Key Uncertainties

It is important to note that there were methodological differences in the two FIA cycles that can produce different estimates of forested area and carbon density. In the Rocky Mountain Region, the FIA program modified the definition of forest cover for the woodlands class of forestland. Earlier FIA cycles defined woodlands as having a tree cover of at least 10%, while the newer sampling methods used a woodlands definition of tree cover of at least 5% (leading to more area being defined as woodland). In woodland areas, the earlier FIA surveys might not have inventoried trees of certain species or with certain tree form characteristics (leading to differences in both carbon density and forested acreage). Also, surveys since 1999 include all dead trees on the plots, but data prior to that are variable in terms of these data. The modifications to FIA surveys are a result of an expanded focus in the FIA program, which historically was only concerned with timber resources, while more recent surveys have aimed at a more comprehensive gathering of forest biomass data.

The effect of these changes in survey methods has not been estimated by the USFS. In states like Utah with significant areas of woodlands, the change in definition could contribute significantly to the increases seen in forested area and the associated CO_2 flux. For these reasons, the USFS provided flux estimates separately for woodlands and non-woodlands (i.e., all other forest classes), so that the relative influence of these classes on total net CO_2 fluxes in UT could be

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[112] Westerling, A.L. et al, "Warming and Earlier Spring Increases Western U.S. Forest Wildfire Activity", *Sciencexpress,* July 6, 2006.
[113] *2002 Fire Emission Inventory for the WRAP Region Phase I – Essential Documentation*, prepared by Air Sciences, Inc., June 2004.
[114] *1996 Fire Emission Inventory,* Draft Final Report, prepared by Air Sciences, Inc., December 2002.
[115] M. O. Andreae and P. Merlet, "Emission of trace gases and aerosols from biomass burning", *Global Biogeochemical Cycles*, Vol. 15, No. 4, pp. 955-966, December 2001.

discerned. As shown in Table H2, the contribution from the woodland areas drives a significant fraction of the flux estimate statewide. Given the differences in FIA survey methods, the forest flux estimates should be viewed as conservatively high for Utah forests.

As stated in the previous section, emission estimates for methane and nitrous oxide from fires were left out of the statewide flux estimates due to a lack of data for years other than 1996 and 2002 (emissions of carbon dioxide from fires are captured in the carbon flux accounting methods used by the USFS). Based on the level of activity in 2002, these additional emissions are on the order of 1 $MMtCO_2e$/yr and would not have a significant impact on the overall flux estimates shown in Table H2 (particularly the potential to significantly offset for overstatement of sequestration in woodlands).

Appendix I. Inventory and Forecast for Black Carbon

This appendix summarizes the methods, data sources, and results of the development of an inventory and forecast for black carbon (BC) emissions in Utah. 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 IPCC (see Appendix J for more information on black carbon and other aerosol species). BC is synonymous with elemental carbon (EC), which is a term common to regional haze analysis. An inventory for 2002 was developed based on inventory data from the Western Regional Air Partnership (WRAP) 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 GHG context. Data from the WRAP for their 2018 forecast inventory were used to assess future year emissions for important BC source sectors.[116]

In addition to the PM inventory data from WRAP, PM speciation data from EPA's SPECIATE database were also used: these data include PM fractions of elemental carbon (also known as black carbon) 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. (Pechan) for EPA on updating the SPECIATE database.[117] These new profiles have just recently been released by EPA. As will be further described below, both BC and OM emission estimates are needed to assess the CO_2e of black carbon emissions. While BC and OM emissions data are available from the WRAP regional haze inventories, CCS favored the newer speciation data available from EPA for the purposes of estimating BC and OM for most source sectors (BC and OM data from the WRAP were used only for the nonroad engines sector). In particular, better speciation data are now available from EPA for important BC emissions sources (e.g., most fossil fuel combustion sources).

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.

Development of BC and OM Mass Emission Estimates

The BC and OM mass emission estimates were derived by multiplying the emissions estimates for particulate matter with an aerodynamic diameter of less than 2.5 micrometers ($PM_{2.5}$) by the appropriate aerosol fraction for BC and OM. The aerosol fractions were taken from Pechan's ongoing work to update EPA's SPECIATE database as approved by EPA's SPECIATE Workgroup members.

After estimating both BC and OM emissions for each source category, we used the BC estimate as described below to estimate the CO_2e emissions. Also, as described further below, the OM

[116] Tom Moore, Western Regional Air Partnership, data files provided to Steve Roe, CCS, December 2006.
[117] Version 4.0 of the SPECIATE database and report: http://www.epa.gov/ttn/chief/software/speciate/index.html#related.

emission estimate was used to determine whether the source was likely to have positive climate forcing potential. The mass emission results for 2002 are shown in Table I1.

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

We used similar methods to those applied previously in Maine and Connecticut for converting BC mass emissions to CO_2e.[118] These methods are based on the modeling of Jacobson (2002)[119] and his updates to this work (Jacobson, 2005a).[120] 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).

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 less than 2.5 microns ($PM_{2.5}$) from onroad diesel exhaust follows:

BC mass = (10 short tons $PM_{2.5}$) x (0.613 ton EC/ton $PM_{2.5}$) = 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 global modeling inputs used by Jacobson (2002, 2005a; i.e., 2 tons of OM/ton of BC).

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[118] 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.

[119] 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.

[120] 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.

For source categories that had an OM:BC mass emissions 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 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 could potentially produce a net 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 and Discussion

We estimate that BC mass emissions in Utah total about 4.9 $MMtCO_2e$ in 2002. This is the mid-point of the estimated range of emissions. The estimated range is 3.1 – 6.6 $MMtCO_2e$ (see Table I1). The primary contributing sectors in 2002 were nonroad diesel (60%), onroad diesel (16%) and rail (8%). The nonroad diesel sector includes exhaust emissions from construction/mining, industrial and agricultural engines. Construction and mining engines contributed about 66% of the diesel nonroad engine total while agricultural engines contributed about 27%. Another significant contributing sector to BC emissions in UT is nonroad gasoline engines at 5% of the total CO_2e. Of this amount, pleasure craft and recreational equipment engines contributed about one-third each to the nonroad gasoline total.

Based on the WRAP's 2018 forecast inventory, the emissions from the two top source sectors will drop significantly in the future. BC emissions for the onoad diesel sector will fall from 0.8 $MMtCO_2e$ in 2002 to 0.2 $MMtCO_2e$ by 2018. For the nonroad sector, the emissions will be reduced from 2.9 $MMtCO_2e$ in 2002 to 0.7 $MMtCO_2e$ by 2018. Hence, the total BC reductions will be about 2.8 $MMtCO_2e$ of the 4.9 $MMtCO_2e$ estimated for the state. These reductions are due to new national engine and fuels standards that will reduce particulate matter emissions. We don't expect that there will be significant reductions in the emissions levels from the other source sectors. For these sectors, emissions will grow based on the growth in activity within each sector. The development of future year emission estimates for the smaller source sectors was beyond the scope of this study.

Wildfires and miscellaneous sources such as fugitive dust from paved and unpaved roads contributed a significant amount of PM and subsequent BC and OM mass emissions (see Table I1); however the OM:BC ratio is >4 for these sources, so the BC emissions were not 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 black carbon. 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).[121] There are also a number of other indirect radiative effects that have been modeled (see, for example, Jacobson, 2002, as noted in footnote on the previous page).

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

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 effects, 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 concentration 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 complicated aerosol influences on cloud 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. 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 Emission Estimates

Sector	Subsector	Mass Emissions			CO_2 Equivalents		Contribution to CO_2e
		BC	OM	BC + OM	Low	High	
		Metric Tons			Metric Tons		
Electric Generating Units (EGUs)							
	Coal	85	121	206	83,833	177,065	2.7%
	Oil	6	2	8	6,202	13,099	0.2%
	Gas	0	25	25	0	0	0.0%
	Other	0	26	26	0	0	0.0%
Non-EGU Fuel Combustion (Residential, Commercial, and Industrial)							
	Coal	5	7	11	4,637	9,795	0.1%
	Oil	50	38	88	49,197	103,911	1.6%
	Gas	0	167	167	0	0	0.0%
	Other[a]	278	1,125	1,404	60,980	128,797	2.0%
Onroad Gasoline (Exhaust, Brake Wear, & Tire Wear)		89	348	437	35,974	75,980	1.2%
Onroad Diesel (Exhaust, Brake Wear, & Tire Wear)		562	237	799	500,065	1,056,199	16.1%
Aircraft		39	68	107	38,870	82,098	1.3%
Railroad[b]		254	83	337	250,968	530,075	8.1%
Other Energy Use							
	Nonroad Gas	156	439	595	154,356	326,018	5.0%
	Nonroad Diesel	1,900	624	2,524	1,881,475	3,973,902	60.5%
	Other Combustion[c]	4	41	46	0	0	0.0%
Industrial Processes		41	623	665	10,939	23,104	0.4%
Agriculture[d]		82	2,174	2,256	0	0	0.0%
Waste Management							0.0%
	Landfills	2	42	44	0	0	0.0%
	Incineration	1	3	4	1,321	2,790	0.0%
	Open Burning	38	163	202	30,249	63,889	1.0%
	Other	0	1	1	0	0	0.0%
Wildfires/Prescribed Burns		1,932	18,726	20,658	0	0	0.0%
Miscellaneous[e]		81	1,372	1,453	0	0	0.0%
Totals		**5,606**	**26,458**	**32,063**	**3,109,065**	**6,566,723**	**100%**

[a] Primarily wood-fired commercial/industrial boilers with some large diesel engines.
[b] Railroad includes Locomotives and Railroad Equipment Emissions.
[c] Other Combustion includes Motor Vehicle Fire, Structure Fire, and Aircraft/Rocket Engine Fire & Testing Emissions.
[d] Agriculture includes Agricultural Burning, Agriculture/Forestry and Agriculture, Food, & Kindred Spirits Emissions.
[e] Miscellaneous includes Paved/Unpaved Roads and Catastrophic/Accidental Release 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[122] 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°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

[122] See FCCC/CP/1999/7 at www.unfccc.de.

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 "concentrations 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:

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

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)
[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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