Addendum to the U.S. Methane Emissions 1990-2020: 2001 Update for Inventories, Projections, and Opportunities for Reductions

1. Introduction

Methane gas is a valuable energy resource and the leading anthropogenic contributor to global warming after carbon dioxide. By mass, methane has 21 times the global warming potential of carbon dioxide over a 100-year lifetime and accounts for 10 percent of U.S. greenhouse gas emissions (excluding sinks). Reducing methane emissions is key to reducing overall greenhouse gas emissions. The major anthropogenic sources of methane emissions in the U.S. are landfills, livestock enteric fermentation and manure management systems, natural gas and oil systems and coal mines. This Addendum presents EPA's updated baseline forecast of methane emissions from the major sources in the U.S., and EPA's cost estimates of reducing these emissions.

1.1 Purpose and Scope of the Addendum Report

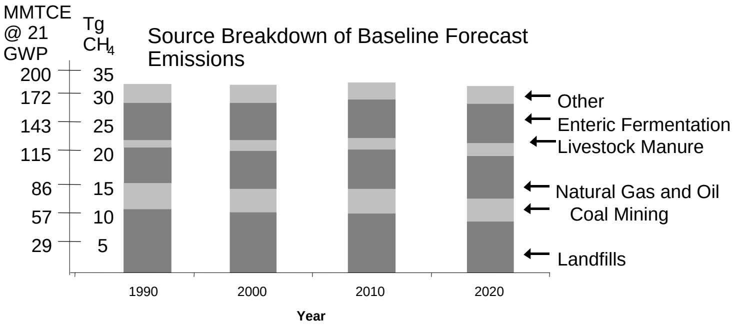
In 1999, the U.S. Environmental Protection Agency (EPA) published *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions.* This report had two objectives. First, it presented EPA's baseline forecast of methane emissions from the major anthropogenic sources in the U.S. and EPA's estimates of the cost of reducing these emissions. The costs and emissions reductions are presented in a marginal abatement cost curve (MAC) format. Second, the report provided a detailed methodology for the calculation of emission estimates and reduction costs, thereby allowing analysts to understand the depth and limitations of the study. This Addendum Report updates *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions,* EPA (1999).

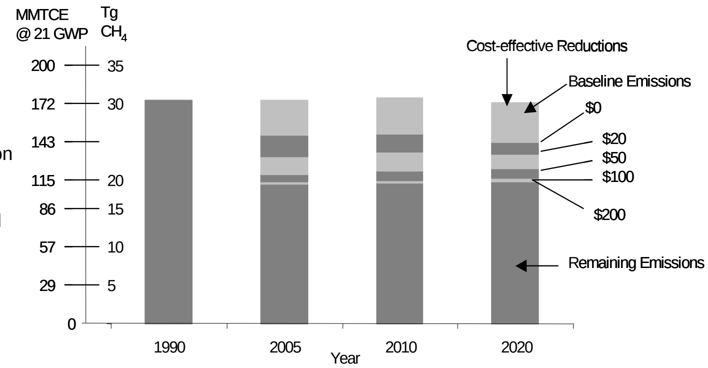
Changes in data and methodology are described in this Addendum by emission sector. Updates to the cost analysis in most sectors are based on the revision of U.S. methane emission projections for 2005, 2010, 2015 and 2020 as well as revised American Energy Outlook (AEO, 2001) estimates for the price of natural gas in these years. Only changes in data and methodology are noted in this report. For a description of the original methodology, see EPA (1999).

The marginal abatement curves (MACs) developed in EPA (1999) and updated here can be used to estimate possible emission reductions at various prices of carbon equivalent emission offsets or the costs of achieving certain amounts of reductions. EPA recognizes that the abatement potential analysis presented here does not reflect the possible introduction of new technologies.

1.2 Organization of Report

This Addendum generally follows EPA (1999) in organization and format. The Addendum is divided into the following sections: Landfills, Natural Gas, Oil, Coal Mining, Livestock Manure Management, and Enteric Fermentation. Within each section, there are two subsections: projected emissions and abatement potential except for the Oil and Enteric Fermentation





sections, which only address projected emissions. Each of these subsections presents updated results and describes changes in underlying data or methodology.

2. Aggregate Results

The leading anthropogenic methane sources in the U.S. are -- in descending order of magnitude -- landfills, natural gas, enteric fermentation, coal mines, and manure management systems. Table 1 shows U.S. estimates for annual emission for 1990-1995, preliminary estimates for 2000 emissions, and forecasts 2005-2020 emissions. Projections of methane baseline emissions were developed in 5-year increments starting from the year 2000 for all the sources identified in the U.S. 1990-1999 GHG emission inventory. Specific methods used to estimate sector- and source-specific methane emissions are described in the sections below.

Table 1. U.S. Baseline Methane Emissions, MMTCE

Sectors	1990 (hist.)	1995 (hist.)	2000 (prelim. est.)	2005 (proj.)	2010 (proj.)	2015 (proj.)	2020 (proj.)
Landfills	59.3	60.8	56.9	55.5	55.1	52.0	47.6
Coal Mines	24.0	20.3	21.2	22.3	22.4	22.2	21.3
Natural Gas	33.1	33.9	35.8	36.5	37.4	38.5	39.8
Manure Management	7.2	8.5	9.4	9.9	10.5	11.2	11.7
Enteric Fermentation	35.3	37.2	35.1	35.5	36.0	36.5	37.0
Other*	17.0	16.7	16.6	16.4	16.2	16.5	16.9
Total	175.8	177.4	175.0	176.2	177.6	177.0	174.2

* - “Other” sources include fossil fuel combustion, oil production, industrial processes, wastewater treatment, rice production, and biomass burning.

The baseline U.S. methane emission forecast for 2010 is 177.6 MMTCE of methane, an increase from the 175.8 MMTCE emitted in 1990. However, the 2010 forecast excludes the expected reductions associated with the U.S. voluntary programs.

Because the U.S. greenhouse gas inventory for the period 1990-2000 will not be finalized until April 2002, this addendum includes a preliminary projection for 2000 emissions. The baseline projection for 2000 is 175.0 MMTCE, which is slightly lower than emissions in 1990. When the actual emissions inventory – including the documented results of voluntary programs to reduce methane emissions – is released, this estimate will be further reduced.

This report also presents the result of extensive financial benefit-cost analyses of the opportunities for both technologies and management practices, to reduce methane emissions from four of the five major U.S. sources: landfills, natural gas systems, coal mining and livestock manure. The major change in the financial analysis from the original report is the update of the analysis based on new AEO (2001) projections for natural gas and electricity prices. The energy price is adjusted in some of the sectors to reflect the sector-specific energy market. The adjustment is described in the sector specific sections of this report and EPA (1999).

The marginal abatement curves (MACs) developed for this report can be used to estimate possible emission reductions at various prices for carbon equivalent emissions or conversely, the costs of achieving certain amounts of reductions. The cost analyses will change with the introduction of new technologies and additional research into methane emission abatement technologies and practices. The cost analysis presented in Table 2 is for the years 2005, 2010, 2015 and 2020. All values are in 1996 constant dollars.

Table 2: Aggregate Emission Reductions Achievable at Different Carbon Equivalent Prices (using sector-specific discount rates[1])

Year	2005		2010		2015		2020	
*Baseline Emissions (MMTCE)	176.2		177.6		177.0		174.2	
	Reductions		Reductions		Reductions		Reductions	
Carbon Value $/TCE	Cumulative	%	Cumulative	%	Cumulative	%	Cumulative	%
($20)	3.7	2%	3.8	2%	7.2	4%	10.5	6%
($10)	13.9	8%	14.5	8%	15.9	9%	17.3	10%
$0	27.1	15%	28.3	16%	29.7	17%	31.2	18%
$10	35.7	20%	35.3	20%	35.7	20%	36.1	21%
$20	44.0	25%	42.2	24%	41.4	23%	40.6	23%
$30	51.9	29%	48.9	28%	46.9	26%	44.9	26%
$40	55.0	31%	52.3	29%	50.3	28%	48.3	28%
$50	58.3	33%	57.0	32%	54.5	31%	52.0	30%
$75	62.4	35%	62.4	35%	59.7	34%	57.0	33%
$100	64.3	37%	64.6	36%	62.0	35%	59.4	34%
$125	65.4	37%	65.7	37%	63.3	36%	61.0	35%
$150	65.7	37%	66.1	37%	63.7	36%	61.4	35%
$175	65.9	37%	66.3	37%	64.1	36%	61.8	35%
$200	66.1	38%	66.5	37%	64.3	36%	62.1	36%
Remaining Emissions	110.1	62%	111.1	63%	112.7	64%	112.2	64%

*** Baseline emissions are "total emissions" from Table 1, which includes all sectors.**

The MAC is derived by rank-ordering individual opportunities by cost per emission reduction amount. On the MACs, energy market prices are aligned to $0/TCE, where no additional price signals from emission reduction values exist to motivate reductions. At and below $0/TCE, all emission reductions are due to increased efficiencies, conservation of methane, the capture and sale of methane as natural gas, and/or the capture of methane and production of electricity. As a value is placed on methane emission reductions in terms of $/TCE, these values are added to the energy market prices and allow for additional reductions to clear the market. Any "below-the-line" reduction amounts, with respect to $/TCE, are cost effective based on the market price of methane sales or electricity generation. Points above $0/TCE illustrate this duel price signal market, i.e., energy prices and emission reduction values.

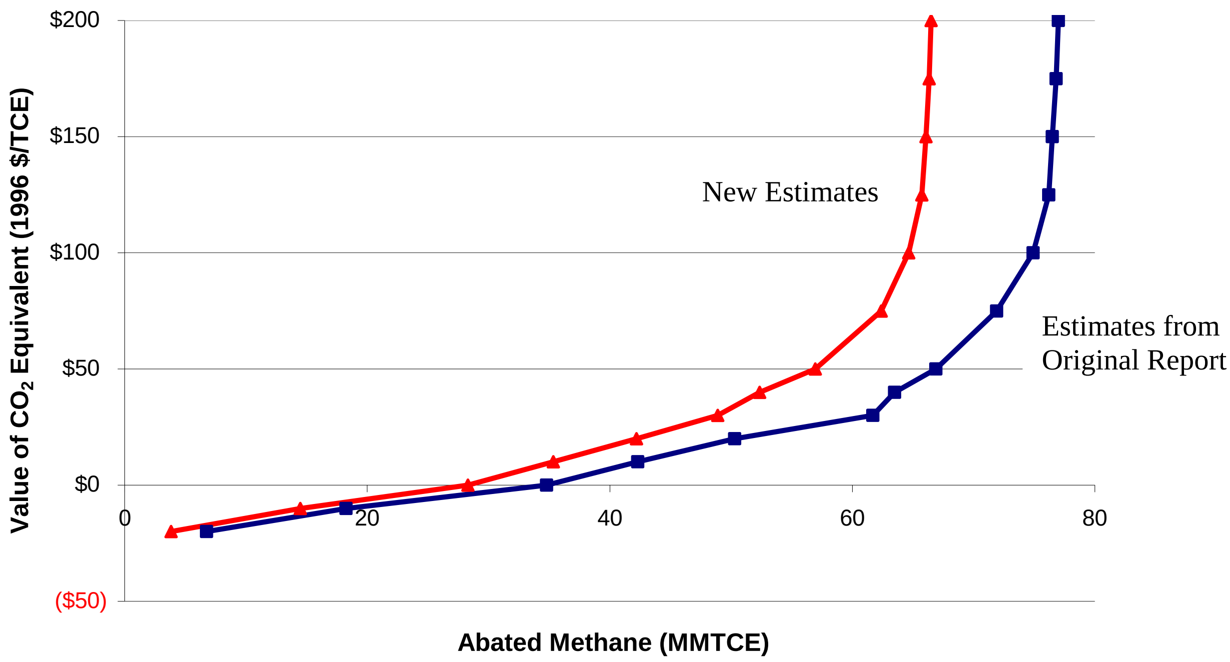
The cost estimates for reducing methane emissions presented in this report can be integrated into economic analyses to produce more comprehensive assessments of total GHG reductions. By

[1] Sector-specific discount rates are as follows: landfills – 10%; natural gas and oil – 20%; coal mining – 15%; manure – 10%.

including methane emission reductions, the overall cost of reducing GHG emissions in the U.S. is reduced due to recovered costs from capture methane and selling the methane as natural gas.

Graph 1 shows the aggregate marginal abatement curves (MAC) using sector-specific discount rates. The exhibit illustrates the differences between the 1999 aggregate estimates (presented in *U.S. Methane Emissions 1990-2020*) and the 2001 aggregate estimates (presented in the Addendum).

Graph 1: Cost Estimates for Abating Methane in 2010 based on the Coal Mining, Natural Gas, Manure Management and Landfill Sectors (using sector-specific discount rates)



The 2001 estimates reflect changes in projected emissions, projected energy prices, and mitigation options. These changes shifted the MAC curve to the left, reflecting mitigation options implemented between 1999 and 2001, lower baselines emission estimates, and flat growth of energy prices. At the market price of energy (represented at $0/TCE), estimated abatement opportunities have decreased to 28 MMTCE from the 1999 estimate of 35 MMTCE. MACs for both years become inelastic as they approach $200/TCE methane; at this value, the 2001 estimate predicts 66 MMTCE would be abated, while the 1999 estimate predicts 77 MMTCE would be abated.

3. Landfills

3.1 Methodology for Projecting Landfill Methane Emissions

Projections of landfill methane emissions are based on two key factors: (1) projections of waste generated; and (2) the percentage of the waste stream that is landfilled each year. To obtain projections for the amount of waste landfilled each year, regression analysis was used to determine the correlation between historical waste generation and human population data. The amount of waste generated was projected to 2020 using AEO population projections from EIA's *Annual Energy Outlook 2001*. Projected waste generation is assumed to be linearly correlated to population. This assumption was based on statistically significant regression results.

The percent of waste generated and disposed in landfills was assumed to be a logarithmic function of historical data of waste disposed. This assumption was made in order to capture the "flattening out" trend in percentage of waste disposed over the past ten years. EPA previously assumed that the amount of waste disposed in landfills would be constant in the future because increases in waste generation would be offset by increases in recycling. The updated analysis does not assume waste disposal is a constant figure. Instead, this analysis projects waste generation and percent disposed separately, resulting in increasing waste disposal projections.

Using the above data for waste landfilled, estimates of methane generation from 2000-2020 were based on the model used to develop the *Inventory of U.S. Greenhouse Gas Emissions and Sinks for 1990-1999.* The estimates of methane flared in 1990-99 were based on flaring equipment vendor data, and the preliminary 2000 emissions level was estimated by using linear trend analysis. Estimates of methane recovered by landfill gas-to-energy projects from 1990-2000 were based on data provided by EPA's Landfill Methane Outreach Program. For 2005-2020, projections were based on the landfill projection model as described in *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions*. The model described above projects methane recovery due to regulatory-driven mitigation options (i.e., New Source Performance Standards or the "Landfill Rule.")[2]

The uncertainties in this analysis stem from uncertainties in the validity of the above assumptions (e.g., whether waste generation is indeed linearly correlated to population). Also, flare estimates from 1990-99 are low due to data availability.

3.2 Achievable Emission Reductions and Marginal Abatement Curves

The methodology used to calculate the marginal abatement cost curves in this report is similar to that described in EPA (1999), but is based on the updated emission projections and a more recent natural gas price forecast. The opening and closing of landfills are modeled over time and methane generation is based on waste disposed over a 30-year period. Unit costs for electricity

[2] The baseline presented in this paper is not the same as the baseline presented in the National Communication. This difference is due to differences in the use of discount rates. The National Communications estimates are based on a sector-specific discount rate of 8 percent, where the results represented in Table 3 are based on a 10 percent discount rate.

and direct gas use projects are the same as those used for EPA (1999). However, the methodology has been refined to determine the cost per quantity of emission reductions for both direct gas use and electricity projects and select the least cost option.[3] In addition, it is now assumed that all direct use projects that have a lower cost than electricity projects will be implemented, rather than the 75 percent of projects used in the 1999 report. The analysis is repeated at a range of values for abated methane and the results of the analysis are used to construct a marginal abatement curve.

Table 3: Landfill Emission Reductions Achievable at Different Carbon Equivalent Prices (@ 10% discount rate)

Year	2005		2010		2015		2020	
Baseline Emissions (MMTCE)	55.5		55.1		52.0		47.6	
	Reductions		Reductions		Reductions		Reductions	
Carbon Value $/TCE	Cumulative	%	Cumulative	%	Cumulative	%	Cumulative	%
($20)	0.0	0%	0.0	0%	0.0	0%	0.0	0%
($10)	0.0	0%	0.0	0%	0.0	0%	0.0	0%
$0	8.0	14%	8.1	15%	8.5	16%	8.9	19%
$10	13.7	25%	12.7	23%	12.2	24%	11.8	25%
$20	19.1	34%	16.8	31%	15.6	30%	14.4	30%
$30	23.9	43%	20.4	37%	18.2	35%	16.0	34%
$40	25.6	46%	22.8	41%	20.1	39%	17.4	37%
$50	26.1	47%	24.1	44%	21.0	40%	18.0	38%
$75	26.2	47%	25.5	46%	22.1	42%	18.7	39%
$100	26.2	47%	25.7	47%	22.4	43%	19.0	40%
$125	26.2	47%	25.7	47%	22.5	43%	19.3	41%
$150	26.2	47%	25.7	47%	22.6	43%	19.5	41%
$175	26.2	47%	25.7	47%	22.7	44%	19.6	41%
$200	26.2	47%	25.7	47%	22.7	44%	19.6	41%
Remaining Emissions	29.2	53%	29.3	63%	29.4	56%	28.0	64%

3 The 1999 report only evaluated direct gas use projects if electricity projects were not cost-effective.

4. Natural Gas and Oil

4.1 Methodology for Inventory and Projections

4.1.1 Natural Gas

The forecast of methane emissions from natural gas systems (production, processing, transmission and distribution) is based upon emission factors for a 1992 base year and projected activity factors. The emissions factors were developed by the EPA and Gas Research Institute (EPA/GRI 1996). Activity factors are forecast using the drivers in EPA (1999). For this addendum, forecasts of the drivers are updated using the Energy Information Administration's (EIA's) *Annual Energy Outlook 2001*, and recent information on the number of wells provided by ICF Incorporated's Gas Systems Analysis Model (GSAM). The methodology for forecasting emissions is the same as in EPA (1999). Emissions reductions that are expected from EPA's Natural Gas STAR Program – a voluntary partnership with the gas industry – have not been subtracted from the baseline projections.

4.1.2 Oil Industry

The methodology for estimating methane emissions from the oil industry has been changed in this Addendum from what is described in EPA (1999). The new methodology is the same as that presented in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1998* (EPA, 2000). The new approach first characterizes the industry by sector and then examines the activities within each sector that produce methane emissions. This approach uses emission factors and activity factors to build a comprehensive, bottom-up inventory of emissions. Projections of emissions are developed by using forecasts of the activity drivers used to adjust the activity factors. Emission factors remain constant over the term of the forecast.

The methodology is based on a comprehensive study of methane emissions from U.S. petroleum systems, *Estimates of Methane Emissions from the U.S. Oil Industry (Draft Report)* (EPA 1999). This study drew upon an earlier study by Radian International LLC, *Methane Emissions from the U.S. Petroleum Industry* (Radian, 1996) that estimated emission factors for 70 petroleum industry activities for a base year. Total emissions for the industry are estimated by summing the products of these emission factors and corresponding activity factors.

Methane emissions from the oil industry arise from three main activities: crude oil production, crude oil transportation, and crude oil refining. There are essentially no methane emissions downstream of refining. The common types of emissions across the sectors are venting, fugitives, combustion, and system upsets. Appendix C of this Addendum presents the emission factors and base activity factors for methane emissions for the petroleum industry. The tables in the Appendix C correspond to similar tables in EPA (1999) showing emission factors and activity factors for the natural gas industry.

The largest source of methane emissions is crude oil production, which contributed 97 percent of the methane emissions from the oil industry in 1998. The five major emission sources in the production sector are venting from crude oil storage tanks pneumatic devices, venting from small pumps, fugitives from wellheads, combustion products from gas engines and process upsets. Methane emissions from crude oil transportation account for about one-half of one percent of total emissions from the industry; methane emissions from refining account for about 2.4 percent of the total.

The major activity factor drivers for projecting methane emissions from the petroleum industry are total domestic production, percent of production that is heavy oil (<20^{o} API), total producing wells, percent of wells for heavy crude, and total stripper wells.

4.2 Achievable Emission Reductions and Marginal Abatement Curves

The methodology used to calculate the marginal abatement cost curves for natural gas is unchanged from EPA (1999). Forecast baseline emissions were updated as described above, using the *Annual Energy Outlook 2001* (EIA, 2001). Natural gas price data for future years also comes from the *Annual Energy Outlook*. As with the 1999 report, a marginal abatement curve has not been developed for the oil sector.

Table 4: Natural Gas Emission Reductions Achievable at Different Carbon Equivalent Prices (@20% discount rate)

Year	2005		2010		2015		2020	
Baseline Emissions (MMTCE)	36.5		37.4		38.5		39.8	
	Reductions		Reductions		Reductions		Reductions	
Carbon Value $/TCE	Cumulative	%	Cumulative	%	Cumulative	%	Cumulative	%
($20)	3.7	10%	3.8	10%	5.7	15%	7.5	19%
($10)	9.1	25%	9.3	25%	9.9	26%	10.5	26%
$0	10.4	28%	11.2	30%	11.5	30%	11.8	30%
$10	11.9	33%	12.2	33%	12.6	33%	12.9	33%
$20	12.2	33%	12.5	33%	12.9	33%	13.3	33%
$30	12.7	35%	13.0	35%	13.3	35%	13.7	35%
$40	12.7	35%	13.0	35%	13.6	35%	14.2	36%
$50	14.6	40%	15.0	40%	15.6	40%	16.2	41%
$75	16.2	44%	16.6	45%	17.3	45%	17.9	45%
$100	17.6	48%	18.0	48%	18.7	49%	19.4	49%
$125	18.2	50%	18.8	50%	19.4	50%	20.1	51%
$150	18.3	50%	18.8	50%	19.5	51%	20.2	51%
$175	18.3	50%	18.8	50%	19.5	51%	20.2	51%
$200	18.3	50%	18.8	50%	19.5	51%	20.2	51%
Remaining Emissions	18.2	50%	18.6	50%	19.0	49%	19.6	49%

5. Coal Mining

5.1 Methodology for Projections of Methane Emissions

Future methane emissions of coalmine methane were estimated using projections of coal production from underground and surface mines in eleven U.S. regions. These projections were obtained from the EIA's *Annual Energy Outlook, 2001*. Future coal mine methane emissions were estimated for the following four categories: underground mining; underground post-mining; surface mining; and surface post-mining. Emissions for 2005, 2010, 2015 and 2020 were estimated separately for each region by projecting emissions from the four sub-sources proportionally to changes in the total region-specific underground and surface coal production. This methodology is different from the one used in EPA (1999), where emissions were projected based on the total surface and underground production, i.e. without accounting for regional differences.

The 1990 and 1995 emissions reported in Table 1 are estimated using the methodology described in the U.S. Greenhouse Gas Inventory (2001) and include the effects of voluntary actions to reduce emissions. Emission projections for 2000 to 2020 and do not reflect the expected reductions that will result from the continued voluntary efforts of the industry.

5.2 Achievable Emission Reductions and Marginal Abatement Curves

The methodology used to calculate the marginal abatement cost curves for coal mine methane is based on EPA (1999). However, these cost curves were updated using the latest emission projections and natural gas price forecast. In addition, the potential abatement options and the assumptions behind the use of abatement technologies differ.

For this update, methane destruction by using ventilation air methane (VAM) technology was modeled as an abatement option. This option was assumed to be used for methane destruction only; electricity or heat production and sales were not considered. Each mine can implement degasification, enhanced degasification and VAM simultaneously. All cost assumptions for the degasification and enhanced degasification options were based on the 1997 data. Costs for the VAM option were taken from the recent EPA analysis (Schultz, 2001). All options are initially applied in the same year for which emissions and prices are estimated – no subsequent changes in emissions/prices occur once the projects are underway. See Appendix A for a thorough description of how the changes in abatement options were modeled.

Table 5: Coal Mine Emission Reductions Achievable at Different Carbon Equivalent Prices (@15 % discount rate)

Year	2005		2010		2015		2020	
Baseline Emissions (MMTCE)	22.3		22.4		22.2		21.3	
	Reductions		Reductions		Reductions		Reductions	
Carbon Value $/TCE	Cumulative	%	Cumulative	%	Cumulative	%	Cumulative	%
($20)	0.0	0%	0.0	0%	1.5	7%	3.0	14%
($10)	4.8	22%	5.2	23%	6.0	27%	6.8	32%
$0	7.3	33%	7.5	34%	8.1	36%	8.7	41%
$10	8.7	39%	8.8	39%	9.1	41%	9.5	44%
$20	10.7	48%	10.7	48%	10.6	48%	10.5	49%
$30	12.2	55%	12.3	55%	11.8	53%	11.4	53%
$40	12.9	58%	12.6	57%	12.4	56%	12.1	57%
$50	13.3	60%	13.3	60%	12.9	58%	12.5	59%
$75	14.0	63%	13.9	62%	13.5	61%	13.1	61%
$100	14.2	64%	14.1	63%	13.6	61%	13.2	62%
$125	14.3	64%	14.2	63%	13.8	62%	13.4	63%
$150	14.4	64%	14.3	64%	13.9	63%	13.5	63%
$175	14.5	65%	14.5	65%	14.1	63%	13.6	64%
$200	14.6	66%	14.5	65%	14.1	64%	13.7	64%
Remaining Emissions	7.7	34%	7.8	35%	8.1	36%	7.6	36%

6. Livestock Manure Management

6.1 Methodology for Projecting Methane Emissions

The inventory model for methane emissions from manure management and enteric fermentation changed significantly between 2000 and 2001. The new methodology for the inventory model is based on the IPCC report *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*.

For beef feedlot cattle, dairy cows, dairy heifers, swine, and poultry, methane emissions were calculated for each animal group as follows:

$$Methane_{animal\ group} = \sum_{state}(Population * VS * B_o * MCF_{animal,\ state} * 0.662)$$

where:

$Methane_{animal\ group}$	=	methane emissions for that animal group (kg CH_4/yr)
Population	=	annual average state animal population for that animal group (head)
VS	=	total volatile solids produced annually per animal (kg/yr/head)
B_o	=	maximum methane producing capacity per kilogram of VS (m^3 CH_4/kgVS)
$MCF_{animal,\ state}$	=	weighted MCF for the animal group and state[4]
0.662	=	conversion factor of m^3 CH_4 to kilograms CH_4 (kg CH_4 /m^3 CH_4)

Methane emissions from other animals (i.e., sheep, goats, and horses) were based on the 1990 methane emissions estimated using the detailed method described in *Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress* (EPA 1993).

Due to the change in the inventory model, the forecast for methane emissions from manure management changed significantly. Each animal group by state was projected forward to obtain 2005-2020 estimates. Estimates of farm size increases over the next 20 years were calculated based on past data and total volatile solids produced per animal was adjusted for increasing milk productivity. Temperature was held at the 10-year average for agricultural regions in each state. All other emission factors, such as maximum methane producing capacity were held constant at 1999 levels. The inventory model was then run with the projected data to calculate projected emissions for 2005, 2010, 2015 and 2020.

6.1 Achievable Emission Reductions and Marginal Abatement Curves

Due to the new methodology for developing emission projections, the old manure management cost model could not be used to estimate new marginal abatement curves. Instead, the marginal abatement curves presented in EPA (1999) were adjusted by the percentage difference in methane emission estimates from the 1999 report and the current analysis. The magnitude of change in potential emission reductions is assumed to be proportional to the changes in baseline emissions between the two analyses.

[4] See "Step 5: Develop Weighted Emission Factors" as described in EPA (2001), p. K-6.

Table 6: Manure Management Emission Reductions Achievable at Different Carbon Equivalent Prices (@10% discount rate)

Year	2005		2010		2015		2020	
Baseline Emissions (MMTCE)	9.9		10.5		11.2		11.7	
	Reductions		Reductions		Reductions		Reductions	
Carbon Value $/TCE	Cumulative	%	Cumulative	%	Cumulative	%	Cumulative	%
($20)	0.0	0%	0	0%	0.0	0%	0.0	0%
($10)	0.0	0%	0	0%	0.0	0%	0.0	0%
$0	1.4	14%	1.5	14%	1.6	14%	1.7	15%
$10	1.5	16%	1.6	16%	1.8	16%	1.9	16%
$20	2.0	20%	2.1	20%	2.3	20%	2.4	21%
$30	3.1	31%	3.3	31%	3.5	32%	3.8	32%
$40	3.7	38%	4.0	38%	4.3	38%	4.6	39%
$50	4.3	43%	4.5	43%	4.9	44%	5.2	45%
$75	6.0	61%	6.4	61%	6.9	61%	7.3	63%
$100	6.4	65%	6.8	65%	7.3	65%	7.8	67%
$125	6.6	68%	7.1	68%	7.6	68%	8.1	69%
$150	6.8	69%	7.2	69%	7.7	69%	8.3	70%
$175	6.9	70%	7.3	70%	7.9	70%	8.4	72%
$200	6.9	71%	7.4	71%	8.0	71%	8.5	73%
Remaining Emissions	2.9	29%	3.1	29%	3.2	29%	3.2	27%

7. Enteric Fermentation

7.1 Methodology for Methane Emission Projections

Future methane emissions from enteric fermentation were assumed to be directly proportional to the livestock population, without accounting for potential changes in emission factors. This methodology differs from the one used in the USEPA 1999 report, which was based on both: changes in the livestock population and changes in emission factors (e.g., due to a shift from dry to liquid treatment systems).

Emissions from enteric fermentation from 1999 onward were projected by livestock group based on forecasts of the total number of animals in each group. Animal population forecasts are based on USDA's (1999) report, which projects animal populations out to 2010. The 2020 estimates are based on applying predicted growth rates to the data in the USDA (1999) report.

Emissions from a particular livestock group in a year X are estimated as follows:

$$E_{i(X)} = E_{i(1999)} * N_{i\,(X)} \div N_{i\,(1999)}$$

where: $E_{i(1999)}$ are the 1999 emissions from the same livestock group, $N_{i\,(X)}$ is the livestock population in year X, and $N_{i\,(1999)}$ is the livestock population in 1999.

Unlike the EPA (1999) analysis, the methane emission projections do not assume any significant changes in the shares of different manure management systems and other factors affecting emissions.

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Appendix A: Methodology for Coal Sector Methane Abatement Curves

Steps One: Define the current set of mines and their characteristics, and estimate future coal and methane production.

Initially, a subset of 59 underground mines emitting over 0.5 mcf of ventilation methane per day was identified. Three of those mines were subsequently excluded due to the lack of coal production data for base years (1997 and 1999). 41 of the remaining 56 mines had both 1997 and 1999 coal production data, while for the rest of mines (15) the 1999 production was estimated based on the 1997 production and changes in emissions from 1997 to 1999 (production was assumed to change proportionally to emissions). The 56 mines selected for the analysis emitted about 94 percent of underground methane emissions in 1999. EPA (1999) was based on the 1997 parameters of 58 mines, which also emitted about 94 percent of methane from underground mining.

The future cost of coalbed methane recovery and utilization at a given mine depends on whether it already has degasification facilities and what mining method is used. These two characteristics were assessed based on 1997 data. For mines that were not included in the 1997 sample, the default assumption was that there was no existing degasification system and that the longwall method of production was used.

Each mine was allocated to one of the five basins with underground production. Future coal production at each mine was assumed to change proportionally to changes in basin-wide underground production (Energy Information Administration, AEO2001 National Energy Modeling System run AEO2001.D101600A). The future volume of liberated methane from each mine was calculated by multiplying the future production by the 1999 methane liberation rate (cf of methane per ton of coal). This approach differs from the one adopted in the 1999 analysis in which coal production at all mines was assumed to grow proportionally to the total US underground coal production. Current and expected future basin-specific shares of methane captured by degasification systems (vertical, horizontal, and gob wells) were kept the same as in the 1999 analysis.

Step Two: Quantify abatement options for each mine.

The three types of modeled recovery and use options analyzed are described below:

Option 1: Degasification and Pipeline Injection

Coal mines recover methane using vertical wells drilled five years in advance of mining, horizontal boreholes drilled one year in advance of mining, and gob wells. It is assumed that all gas produced by the vertical and horizontal drilling is sold to the pipeline, while only the higher quality gob gas is sold to the pipeline.

Option 2: Enhanced Degasification, Gas Enrichment, and Pipeline Injection

Coal mines recover methane in the same manner as above, but tighten well spacing to increase recovery efficiency. Mines also invest in enrichment technologies to enhance gob gas for sale to natural gas companies. This increases recovery efficiency by 20 percent above what is achieve with Option 1.

Option 3: Catalytic Oxidation

New technological options for oxidizing ventilation air methane (VAM) now appear ready for commercialization. These technologies oxidize methane contained in mine ventilation airflows and can be applied simply to destroy VAM or to destroy VAM and capture the thermal energy that its destruction liberates. If the methane concentration in ventilation air exceeds the level necessary for self-sustained operation, the process can recover high-quality heat and still maintain a steady-state operation. For the two VAM technologies, the type and cost-effectiveness of the technology depend on the amount of methane available, its typical concentration, and the prevailing energy prices.

In the current analysis, the following assumptions were made:

- Option 3 was assumed to be used for methane destruction only; electricity or heat production and sales were not considered.
- Each mine implements all three options at once: Option 2 is incremental to Option 1 and Option 3 is incremental to Options 1 and 2. It is assumed that Option 3 consumes 98% of methane remaining after Options 1 and 2 are implemented and destroys it with the 99.9% efficiency.
- All cost assumptions for Options 1 and 2 were based on the 1997 data. Costs for Option 3 were taken from the recent EPA analysis.
- Methane destroyed by Option 3 is adjusted to reflect resulting CO_2 emissions.
- All options are initially applied in the same year for which emissions and prices are estimated – no subsequent changes in emissions/prices occur once the projects are underway.
- CBM prices were based on 1999 wellhead natural gas prices expressed in 1996 $US using the 1996-1999 GDP deflator.

<u>Step Three</u>: Calculate additional value of carbon for each option at each mine and develop an abatement schedule.

For each option at each mine, a discounted cash flow analysis was performed to calculate a break-even methane price (i.e. a price at which the net present value of a given project equals zero). This calculation was performed for the years 2005-2020. The discount rate was set to 15% and the tax rate to 40%. It was also assumed that the lifetime and the depreciation period of all projects are equal to 15 years. For Options 1 and 2 the estimated break-even price at some mines was less than the natural gas price in the same year, which indicates that these options could be implemented cost-effectively. At the same time, since Option 3 was not associated with any revenue from energy sales, its implementation at any given mine was not cost effective. In order to compare Options 1,2, and 3 in the same system of coordinates, the additional value of carbon (AVC) was estimated for each potential project. For Options 1 and 2 AVC was equal to the difference between the break-even price and the current natural gas price. Hence, for cost-effective projects AVC was less or equal to zero and was positive for the rest of the projects. For Option 3, AVC was equal to the break-even methane price estimated by the cash flow analysis (i.e., the "value" of methane destroyed by Option 3 is associated only with preventing its release into the atmosphere).

Once the AVC (expressed in $US/TCE) was determined for each potential abatement project for each mine, the list of mines was sorted by the AVC value in the ascending order, so that the first project on the abatement schedule for a given year has the lowest AVC.

<u>Step Four</u>: Estimate emission reductions at different carbon prices.

The abatement schedule developed at the previous step for each year was used to estimate the volume of CBM reductions achievable at each carbon price level. For example, cost-effective reductions at all mines were estimated by summing up reductions by all the projects where the AVC is less or equal to zero. The reductions achievable at the carbon price under 10, 20, 30, $US/TCE and other prices were estimated using the same approach.

Appendix D: U.S. Sector Specific Marginal Abatement Curves at Various Discount Rate and Tax Rate Combinations – See Excel Spreadsheet for data files.