CLIMATE CHANGE
Supplementary Information Report

Montana, North Dakota and South Dakota
Bureau of Land Management

Prepared for:

Bureau of Land Management
Montana State Office
5001 Southgate Drive
Billings, MT 59101

Prepared by:

URS

URS Corporation
8181 Tufts Avenue
Denver, CO 80237

URS Project 22241790

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EXECUTIVE SUMMARY

This *Climate Change Supplementary Information Report for the Montana, North Dakota and South Dakota Bureau of Land Management* (BLM) describes the data and methodologies used to estimate greenhouse gas (GHG) emissions. The report also provides data for considering potential climate change impacts that may result from future oil and gas development of federal mineral estate in Montana, North Dakota, and South Dakota.

The report summarizes oil and gas Reasonably Foreseeable Development (RFD) scenarios and GHG emission inventories for the BLM planning areas listed below. The BLM GHG emission inventories include a comprehensive set of GHG emission sources and are estimated based on use of current oil and gas exploration and production techniques.

- Billings
- Butte
- Dillon
- Hi-Line Planning Area (includes Malta, Glasgow, and Havre Field Offices)
- Lewistown
- Miles City
- North Dakota
- South Dakota

GHG mitigation methods are also described. These methods may potentially be used to reduce GHG emissions from oil and gas operations in Montana, North Dakota, and South Dakota.

On a larger geographic scope, current and future predicted state, national, and global GHG emission inventories are summarized. Although comparisons are not included in this report, the state, national, and global GHG inventories can be used to provide insight into the relative magnitude of BLM planning area GHG emissions. This report also provides context for analyzing potential effects of GHG emissions. Background information describing current climate science and predicted climate change impacts in global and national contexts is discussed. Then, the focus shifts to modeled climate change impacts as they related to Montana, North Dakota, and South Dakota.

Data presented in this report are based on current knowledge in a rapidly changing regulatory and market environment. A brief summary of U.S. GHG regulation, economic factors, and uncertainties is also provided.

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ACRONYMS

AOGCM	Atmospheric-ocean general-circulation model
APD	Application for Permit to Drill
API	American Petroleum Institute
bbl	barrel
BCF	billion cubic feet
BLM	Bureau of Land Management
BOR	Bureau of Reclamation
CAA	Clean Air Act
CBM	Coal bed methane
CBNG	Coal bed natural gas
CCI	Cover-cycle index
CFC	Chlorofluorocarbon
CFR	*Code of Federal Regulations*
CH_4	Methane
CMIP3	Coupled Model Intercomparison Project Three (model)
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DJF	December, January, February
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ESD	Emergency shutdown
FO	Field Office
FR	*Federal Register*
GCM	General circulation model
GHG	Greenhouse gas
GIS	Geographical information system
GRI	Gas Research Institute
Gt	Gigatonne (10^9 metric tons)
GWP	Global warming potential
HAP	Hazardous air pollutant
HDDV	Heavy duty diesel vehicle
HFC	Hydrofluorocarbon
IPCC	Intergovernmental Panel on Climate Change

ACRONYMS (cont.)

JJA	June, July, August
km	kilometer
LDDV	Light duty diesel vehicle
LDGT	Light duty gasoline truck
LOP	Life of project
m	meters
MAC	Marginal abatement curve
MBOGC	Montana Board of Oil and Gas Conservation
MCFO	Miles City Field Office
mm	millimeter
MMBtu	million British thermal units
MMscfd	Million standard cubic feet per day
MOC	Meridional overturning circulation
Mt	Million metric tons
N_2O	Nitrous oxide
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NO_2	Nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NOC	National Operations Center (BLM)
NO_x	Nitrogen oxides
NSCR	Nonselective catalytic reduction
PFC	Perfluorocarbon
PGW	Producing gas well
POW	Producing oil well
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
PSV	Pressure safety valve
RF	Radiative forcing
RFD	Reasonably foreseeable development
RMP	Resource Management Plan

ACRONYMS (cont.)

RMPA	Resource Management Plan Amendment
scfm	standard cubic feet per minute
SCM	Simple Climate Model
SEIS	Supplementary Environmental Impact Statement
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
SRES	Special Report on Emission Scenarios
TEG	Triethylene glycol
tpy	short tons per year (2,000 pounds per ton)
UNFCCC	United Nations Framework Convention on Climate Change
USEPA	U.S. Environmental Protection Agency
USFS	U.S. Forest Service
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Service
VMT	Vehicle miles traveled
VOC	Volatile organic compound
VRU	Vapor recovery unit

1.0 INTRODUCTION

This *Climate Change Supplementary Information Report for the Montana, North Dakota and South Dakota Bureau of Land Management* (BLM) describes the data and methodologies used to estimate greenhouse gas (GHG) emissions and consider potential climate change impacts resulting from future oil and gas development of Montana, North Dakota, and South Dakota federal mineral estate. GHG emissions are estimated based on use of current oil and gas exploration and production techniques. The report provides a summary of planning area oil and gas Reasonably Foreseeable Development (RFD) scenarios in the following BLM Field Offices (FOs). GHG emission inventories are also included for these planning areas.

- Billings
- Butte
- Dillon
- Hi-Line Planning Area (includes Malta, Glasgow, and Havre FOs)
- Lewistown
- Miles City
- North Dakota
- South Dakota

GHG mitigation methods that may be used to reduce GHG emissions from oil and gas operations in the Montana, North Dakota, and South Dakota areas are also described.

This report is intended to summarize the body of scientific knowledge and professional judgment of global climate change scientists, in order to provide a context for evaluating potential climate change impacts. The report provides an overview of climate change, associated science, and projected impacts. Potential global effects to resources as a result of climate change, and potential global impacts of continuing anthropogenic contributions of GHGs to climate change, are also summarized. Regional information on effects to resources is presented, where available.

Information provided here summarizes current knowledge based on reports from the Intergovernmental Panel on Climate Change (IPCC), other peer-reviewed scientific publications, and U.S. federal agencies. The growing level of international attention to climate change has resulted in a high level of ongoing scientific study and analysis. The body of scientific knowledge is evolving rapidly. The information contained herein is likely to change, but does present the state of knowledge at this time. The reports referenced herein, and any subsequent reports provided by IPCC or other governmental bodies, should be consulted in the future for more detailed and current information.

Data presented in this report are based on current knowledge in a rapidly changing regulatory and market environment. A brief summary of U.S. GHG regulation, economic factors, and uncertainties is provided below.

1.1. U.S. GHG Regulation

Historical emission data presented in this report were gathered prior to the advent of U.S. emission control regulation of GHGs. Consequently, the effect of U.S. limits on GHG emissions is not accounted for in the BLM oil and gas emission inventories or in GHG emission inventory projections contained in this report. As the U.S. Environmental Protection Agency (USEPA) begins regulating GHGs, more detailed GHG emission data will become available and better predictions can be made when estimating future GHG emissions.

The USEPA is in the early stages of regulating GHGs as air pollutants under the Clean Air Act (CAA). In its "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," the USEPA determined that the six GHGs listed in Table 1-1 are air pollutants subject to regulation under the CAA. Generally, these pollutants are regulated as a group, although emission standards may be set for the group of six GHGs or for a subset of these GHGs (e.g., CO_2 only or CO_2 and methane) at USEPA's discretion.

Each GHG has a global warming potential (GWP). As defined by USEPA, the GWP provides a "ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of CO_2" (GPO 2010a). In other words, the GWP accounts for the intensity of each GHG's heat trapping effect and its longevity in the atmosphere. The GWP provides a method to quantify the cumulative effect of multiple GHGs released into the atmosphere by calculating carbon dioxide equivalent (CO_2e) for the GHGs.

Table 1-1. GHGs Regulated by USEPA and Global Warming Potentials

Air Pollutant	Chemical Symbol or Acronym	Global Warming Potential
Carbon dioxide	CO_2	1
Methane	CH_4	21
Nitrous oxide	N_2O	310
Hydrofluorocarbons	HFCs	Varies
Perfluorocarbons	PFCs	Varies
Sulfur hexafluoride	SF6	23,900

Sources: GPO 2009; GPO 2010b, Table A-1.

CO_2e emissions are calculated by summing, for each GHG, the product of the quantity of GHG released and the GWP for that GHG. GHG emissions are typically reported in terms of metric tons, million metric tons (Mt), or gigatonnes (Gt, 10^9 metric tons). An example calculation of CO_2e for combined emissions of CO_2, methane, and N_2O is provided below. This calculation could be extended to include additional GHGs. The units of CO_2e are the same as the units used to represent the quantity of CO_2, methane, and N_2O emissions.

$$CO_2e = [CO_2 \times 1] + [CH_4 \times 21] + [NO_2 \times 310]$$

The first USEPA regulation to limit emissions of GHGs affects light-duty vehicles, including passenger cars and light trucks. The rule sets vehicle manufacturer emission limits for CO_2 and became effective on July 6, 2010 (GPO 2010c).

As of July 2010, USEPA had not set GHG emission limits for any stationary sources. However, the USEPA is gathering detailed GHG emission data from thousands of facilities throughout the United States. Data gathered during this effort will be used by USEPA to develop an improved national GHG inventory and to inform future GHG emission control regulations. Beginning in 2010, many facilities across the United States will estimate GHG emissions in accordance with USEPA's GHG Mandatory Reporting Rule [40 *Code of Federal Regulations* (*CFR*) Part 98, GPO 2010b] and will report annual GHG emissions beginning on March 31, 2011. Many oil and gas facilities will begin estimating emissions in 2011 and will submit their first annual GHG emission reports on March 31, 2012.

Beginning in 2011, GHG emissions from some facilities will become subject to federal air quality permitting programs, such as the Title V Operating Permit Program and the Prevention of Significant Deterioration (PSD) Program. Historically, GHG emissions were not measured by facilities under these programs and issued permits did not address GHGs. However, USEPA and state and local air quality permitting agencies will begin reviewing GHG emissions under these programs in accordance with USEPA's "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GPO 2010d). This review may lead to more accurate estimates of GHG emissions from these facilities and may prompt GHG emission monitoring in some cases.

Based largely on GHG emission data submitted under the GHG Mandatory Reporting Rule, USEPA plans to develop stationary source GHG emission reduction rules that could mandate substantial reductions in U.S. GHG emission reductions. Alternatively, the U.S. Congress may develop cap-and-trade legislation as another means to reduce GHG emissions.

Future year projected emission data included in this report do not reflect future impacts of recently promulgated and expected U.S. GHG regulations. These regulations are intended to have the following effects.

- Mandatory GHG reporting and GHG permitting will result in more comprehensive and more accurate GHG emission data availability in the future.
- Mandatory GHG emission reductions for light-duty vehicles will reduce GHG emissions from these U.S. vehicles.
- Future stationary source GHG emission control rules will reduce GHG emissions from a variety of industries, including the oil and gas industry.

1.2. Energy Market Effects on Oil and Gas Development

Potential oil and gas development planned for federal minerals in Montana, North Dakota, and South Dakota are subject to U.S. and global energy markets. Market forces favor oil and gas development in areas with low production and transportation prices, as well as low production risk. As GHGs become regulated and if a carbon tax or cap-and-trade requirement is implemented, low GHG-emitting fossil fuels would be preferred.

Natural gas combustion emits fewer GHGs than combustion of other fossil fuels. Consequently, natural gas may displace coal and oil as the fossil fuel of choice in many applications. Table 1-2 provides a comparison of natural gas and other fossil fuel emissions. In terms of GHG emissions per million British thermal units (MMBtu) of heat input, natural gas substitution would reduce GHG emissions from coal combustion by approximately 44 percent and would reduce GHG emissions from petroleum combustion by approximately 25 to 28 percent.

Table 1-2. Comparison of GHG Emissions From Fossil Fuel Combustion

Fuel	Emissions (kg/MMBtu)			
	CO_2	CH_4	N_2O	CO_2e
Natural Gas	53.02	0.001	0.0001	53.07
Coal [1]	94.38	0.011	0.0016	95.11
Diesel Fuel	73.25	0.003	0.0006	73.50
Gasoline	70.22	0.003	0.0006	70.47

Source: 40 CFR Part 98, Subpart C, Tables C-1 and C-2 (GPO 2010b).
kg = kilogram
MMBtu = Million British thermal units
[1] The coal CO_2 emission factor is based on a mixture of coal types and represents coal used in electricity generation. The range of coal CO_2 emissions factors is 93.4 to 103.54 kg/MMBtu.

To the extent that economics, availability, and regulatory requirements encourage natural gas replacement of other existing fossil fuel use, global GHG emissions could be reduced by increased production of natural gas. For example, the U.S. Energy Information Administration (EIA) predicts that fuel switching will prompt an 83 percent increase in electric power sector natural gas consumption from 2009 to 2030 (EIA 2009).

While natural gas is likely to displace some fossil fuels, renewable energy is expected to replace some natural gas usage in a variety of applications, such as home heating and electric power generation. The EIA predicts that total natural gas consumption in the United States will fall by 14 percent from 2009 to 2030 (EIA 2009). If natural gas consumption decreases, natural gas production of federal minerals in Montana, North Dakota, and South Dakota may be less than the levels of development included in the RFD scenarios included in Chapter 4.

U.S. GHG emissions may not necessarily increase by the magnitude of potential GHG emissions from oil and gas production of federal minerals in Montana, North Dakota, and South Dakota. Oil and gas development may decline in other portions of the United States, thereby decreasing total U.S. GHG emissions from oil and gas production, even when new development in these areas is added. If GHG emission reduction regulations applicable to oil and gas activities are implemented by USEPA in the future, oil and gas development may preferentially increase in fields that produce these fuels with lower than average GHG emissions.

1.3. Uncertainties

Many uncertainties are associated with the data included in this report. Assumptions and uncertainties associated with the BLM RFDs and with BLM Field Office oil and gas emission inventories are described in the BLM Field Office emission inventories and in the supporting BLM RFD documents.

Climate change data and particularly predictions of potential climate change impacts are subject to varying degrees of uncertainty. The level of uncertainty is often addressed by the use of specific terminology by the organization that prepared a climate change report. For example, the Intergovernmental Panel on Climate Change (IPCC) addresses the probability of an occurrence using the following phrases and associated probabilities.

- Virtually certain, >99%
- Extremely likely, >95%
- Very likely, >90%
- Likely, >66%
- More likely than not, >50%
- About as likely as not, 33% to 66%
- Unlikely, <33%
- Very unlikely, <10%
- Extremely unlikely, <5%
- Exceptionally unlikely, <1%

USEPA uses similar terminology in some of its climate change reports, though with fewer uncertainty categories. For example, USEPA language includes the "very likely" and "likely" phrases to describe some levels of uncertainty. The probabilities associated with this terminology are the same as those used by the IPCC.

Resource documents referenced in this report frequently provide detailed explanations of key uncertainties. Readers are encouraged to access referenced documents in order to better understand the basis for the data and findings that are summarized in this report.

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2.0 CLIMATE SCIENCE

Climate change has occurred throughout Earth's history due to natural variations, such as cyclical changes in the sun's energy reaching the Earth, and also to unusual natural events such as large volcanic eruptions that have caused significant and abrupt temporary climate change. However, recent climate changes indicate a discernable upward trend in global warming and other climate changes. Many of these changes have been linked to anthropogenic (human-caused) activities that increase GHG emissions and atmospheric concentrations of these gases.

"Climate change" is defined by the IPCC as "a change in the state of the climate that can be identified (e.g., by using statistical tests) by changes in the mean and/or the variability of its properties, and persist for an extended period, typically decades or longer. It refers to any change in climate over time, whether due to natural variability or as a result of human activity." (IPCC 2007a). USEPA concurs that climate change may be due to natural or human-induced causes (USEPA 2010a). However, the United Nations Framework Convention on Climate Change (UNFCCC) defines climate change as a change that is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and that is in addition to natural climate variability observed over comparable time periods. In this report, the IPCC and USEPA climate change definition will be used and human-induced climate change will be identified as such.

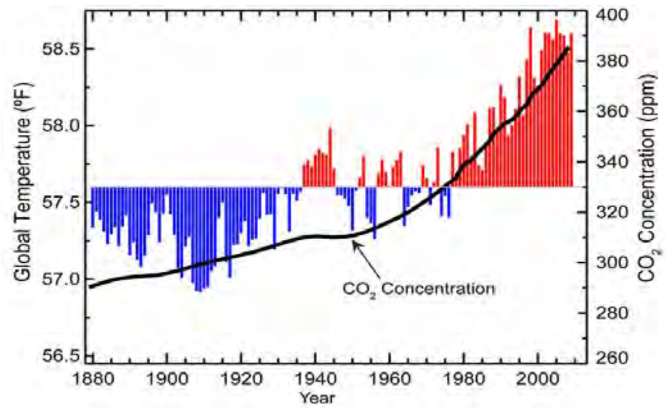
2.1. Observed Climate Changes

Warming of the Earth's surface and water bodies has been observed. Known as global warming, these increases in the Earth's temperature cause many additional climate changes. Several of the most important climate changes are summarized below. Additional information on observed climate changes can be obtained from the IPCC, USEPA, UNFCCC, National Oceanic and Atmospheric Administration (NOAA), and other sources.

2.1.1. Global Temperature Increases

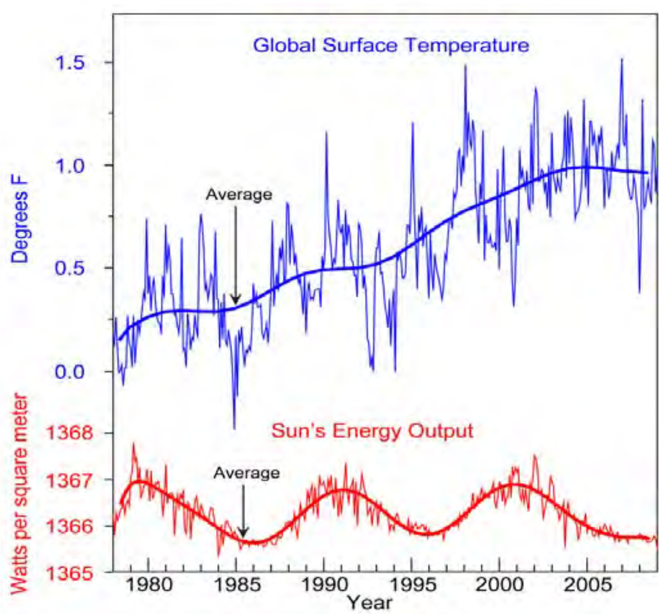
The global average temperature has increased approximately 1.4°F since the early 20th Century (NOAA 2010a), as shown in Figure 2-1. Furthermore, the 20 warmest years have occurred since 1981, and the 10 warmest have occurred in the past 12 years. Global surface temperature is based on air temperature data over land and sea-surface temperatures observed from ships, buoys, and satellites. A clear long-term global warming trend is apparent, although some individual years show brief temperature decreases relative to the previous year. Some year-to-year fluctuations in temperature are due to natural processes, such as the effects of El Ninos, La Ninas, and the eruption of large volcanoes. Red bars on Figure 2-1 indicate temperatures above the 1901-2000 average temperature and blue bars indicate temperatures below the average. The black curve indicates the atmospheric CO_2 concentration in parts per million (ppm).

Energy from the sun warms the Earth. However, the observed decades-long global temperature increases are extremely unlikely to be attributable to solar energy variations, which have been measured by satellites since 1978 (NOAA 2010a). As shown in Figure 2-2, variations in solar energy are cyclical, with approximate 11-year cycles. While solar energy output shows no net increase since 1978, the global surface temperature has increased noticeably.



Source: NOAA 2010a.

Figure 2-1. Observed Global Temperatures from 1880 to 2009



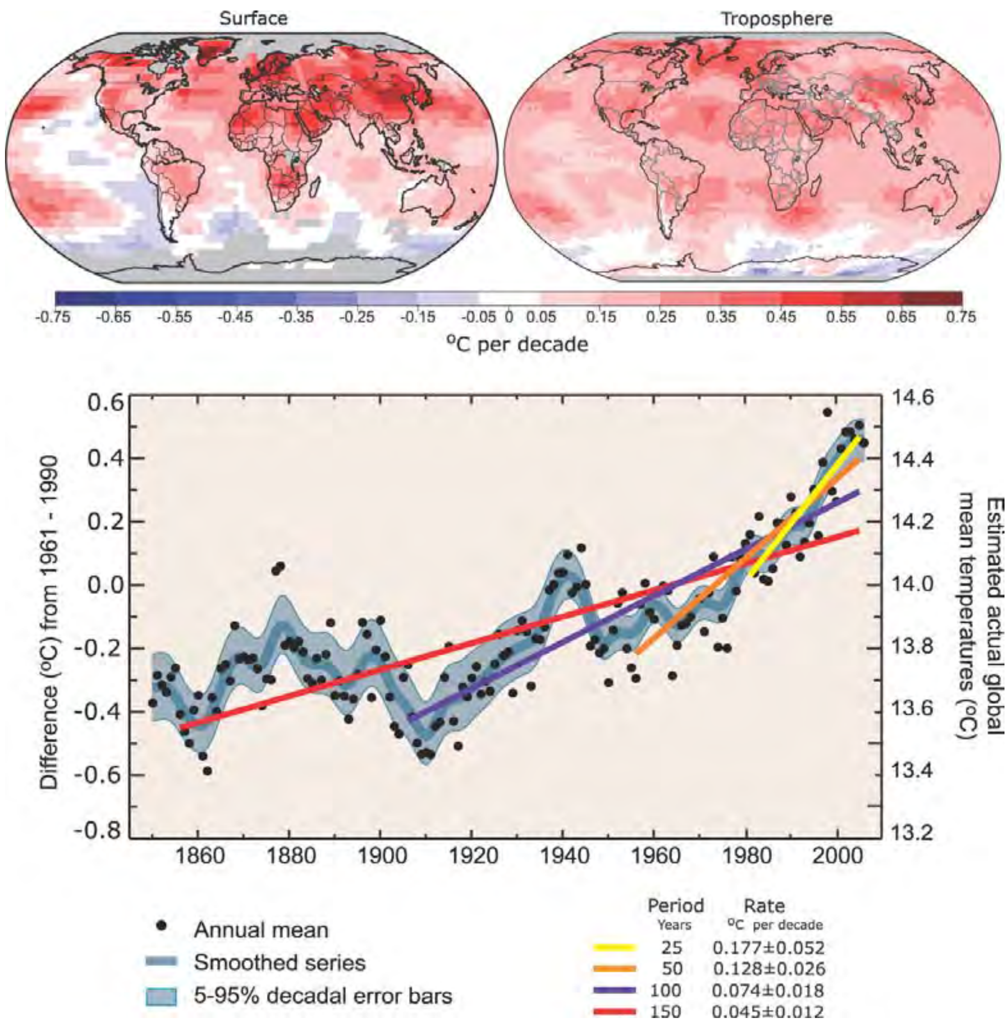
Source: NOAA 2010a.

Figure 2-2. Observed Global Temperatures Compared to Solar Energy Output

The IPCC states (IPCC 2007b):

> "Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level (see Figure SPM.3 [not included here])."

Warming has occurred on land surfaces, oceans and other water bodies, and in the troposphere. Figure 2-3 shows that the Earth's surface has warmed more than the troposphere. Furthermore, the global warming trend is accelerating. The linear warming trend over the past 50 years of 0.13°C per decade was nearly twice that of the last 100 years (IPCC 2007b). Figure 2-3 illustrates the relative rates of warming over the last 25, 50, 100, and 150 years. The yellow curve, which represents the warming trend over the last 25 years, shows the greatest rate of global warming. The 25-year warming trend indicates an increase of 0.177°C per decade.



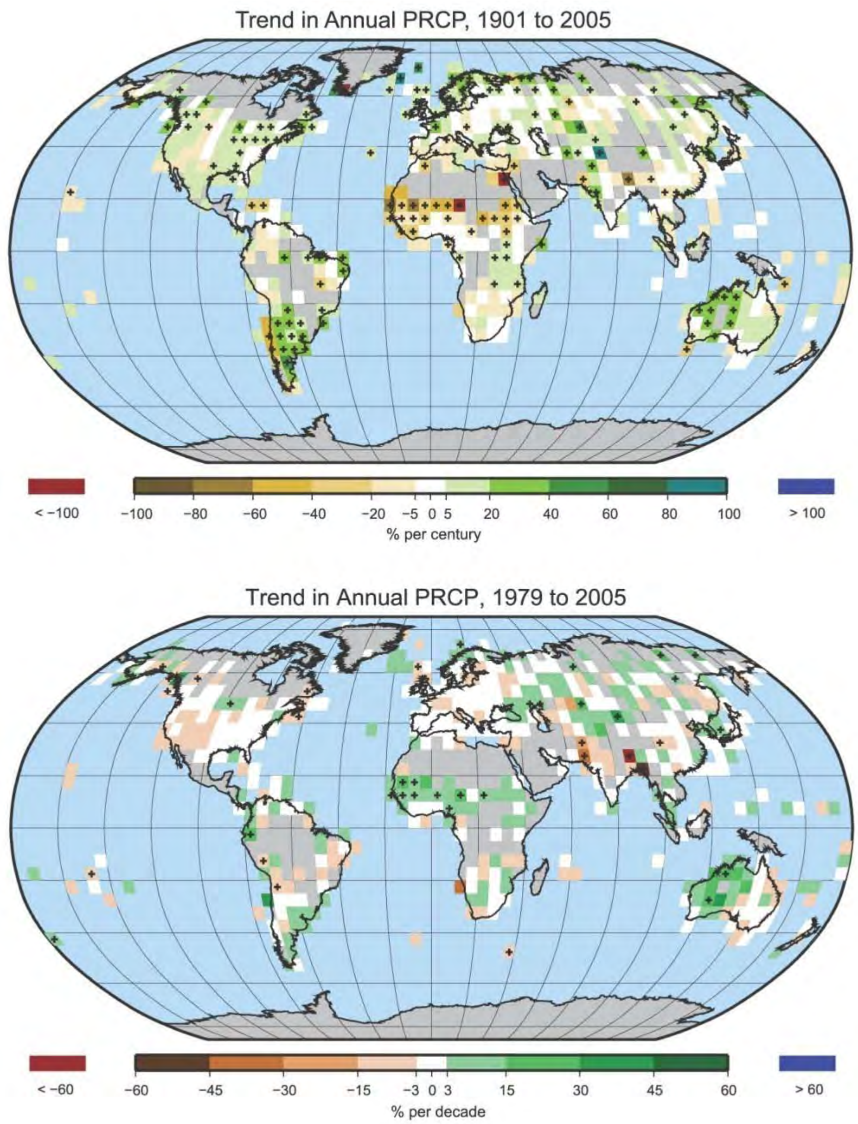
Source: Adapted from Figure TS.6 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

(Top) Patterns of linear global temperature trends over the period 1979 to 2005 estimated at the surface (left), and for the troposphere from satellite records (right). Grey indicates areas with incomplete data. (Bottom) Annual global mean temperatures (black dots) with linear fits to the data. The left axis shows temperature anomalies relative to the 1961 to 1990 average and the right axis shows estimated actual temperatures, both in °C. Linear trends are shown for the last 25 (yellow), 50 (orange), 100 (purple), and 150 years (red). The smooth blue curve shows decadal variations, with the decadal 90% error range shown as a pale blue band about that line. The total temperature increase from the period 1850 to 1899 to the period 2001 to 2005 is 0.76°C ± 0.19°C.

Figure 2-3. Global Temperature Warming Trends

2.1.2. Increased Precipitation and Changes in Precipitation Timing

Long-term trends in annual average precipitation quantities have been observed in large regions of the globe (IPCC 2007b). Areas showing significant precipitation increases include the eastern portions of North and South America, northern Europe, and northern and central Asia. Drying has been observed in the Sahel, the Mediterranean, southern Africa, and parts of southern Asia. Figure 2-4 illustrates precipitation trends for two time scales, 1901–2005 and 1979–2005. As shown, changes in average annual precipitation vary greatly by location. Additional data is needed for areas shown in grey in order to determine trends over these time frames.

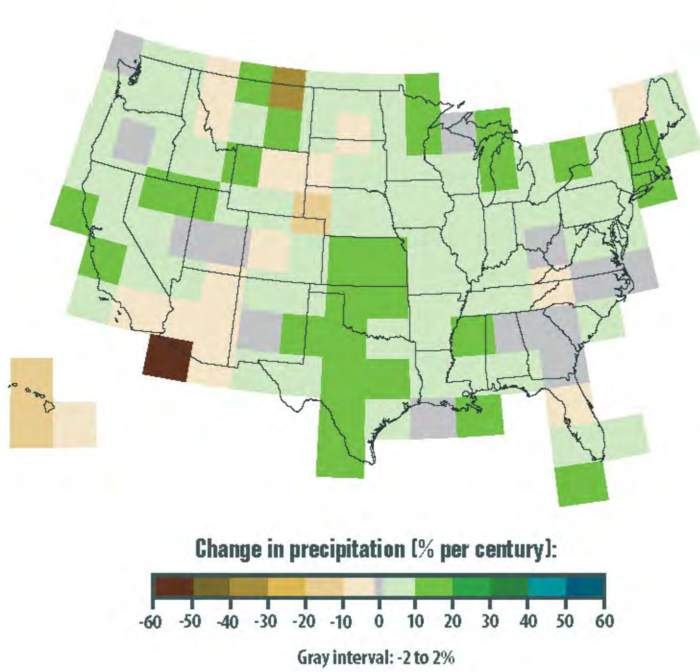


Source: Adapted from Figure TS.9 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

(Top) distribution of linear trends of annual land precipitation amounts over the period 1901 to 2005 (% per century) and (bottom) 1979 to 2005 (% per decade). Areas in grey have insufficient data to produce reliable trends. The percentage is based on the 1961 to 1990 period.

Figure 2-4. Global Mean Precipitation Trends

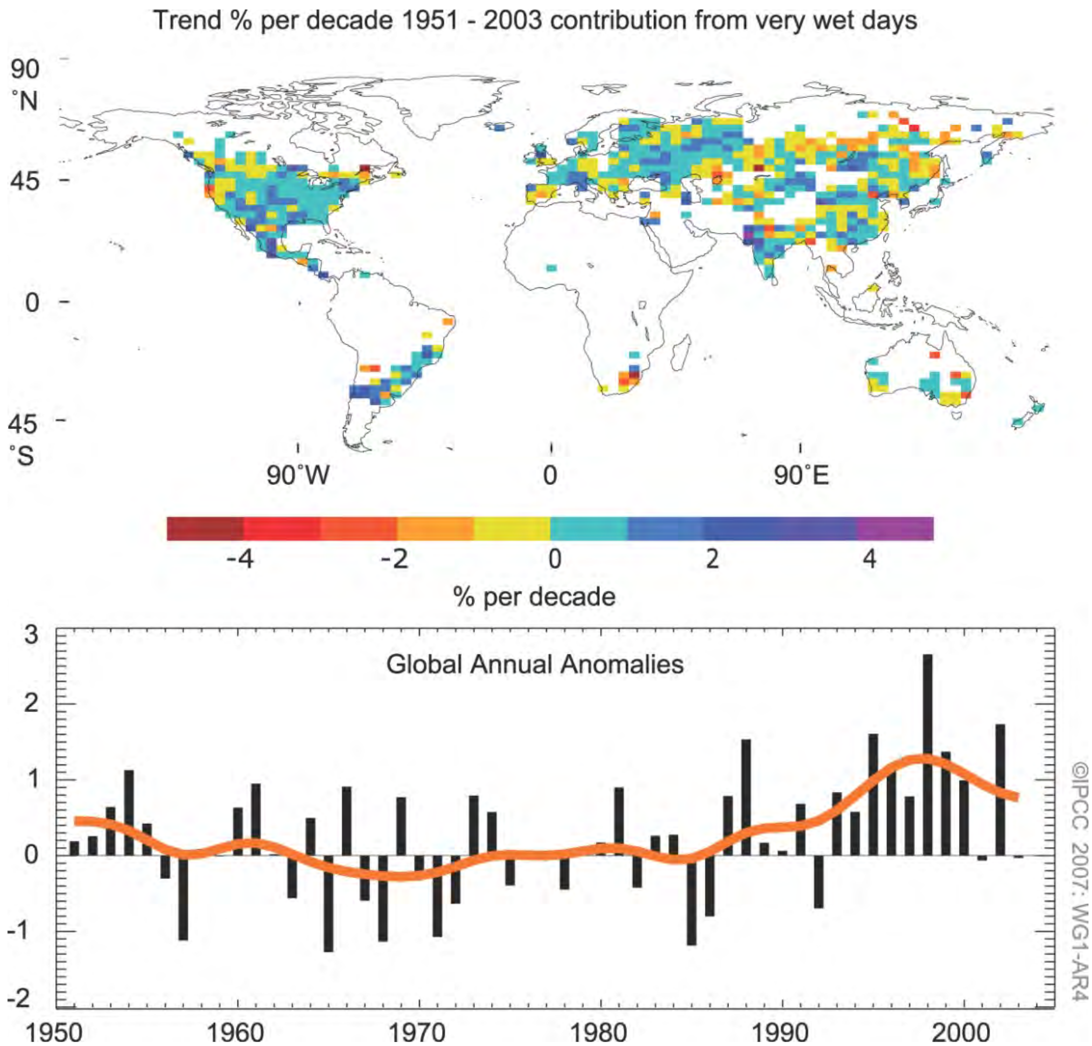
Within the United States, changes in annual precipitation also vary based on location. Figure 2-5 illustrates annual average precipitation changes in the lower 48 states since 1901 and in Hawaii since 1905. Alaska is not shown due to limited data coverage. Within the 48 states as a whole, annual precipitation has increased at a rate of 6.4 percent per century, though some portions of the nation have seen a much greater increase than others. A few areas, including Hawaii and part of the Southwest have experienced more than a 10 percent decrease in average precipitation (USEPA 2010a).



Source: *Climate Change Indicators in the United States (USEPA 2010a).*

Figure 2-5. U.S. Rate of Precipitation Change, 1901–2008

Substantial increases in heavy precipitation events have been observed, particularly in the last 50 years (IPCC 2010b). Furthermore, heavy precipitation events have occurred in areas in which annual total precipitation has decreased. In Figure 2-6, turquoise to purple shaded areas indicate an increase of up to 5 percent per decade in the quantity of precipitation that occurs on very wet days. Yellow to dark red shaded areas indicate a decrease precipitation occurring on very wet days.

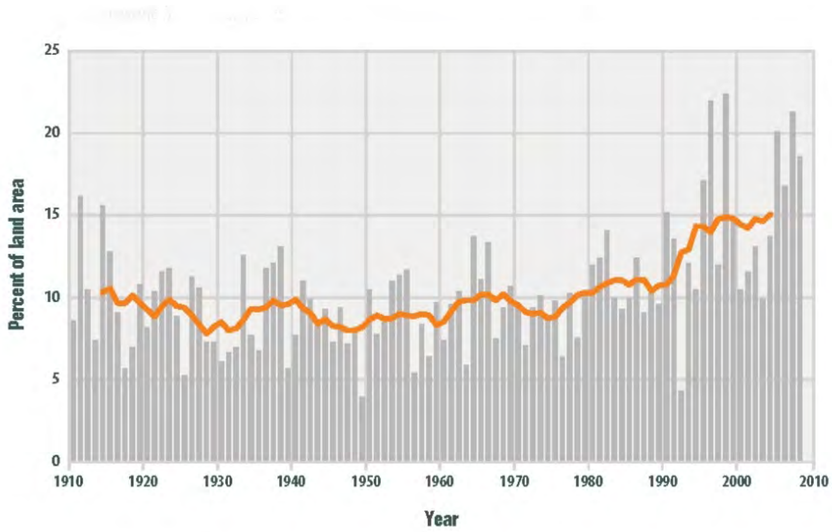


Source: Figure TS.10 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

(Top) Observed trends (% per decade) over the period 1951 to 2003 in the contribution to total annual precipitation from very wet days (i.e., corresponding to the 95th percentile and above). White land areas have insufficient data for trend determination. (Bottom) Anomalies (%) of the global (regions with data shown in top panel) annual time series of very wet days (with respect to 1961–1990) defined as the percentage change from the base period average (22.5%). The smooth orange curve shows decadal variations.

Figure 2-6. Global Extreme Precipitation Trends, 1951-2003

As shown above, much of the United States has experienced an increased percentage of rainfall during heavy precipitation events. Figure 2-7 provides a time series showing the percentage of the land area of the lower 48 states where a much greater than normal portion of total annual precipitation has come from extreme single-day precipitation events. The bars represent individual years, while the line is a smoothed nine-year moving average. In the most recent four years, more than 15 percent of U.S. land area has experienced extreme one-day precipitation events.



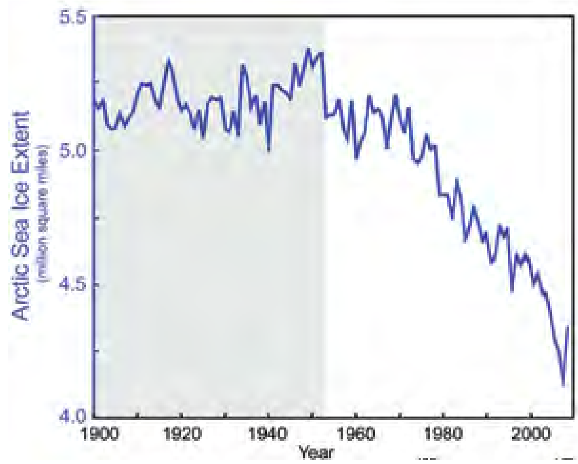
Source: *Climate Change Indicators in the United States (USEPA 2010a).*

Figure 2-7. U.S. Extreme One-Day Precipitation Events in the Lower 48 States, 1910–2008

2.1.3. Decreased Ice and Snow Coverage

Arctic sea ice is declining rapidly and this trend is very likely to continue (USGCRP 2009). Sea ice plays an important role in Alaska and northernmost national climates. The ice affects the amount of ocean surface reflectivity because sea ice reflects more sunlight than open ocean water. Sea ice also affects ocean currents, cloudiness, humidity, and the transfer of heat and moisture at the ocean's surface.

Satellite observations of sea ice have been recorded since the 1970s. Earlier sea ice records come from aircraft, ship, and coastal observations dating back to 1900 for the northern hemisphere. Based on these records, arctic sea ice has declined at a rate of 3 to 4 percent per decade over the last three decades based on an annual average of areal ice extent, as shown in Figure 2-8. The declining trend is more pronounced when the trend of end-of-summer Arctic sea ice is reviewed, and indicates a decline of 11 percent per decade.

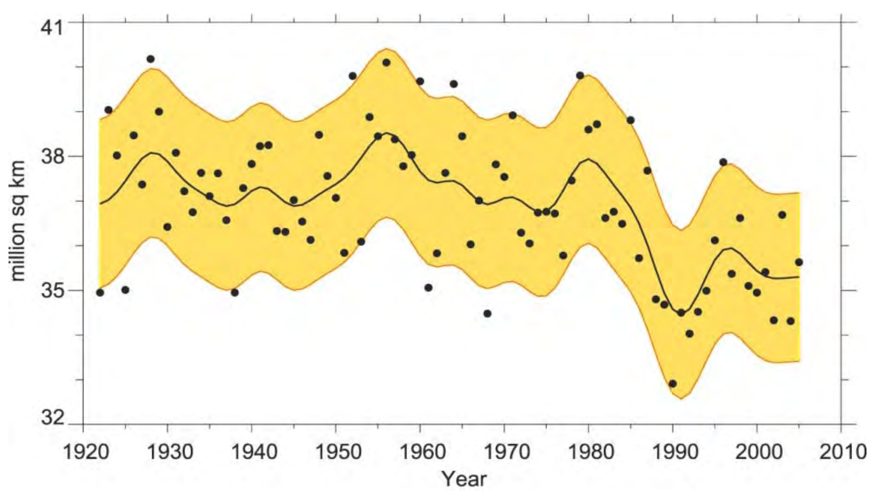


Source: Adapted from *Global Climate Change Impacts in the United States (USGCRP 2009).*

Grey shading indicates less confidence in the data before 1953.

Figure 2-8. Arctic Sea Ice Areal Decreases From 1900 to 2008

Global warming has also caused global glacial recession during the summer. Widespread ice mass losses have contributed to sea level rise during the 20th century (IPCC 2007b). The areal extent of snow cover has decreased in most regions, particularly in the spring. Northern hemisphere snow cover from 1966 to 2005 decreased in every month except November and December, with a stepwise drop of 5 percent in the annual mean in the late 1980s (IPCC 2007b). Decreases in snowpack, permafrost, and seasonally frozen ground have also been observed.



Source: Adapted from Figure TS.12 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

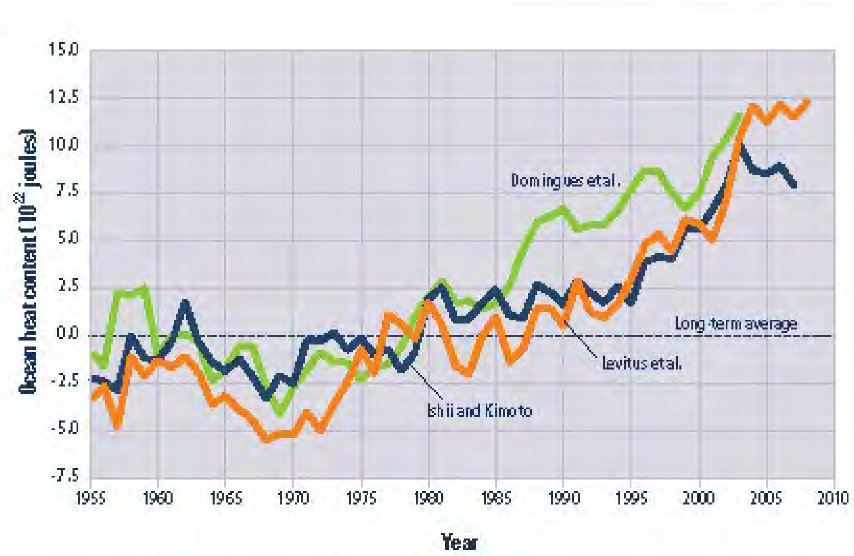
Data points indicate actual observations, while the smooth curve shows decadal variations. The shaded area indicates the 5 to 95% confidence level.

Figure 2-9. Changes in Snow Cover in the Northern Hemisphere During March and April

2.1.4. Oceanic Observations

The oceans and the atmosphere interact constantly by exchanging heat, water, gases, and particles. Because they cover nearly 70 percent of the Earth's surface and because water has a greater specific heat than air, oceans store a vast amount of heat energy and transport this energy around the globe through currents.

Figure 2-10 illustrates changes in ocean heat content between 1955 and 2008; heat content has increased substantially since 1955 (USEPA 2010a). Ocean heat content is measured in joules, a unit of energy, and compared against the long-term average heat content, which is set at zero. The blue, orange, and green curves illustrate results from three separate studies.

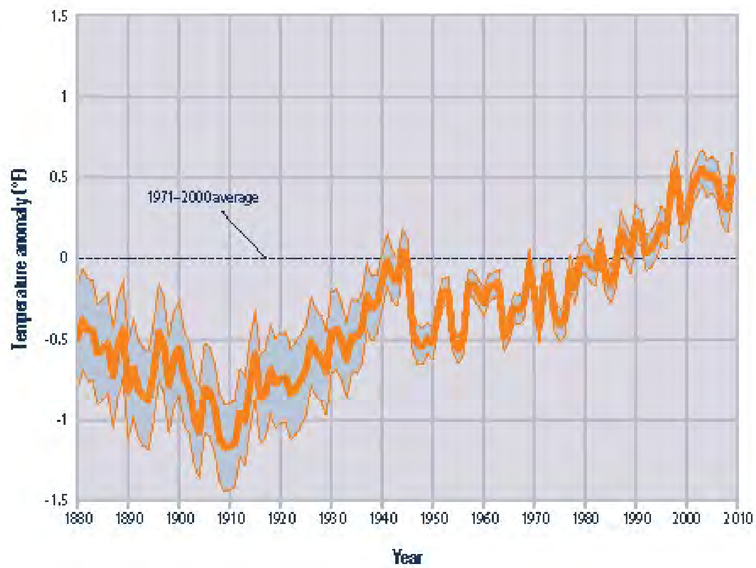


Source: *Climate Change Indicators in the United States (USEPA 2010a).*

Figure 2-10. Global Ocean Heat Content, 1955–2008

Sea surface temperature is also an important ocean characteristic because it plays a large role in ocean-atmospheric interaction. Figure 2-11 depicts the increased average surface temperature of the world's oceans since 1880 compared to a 1971-2000 average baseline. The shaded band shows the likely range of values, based on the number of measurements collected and the precision of the methods used. From 1901 through 2009, temperatures rose at an average rate of 0.12°F per decade. Over the last 30 years, these temperatures have risen at a faster pace of 0.21°F (USEPA 2010a).

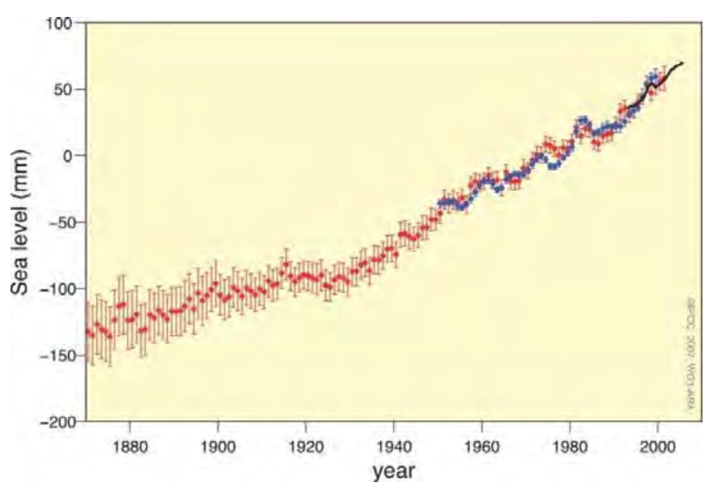
The sea surface temperature partially determines the amount of moisture that evaporates into the air and affects the intensity of hurricanes and other storms. Based on changes in these temperatures, the amount of atmospheric vapor over the oceans is estimated to have increased by approximately 5 percent during the 20th century (IPCC 2007b).



Source: *Climate Change Indicators in the United States (USEPA 2010a).*

Figure 2-11. Average Global Sea Surface Temperature, 1880–2009

Sea levels have risen consistently as shown in Figure 2-12. The global average rate of sea level increase during 1993 to 2003 is 3.1 millimeters (mm) per year (IPCC 2007b). The sea level increase is consistent with the expansion of water due to temperature increase and to the addition of water due to land ice melting. Sea level is not rising consistently along all coasts. The largest sea level rise since 1992 has occurred in the western Pacific and in the eastern Indian Oceans. Sea levels have been falling in the eastern Pacific and western Indian Oceans (IPCC 2007b).

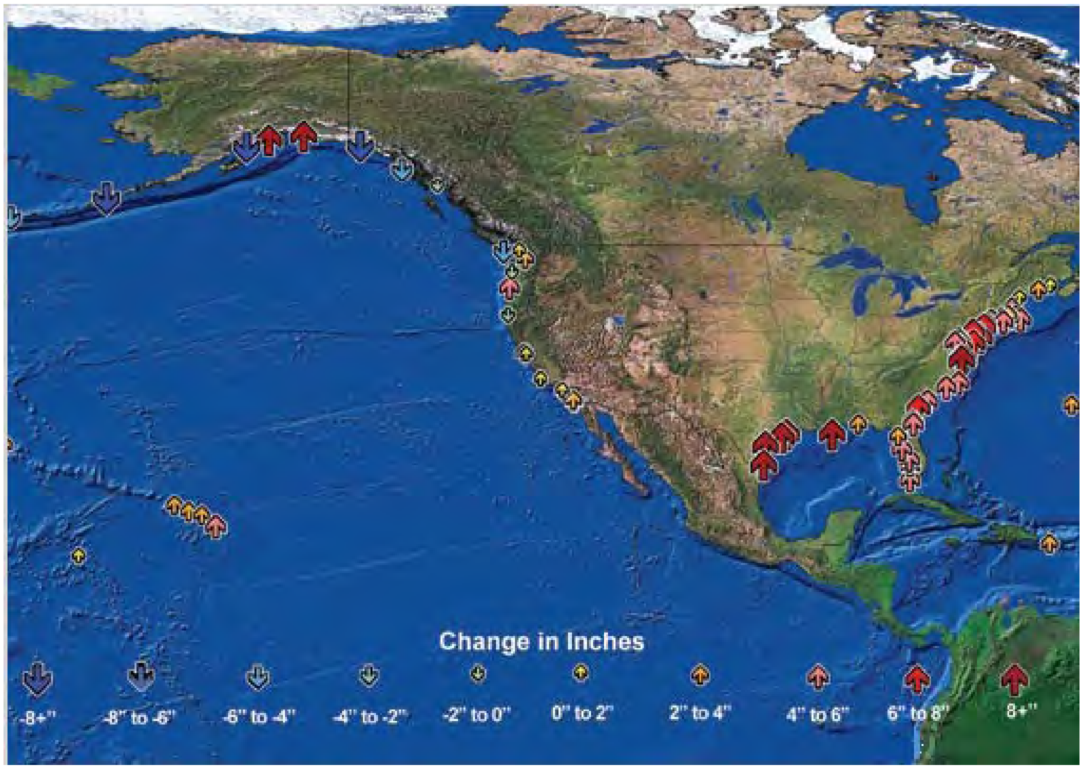


Source: Adapted from Figure TS.18 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Annual averages of the global mean sea level based on reconstructed sea level fields since 1870 (red), tide gauge measurements since 1950 (blue) and satellite altimetry since 1992 (black). Units are in millimeters (mm) relative to the average for 1961 to 1990. Error bars are 90% confidence intervals.

Figure 2-12. Global Mean Sea Level

Sea level changes during the last 50 years (1958 to 2008) along U.S. coasts are shown in Figure 2-13. Some areas along the Atlantic and Gulf coasts saw increases greater than 8 inches over the past 50 years, while other coastal areas have seen small increases or even decreases in sea level (USGCRP 2009).



Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 2-13. Relative Sea Level Changes on U.S. Coastlines, 1958 to 2008

2.1.5. Other Observed Climate Changes

The above discussion provides a brief summary of some observed climate changes; many more types of climate change have been scientifically observed and documented. USEPA recently published *Climate Change Indicators in the United States* (USEPA 2010a), which states that a National Academy of Sciences climate change workshop in 2004 identified 110 separate indicators of climate change. Of these, USEPA identified a subset of 24 indicators for its report. USPEA-selected indicators included in its Climate Change Indicators document are grouped into five categories and are listed in Table 2-1. Note that while USEPA selected these topics for its document, it is not restricting its climate change review or efforts to these indicators.

Table 2-1. USEPA Climate Change Indicators

Greenhouse Gases	Oceans	Society and Ecosystems
• U.S. Greenhouse Gas Emissions • Global Greenhouse Gas Emissions • Atmospheric Concentrations of Greenhouse Gases • Climate Forcing	• Ocean Heat • Sea Surface Temperature • Sea Level • Ocean Acidity	• Heat-Related Deaths • Length of Growing Season • Plant Hardiness Zones • Leaf and Bloom Dates • Bird Wintering Ranges
Weather and Climate	**Snow and Ice**	
• U.S. and Global Temperature • Heat Waves • Drought • U.S. and Global Precipitation • Heavy Precipitation • Tropical Cyclone Intensity	• Arctic Sea Ice • Glaciers • Lake Ice • Snow Cover • Snowpack	

Source: USEPA 2010a.

Key additional climate change observations from the IPCC are quoted below. For information concerning uncertainties related to climate change topics, refer to Section TS.6 of the Technical Summary of *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* (IPCC 2007b).

- Changes in Natural Drivers of Climate
  - Current atmospheric concentrations of CO_2 and CH_4, and their associated positive RF, far exceed those determined from ice core measurements spanning the last 650,000 years.
  - Natural processes of CO_2 uptake by the oceans and terrestrial biosphere remove about 50 to 60 percent of anthropogenic emissions (i.e., fossil CO_2 emissions and land use change flux). Uptake by the oceans and the terrestrial biosphere are similar in magnitude over recent decades but that by the terrestrial biosphere is more variable.
- Atmosphere and Surface
  - Global mean surface temperatures continue to rise. Eleven of the last 12 years rank among the 12 warmest years on record since 1850.
  - Rates of surface warming increased in the mid-1970s and the global land surface has been warming at about double the rate of ocean surface warming since then.
  - Changes in surface temperature extremes are consistent with warming of the climate.
  - Estimates of mid- and lower-tropospheric temperature trends have substantially improved. Lower-tropospheric temperatures have slightly greater warming rates than the surface from 1958 to 2005.
  - Long-term trends from 1900 to 2005 have been observed in precipitation amount in many large regions.

- Increases have occurred in the number of heavy precipitation events.
- Droughts have become more common, especially in the tropics and subtropics, since the 1970s.
- Tropospheric water vapor has increased, at least since the 1980s.

- Snow, Ice, and Frozen Ground
  - The amount of ice on the Earth is decreasing. There has been widespread retreat of mountain glaciers since the end of the 19th century. The rate of mass loss from glaciers and the Greenland Ice Sheet is increasing.
  - The extent of Northern Hemisphere snow cover has declined. Seasonal river and lake ice duration has decreased over the past 150 years.
  - Since 1978, annual mean arctic sea ice extent has been declining and summer minimum arctic ice extent has decreased.
  - Ice thinning occurred in the Antarctic Peninsula and Amundsen shelf ice during the 1990s. Tributary glaciers have accelerated and completed breakup of the Larsen B Ice Shelf occurred in 2002.
  - Temperature at the top of the permafrost layer has increased by up to 3°C since the 1980s in the Arctic. The maximum extent of seasonally frozen ground has decreased by about 7 percent in the northern hemisphere since 1900, and its maximum depth has decreased by about 0.3 meters (m) in Eurasia since the mid-20th century.
- Oceans and Sea Level
  - The global temperature (or heat content) of the oceans has increased since 1955.
  - Large-scale regionally coherent trends in salinity have been observed over recent decades with freshening in subpolar regions and increased salinity in the shallower parts of the tropics and subtropics. These trends are consistent with changes in precipitation and inferred larger water transport in the atmosphere from low latitudes to high latitudes and from the Atlantic to the Pacific.
  - Global average sea level rose during the 20th century.
  - There is high confidence that the rate of sea level rise increased between the mid-19th and mid-20th centuries. During 1993 to 2003, sea level rose more rapidly than during 1961 to 2003.
  - Thermal expansion of the ocean and loss of mass from glaciers and ice caps made substantial contributions to the observed sea level rise.
  - The observed rate of sea level rise from 1993 to 2003 is consistent with the sum of observed contributions from thermal expansion and loss of land ice.
  - The rate of sea level change over recent decades has not been geographically uniform.
  - As a result of uptake of anthropogenic CO_2 since 1750, the acidity of the surface ocean has increased.

2.2. Climate Change Causes

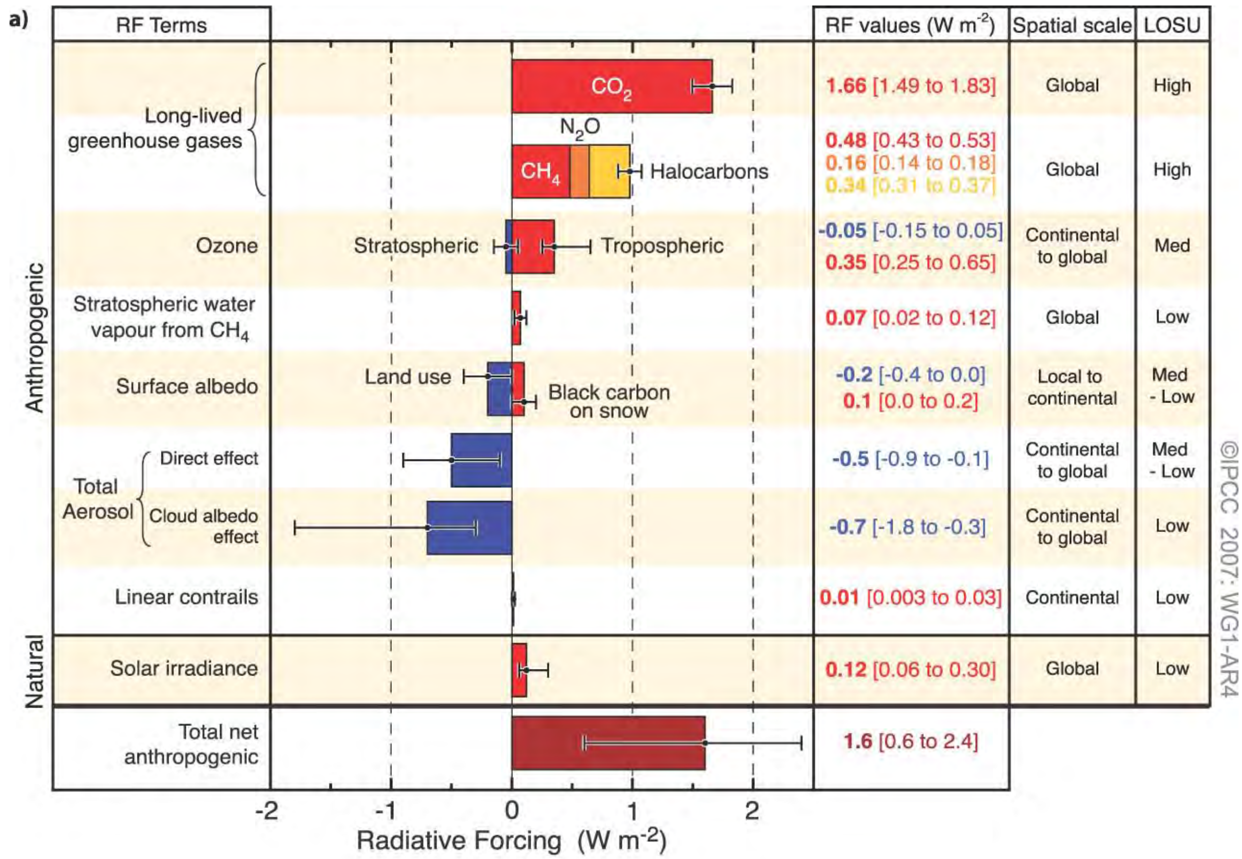
The IPCC reports with greater than 95 percent probability that global warming during the past half century cannot be explained without external radiative forcing (RF) (IPCC 2007b). In other words, observed climate changes cannot be explained based solely on natural influences. This section explains RF and other scientific concepts linking climate change to anthropogenic sources.

2.2.1. Radiative Forcing

The IPCC defines RF as "a measure of the influence that a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system and is an index of the importance of the factor as a potential climate change mechanism. Positive forcing tends to warm the surface while negative forcing tends to cool it. In this report [IPCC 2007b], RF values are for 2005 relative to pre-industrial conditions defined at 1750 and are expressed in watts per square metre ($W\ m^{-2}$)." In simpler terms, RF provides a means to compare how a range of human and natural factors drive warming or cooling of the Earth.

Figure 2-14 illustrates major components of RF. Red, orange, and yellow bars indicate positive (warming) forcing, while blue bars indicate negative (cooling) forcing. As shown in the figure, positive RF is primarily caused by long-lived GHGs resulting from human activities. CO_2 is responsible for most of the forcing, and has a greater positive effect than combined methane, N_2O, and halocarbons. Ground-level (tropospheric) ozone also warms the atmosphere (while stratospheric ozone cools the atmosphere). However, since tropospheric ozone is short-lived, it does not pose the same global warming risk that USEPA-regulated GHGs do.

Solar irradiance is the natural RF source. The solar irradiance shown in Figure 2-14 includes only the change in RF since 1750 (an approximate date for the industrial revolution). Total solar irradiance would be greater. The total net estimated anthropogenic RF is 1.6 $W\ m^{-2}$ (IPCC 2007b).



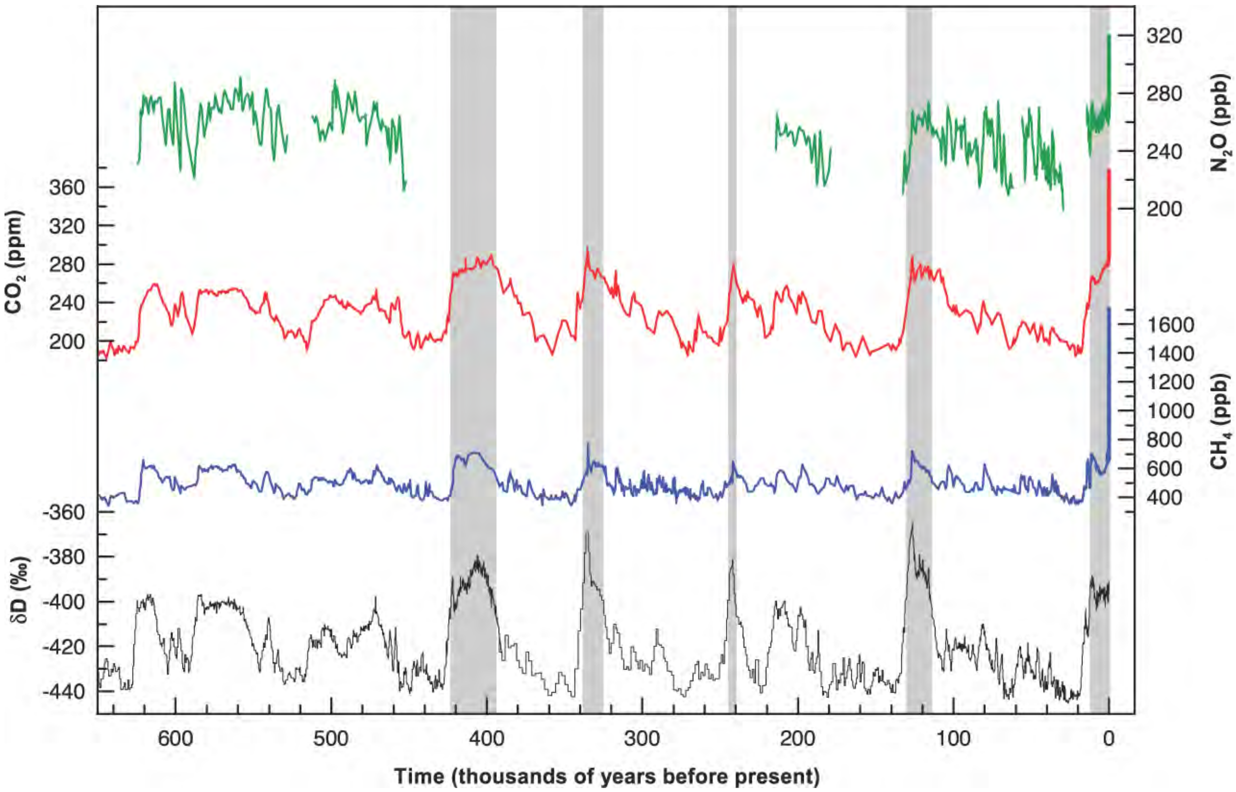
Source: Adapted from Figure TS.5 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Global mean radiative forcings (RF) and their 90% confidence intervals in 2005 for various agents and mechanisms. Columns on the right specify best estimates and confidence intervals (RF values); typical geographical extent of the forcing (Spatial scale); and level of scientific understanding (LOSU) indicating the scientific confidence level. Errors for CH_4, N_2O and halocarbons have been combined. The net anthropogenic radiative forcing and its range are also shown. Additional forcing factors not included here are considered to have a very low LOSU. Volcanic aerosols contribute an additional form of natural forcing but are not included due to their episodic nature. The range for linear contrails does not include other possible effects of aviation on cloudiness.

Figure 2-14. Global Mean Radiative Forcing

2.2.2. Increased Atmospheric GHG Concentrations

Historically, there is a strong link between temperature and atmospheric GHG concentrations, as shown in Figure 2-15. Gray shading identifies warm global periods and peak GHG concentrations correspond to these warm periods. Atmospheric GHG concentrations have increased substantially over the last 650,000 years. CO_2, methane, and N_2O concentrations are much greater now than they were prior to the industrial age and the increased concentrations result primarily from human activity.

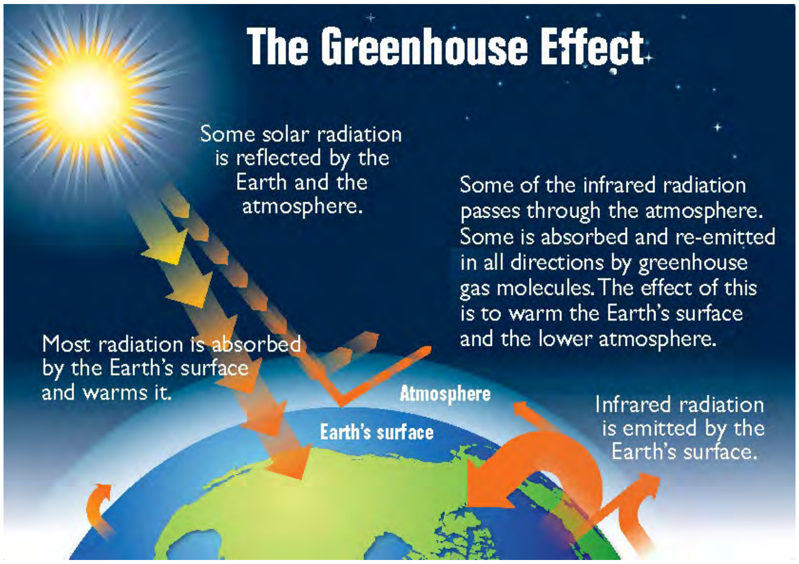


Source: Figure TS.1 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Atmospheric concentrations of the greenhouse gases nitrous oxide (N_2O, green), carbon dioxide (CO_2, black), and methane (CH_4, blue) in air trapped within the ice cores and from recent atmospheric measurements. At the bottom of the graph, the percentage of deuterium (δD) in Antarctic ice is a proxy for local temperature. Data cover 650,000 years and the shaded bands indicate current and previous interglacial warm periods.

Figure 2-15. Ice Core Data Showing GHG Concentrations and Indicating Local Temperature

The link between GHGs and climate change is explained scientifically due to the effect of these compounds in the atmosphere. Earth has a natural greenhouse effect involving naturally occurring atmospheric components such as water vapor, CO_2 (due to animal/vegetation respiration), methane (due to decay), and N_2O. Without the natural GHG effects, Earth would be approximately 60°F cooler (USGCRP 2009). The Earth's temperature fluctuates based on a global energy balance of incoming energy from the sun and outgoing energy radiated back into space, as shown in Figure 2-16.



Source: *Climate Change Indicators in the United States (USEPA 2010a).*

Figure 2-16. Greenhouse Effect Schematic

Increased emissions of anthropogenic GHGs are contributing to global warming by increasing atmospheric concentrations of these compounds, which absorb energy from the Earth's surface and re-emit a larger portion of Earth's heat back to the Earth rather than allowing the heat to escape into space. Increased GHG concentrations will cause significant adverse climate impacts (see Chapter 3.0).

Characteristics of the heat-trapping gases with the greatest global warming impact are summarized below. In addition, GHGs with relatively low impact on climate change are also described.

CO_2 — Over the past several decades, approximately 80 percent of anthropogenic CO_2 resulted from fossil fuel combustion (primarily in electricity generation, transportation, and industrial and residential use), while most of the remainder resulted from deforestation and agricultural practices (USGCRP 2009).

Methane — Methane primarily results from agriculture (primarily livestock) and energy production (coal, gas, and oil). Anthropogenic sources now account for approximately 70 percent of methane emissions (USGCRP 2009).

N_2O — Atmospheric concentrations of N_2O primarily result from fertilizer use and fossil fuel combustion; thus, these emissions are primarily human caused (USGCRP 2009).

Halocarbons — Halocarbons are man-made substances used extensively in refrigeration and other industrial processes. Many halocarbons (such as chlorofluorocarbons [CFCs]) have been banned due to efforts to preserve stratospheric ozone. However, many of the HFCs and PFCs used to replace CFCs have high GWPs.

Water vapor — Water vapor is the most abundant GHG in the atmosphere. However, human activity produces only a small increase in direct water vapor release through irrigation and combustion. Global surface warming caused by the release of non-water GHGs leads to increased water vapor in the atmosphere since warm air can hold more moisture. Increased water vapor due to global warming can create a feedback loop that amplifies warming (USGDCRP 2009).

Ozone — Tropospheric ozone is a GHG that is continually produced and destroyed in the lower atmosphere by chemical reactions. Ground-level ozone is formed in the atmosphere by photochemical reactions involving volatile organic compounds (VOCs) and nitrogen oxides (NO_x), which are often called ozone precursors. Ozone is regulated under the CAA and USEPA regulations limit emissions of ozone precursors. The National Ambient Air Quality Standard (NAAQS) for ozone is being reviewed by USEPA and may become more stringent than the current standard of 0.075 ppm.

GHG life spans and GWPs vary greatly, as shown in Table 2-2. Due to the long life spans of some GHGs, emission reductions will not substantially reduce atmospheric GHG concentrations for many years. This is particularly true for CO_2, which accounts for the largest share of anthropogenic climate change, and for which emissions continue to increase (USEPA 2010a). N_2O emissions also continue to increase. In contrast, methane emissions have remained steady overall (and are declining from some sources). Future methane reductions could cause decreases in atmospheric concentrations within approximately 12 years.

Table 2-2. Life Spans and Global Warming Potentials for Selected GHGs

GHG	Average Atmospheric Life Time (years)	Global Warming Potential
CO_2	50–200 [1]	1
CH_4	12	21 [2]
N_2O	120	310
CFC-12 [2]	100	10,600
CFC-11	45	4,600
HFC-134a	14.6	1,300
SF_6	3,200	23,900

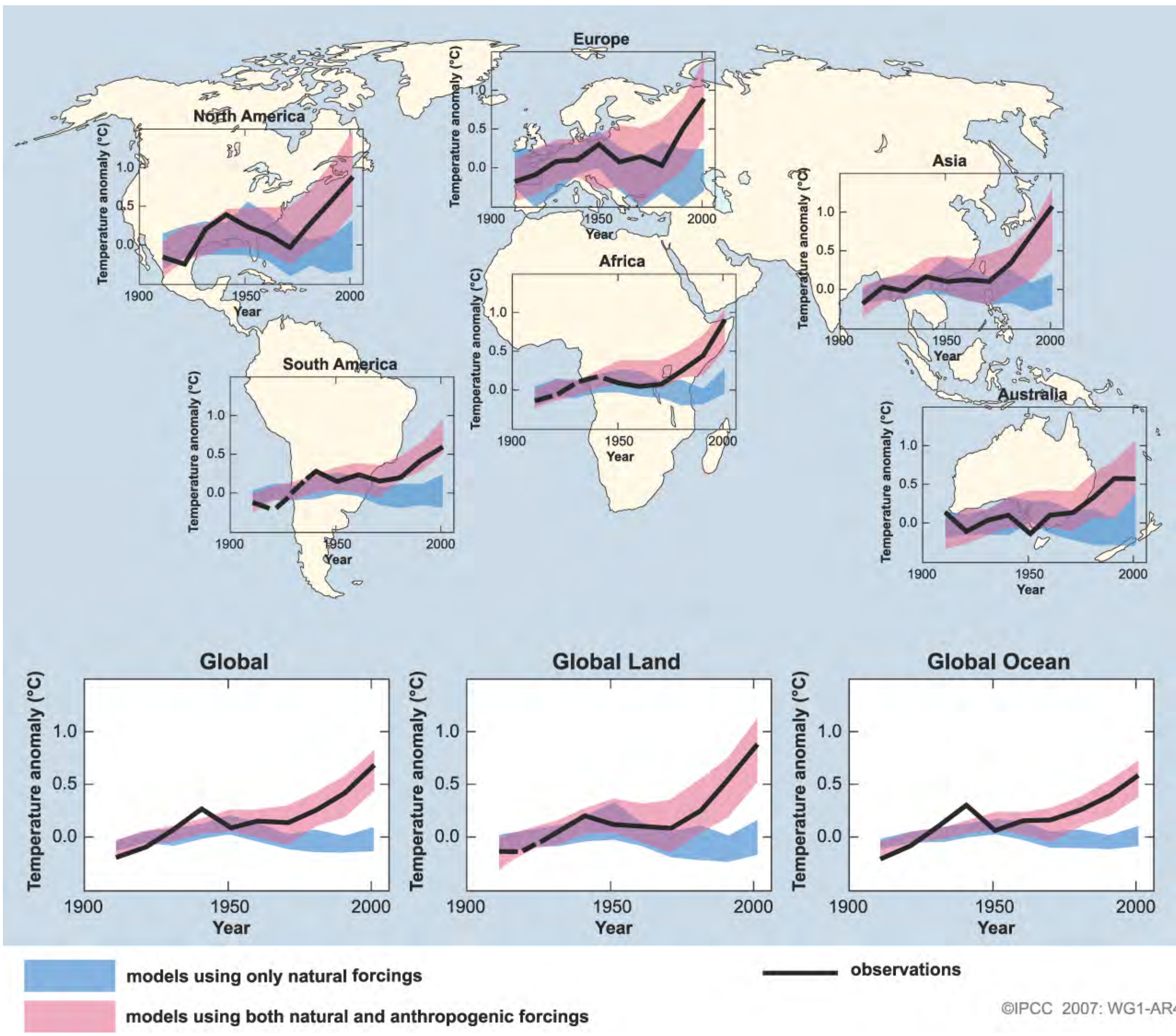
Source: USEPA 2010a.

[1] CO_2's lifetime is varies because it is not destroyed in the atmosphere; instead, CO_2 moves between the ocean, the atmosphere, and land and plants. Some CO_2 will be absorbed out of the atmosphere quickly, but some will remain in the atmosphere for many years.

[2] GWP is based on a 100-year time frame. Due to its relatively short atmospheric lifetime, methane is 72 times more potent than CO_2 over a 20-year time frame.

2.2.3. Ability to Predict Climate Change with Models

Climate models are based on well-established physical principles and can reproduce observed climate patterns. When these models include atmospheric GHG concentrations and other human-induced factors, the models predict many observed climate characteristics. Figure 2-17 compares global climate model temperature predictions to observed temperatures from the early 1900s to 2005. Black lines indicate historic temperatures for six continents and for global average temperature, global average land temperature, and global average ocean temperatures.



Source: Figure TS.22 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Comparison of observed continental- and global-scale changes in surface temperature with results simulated by climate models using natural and anthropogenic forcings. Decadal averages of observations are shown for the period 1906 to 2005 (black line) plotted against the center of the decade and relative to the corresponding average for 1901 to 1950. Lines are dashed where spatial coverage is less than 50%. Blue shaded bands show the 5% to 95% range for 19 simulations from 5 climate models using only the natural forcings due to solar activity and volcanoes. Red shaded bands show the 5% to 95% range for 58 simulations from 14 climate models using both natural and anthropogenic forcings.

Figure 2-17. Climate Model Prediction of Observed Temperatures

Climate model simulations are shown with red and blue bands. Natural and human factors were included in the models whose simulations are shown in red; these model results are consistent with observed temperatures. In contrast, model simulations shown in blue included only natural factors and their results diverge from observed temperatures as atmospheric GHG concentrations increase.

The IPCC concludes that it is likely that significant anthropogenic warming has occurred over the past 50 years for each continent except Antarctica. Observed patterns of warming, including greater warming over land than over the ocean, and their changes over time, are only simulated by models that include anthropogenic forcing (IPCC 2007b).

2.3. Climate Change Modeling Capability

Atmospheric-ocean general circulation models (AOGCMs) are the primary tool used for understanding and attributing past climate changes and for predicting future climate characteristics. AOGCMs include dynamic components describing atmospheric, oceanic, and land surface processes, sea ice, and other components. Lack of knowledge concerning some physical processes require parameterization of these processes, including cloud formation and precipitation, ocean mixing due to wave processes, and the formation of water masses. In general, parameterization uses one or more physical properties or constants to provide a simpler means to estimate a more complex physical process. For example, relative humidity and temperature could be used as parameters in the models to estimate cloud formation. Differences in parameterizations are the main reason why the more than 20 different AOGCM models provide somewhat different climate projections.

Climate change impacts can be predicted with much more certainty over global or continental scales. The models have difficulty reliably simulating and attributing observed temperature changes at smaller scales. On smaller scales, natural climate variability is relatively larger, making it harder to distinguish changes expected due to external forcings. Uncertainties in local forcings and feedbacks also make it difficult to estimate the contribution of GHG increases to observed small-scale temperature changes (IPCC 2007b).

AOGCMs have a typical model resolution of 250–600 kilometers. While the spatial resolution of AOGCMs is improving, efforts to model regional or smaller geographic areas sometimes involve using the output from AOGCMs to drive smaller-scale modeling using regional climate models. “Downscaling” can be used to model climate change at finer resolutions. Statistical downscaling uses larger scale modeling and empirical relationships to predict future climate change by identifying links between large-scale patterns of climate elements (known as predictors) and local climate (the predictand). Successful downscaling assumes that the current relationships between predictors and predictands will remain valid under future climate conditions. One advantage of downscaling is that it is less technically demanding than regional modeling. However, results from statistical downscaling may be misleading if the projected climate change exceeds the range of data used to develop the model. Downscaling techniques generally give more consistent results compared to regional modeling when modeling present-day scenarios, but downscaling is more likely to have less-consistent results when modeling future climate projections (Kattsov 2010).

2.4. Key Climate Change Causality Statements

Key additional climate change projections from the IPCC are quoted below (IPCC 2007b).

- The sustained rate of increase in RF from CO_2, CH_4, and N_2O over the past 40 years is larger than at any time during at least the past 2000 years.
- From new estimates of the combined anthropogenic forcing due to greenhouse gases, aerosols and land surface changes, it is extremely likely that human activities have exerted a substantial net warming influence on climate since 1750.
- Solar irradiance contributions to global average RF are considerably smaller than the contribution of increases in greenhouse gases over the industrial period.

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3.0 PREDICTED CLIMATE CHANGE AND IMPACTS

If predicted anthropogenic climate change occurs, impacts would be geographically pervasive and would affect ecosystems and human health. This chapter provides discussions of predicted climate change impacts based on climate modeling, with examples showing predicted global and U.S. impacts. Examples of predicted regional impacts are also included for the Montana and Dakotas region.

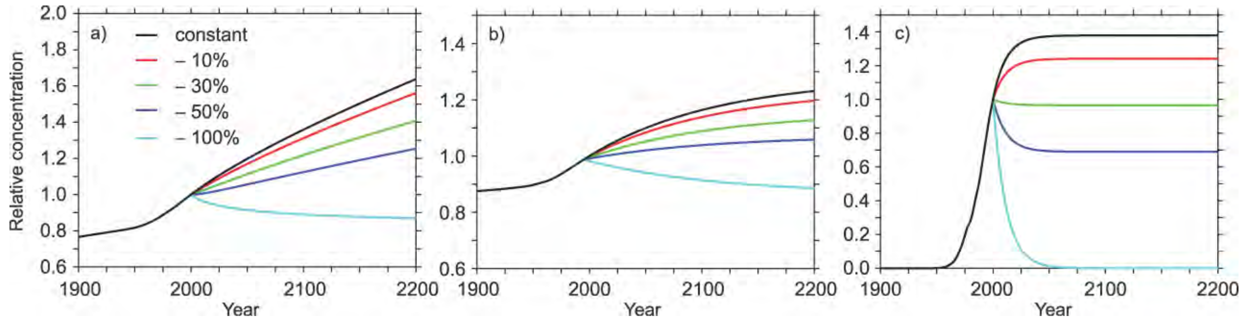
This chapter first addresses predicted climate change characteristics such as predicted GHG RF drivers and their predicted effects on climate characteristics such as temperature, oceans, and precipitation. Then climate change effects, including predicted effects on agriculture, ecosystems, and human health, are described. Finally, predicted impacts at a smaller scale are described for Montana, North Dakota, and South Dakota.

3.1. Predicted Climate Change Characteristics

3.1.1. Committed Climate Change

Based on atmospheric GHG concentrations as of year 2000, mean global warming after stabilization of RF is expected to be about 0.5 to 0.6°C, which would occur mostly within the next century (IPCC 2007b). Committed climate change is due largely to the massive quantity of thermal mass in the oceans and their slow mixing time, which cause a significant lag in responsiveness to reduced atmospheric GHG concentrations. USEPA estimates that oceans can take decades, or even centuries, to adjust to climate changes (USEPA 2010a).

Another lag results from the long atmospheric lifetime of many GHGs, as shown in Figure 3-1. Even when GHG emissions are immediately reduced, atmospheric GHG concentrations continue increasing for GHGs having moderate to high GWPs. The three graphs represent three different types of GHGs from left to right depicting modeled CO_2 concentration changes (lifetime of 50–200 years), a GHG with a 120-year lifetime, and a GHG with a 12-year lifetime (equivalent to methane). The colored curves represent five emission reduction scenarios: constant emissions (black), 10 percent reduction (red), 30 percent reduction (green), 50 percent reduction (blue), and 100 percent reduction (turquoise). Under most scenarios, GHG concentrations continue increasing. Concentration decreases occur immediately only under highly unlikely scenarios such as 100 percent reduction for all three types of GHGs or 30 percent or greater reductions in short-lived GHGs.



Source: FAQ 10-3 Figure 1 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Figure 3-1. GHG Emission Reduction Atmospheric Concentration Scenarios

3.1.2. Predicted GHG Concentrations

The links between GHG and sulfur dioxide (SO_2) emissions, GHG concentrations, RF, and global temperature change are shown in Figure 3-2. SO_2 is a chemical precursor for sulfate aerosols, which have a climate cooling effect.

Six Special Report on Emission Scenarios (SRES) non-mitigation scenarios are included in the analysis shown below. Each scenario includes assumptions about global population growth, energy supply, and economic development that were used to estimate future year GHG, SO_2, CO_2, NO_x, and VOC emissions. The scenarios are grouped into four families based on the first two letters of each scenario. Each scenario family has a storyline and one or more subgroups, which are briefly summarized below (IPCC 2000).

- The A1 storyline and scenario family describes a future world of very rapid economic growth, global population that peaks in mid-century and declines thereafter, and the rapid introduction of new and more efficient technologies. Major underlying themes are convergence among regions, capacity building, and increased cultural and social interactions, with a substantial reduction in regional differences in per capita income. The A1 scenario family develops into three groups that describe alternative directions of technological change in the energy system. The three A1 groups are distinguished by their technological emphasis: fossil intensive (A1FI), non-fossil energy sources (A1T), or a balance across all sources (A1B).
- The A2 storyline and scenario family describes a very heterogeneous world. The underlying theme is self-reliance and preservation of local identities. Fertility patterns across regions converge very slowly, which results in continuously increasing global population. Economic development is primarily regionally oriented and per capita economic growth and technological change are more fragmented and slower than in other storylines.
- The B1 storyline and scenario family describes a convergent world with the same global population that peaks in midcentury and declines thereafter, as in the A1 storyline, but with rapid changes in economic structures toward a service and information economy, with reductions in material intensity, and the introduction of clean and resource-efficient technologies. The emphasis is on global solutions to economic, social, and

environmental sustainability, including improved equity, but without additional climate initiatives.

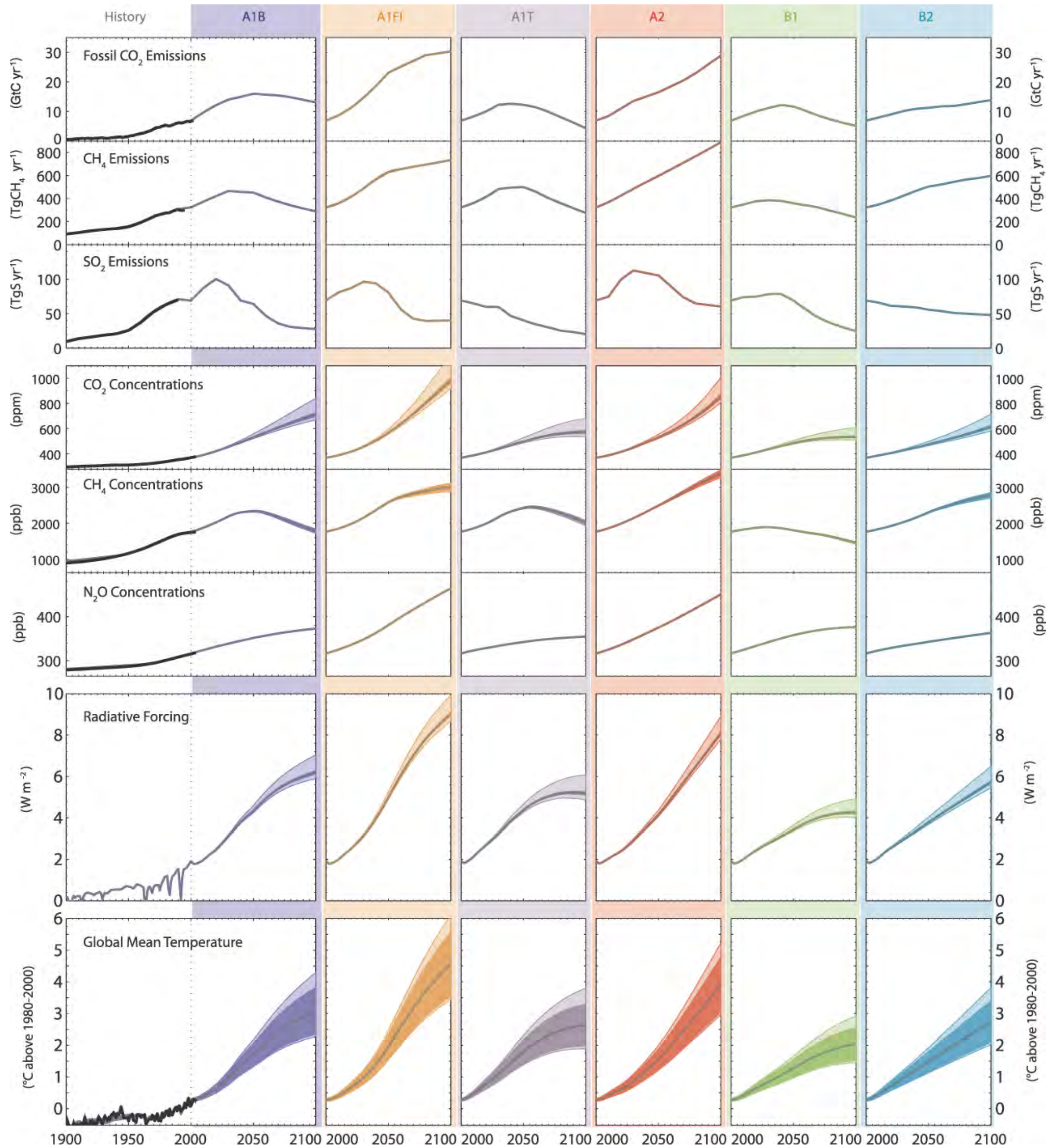
- The B2 storyline and scenario family describes a world in which the emphasis is on local solutions to economic, social, and environmental sustainability. It is a world with continuously increasing global population at a rate lower than A2, intermediate levels of economic development, and less rapid and more diverse technological change than in the B1 and A1 storylines. While the scenario is also oriented toward environmental protection and social equity, it focuses on local and regional levels.

Each modeled SRES scenario is considered to be a plausible future assuming that no climate policies, such as the Kyoto Protocol, will be implemented. None of the scenarios are considered preferred scenarios and none are considered to be more probable than the others. RF projections included anthropogenic and natural (solar and volcanic) forcing. A Simple Climate Model (SCM) capable of accurately predicting surface temperatures was tuned to 19 AOGCMs.

Figure 3-2 illustrates, from top to bottom, the links between GHG (CO_2 and methane) emissions and concentrations, as well as the combined change in RF and the resulting modeled change in global mean temperature. For example, modeled increases in CO_2 emissions predict even steeper increases in atmospheric CO_2 concentrations due to the pollutant's long lifetime, while modeled CO_2 emission reductions indicate that many years (more than the 100 years shown in the figure) would pass before reductions in CO_2 concentrations would be expected. In contrast, modeled methane emission reductions would cause relatively rapid reductions in methane concentrations. The RF curves near the bottom of the figure provide a visual sense of the predicted cumulative effect of three GHG (CO_2, methane, and N_2O) concentrations. Finally, the relative change in global average temperature appears to closely match the relative change in RF.

All six modeled emission scenarios indicate an increase in global temperature. The multimodel mean surface air temperature warming and associated uncertainty ranges predicted for 2090 to 2099 relative to 1980 to 1999 are as follows (IPCC 2007b).

- A1B: +2.8°C (1.7°C to 4.4°C)
- A1FI: +4.0°C (2.4°C to 6.4°C)
- A1T: +2.4°C (1.4°C to 3.8°C)
- A2: +3.4°C (2.0°C to 5.4°C)
- B1: +1.8°C (1.1°C to 2.9°C)
- B2: +2.4°C (1.4°C to 3.8°C)



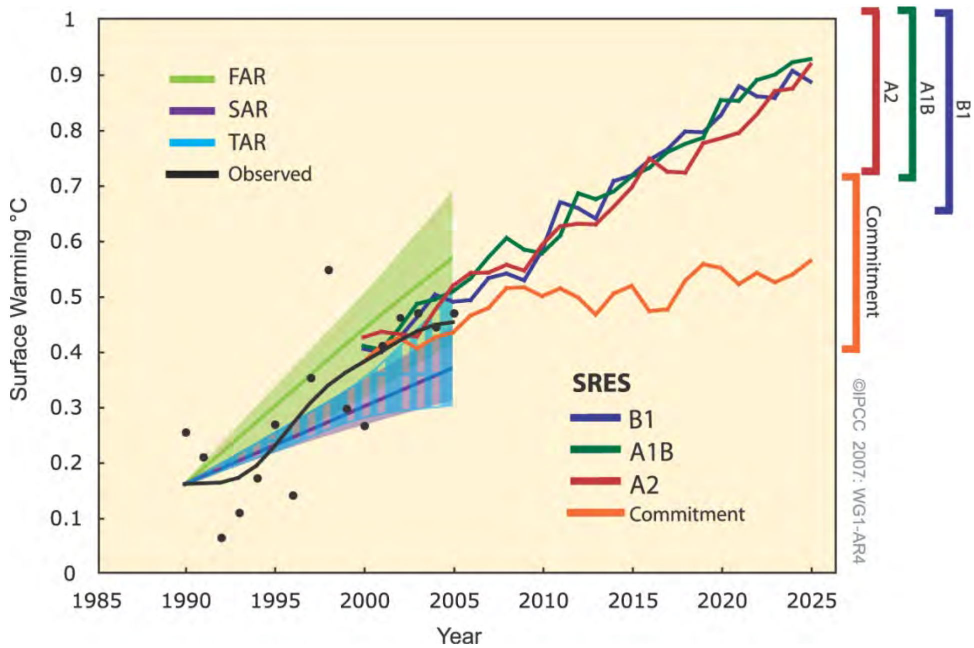
Source: Figure 10-26 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Fossil CO_2, CH_4 and SO2 emissions for six illustrative SRES non-mitigation emission scenarios, their corresponding CO_2, CH_4 and N_2O concentrations, radiative forcing and global mean temperature projections based on an SCM tuned to 19 AOGCMs. The dark shaded areas in the bottom temperature panel represent the mean ±1 standard deviation for the 19 model tunings. The lighter shaded areas depict the change in this uncertainty range, if carbon cycle feedbacks are assumed to be lower or higher than in the medium setting. Mean projections for mid-range carbon cycle assumptions for the six illustrative SRES scenarios are shown as thick colored lines. Historical emissions (black lines) are shown for fossil and industrial CO_2 (Marland et al., 2005), for SO_2 (van Aardenne et al., 2001) and for CH_4 (van Aardenne et al., 2001, adjusted to Olivier and Berdowski, 2001). Global mean temperature results from the SCM for anthropogenic and natural forcing compare favorably with 20th-century observations (black line) as shown in the lower left panel (Folland et al., 2001; Jones et al., 2001; Jones and Moberg, 2003).

Figure 3-2. Predicted Global GHG Emissions, Concentrations, and Climate Warming

3.1.3. Predicted Global Temperature

As shown above, modeled global mean warming is expected to increase over time and the amount of warming would depend on the level of GHG emissions in the future. Figure 3-3 shows model projections of global mean warming from 2005 to 2025 and also shows observed warming from 1990 through 2004. Committed warming is shown as the orange line. In contrast, predicted warming trends for three GHG emission growth SRES scenarios are shown with red, green, and blue curves.



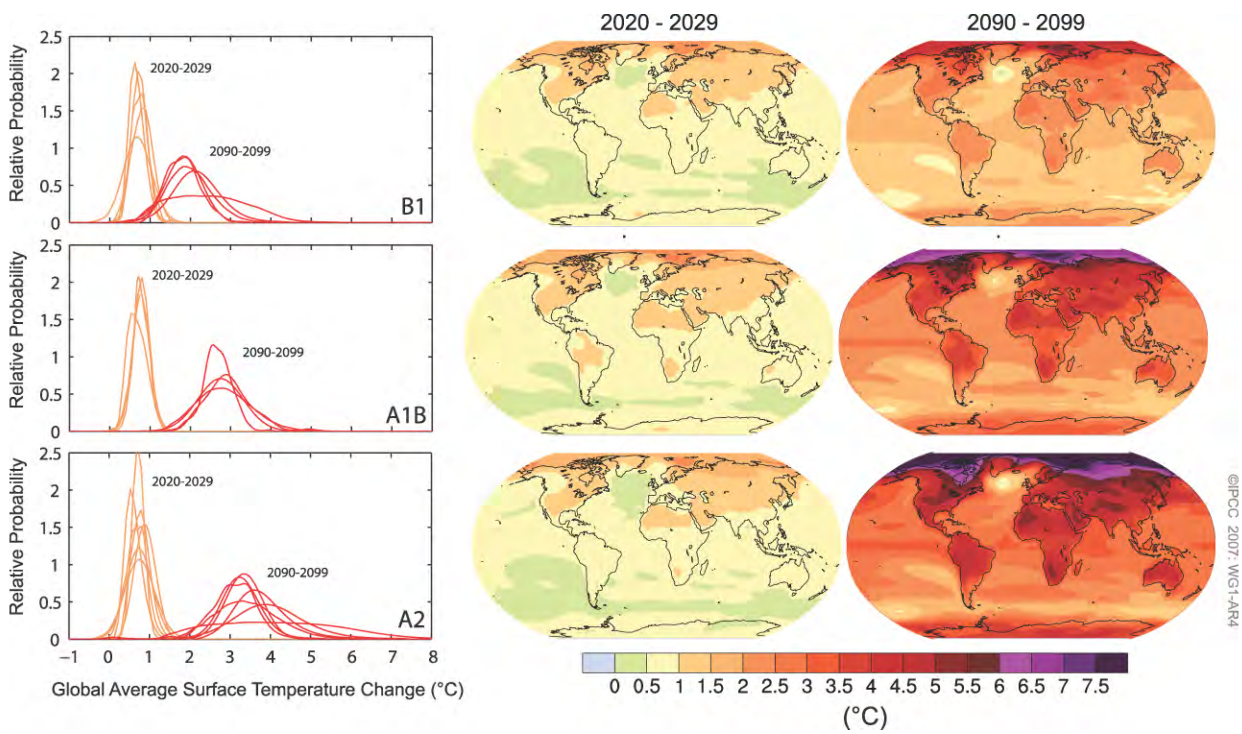
Source: Figure TS.26 Figure 1 of *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Observed temperature anomalies are shown as annual (black dots) and decadal average values (black line). Projected trends and their ranges from the IPCC First (FAR) and Second (SAR) Assessment Reports are shown as green and magenta solid lines and shaded areas, and the projected range from the Third Assessment Report (TAR) is shown by vertical blue bars. These projections were adjusted to start at the observed decadal average value in 1990. Multi-model mean projections from this report for the SRES B1, A1B and A2 scenarios are shown for the period 2000 to 2025 as blue, green and red curves with uncertainty ranges indicated against the right-hand axis. The orange curve shows model projections of warming if greenhouse gas and aerosol concentrations were held constant from the year 2000 – that is, the committed warming.

Figure 3-3. Global Mean Warming Model Predictions for Committed Warming and Three Emission Increase Scenarios

The differences in predicted mean global warming become more pronounced towards the end of the 21st century as shown in Figure 3-4. Regardless of the SRES scenario, the projected 21st century temperature change is positive everywhere on the globe. The predicted temperature change is greatest over land and at most high latitudes in the northern hemisphere during winter, and increases going from the coasts into the continental interiors. Within otherwise geographically similar areas, modeled warming is typically greater in arid rather than in moist regions (IPCC 2007b).

The least predicted warming occurs over the southern oceans and parts of the North Atlantic Ocean. Temperatures are predicted to increase, including over the North Atlantic and Europe, despite a projected slowdown of the meridional overturning circulation (MOC) in most models, due to the much larger influence of the increase in GHG concentrations (IPCC 2007b). Very few AOGCM studies have accounted for the impact of additional freshwater from melting of the Greenland Ice Sheet. However, the models that include this additional freshwater do not suggest that it will lead to complete MOC shutdown. It is very likely that the MOC will reduce, but very unlikely that the MOC will undergo a large abrupt transition during the course of the 21st century (IPCC 2007b). Longer-term changes in the MOC cannot be assessed with confidence (IPCC 2007b).



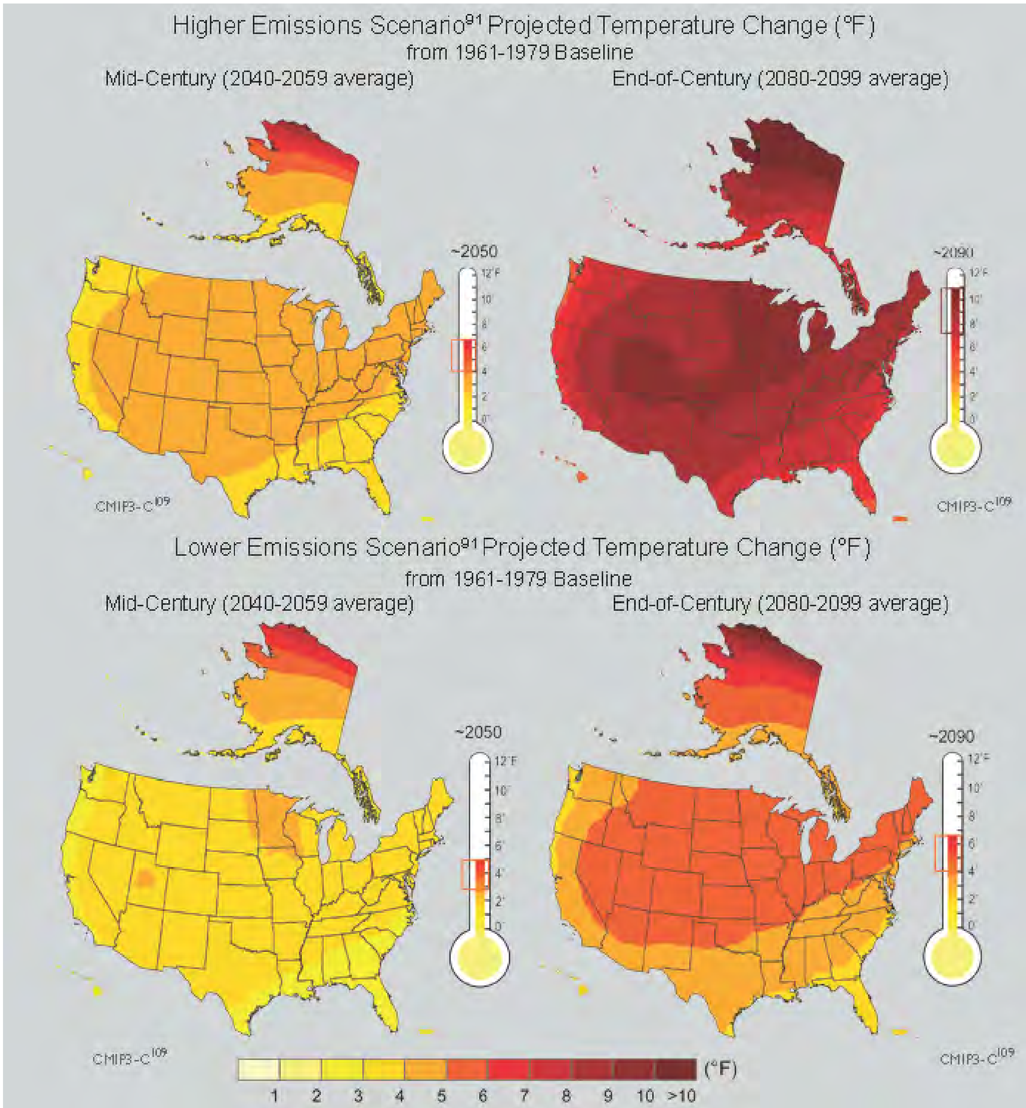
Source: Figure TS.28 Figure 1 of *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Projected surface temperature changes for the early and late 21st century relative to the period 1980 to 1999. The central and right panels show the AOGCM multi-model average projections (°C) for the B1 (top), A1B (middle) and A2 (bottom) SRES scenarios averaged over the decades 2020 to 2029 (center) and 2090 to 2099 (right). The left panel shows corresponding uncertainties as the relative probabilities of estimated global average warming from several different AOGCM and EMIC studies for the same periods. Some studies present results only for a subset of the SRES scenarios, or for various model versions. Therefore the difference in the number of curves, shown in the left-hand panels, is due only to differences in the availability of results.

Figure 3-4. Global Predicted Surface Temperatures for Early and Late 21st Century

A close-up look at predicted surface temperatures in the United States shows temperature increases for the middle (2040-2059) and end (2080-2099) of the 21st century. Predicted results for higher (A2) and lower (B1) SRES scenarios are shown in Figure 3-5. As described earlier, the greatest predicted temperature changes would occur in the interior of the nation. In the higher emission scenario for the end-of-century time period, predicted temperature increases may exceed 10°F in a large swath of the interior U.S. and in the northernmost portion of Alaska. Depending on the emission scenario, predicted temperature increases in Montana and the

Dakotas are between 4–5°F at mid-century and between 5–9°F at the end of the century (USGCRP 2009).

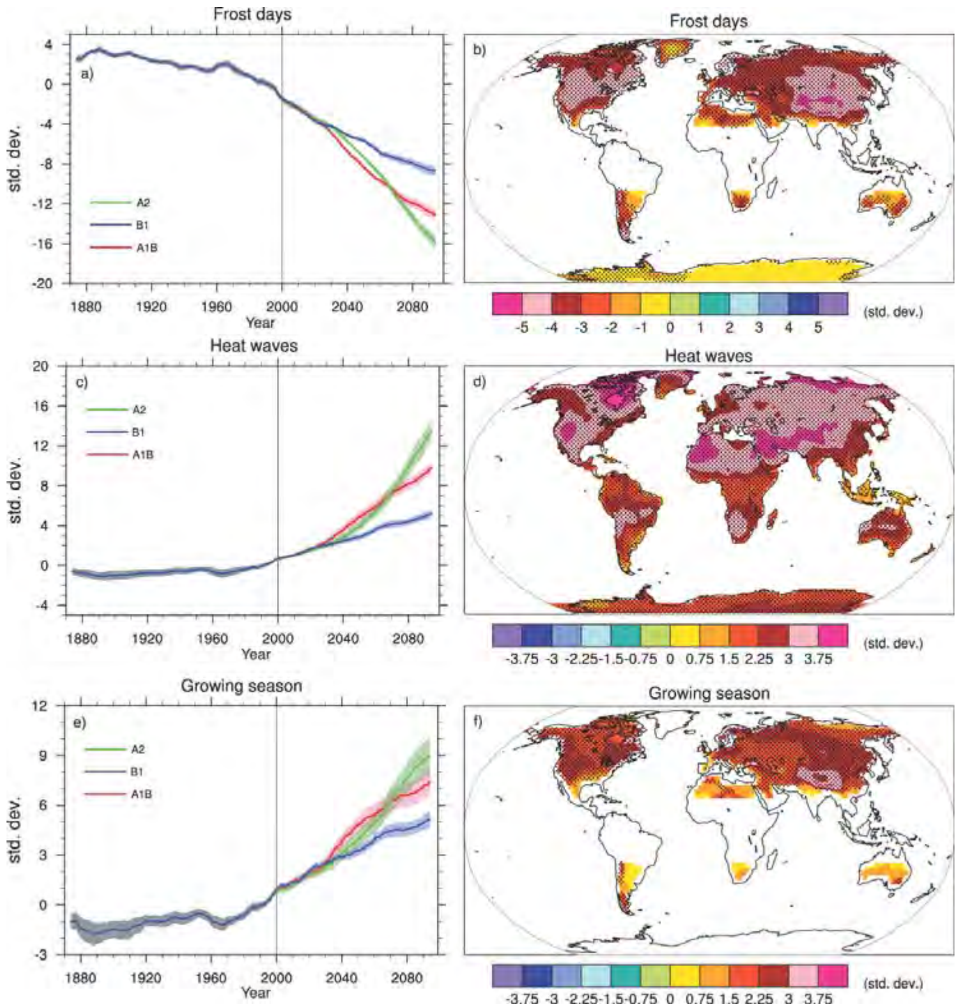


Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

This map is based on projections of future temperature by 16 of the Coupled Model Intercomparison Project Three (CMIP3) climate models using two emissions scenarios from the Intergovernmental Panel on Climate Change (IPCC), Special Report on Emission Scenarios (SRES). The “lower” scenario here is B1, while the “higher” is A2. The brackets on the thermometers represent the likely range of model projections, though lower or higher outcomes are possible.

Figure 3-5. Projected U.S. Temperature Changes from 1961-1979 Baseline

If the planet warms as modeled, a larger number of extreme heat episodes are predicted and fewer extreme cold events would occur (IPCC 2007b). In Figure 3-6, modeled extreme temperature changes are shown in terms of standard deviations. Positive standard deviations indicate an increase in the predicted number of days of the extreme event occurring, while negative standard deviations indicate fewer extreme days or events. On the left side of the figure, predicted changes based on three SRES scenarios are depicted. The maps on the right side of the figure show spatial results for scenario A1B and compares changes between two 20-year means (2080–2099 minus 1980–1999).



Source: Figure 10-19 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

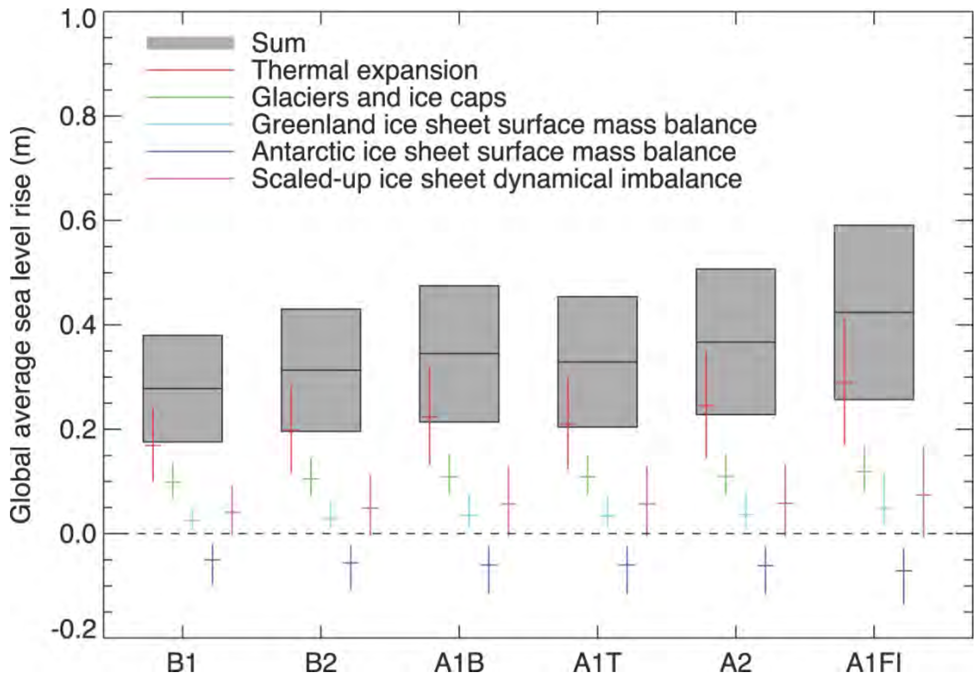
Changes in extremes based on multi-model simulations from nine global coupled climate models, adapted from Tebaldi et al. (2006). (a) Globally averaged changes in the frost day index (defined as the total number of days in a year with absolute minimum temperature below 0°C) for a low (SRES B1), middle (SRES A1B) and high (SRES A2) scenario. (b) Changes in spatial patterns of simulated frost days between two 20-year means (2080–2099 minus 1980–1999) for the A1B scenario. (c) Globally averaged changes in heat waves (defined as the longest period in the year of at least five consecutive days with maximum temperature at least 5°C higher than the climatology of the same calendar day). (d) Changes in spatial patterns of simulated heat waves between two 20-year means (2080–2099 minus 1980–1999) for the A1B scenario. (e) Globally averaged changes in growing season length (defined as the length of the period between the first spell of five consecutive days with mean temperature above 5°C and the last such spell of the year). (f) Changes in spatial patterns of simulated growing season length between two 20-year means (2080– 2099 minus 1980–1999) for the A1B scenario. Solid lines in (a), (c) and (e) show the 10-year smoothed multi-model ensemble means; the envelope indicates the ensemble mean standard deviation. Stippling in (b), (d) and (f) denotes areas where at least five of the nine models concur in determining that the change is statistically significant. Extreme indices are calculated only over land. Frost days and growing season are only calculated in the extratropics. Extremes indices are calculated following Frich et al. (2002). Each model's time series was centered around its 1980 to 1999 average and normalized (rescaled) by its standard deviation computed (after de-trending) over the period 1960 to 2099. The models were then aggregated into an ensemble average, both at the global and at the grid-box level. Thus, changes are given in units of standard deviations.

Figure 3-6. Predicted Global Changes in Extreme Temperatures

3.1.4. Predicted Oceanic Changes

Modeled ocean temperature increases are greatest near the ocean's surface. Predicted warming increases are relatively large in the Arctic and along the equator in the eastern pacific. Less warming is predicted in the North Atlantic and the Southern Oceans (IPCC 2007b).

Sea level is predicted to rise due to thermal expansion of the water and also to dynamic balancing relating to the ocean's density and its circulation. In addition, predicted melting of glaciers, ice caps, and ice sheets would contribute water to the oceans. Figure 3-7 provides predictions based on six SRES scenarios. The grey bars show the range of the sum of the multiple components of sea level rise predicted for 2090–2099 compared to 1980–1999. Scenario A1F1 is predicted to have the greatest sea level increase of approximately 0.41 m.



Source: Figure 10-33 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

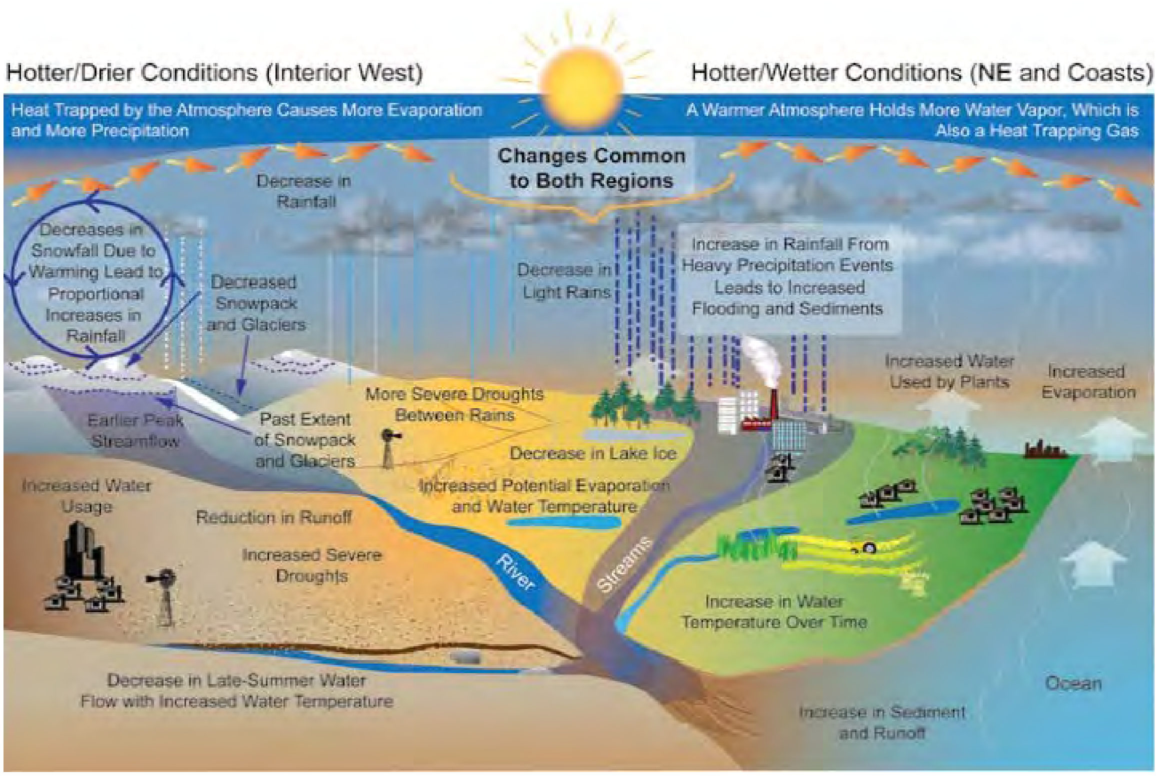
Projections and uncertainties (5 to 95% ranges) of global average sea level rise and its components in 2090 to 2099 (relative to 1980 to 1999) for the six SRES marker scenarios. The projected sea level rise assumes that the part of the present-day ice sheet mass imbalance that is due to recent ice flow acceleration will persist unchanged. It does not include the contribution shown from scaled-up ice sheet discharge, which is an alternative possibility. It is also possible that the present imbalance might be transient, in which case the projected sea level rise is reduced by 0.02 m. It must be emphasized that we cannot assess the likelihood of any of these three alternatives, which are presented as illustrative. The state of understanding prevents a best estimate from being made.

Figure 3-7. Predicted Global Sea Level Changes for Six Prediction Scenarios

Global modeling indicates that the ocean will continue to acidify due to increased CO_2 concentrations in the atmosphere. As CO_2 enters ocean water, it lowers the pH of the water. Surface ocean pH is already 0.1 unit lower than pre-industrial values, and pH is projected to decrease by another 0.3 to 0.4 units by 2100 based on one modeling scenario. Carbonate ion concentrations would also decrease and when water is under saturated with calcium carbonate, marine organisms would not be able to form calcium carbonate shells (IPCC 2007b).

3.1.5. Predicted Precipitation Changes

Climate change effects on the water cycle are complex and would vary by region and in their timing. Figure 3-8 summarizes expected changes in the water cycle for the U.S. Interior West and for the Northeast and coastal regions. Although global warming is predicted to cause increased average annual global precipitation, it could also simultaneously increase drought conditions, particularly in the summer, and also increase the intensity of storms and the frequency of floods. In areas where snowpack plays a major role in water supply, runoff timing is expected to shift earlier in the spring and water flows would be lower in late summer. Consequently, climate change would place additional burdens on stressed water systems. The past century will no longer be a reasonable guide to the future for water management purposes (USGCRP 2009).



Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-8. U.S. Regional Projected Changes in the Water Cycle

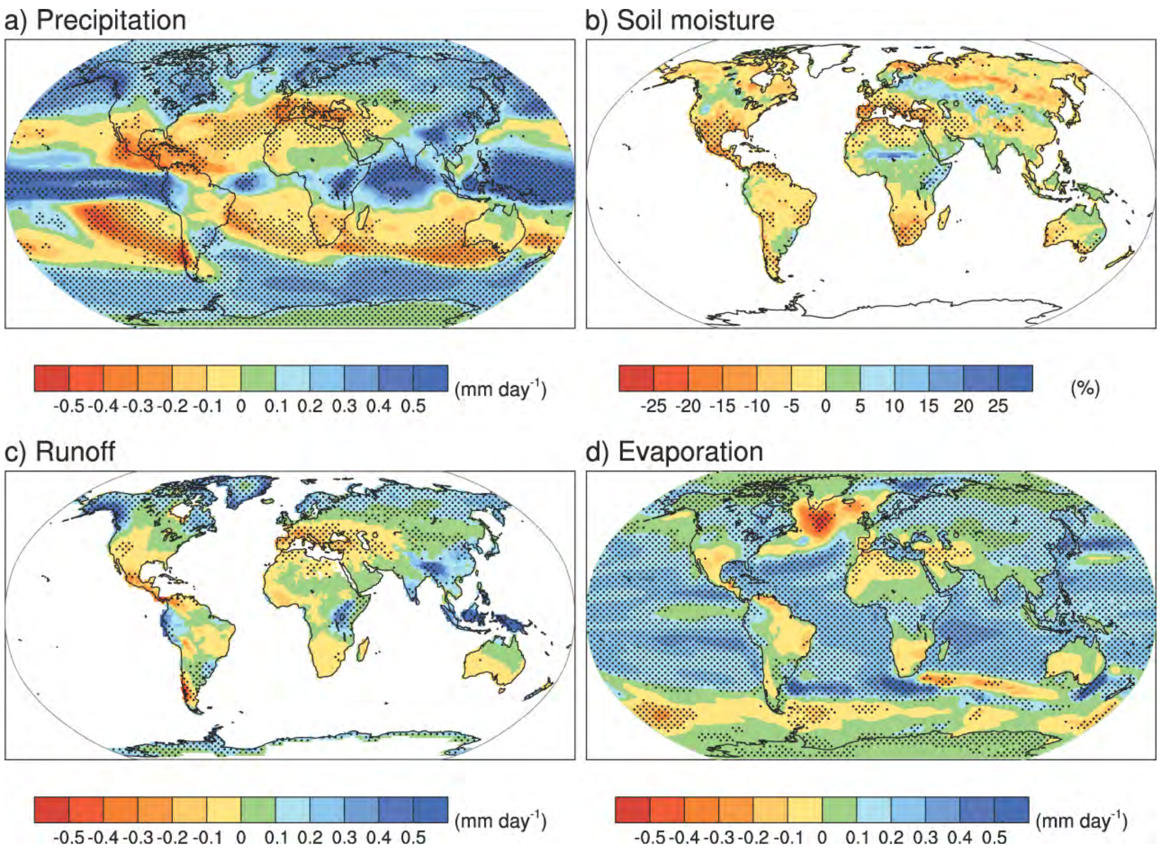
3.1.5.1. Overall Increased Precipitation

Predicting precipitation with global models has less consistency than predicting temperature changes. However, increases in precipitation at high latitudes are consistent across many models. Figure 3-9 illustrates model predictions for the period 2080–2099 relative to 1980–1999 and addresses (a) annual mean precipitation, (b) soil moisture, (c) runoff, and (d) evaporation.

Overall, modeled precipitation over land increases by approximately 5 percent, while modeled precipitation over the oceans increases by an average of 4 percent. However, larger increases of more than 20 percent are predicted to occur at most high latitudes, in the equatorial Pacific Ocean, and in some other areas. Substantial decreases are expected to occur in the Mediterranean and Caribbean regions and the subtropical western coasts of each continent (IPCC 2007b).

On land, runoff (excluding runoff from ice sheet melting) and evaporation tend to balance precipitation. As shown in the figure, areas with greater modeled positive changes in runoff and evaporation are spatially similar to areas with increased modeled precipitation.

Soil moisture in the upper few meters of the land surface are also simulated by the models, though with somewhat less accuracy than precipitation. As expected, decreases in soil moisture are predicted for areas with decreased precipitation. In addition, decreases in soil moisture are predicted to occur at high latitudes where snow cover is predicted to decrease.

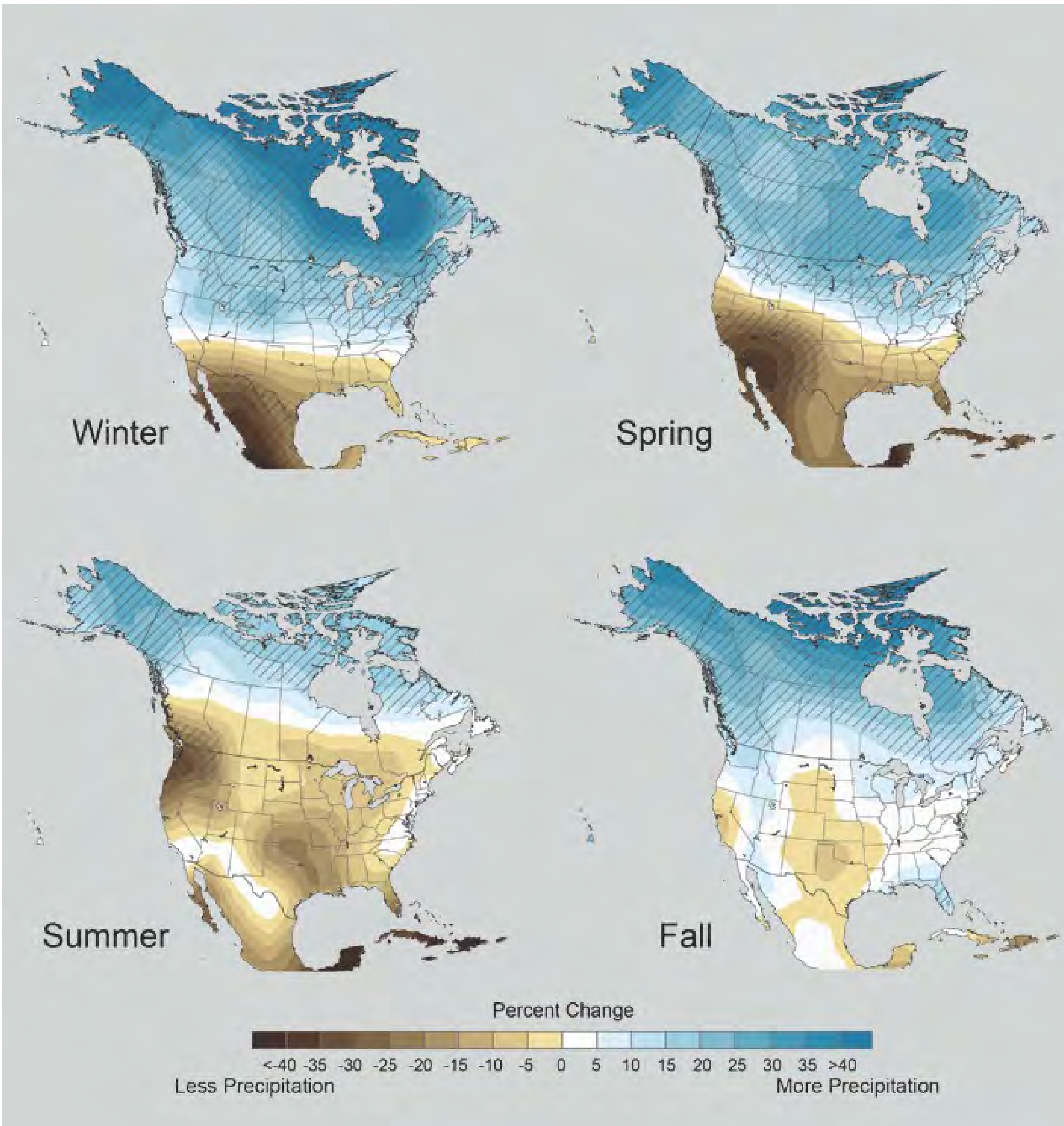


Source: Figure 10-12 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Multi-model mean changes in (a) precipitation (mm day^{-1}), (b) soil moisture content (%), (c) runoff (mm day^{-1}) and (d) evaporation (mm day^{-1}). To indicate consistency in the sign of change, regions are stippled where at least 80% of models agree on the sign of the mean change. Changes are annual means for the SRES A1B scenario for the period 2080 to 2099 relative to 1980 to 1999. Soil moisture and runoff changes are shown at land points with valid data from at least 10 models.

Figure 3-9. Predicted Global Water Cycle Changes for 2080-2099

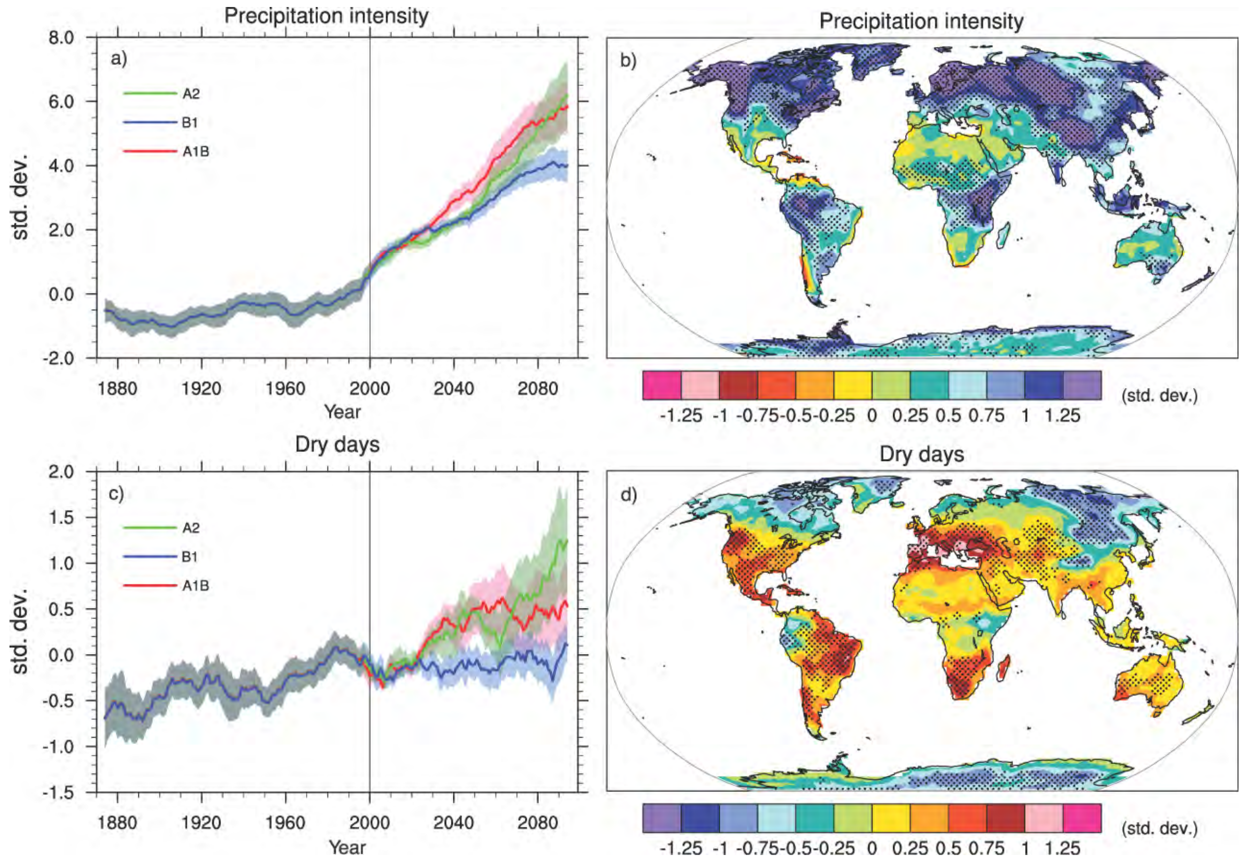
Figure 3-10 provides a closer look at precipitation predictions for the United States during each of the four seasons, based on a high emission (A2) scenario. The maps were compiled based on the results of 15 climate models. Percentage changes in precipitation for the years 2080–2099 are compared to the recent past. Precipitation increases are predicted to occur consistently in the northern U.S. in winter and spring, with predicted increases in Montana, North Dakota, and South Dakota of up to 25 percent in some areas of these states in winter and spring. However, the states are predicted to experience precipitation decreases of up to 5 percent during summer and fall (with even greater precipitation reductions in western Montana during the summer).



Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-10. Projected Change in North American Precipitation by 2080-2099

Based on modeling results, precipitation extremes are expected to increase in many areas of the globe. On the left side of Figure 3-11, three modeled scenarios are compared based on standard deviation. Spatial occurrences are shown on the right for the A1B scenario. Within the United States, precipitation intensity is expected to increase in the Northeast and in Alaska, while the number of dry days are expected to increase throughout the nation.

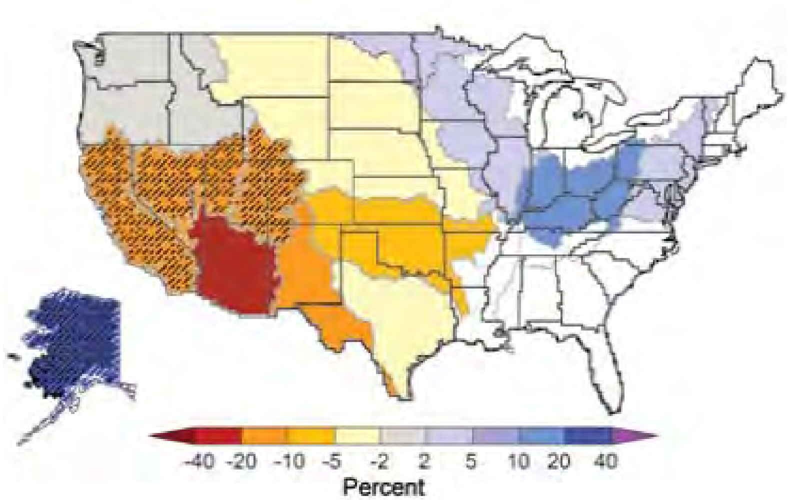


Source: Figure 10-18 from *Climate Change 2007: The Physical Science Basis* (IPCC 2007b).

Changes in extremes based on multi-model simulations from nine global coupled climate models, adapted from Tebaldi et al. (2006). (a) Globally averaged changes in precipitation intensity (defined as the annual total precipitation divided by the number of wet days) for a low (SRES B1), middle (SRES A1B) and high (SRES A2) scenario. (b) Changes in spatial patterns of simulated precipitation intensity between two 20-year means (2080–2099 minus 1980–1999) for the A1B scenario. (c) Globally averaged changes in dry days (defined as the annual maximum number of consecutive dry days). (d) Changes in spatial patterns of simulated dry days between two 20-year means (2080–2099 minus 1980–1999) for the A1B scenario. Solid lines in (a) and (c) are the 10-year smoothed multi-model ensemble means; the envelope indicates the ensemble mean standard deviation. Stippling in (b) and (d) denotes areas where at least five of the nine models concur in determining that the change is statistically significant. Extreme indices are calculated only over land following Frich et al. (2002). Each model's time series was centered on its 1980 to 1999 average and normalized (rescaled) by its standard deviation computed (after de-trending) over the period 1960 to 2099. The models were then aggregated into an ensemble average, both at the global and at the grid-box level. Thus, changes are given in units of standard deviations.

Figure 3-11. Predicted Changes in Global Precipitation Intensity

Predicted changes in median runoff for 2041–2060, relative to a 1901–1970 reference period, are mapped in Figure 3-12 by water-resource region. The predictions are based on an emission scenario in between the lower and higher emissions scenarios described earlier. Hatched areas indicate greater confidence due to strong agreement among model projections, while white areas indicate divergence among model projections. For most of Montana and the Dakotas, predicted annual runoff is expected to decrease between 2 to 5 percent.



Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-12. Projected Changes in Annual Runoff

3.1.6. Potential Climate Change Thresholds

The IPCC states: "Theories, models and paleoclimate reconstructions (see Chapter 6 [IPCC 2007b]) have established the fact that changes in the climate system can be abrupt and widespread. A working definition of 'abrupt climate change' is given in Alley et al. (2002): 'Technically, an abrupt climate change occurs when the climate system is forced to cross some threshold, triggering a transition to a new state at a rate determined by the climate system itself and faster than the cause.' [IPCC 2007b]" A number of potential climate change thresholds have been postulated. These thresholds are sometimes referred to as "tipping points." If one of the thresholds is crossed, climate change could potentially shift to a different equilibrium, or stable state. If an abrupt climate change were to occur, the change could be irreversible or it could be reversible over hundreds or thousands of years.

On July 16, 2010, the National Research Council (NRC) issued a prepublication copy of *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (NRC 2010), which describes current science addressing potential climate change thresholds and the Earth's sensitivity to climate feedback systems.

Examples of thresholds that could potentially cause abrupt climate change include the following.

- Complete deglaciation of the Greenland and Antarctica ice sheets (NRC 2010)
- Cessation of the Atlantic Meridional Overturning Circulation (MOC) (IPCC 2007b)
- Exceptionally large biogeochemical emissions of carbon due to methane releases from permafrost and/or from under the sea floor (NRC 2010)

With regard to the first example, melting of the Greenland icecap could be irreversible, even if CO_2 emissions and concentrations were reduced. The Greenland icecap might not recover even if CO_2 concentrations were restored to pre-industrial levels (NRC 2010).

Specific atmospheric CO_2 concentrations have been postulated as thresholds beyond which abrupt climate change would occur. For example, a target CO_2 concentration of 350 ppm (less than the current 385 ppm concentration) has been identified as the level needed to avoid abrupt climate change (Hansen 2008). However, the NRC report suggests that peak CO_2 concentrations could exceed 350 ppm for hundreds of years "without incurring a risk of triggering the long-term feedbacks, so long as it subsides to 350 ppm or less over a few thousand years." (NRC 2010). Furthermore, the NRC asserts that global temperature rather than CO_2 concentration would be a better indicator to use when assessing potential future climate impacts.

Additional modeling and research is needed to identify climate change thresholds associated with abrupt climate change, the associated risks of any predicted abrupt climate change, and mitigation strategies.

3.2. Predicted Climate Change Effects

The following description of climate change effects focuses on three major areas of concern to Montana and the Dakotas: agriculture, ecosystems, and human health. Links are drawn between climate characteristics and their effects on food supply, plants and wildlife, and human health.

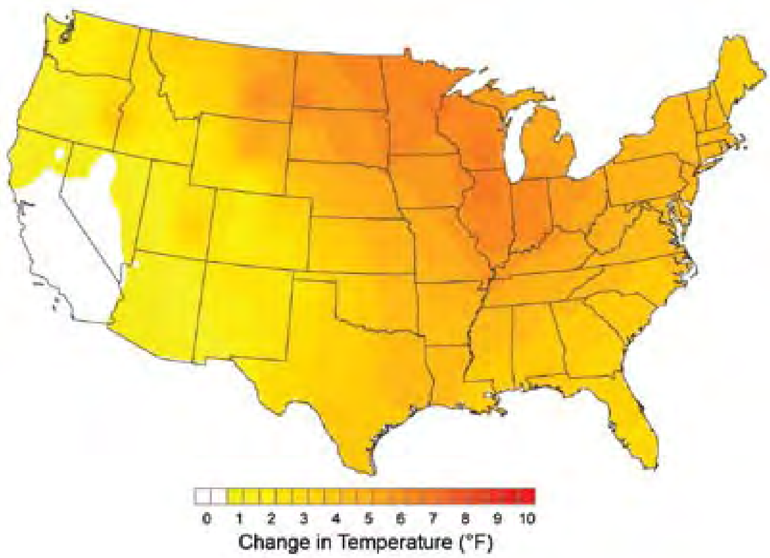
3.2.1. Agriculture

Agriculture contributes to global warming and agricultural productivity will likely be affected by global warming. Globally, agriculture contributes approximately 13.5 percent of all anthropogenic GHG emissions. In the United States, agriculture contributes approximately 8.6 percent of the nation's GHGs, including 80 percent of N_2O emissions and 31 percent of methane emissions (USGCRP 2009).

Predicted changes in atmosphere CO_2 concentrations, temperature, and precipitation are expected to have noticeable impacts on agriculture. Up to a certain extent, increased CO_2 concentrations and warmer temperatures increase plant growth. Optimal temperature ranges, both during the day and during the night, depend on specific crops. Excessively high temperatures for a given crop can reduce plant yields, prevent seed production, and increase crop water demands due to water transpiration need to keep plants cool.

Livestock also are sensitive to heat and are expected to experience greater adverse reactions to summer heat than to reap rewards from milder winters. Greater humidity will also stress animals and may reduce animals' ability to produce milk, gain weight, and reproduce. Swine, beef, and milk production are expected to decline. Agricultural operations with confined feeding facilities will likely incur more costs keeping animals cool during the summer.

Winter temperature trends also play a role in agricultural plant viability, particularly for some fruits that require long winter chilling periods. However, winter temperatures have been increasing, particularly in eastern Montana and in the Dakotas. Over a recent 32-year period, observed winter temperatures in these states increased up to 7°F, as shown in Figure 3-13. Although this increase would seem to reduce the likelihood of frost damage to plants, mild winters and warm early springs can induce early plant growth and blooming, which can expose the young plants to late-season frosts.



Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-13. U.S. Winter Temperature Trends, 1975 to 2007

Additional potential climate change impacts on agriculture include the following (USGCRP 2009).

- Weeds, diseases, and insect pests benefit from warming, and weeds also benefit from a higher CO_2 concentration; increasing weed and pest populations increase stress on crop plants and requires more attention to weed control.
- Extreme events such as heavy downpours and droughts are likely to reduce crop yields because excesses or deficits of water have negative impacts on plant growth.
- Plants sensitive to ozone may have lower crop yields if increased temperature cause an increase in ozone concentrations.
- Forage quality in pastures and rangelands generally declines with increasing CO_2 concentration because of the effects on plant nitrogen and protein content, thereby reducing the land's ability to supply adequate livestock feed.

3.2.2. Ecosystems

Ecosystems have developed over millennia and comprise a complex web of interactions between land, vegetation, and animals. Anthropogenic climate change may break multiple ecosystem links because climate change may occur too rapidly for species adaptation. One adaptive strategy for many living organisms is to migrate into new regions in order to remain within a relatively constant environment. Large-scale shifts have already occurred in the ranges of species and the timing of the seasons and animal migration, and these shifts are very likely to continue (USGCRP 2009). Climate changes include warming temperatures throughout the year and the arrival of spring an average of 10 days to 2 weeks earlier through much of the United States compared to 20 years ago. Multiple bird species now migrate north earlier in the year. Examples of adaptive shifts to increased temperatures include the following.

- Migration of vegetation, insects, and animals to more northerly regions
- Migration of some plants to higher elevations

However, species may not be able to successfully migrate due to the breakup of existing ecosystems. As warming drives changes in timing and geographic ranges for various species, entire communities of species may not shift intact. Instead, the range and timing of each species is likely to shift in response to its sensitivity to climate change, its mobility, its lifespan, and the availability of its needs (such as soil, moisture, food, and shelter). In addition, migratory paths must be available. Examples of migratory paths include northward rivers for fish and unblocked routes for other wildlife (USGCRP 2009).

The IPCC estimated that if warming of 3.5 to 5.5°F occurs, 20 to 30 percent of species that have been studied would be in climate zones that are far outside of their current ranges and would therefore likely to be at risk of extinction.

Fires, insect pests, disease pathogens, and invasive weed species have increased, and these trends are likely to continue (USGCRP 2009). Changes in the timing of precipitation and earlier runoff increase fire risks. Within the United States, Alaska has been particularly affected. June air temperatures have been linked to an approximate 38 percent increase in annual burn areas from 1950 to 2003 (USGCRP 2009).

Insect pests and the amount of damage that they inflict have also been on the rise. The combination of higher temperatures and dry conditions have increased pest populations such as pine beetles, which have killed trees on millions of acres in Canada, Colorado, and Alaska. Warmer winters allow the beetles to survive the cold season, which would normally limit populations. At the same time, drought weakens the trees, making them more susceptible to insect attack.

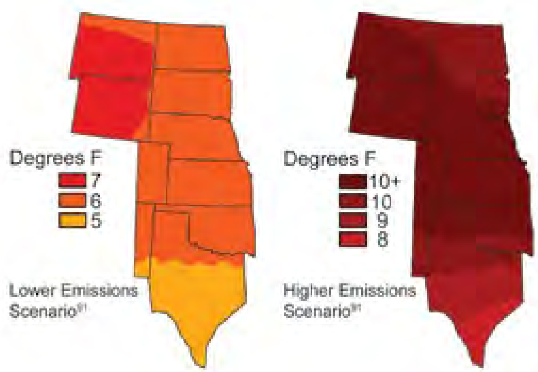
Oceans and the Arctic are also extremely susceptible to anthropogenic global warming. As mentioned earlier, increased atmospheric CO_2 concentrations is predicted to acidify oceans and limit marine animal calcium carbonate shell building. Coral reefs are dying or are being severely damaged due to increased water temperatures and other environmental factors.

With regard to the Arctic, sea ice ecosystems are being adversely affected by the loss of summer sea ice and further changes are expected (USGCRP 2009). Ecosystems that are dependent on Arctic sea ice are especially vulnerable because the ice is vanishing rapidly and is expected to disappear during summertime before the end of this century (USGCRP 2009). Algae that bloom on the underside of the ice form the base of a food web linking microscopic animals and fish to seals, whales, polar bears, and people. Approximately two-thirds of the world’s polar bears are projected to be gone by the middle of this century and no wild polar bears are predicted to survive in Alaska in 75 years (USGCRP 2009).

3.2.3. Human Health

Human health can be affected due to anthropogenic climate change through direct climate changes (such as heat waves) or through indirect effects (such as increased disease risks) that become more prevalent due to climate change.

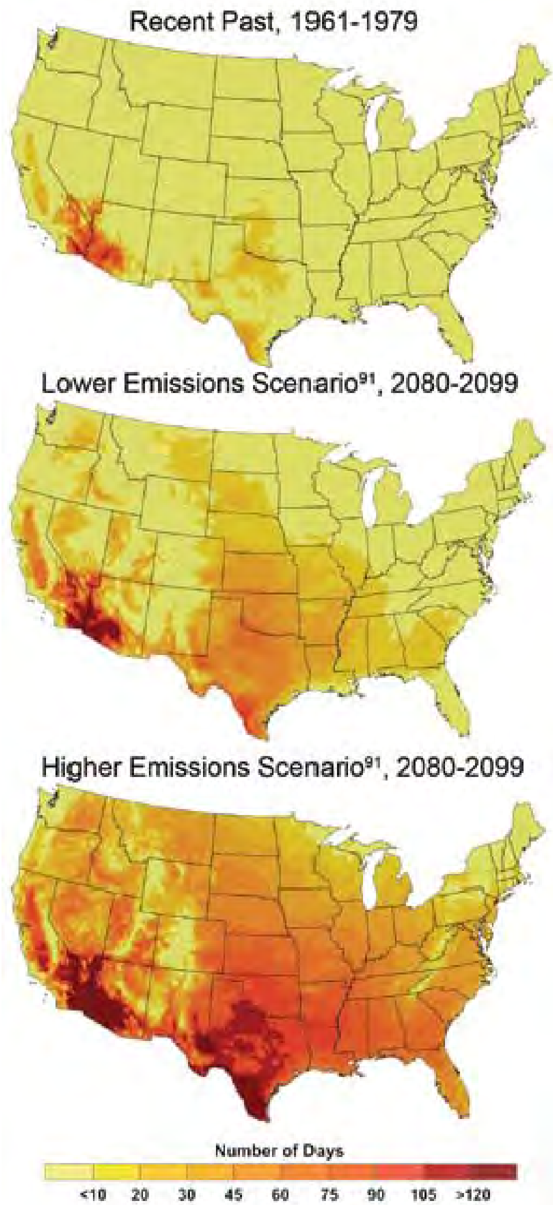
Mortality can occur during intense storms or heat waves, which are predicted to occur with increasing frequency. For example, temperatures in the Great Plains (and elsewhere) are projected to increase significantly by the end of this century. Depending on whether a lower emission or higher emission scenario is modeled, summer temperatures are predicted to rise by as much as 7°F or 10°F or more, respectively, in Montana and/or portions of the Dakotas, as shown in Figure 3-14.



Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-14. Projected U.S. Summer Temperature Change by 2080-2099

As the mean surface temperature rises, more heat waves are predicted to occur. As shown in Figure 3-15, the number of days in which the temperature exceeds 100°F by the late 21st century, compared to the 1960s and 1970s, is projected to increase strongly across the United States, with the greatest number of occurrences in the southwestern U.S. Under the higher emission scenario, between 45 to 60 days per year with temperatures greater than 100°F are predicted for parts of Montana and the Dakotas. Heat waves are particularly dangerous for older adults. Projections for Chicago suggest that the average number of deaths due to heat waves would more than double by 2050 under a lower emission scenario and more than quadruple under a high emission scenario (USGCRP 2009). By the 2090s, heat wave related deaths could increase by a factor of 5 to 7 compared to a 1990s baseline of approximately 165 deaths (USGCRP 2009).



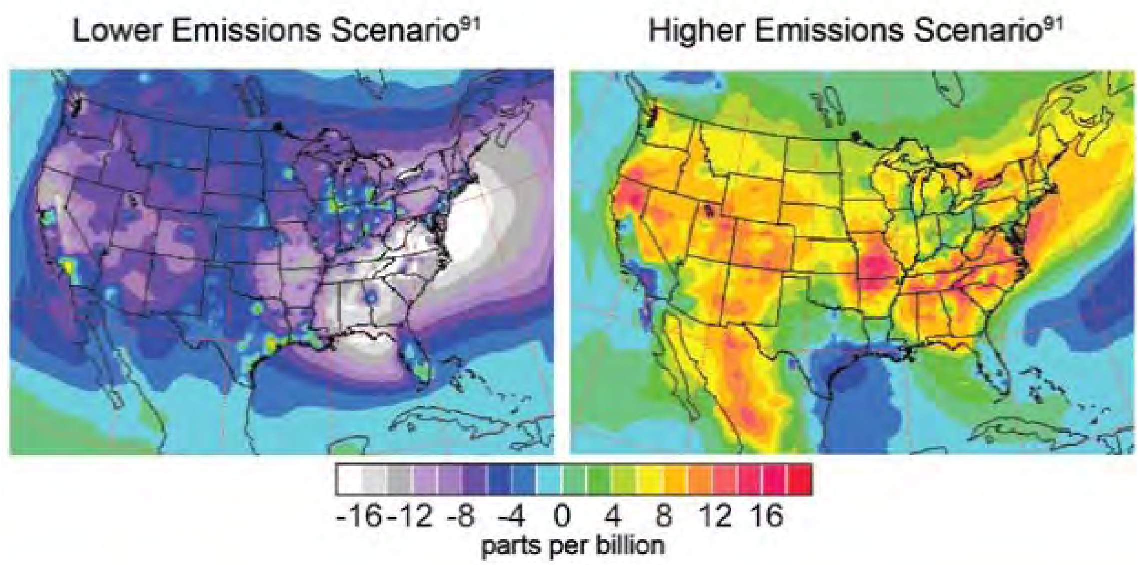
Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-15. Predicted Number of U.S. Days Over 100°F

The expected increased risk of heat-related deaths would be somewhat offset by a decrease in deaths related to extreme cold. However, cold snaps have historically been shown to increase death rates by 1.6 percent, while heat waves triggered a 5.7 percent increase in death rates (USGCRP 2009).

Warming also is predicted to prompt adverse changes in air quality, particularly with regard to ground-level ozone. Ozone formation occurs more frequently when ambient temperatures are high. Figure 3-16 illustrates predicted ozone concentration changes in the United States for lower and higher emission scenarios, based on averages for June through August. Ozone concentration changes, in parts per billion (ppb), compare predicted levels in the 2090s to concentrations in 1996–2000. Ozone is highly dependent on ratios of pollutant precursors (VOCs and NO_x) and other factors (such as stagnation and inversions). Ozone decreases are predicted through much of the United States based on the lower emission scenario, although major metropolitan areas, including Los Angeles, Houston, and Chicago are predicted to have slight increases. Under the higher emission scenario, ozone increases are predicted for most of the United States, with extremely high concentrations predicted in the middle latitudes of the nation.

Ozone causes short-term decreases in lung function and damages the cells lining the lungs. It is particularly dangerous to people with asthma and leads to increased hospitalization rates and deaths. High ozone episodes also reduce people's ability to exercise outdoors, since high physical exertion increases lung damage due to ozone exposure.



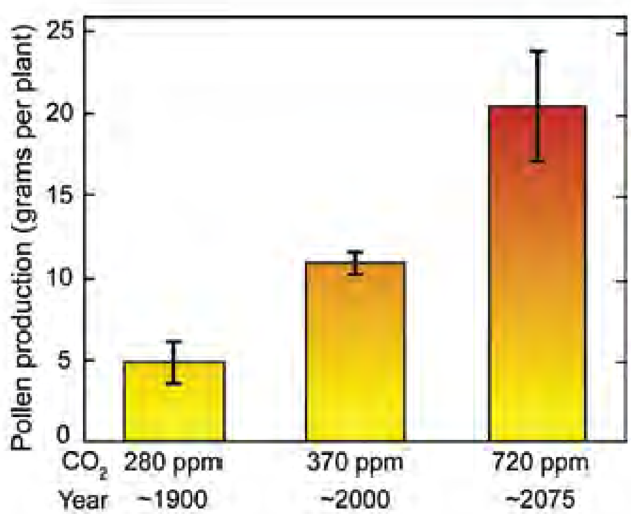
Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-16. Projected Change in U.S. Ground-Level Ozone, 2090s

The existence of high urban CO_2 concentrations (sometimes referred to as "CO_2 domes") has been documented in multiple studies and is potentially linked to human health effects and possible morbidity. CO_2 concentration increases of 67 percent greater than the surrounding rural area were measured in Phoenix, Arizona, with nearly 80 percent of the CO_2 concentration increase attributed to vehicle exhaust (CSCDGC 2010). Some modeling studies indicate that high urban CO_2 concentrations can cause localized temperature increases. However, temperature increases due to the heat island effect resulting from the large thermal mass of urban areas are greater than local temperature increases attributed to high local concentrations of CO_2. A Phoenix study found that "warming induced by the urban CO_2 dome of Phoenix is possibly two orders of magnitude smaller than that produced by other sources of the city's urban heat island (CSCDGC 2010)."

Local CO_2 emission modeling results from a California study have shown an increase in ozone and particulate matter concentrations, which could affect the health of urban residents. The study suggested that reducing local CO_2 concentrations could avoid 300–1,000 premature air pollution mortalities in the United States (Jacobson 2010).

Pollen is another airborne hazard linked to global warming. Rising temperature and increased CO_2 concentration would increase pollen production and prolong the pollen season in a number of plants with highly allergenic pollen (USGCRP 2009). Figure 3-17 shows predicted pollen production increases for ragweed on a grams-per-plant basis.



Source: *Global Climate Change Impacts in the United States (USGCRP 2009).*

Figure 3-17. U.S. Pollen Counts Rise with Increasing CO_2

Hot, dry weather, which is predicted to occur more frequently throughout the United States, is directly related to wildfires. In the western U.S., wildfires have already nearly quadrupled. In addition to potential risks of death, fires also degrade air quality and increase respiratory illnesses.

Storms, especially heavy precipitation events, are directly hazardous due to flooding. These events also have longer implications after the initial emergency. Heavy rains increase cases of waterborne illnesses due to public drinking water contamination and contamination of recreational waters. This contamination can occur due to flooding of public drinking water and wastewater treatment plants, sewer overflows, and release of livestock waste into food crop fields.

Increased disease also results from increased temperatures, due to an increased risk of food poisoning and increased risks of insect-borne illness via mosquitoes (West Nile Virus) and ticks

(Rocky Mountain Spotted Fever). Diseases that have historically been limited to more southern regions of the nation or in other countries may migrate north.

3.3. Predicted Climate Change Effects on Montana, North Dakota, and South Dakota

Although this report does not reference any modeling results that are specific to an individual state, predictions of climate change effects can be identified for Montana, North Dakota, and South Dakota based on results from global and regional models. When regional climate change is examined, North and South Dakota and the eastern portion of Montana are often characterized as the northern portion of the Great Plains, while western Montana is characterized as part of the Northwest.

A summary of potential climate changes and effects is provided below for each state. The first portion of each summary provides brief descriptions of predicted climate change impacts that have been previously discussed. Then examples of additional state-specific issues are provided.

3.3.1. Montana

As mentioned earlier, Montana straddles two regions of the United States due to the large differences between the mountainous western portion of the state and the plains to the east. Predicted climate change impacts are summarized below.

- **Temperature** — Under the higher emission scenario (SRES A2), Montana temperatures are predicted to increase 4–5°F by the mid-21st century and by 8–9°F by the end of the century over most of the state. Under the lower emission scenario (SRES B1), temperatures are predicted to increase 3–4°F by the mid-21st century and by 5–6°F by the end of the century over most of the state. Slightly lower temperature increases are predicted for the extreme northwest corner of the state (west of Glacier National Park) for all modeled scenarios except the mid-century, lower emission scenario (see Figure 3-5).
- **Precipitation** — For the years 2080–2099 compared to recent years, Montana precipitation is predicted to increase by 15–20 percent in the winter, increase by 10–25 percent in the spring, decrease by 0–20 percent in the summer, and increase or decrease in the fall. Summer precipitation decreases are predicted to be more pronounced in the western portion of the state. In the fall, the western portion of the state would see little change while the northwestern portion of the state would experience precipitation increases of 5–10 percent (see Figure 3-10).
- **Annual runoff**:
    - **Median runoff** — Predicted median runoff for 2041–2060 compared to 1901–1970 is expected to decrease by 2–5 percent in most of the state; however, runoff changes in the northwestern part of the state may remain stable (see Figure 3-12).
    - **Mountain snowpack** — The IPCC projected with “high confidence” that “water supplies stored in mountain snowpacks will decline around the world, reducing water availability in regions supplied by meltwater.” (IPCC 2007b)

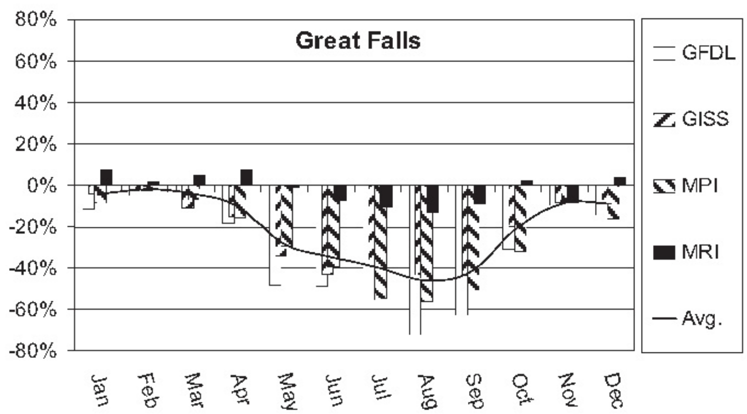
- **Glaciers** — In 2003, U.S. Geological Survey (USGS) researchers predicted that all glaciers in Glacier National Park could be completely melted by 2030. This prediction was updated in 2007 when a USGS researcher stated that the glaciers were melting faster than expected. The Grinnell Glacier lost approximately 9 percent of its acreage between 2005 and 2007 (RMCO 2008).
- **Agriculture** — Up to an approximate 2°C temperature increase, crop yields may increase in northern latitudes, including Montana (NRC 2010).
- **Ecosystems**:
    - **Wetlands** — Changes to Montana wetlands located across much of the northern part of the state are predicted to remain relatively stable, although a small portion of moderate wetland habitat near Cutbank, MT is predicted to degrade to less favorable conditions. (See the map and discussion within Section 3.3.1.1.)
    - **Fish** — Increased temperatures would raise water temperatures in lakes, reservoirs, rivers, and streams. Fish populations are expected to decline due to warmer waters, which could lead to closure of fishing waters, as has occurred during recent years (RMCO 2008).
    - **Fire** — The modeled risk of wildfire is expected to increase throughout the state, as described in Section 3.3.1.2.
- **Human health**:
    - **Ozone** — Predicted future ozone concentrations during the 2090s could increase or decrease depending on the level of GHG emissions (see Figure 3-16).
    - **Heat waves** — In the late 21st century, the number of days per year with temperatures above 100°F are predicted to be between 10 and 45, depending on the level of emissions, with the largest increase in the number of 100+ days occurring in the eastern portion of the state (see Figure 3-15).
- **Wind power production** — Wind power production efficiency is predicted to decline in Montana based on modeling focused on the Great Falls area. (See the discussion below.)

3.3.1.1. Wind Power Generation

As a renewable energy source, power produced by wind turbines can decrease GHG emissions from the electricity generation sector. Wind farms are operating or planned in many states, including Montana. A recent modeling study focused on five northwestern states indicates that climate change could reduce wind turbine productivity throughout the region.

The modeling study used general circulation models (GCMs) that were statistically downscaled to better predict local winds. Direct wind statistics output from several GCMs were determined to be of poor quality when compared to airport weather station data. Downscaling modeling was then attempted using six GCM output variables including: zonal, meridional, and total wind speeds, maximum and minimum air temperatures, and sea level pressure. Downscaled modeled wind data outputs were much closer to observed data. After determining that the downscaled modeling performed well, two SRES future year emission inventories (A1B and A2, see Section 3.1.2) were modeled with four GCMs (GISS, MPI, GFDL, and MRI).

Figure 3-18 shows the changes in monthly wind power generation predicted for the Great Falls, Montana area based on the SRES A1B emission scenario. The percentage change compares estimated winds during 2050 to present observed winds. Predicted wind power changes vary among models in winter and early spring months, with most models predicting slight decreases while one model predicts slight increases in wind power. In contrast, all five models predict wind power reductions in May through September and four of the five models predict summer wind power reductions of 30 percent or more in these months.

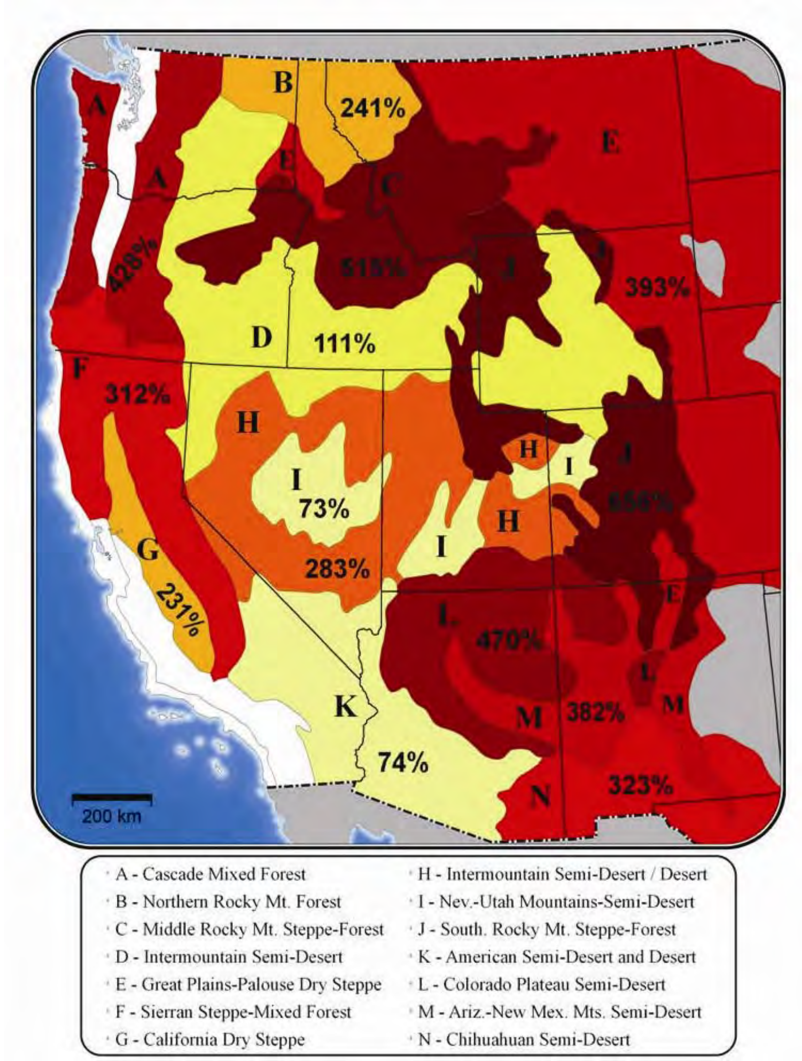


Source: Adapted from Figure 7 from "Climate Change Implications for Wind Power Resources in the Northwest United States" (Sailor 2008).

Figure 3-18. Predicted Changes in Monthly Wind Power in Great Falls, Montana

3.3.1.2. Wildfire Risk

Wildfire risk is predicted to increase due to a combination of climate change effects on temperature, precipitation, and wind. Together, these climate characteristics affect fuel availability and fuel moisture content. One study modeled the change in median annual average area burned in the western United States that would occur due to a 1°C global average temperature increase above the median annual area burned during 1950–2003. The predicted increases are shown for 14 western ecoprovinces in Figure 3-19. In Montana, the increase in median annual area burned is predicted to be an increase of 241 percent to 515 percent, with the largest modeled increase occurring in the southwest portion of the state.



Source: Figure 5.8 from *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (NRC 2010, unpublished).

Figure 3-19. Predicted Changes in Wildfire Area Burned in the Western United States

3.3.2. North Dakota

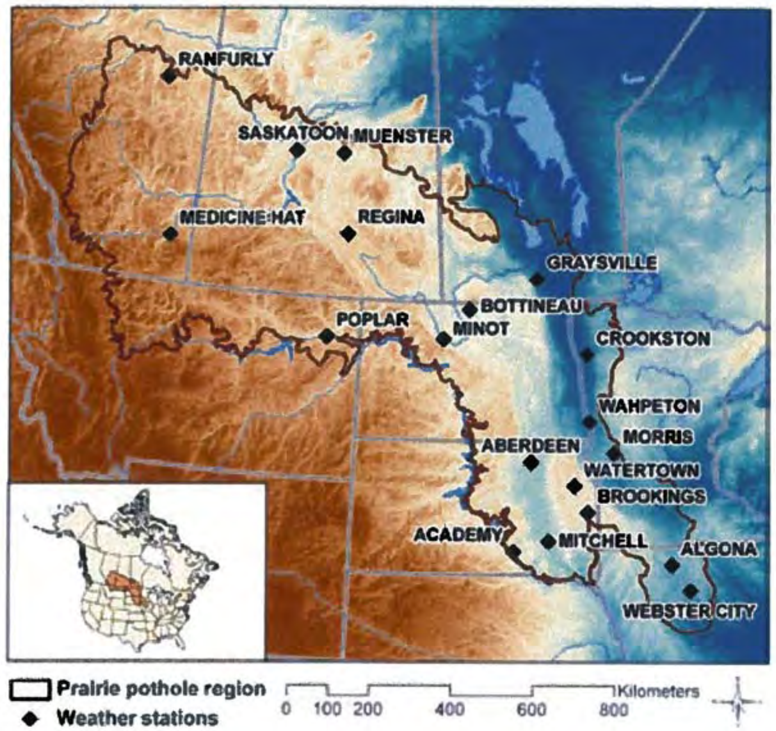
Based on many climate studies, North Dakota is expected to experience many changes associated with climate change. Some of the predicted changes are summarized below.

- **Temperature —** Under the higher emission scenario (SRES A2), North Dakota temperatures are predicted to increase 4–5°F by the mid-21st century and by 8–10°F by the end of the century over most of the state. Under the lower emission scenario (SRES B1), temperatures are predicted to increase 3–5°F by the mid-21st century and by 5–6°F by the end of the century. Slightly higher temperature increases are predicted for the eastern edge of the state for some modeled scenarios (see Figure 3-5).

- **Precipitation** — For the years 2080–2099 compared to recent years, North Dakota precipitation is predicted to increase by 15–20 percent in the winter, increase by 20–30 percent in the spring, decrease slightly in the summer, and remain relatively unchanged in the fall (see Figure 3-10).
- **Annual median runoff** — Predicted median runoff for 2041–2060 compared to 1901–1970 is expected to decrease by 2–5 percent in the western portion of the state, while runoff changes in the northeastern part of the state would increase by 5–10 percent (see Figure 3-12).
- **Agriculture** — Up to an approximate 2°C temperature increase, crop yields may increase in northern latitudes, including North Dakota (NRC 2010).
- **Ecosystems**:
  - **Wetlands** —North Dakota's wetlands are predicted to decline in quality (see the map and discussion within Section 3.3.1.1.)
  - **Fire** — The modeled change in area burned due to a 1°C increase in global temperature is expected to increase by 393 percent in the western portion of the state (see Figure 3-19). Note that the cited study and the map do not include the eastern portion of North Dakota.
- **Human health**:
  - **Ozone** — Predicted future ozone concentrations during the 2090s could increase or decrease depending on the level of GHG emissions (see Figure 3-16).
  - **Heat waves** — In the late 21st century, the number of days per year with temperatures above 100°F is predicted to be between 10 and 45, depending on the level of emissions, with the largest increase in the number of 100+ days occurring in the southern portion of North Dakota (see Figure 3-15).

3.3.2.1. Wetland Drying

As shown in Figure 3-20, more than half of North Dakota contains wetlands known as the Prairie Pothole Region (PPR) of the northern United States. The region also extends south through most of the eastern half of South Dakota and across most of the northern portion of Montana.



Source: Figure 1 of "Prairie Wetland Complexes as Landscape Functional Units in a Changing Climate" (Johnson 2010).

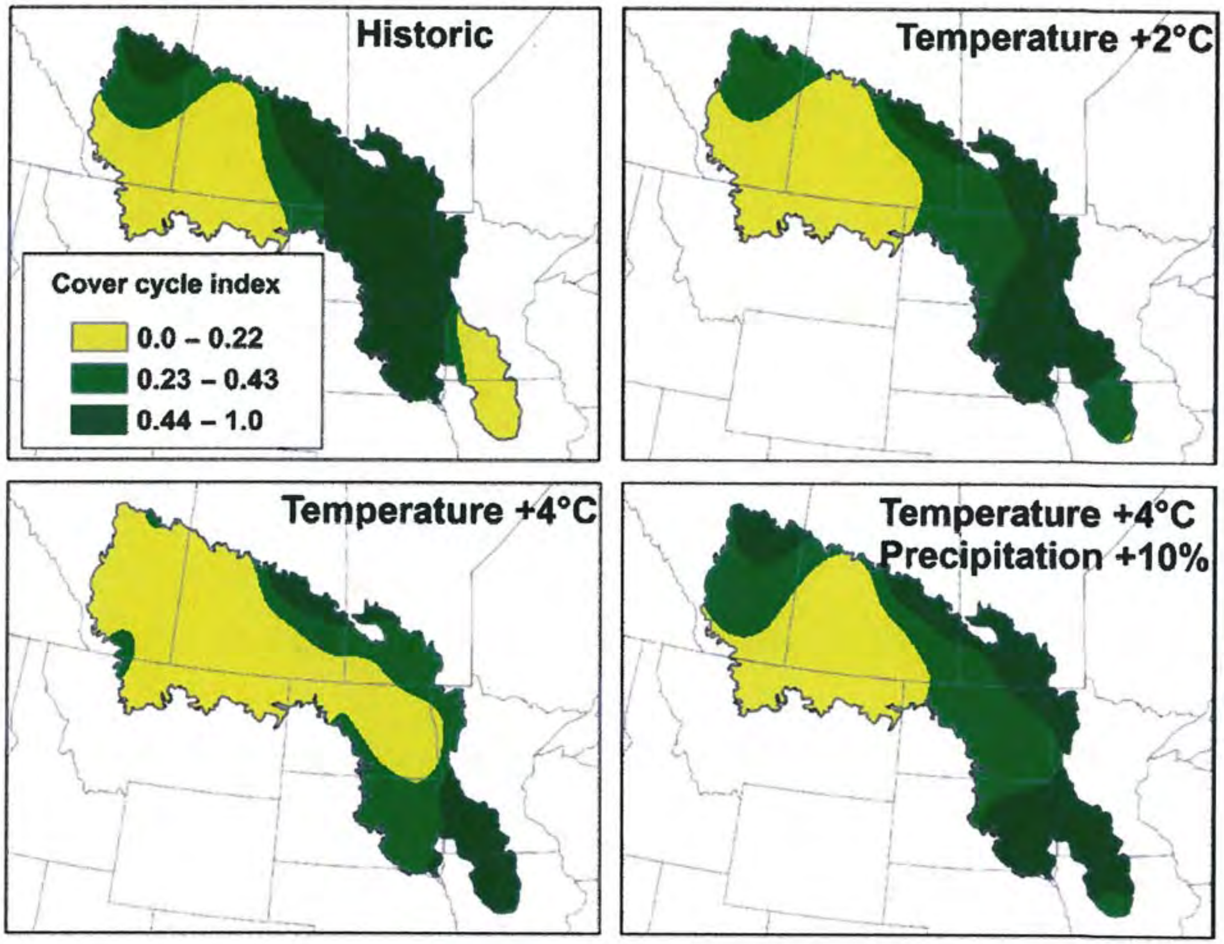
Figure 3-20. Prairie Pothole Region of Northern U.S. and Canada

These freshwater wetlands are predicted to be vulnerable to climate change due to their shallow depths and rapid evaporation rates (Johnson 2010). Historically, PPR wetlands dry up seasonally during most years. Recent simulation of potential climate changes using the WETLANDSCAPE model indicate that the PPR will continue a recently recognized pattern of becoming drier in the western portion of the PPR and wetter in the eastern portion.

Biological productivity of the PPR is greatest when the vegetation cover cycle is robust. The wetland cover cycle includes four stages: (1) a dry stage with dense emergent cover and little or no standing water; (2) a regenerating stage with germination, reflooding, and vegetative propagation; (3) a degenerating stage when emergency plants start to decline; and (4) the lake stage with high water (Johnson 2010). If wetlands do not cycle between these stages, they become less productive for bird populations. As part of the PPR modeling effort, a cover-cycle index (CCI) was developed to represent wetland productivity. Figure 3-21 illustrates historic (top left) and predicted future changes to the CCI. Large swaths of North and South Dakota have historically had high CCIs, indicating high wetland productivity. The following tree future climate warming scenarios were modeled.

- Temperature increase of 2°C (top, right)
- Temperature increase of 4°C (bottom, left)
- Temperature increase of 4°C and a precipitation increase of 10 percent (bottom, right)

As shown in Figure 3-21, the CCI is predicted to decrease throughout much of North Dakota in all three modeled scenarios. The predicted geographic shifts and shrinkage of the most productive wetland areas suggest that waterfowl populations may decrease. According to another study referenced by the PPR modeling report, survival of mallard ducklings in North Dakota was 7.6 times lower when fewer seasonal wetlands were available during drought than when water was abundant in the same wetland areas during subsequent years (Johnson 2010).



Source: Figure 8 of "Prairie Wetland Complexes as Landscape Functional Units in a Changing Climate" (Johnson 2010).

Figure 3-21. Cover-Cycle Index Changes in Prairie Pothole Region of Northern U.S. and Canada

3.3.3. South Dakota

Based on multiple climate studies, South Dakota is expected to experience many changes associated with climate change. Some of the predicted changes are summarized below.

- **Temperature —** Under the higher emission scenario (SRES A2), South Dakota temperatures are predicted to increase 4–5°F by the mid-21st century and by 8–10°F by the end of the century over most of the state. Under the lower emission scenario (SRES

B1), temperatures are predicted to increase 3–5°F by the mid-21st century and by 5–6°F by the end of the century. Slightly higher temperature increases are predicted for the eastern edge of the state for some modeled scenarios (see Figure 3-5).

- **Precipitation —** For the years 2080–2099 compared to recent years, South Dakota precipitation is predicted to increase by 15–25 percent in the winter, increase by 10–20 percent in the spring, decrease by 0–10 percent in the summer, and remain relatively unchanged in the fall (see Figure 3-10).
- **Annual median runoff —** Predicted median runoff for 2041–2060 compared to 1901–1970 is expected to decrease by 2–5 percent throughout South Dakota (see Figure 3-12).
- **Agriculture —** Up to an approximate 2°C temperature increase, crop yields may increase in northern latitudes, including South Dakota (NRC 2010).
- **Ecosystems:**
  - **Wetlands —**South Dakota's wetland extent and quality is predicted to remain fairly stable if temperature increases are limited to approximately 2°C or if a temperature increase of up to 4°C were accompanied by a 10 percent increase in precipitation (see Figure 3-21). However, a temperature increase of approximately 4°C without a significant precipitation increase is predicted to cause wetland degradation.
  - **Fire —** The modeled change in area burned due to a 1°C increase in global temperature is expected to increase by 393 percent in the western portion of the state (see Figure 3-19). Note that the cited study and the map do not include the eastern portion of South Dakota.
- **Human health:**
  - **Ozone —** Predicted future ozone concentrations during the 2090s could increase or decrease depending on the level of GHG emissions (see Figure 3-16).
  - **Heat waves** — In the late 21st century, the number of days per year with temperatures above 100°F is predicted to be between 30 and 60, depending on the level of emissions, with the largest increase in the number of 100+ days occurring in the southern portion of South Dakota (see Figure 3-15).

3.4. Key Climate Change Predictions

Key additional climate change projections from the IPCC are quoted below (IPCC 2007b).

- Equilibrium and Transient Climate Sensitivity
  - Equilibrium climate sensitivity is likely to be in the range 2°C to 4.5°C with a most likely value of about 3°C, based upon multiple observational and modeling constraints. It is very unlikely to be less than 1.5°C.
  - The transient climate response is better constrained than the equilibrium climate sensitivity. It is very likely larger than 1°C and very unlikely greater than 3°C.
  - There is a good understanding of the origin of differences in equilibrium climate sensitivity found in different models. Cloud feedbacks are the primary source of intermodal differences in equilibrium climate sensitivity, with low cloud being the largest contributor.

- Global Projections
    - Even if concentrations of RF agents were to be stabilized, further committed warming and related climate changes would be expected to occur, largely because of time lags associated with processes in the oceans.
    - Near-term warming projections are little affected by different scenario assumptions or different model sensitivities, and are consistent with that observed for the past few decades. The multi-model mean warming, averaged over 2011 to 2030 relative to 1980 to 1999 for all AOGCMs considered here, lies in a narrow range of 0.64°C to 0.69°C for the three different SRES emission scenarios B1, A1B, and A2.
    - Geographic patterns of projected warming show the greatest temperature increases at high northern latitudes and over land, with less warming over the southern oceans and North Atlantic.
    - Changes in precipitation show robust large-scale patterns: precipitation generally increases in the tropical precipitation maxima, decreases in the subtropics, and increases at high latitudes as a consequence of a general intensification of the global hydrological cycle.
    - As the climate warms, snow cover and sea ice extent decrease; glaciers and ice caps lose mass and contribute to sea level rise. Sea ice extent decreases in the 21st century in both the Arctic and Antarctic. Snow cover reduction is accelerated in the Arctic by positive feedbacks and widespread increases in thaw depth occur over much of the permafrost regions.
    - Based on current simulations, it is very likely that the Atlantic Ocean MOC will slow down by 2100. However, it is very unlikely that the MOC will undergo a large abrupt transition during the course of the 21st century.
    - Heat waves become more frequent and longer lasting in a future warmer climate. Decreases in frost days are projected to occur almost everywhere in the mid- and high latitudes, with an increase in growing season length. There is a tendency for summer drying of the mid-continental areas during summer, indicating a greater risk of droughts in those regions.
    - Future warming would tend to reduce the capacity of the Earth system (land and ocean) to absorb anthropogenic CO_2. As a result, an increasingly large fraction of anthropogenic CO_2 would stay in the atmosphere under a warmer climate. This feedback requires reductions in the cumulative emissions consistent with stabilization at a given atmospheric CO_2 level compared to the hypothetical case of no such feedback. The higher the stabilization scenario, the larger the amount of climate change and the larger the required reductions.
- Sea Level
    - Sea level will continue to rise in the 21st century because of thermal expansion and loss of land ice. Sea level rise was not geographically uniform in the past and will not be in the future.
    - Projected warming due to emission of greenhouse gases during the 21st century will continue to contribute to sea level rise for many centuries.

  - Sea level rise due to thermal expansion and loss of mass from ice sheets would continue for centuries or millennia even if RF were to be stabilized.
- Regional Projections
  - Temperatures averaged over all habitable continents and over many sub-continental land regions will very likely rise at greater than the global average rate in the next 50 years and by an amount substantially in excess of natural variability.
  - Precipitation is likely to increase in most subpolar and polar regions. The increase is considered especially robust, and very likely to occur, in annual precipitation in most of northern Europe, Canada, the northeast United States, and the Arctic, and in winter precipitation in northern Asia and the Tibetan Plateau.
  - Precipitation is likely to decrease in many subtropical regions, especially at the poleward margins of the subtropics. The decrease is considered especially robust, and very likely to occur, in annual precipitation in European and African regions bordering the Mediterranean and in winter rainfall in south-western Australia.
  - Extremes of daily precipitation are likely to increase in many regions. The increase is considered as very likely in northern Europe, south Asia, East Asia, Australia and New Zealand – this list in part reflecting uneven geographic coverage in existing published research.

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4.0 OIL AND GAS REASONABLY FORESEEABLE DEVELOPMENT SCENARIOS

This chapter includes RFD scenario summaries for the following BLM FO planning areas.

- Billings
- Butte
- Dillon
- Hi-Line Planning Area (includes Malta, Glasgow, and Havre FOs)
- Lewistown
- Miles City
- North Dakota
- South Dakota

4.1. Billings Drilling Activity Forecast (20-Year Forecast)

The Billings FO drilling activity forecast covers a 20-year time frame and is based on information contained in the *Reasonably Foreseeable Development Scenario for the Billings/Pompeys Pillar Resource Management Plan* (BLM 2010).

4.1.1. General Assumptions

4.1.1.1. Crazy Mountain Basin

The Crazy Mountain Basin is the location of the only new play in the area. The basin is located in Sweet Grass and Park Counties (Park County is in the Butte FO). The exploration target is organic shales. These shales are generally continuous, stratigraphic traps. Extensive "frac" jobs are required. The Bill Barrett Corp and Devon Energy are involved in exploration activities. A discovery in the Crazy Mountain Basin would require the construction of a major transmission pipeline. Such a line would be buried; however, gathering lines and other infrastructure would create long term disturbance.

4.1.1.2. Coal Bed Natural Gas

BLM has identified the potential for coal bed natural gas (CBNG) in Upper Cretaceous and Paleocene coal beds in the Bighorn Basin and Bull Mountain Basin. The BLM does not anticipate that CBNG development in the Billings FO would have the same intensity as in the Powder River Basin for a number of reasons. Compared to the Powder River Basin, coals in these areas have the following characteristics.

- Thinner
- Higher rank, with likely higher adsorbed gas level
- More deeply buried
- Drilling and development likely would have a lower well density
- There would likely be a single well per spacing unit (no thick, stacked coals)

- The coals are generally too deep below the surface to supply groundwater for most domestic and agricultural purposes
- Groundwater within the coals likely has higher salinities and would not be suitable for domestic or agricultural purposes

4.1.1.3. Drilling Levels

Development potential has been identified in the planning area (refer to page 78, Appendix A, Map 1 – Fluid Minerals Potential Map of the Billings RFD). No areas were classified as high potential. Areas of low potential are forecast to have no more than 1 well per township drilled per year. Areas of moderate potential are expected to have between 1 and 5 wells per township drilled per year.

The total number of wells drilled per year is 20 per year. Of these, 3 to 4 Federal wells would be drilled per year.

Table 4-1. Billings FO Surface, Oil & Gas Mineral Ownership, and Acres of O&G Leases by County (All Surface Management Agencies)

Federal Surface Ownership (acres)	Federal Oil & Gas Mineral Ownership (acres)	O&G Leases	Leased Acres (acres)	Percent of O&G Leased
1,307,472.15	1,611,184.65	280	186,264.56	11.5%

Table 4-2. Billings FO Surface, Oil & Gas Mineral Ownership, and Acres of O&G leases by County (Managed by the Billings FO)

BLM-Managed Surface (acres)	BLM-Managed Oil & Gas Mineral Ownership (acres)	O&G Leases	Leased Acres (acres)	Percent of O&G Leased
397,906.24	689,680.44	275	179,439.91	26.0%

Table 4-3. Billings FO Forecast Drilling Depths and Initial Surface Disturbance by Basin

Location	Common Drilling Depth (feet)	Likely Product	Size of Drill Site (acres)	Access and Ancillary Facilities (acres)
Central Montana Uplift and Bull Mountain Basin CBNG	5,000	Oil with associated gas; CBNG	2	1½
Big Horn Basin conventional and CBNG	7,000	Oil with associated gas; Gas; CBNG	3	1½
Crazy Mountain Basin	8,000–10,000	Gas	4	1½

Table 4-4. Billings FO Forecast Drilling Activity and Surface Disturbance, 2010–2014

Location	Size of Drill Site (acres)	Access and Ancillary Facilities (acres)	Number of Wells Drilled per Year	Short Term Disturbance (acres)	Long Term Disturbance (acres) [1]
Central Montana Uplift and Bull Mountain Basin CBNG	2	1½	8: 4 wildcat, 4 development	28	14
Big Horn Basin conventional and CBNG	3	1½	8: 4 wildcat, 4 development	36	18
Crazy Mountains Basin	4	1½	4: 4 wildcat	22	5½
			Total annual disturbance	**86**	**37½**

[1] 75% success for development wells, 25% for exploratory wells, with interim reclamation

Table 4-5. Billings FO Forecast Drilling Activity and Surface Disturbance, 2015–2030

Location	Size of Drill Site (acres)	Access and Ancillary Facilities (acres)	Number of Wells Drilled per Year	Short Term Disturbance (acres)	Long Term Disturbance (acres) [1]
Central Montana Uplift and Bull Mountain Basin CBNG	2	1½	8: 4 wildcat, 4 development	28	14
Big Horn Basin conventional Oil and gas and CBNG	3	1½	8: 4 wildcat, 4 development	36	18
Crazy Mountain Basin	4	1½	8: 4 wildcat, 4 development	44	22
			Total annual disturbance	**108**	**54**

[1] 75% success for development wells, 25% for exploratory wells, with interim reclamation

Table 4-6. Billings FO Federal Oil and Gas Wells

Location	Size of Drill Site (acres)	Access and Ancillary Facilities (acres)	Number of Wells Drilled per Year	Short Term Disturbance (acres)	Long Term Disturbance (acres) [1]
Central Montana Uplift and Bull Mountain Basin CBNG	2	1½	1–2; development	3½ – 7	2 – 5
Big Horn Basin conventional Oil and gas and CBNG	3	1½	1–2: development	4½ – 9	3½ – 6
Crazy Mountain Basin	4	1½	1–2; wildcat	5½ – 11	0 – 4½
			Total annual disturbance	**13½ – 27**	**5½ – 15½**

[1] 75% success for development wells, 25% for exploratory wells, with interim reclamation

4.2. Butte Drilling Activity Forecast (15- to 20-Year Forecast)

The Butte FO drilling activity forecast covers a 15- to 20-year time frame and is based on information contained in the *Proposed Butte Field Office Resource Management Plan (RMP) and Environmental Impact Statement* (EIS) (BLM 2008). Forecast annual production is expected to be 980,000 thousand cubic feet (Mcf) of gas. Lands within the Butte Planning Area include the following.

- BLM Surface Acres: 307,309
- BLM Mineral Estate: 652,194
- Total Acres: 7,192,349

Table 4-7. Butte FO Drilling Activity

Area	Total Wildcat Wells	Wildcat Dry Holes	Wildcat Discoveries	Step-out Wells	Commodity
1 [1]	2	2	0	0	
2 [2]	5	4	1	2	Gas
3 [3]	4	3	1	2	Gas
4 [4]	4	2	1 deep & 1 shallow	2 deep & 2 shallow	deep = gas; shallow = oil
Barrett Corp Area [5]	4	2	2	4	gas
Total Conventional Wells	19	13	6	12	
Area 5 [6]	16	10	6	24	CBNG

Source: Proposed Butte FO RMP/EIS, 2008, Appendix M (BLM 2008).

[1] Area #1 Southern Deerlodge Valley Basin Area, fee wells.
[2] Area #2 Imbricate Thrust Zone, 1 federal discovery.
[3] Area #3 Helena Salient Gas Play Zone, 1 federal discovery.
[4] Area #4 Crazy Mountain Oil & Gas Play, fee or FS lands.
[5] Bill Barrett Area Crazy Mountain Basin, deep gas, fee wells
[6] Area #5 includes only CBNG wells.

4.2.1. Butte FO Estimation of Surface Disturbance Assumptions

4.2.1.1. Conventional Oil and Gas

- The maximum area cleared per well pad would be 3.5 acres (about 380 ft. x 400 ft.) and 2.3 acres would be stabilized in about 2 years
- The maximum area cleared per access road per well would be 17 acres (about 40 ft. x 18480 ft.) and 9 acres would be stabilized in 2 years.
- All field gathering pipelines for gas (2–4 inch diameter) will follow existing or new access roads and no additional disturbance would result.
- The maximum area cleared for trunk lines to transport gas from four different fields to the existing transmission lines running through the Butte Field Office would be 254.5 acres (about 25 ft. x 443,520 ft.) and the entire area of disturbance would be stabilized in about 2 years.
- All perennial stream crossings would use horizontal drilling to avoid disturbance to the stream, its bed, and banks.
- Produced oil would be trucked from the well sites.
- Dry and abandoned wells would be reclaimed.

4.2.1.2. Coal Bed Natural Gas

- The maximum area disturbed per well site would be 0.25 acres per well pad. Most sites are not cleared (no pad is constructed).
- Access to individual well sites would be two-track trails.
- Surface disturbance for field and sales compressors would be 0.5 miles.

- Gathering lines from the well sites to the field and sales compressors would follow access routes and be buried.

4.2.1.3. Gas Field Assumptions

- Gas fields would be discovered east of Lincoln (Area #2), northeast of Townsend (Area #3), east of Livingston (Area #4) and near Wilsall (where the Barrett Corporation is now drilling).
- Fields would be roughly 3 square miles in surface area except for the field developed near Wilsall where the Barrett Corporation is drilling which would be 6 square miles.
- Full development would require 3 wells (one discovery and two step-out wells) except for the field being tested by Barrett. That field would consist of 2 discoveries and 2 dry holes. The 2 discoveries would each have two step-out wells. 3-D seismic would be run to refine step out well locations.
- Gas would be transported by pipeline in order to be marketed. From Area #2 it would be transported west to a main north-south transmission line running through the Butte Field Office for approximately 18 miles. From Area #3 it would be transported approximately 30 miles to a main east-west transmission line running through the Butte Field Office. From Area #4 it would be transported approximately 6 miles north to a main east-west transmission line running through the Butte Field Office. From the area being explored by the Barrett Corporation it would be transported approximately 30 miles south to the main east-west transmission line running through the Butte Field Office.
- Compressor stations would be necessary along the pipeline route, with one of those stations being within one mile of the main line in order to boost the pipeline gas to the pressure of the main line. Wells would be drilled 10,000 to 15,000 feet deep. One well would be drilled from each well pad. Only one development well would be drilled at a time.
- Wells would take approximately 300 days to drill.
- Condensate, gas, and water separation would occur at the wellsites. Water disposal would be into a lined pit at the surface or water would be injected into the subsurface through a dry hole converted into a water disposal well.
- Condensate would be shipped by truck (1 truck every 4 days).
- The field is expected to produce for 25 years.
- Well servicing, repair, and maintenance would continue throughout the life of the field. Well servicing operations would take 5 days per well and occur 6 times /well of the 25 year life of the field. A well tender would make one trip per well per day.

4.2.1.4. Oil Field Assumptions

- An oil field is possible in the vicinity of Livingston.
- Field would be roughly 1 ½ square miles in surface area.
- Full field development would require 3 wells (one discovery and two step-out wells), 3-D seismic would be run to refine step out well locations.
- Oil would be transported by truck to the appropriate refining facility.
- Wells would be 2,500 to 3,500 feet deep. One well would be drilled from each well pad. Only one development well would be drilled at a time.

- The wells would take approximately 21 days to drill.
- Oil, gas, and water separation would occur at the well sites. Water disposal would be into a lined pit at the surface or water would be injected into the subsurface through a dry hole converted into a water disposal well. Gas would be used on lease to separate oil and water and to heat oil. Gas not used on lease would be sold or vented/flared to the atmosphere. If sufficient gas quantities are produced this gas may also be captured and sold. For this analysis all unused gas is assumed to be reinjected for pressure maintenance
- The field is expected to produce for 25 years.
- Well servicing, repair, and maintenance continue throughout the life of the field. Well servicing operations would take 5 days per well and occur 6 times/well over the 25 year life of the field. A well tender would make one trip per day.

4.2.1.5. CBNG Field Assumptions

- Two coal bed natural gas fields are expected in the area of Bozeman Pass within the Trail Creek-Livingston coal field.
- Each field would be approximately 1.75 square miles in surface area.
- Each field would require 1 field compressor and one sales compressor may be needed depending on where the wells are located.
- Ten to 27 miles of plastic low-pressure gathering lines would be required. These would be laid in the travel routes and follow existing roads to field compressors. Two to four miles of low-pressure steel lines would be laid from the field compressors to the sales compressor.
- No more than 20 miles of sales lines would be laid to the main transmission line in the area.
- Total disturbance excluding the actual well sites including compressors, pipelines, and access routes would be 220 acres.

Table 4-8. Butte FO Direct Cumulative Surface Disturbance

Surface Activity	Unsuccessful Wildcats (acres)		Productive Wells (acres)	
	Acres Disturbed Pre-Site Reclamation	Post-Site Reclamation	Acres Disturbed Pre-Site Reclamation	Post-Site Reclamation
Conventional Oil and Gas				
Well Sites	45.5	0	63	21.5 (2 years)
Access Roads	221	0	189.6	103.7 (2 years)
Pipelines	0	0	254.5	0 (2 years)
CBNG				
Well Sites	1	0	7.5	5 (2 years)
Compressors, Pipelines & Access Roads	3	0	220	147 (2 years)
Consolidate crude oil production and water storage tanks	4,200	>$10K	<$0.1K	1 – 3 yr
Total Acres Disturbed	**270.5**	**0**	**734.6**	**272.2 (2 years)**

4.3. Dillon Drilling Activity Forecast (10- to 15-Year Forecast)

The Dillon FO drilling activity forecast covers a 10- to 15-year time frame and is based on information contained in the *Proposed Dillon Field Office Resource Management Plan and Final Environmental Impact Statement*, Volume II, Appendix H (BLM 2005). Forecast annual production is expected to be 18,350 barrels (bbl) of oil and 3,529,297 Mcf of natural gas. Lands within the Dillon Planning Area include the following.

- Total Surface Acres
    - Beaverhead County: 3,546,775
    - Madison County: 2,302,945
- BLM Mineral Estate Acreage
    - BLM Surface/Federal Minerals: 893,800
    - Split Estate: 444,559
    - Bureau of Reclamation (BOR) Surface/Federal Minerals: 1,305
    - ARS Surface/Federal Minerals: 15,538
    - Total: 1,355,202

4.3.1. Drilling Areas

During preparation of the RFD, the BLM identified and mapped the four areas in the planning area where it was considered most likely that wells would be drilled. These areas are depicted on Map 83 – Mineral Potential (Proposed Dillon RMP/FEIS, BLM 2005) and listed below.

- Area #1: Big Hole Basin – Natural Gas
- Area #2: Dillon – Beaverhead River Basin around Dillon, Retort Mountain area, Armestead thrust area, and Blacktail Salient
- Area #3: Lima – Tendoy Overthrust, foreland east of the thrust sheet, and also a Cretaceous foreland basin at the south end of the Tendoy Mountains – Natural Gas and possibly Oil
- Area #4 Gravelly – Gravelly Range and Snowcrest Trough and south and west of the Gravelly Range

4.3.2. Estimation of Surface Disturbance Assumptions

- The maximum area cleared per well pad would be 3.5 acres (about 380 ft. x 400 ft.) and 2.3 acres would be stabilized in about 2 years.
- The maximum area cleared per access road per well would be 17 acres (about 40 ft. x 18480 ft.) and 9 acres would be stabilized in about 2 years.
- All field gathering pipelines (2-4 inch diameter) will follow existing or new access roads and no additional disturbance would result.
- The maximum area cleared for trunk lines to transport gas from two different fields to the existing transmission line near Dillon, Montana would be 318 acres (about 25 ft x 554,400 ft.) and the entire area of disturbance would be stabilized in about 2 years. All perennial stream crossings would use horizontal drilling to avoid disturbance to the stream, its bed and banks.

- Dry and abandoned wells would be reclaimed.

Table 4-9. Dillon FO Direct Cumulative Surface Disturbance

Surface Activity	Unsuccessful Wildcat Wells (acres)		Commercially Productive Wells (acres)	
	Pre-Site Reclamation	Post-Site Reclamation	Pre-Site Reclamation	Post-Site Reclamation
Well Sites	14	0	21	7.2
Access Roads	68	0	102	48
Pipelines	0	0	318	0
Total Acres Disturbed	**82**	**0**	**441**	**52.2**

4.3.2.1. Gas Field Assumptions

- Gas fields would be discovered in the Lima and Big Hole Basin areas.
- Fields would be roughly 3 square miles in surface area.
- Full development would require 3 wells (one discovery and two step-out wells). 3-D seismic would be run to refine step out well locations.
- Gas would be transported by pipeline in order to be marketed. From Lima it would be transported north to Dillon for approximately 45 miles. From the Big Hole Basin it would be transported approximately 60 miles to the south and east to Dillon.
- Compressor stations would be necessary along the pipeline route, with one of those stations being within one mile of the main line in order to boost the pipeline gas to the pressure of the main line.
- Wells would be drilled 10,000 to 15,000 feet deep. One well would be drilled from each well pad. Only one development well would be drilled at a time.
- Wells would take approximately 300 days to drill.
- Condensate, gas, and water separation would occur at the wellsites. Water disposal would be into a lined pit at the surface or water would be injected into the subsurface through a dry hole converted into a water disposal well. Condensate would be shipped by truck (1 truck every 4 days).
- The field is expected to produce for 25 years.
- Well servicing, repair, and maintenance would continue throughout the life of the field. Well servicing operations would take 5 days per well and occur 6 times/well over the 25 year life of the field. A well tender would make one trip per day.

4.3.2.2. Oil Field Assumptions

- An oil field is possible at the Lima area.
- Field would be roughly 1-1/2 square miles in surface area.
- Full field development would require 3 wells (one discovery and two step out wells). 3-D seismic would be run to refine step out well locations.
- Wells would be 10,000 to 15,000 feet deep. One well would be drilled from each well pad. Only one development well would be drilled at a time.
- The wells would take approximately 300 days to drill.

- Oil, gas, and water separation would occur at the wellsites. Water disposal would be into a lined pit at the surface or water would be injected into the subsurface through a dry hole converted into a water disposal well. Gas would be used on lease to separate oil and water and to heat oil. Gas not used on lease would be sold or vented/flared to the atmosphere. If sufficient gas quantities are produced this gas may also be captured and sold. For this analysis all unused gas is assumed to be reinjected for pressure maintenance.
- The field is expected to produce for 25 years.
- Well servicing, repair, and maintenance continue throughout the life of the field. Well servicing operations would take 5 days per well and occur 6 times/well over the 25 year life of the field. A well tender would make one trip per day.

Table 4-10. Dillon FO Oil and Gas Activity Vehicle Trips

Activity	Approx. Time Frame	Number of Workers	Vehicles and Equipment	Number of Trips
Construction of well pad and access road	1 week	5 to 6	2 Bulldozers	2 (1/wk per dozer)
			2 Scrapers	2 (1/wk per scraper)
			Grader	1 (1/wk)
			Water Truck	35 (5/day)
			Worker's Vehicles	28 (4/day)
Well Drilling	300 days	5 to 6 during drilling phase, 10 during cementing & casing	Rig set-up (semi trucks)	200 (20/day for 10 days)
			Maintenance (pickup)	300 (1/day)
			Well logging	3 (1/day, 3 separate days)
			Semi-truck carrying casing	30 (5/day, 6 separate days)
			Semi-truck carrying drilling steel	8 (1/day, 8 separate days)
			Service trucks (mud, bits, special equipment)	86 (2/wk)
			Water trucks	600 (2/day)
			Worker's vehicles	1800 (96/day)
			Salesmen's vehicles	86 (2/wk)
Well Testing and Completion[1]	1 week to 1 month	4 (during testing), 10 to 12 (during completion)	Truck carrying tubing, packers	6 (3/day for 2 days)
			Truck carrying wellhead	1 (1 in 1 day)
			Truck carrying testing tools	12 (3/wk)
			Truck carrying perforation tools	3 (1/day for 3 days)
			Pump & bulk loads	10 (5 on 2 separate days)

Table 4-10 (cont). Dillon FO Oil and Gas Activity Vehicle Trips

Activity	Approx. Time Frame	Number of Workers	Vehicles and Equipment	Number of Trips
Placement of production facilities	1 week	4 to 5	Truck carrying meter device	1 (1/wk)
			Truck carrying pipe fittings, etc.	1 (1/wk)
			Truck carrying dehydrator	1 (1/wk)
			Truck carrying tank	3 (3/wk)
			Backhoe	1 (1/wk)
			Worker's vehicles	28 (4/day)
Pipeline Construction-per mile	1 week	5 to 8	Trencher	1 (1/wk)
			Dozer	1 (1/wk)
			Welding truck	14 (2/day)
			Pipeline truck	5 (5/wk)
			Worker's vehicles	28 (4/day)
Abandonment/ Reclamation	3 weeks	5 to 6	Workover rig and associated equipment	24 (3/day for 8 days)
			Dozer, scraper & road grader	3
			Maintenance (pickup truck)	21 (1/day)
			Semi-truck for equipment hauling	3
			Service trucks	4
			Worker's vehicles	126 (6/day)

[1] The drilling rig is typically used to set the casing. A completion rig (smaller in size) is used to complete well for production.

The reserve pit is 125 ft x200 ft x12 ft deep; lined with 8–10 mil reinforced nylon/ plastic. Its location is fixed by rig location.

Access Road Culverts would be added if stream channels must be crossed, but operators usually would lengthen road to avoid drainages to minimize maintenance and to maintain maximum grade of 10% or less.

In extreme terrain or remote locations, the company may put up camps at drill site. Additional buildings (portable) for sleeping quarters and cooking and eating are used. Camp crew includes a cook and an assistant cook. Support facilities include septic systems and refrigerated food storage. Camp jobs eliminate some traffic due to shift changes.

Water trucks would make several trips per day (fresh water required to drill through all fresh water aquifers ranging from 600 ft to 2500 ft below surface, at rate of 10 bbl per ft). About 40,000 bbl of water required to drill remainder of well unless lost circulation problems occur, then more water required. A separate water truck may make 2–3 trips per day to spray fresh water on roads for dust control. Water source well is usually drilled for rank wildcat wells.

4.4. Hi-Line Planning Area Drilling Activity Forecast (20-Year Forecast)

The Hi-Line Planning Area drilling activity forecast covers a 20-year time frame and is based on information contained in the Hi-Line RFD. The RFD is a 2009 unpublished report that is available from the BLM.

4.4.1. Projected Oil and Gas Drilling Activity

The Hi-Line Planning Area contains about 15,873,473 surface acres of all mineral ownership types. Total Federal oil and gas mineral ownership, in the Planning Area, amounts to about 4,307,538 acres, or about 27 percent of total acres. The BLM manages most of the Federal oil and gas mineral lands in the Planning Area (81 percent). About 1,151,548 acres of state and private surface lands within Planning Area boundaries overlie BLM managed oil and gas mineral lands. All BLM managed oil and gas mineral lands will be covered by decisions made in the associated RMP EIS. BLM managed oil and gas mineral lands are lowest in Glacier County (about 6,165 acres), Liberty County (about 53,964 acres), Hill County (about 72,419 acres), Chouteau County (about 112,272 acres) ,and Toole County (about 113,879 acres). The remaining three counties (Blaine, Phillips, and Valley) contain the remaining 3,121,468 acres of BLM managed oil and gas mineral lands.

Smaller amounts of Federal oil and gas mineral lands within the Hi-Line Planning Area are managed by the National Park Service (8 percent), National Wildlife Refuges (8 percent), U.S. Forest Service (0.7 percent), and other minor ownership agencies.

4.4.2. General Assumptions

4.4.2.1. Conventional Oil & Gas

- During the 20-year planning cycle of 2007 to 2026, as many as 6,866 wells will be drilled in the Planning Area.
- Up to 150 of these wells could be CBNG wells.
- Of the 6,716 remaining wells, 1,351 wells are projected to lie within the Bowdoin Dome area.
- High development potential indicates areas where the estimates average drilling density will exceed 100 well locations per township during 2007 to 2026.
- Moderate development potential indicates 20 to 100 wells per township.
- Low development potential indicates 2 to 20 well locations per township.
- Very low development potential is defined as 2 wells or less per township.
- Average well depths will remain in the present range (less than 6,000 feet with a few deep wells on the edge of the Montana Thrust Belt). (See below)

4.4.2.2. Coal Bed Natural Gas

- The potential for coal bed natural gas in the Hi-Line Planning Area does not appear to be as large as in other parts of the state.
- Only areas of very low potential and no potential were outlined. Areas of very low development potential are defined as averaging 2 wells or less per township.
- Areas of known coal strata at shallow depths (less than 3,000 feet) were assigned a very low development potential.
- This is a hypothetical play.

4.4.2.3. Producing Zones

- Oldest —Birdbear (Nisku) Devonian Age
- Youngest —Upper Cretaceous Judith River

4.4.3. Potential Surface Disturbance (Baseline Projection)

The following tables present estimates of short- and long-term surface disturbance associated with the baseline projection of wells that could be drilled for the period of 2007 through 2026. The top portion of the material shows wells that could be drilled and existing unplugged wells. It also includes associated short-term disturbance.

Table 4-11. Hi-Line Planning Area Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)

Wells			Acres of Surface Disturbance			
Type	**Total**	**BLM Managed**	**Access Roads/ Flow Lines**	**Well Pad**	**Total**	**BLM Managed**
New Exploratory and Development Wells – Coal bed gas	150	24	1.85	1	428	68
New Exploratory and Development Wells - Bowdoin Dome Area	1,351	776	1.85	1	3,850	2,212
New Exploratory and Development Wells - Rest of Planning Area	5,365	1,447	3.1	2.1	27,898	7,527
Existing Wells - Bowdoin Dome Area	1,706	988	0.25	0.5	1,280	741
Existing Wells - Rest of Planning Area	7,176	571	0.78	0.14	6,602	525
Total Wells/Disturbance	**15,748**	**3,806**			**40,057**	**11,073**

Table 4-12. Hi-Line Planning Area Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)

Wells			Acres of Surface Disturbance			
Type	Total	BLM Managed	Access Roads/ Flow Lines	Well Pad	Total	BLM Managed
New Exploratory and Development Wells – Coal bed gas	135	22	0.25	0.5	101	16
New Exploratory and Development Wells - Bowdoin Dome Area	1,310	753	0.25	0.5	983	565
New Exploratory and Development Wells - Rest of Planning Area	4,118	1,111	0.78	0.14	3,788	1,022
Existing Wells - Bowdoin Dome Area	1,573	911	0.25	0.5	1,180	683
Existing Wells - Rest of Planning Area	5,533	440	0.78	0.14	5,090	405
Total Wells/Disturbance	**12,669**	**3,236**			**11,142**	**2,691**

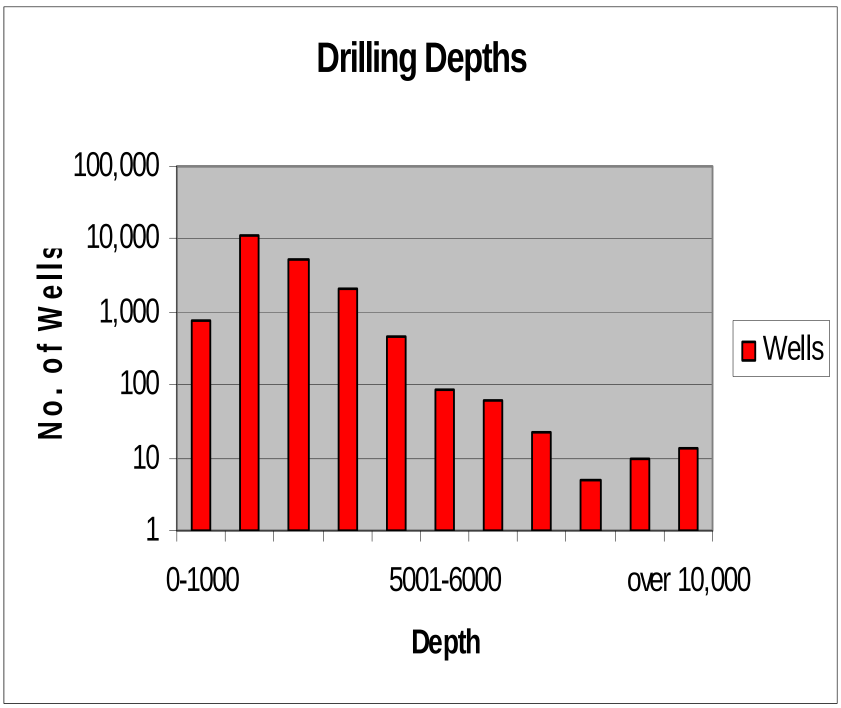
Table 4-13. Hi-Line Planning Area Baseline Projected New Producing Well Numbers, and Oil and Gas Production for All Producing Well and for All Federal Producing Wells, 2007–2026

Year	Gas Produced (mcf[1])	Oil Produced (mbo[2])	New Oil Wells	New Gas Wells	Total New Producing Wells	New Federal Oil Wells	Federal Oil Produced (mbo[2])	New Federal Gas Wells	Federal Gas Produced (mcf[1])	Federal Wells Abandoned
2007	56,000	1,227	11	240	251	1.29	144	84.96	19,825	10.4
2008	56,000	1,202	11	245	256	1.29	141	86.66	19,807	10.4
2009	56,000	1,178	11	250	261	1.29	138	88.35	19,790	10.4
2010	56,000	1,155	11	255	266	1.29	136	90.04	19,774	10.4
2011	56,000	1,132	11	260	271	1.29	133	91.73	19,758	10.4
2012	56,000	1,109	11	265	276	1.29	130	93.43	19,743	10.4
2013	56,000	1,087	11	270	281	1.29	128	95.12	19,728	10.4
2014	56,000	1,065	11	275	286	1.29	125	96.81	19,714	10.4
2015	56,000	1,044	11	280	291	1.29	123	98.50	19,701	10.4
2016	55,440	1,023	11	260	271	1.29	120	91.73	19,560	10.4
2017	54,886	1,002	11	260	271	1.29	118	91.73	19,365	10.4
2018	54,337	982	11	260	271	1.29	115	91.73	19,171	10.4
2019	53,793	963	11	260	271	1.29	113	91.73	18,979	10.4
2020	53,255	943	11	260	271	1.29	111	91.73	18,790	10.4
2021	52,723	925	11	260	271	1.29	109	91.73	18,602	10.4
2022	52,196	906	11	260	271	1.29	106	91.73	18,416	10.4
2023	51,674	888	11	260	271	1.29	104	91.73	18,232	10.4

Table 4-13 (cont). Hi-Line Planning Area Baseline Projected New Producing Well Numbers, and Oil and Gas Production for All Producing Well and for All Federal Producing Wells, 2007–2026

Year	Gas Produced (mcf[1])	Oil Produced (mbo[2])	New Oil Wells	New Gas Wells	Total New Producing Wells	New Federal Oil Wells	Federal Oil Produced (mbo[2])	New Federal Gas Wells	Federal Gas Produced (mcf[1])	Federal Wells Abandoned
2024	51,157	870	11	260	271	1.29	102	91.73	18,049	10.4
2025	50,645	853	11	260	271	1.29	100	91.73	17,869	10.4
2026	50,139	836	11	269	280	1.29	98	94.78	17,666	10.4
Totals	**1,084,245**	**20,388**	**220**	**5,209**	**5,429**	**26**	**2,396**	**1,838**	**382,538**	**208**

[1] mcf = thousand cubic feet
[2] mbo = thousand barrels of oil



Source: IHS Energy Group (2007) and Montana Oil and Gas Conservation Division (2007).

Figure 4-1. Hi-Line Planning Area Well Drilling Depth (feet)

4.5. Lewistown Drilling Activity Forecast (20-Year Forecast)

This Lewistown FO drilling activity 20-year forecast was prepared by the Montana State Office, Branch of Fluid Minerals in July 2010.

4.5.1. General Assumptions

The Lewistown FO Planning Area contains approximately 13,135,718 surface acres (based on GIS) of all mineral ownership types, Federal, Private, and State. Total Federal oil and gas mineral ownership, in the Lewistown FO Planning Area, amounts to about 3,426,577 acres, or about 26 percent of total acres. All Bureau managed oil and gas mineral lands will be covered by decisions made in the Lewistown FO RMP EIS. The boundaries of the Lewistown FO encompass nine counties: Cascade, Choteau, Fergus, Judith Basin, Lewis and Clark, Meagher, Petroleum, Pondera, and Teton Counties. Two of these counties are only partially located within the boundaries of the Lewistown FO. Those lands located in Lewis and Clark County that lie north of the Township 15 North, and those lands in Choteau County that lie south of the Missouri River are located within the Lewistown FO. Please refer to Table 4-14 for a breakdown of the associated acreages for these counties and acreages with Federal minerals, along with the associated acreages by county for lands managed by other federal agencies. Also included are the number of authorized leases in effect with their corresponding acreages by county and the remaining unleased lands within those counties.

Table 4-14. Lewistown FO Surface, Oil and Gas Mineral Ownership, and Acres of Oil and Gas Leases by County

County	Total Federal Mineral Acres	Total Federal Surface By SMA				No. of Authorized Leases In Effect	No. of Authorized Leased Acres In Effect	Remaining Unleased Federal Minerals
		BLM	BOR	USFS	NWR			
Pondera	177,119	1,358	0	106,831	1,020	61	66,816	110,303
Petroleum	264,668	331,627	0	0	55,563	103	72,576	192,092
Teton	365,996	17,489	23,112	230,506	1,293	8	2,709	363,287
Fergus	702,503	348,228	0	94,232	49,687	52	33,720	668,783
Cascade	242,776	24,757	1,343	179,005	7,090	0	0	242,776
Judith Basin	326,305	12,256	0	298,888	0	0	0	326,305
Lewis and Clark	739,636	9,381	5,112	669,957	0	2	199	739,437
Meaghar	481,241	8,641	0	473,436	0	13	21,034	460,207
Choteau	126,333	66,000	0	30,741	1,200	4	4,016	122,317
TOTALS	**3,426,577**	**819,737**	**29,567**	**2,083,596**	**115,853**	**243**	**201,070**	**3,225,507**

4.5.2. Oil and Gas Resources

A petroleum system exists wherever certain essential geologic elements and processes occur together in time and place. The essential geologic elements of a petroleum system include the presence of a source rock, reservoir rock, seal rock, and overburden rock. Formation of the trap, and the generation, migration, and entrapment of hydrocarbons are the two processes involved with a petroleum system. These essential geologic elements and processes must be correctly placed in time and space so that organic matter in a source rock can be converted into petroleum, which then migrates and accumulates into a hydrocarbon trap (Magoon and Beaumont, 1999). The absence of any essential geologic element or process prevents the accumulation of hydrocarbons into a trap.

There are effective petroleum systems present within the study area, as evidenced by the presence oil and gas fields in Pondera, Petroleum, Teton, Fergus, and Cascade counties.

4.5.3. Total Wells Drilled Per Year

It is assumed that future drilling rates and the number of successful wells during the 20-year planning period will be similar to what has occurred during the past 20 years.

Based upon the BLM's AFMSS (Automated Fluid Minerals Support System) well database, IHS Energy's well database, and the Montana Board of Oil and Gas well database, there are approximately 3,600 wells drilled within the study area. Figure 4-2 is a graph illustrating the total number of wells drilled within the jurisdiction of the Lewistown FO by decade. It is interesting to note the high level of activity during the 1920s, and from most of the 1950s through the 1990s. However, during the past couple of decades the study area has received relatively little interest from the oil industry compared to prior decades, when more than 50 wells were drilled per year during some years.

Figure 4-3 is a graph illustrating the total number of wells drilled within the jurisdiction of the Lewistown FO since 1986.

Based upon historical drilling during the past 20 years, it is anticipated that between 0 and 35 wells will be drilled per year during the 20-year planning period, with a most-likely estimate of about 12 wells drilled per year. It is further estimated that out of the average 12 wells expected to be drilled per year, 0–2 wells will be drilled on Federal mineral lands and 0–10 wells will be drilled per year on Private and State mineral lands.

It is possible that more or less wells will be drilled in the future during the 20-year planning period than anticipated in this document if events occur that are unforeseen, unexpected, or impossible to predict at this time. Such unanticipated events may include new technological advancements, large changes in oil and gas prices, large changes in global energy supply and demand patterns, and other global events such as war, oil embargos, etc.

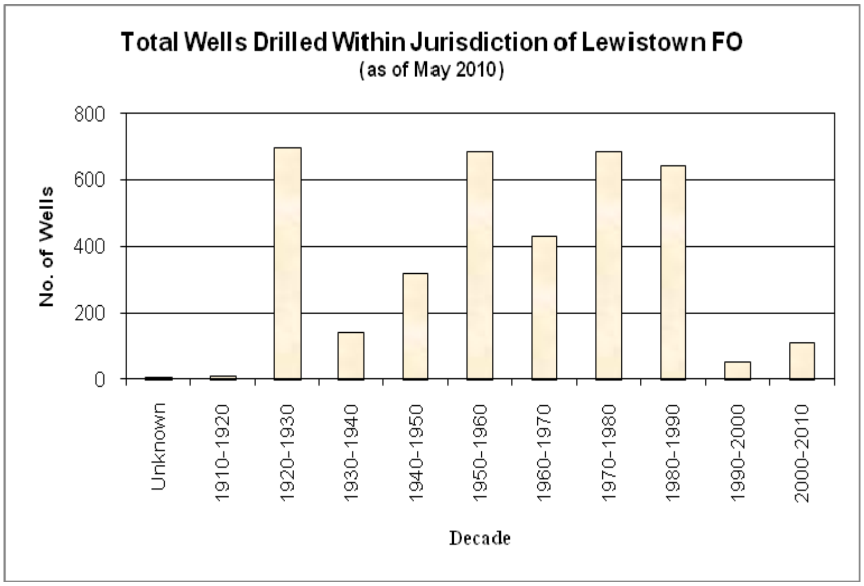


Figure 4-2. Total Wells Drilled Within the Lewistown Study Area by Decade

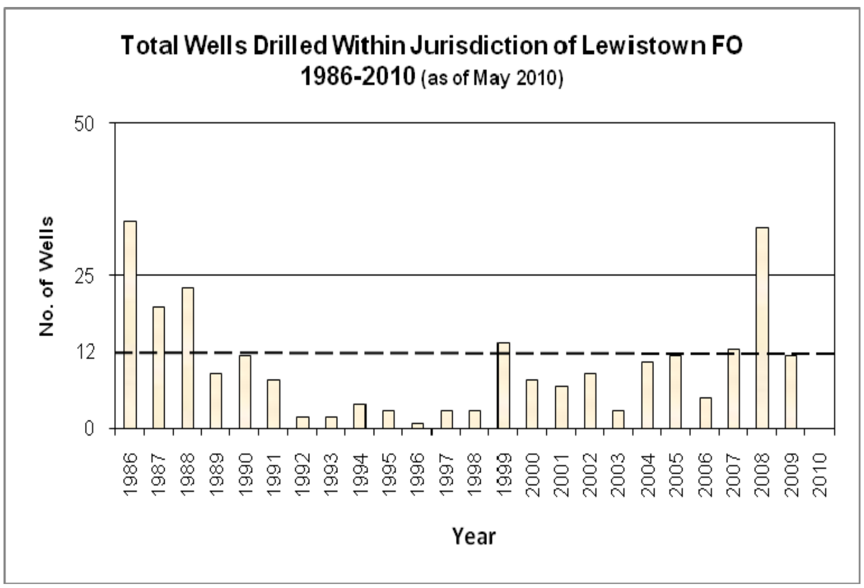


Figure 4-3. Total Wells Drilled Within the Lewistown Study Area by Year 1996 Through May 2010

Out of the approximately 3,600 wells drilled within the study area, about 12 percent of the wells were drilled on Federal mineral lands and about 88 percent of the wells were drilled on Private/State mineral lands. It is anticipated that future wells drilled within the study area will be respectively drilled on Federal and Private/State mineral lands in the same relative percentages as in the past.

There are approximately 472 wells within the study that are producing either oil or gas. Approximately 74 percent of all producing wells are oil wells and 26 percent are gas wells.

About 9 percent of all producing oil wells (POW) are located on Federal mineral lands and about 7 percent of all producing gas wells (PGW) are located on Federal mineral lands. It is anticipated that future productive wells drilled on Federal mineral lands within the study area will respectively produce oil and gas in the same relative percentages as in the past. The success rate for a well drilled on either Federal or Private and State (non-Federal) mineral land is assumed to be approximately 30 percent.

The formula used to estimate the number of POW drilled per year on Federal mineral lands within the study area during the 20-year planning period is as follows:

= Estimated number of wells drilled per year × success rate × % POW × % Federal POW
= 12 × 30% × 74% × 9%
= 0.24 Federal POW drilled per year

The formula used to estimate the number of PGW drilled/year on Federal mineral lands within the study area during the 20-year planning period is as follows:

= 12 × 30% × 26% × 7%
= 0.07 Federal PGW drilled per year

The formula used to estimate the number of POW drilled per year on Private and State mineral lands within the study area during the 20-year planning period is as follows:

= Estimated number of wells drilled per year x success rate × % POW × % Private and State POW
= 12 × 30% × 74% × 91%
= 2.42 Private and State POW drilled per year

The formula used to estimate the number of PGW drilled per year on Private and State mineral lands within the study area during the 20-year planning period is as follows:

= Estimated number of wells drilled per year × success rate × % PGW × % Private and State PGW
= 12 × 30% × 26% × 93%
= 0.88 Private and State PGW drilled per year

Thus, during the 20-year planning period, it is estimated that approximately 4 to 5 POW and 1 to 2 PGW will be drilled on Federal lands within the Planning Area (estimates are rounded whole numbers).

It is further estimated that, during the 20-year planning period, approximately 48 to 49 POW and 17 to 18 PGW will be drilled on Private and State lands within the Planning Area (estimates are rounded whole numbers). Table 4-15 shows the approximate number of Federal, Private, and State wells (non-Federal) drilled within the study area and identified by well type in each county.

Table 4-15. Approximate Number of Federal and Non-Federal Wells by Well Type in Each County Comprising the Lewistown FO

Well Type	Pondera		Petroleum		Teton		Fergus		Cascade		Judith Basin		Lewis and Clark		Meagher		Choteau		Totals	
	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.	Fed.	Non-Fed.
POW	14	210	17	36	0	102	0	0	0	0	0	0	0	0	0	0	0	0	**31**	**348**
PGW	4	111	0	0	0	8	5	5	0	0	0	0	0	0	0	0	0	0	**9**	**124**
OSI	11	206	4	34	0	80	0	0	0	0	0	0	0	0	0	0	0	0	**15**	**320**
GSI	2	32	0	0	1	13	0	5	0	0	0	0	0	0	0	0	0	1	**3**	**51**
WIW	0	26	5	10	0	9	0	0	0	0	0	0	0	0	0	0	0	0	**5**	**45**
WSW	0	2	2	27	0	2	0	24	0	17	0	7	0	1	0	4	0	15	**2**	**99**
P&A	16	871	188	571	32	523	113	335	7	83	1	52	0	23	0	6	0	91	**357**	**2,555**
TA	20	32	0	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	**20**	**35**
WDW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1**	**0**
Total	**67**	**1,490**	**217**	**680**	**33**	**738**	**118**	**369**	**7**	**100**	**1**	**59**	**0**	**24**	**0**	**10**	**0**	**107**	**443**	**3,577**

Well Type Abbreviations:

POW = Producing Oil Well
PGW = Producing Gas Well
OSI = Oil Shut-In
GSI = Gas Shut-In
WIW = Water Injection Well
WSW = Water Source Well
P&A = Plugged and Abandoned
TA = Temporarily Abandoned
WDW = Water Disposal Well

Separate graphs (Figure 4-4 through Figure 4-12) were also compiled to illustrate the historical level of drilling activity in each county comprising the study area. The counties with the higher level of drilling activity, such as Pondera County, the northern part of Teton County, and the southern part of Petroleum County, have been identified by the oil and gas industry as being geologically more prospective to contain commercial quantities of hydrocarbons than those counties which have received relatively little drilling interest.

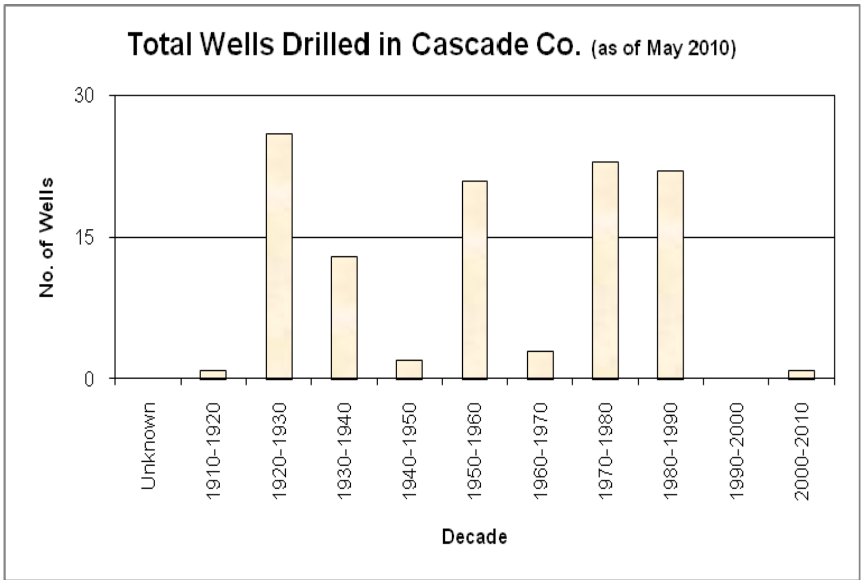


Figure 4-4. Total Wells Drilled Within Cascade County by Decade

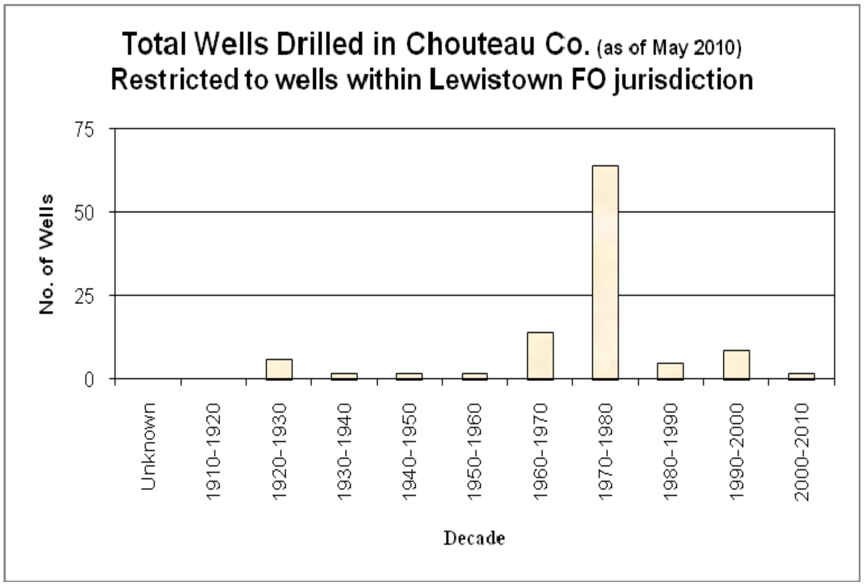


Figure 4-5. Total Wells Drilled Within That Part of Chouteau County Administered by the Lewistown FO by Decade

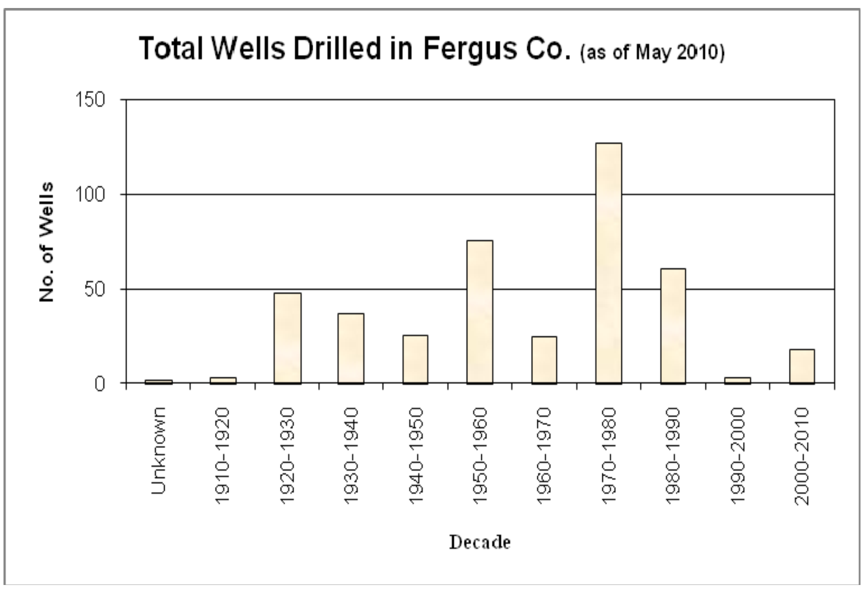


Figure 4-6. Total Wells Drilled Within Fergus County by Decade

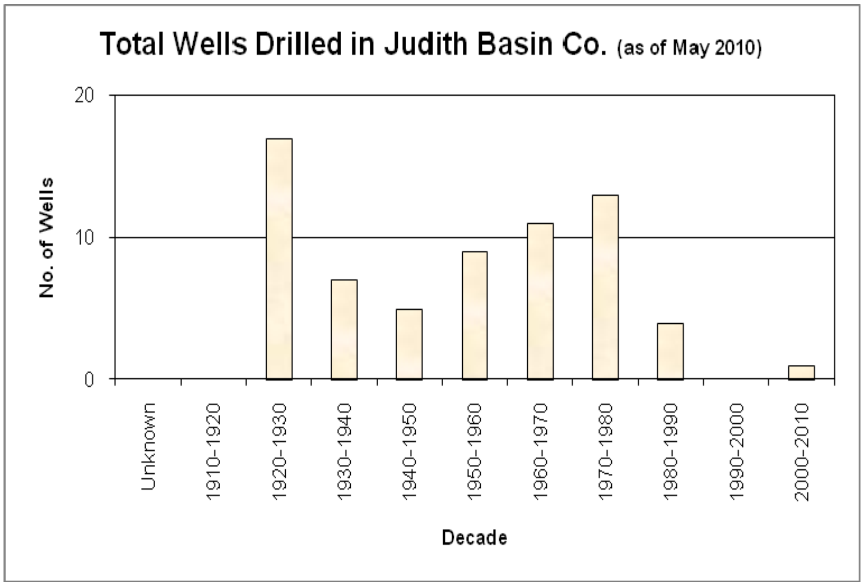


Figure 4-7. Total Wells Drilled Within Judith Basin County by Decade

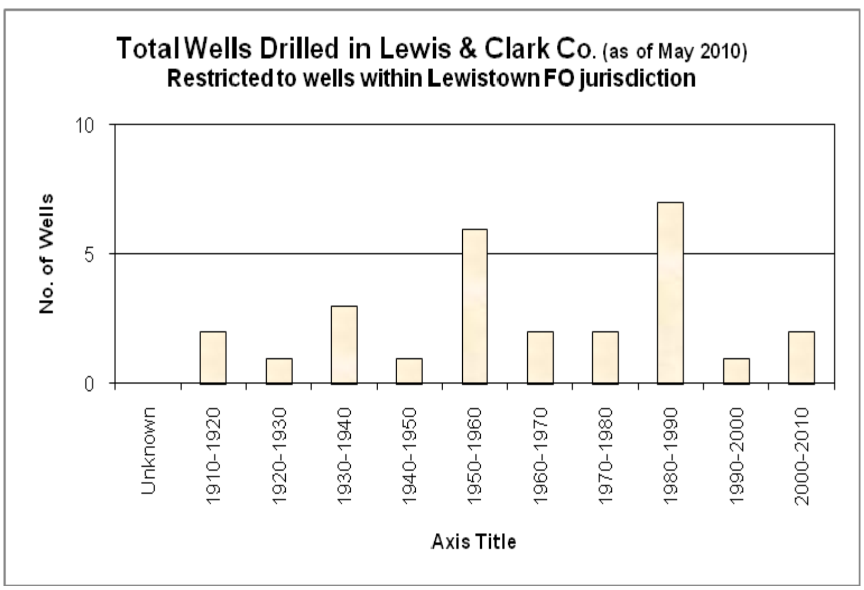


Figure 4-8. Total Wells Drilled Within Lewis & Clark County Administered by the Lewistown FO by Decade

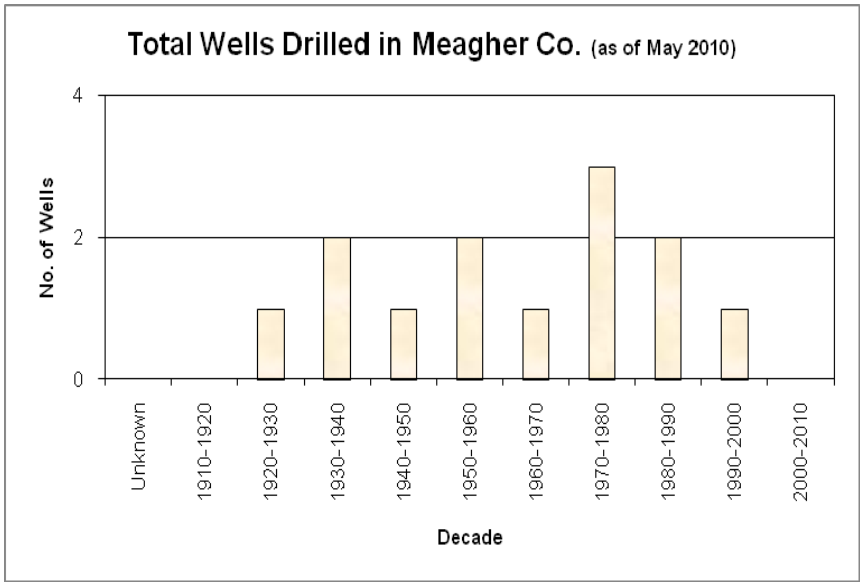


Figure 4-9. Total Wells Drilled Within Meagher County by Decade

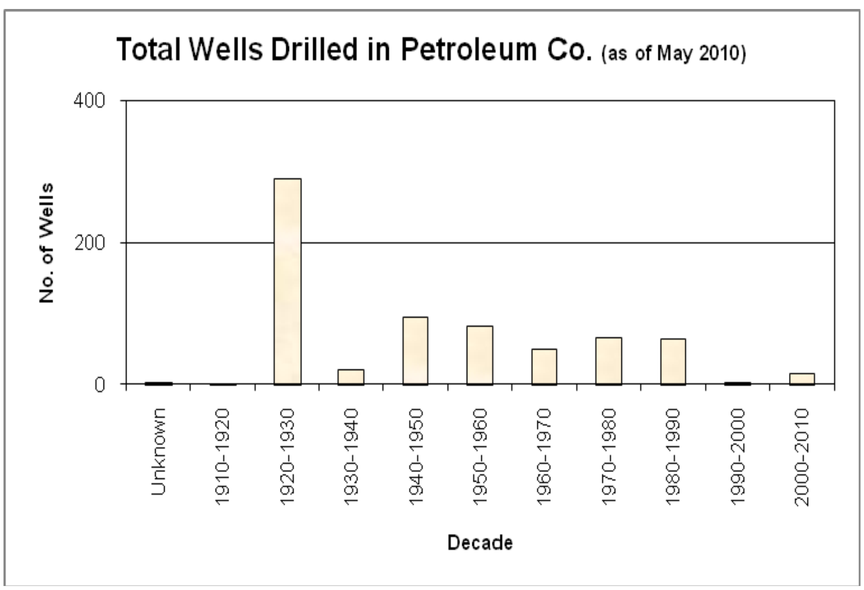


Figure 4-10. Total Wells Drilled Within Petroleum County by Decade

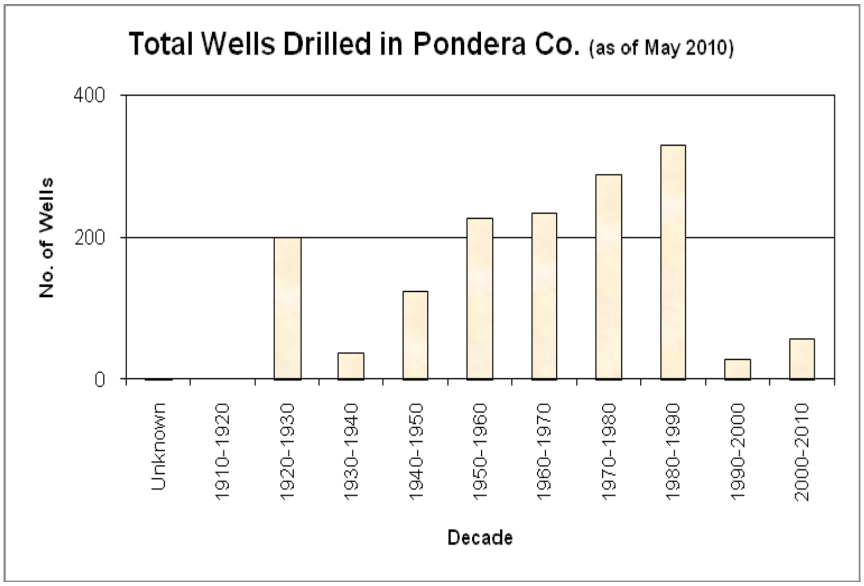


Figure 4-11. Total Wells Drilled Within Pondera County by Decade

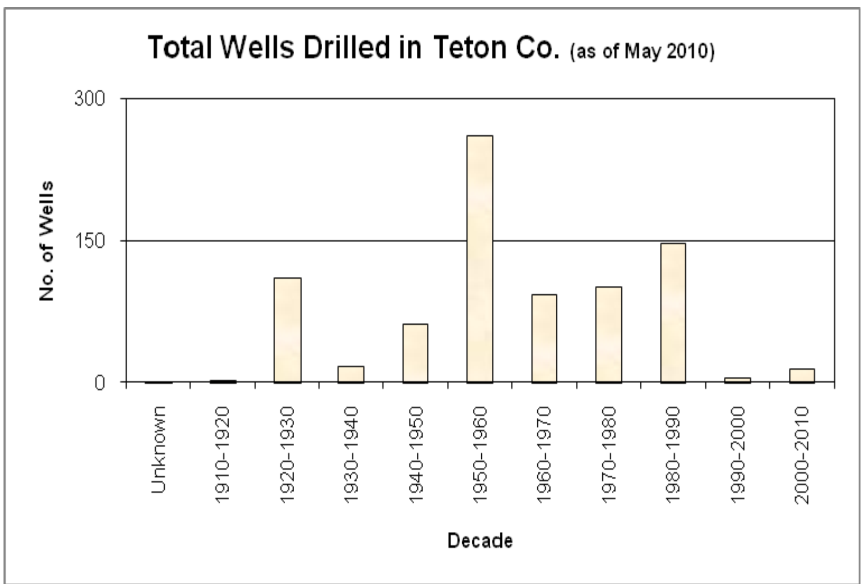


Figure 4-12. Total Wells Drilled Within Teton County by Decade

4.5.4. Well Depths

Only about six wells have been drilled within the study area to a depth greater than 10,000 feet, with the deepest well being drilled to a depth of 13,225 feet. The average depth of the wells drilled within the study area is approximately 2,300 feet. As indicated in Figure 4-13, which shows the depths of the wells drilled within the study area, a majority of the wells have been drilled to a depth between 1,000 feet and 4,000 feet. It is anticipated that most wells drilled during the 20-year planning period will be drilled to a depth between 1,000 feet and 4,000 feet.

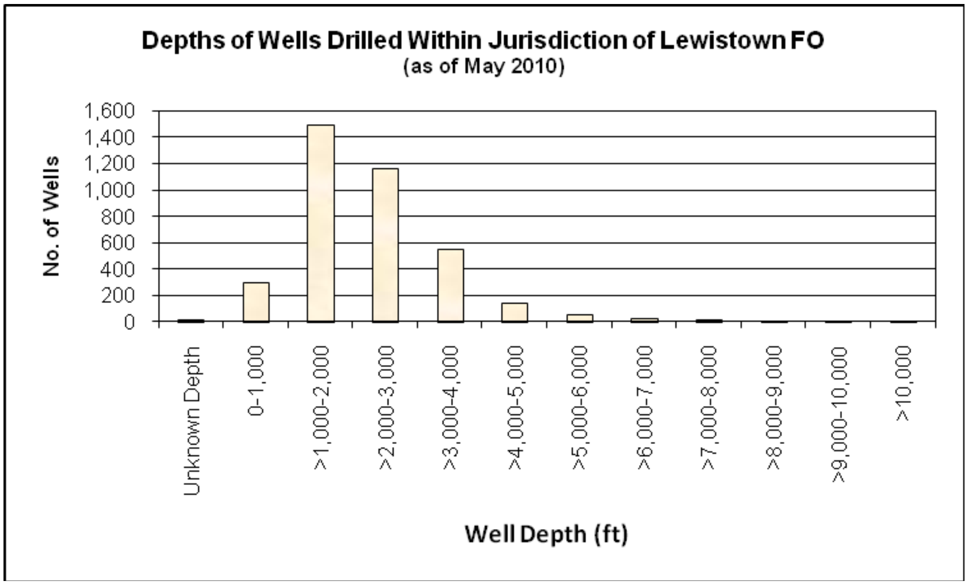


Figure 4-13. Depths of Wells Drilled Within the Study Area

Most of the wells drilled within the study area are vertical, and most future wells are also anticipated to be vertical. It is possible that some future wells will be horizontally drilled to minimize surface environmental impacts, comply with restrictions on surface occupancy, or to recover hydrocarbons that would not otherwise be economically feasible to recover with a vertical well. Approximately 74 percent of the currently producing wells are oil wells, and it is expected that most wells drilled during the 20-year planning period will be oil wells.

4.5.5. Compressors/Pipelines

Most of the production in the Lewistown FO is located in the northwestern part of the Field Office administrative area in Pondera and Teton Counties (oil and gas), directly south of the Little Missouri River in Choteau County (mostly gas), and in Petroleum County (oil and gas). Table 4-16 identifies the oil and gas fields located in those counties. In addition, since gas compressors are a necessity in those areas producing gas in order to get the gas to market, Table 4-17 identifies the locations of those gas compressors. The BLM’s records indicate no gas compressors are currently operating on Federal lands in the following counties: Chouteau, Meagher, Lewis and Clark, Judith Basin, Cascade, Fergus, and Petroleum.

Table 4-16. Oil and Gas Fields by County in the Lewistown FO Area

Pondera	Petroleum	Teton	Fergus	Cascade	Judith Basin	Lewis and Clark	Meaghar	Choteau
Brady	Brush Creek	Agawam	Armells	Otter Creek	N/A	N/A	N/A	N/A
Broken Arrow	Cat Creek	Bannatyne	Leroy					
Conrad, South	Cat Creek, Mosby Dome	Bills Coulee	Spindletop					
Crocker Springs, East	Cat Creek, West Dome	Blackleaf Canyon						
Cutbank	Kootenai	Gypsy Basin						
Dry Fork	McDonald Creek	Highview						
Fort Conrad	Oiltana	Pondera						
Gypsy Basin	Rattlesnake Butte	Pondera Coulee						
Gypsy Basin, North		Runaway						
Hardpan		Second Guess						
Highview								
Lake Francis								
Ledger								
Marias River								
Marias River, South								
Meander								
Midway								
Pondera								
Pondera Coulee								
Valier								
Williams								
Wishbone								

At this time, the BLM does not envision any additional placement of gas compressors in these areas based on the BLM's projected development and because the current infrastructure is expected to handle the current and future demand. Any change to the current infrastructure will only occur if a major gas discovery is made in areas not currently producing gas.

In regards to oil production, oil production is currently contained on existing tank batteries at each location and transported by truck to local markets. No major oil pipelines are anticipated in these areas at this time unless a major oil discovery is made in an unforeseen new resource play.

Table 4-17. Current Gas Compressors by Legal Description in the Lewistown FO Area

Operator	Size (HP)	QtrQtr	Sec.	Twp.	Rng.	County	Gas Field
Balko, Inc.	400	NESE	14	29N	2W	Pondera	Ledger
Genesis Energy	204	SENW	36	29N	5W	Pondera	Lake Francis
Genesis Energy	360	SENW	36	29N	4W	Pondera	Shelby Williams
Genesis Energy	86	?	?	?	?	Pondera	Lake Francis
Montana Star Pipeline	195	SENW	24	29N	5W	Pondera	Lake Francis
Ranck	100	?	?	?	?	Pondera	Fort Conrad
Sleepy Hollow	203	?	29	19N	19E	Fergus	?
Sleepy Hollow	203	?	29	15N	18E	Fergus	?

4.5.6. Oil and Gas Production

Based on the historical production for gas wells in the study area, the BLM has estimated that a typical gas well capable of production in these areas would ultimately produce approximately 400,000 Mcf (0.4 Bcf) of gas. At this time, it appears there has recently developed some interest by the industry in exploration in Petroleum County with the Mississippian-age Heath Formation and in Fergus County with the Eagle and Colorado Shale as the primary reservoir objectives. As of July 19, 2010, the Montana Board of Oil and Gas Conservation (MBOGC) has received and approved three drilling permits (oil) (Central Montana Resources, LLC) to test the Heath Formation in Petroleum County, and nine drilling permits (gas) (Kykuit Resources, LLC) to test the Eagle and Colorado Shale Formation in Fergus County. However, there has been no new Application for Permit (APD) recently filed on federal lands. With the varying mineral ownership within this area, it is likely that an APD may eventually be filed on federal lands within this area to evaluate these potentially emerging plays.

4.6. Miles City Drilling Activity Forecast (20-Year Forecast)

The Miles City FO drilling activity forecast covers a 20-year time frame and is based on information contained in the Miles City FO RFD. The RFD was developed in 2005 and revised in 2009; it is an unpublished report that is available by contacting the BLM.

The Big Dry RMP Record of Decision (ROD) was signed April 24, 1996. The Planning Area consists of 1.7 million acres of BLM-administered surface acres and 7.6 million acres of BLM-administered mineral resources.

The Powder River RMP ROD was signed March 15, 1985. The Planning Area in southeastern Montana consists of 1,080,675 surface acres of land and 4,103,700 acres of subsurface minerals (including minerals in Custer National Forest).

4.6.1. General Assumptions

RFD development included the following assumptions.

- Projections are based on activity through 2004/2005 (with some updates).
- The RFD incorporates the projections from the Supplementary Environmental Impact Statement (SEIS) for CBNG activity.
- Well depth ranges are provided in the following figures.
- See page 4-22 through 4-25 of the Miles City RFD document for production profiles.

Table 4-18. Miles City FO RMP Area Predicted New Well Development

Develop Area/ Well Type	Total Wells Drilled		Total Producing Wells		Federal Producing Wells		Tribal Producing Wells		State Producing Wells		Private Producing Wells	
	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
Williston NE												
Oil	1,520	761	1,246	624	46	23	18	9	68	34	1,114	558
Gas	0	0	0	0	0	0	0	0	0	0	0	0
Total	**1,520**	**761**	**1,246**	**624**	**46**	**23**	**18**	**9**	**68**	**34**	**1,114**	**558**
Cedar Creek Anticline												
Oil	3,149	1,568	2,581	1,285	602	300	0	0	165	82	1,812	903
Gas	9,666	1,336	7,922	1,095	1,844	255	0	0	508	70	5,570	770
Total	**12,815**	**2,904**	**10,503**	**2,380**	**2,446**	**555**	**0**	**0**	**673**	**152**	**7,382**	**1,673**
Poplar Dome												
Oil	105	54	86	44	3	1	37	19	1	0	45	24
Gas	501	0	410	14	0	0	176	0	5	0	215	0
Total	**105**	**54**	**496**	**44**	**3**	**1**	**37**	**19**	**1**	**0**	**260**	**24**
Williston Basin Other												
Oil	28	15	23	12	4	2	1	1	2	1	16	8
Gas/CBNG	100	0	0	0	0	0	0	0	0	0	0	0
Total	**128**	**15**	**23**	**12**	**4**	**2**	**1**	**1**	**2**	**1**	**16**	**8**
Powder River Basin												
Oil	844	192	805	183	191	46	44	10	54	12	516	115
Gas	126	29	120	28	29	7	7	1	8	2	76	18
CBNG	15,635	5,485	14,072	4,895	6,954	2,420	3,600	1,253	900	313	2,618	909
Total	**16,605**	**5,706**	**14,997**	**5,106**	**7,174**	**2,473**	**3,651**	**1,264**	**962**	**327**	**3,210**	**1,042**
Porcupine Dome												
Oil	67	37	55	30	10	5	0	0	4	2	41	23
Gas	501	0	411	0	75	0	0	0	30	0	306	0
Total	**568**	**37**	**466**	**30**	**85**	**5**	**0**	**0**	**34**	**2**	**347**	**23**

Table 4-18 (cont). Miles City FO RMP Area Predicted New Well Development

Develop Area/ Well Type	Total Wells Drilled		Total Producing Wells		Federal Producing Wells		Tribal Producing Wells		State Producing Wells		Private Producing Wells	
	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
MCFO Other												
Oil	66	33	54	27	14	7	0	0	3	2	37	18
Gas	1,056	0	864	0	224	0	0	0	48	0	592	0
Total	**1,122**	**33**	**918**	**27**	**238**	**7**	**0**	**0**	**51**	**2**	**629**	**18**
MCFO RMP Total												
Oil	5,779	2,660	4,850	2,206	870	384	100	39	297	133	3,583	1,650
Gas	11,850	1,364	9,727	1,123	2,186	262	183	1	599	72	6,759	788
CBNG	15,735	5,485	14,072	4,895	6,954	2,420	3,600	1,253	900	313	2,618	909
Total	**33,364**	**9,509**	**28,649**	**8,223**	**10,010**	**3,066**	**3,883**	**1,293**	**1,796**	**518**	**12,960**	**3,347**

Table 4-19. Miles City FO Level of Disturbance for CBNG Wells and Associated Production Facilities

Facilities	Exploratory Well Disturbance (acres/well)	Construction Disturbance (acres/well)	Operation / Production Disturbance (acres/well)
Well Sites	0.25	0.25	0.05
Access Roads/Routes to Well Sites			
Two -track	N/A	0.3	0.3
Graveled	N/A	0.1	0.1
Bladed	0.75	0.075	0.1
Utility Lines			
Water	N/A	0.35	…..[1]
Overhead Electricity	N/A	0.2	0.2
Underground Elec.	N/A	0.35	…..[1]
Transportation Lines			
Low Pressure Gas	N/A	0.9	…..[1]
Intermediate Pressure Gas	N/A	0.25	…..[1]
Processing Area			
Battery Site	N/A	0.02	0.02
Access Roads	N/A	0.15	0.15
Field Compressor	N/A	…..	0.02 (0.5 acres per 24 producing wells)
Sales Compressor	N/A	…..	0.005 (1 acre per 240 producing wells)
Plastic Line	N/A	…..	0.5 [2]
Gathering Line	N/A	…..	0.25
Sales Line	N/A	…..	0.075
Produced Water Management			
Discharge Point	N/A	0.01	0.002
Storage Impoundment	N/A	0.3	0.25
Total Disturbance	**1**	**3.25**	**2**

[1] The operation disturbance for utilities assumes all utilities will be completed underground, and the land surface will be reclaimed so that no disturbance should remain except where noted.
[2] Plastic lines within the processing area are assumed to disturb an average corridor with of 25 feet.

Table 4-20. Miles City FO Level of Disturbance for Oil and Gas Wells and Associated Production Facilities

Facilities	Exploratory Well Disturbance (acres/well)	Construction Disturbance (acres/well)	Operation/ Production Disturbance (acres/well)
Well Pad [1]			
Pad is 360-foot by 360-foot during drilling and construction, 200-foot by 200-foot during operations	3	3	1
Access Roads to Well Sites			
Two-Track (12-foot wide by 0.21 miles long)	N/A	0.3	0.3
Graveled (12-foot wide by 0.075 miles long)	0.5	0.1	0.1
Bladed (12-foot wide by 0.05 miles long)	0.5	0.075	0.075
Utility Lines [2]			
Water lines (15-foot by 0.2 miles)	N/A	0.35	1
Overhead Elec. (10-foot by 0.15 miles)	N/A	0.2	0.2
Underground Elec. (15-foot by 0.20 miles)	N/A	0.35	0
Transportation Lines			
Intermediate Pressure Gas line to and from field compressor (25-foot by 0.08 miles)	N/A	0.25	0.0001
High Pressure Gas or Crude Oil Gathering Line (25-foot by 0.3 miles)	N/A	0.9	0.2
Processing Areas			
Tank Battery (one 0.50-ac tank battery per 12.5 wells)	N/A	0.02	0.04
Access Roads (25-foot by 0.05 miles)	N/A	0.15	0.15
Field Compressor (0.5-acre pad per 12.5 wells)	N/A	0.2	0.04
Sales Compressor (2-ac pad for 240 wells)	N/A	0.01	0.01
Sales Line (25-foot by 6 miles per 240 wells)	N/A	0.075	0.075
Produced Water Management			
Produced Water pipeline (25-foot by 0.3 miles)	N/A	0.9	0.2
Water plant/ Injection well (6 ac site per 12.5 wells)	N/A	0.25	0.5
Total Disturbance per Conventional Oil or Gas Well (acres)	**4**	**7.1**	**3**

[1] It is assumed that each conventional oil and gas well will need product pipeline and produced water line from the well. In addition, some wells will need intermediate pipeline run from the field compressor to sales line.
[2] The operation disturbance for utilities assumes all utilities will be completed underground, and the land surface will be reclaimed so that no disturbance should remain except where noted.

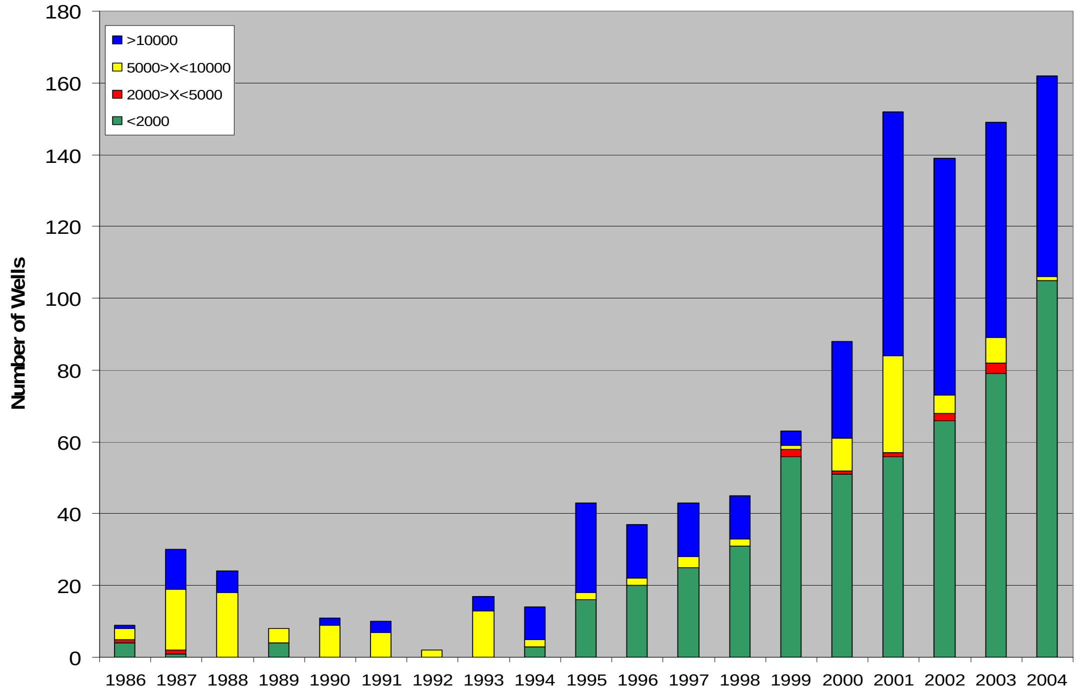


Figure 4-14. Wells Drilled per Year by Depth (feet) Within the Cedar Creek Anticline

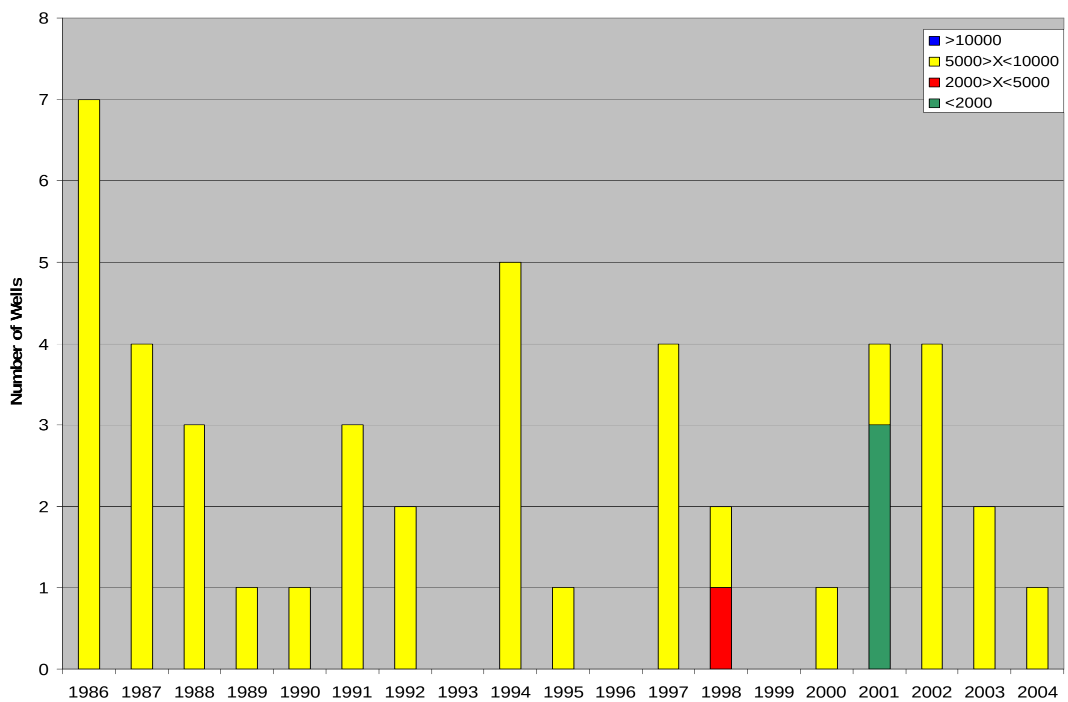


Figure 4-15. Wells Drilled per Year by Depth (feet) Near the Poplar Dome, 1986–2004

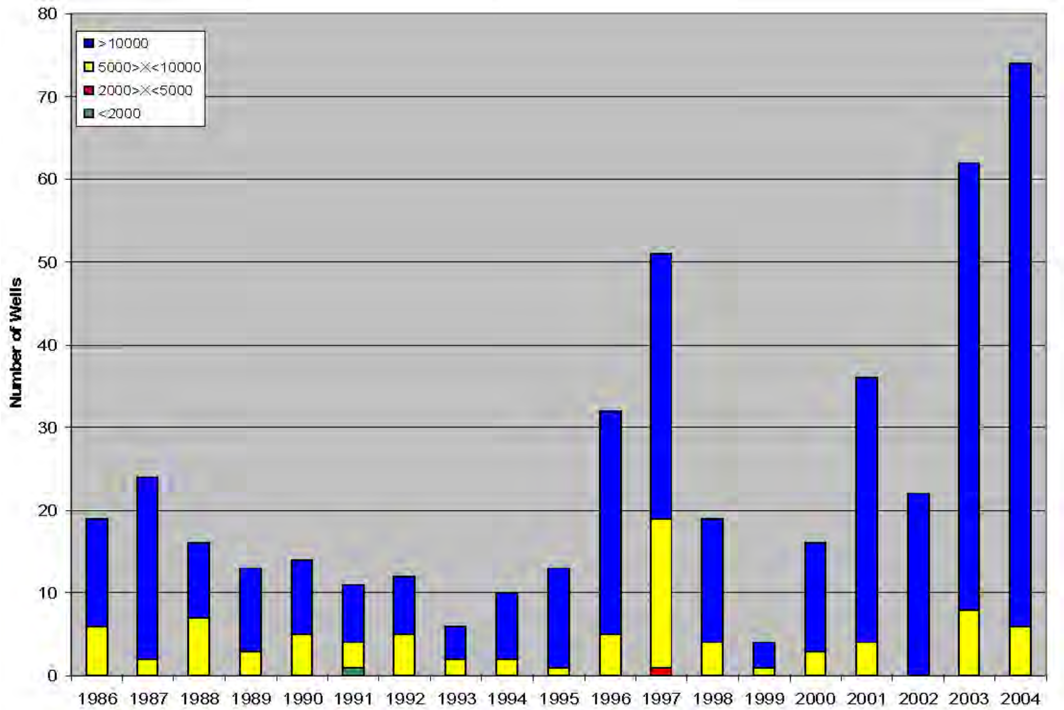


Figure 4-16. Wells Drilled per Year by Depth (feet) Within Williston Basin Northeast

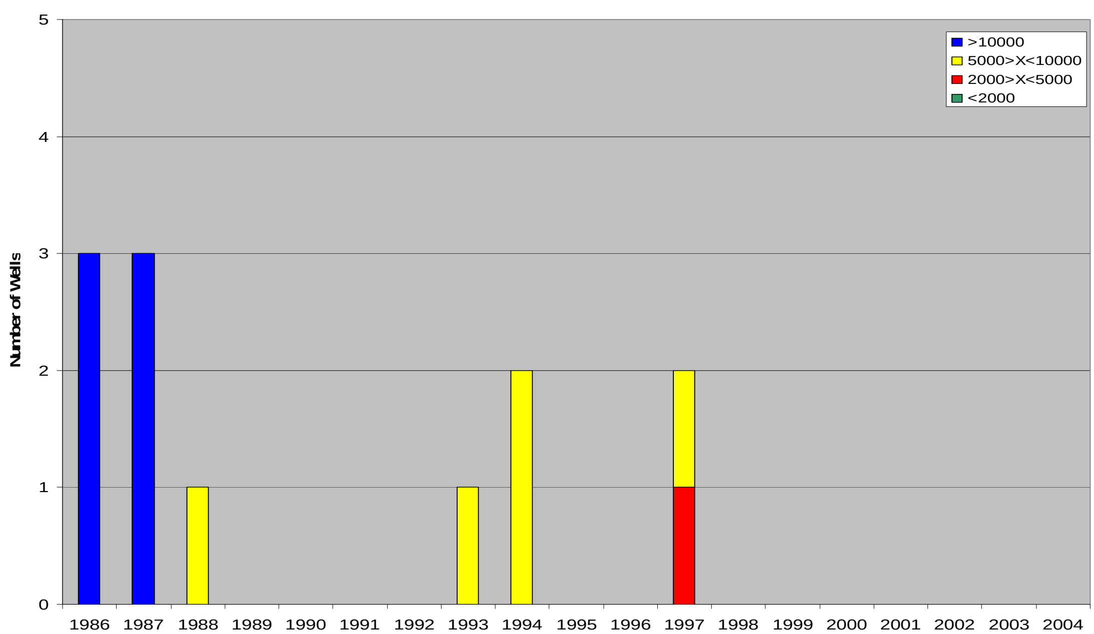


Figure 4-17. Wells Drilled per Year by Depth (feet) Within the Other Williston Basin Areas, 1986–2004

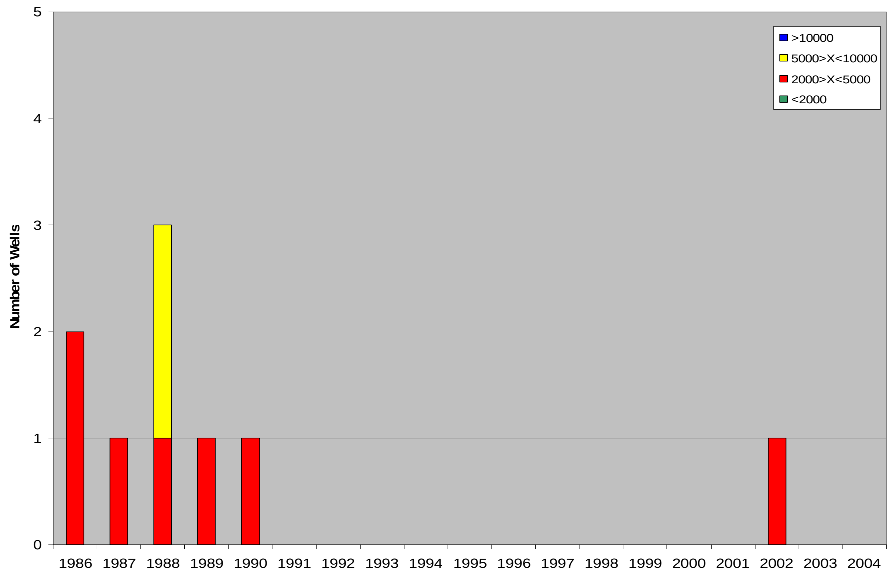


Figure 4-18. Wells Drilled per Year by Depth (feet) Near the Porcupine Dome Area

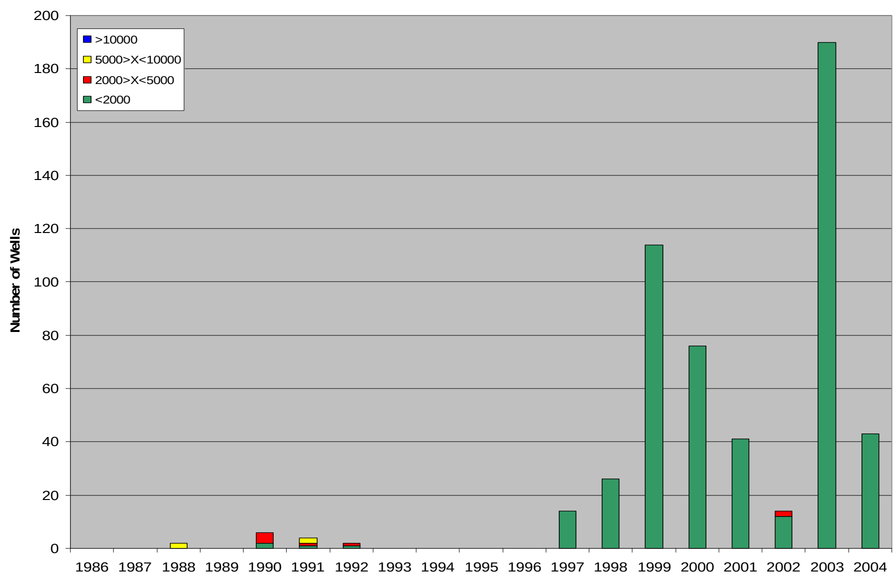


Figure 4-19. Wells Drilled per Year by Depth (feet) Within the Powder River Basin

4.7. North Dakota Drilling Activity Forecast (20-Year Forecast)

The North Dakota FO drilling activity forecast covers a 20-year time frame and is based on information contained in the *Reasonable Foreseeable Development Scenario for Oil and Gas Activities on Bureau Managed Lands in the North Dakota Study Area* (BLM 2009a). The Study Area contains about 25,430,243 surface acres of all oil and gas mineral ownership types. The BLM manages about 56,486 acres where there is available Geographical Information System

(GIS) data (the western two thirds of the Study Area). In the counties east of the GIS data, an additional 2,129.67 acres of BLM managed surface includes the following areas.

- Bottineau 0.05 acres
- McHenry 921.94 acres
- Pierce 39 acres
- Ward 40 acres
- McLean 44.40 acres
- Sheridan 192.5 acres
- Burleigh 144.97 acres
- Kidder 38 acres
- Oliver 38 acres
- Morton 124.57 acres
- Emmons 2.49 acres
- Sioux Reservation lands – no BLM lands
- Grant 543.75 acres

Total Federal oil and gas mineral ownership, in the Study Area, amounts to about 986,324 acres, or about 3.9 percent of total acres.

The BLM manages about 324,269 acres of oil and gas minerals within the Study Area.

4.7.1. General Assumptions

4.7.1.1. Conventional Production

Areas have been classified based on estimated average drilling densities for each township (one township is approximately 36 square miles). Figure 34 of the RFD (BLM 2009a), illustrates estimated drilling densities in accordance with the following density definitions.

- Very High: >20 wells
- High: 10–20 wells
- Moderate: 2 to <10 wells
- Low: 1 to <2 wells
- Very Low: <1 wells

4.7.1.2. CBNG

CBNG development is a hypothetical play. Pilot projects in the Study Area will contain 16 to 25 wells. A projection of 150 new coal bed gas wells will allow some exploration activity and preliminary development if a newly discovered play is determined economic to produce. (See Figure 36 of the RFD [BLM 2009a]).

4.7.1.3. Horizontal Drilling

Marathon Oil Company has reported drilling performance information for their Bakken Formation horizontal drilling in the Study Area (Roberts et al., 2008). The company reports the following well characteristics.

- The average lateral length is 9,300 ft
- Spud to total depth is 31 days
- Spud to first production is 61 days

Directional and horizontal drilling depths (measured depth) in the study area range from 4,413 to 21,727 feet for oil wells, and 4,173 to 19,954 feet for gas wells. However, most of the oil wells have a measured depth that is within the 13,000 to 16,000 foot range; and the measured depth of gas wells are typically within the 13,000 to 14,000 foot range. Most of the gas production is from the Mississippian-age. As of August, 2008, there were a total of 40 active horizontal and directional injection wells in the Study Area (21 water injection, 15 air injection, and 4 gas injection). The majority of the injection wells are horizontal wells to the Red River Formation in southwestern Slope and Bowman counties.

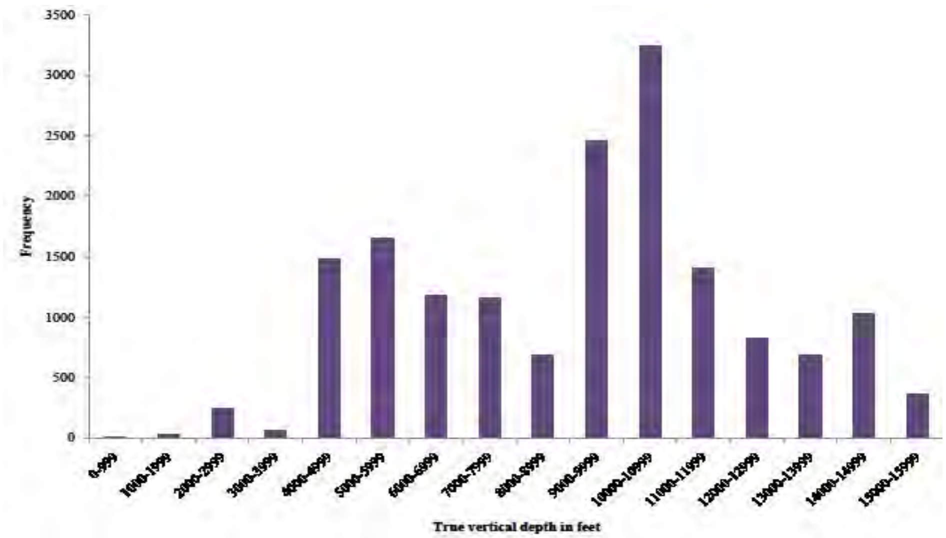
4.7.1.4. Vertical Wells

The majority of oil and gas wells in the Study Area have traditionally been drilled vertically. Of the 2,983 wells spud between January 1998 and December 2007 (Figure 22 in the RFD [BLM 2009a]), only 787 were vertical wells (IHS Energy Group, 2008). In 2007, only 64 (12 percent) of the 537 wells spud were vertical. The vertical wells producing in the Study Area are completed in a variety of formations for both gas and oil. To date, the most productive horizons for vertical completions have been those of the Mississippian Madison Group including the Charles, Mission Canyon, and Lodgepole formations, and the Ordovician Red River Formation.

Vertical well depths in North Dakota range from a few hundred feet in the northeastern portion of the Study Area, to over 15,000 feet near the center of the Williston Basin in McKenzie County. The deepest productive vertical well drilled to date was the Gulf Oil Corporation, Zabolotny 1-2-4A well producing oil from the Duperow Formation in the Little Knife Field of Billings County (See Figure 5 of the RFD [BLM 2009a]). The well reached a total depth of 15,380 feet.

4.7.1.5. Typical Well Depths

Figure 4-20 provides a summary of depths for vertical wells. Additional information is provided in Figure 24 of the RFD (BLM 2009a).



Source: IHS Energy Group.

Figure 4-20. Range of True Vertical Drilling Depths for Wells Drilled in the North Dakota Study Area

4.7.1.6. Surface Disturbance

Table 4-21. North Dakota FO Short-Term Surface Disturbance

Wells			Acres of Surface Disturbance			
Type	**Total**	**BLM Managed**	**Access Roads**	**Well Pad**	**Total**	**BLM Managed**
New Exploratory and Development Coal Bed Gas Wells (2010–2029)	150	16	0.6	0.5	165	18
New Exploratory and Development Gas Wells (2010–2029)	315	38	0.6	0.5	347	42
New Exploratory and Development Oil Wells (2010–2029)	8,000	912	2.6	4.3	55,200	6,293
Total New Exploratory and Development Wells	**8,465**	**966**			**55,712**	**6,352**
Existing Active Gas Wells (as of August 2008)	193	141	0.3	0.25	106	78
Projected New Gas Wells (August 2008–December 2009)	49	5	0.3	0.25	27	3
Existing Active Oil Wells (as of August 2008)	5,613	260	1.5	2	19,646	910
Projected New Oil Wells (August 2008–December 2009)	648	71	1.5	2	2,268	249
Total Existing and Projected Wells	**6,503**	**477**			**22,047**	**1,239**
Total Wells	**14,968**	**1,443**	**Total Short–Term Disturbance**		**70,508**	**7,591**

Table 4-22. North Dakota FO Long-Term Surface Disturbance

Wells			Acres of Surface Disturbance			
Type	Total	BLM Managed	Access Roads	Well Pad	Total	BLM Managed
New Producing Coal Bed Gas Wells (2010–2029)	135	6	0.3	0.25	74	6
New Producing Gas Wells (2010–2029)	293	21	0.3	0.25	161	12
New Producing Oil Wells (2010–2029)	5,597	468	1.5	1.75	18,191	1,573
Total New Producing Wells	**6,025**	**495**			**18,427**	**1,588**
Existing Active Gas Wells (as of August 2008)[1]	185	135	0.3	0.25	102	79
Projected Producing Gas Wells (August 2008 – December 2009)	45	33	0.3	0.25	25	19
Existing Active Oil Wells (as of August 2008)[1]	4,883	226	1.5	1.75	15,871	759
Projected Producing Oil Wells (August 2008 – December 2009)	577	27	1.5	1.75	1,875	90
Total Existing and Projected Wells	**5,691**	**421**			**17,873**	**948**
Total Wells	**11,716**	**917**	**Total Long-Term Disturbance**		**36,299**	**2,536**

[1] Minus abandonments during August 2008 – December 2029 period.

4.7.1.7. Drilling and Production

Table 4-23. Annual Projection of North Dakota Study Area Wells Drilled and Associated Confidence Interval, 2010–2029

Year	Low	Mean	High
2010	563	646	807
2011	449	506	616
2012	219	283	404
2013	76	153	302
2014	254	330	477
2015	296	360	501
2016	31	106	250
2017	380	435	538
2018	129	203	345
2019	185	260	405
2020	416	495	648
2021	67	139	277
2022	207	290	450

Table 4-23 (cont). Annual Projection of North Dakota Study Area Wells Drilled and Associated Confidence Interval, 2010–2029

Year	Low	Mean	High
2023	323	400	550
2024	212	289	437
2025	452	541	717
2026	770	851	1,013
2027	385	458	600
2028	278	373	555
2029	275	367	549
Total Wells	**5,967**	**7,491**	**10,441**

Table 4-24. Forecast of North Dakota Study Area Annual and Cumulative Oil and Gas Production, 2010–2029

Year	Annual Oil (bbl)	Cumulative Oil (bbl)	Annual Gas (mcf)	Cumulative Gas (mcf)
2010	45,989,017	45,989,017	71,429,711	71,429,711
2011	46,630,723	92,619,740	73,412,392	144,842,103
2012	47,264,419	139,884,159	70,244,327	215,086,430
2013	46,435,503	186,319,662	72,538,387	287,624,817
2014	48,603,354	234,923,016	75,397,072	363,021,889
2015	49,865,746	284,788,762	75,149,230	438,171,119
2016	47,872,466	332,661,228	73,866,630	512,037,749
2017	50,020,690	382,681,918	76,435,966	588,473,715
2018	50,479,396	433,161,314	76,942,422	665,416,137
2019	51,588,348	484,749,662	77,494,009	742,910,146
2020	51,133,242	535,882,904	78,157,106	821,067,252
2021	51,899,668	587,782,572	79,902,146	900,969,398
2022	52,941,423	640,723,995	78,195,035	979,164,433
2023	53,128,728	693,852,723	78,703,060	1,057,867,493
2024	54,538,729	748,391,452	77,651,026	1,135,518,519
2025	55,246,740	803,638,192	81,519,760	1,217,038,279
2026	54,485,626	858,123,818	78,291,302	1,295,329,581
2027	55,682,523	913,806,341	78,804,074	1,374,133,655
2028	55,484,742	969,291,083	85,088,333	1,459,221,988
2029	57,329,351	1,026,620,434	82,377,505	1,541,599,493

4.8. South Dakota Drilling Activity Forecast (20-Year Forecast)

The South Dakota FO drilling activity forecast covers a 20-year time frame and is based on information contained in the *South Dakota Reasonable Foreseeable Development Scenario* (BLM 2009b). The RFD is unpublished, but is available from the BLM. The South Dakota Study Area contains about 25,838,451 surface acres of all oil and gas mineral ownership types. Total Federal oil and gas mineral ownership, in the South Dakota Study Area, amounts to about 3,374,457 acres, or about 13 percent of total acres. Indian tribes and individual Allottees own about 7,028,785 surface acres, or about 27 percent of total acres. The oil and gas resource on these lands are managed for the tribes by the Bureau of Indian Affairs and the BLM. The remaining 15,435,209 acres (60 percent) is owned by state and private interests.

The U.S. Forest Service manages most of the Federal oil and gas mineral lands in the South Dakota Study Area (about 1.774 million acres, or about 53 percent). The BLM manages about 1.471million acres of the Federal oil and gas mineral lands in the Study Area (about 44 percent). All BLM managed oil and gas mineral lands will be covered by decisions made in the associated RMP EIS.

Smaller amounts of Federal oil and gas mineral lands within the Study Area are managed by the National Park Service (about 103,845 acres or about three percent), BOR (about 14,219 acres) and Military Reservations/Corps of Engineers (about 14,219 acres).

4.8.1. General Assumptions

The majority of oil and gas wells in the Study Area have traditionally been drilled vertically, but recent activity in the Red River Formation in Harding County has reversed this trend. Of the 189 wells spudded between January 1998 and December 2007, only 61 were vertical wells, with the remainder being horizontal (117) or directional (11).

All currently producing horizontal wells are in the Red River Formation and in Harding County.

The vertical wells producing in the Study Area are completed in a variety of formations for both gas and oil ranging from the Createaceus Eagle to the Red River. Production has occurred in Dewey, Custer, Fall River, and Harding counties.

True vertical well depths in the Study Area range from a few hundred feet in the Powder River Basin, in the southwestern corner of the state (Fall River County), to over 9,771 feet in Harding County.

4.8.1.1. Conventional Oil and Gas Development Potential

The majority of additional activity will be additional drilling to grow reserves. Estimated average drilling density is classified into the following five categories.

- High — 10 to 29 well locations per township
- Moderate — 2 to 10 wells per township
- Low — 1 to 2 wells per township
- Very Low — less than 1 well per township

- No potential — Areas of the Black Hills where igneous rocks are at or near the surface

4.8.1.2. CBNG

A CBNG play is hypothetical. No CBNG present production or exploration activities are occurring in the Planning Area. As much as 29.91 Bcf could be present in the Planning Area.

It is assumed that 16 to 25 wells would be required in an exploration Plan of Development. If CBNG does come on line during the life of the RFD, it would only be a minor portion of the natural gas production in the FO.

4.8.2. Surface Disturbance Estimate

Table 4-25. South Dakota FO Surface Disturbance Associated With New Drilled Wells, Existing Wells, and Projected Active Wells for the Baseline Scenario (Short-Term Disturbance)

Wells			Acres of Surface Disturbance			
Type	Total	BLM Managed	Access Roads	Well Pad	Total	BLM Managed
New Exploratory and Development Coal Bed Gas Wells (2010–2029)	75	4	0.6	0.5	83	4
New Exploratory and Development Gas Wells (2010–2029)	112	23	0.6	0.5	123	25
New Exploratory and Development Oil Wells (2010–2029)	337	71	2.9	4	2,325	490
Total New Exploratory and Development Wells	**524**	**98**			**2,531**	**520**
Existing Active Gas Wells (as of August 2008)	100	31	0.3	0.25	55	17
Projected New Gas Wells (August 2008 – December 2009)	7	2	0.3	0.25	4	1
Existing Active Oil Wells (as of August 2008)	308	30	1.5	1.75	1,001	98
Projected New Oil Wells (August 2008 – December 2009)	21	2	1.5	1.75	68	7
Total Existing and Projected Wells	**436**	**65**			**1,128**	**122**
Total Wells	**960**	**163**	**Total Short-Term Disturbance**		**3,659**	**642**

4.8.3. Assumptions

RFD development included the following assumptions.

- 28 additional wells (seven classed as gas wells and 21 classed as oil wells) will be drilled between August 2008 and December 2009.
- Of the existing active wells in August 2008, 75 gas wells and 37 oil wells will be abandoned by December 2029.
- Of the new producing wells drilled between August 2008 and December 2029, all will remain in an unplugged status.
- The success rate of new CBNG wells will be 90 percent.
- The success rate of new non-coal bed oil and gas wells will be 60 percent as determined by the previous 20 years of drilling history.

Table 4-26. South Dakota FO Disturbance Associated With New Producing Wells, Existing Wells, and Projected Producing Wells for the Baseline Scenario (Long-Term Disturbance)

Wells			Acres of Surface Disturbance			
Type	Total	BLM Managed	Access Roads	Well Pad	Total	BLM Managed
New Producing Coal Bed Gas Wells (2010–2029)	68	4	0.3	0.25	37	2
New Producing Gas Wells (2010–2029)	67	14	0.3	0.25	37	8
New Producing Oil Wells (2010–2029)	202	43	1.5	1.75	657	140
Total New Producing Wells	**337**	**60**			**731**	**148**
Existing Active Gas Wells (as of August 2008)[1]	25	9	0.3	0.25	14	5
Projected Producing Gas Wells (August 2008 – December 2009)	4	1	0.3	0.25	2	1
Existing Active Oil Wells (as of August 2008)[1]	271	25	1.5	1.75	881	81
Projected Producing Oil Wells (August 2008 – December 2009)	13	1	1.5	1.75	41	4
Total Existing and Projected Wells	**313**	**37**			**938**	**91**
Total Wells	**650**	**97**	**Total Long-Term Disturbance**		**1,669**	**239**

Table 4-27. Annual Projection of South Dakota Study Area Wells and Associated Confidence Interval, 2010–2029

Year	Low	Mean	High
2010	15	25	44
2011	20	29	46
2012	2	10	27
2013	27	33	48
2014	21	30	48
2015	20	30	50
2016	16	23	37
2017	18	28	49
2018	7	15	30
2019	0	6	22
2020	7	15	33
2021	11	18	32
2022	26	35	56
2023	0	5	27
2024	14	22	37
2025	17	25	42
2026	21	30	51
2027	17	29	55
2028	8	16	31
2029	15	25	45
Total Wells	**282**	**449**	**810**

Table 4-28. Forecast of South Dakota Study Area Annual and Cumulative Oil and Gas Production, 2010–2029

Year	Annual Oil (bbl)	Cumulative Oil (bbl)	Annual Gas (mcf)	Cumulative Gas (mcf)
2010	1,786,948	5,074,603	13,466,075	37,998,982
2011	1,733,147	6,807,750	13,739,501	51,738,483
2012	1,710,074	8,517,824	14,062,507	65,800,990
2013	1,760,897	10,278,721	14,291,960	80,092,950
2014	1,895,065	12,173,786	13,874,344	93,967,294
2015	1,835,697	14,009,483	13,801,862	107,769,157
2016	1,744,162	15,753,645	15,033,534	122,802,691
2017	1,801,011	17,554,656	16,957,656	139,760,347
2018	1,819,946	19,374,602	16,288,638	156,048,985
2019	1,824,190	21,198,792	16,852,283	172,901,267
2020	1,768,595	22,967,388	17,295,408	190,196,675

Table 4-28 (cont). Forecast of South Dakota Study Area Annual and Cumulative Oil and Gas Production, 2010–2029

Year	Annual Oil (bbl)	Cumulative Oil (bbl)	Annual Gas (mcf)	Cumulative Gas (mcf)
2021	1,864,647	24,832,035	17,666,339	207,863,014
2022	1,829,170	26,661,205	19,853,677	227,716,690
2023	1,875,085	28,536,290	20,109,885	247,826,575
2024	1,920,304	30,456,594	19,715,937	267,542,512
2025	1,913,306	32,369,900	19,842,636	287,385,148
2026	1,943,632	34,313,532	20,196,635	307,581,783
2027	1,882,287	36,195,819	21,069,274	328,651,057
2028	1,863,648	38,059,467	20,408,592	349,059,649
2029	1,929,270	39,988,736	21,204,288	370,263,938

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5.0 BLM MONTANA, NORTH DAKOTA, AND SOUTH DAKOTA OIL AND GAS GHG EMISSION INVENTORIES

This chapter describes the methods and assumptions used to develop GHG emission inventories for the following BLM FOs.

- Billings
- Butte
- Dillon
- Hi-Line Planning Area (includes Malta, Glasgow, and Havre FOs)
- Lewistown
- Miles City
- North Dakota
- South Dakota

A common calculation Tool was developed in order to produce consistent GHG and criteria pollutant emission inventories. Development of the Tool is explained first, followed by a discussion of data gathering activities. Descriptions and summaries of FO-specific GHG emission inventories are then provided.

5.1. *Calculation Tool Development*

Development of a sufficient calculation Tool that estimates emissions based on oil and gas development and operation activities was a critical first step for the development of the GHG emission inventories included in this Chapter. The following sections describe the calculation Tool and the data sources and methods that were used to develop the GHG (CO_2, methane, and N_2O) emission inventories.

The BLM NOC provided URS with copies of calculation Tools that estimate emissions for oil, natural gas, and coal bed methane (CBM) wells. URS then conducted a thorough quality assurance check of the Tools and updated several cell references and some emission calculations. After correspondence with the BLM, URS added new emission calculation worksheets for some oil, gas, and CBM activities occurring in many of the BLM FOs that were not previously included in the calculation Tool. The final Tool upgrades the original BLM Tool in order to provide a more comprehensive GHG emission inventory of activities occurring in BLM FOs.

5.2. *Activity and Equipment Data Gathering*

To gather equipment and operating parameters needed to estimate emissions, multiple surveys were sent to BLM personnel at multiple FOs. The surveys requested information including items such as: 1) equipment types and power ratings; 2) frequency and volume of natural gas venting; and 3) size and duration of land disturbance. The data responses were analyzed and compiled in order to identify typical operations and activities for which emissions could be calculated. For the Miles City FO (MCFO), the latest SEIS for the area was also used as a source of information for other data values needed to characterize the MCFO RMP oil and gas development and operation activities for the emissions calculations.

5.3. Emission Calculation Methods and Description

A variety of emission calculation methods were used to estimate emissions. Detailed calculations and source data documentation are included in the emission calculation spreadsheets included in Appendices B through I. Calculations were based on factors from the following documents and models.

- *AP 42 Fifth Edition*, *Volume 1* (USEPA 1998, 2000, 2006k)
- USEPA Mandatory GHG Reporting Rule (GPO 2010b)
- USEPA NONROADS 2008a
- MOBILE6.2.03
- *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry* (API 2009)
- *Protocol for Equipment Leak Emissions Estimates* (USEPA 1995)

5.3.1. Drill Rig Engines

Diesel drilling engine emissions of CO_2, methane, and N_2O were calculated based on USEPA's non-road engine regulations (http://epa.gov/nonroad-diesel/regulations.htm). These regulations apply to newly manufactured engines and are structured as a tiered program by horsepower rating and year of manufacture (from 2000 forward). Tier 1 standards were phased in from 1996 to 2000. Tier 2 standards took effect from 2001 to 2006, Tier 3 standards (for smaller engines only) took effect from 2006 to 2008, and Tier 4 standards will be phased in from 2008 to 2015.

Since the fleet of drilling engines includes engines manufactured in different years, USEPA NONROADS (2008a) factors for year 2018 were used for CO_2, and methane estimates, which accounts for a mixture of Tier 1–3 engines. N_2O emissions were derived from the *Compendium of GHG Emissions Methodologies for the Oil and Gas Industry* (2009), Table 4-17.

The number of drilling engines was based on the expected number of well pads to be drilled and assumed a linear increase from current drilling activity over the 20-year RMP projection.

5.3.2. Well Completion and Re-Completion

Methane and small amounts of CO_2 can be released during well completion, recompletion, and workover activities. Based on information collected from BLM personnel, well completion natural gas emissions are vented into the atmosphere. The natural gas is sweet (negligible levels of sulfur) and has an average heat content of approximately 1,000 Btu/scf.

Engine emissions are also associated with well recompletion and workover activities. Emissions of CO_2, methane, and N_2O were calculated based on the USEPA's non-road engine regulations (http://epa.gov/nonroad-diesel/regulations.htm). Similar to standard well drilling procedures, USEPA NONROADS (2008a) factors for year 2018 were used for CO_2, and methane estimates, which accounts for a mixture of Tier 1–3 engines. N_2O emissions were derived from the *API Compendium* (2009), Table 4-17.

5.3.3. Glycol Dehydrators

Based on information provided by BLM personnel, all natural gas is assumed to be dehydrated at sales compressor stations prior to being placed in sales gas pipelines. Glycol dehydrator emissions were calculated using actual throughput data from the South Baker Compressor Station located in the MCFO.

When determining emissions from a typical dehydrator, the Gas Research Institute (GRI) GLYCalc program was run, with input parameter values and the extended natural gas analysis provided by the BLM for the FO and a typical well found within the FO. A GLYCalc run was made for each well type (CBM, natural gas, and oil) due to the different gas analyses. Glycol reboiler and flash tank GHG emissions were assumed to be uncontrolled.

5.3.4. Oil and Produced Water Tanks

Oil and produced water tanks are located at oil well pads. Emissions were calculated based on the assumption that oil and produced water tanks are uncontrolled. Fugitive emissions associated with truck loading were also estimated with the assumption that trucks transport all produced oil and water resulting from oil wells.

For CBM and natural gas wells BLM personnel reported that very little condensate is produced in the area. Produced water from CBM and natural gas wells is transported via pipeline to treatment facilities or discharge points. Water disposal well drilling GHG emissions were estimated using the factors and methodology shown in Section 5.3.1 (Drill Rig Engines).

5.3.5. Equipment Leaks Fugitive

Fugitive emissions associated with equipment leaks were calculated based on data collected from BLM FO personnel. The BLM FO provided projected valve, pump seal, compressor seal, relief valve, connector, and open ended line counts for a typical well pad for each of the well types (CBM, natural gas, and oil), as well as for a representative field compressor station. Oil and gas production operations average emission factors from Table 2-4 of the *Protocol for Equipment Leak Emission Estimates* (USEPA 1995) were used in conjunction with FO specific gas analysis data to estimate equipment leak emissions.

5.3.6. Pneumatic Pumps and other Pneumatic Devices

According to data provided by the BLM FO personnel, pneumatic pumps or other pneumatic devices are not found at a typical CBM or natural gas well.

5.3.7. Compressor Stations and Oil Pumps

BLM FO data were used to derive future gas compression requirements for the RMP. Compressors were assumed to be equipped with nonselective catalytic reduction (NSCR) catalyst, and would comply with the USEPA New Source Performance Standards in 40 *Code of Federal Regulations* Part 60, Subpart JJJJ. Based on information provided by BLM FO personnel, each oil well was equipped with a natural gas powered 40 hp pump. USEPA

Mandatory GHG Reporting Rule, Part 98, Subpart C, Tables C-1 and C-2 (GPO 2010b) GHG emissions factors were used for estimating GHG emissions for compressor and oil pump engines.

5.3.8. Vehicle Exhaust

Vehicle exhaust GHG emissions were calculated for heavy duty diesel vehicles (HDDV) associated with activities such as pad and road construction and maintenance, oil and produced water hauling, drill rig hauling and tanker equipment, and well pad and road reclamation activities. Vehicle exhaust emissions were also calculated for light duty diesel vehicles (LDDV) and light duty gasoline trucks (LDGT) associated with activities such as well pad and compressor station visits, and worker transportation for all of the development and operations activities. Emissions for heavy-duty construction vehicles were calculated based on the number of hours of operation during construction activities, while emissions from vehicle travel for all types of vehicles were based on the number of vehicle miles traveled (VMT). Detailed emission calculations are provided in Appendix G.

5.4. Specific Planning Area GHG Emission Summaries

The following sections provide summaries of estimated GHG emissions for each of the Planning Areas in Montana, North Dakota, and South Dakota. Annual emissions are provided for the year with the maximum predicted emissions during the next 18 to 20 years based on development activity included in recent RMPs.

5.4.1. Billings Planning Area GHG Emissions

RMP year 2030 was chosen for reporting Billings Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the Billings Planning Area. Development within the area is expected to remain low, increasing slightly from the level of current drilling activity. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the life of Project (LOP) in year 2030.

Table 5-1 summarizes GHG emissions for Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a “per well” annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 2030 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, CH_4, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-1 for wells on federal and non-federal land. Pollutant-specific emissions are reported in short tons per year (tpy), while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix B.

Table 5-1. Billings Planning Area Estimated GHG Emissions for Year 2030

Ownership / Well Type	Emissions (tpy)				Emissions (metric tons/yr)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Federal					
Conventional Natural Gas Wells	354.6	5.2	0.002	464.9	421.9
CBNG Wells	0.0	0.0	0.000	0.0	0.0
Oil Wells	8,352.9	53.9	0.044	9,497.8	8,618.7
Federal Total	**8,707.5**	**59.1**	**0.046**	**9,962.8**	**9,040.6**
Non-Federal					
Conventional Natural Gas Wells	3,946.6	45.2	0.013	4,899.2	4,445.7
CBNG Wells	0.0	0.0	0.000	0.0	0.0
Oil Wells	8,352.9	53.9	0.044	9,497.8	8,618.7
Non-Federal Total	**12,299.5**	**99.0**	**0.057**	**14,397.0**	**13,064.4**
Total Federal and Non-Federal	**21,007.0**	**158.1**	**0.103**	**24,359.8**	**22,105.1**

5.4.2. Butte Planning Area GHG Emissions

RMP year 2028 was chosen for reporting Butte Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the Butte Planning Area. Development within the Butte Planning Area is expected to remain low, increasing slightly from the level of current drilling activity. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the LOP in year 2028.

Table 5-2 summarizes GHG emissions for Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a “per well” annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 2028 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, CH_4, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-2 for wells on federal and non-federal land. Pollutant-specific emissions are reported in tpy, while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix C.

Table 5-2. Butte Planning Area Estimated GHG Emissions for Year 2028

Ownership / Well Type	Emissions (tpy)				Emissions (metric tons/yr)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Federal					
Conventional Natural Gas Wells	420.2	9.4	0.003	618.0	560.8
CBNG Wells	0.0	0.0	0.000	0.0	0.0
Oil Wells	0.0	0.0	0.000	0.0	0.0
Federal Total	**420.2**	**9.4**	**0.003**	**618.0**	**560.8**
Non-Federal					
Conventional Natural Gas Wells	630.4	14.0	0.004	926.7	840.9
CBNG Wells	1,218.9	59.6	0.005	2,471.6	2,242.8
Oil Wells	1,890.7	3.3	0.001	1,961.0	1,779.5
Non-Federal Total	**3,739.9**	**77.0**	**0.010**	**5,359.3**	**4,863.2**
Total Federal and Non-Federal	**4,160.1**	**86.3**	**0.013**	**5,977.3**	**5,424.0**

5.4.3. Dillon Planning Area GHG Emissions

RMP year 2020 was chosen for reporting Dillon Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the Dillon Planning Area. Development within the Dillon Planning Area is expected to remain low, increasing slightly from the level of no activity. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the LOP in year 2020.

Table 5-3 summarizes GHG emissions for Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a "per well" annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 2020 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, CH_4, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-3 for wells on federal and non-federal land. Pollutant-specific emissions are reported in tpy, while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix D.

Table 5-3. Dillon Planning Area Estimated GHG Emissions for Year 2020

Ownership / Well Type	Emissions (tpy)				Emissions (metric tons/yr)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Federal					
Conventional Natural Gas Wells	271.3	39.7	0.003	1,105.1	1,002.8
CBNG Wells	0.0	0.0	0.000	0.0	0.0
Oil Wells	789.0	2.2	0.007	837.0	759.5
Federal Total	**1,060.3**	**41.8**	**0.010**	**1,942.1**	**1,762.3**
Non-Federal					
Conventional Natural Gas Wells	271.3	39.7	0.003	1,105.1	1,002.8
CBNG Wells	0.0	0.0	0.000	0.0	0.0
Oil Wells	550.8	0.4	0.006	561.5	509.5
Non-Federal Total	**822.1**	**40.1**	**0.009**	**1,666.5**	**1,512.3**
Total Federal and Non-Federal	**1,882.4**	**81.9**	**0.018**	**3,608.6**	**3,274.6**

5.4.4. Hi-Line Planning Area GHG Emissions

RMP year 2026 was chosen for reporting Hi-Line Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the Hi-Line Planning Area. Development within the Hi-Line Planning Area is expected to remain relatively constant throughout the life of the plan. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the LOP.

Table 5-4 summarizes GHG emissions for Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a “per well” annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 2026 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, CH_4, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-4 for wells on federal and non-federal land. Pollutant-specific emissions are reported in tpy, while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix E.

Table 5-4. Hi-Line Planning Area Estimated GHG Emissions for Year 2026

Ownership / Well Type	Emissions (tpy)				Emissions (metric tons/yr)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Federal					
Conventional Natural Gas Wells	120,755.6	1,041.1	0.874	142,889.9	129,664.2
CBNG Wells	883.9	48.4	0.003	1,901.2	1,725.3
Oil Wells	2,380.4	15.9	0.012	2,718.9	2,467.2
Federal Total	**124,020.0**	**1,105.5**	**0.889**	**147,510.0**	**133,856.7**
Non-Federal					
Conventional Natural Gas Wells	230,463.7	1,988.7	1.151	272,584.0	247,353.9
CBNG Wells	4,736.3	261.3	0.014	10,228.8	9,282.1
Oil Wells	19,559.6	123.6	0.052	22,170.3	20,118.2
Non-Federal Total	**254,759.5**	**2,373.6**	**1.218**	**304,983.1**	**276,754.2**
Total Federal and Non-Federal	**378,779.5**	**3,479.1**	**2.106**	**452,493.2**	**410,610.9**

5.4.5. Lewistown Planning Area GHG Emissions

RMP year 2029 was chosen for reporting Lewistown Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the Lewistown Planning Area. Development within the Lewistown Planning Area is expected to remain low, increasing slightly from the level of current drilling activity. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the LOP in year 2029.

Table 5-5 summarizes GHG emissions for Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a “per well” annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 2029 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, CH_4, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-5 for wells on federal and non-federal land. Pollutant-specific emissions are reported in tpy, while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix F.

Table 5-5. Lewistown Planning Area Estimated GHG Emissions for Year 2029

Ownership / Well Type	Emissions (tpy)				Emissions (metric tons/yr)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Federal					
Conventional Natural Gas Wells	593.9	2.1	0.006	640.1	580.9
CBNG Wells	0.0	0.0	0.000	0.0	0.0
Oil Wells	727.6	1.4	0.007	759.2	688.9
Federal Total	**1,321.6**	**3.5**	**0.013**	**1,399.3**	**1,269.8**
Non-Federal					
Conventional Natural Gas Wells	939.3	6.2	0.009	1,072.4	973.2
CBNG Wells	0.0	0.0	0.000	0.0	0.0
Oil Wells	3,115.9	12.6	0.012	3,383.4	3,070.2
Non-Federal Total	**4,055.3**	**18.8**	**0.021**	**4,455.8**	**4,043.4**
Total Federal and Non-Federal	**5,376.8**	**22.3**	**0.034**	**5,855.2**	**5,313.2**

5.4.6. Miles City Planning Area GHG Emissions

RMP year 20 was chosen for reporting Miles City Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the area. Development within the area is expected to increase linearly from the level of current drilling activity. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the LOP in year 2028.

Data supplied by the Miles City FO indicate that there are approximately 867 CBM wells being serviced by 36 field and 6 sales compressors. The field compressors are about 300 hp each and the sales compressors are approximately 1680 hp each. The typical CBM gas production per well is 45 mcfd.

Table 5-6 summarizes GHG emissions for Miles City FO Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a “per well” annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 20 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, methane, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-6 for wells on federal and non-federal land. Pollutant-specific emissions are reported in tpy, while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix G.

Table 5-6. Miles City Planning Area Estimated GHG Emissions for Year 2028

Ownership / Well Type	Emissions (tpy)				Emissions (metric tons/yr)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Federal					
Conventional Natural Gas Wells	158,154.7	1,572.8	1.2	190,984.1	173,817.6
CBNG Wells	268,477.4	5,194.6	0.9	377,826.5	342,855.2
Oil Wells	91,689.0	562.7	0.5	103,663.3	94,068.3
Federal Total	**518,321.1**	**7,330.0**	**2.5**	**672,473.8**	**610,741.1**
Non-Federal					
Conventional Natural Gas Wells	545,689.1	5,425.9	2.1	658,344.3	599,170.7
CBNG Wells	274,925.2	5,330.5	0.9	387,135.7	351,302.8
Oil Wells	422,033.9	2,576.3	1.3	476,522.7	432,416.3
Non-Federal Total	**1,242,648.3**	**13,332.7**	**4.2**	**1,522,002.7**	**1,382,889.7**
Total Federal and Non-Federal	**1,760,969.4**	**20,662.7**	**6.8**	**2,194,476.5**	**1,993,630.8**

5.4.7. North Dakota Planning Area GHG Emissions

RMP year 2029 was chosen for reporting North Dakota Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the North Dakota Planning Area. Development within the North Dakota Planning Area is expected to remain low, increasing slightly from the level of current drilling activity. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the LOP in year 2029.

Table 5-7 summarizes GHG emissions for Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a “per well” annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 2029 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, CH_4, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-7 for wells on federal and non-federal land. Pollutant-specific emissions are reported in tpy, while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix F.

Table 5-7. North Dakota Planning Area Estimated GHG Emissions for Year 2029

	Emissions (tpy)				Emissions (metric tons/yr)
Ownership / Well Type	**CO_2**	**CH_4**	**N_2O**	**CO_2e**	**CO_2e**
Federal					
Conventional Natural Gas Wells	562.69	116.72	0.01	3,016.03	2,736.87
CBNG Wells	3,822.02	49.22	0.07	4,876.90	4,425.50
Oil Wells	547,165.01	1,132.11	7.44	573,246.85	520,187.71
Federal Total	**551,549.72**	**1,298.05**	**7.52**	**581,139.78**	**527,350.08**
Non-Federal					
Conventional Natural Gas Wells	3,173.45	645.05	0.04	16,730.62	15,182.05
CBNG Wells	24,152.94	307.60	0.43	30,746.53	27,900.66
Oil Wells	3,382,213.37	6,987.58	36.96	3,540,410.75	3,212,713.93
Non-Federal Total	**3,409,539.76**	**7,940.23**	**37.43**	**3,587,887.90**	**3,255,796.64**
North Dakota Trust (Fort Berthold)					
Conventional Natural Gas Wells	371.34	73.72	0.00	1,920.88	1,743.08
CBNG Wells	2,675.02	33.84	0.05	3,400.44	3,085.70
Oil Wells	382,453.66	789.50	5.20	400,645.54	363,562.19
North Dakota Trust Total	**385,500.02**	**897.06**	**5.25**	**405,966.86**	**368,390.97**
Forest Service					
Conventional Natural Gas Wells	728.49	132.08	0.01	3,504.99	3,180.57
CBNG Wells	5,579.43	70.75	0.10	7,096.16	6,439.35
Oil Wells	773,843.28	1,598.86	10.53	810,682.18	735,646.26
Forest Service Total	**780,151.20**	**1,801.69**	**10.64**	**821,283.33**	**745,266.18**
Total Federal, Non-Federal, Fort Berthold, and Forest Service	**5,126,740.70**	**11,937.03**	**60.84**	**5,396,277.87**	**4,896,803.87**

5.4.8. South Dakota Planning Area GHG Emissions

RMP year 2029 was chosen for reporting South Dakota Planning Area emissions because this is the year of highest expected combined construction and production emissions for oil and gas sources within the South Dakota Planning Area. Development within the South Dakota Planning Area is expected to remain low, increasing slightly from the level of current drilling activity. Consequently, the greatest construction activities and operating activities are expected to occur at the end of the LOP in year 2029.

Table 5-8 summarizes GHG emissions for Federal and non-Federal sources. Emissions for each activity described earlier in this document were developed on a “per well” annual basis (in short tons per year) for each well type. The per well estimates were applied to RMP year 2029 well counts for each well type to determine the total FO projected emissions. The same per well emission estimates were used for Federal and non-Federal wells.

Total CO_2, CH_4, and N_2O emissions, as well as total emissions in terms of CO_2e are summarized in Table 5-8 for wells on federal and non-federal land. Pollutant-specific emissions are reported in tpy, while CO_2e is provided in units of tpy and in metric tons per year. Detailed emission calculations are provided in Appendix I.

Table 5-8. South Dakota Planning Area Estimated GHG Emissions for Year 2029

Ownership / Well Type	Emissions (tpy)				Emissions (metric tons/yr)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Federal					
Conventional Natural Gas Wells	455.89	99.25	0.01	2,542.29	2,306.98
CBNG Wells	283.97	17.26	0.00	647.81	587.85
Oil Wells	704,439.61	803.82	12.53	725,203.06	658,079.00
Federal Total	**705,179.47**	**920.33**	**12.54**	**728,393.16**	**660,973.83**
Non-Federal					
Conventional Natural Gas Wells	1,796.42	384.04	0.03	9,869.70	8,956.17
CBNG Wells	1,385.77	306.37	0.02	7,826.05	7,101.68
Oil Wells	190,613.56	214.59	3.53	196,214.94	178,053.48
Non-Federal Total	**193,795.75**	**905.00**	**3.58**	**213,910.69**	**194,111.33**
Total Federal and Non-Federal	**898,975.22**	**1,825.33**	**16.12**	**942,303.85**	**855,085.16**

5.5. Montana, North Dakota, and South Dakota GHG Emission Summaries

The following discussion summarizes total potential GHG emissions from energy development within the eight Planning Areas in Montana, North Dakota, and South Dakota. As shown in Figure 5-1, oil production accounts for 76 percent of total potential GHG emissions, with conventional natural gas and CBNG accounting for 15 percent and 9 percent, respectively. Total potential GHG emissions are based on level of activity and the emission calculations shown in Appendices B through I.

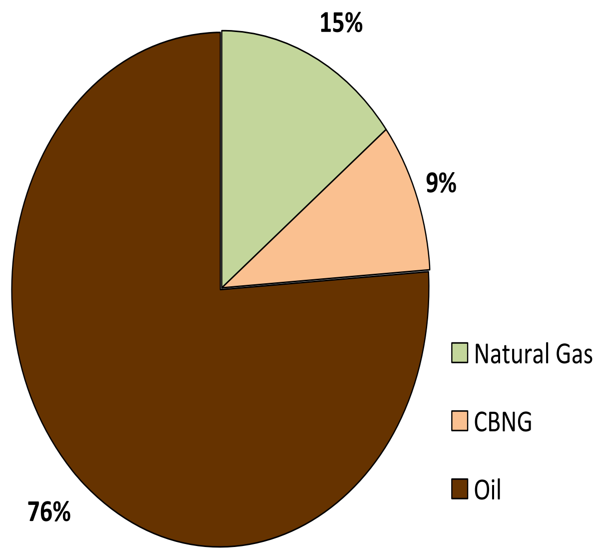


Figure 5-1. Potential Energy Production GHG Emissions

Table 5-9 summarizes estimated potential GHG emissions for Planning Areas in Montana, North Dakota, and South Dakota. For easier comparison to state and national GHG emission inventories, these emissions are shown in million short tons per year and in million metric tons (Mt) of CO_2e. Total annual estimated GHG emissions based on each Planning Area's year with the greatest estimated emissions (during the next 20 years) are approximately 8.6 Mt for Planning Areas in the three-state region.

Table 5-9. Montana, North Dakota, and South Dakota Planning Area GHG Emissions

State / Planning Area	Emissions (10^6 tpy)				Emissions (Mt)
	CO_2	CH_4	N_2O	CO_2e	CO_2e
Montana					
Billings	0.021	0.000	1.030E-07	0.024	0.022
Butte	0.004	0.000	1.300E-08	0.006	0.005
Dillon	0.002	0.000	1.800E-08	0.004	0.003
Hi-Line	0.379	0.003	2.106E-06	0.452	0.411
Lewistown	0.005	0.000	3.400E-08	0.006	0.005
Miles City	1.761	0.021	6.800E-06	2.194	1.994
Montana Total	**2.172**	**0.024**	**9.074E-06**	**2.687**	**2.440**
North Dakota	**5.127**	**0.012**	**6.080E-05**	**5.396**	**4.897**
South Dakota	**0.899**	**0.002**	**1.610E-05**	**0.942**	**0.855**
Total Montana, North Dakota, and South Dakota	**8.198**	**0.038**	**8.597E-05**	**9.025**	**8.192**

The following sections of this report compare Planning Area federal and non-federal emissions for oil, conventional natural gas, and CBNG production activities. In each of the sector-specific charts, GHG emissions are shown on a logarithmic scale, in which each incremental increase in bar height represents a ten-fold increase in emissions.

More detailed GHG emission graphs are included in Appendices B though I for each of the eight Planning Areas. In graphs following emission summary tables for each type of energy production, GHG emissions are broken down in terms of GHG pollutant (CO_2, methane, and N_2O) and source type (e.g., well workovers, vehicle exhaust, and tank emissions). The graph on page B-5 is one example; it shows the detailed emission breakdown for oil production emissions from federal mineral estate in the Billings Planning Area. The graph on page B-30 provides the emission breakdown for conventional natural gas wells in the Billings Planning Area federal mineral estate.

Each of the graphs in Appendices B through I have logarithmic scales for GHG emissions, with units of short tons for CO_2, methane, N_2O, and CO_2e, as well as units of metric tons for CO_2e. Emission sources with potential GHG emissions of more than 1 tpy have bars extending above the 1-tpy line, while sources with potential emissions less than 1 tpy have bars extending below this line.

5.5.1. Oil GHG Emissions

The North Dakota Planning Area has the largest potential oil production GHG emissions from both federal and non-federal mineral estate. As shown in Figure 5-2, more than 1 million metric tons of CO_2e may be produced from oil wells on federal mineral estate and from oil wells on non-federal mineral estate. In addition, the South Dakota and Miles City Planning Areas each may also potentially produce 100,000 metric tons per year of CO_2e emissions from wells on federal and on non-federal mineral estate. All other Planning Areas are estimated to have substantially lower potential CO_2e emissions.

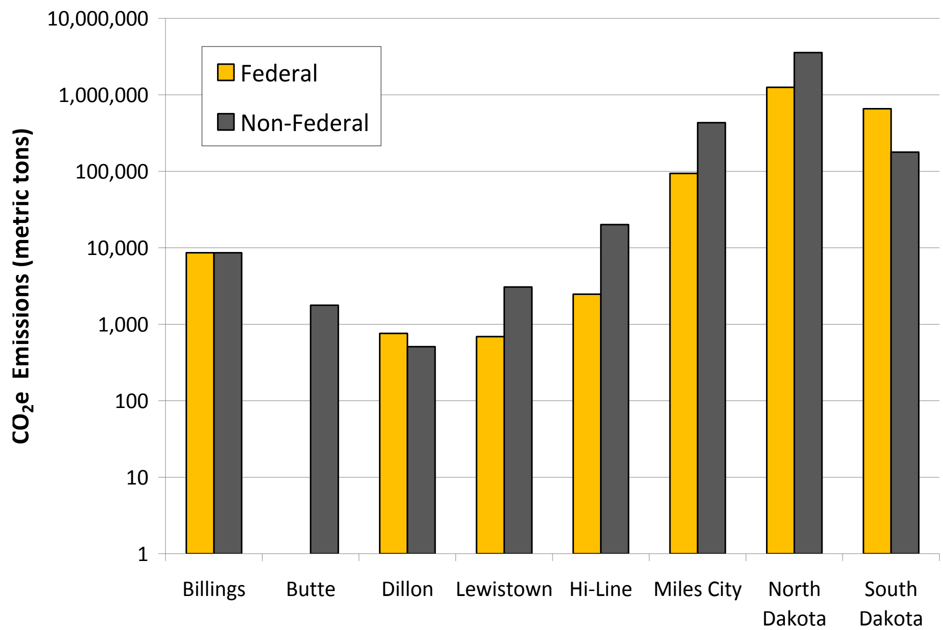


Figure 5-2. Potential Oil GHG Emissions

5.5.2. Conventional Natural Gas GHG Emissions

Figure 5-3 illustrates potential GHG emissions from conventional natural gas production. The following groups of natural gas wells are estimated to emit more than 100,000 metric tons of CO_2e: federal wells in the Hi-Line and Miles City Planning Areas and non-federal wells in each of these Planning Areas. Most Planning Areas are estimated to have federal and non-federal natural gas production CO_2e emissions less than 10,000 metric tons.

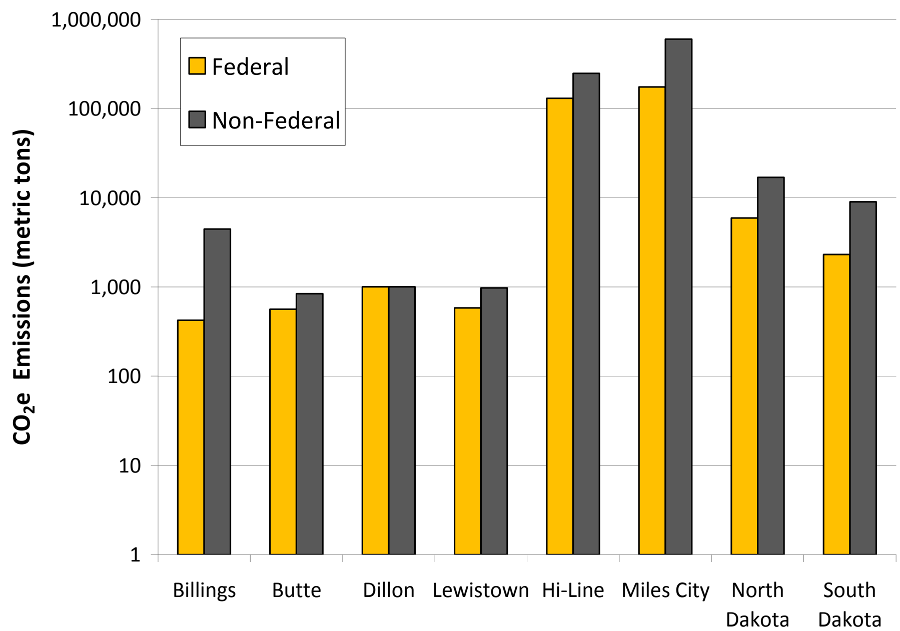


Figure 5-3. Potential Conventional Natural Gas GHG Emissions

5.5.3. Coal Bed Natural Gas GHG Emissions

Figure 5-4 provides estimated CO_2e emissions for those Planning Areas expected to develop coal bed natural gas wells. The Miles City Planning Area is estimated to produce more than 100,000 metric tons of CO_2e from CBNG wells on federal and on non-federal mineral estate. In the Butte Planning Area, CBNG wells are expected to be located on non-federal mineral estate. However, the Billings, Dillon, and Lewistown Planning Areas are not expected to produce CBNG in the near future.

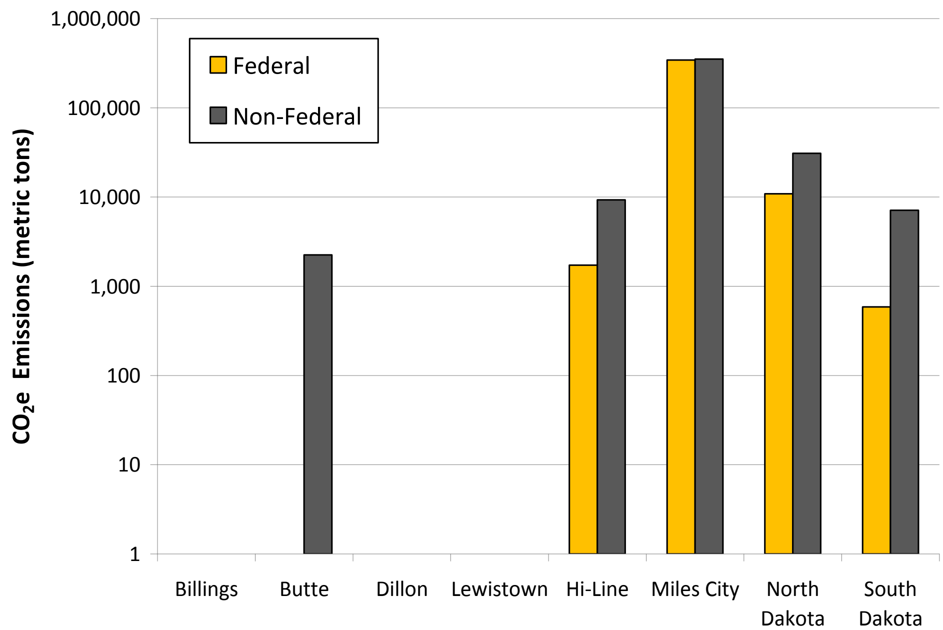


Figure 5-4. Potential CBNG GHG Emissions

6.0 OIL AND GAS GHG MITIGATION

Existing and potential oil and gas mitigation technologies for sources that could be used to develop federal minerals in Montana, North Dakota, and South Dakota are described in this chapter. Within the natural gas and CBM industries, GHG emission reduction technology discussions are included for the production and gathering/processing sectors. Within the oil industry, emission reduction strategies for the production sector are addressed.

Emission reduction technologies included in this chapter focus on emission reductions for methane and CO_2, since these two GHGs are expected to account for the largest RF effects from oil and gas operations. Small amounts of N_2O are also emitted from combustion sources such as flares, heaters, and engines. Achieving high energy efficiency and avoiding flaring are the most practical N_2O mitigation strategies.

Before beginning the emission reduction technology descriptions, relevant GHG mitigation programs and state Climate Action Plans are discussed. At the end of the specific technology descriptions, potential global energy sector GHG emission reductions and marginal mitigation costs are summarized.

6.1. GHG Mitigation Programs and Plans

GHG mitigation has historically been a voluntary effort and continuing voluntary efforts play a large role in ongoing GHG emission reduction. USEPA, states, and industry organizations lead a variety of voluntary efforts. Two of these efforts, the USEPA Natural Gas STAR Program and the Montana Climate Action Plan are described below. As of July 2010, North and South Dakota did not have climate action plans, nor were plans currently being developed, as reported by the Pew Center on Global Climate Change (PCGCC 2010).

6.1.1. USEPA Natural Gas STAR Program

The Natural Gas STAR Program was established in 1993 with the goal of helping oil and natural gas companies reduce methane emissions through technology transfer and other means of communication. The program solicits voluntary participation from domestic and international oil and natural gas companies. Natural Gas STAR industry partners now represent 60 percent of the natural gas industry in the United States, including 18 of the top 25 natural gas production companies. The international program launched in 2006 and has more than 130 partner companies (12 of which are international partners) and is endorsed by 20 major industry trade associations. In order to participate in the program, Natural Gas STAR partners sign a memorandum of understanding with USEPA, develop a methane reduction implementation program, implement the program, and submit annual reports describing mitigation activities and methane emissions.

Since 1993, the U.S. oil and natural gas industry has eliminated more than 822 Bcf of domestic methane emissions through the implementation of approximately 150 technologies and practices. For calendar year 2008, Natural Gas STAR partners reported domestic emission reductions of more than 114 Bcf. The 2008 voluntary domestic emission reductions are equivalent to the following (USEPA 2009b).

- The additional revenue of more than $802 million in natural gas sales based on a natural gas price of $7.00 per thousand cubic feet (Mcf)
- The avoidance of 46.3 Mt of CO_2e
- The CO_2 emissions from the annual electricity consumption of more than 6 million homes
- The annual greenhouse gas emissions from 8.5 million passenger vehicles
- The carbon sequestered annually by 10.5 million acres of pine or fir forests

Natural Gas STAR methane emission reductions during 2008 and cumulative reductions since 1990 are summarized in Table 6-1. Emission reductions are provided for production and gathering/processing sectors and by the type of emission reduction technology. Total emission reductions for each sector are provided in Bcf of methane. Technologies accounting for the emission reductions are shown, along with the percentage of the total reduction that each technology contributed.

Table 6-1. Methane Emission Reductions Reported Under USEPA Natural Gas STAR Program [1]

Industry Sector / Technology	2008 Emission Reduction	Total Emission Reduction Since 1990
Production	**89.3 Bcf**	**537.4 Bcf**
Artificial lift: gas lift	3%	— [2]
Artificial lift; install plunger lifts	11%	12%
Artificial lift; install smart lift automated systems on gas wells	4%	3%
Convert to instrument air systems	3%	3%
Foaming agent use to reduce blowdown frequency	4%	— [2]
Install flash tank separators on glycol dehydrators	— [2]	2%
Install vapor recovery units	— [2]	12%
Reduced emission completions	50%	36%
Replace high-bleed pneumatic devices	5%	9%
Other	20%	23%

Source: USEPA 2009b.

[1] Methane emission reduction technologies for the transmission and distribution sectors are not included.
[2] The emission reduction percentage contribution for this technology is included in the “other” category for this time period.

DI&M = direct inspection and maintenance
ESD = emergency shutdown
N2 = nitrogen

Table 6-1 (cont). Methane Emission Reductions Reported Under USEPA Natural Gas STAR Program [1]

Industry Sector / Technology	2008 Emission Reduction	Total Emission Reduction Since 1990
Gathering and Processing Sector	**7 Bcf**	**42.8Bcf**
DI&M aerial leak detection using laser and/or infrared technology	24%	20%
DI&M leak detection using infrared camera/optical imaging	— [2]	7%
Eliminate unnecessary equipment and/or systems	6%	9%
Install electric compressors	22%	15%
Install flash tank separators on glycol dehydrators	5%	— [2]
Install vapor recovery units	9%	— [2]
Optimize N2 rejection unit to reduce methane in N2 reject stream	6%	10%
Pipeline replacement and repair	— [2]	5%
Redesign blowdown/alter ESD practices	8%	7%
Other	20%	27%

Source: USEPA 2009b.

[1] Methane emission reduction technologies for the transmission and distribution sectors are not included.
[2] The emission reduction percentage contribution for this technology is included in the "other" category for this time period.

DI&M = direct inspection and maintenance
ESD = emergency shutdown
N2 = nitrogen

6.1.2. Montana Climate Action Plan

The Montana Climate Action Plan (MCCAC 2007) estimates that GHGs from the natural gas sector can be reduced by 3.9 to 6.6 Mt of CO_2e between 2007 and 2020 with a net economic benefit. The larger emission reduction estimate is based on a high natural gas growth rate during that time period. CO_2 and methane emission reductions are included in the estimate.

Montana's Climate Action Plan policy description recommends that the state "adopt a policy to encourage natural gas companies in the state to participate in EPA's Natural Gas STAR Program and provide enforcement and verification of participation (MCCAC 2007)." Many of Montana's natural gas operators are smaller companies that may not be participating in the Natural Gas STAR Program. The Montana Climate Change Advisory Committee (CCAC) recommends that the state consider whether participation by smaller companies would be a significant burden and possibly provide incentives if needed. The MCCAC suggests a goal of reducing methane emissions by 30 percent below business as usual (BAU) levels by 2020 (MCCAC 2007).

Montana's Climate Action Plan recommends use of the following practices to decrease methane and CO_2 emissions (MCCAC 2007).

- Methane
    - Preventive maintenance (improving the overall efficiency of the gas production and distribution system)
    - Reducing flashing losses (releases when pressure drops at storage tanks, wells, compressor stations, or gas plants)
    - Changing and replacing parts and devices to reduce leaks and improve efficiency
- CO_2
    - Using new efficient compressors
    - Optimizing gas flow to improve compressor efficiency
    - Improving performance of compressor cylinder ends
    - Capturing compressor waste heat
    - Replacing compressor driver engines
    - Using waste heat recovery boilers

For the oil industry, the Climate Action Plan did not assess opportunities for GHG emission reductions in oil industry production fields. Instead, all recommendations addressed petroleum refining emission reduction strategies, which are beyond the scope of this report.

6.2. Natural Gas Sector Mitigation Technologies

Methane is the largest GHG of concern in the natural gas system, accounting for more than 76 percent of natural gas sector CO_2e (Table 7-7). Although CO_2 emissions from the natural gas sector are still a major source of CO_2e, they primarily result from combustion sources for which relatively few large-scale emission reductions are possible, particularly in gas production activities. One method for reducing combustion CO_2 emissions is to switch from a high CO_2-emitting fuel to a low CO_2-emitting fuel. However, this method has relatively little application in the natural gas industry because natural gas is the predominant fuel used within the industry and natural gas has the lowest CO_2 combustion emissions of all fossil fuels on a heat input basis.

Consequently, this report focuses exclusively on methane emission reduction technologies for the natural gas industry. In general terms, the three most promising methane abatement strategies are summarized below (USEPA 2006a).

- Substituting compressed air for pressurized natural gas in pneumatic control devices throughout the natural gas system to eliminate the constant bleed of natural gas into the atmosphere.
- Changing operational practices, such as using pumpdown techniques to remove natural gas from sections of pipelines and from compressors during maintenance and repair.
- Implementing direct inspection and maintenance programs to eliminate as much as 80 percent of fugitive methane emissions resulting from equipment and pipeline leaks throughout natural gas systems.

USEPA's Natural Gas STAR program has identified more than 150 potentially cost-effective technologies for decreasing methane emissions from the oil and natural gas industry (see htpp://epa.gov/gasstar/tools/recommended.html). Of these, the following discussion selects technologies that focus primarily on natural gas production and gathering equipment and on emission sources for which BLM may have a major role in identifying mitigation measures. GHG emission sources in the transmission and distribution sectors are generally not addressed here because they are unlikely to include many sources that would fall under BLM jurisdiction. Furthermore, some large methane sources are not discussed below for the following reasons.

- **High-emitting stationary sources —** Large-quantity methane emission reductions are possible from large gas processing facilities and large compressor stations. However, local, state, and federal air quality permitting agencies will have primary responsibility for reviewing and permitting GHG emissions from these sources. These agencies also have the authority to require emission reductions from both existing and new sources.
- **Large pipelines —** High-volume, high-pressure transmission pipelines also have large GHG emissions and mitigation opportunities. Emissions from these operations are likely to be regulated under new USEPA GHG emission reduction rules.

The Natural Gas STAR Program focuses on disseminating practical technical and cost information through the use of case study information provided by Natural Gas STAR participants. Consequently, the reported emission reductions are often specific to an individual project or company or to several companies. Application of some technologies may achieve different levels of emission reduction than reported in Gas STAR technology documents. Furthermore, some technologies may not be technically or economically feasible for all gas basins or for all facilities.

Estimated methane emission reductions in Mcf, technology costs and savings, and payback periods are included in USEPA's Natural Gas STAR technology descriptions. These costs and payback periods should be interpreted as general indicators of implementation costs and potential cost savings for the following reasons.

- Much of the cost information is somewhat dated since many source documents were published in 2004 and 2006. Future implementation costs may be greater due to inflation or may be less due to new efficiencies or economies of scale.
- Due to differences in producing basins and existing equipment types and configurations, some technologies may be more or less expensive to implement and may be more or less effective. Technology costs and increased revenue due to methane savings may also be affected by well production rates and equipment throughput.
- The natural gas price is needed to determine breakeven cost and payback periods. Natural gas values fluctuate dramatically over time due to markets and the location of the producing basin. The natural gas prices used to determine payback periods are listed in Table 6-2.

Table 6-2. Selected Methane Emission Reductions Reported Under the USEPA Natural Gas STAR Program [1]

Source Type / Technology	Annual Methane Emission Reduction [1] (Mcf/yr)	Capital Cost Including Installation ($)	Annual Operation and Maintenance Cost ($)	Payback (Years or Months)	Payback Gas Price Basis ($/Mcf)
Wells					
Reduced emission (green) completion	7,000 [2]	$1K – $10K	>$1,000	1 – 3 yr	$3
Plunger lift systems	630	$2.6K – $10K	NR	2 – 14 mo	$7
Gas well smart automation system	1,000	$1.2K	$0.1K – $1K	1 – 3 yr	$3
Gas well foaming	2,520	>$10K	$0.1K – $1K	3 – 10 yr	NR
Tanks					
Vapor recovery units on crude oil tanks	4,900 – 96,000	$35K – $104K	$7K – $17K	3 – 19 mo	$7
Consolidate crude oil production and water storage tanks	4,200	>$10K	<$0.1K	1 – 3 yr	NR
Glycol Dehydrators					
Flash tank separators	237 – 10,643	$5K – $9.8K	Negligible	4 – 51 mo	$7
Reducing glycol circulation rate	394 – 39,420	Negligible	Negligible	Immediate	$7
Zero-emission dehydrators	31,400	>$10K	>$1K	0 – 1 yr	NR
Pneumatic Devices and Controls					
Replace high-bleed devices with low-bleed devices					
End-of-life replacement	50 – 200	$0.2K – $0.3K	Negligible	3 – 8 mo	$7
Early replacement	260	$1.9K	Negligible	13 mo	$7
Retrofit	230	$0.7K	Negligible	6 mo	$7
Maintenance	45 – 260	Negl. to $0.5K	Negligible	0 – 4 mo	$7
Convert to instrument air	20,000 (per facility)	$60K	Negligible	6 mo	$7
Convert to mechanical control systems	500	<$1K	<$0.1K	0 – 1 yr	NR
Valves					
Test and repair pressure safety valves	170	NR	$0.1K – $1K	3 – 10 yr	NR
Inspect and repair compressor station blowdown valves	2,000	<$1K	$0.1K – $1K	0 – 1 yr	NR

Table 6-2 (cont). Selected Methane Emission Reductions Reported Under the USEPA Natural Gas STAR Program [1]

Source Type / Technology	Annual Methane Emission Reduction [1] (Mcf/yr)	Capital Cost Including Installation ($)	Annual Operation and Maintenance Cost ($)	Payback (Years or Months)	Payback Gas Price Basis ($/Mcf)
Compressors					
Install electric compressors	40 – 16,000	>$10K	>$1K	>10 yr	NR
Replace centrifugal compressor wet seals with dry seals	45,120	$324K	Negligible	10 mo	$7
Flare Installation	2,000	>$10K	>$1K	None	NR

Source: Multiple USEPA Natural Gas STAR Program documents. Individual documents are referenced in the summaries provided below.

[1] Unless otherwise noted, emission reductions are given on a per-device basis (e.g., per well, per dehydrator, per valve, etc).
[2] Emission reduction is per completion, rather than per year.

K = 1,000
mo = months
Mcf = thousand cubic feet of methane
NR = not reported
yr = year

6.2.1. Wells

Gas well methane reduction technologies focus on reduced well venting, either through gas capture or by reducing the number of well workovers and blowdowns. In addition to the four technologies described below and included in Table 6-2, USEPA's Natural Gas STAR Program has identified the following methane reduction technologies for gas wells.

- Connect casing to vapor recovery unit (VRU)
- Optimize gas well unloading time
- Install compressors to capture casinghead gas
- Reduce heater-treater temperature
- Install velocity tubing strings
- Install downhole separator pumps
- Install pumpjacks on low water production gas wells

6.2.1.1. Reduced Emission (Green) Completion

Reduced emission completion, also known as green completion, captures and cleans up natural gas (mostly methane) that would otherwise be vented during the well completion process. After a well is drilled, contaminants such as sand, cuttings, and reservoir fluids must be removed from the well bore. Typically, natural gas escapes from the well and is vented to the atmosphere as well completion contaminants exit the well and are placed in tanks or open pits.

Green completion requires additional equipment to capture the completion gas and remove sand and liquid from the gas using special gas-liquid-sand separators. The equipment also provides gas dehydration, allowing the completion natural gas to enter the gas sales line. Green completion equipment is often skid-mounted and moves from one well to another as well completions are occurring. In addition to the green completion gas capture and cleanup equipment, this technology requires that piping to the natural gas sales line (and a sales agreement) be in place before well drilling is completed.

Various gas capture efficiencies have been reported. A conservative estimate is that 70 percent of natural gas that was formerly vented during the completion process is captured (USEPA 2004a).

6.2.1.2. Plunger Lift Systems

Fluid accumulation in gas wells reduces well productivity and can sometimes completely halt well production. This is particularly true of mature gas wells. In order to restore productivity, gas wells are worked over or blown down to remove accumulated liquid. During these procedures, natural gas is typically vented to the atmosphere, which causes increased methane emissions and lost revenue due to lost product.

Mechanical plunger lift systems can be installed in wells to remove liquids while minimizing natural gas venting (USEPA 2006d). (Plunger lift systems can also replace older beam lifts that frequently require more well workovers and mechanical repairs.) The plunger gas lift system uses gas pressure buildup during a temporary well shut-in to lift a column of accumulated fluid out of the well. Regular operation of the plunger gas lift system provides greater gas production over time by removing liquids more frequently, thereby allowing better gas flow from the well. In addition, the mechanical action of the steel plunger can also remove paraffin and scale from the well bore, thereby avoiding or reducing the need for well bore workovers or blow downs.

6.2.1.3. Smart Automation for Plunger Lift Systems

The effectiveness of plunger lift systems can be improved by using “smart” automation to optimize plunger lift system performance (USEPA 2004c). Most plunger lift systems operate on a fixed cycle or on a preset differential pressure. The smart automation system monitors several well production parameters and uses “artificial intelligence” to control plunger lift cycles and improve well production. In addition, the system can report well problems, such as high-venting wells. Smart automation well monitoring reduces gas well venting by alerting operators that a well may need maintenance to reduce excessive venting.

Smart automation systems require remote telemetry units, tubing and casing transmitters, gas measurement equipment, a control valve, and a plunger detector to optimize flow and reduce methane emissions. A host computer system is also required.

6.2.1.4. Well Foaming Agents

When gas wells have insufficient reservoir pressure to lift wellbore fluids, the use of foaming agents may reduce the number of well blowdowns needed to maintain gas production (USEPA 2004i). This technology, however, is not recommended for gas wells that produce condensate.

A foaming agent (typically soap) is injected into the casing/tubing annulus by a chemical pump on a timed basis. Natural gas bubbling up through the soap-water solution creates gas-water foam that can be more easily lifted to the surface for water removal. At a minimum, well foaming requires installation of the foaming agent injection system at the wellhead. If capillary tubing is required, a workover rig and crew will need to install the tubing during one day.

6.2.2. Tanks

More than 500,000 crude oil storage tanks exist in the United States (USEPA 2006e). During temporary storage in gas and oil fields, methane, VOCs, natural gas liquids (NGLs), and hazardous air pollutants (HAPs) flash from the liquid and collect in tank headspace. As the liquid level in these tanks fluctuates, headspace vapors are often vented to the atmosphere. Two tank methane emission technologies are described below. Additional technologies identified under USEPA's Natural Gas STAR program include the following.

- Purge and retire low pressure gasholders
- Convert water tank blanket from natural gas to produced CO_2 gas
- Recover gas during condensate loading
- Install pressurized storage of condensate

6.2.2.1. Install Vapor Recovery Units

VRUs can be installed on one or more crude oil storage tanks to capture organic emissions that would otherwise be vented from tank headspace. Methane is the largest component of the vapors, typically constituting 40 to 60 percent of the total vapor (USEPA 2006e). VRUs can recover more than 95 percent of the vapors, which have high heat content due to NGLs in the vapor.

VRUs pull vapors out of the tank(s) at low pressure and use a suction scrubber to separate liquids from the vapor (liquids are returned to the storage tank). Vapors from the suction scrubber are then routed to a gas sales line, used for onsite fuel supply, or piped to a stripper unit to separate NGLs.

6.2.2.2. Consolidate Crude Oil Production and Water Storage Tanks

Centralizing production tank batteries has several environmental benefits in addition to reducing emissions of methane and other organic compounds. Consolidated tank batteries reduce tankage footprints, wildlife impacts, and truck traffic. Oil and gas fields with a significant decline in production may be good candidates for reducing the number of crude oil and water storage tanks (USEPA 2004j). When new oil and gas development activities are analyzed, tank centralization should be assessed.

Underutilized tanks have greater headspace volume and contain a greater quantity of organic vapors. Emissions of methane and other organic compounds are increased when tanks are underutilized due to increased standing losses resulting from temperature variations and due to working losses from changing fluid levels and agitation. Reducing the number of tanks reduces methane and other organic compound emissions from uncontrolled tanks. Some tanks may be eliminated because their capacity is no longer needed. In this case, the tank and associated piping are removed from a site. In other cases, tanks may be removed from well sites and replaced with a tank battery at a nearby location that serves multiple well sites. Consolidating tanks in centralized areas makes installation and use of vapor recovery systems more feasible due to economies of scale.

6.2.3. Glycol Dehydrators

USEPA estimates that there are approximately 36,000 glycol dehydrators in the United States (USEPA 2006f). Most of these dehydrators use triethylene glycol (TEG) to absorb water from natural gas. Methane (and VOCs and HAPs) are also absorbed into the glycol. As part of the TEG regeneration process, the moisture-laden TEG is heated in a reboiler and water and organic compounds are vented to the air.

Emissions of methane and other organic compounds can be decreased by the installation of additional equipment, by optimizing operational parameters, and by using newer zero-emission dehydrators. Three of these techniques are summarized below. Additional technologies identified by USEPA include the following.

- Solar power applications
- Convert gas-driven chemical pumps to instrument air
- Pipe glycol dehydrators to a VRU
- Replace glycol dehydration units with methanol injection
- Use portable desiccant dehydrators
- Replace gas-assisted glycol pumps with electric pumps
- Replace glycol dehydrators with desiccant dehydrators
- Replace glycol dehydrators with separators and in-line heaters

6.2.3.1. Flash Tank Separators

Smaller and older dehydrators used in gas production and natural gas processing send moisture- and organic-laden TEG directly to the regenerator, where the methane and VOCs are boiled off and vented to the atmosphere (USEPA 2006f). A flash tank separator removes methane and other organics from the TEG, while water remains in the TEG solution that enters the regenerator. The flash tank separator removes approximately 90 percent of the methane and 10 to 40 percent of the VOCs from the TEG prior to the reboiler. Captured methane and VOCs can be used as fuel gas for the reboiler or a compressor engine, piped to a sales line, or flared.

6.2.3.2. Optimize Glycol Recirculation

The amount of methane absorbed in TEG is directly proportional to the TEG circulation rate (USEPA 2006f). TEG recirculation rates are often greater than needed, often because the recirculation rates were set for maximum gas throughput. If gas production rates at a well or in a field have fallen, TEG recirculation rates may be two to three times greater than necessary, resulting in high methane emissions with little or no improvement in gas moisture reduction.

USEPA provides calculation procedures for optimizing TEG recirculation rates (USEPA 2006f). At some dehydrators, TEG recirculation rates can be reduced to the optimal rate by adjusting the existing TEG recirculation pump. In other cases, the required recirculation rate turndown may require replacing the existing TEG recirculation pump with a different pump.

6.2.3.3. Zero-Emission Dehydrators

Zero-emission dehydrators are designed to prevent most methane emissions from the reboiler vent and from natural gas driven TEG recirculation pumps. Zero-emission dehydrators collect all condensable components (e.g., water) from the reboiler vapor stream and use the remaining non-condensable vapor components (methane and ethane) as fuel for the reboiler (USEPA 2004f). A water exhauster removes water from the glycol and essentially replaces the gas stripper that is used in a typical dehydrator.

In addition, zero-emission dehydrators replace traditional Kimray pumps with electric pumps. Kimray pumps, named for their manufacturer, are also known as glycol energy exchange pumps; they are widely used on glycol dehydrators. The natural gas-driven pumps transfer energy from high-pressure wet glycol to an equivalent volume of low-pressure dry glycol. Natural gas is emitted continuously as the pump operates. In order to replace Kimray pumps with electric pumps, electrical power must be available at the site, either from a power grid or through the use of an engine-generator set.

6.2.4. Pneumatic Devices and Control Systems

Pneumatic devices and pneumatic control systems powered by pressurized natural gas are used through the natural gas industry as liquid level controllers, pressure regulators, and valve controllers (USEPA 2006). Reducing or eliminating natural gas emissions from pneumatic devices and controllers can achieve large cumulative methane emission reductions. In addition to the technologies described below, emission reductions can also be achieved using the following strategies for production, gathering, and processing activities.

- Install electronic flare ignition devices
- Use solar power

6.2.4.1. Replace High-Bleed Devices with Low-Bleed Devices

USEPA estimates that approximately 413,000 pneumatic devices are used in natural gas production and processing applications (USEPA 2006i). These devices emit (or bleed) natural gas into the atmosphere as part of their normal operations in actuating valves to control pressure, flow, temperature, or liquid levels for a variety of equipment, including dehydrators, separators, flash tanks, and isolation valves. Emissions may be continuous or intermittent. Pneumatic devices are often used in locations where electricity is unavailable.

Substantial methane emission reductions can be achieved by replacing high-bleed pneumatic devices with low-bleed devices. Replacement of high-bleed devices may occur when a high-bleed device wears out (end-of-life replacement) or as part of an early replacement program. In addition, some existing high-bleed devices may be retrofitted to achieve low-bleed emission rates. Improved maintenance practices can also reduce methane emissions. Avoided methane emissions are no longer lost to the atmosphere and instead enter the sales pipeline.

6.2.4.2. Convert Gas Pneumatic Controls to Another Motive Force

Another option to avoid methane emissions from pneumatic devices is to replace the natural gas motive force with another gas (air or nitrogen) or a mechanical system (USEPA 2006i). Potential natural gas substitutions are summarized below.

- **Instrument air** — If electricity is available or if a generator-engine set can be installed and operated, pneumatic controls can be replaced with instrument air (dry, pressurized air) (USEPA 2006j).
- **Nitrogen gas** — Cryogenic liquid nitrogen cylinders used in conjunction with a liquid nitrogen vaporizer and a pressure regulator can be used as the motive gas. This type of system does not require electricity. However, cryogenic nitrogen cylinders would need to be refilled. This type of system can be expensive and involves potential safety hazards (USEPA 2006i).
- **Mechanical control systems** — These systems use a combination of springs, levels, flow channels, and other means to actuate devices. The control device must be located in close proximity to the measured process characteristic that drives the mechanical linkage (USEPA 2004l).

6.2.5. Valves

Methane emissions from production and gathering/processing activities can be decreased by inspecting, repairing, and replacing valves. Two of these techniques are summarized below. Additional technologies identified by USEPA include the following.

- Install BASO® valves
- Replace burst plates with secondary relief valves
- Use ultrasound to identify leaks
- Use YALE® closures for emergency shut down (ESD) testing

6.2.5.1. Test and Repair Pressure Safety Valves

Pressure safety valves (PSVs) are common throughout natural gas systems. These valves are designed to open if the pressure in a compressor, pipeline, or vessel exceeds the maximum allowable pressure. However, valve components wear out or become fouled over time and then leak methane to the atmosphere, sometimes at substantial cost to the operator (USEPA 2004k).

Methane emissions may be reduced by identifying PSV leaks through a testing and repair program. Testing methods include use of an organic vapor analyzer, acoustical leak detector, or a high-volume sampler while PSVs are under normal operating pressure. If leaks are found, they can be repaired, especially when it is cost-effective to reduce the methane leaks and gain additional revenue.

6.2.5.2. Inspect and Repair Compressor Station Blowdown Valves

Compressor station blowdown valves are subjected to high pressure and may develop leaks over time. Frequently, these valves are located on stacks and are difficult to access (USEPA 2004g). However, inspecting the valves on an annual basis can result in significant methane emission reductions. Annual inspection can reduce methane emissions from a single facility by 2,000 Mcf/yr.

6.2.6. Compressors

Methane leakage reductions from compressor engines or turbines are achievable using many different methods. Two of these methods are described below. In addition, USEPA has identified the following emission reduction strategies.

- Convert engine starting to nitrogen
- Reduce the frequency of engine starts with gas
- Replace gas starters with air
- Reduce emissions when taking compressors offline
- Install electric starters
- Install automated air/fuel ratio controllers
- Replace compressor rod packing systems

6.2.6.1. Electrify Compressors

When electricity is available, installing electric motors to drive compressors can eliminate methane leak points in existing natural gas compressors (USEPA 2004d). In gas compressors, methane emissions occur due to gas leakage in the engine gas supply line and due to incomplete combustion. (Methane emissions due to system upsets would not be reduced by compressor electrification since blowdown of the gas line would occur, regardless of the compressor type.) New compressors installed in areas with electric power are good candidates for electric compressors.

6.2.6.2. Replace Wet Seals with Dry Seals

Dry seals should be specified for new centrifugal compressors because they allow less natural gas to escape through seals surrounding a compressor's rotating shaft (USEPA 2006g). Methane emissions from wet (oil-based) seals typically range from 40 to 200 standard cubic feet per minute (scfm), while dry seals emit 6 scfm or less (USEPA 2006g). In addition, dry seals have lower power requirements, improve performance, and require less maintenance.

On existing centrifugal compressors, replacing wet seals with dry seals can save approximately 45,000 Mcf/yr depending on compressor throughput. Replacement may not be feasible on all existing centrifugal compressors due to compressor housing design or operational requirements.

6.2.6.3. Flare Installation

Flare installation is not a preferred method for decreasing methane emissions because combustion generates CO_2 and N_2O emissions and because gas that would otherwise be saleable is burned with no energy recovery. However, flare installation may be necessary in cases where remote operations (such as wells or small compressor stations) have low-pressure natural gas and VOC and HAP vapors that should not be emitted into the atmosphere (USEPA 2004m). The gas is typically routed from equipment such as storage tanks, dehydrator vents, and other non-fugitive sources.

6.3. Oil Sector Mitigation Technologies

Methane emissions account for more than 98 percent of total U.S. CO_2e emissions associated with oil production. Consequently, GHG emission reduction efforts concentrate on methane. The majority of U.S. oil production GHG emissions are emitted by high-bleed pneumatic devices, flaring, chemical and injection pumps, and wellheads for light crude (USEPA 2006a).

Oil contains a substantial quantity of methane. Similar to natural gas wells, methane is released to the atmosphere as oil reaches the surface and while oil is stored temporarily in the production field. Depending on the quantity of natural gas generated during oil production, the gas may be captured, treated, and piped to a natural gas sales line. In these cases, methane emission technologies summarized above for natural gas systems are also relevant to natural gas produced during oil production.

However, in many oil production fields natural gas cannot be captured and sold due to a lack of gas processing facilities and the absence of a nearby natural gas pipeline. When the gas cannot be sold, it can be vented, used as onsite fuel, flared, or reinjected into the oil field. Onsite natural gas fuel use is rare in onshore oil production applications.

6.3.1. Natural Gas Flaring

Natural gas flaring is frequently used to mitigate methane emissions from oil wells and oil tanks at locations where natural gas cannot be routed to a sales pipeline. Flaring typically achieves at least 98 percent emission reduction of methane, a potent GHG with a GWP of 21. However, flares produce two GHG combustion by-products: CO_2 (GWP of 1) and small quantities of N_2O (GWP of 320). When all three GHGs are considered, flaring provides a net GHG emission reduction. For onshore oil fields, total capital costs for flaring in 2006 were estimated to be approximately $34 per metric ton of avoided CO_2e (USEPA 2006a). Annual flaring operating and maintenance costs are estimated to be approximately $1.10 per ton of CO_2e (USEPA 2006a). On an annualized basis, the total capital and operating cost was estimated to be approximately $7 per ton of avoided CO_2e emissions (USEPA 2006a). The annualized cost calculation assumed a 10 percent discount rate and a 40 percent tax rate, with equipment lifetime of 15 years.

6.3.2. Methane Reinjection

Methane-containing natural gas may be reinjected into the oil field as a means to enhance oil recovery. Methane reinjection has an estimated emission reduction efficiency of 95 percent and is assumed to have a technical lifetime of 15 years (USEPA 2006a). The estimated capital and annual operating costs are estimated to be $67 and $2.20 per avoided ton of CO_2e, respectively. Using the same financial parameters described above for flaring, the total annualized price for methane reinjection is estimated to be approximately $10 per ton of CO_2e, which is more expensive than flaring. However, methane reinjection has several potential benefits over flaring, including (1) increasing oil well production, (2) avoiding combustion emissions, and (3) preserving natural gas in the well field for potential recovery at a later time.

6.3.3. CO_2 Injection

Similar to methane reinjection, oil well production can be enhanced by injection of CO_2 from other sources. Injecting CO_2 increases reservoir pressure and helps push oil toward existing wells. This technology has been used in the past to increase oil production from aging fields. CO_2 injection effectively sequesters CO_2, thereby preventing it from entering the atmosphere. CO_2 sequestration is not fully understood and sequestration life span is not known with certainty. However, emissions from large sources of concentrated CO_2, such as coal gasification plants, may be mitigated by injecting CO_2 into oil production fields. One technical challenge of sequestering CO_2 is determining how to economically transport large volumes of CO_2 from its source to an appropriate oil field.

6.4. Coal Bed Methane Well Mitigation Technologies

Coal bed methane wells are, in themselves, a methane mitigation technology for existing or abandoned coal mines. By removing methane from coal mines or coal beds and distributing it for sale, methane that might otherwise be vented into the atmosphere is used as a natural gas energy source.

6.4.1. CBM Wells Remove Methane

"Most coal beds are permeated with methane, and a cubic foot of coal can contain six or seven times the volume of natural gas that exists in a cubic foot of a conventional sandstone reservoir (NETL 2010)." This methane may seep out of an operating mine, abandoned coal mine, or unmined coal seam. In fact, ventilation of coal mines to reduce methane concentrations and improve miner safety accounts for a noticeable percentage of U.S. methane emissions. Coal mine methane emissions account for approximately 10 percent of total U.S. emissions (NETL 2010).

Coal beds typically contain significant quantities of water. This water must be pumped out of the coals (dewatering) in order to reduce the reservoir pressure and allow methane to desorb from coal surfaces. The methane then diffuses through the coal bed and flows through a system of natural fractures (cleats) and into a well for delivery to the surface.

GHG mitigation technologies for CBM wells are similar to those for natural gas once the CBM gas is collected at the wellhead. The gas must be dehydrated, transported, and treated similar to conventional gas. Consequently, most of the methane mitigation measures described in Section 6.2 are applicable to CBM wells and gathering systems.

6.4.2. CBM Wells Sequester CO_2

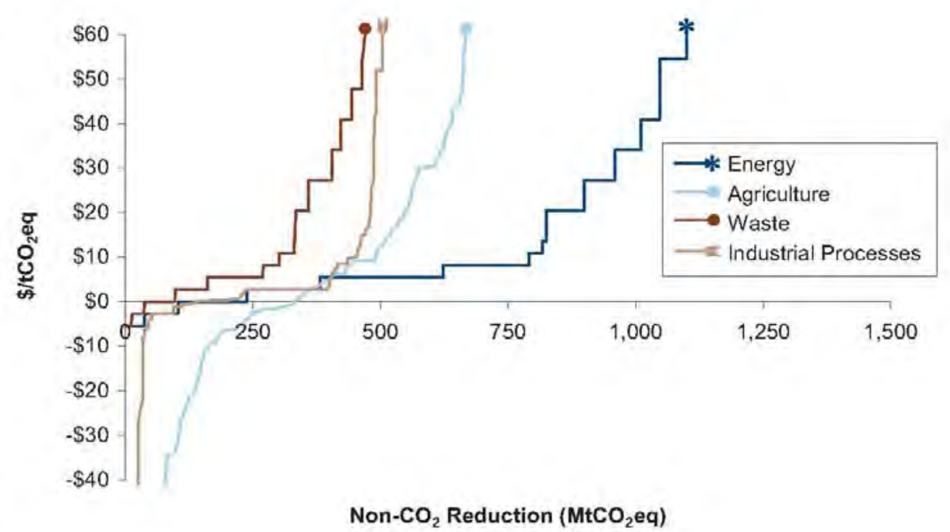
Coal beds can also potentially sequester CO_2 generated from other sources. In fact, pumping CO_2 into a CBM formation can improve natural gas production from the well. According to the

National Energy Technology Laboratory (NETL), coal beds (especially unminable coal beds) have an enormous capacity for CO_2 storage. CO_2 can be injected into a coal bed via wells drilled into the coal, and pressure from the CO_2 would displace methane out of the coal. "CO_2 storage is feasible because coal preferentially adsorbs CO_2 at twice the volume that it stores methane. The net result would be less CO_2 in the atmosphere and additional recovery of sorely needed natural gas (NETL 2010)." This technology has not yet been implemented, but is actively being researched.

6.5. *Global Energy Supply GHG Mitigation*

CO_2 emission reduction from the energy supply sector is based primarily on reducing CO_2e emissions from combustion through a variety of technologies. Due to the large potential for reducing CO_2 emissions, electricity production is the focus of many mitigation strategies. Achieving low CO_2e combustion may involve switching to natural gas from a high CO_2-emitting fuel, adopting more efficient combustion processes (integrated gasification combined cycle), or carbon capture and sequestration. Alternatively, fossil fuels may be replaced with renewable energy such as wind, solar, or hydroelectric power sources.

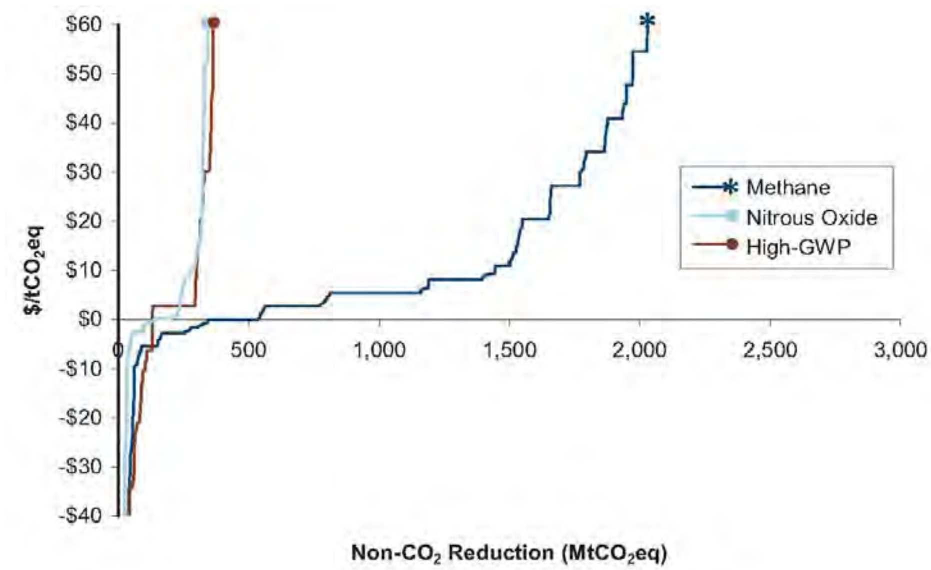
The energy and agriculture sectors are the sectors with the greatest global potential for decreasing non-CO_2 GHG emissions, as reported in *Global Mitigation of Non-CO_2 Greenhouse Gases* (USEPA 2006a). Figure 6-1 provides a marginal abatement curve (MAC) illustrating the cost per metric ton of removing CO_2e and the quantity of CO_2e emissions reduction in million metric tons (Mt) per year for four sectors, including energy, agriculture, waste, and industrial processes. Negative costs per ton of CO_2e removal indicate cost savings. As shown in the figure, the energy sector has the greatest potential for reducing worldwide non-CO_2 emissions.



Source: Figure ES-2 of *Global Mitigation of Non-CO_2 Greenhouse Gases* (USEPA 2006a).

Figure 6-1. Global 2020 MACs for Non-CO_2 GHGs by Major Sector

Of global non-CO_2 GHGs, methane has the largest potential for reducing CO_2e emissions, as shown in Figure 6-2. This is true based on the potential total quantity of global methane-based CO_2e emissions reduction and on the cost-effectiveness of methane emission reductions. Slightly more than 500 Mt of CO_2e emissions may be avoided using cost-saving technologies or zero-cost techniques. The potential for reducing methane emissions grows to nearly 1,800 Mt of CO_2e at a cost of up to $30 per metric ton of CO_2e.



Source: Figure ES-3 of *Global Mitigation of Non-CO_2 Greenhouse Gases* (USEPA 2006a).

Figure 6-2. Global 2020 MACs by Non-CO_2 GHG Type

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7.0 STATE, NATIONAL, AND GLOBAL GHG EMISSION INVENTORIES

State, national, and global GHG emission inventories are summarized in this section, based on the most recent publically available inventories developed by credible sources. These inventories are not necessarily consistent in their methods or in the variety of GHG sources that are inventoried. Thus, multiple GHG emission inventories may report substantially different emissions.

GHG emissions can vary greatly in their scope and comprehensiveness. For example, some state emission inventories appear to include only the largest GHG emission source types and do not include GHG emissions for all sectors of their economies. In contrast, other states have detailed inventories addressing all relevant sectors of detailed national GHG inventories.

GHG emission inventories for the oil and gas industry (and other industries) often underestimated total GHG emissions because they did not adequately account for GHG emissions from fugitive (non-point) sources. More recent oil and gas inventories include much more detailed data for fugitive GHG emissions, including those from well venting, pneumatic devices, and equipment leaks.

Emission inventories use different methods for determining GHG emissions. Inventories may use one or more of the following types of emission data.

- Monitored emission data reported by oil and gas operators
- Estimated emission data reported by oil and gas operators
- Estimated emission data developed using field-specific knowledge of equipment and operational practices
- Estimated emission data based on activity levels and emission factors without specific knowledge of equipment and operational practices

BLM GHG emission inventories are becoming more detailed and recent inventories (including those summarized in Chapter 5.0) include comprehensive estimates of point and non-point (fugitive) GHG sources. BLM emission inventory methodologies use field-specific knowledge of well characteristics, oil and gas equipment, and operational practices to calculate GHG emissions. Additional information on BLM GHG emission inventory methodologies is provided in Chapter 5.0.

GHG emission inventories are constantly evolving and improving, particularly in the oil and gas industry. As USEPA begins receiving and compiling GHG emission inventories from entities subject to the GHG Mandatory Reporting Rule, state and national GHG inventories will become more consistent and more detailed. Data deriving from the Mandatory Reporting Rule provisions specific to the oil and gas industry, which are slated to be promulgated in 40 CFR Part 98, Subpart W will add much more detail and consistency to future year oil and gas GHG emission inventories.

7.1. Types of GHG Emission Inventories

Two types of GHG emission inventories are provided below: total inventories and oil and gas inventories. The oil and gas inventories comprise a subset of the total inventories and are provided to show more detail about the types of facilities and emissions associated with the oil and gas industry.

7.1.1. Total GHG Emission Inventories

Total GHG inventories are comprehensive inventories that estimate GHG emissions from a wide variety of sources, including energy supply (e.g., coal, oil, natural gas, electricity, and renewable energy), industrial processes, forestry (including deforestation), transportation, agriculture, residential and commercial buildings, and waste and wastewater. Because these inventories span all sectors of the relevant economies, development of consistent national or global total GHG emission inventories require years to complete. Consequently, the most recent total GHG emission inventories are several years old.

The references associated with each inventory provide additional detail about the type of sources included in the inventories and the methodologies used to develop the inventories.

7.1.2. Oil and Gas GHG Emission Inventories

The oil and gas inventories presented below provide estimates of petroleum and natural gas GHG emissions, including detailed estimates of emissions from specific types of oil and gas sources at the national level. Development of detailed oil and gas emission inventories has been a priority for multiple U.S. agencies, including USEPA and BLM.

7.2. State GHG Emission Inventories

The level of detail and comprehensiveness of state GHG emission inventories varies among states. Available GHG emission inventory information for Montana, North Dakota, and South Dakota are provided below. While moderately comprehensive Montana and South Dakota GHG emission inventories were published during 2007, a similarly detailed inventory is not available for North Dakota.

7.2.1. Montana

Montana's 2005 CO_2e consumption-based emissions were estimated at 37 Mt, which is equivalent to 0.6 percent of total U.S. CO_2e emissions (CCS 2007a). The estimate of consumption-based emissions excluded two types of GHG emissions: (1) emissions removed due to forestry and agricultural soils, and (2) emissions associated with electricity exported outside of Montana.

GHG emission growth was projected for 2010 and 2020 for a reference case and a high fossil fuel growth case. Table 7-1 provides a summary of Montana's historical (1990, 2000, 2005) and reference case projected (2010, 2020) emissions.

Table 7-1. Montana Historical and Future Reference Case GHG Emissions

Sector	CO_2e Emissions (million tons)				
	1990	**2000**	**2005**	**2010**	**2020**
Electricity Generation [1]	8.9	9.5	10.0	10.0	11.0
Residential, Commercial, Industrial and Institutional (RCI) Fossil Fuel Combustion [2]	4.5	4.5	4.8	5.2	5.3
Transportation	5.9	7.3	8.0	8.8	10.4
Fossil Fuel Industry	3.5	4.1	5.0	5.2	5.3
Industrial Processes	1.2	1.0	0.9	1.1	1.5
Waste Management	0.2	0.2	0.3	0.3	0.4
Agriculture	7.9	9.5	7.9	7.9	7.9
Total Gross Emissions [3]	**32.2**	**36.1**	**36.8**	**38.5**	**41.7**
Increase Relative to 1990		**12%**	**14%**	**19%**	**30%**

Source: Modified from Table ES-1 from Montana GHG Inventory and Reference Case Projections 1990-2020 (CCS 2007a).
[1] Excludes emissions associated with electricity transported to other states.
[2] Does not include fossil fuel combustion from the fossil fuel industry.
[3] Does not include CO_2 sinks (forestry and agricultural soils). Totals may not equal the sum of sector totals due to rounding.

In 2005, the electricity sector accounted for 27 percent of total CO_2e emissions. The fossil fuel industry accounted for approximately 13 percent of total CO_2e emissions. The fossil fuel industry includes the natural gas industry, oil industry, coal mining, and coal-to-liquids industry. However, no coal-to-liquids industry currently exists in Montana and the industry is not expected to develop in the state before 2020. In the reference case fossil fuel industry emissions would increase by 6 percent by 2020 from 2005 levels. In contrast, under a high fossil fuel scenario, fossil fuel industry emissions would increase by approximately 214 percent to an estimated 15.7 Mt of CO_2e by 2020.

7.2.1.1. Montana Natural Gas Industry Emissions

Montana's natural gas industry emissions are broken down by production, processing, transmission, and distribution activities. For each of these activities, GHG emissions are estimated based on the type of GHG emission. Two types of GHG emissions account for the majority of Montana's natural gas industry GHG emissions. The greatest quantity of CO_2e results from methane emissions. CO_2 emissions from fuel combustion are also significant. Emissions of N_2O were not quantified. Table 7-2 summarizes natural gas CO_2e emissions for Montana's natural gas industry based on historical data and the reference case and high fossil fuel growth projection scenarios.

Table 7-2. Montana Historical and Future Natural Gas Industry CO_2e Emissions

Industry Sector	Emissions (Mt CO_2e) [1]				
	1990	2000	2005	2010	2020
Reference Case					
Production Subtotal	0.3	0.4	0.7	0.8	0.8
Fuel Use (CO_2)	0.1	0.1	0.2	0.3	0.3
Methane	0.2	0.3	0.4	0.5	0.5
Processing Subtotal	0.2	0.1	0.1	0.1	0.1
Fuel Use (CO_2)	0.0	0.0	0.0	0.0	0.0
Methane	0.2	0.1	0.1	0.1	0.1
Transmission Subtotal	0.7	1.0	1.0	1.1	1.1
Fuel Use (CO_2)	0.1	0.4	0.4	0.5	0.5
Methane	0.6	0.6	0.6	0.6	0.7
Distribution Subtotal	0.1	0.2	0.2	0.2	0.3
Methane	0.1	0.2	0.2	0.2	0.3
Total Reference Case Emissions	**1.4**	**1.7**	**2.0**	**2.3**	**2.4**
Fuel Use (CO_2)	**0.2**	**0.6**	**0.7**	**0.8**	**0.8**
Methane	**1.1**	**1.1**	**1.3**	**1.5**	**1.6**
High Fossil Fuel Growth Case					
Production Subtotal	0.3	0.4	0.7	1.4	1.9
Fuel Use (CO_2)	0.1	0.1	0.2	0.3	0.3
Methane	0.2	0.3	0.4	1.1	1.6
Processing Subtotal	0.2	0.1	0.1	0.1	0.1
Fuel Use (CO_2)	0.0	0.0	0.0	0.0	0.0
Methane	0.2	0.1	0.1	0.1	0.1
Transmission Subtotal	0.7	1.0	1.0	1.1	1.3
Fuel Use (CO_2)	0.1	0.4	0.4	0.4	0.5
Methane	0.6	0.6	0.6	0.6	0.7
Distribution Subtotal	0.1	0.1	0.2	0.2	0.3
Methane	0.1	0.1	0.2	0.2	0.3
Total High Fossil Fuel Case Emissions	**1.4**	**1.7**	**2.0**	**2.8**	**3.6**
Fuel Use (CO_2)	**0.2**	**0.6**	**0.7**	**0.8**	**0.9**
Methane	**1.1**	**1.1**	**1.3**	**2.0**	**2.7**

Source: Adapted from Tables E-4 and E-5 from Montana GHG Inventory and Reference Case Projections 1990-2020 (CCS 2007a).

[1] Totals may not equal the sum of sector totals due to rounding.

7.2.1.2. Montana Oil Industry Emissions

Montana's oil industry emissions are broken down by production and refining activities. In contrast to the natural gas industry, the greatest quantity of CO_2e emissions result from CO_2 emissions generated during fuel combustion. Emissions of N_2O were not quantified. Table 7-3 summarizes oil industry CO_2e emissions for Montana's based on historical data and the reference case and high fossil fuel growth projection scenarios.

Table 7-3. Montana Historical and Future Oil Industry CO_2e Emissions

Industry Sector	Emissions (Mt CO_2e) [1]				
	1990	2000	2005	2010	2020
Reference Case					
Production Subtotal	0.1	0.1	0.3	0.3	0.3
Fuel Use (CO_2)	0.0	0.0	0.0	0.0	0.0
Methane	0.1	0.1	0.3	0.3	0.3
Refining Subtotal	1.8	2.1	2.4	2.4	2.4
Fuel Use (CO_2)	1.8	2.1	2.4	2.4	2.4
Methane	0.0	0.0	0.0	0.0	0.0
Total Reference Case Emissions	**2.0**	**2.2**	**2.7**	**2.8**	**2.8**
Fuel Use (CO_2)	**1.8**	**2.1**	**2.4**	**2.4**	**2.4**
Methane	**0.1**	**0.1**	**0.3**	**0.3**	**0.3**
High Fossil Fuel Growth Case					
Production Subtotal	0.1	0.1	0.3	0.3	0.3
Fuel Use (CO_2)	0.0	0.0	0.0	0.0	0.0
Methane	0.1	0.1	0.3	0.3	0.3
Refining Subtotal	1.8	2.1	2.4	2.8	4.1
Fuel Use (CO_2)	1.8	2.1	2.4	2.8	4.1
Methane	0.0	0.0	0.0	0.0	0.0
Total High Fossil Fuel Case Emissions	**2.0**	**2.2**	**2.7**	**3.1**	**4.4**
Fuel Use (CO_2)	**1.8**	**2.1**	**2.4**	**2.8**	**4.1**
Methane	**0.1**	**0.1**	**0.3**	**0.3**	**0.3**

Source: Adapted from Tables E-4 and E-5 from Montana GHG Inventory and Reference Case Projections 1990-2020 (CCS 2007a).

[1] Totals may not equal the sum of sector totals due to rounding.

7.2.2. North Dakota

The available North Dakota GHG emission inventory provides CO_2 emissions from fossil fuel combustion for the years 1990 through 2007. A subset of this data is provided in Table 7-4. The GHG inventory does not estimate future emissions.

The North Dakota GHG emission inventory is limited to CO_2 emissions from fossil fuel combustion only and totaled 48.98 Mt of CO_2e in 2007. The inventory underestimates total GHG emissions because (1) CO_2 emissions from non-combustion sources are not included, and (2) methane and other non-CO_2 GHG emissions are excluded from the inventory. No estimate of natural gas and oil industry emissions is included.

Table 7-4. North Dakota Historical CO_2 Emissions From Combustion Sources

Sector	Emissions (Mt CO_2e)				
	1990	**1995**	**2000**	**2005**	**2007**
Electricity	27.93	29.68	32.17	32.85	31.92
Commercial	0.85	0.90	0.95	1.13	1.05
Industrial	6.04	7.07	7.70	7.52	7.74
Residential	1.11	1.13	1.26	1.24	1.17
Transportation	4.61	5.10	5.54	6.23	7.09
Total CO_2 Emissions [1]	**40.54**	**43.88**	**47.63**	**48.97**	**48.98**
Increase Relative to 1990		**8%**	**17%**	**21%**	**21%**

Source: Adapted from a GHG Emission Inventory provided by the North Dakota Division of Air Quality (ND DAQ 2010).
[1] Totals may not equal the sum of sector totals due to rounding.

7.2.3. South Dakota

South Dakota's 2005 CO_2e consumption-based emissions were estimated at 36.5 Mt, which is equivalent to 0.5 percent of total U.S. CO_2e emissions (CCS 2007b). The estimate of consumption-based emissions excluded two types of GHG emissions: (1) emissions removed due to forestry and agricultural soils, and (2) emissions associated with electricity exported outside of South Dakota. The state's GHG emissions increased approximately 36 percent from 1990 to 2005, compared to a national GHG emission increase of 16 percent from 1990 to 2004. Agriculture accounted for approximately 46 percent of South Dakota's consumption-based GHG emissions during 2005.

GHG emission growth was projected for 2010 and 2020. Table 7-5 provides a summary of South Dakota's historical (1990, 2000, 2005) and projected (2010, 2020) emissions. South Dakota's emissions are projected to rise to 46.6 Mt of CO_2e per year in 2020.

Table 7-5. South Dakota Historical and Future GHG Emissions

Sector	Emissions (Mt CO_2e)				
	1990	2000	2005	2010	2020
Electricity [1]	3.6	3.6	7.0	7.1	8.4
Residential, Commercial, Industrial and Institutional (RCI) Fossil Fuel Combustion [2]	4.1	4.5	4.1	4.5	5.1
Transportation	5.5	6.4	6.9	7.1	7.8
Fossil Fuel Industry	0.2	0.3	0.5	0.5	0.6
Industrial Processes	0.5	0.7	0.9	1.0	1.4
Waste Management	0.3	0.4	0.4	0.5	0.6
Agriculture	12.5	17.1	16.7	18.3	22.6
Total Gross Emissions [3]	**26.7**	**33.0**	**36.5**	**39.1**	**46.6**
Increase Relative to 1990		**23%**	**36%**	**46%**	**74%**

Source: Adapted from Table ES-1 from *South Dakota GHG Inventory and Reference Case Projections 1990-2020* (CCS 2007b).

[1] Excludes emissions associated with electricity transported to other states.

[2] Does not include fossil fuel combustion from the fossil fuel industry.

[3] Does not include CO_2 sinks (forestry and agricultural soils). Totals may not equal the sum of sector totals due to rounding.

Only methane emissions are estimated from the oil and natural gas industry in the CCS South Dakota GHG emission inventory. Historical and projected methane emissions from the natural gas and oil industries are shown in Table 7-6. Natural gas CO_2e emissions are expected to increase by 33 percent between 2005 and 2020 while oil industry emissions will remain steady.

Table 7-6. South Dakota Historical and Future Natural Gas and Oil Industry CO_2e Emissions

Industry Sector	Emissions (Mt CO_2e)				
	1990	2000	2005	2010	2020
Natural Gas Industry(Methane)					
Production	0.00	0.01	0.00	0.00	0.00
Processing	0.00	0.00	0.00	0.00	0.00
Transmission	0.16	0.22	0.29	0.33	0.38
Distribution	0.07	0.11	0.16	0.19	0.22
Total Natural Gas Industry Emissions	**0.23**	**0.34**	**0.45**	**0.52**	**0.60**
Oil Industry(Methane)					
Production	0.01	0.01	0.01	0.01	0.01
Refining	0.00	0.00	0.00	0.00	0.00
Total Oil Industry Emissions	0.01	0.01	0.01	0.01	0.01

Source: Adapted from Table E2 from *South Dakota GHG Inventory and Reference Case Projections 1990-2020* (CCS 2007b).

7.3. National GHG Emission Inventory

USEPA published the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008* in April 2010 (USEPA 2010). Total U.S. GHG emissions on a CO_2e basis were 6,957 Mt in 2008. When considering CO_2 sinks, net GHG emissions were 6,016 CO_2e in 2008. CO_2 emissions from fuel combustion accounted for approximately 79 percent of total GHG emissions during 1990 through 2008.

Table 7-7 provides historical GHG emissions on a CO_2e basis for major economic sectors.

Table 7-7. U.S. Historical GHG Emissions

Sector	Emissions (Mt CO_2e)				
	1990	1995	2000	2005	2008
Electricity Generation					
CO_2	1,820.8	1,947.9	2,296.9	2,402.1	2,363.5
Methane [1]	7.4	7.1	6.6	6.6	6.7
N_2O [1]	12.8	13.3	14.5	14.7	14.2
SF6	26.6	21.4	15.0	14.0	13.1
Residential, Commercial, Industrial and Institutional (RCI) Fossil Fuel Combustion					
CO_2	1,429.1	1,473.6	1,487.0	1,455.9	1,424.0
Non-Energy Use of Fuels					
CO_2	119.6	142.9	146.1	136.5	134.2
Transportation					
CO_2	1,485.8	1,608.0	1,809.5	1,895.3	1,785.3
Methane	4.7	4.3	3.4	2.5	2.0
N_2O	43.9	54.0	53.2	36.9	26.1
Natural Gas Systems					
CO_2 [2]	37.3	42.2	29.4	29.5	30.0
Methane [2]	129.5	132.6	130.7	103.6	96.4
Oil Systems					
CO_2	0.6	0.5	0.5	0.5	0.5
Methane	33.9	32.0	30.2	28.2	29.1
Other Fossil Fuel Industry (e.g., coal)					
Methane	90.1	75.3	67.8	62.5	73.5

Table 7-7 (cont). U.S. Historical GHG Emissions

Sector	Emissions (Mt CO_2e)				
	1990	1995	2000	2005	2008
Industrial Processes					
CO_2	191.5	192.6	187.7	167.0	162.1
Methane	1.9	2.1	2.2	1.8	1.6
N_2O	39.1	43.2	31.2	27	25.5
HFCs	36.9	62.2	103.2	119.3	126.9
PFCs	20.8	15.6	13.5	6.2	6.7
SF6	5.9	6.5	4.1	3.9	3.1
Waste Management					
CO_2	8.0	11.5	11.3	12.6	13.1
Methane	173.2	169.6	147.1	151.5	152.3
N_2O	4.0	4.8	5.8	6.5	6.8
Agriculture					
Methane	169.6	185.9	183.7	186.7	194.0
N_2O	218.3	221.8	227.2	233.0	235.5
Land Use					
CO_2	8.1	8.1	8.8	8.9	8.6
Methane	3.2	4.3	14.3	9.8	11.9
N_2O	3.7	4.9	13.2	9.8	11.7
Total Gross Emissions [3]	**6,126.8**	**6,488.8**	**7,044.5**	**7,133.2**	**6,956.8**
Increase Relative to 1990		**6%**	**15%**	**16%**	**14%**
Land Use, Land-Use Change (Sink)					
CO_2	(909.4)	(842.9)	(664.2)	(950.4)	(940.3)
Total Net Emissions [3]	**5,217.3**	**5,646.0**	**6,380.2**	**6,182.8**	**6,016.4**
Increase Relative to 1990		**8%**	**22%**	**19%**	**15%**

Source: Adapted from Tables 2-1, 2-6, 2-8, 2-10, and 2-11 from *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2008* (USEPA 2010b). Categories have been grouped to simplify this table.

[1] Includes electricity generation and other stationary combustion.

[2] In its April 10, 2010 proposed GHG Mandatory Reporting Rule re-proposal for petroleum and natural gas reporting (GPO 2010a), USEPA stated that some natural gas system emissions were underestimated. Consequently, the reported methane and CO_2 emissions shown here are less than actual emissions.

[3] Totals may not equal the sum of sector totals due to rounding.

Although the USEPA 2008 GHG inventory is the most recent national GHG inventory published by the agency, a more comprehensive national GHG emission inventory is available for the oil and gas industry. Due to a more detailed look at natural gas industry emissions, particularly fugitive emissions, the sector-specific detailed emission inventories described below indicate greater emissions from the natural gas and oil sectors than were included in USEPA's multiyear inventory. This discrepancy illustrates the ongoing improvement in GHG emission inventories as more data are collected over time.

7.3.1. U.S. Natural Gas System Emission Inventory

A summary of total CO_2 and methane emissions is provided in terms of CO_2e in Table 7-8. This emission summary was included in the preamble to USEPA's re-proposed rule to set mandatory reporting requirements for Petroleum and Natural Gas Systems (April 12, 2010, GPO 2010a). Although most of the emission sector categories in the table include only natural gas activities, the onshore and offshore production categories include both natural gas and petroleum production. Detailed emission breakdowns for gas industry methane-only emissions are provided in Appendix A. Consequently, the methane-only CO_2e emissions provided in Appendix A are less than the CO_2e emissions based on combined CO_2 and methane shown in Table 7-8. However, there appears to be a discrepancy in transmission sector emissions between the two inventories. Transmission sector methane-only CO_2e is greater than the CO_2e emissions shown in Table 7-8. This discrepancy may be due to difficulties in achieving consistency among multiple oil and gas emission inventories while new emission sources are being added to inventories in ongoing efforts to compile more comprehensive inventories.

Table 7-8. U.S. CO_2e Emission Breakdown for Petroleum and Natural Gas Industry

Sector	CO_2e Emissions (metric tons)
Onshore Petroleum & Gas Production	277,798,737
Offshore Petroleum & Gas Production	11,261,305
Natural Gas Processing	33,984,015
Natural Gas Transmission Compression	64,059,125
Underground Natural Gas Storage	9,713,029
LNG Storage	2,113,601
LNG Import and Export	315,888
Natural Gas Distribution	25,258,347
Total Emissions	**424,504,047**

Source: Adapted from Table W-2 of 75 *FR* 18608 (GPO 2010a).

7.3.2. U.S. Oil System Emission Inventory

Currently, USEPA estimates methane emissions from crude oil production operations, transportation activities, and refining. In contrast, CO_2 emissions are estimated only for crude oil production, though future estimates will be undertaken by the agency for other large petroleum industry sources of CO_2.

Of the 29.1 Mt of CO_2e due to methane that was emitted in 2008 (as shown in Table 7-7), the breakdown among industry sub-sectors is as follows (USEPA, undated).

- Crude oil production: 97 percent
- Crude oil transportation: <0.5 percent
- Crude oil refining: slightly more than 2 percent (most methane outgases prior to refinery entry)

7.3.3. U.S. 2020 Emission Inventory

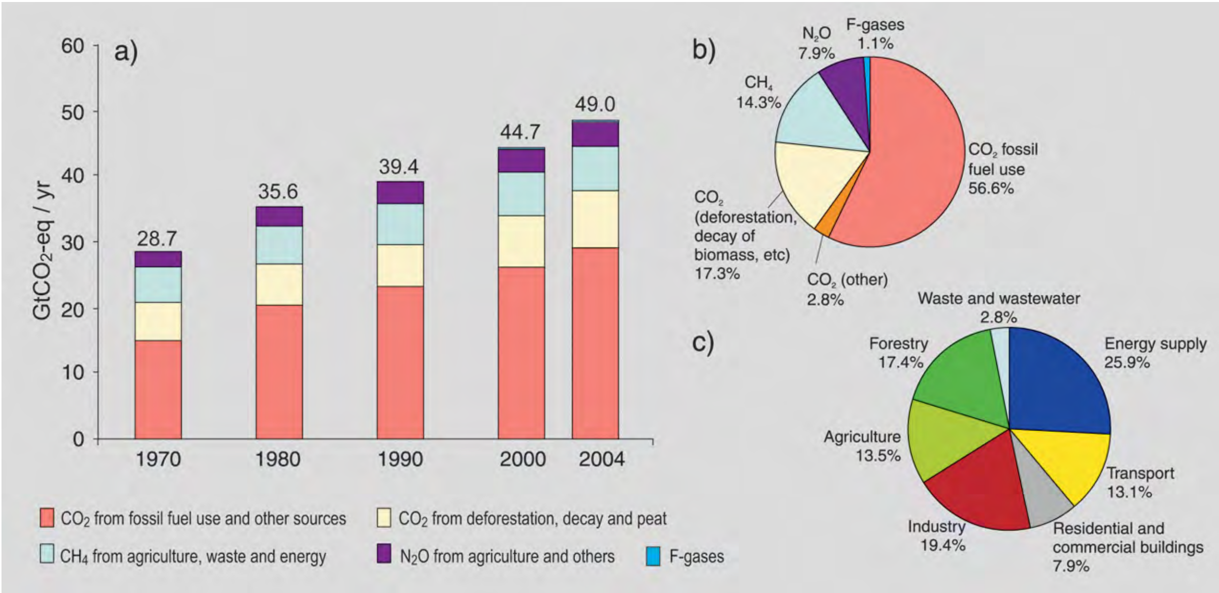
U.S. GHG emissions are expected to continue increasing in the near future. Energy-related CO_2 emissions (including emissions from combustion of fossil fuels) are expected to rise to 5,905 Mt by 2020 (EIA 2010b). In addition, GHG emissions of methane, N_2O, and other high-GWP pollutants are expected to contribute approximately 1,278 Mt of CO_2e in 2020 (USEPA 2006b). Of these high-GWP GHGs, methane from natural gas and oil system fugitive emissions would account for approximately 169 Mt of CO_2e (EIA 2010b).

7.4. Global GHG Emission Inventory

Global anthropogenic GHG emissions are expressed in Gt per year. As shown in Figure 7-1 (a), total global 2004 CO_2e emissions were approximately 49.0 Gt (IPCC 2007a). CO_2 and methane are the two GHG pollutants with the greatest emissions. CO_2 emissions from all sources accounted for a total of 76.9 percent of CO_2e emissions, with emissions from fossil fuel use accounting for most of the emissions [Figure 7-1(b)]. Methane accounted for 14.3 percent of total CO_2e emissions. On a CO_2e basis, total GHG emissions increased by approximately 70 percent from 1970 to 2004.

7.4.1. Global Energy Supply GHG Emissions

The largest economic sector producing global GHG emissions is the energy supply sector, which accounts for 25.9 percent of emissions [Figure 7-1(c)]. In order to avoid double-counting, the energy supply percentage does not include emissions resulting from electricity provided to the other sectors shown below.



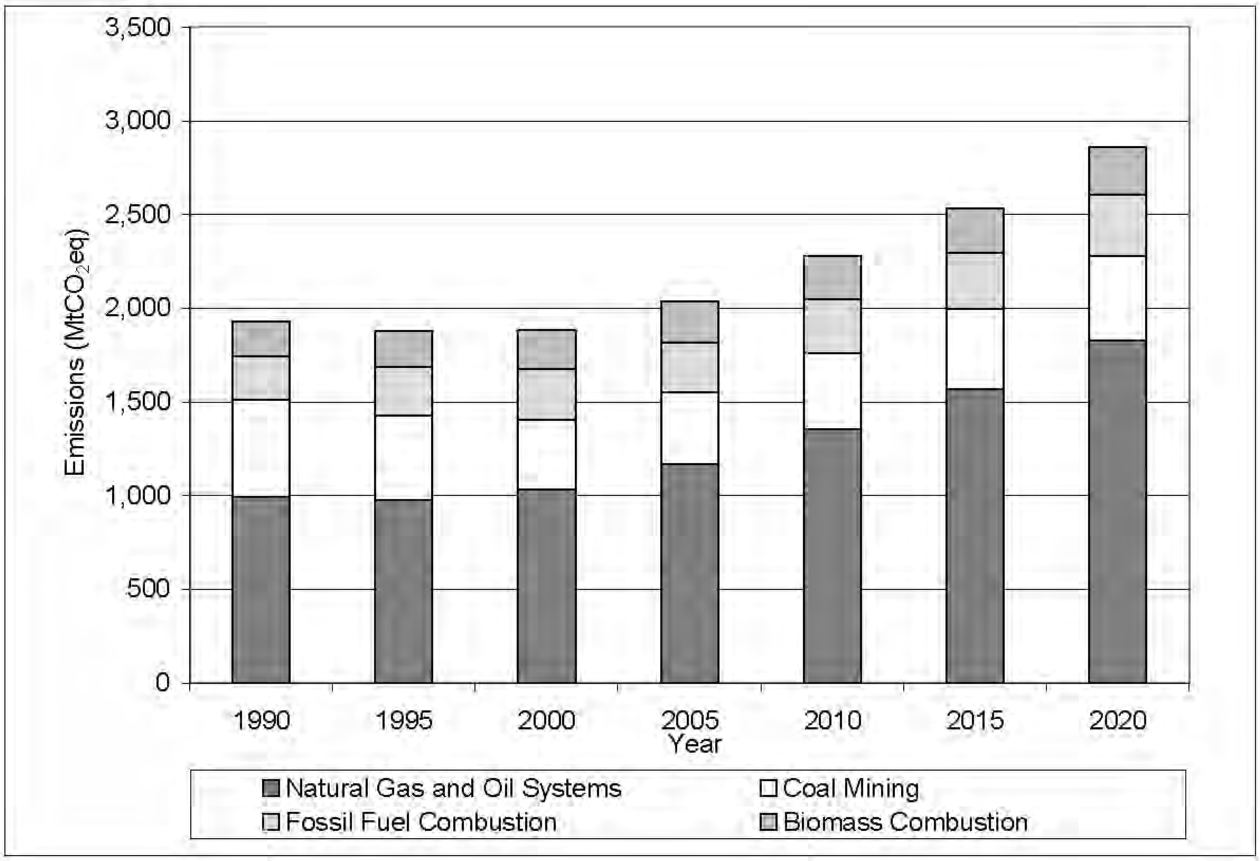
Source: Figure 2.1 of *Climate Change 2007: Synthesis Report* (IPCC 2007a).

(a) Global annual emissions of anthropogenic GHG from 1970 to 2004. (b) Share of different anthropogenic GHGs in total emissions in 2004 in terms of CO_2eq. (c) Share of different sectors in total anthropogenic GHG emissions in 2004 in terms of CO_2e. (Forestry includes deforestation.)

Figure 7-1. Global GHG Emissions

Fossil energy use is responsible for approximately 85 percent of anthropogenic CO_2 emissions produced annually (IPCC 2007d) while power generation from fossil fuels accounts for approximately 41 percent of global energy-related CO_2 emissions (IEA 2010). Due to having the lowest CO_2 combustion emissions of fossil fuels, natural gas may substitute for other fossil fuels in electricity production and other energy-producing uses. However, the level of substitution will vary regionally based on a number of factors, including natural gas availability, price, and regulatory requirements or incentives to reduce GHG emissions. Total natural gas demand is projected to grow 1.8 percent annually from 2006 through 2030, while oil demand is expected to grow 1.0 percent (IEA 2008). Natural gas usage for electricity generation is projected to increase from 39 percent to 45 percent in 2030 (IEA 2008).

At approximately 14 percent of global CO_2e emissions, methane is the second largest type of CO_2e emissions after CO_2 from fuel combustion (IPCC 2007a). The sectors with the greatest methane emissions are agriculture and energy (USEPA 2006b). Within the energy sector, natural gas and oil systems account for more than half of non-CO_2 emissions as shown in Figure 7-2 (USEPA 2006b). Non-CO_2 emissions from the energy sector are primarily methane.



Source: Figure 3-1 of *Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990-2020*. (USEPA 2006b).

Figure 7-2. Energy Sector Breakdown of Global Methane and N_2O Emissions

7.4.1.1. Global Natural Gas System GHG Emissions

Methane and CO_2 are the primary GHGs emitted from global natural gas systems. The natural gas sector is a leading source of anthropogenic methane emissions and accounts for more than 970 Mt of CO_2e globally, which is equivalent to approximately 8 percent of global methane emissions (USEPA 2006a). Sources of natural gas within the global natural gas sector are similar to those described earlier for U.S. natural gas sector.

Nitrous oxide emissions from global natural gas systems are generated primarily by fossil fuel combustion during natural gas production, processing, transmission/storage, and distribution. Natural gas system N_2O emissions are minimal contributors to total natural gas system CO_2e emissions.

7.4.1.2. Global Oil System GHG Emissions

Methane is the primary GHG emitted from global oil systems. It accounted for 57 Mt of CO_2e during 2000 and is the 11th largest source of global anthropogenic methane emissions, contributing approximately 0.5 percent of total global methane emissions (USEPA 2006a). Emissions from oil production fields accounted for more than 97 percent of total oil industry emissions. Refining accounted for 2 percent of total methane emissions, while oil transportation accounted for the remaining 1 percent (USEPA 2006a).

Nitrous oxide emissions from global oil systems are generated primarily by fossil fuel combustion during oil production, refining, and transport. Oil System N_2O emissions are minimal contributors to total oil system CO_2e emissions.

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