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Methodologies for U.S. Greenhouse Gas Emissions Projections:

Non-CO₂ and Non-Energy CO₂ Sources

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Draft for Public Review

U.S. Environmental Protection Agency

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U.S.A.

Preface

This report was prepared by the U.S. Environmental Protection Agency (EPA) with the support of its contractors, ERG and Ricardo-AEA. This report describes the methodology used by EPA to project emissions of greenhouse gas (GHG) emissions other than combustion-related carbon dioxide (CO₂) out to the year 2030 in a range of source categories. The sources of U.S. non-CO₂ GHG and non-energy CO₂ emissions are in the energy; industrial processes; solvent and product use; waste; agriculture; and land use, land-use change, and forestry sectors.

In May through July of 2013, the draft final report was peer reviewed for its technical content by: Mr. Shankar Ananthakrishna of Chevron; Dr. Morton A. Barlaz of North Carolina State University; Mr. E. Lee Bray of the U.S. Geological Survey; Mr. Stuart Day of Australia' Commonwealth Scientific and Industrial Research Organisation; Mr. Jon Elliott of the United Kingdom Department of Energy and Climate Change; Ms. Céline Gueguen of the Interprofessional Technical Centre for Studies on Air Pollution (CITEPA); Dr. Lena Höglund-Isaksson of the International Institute for Applied Systems Analysis; Dr. Lambert Kuijpers of the Technical University Eindhoven and a member of the Montreal Protocol's Technology and Economic Assessment Panel; Dr. Peter Lahm of the U.S. Forest Service; Dr. Sim Larkin of the U.S. Forest Service; Dr. Jan Lewandrowski of the U.S. Department of Agriculture; Dr. Gregg Marland of Appalachian State University; Mr. Etienne Mathias of CITEPA; Dr. David McCabe of the Clean Air Task Force; Dr. John Reilly of the Massachusetts Institute of Technology; Mr. Lukas Rothlisberger of the DILCO Company; Mr. Bruce Steiner of the American Coal and Coke Institute; Mr. Hendrik G. van Oss of the U.S. Geological Survey; Mr. Julien Vincent of CITEPA; and Ms. Lynn Yeung of the California Air Resources Board. The peer reviewers were asked to draw upon their expertise in non-CO₂ and non-energy CO₂ sectors and source categories, as well as in GHG emission projection methods, to comment on whether the data inputs, approach, and methodologies presented in the report reflect sound scientific and analytical practice, and adequately address the questions at hand.

Written comments were received from the peer reviewers. The reviewers generally commented that the methodologies used in this report represented a sound approach to projecting U.S. non-CO₂ GHG and non-energy CO₂ emissions. A number of comments identified areas for technical clarification, alternative datasets, and opportunities for future improvements. All comments of the reviewers were considered, and the document was modified appropriately.

EPA wishes to acknowledge everyone involved in the development of this report, and to thank the peer reviewers for their time, effort, and expert guidance. The involvement of the peer reviewers greatly enhanced the technical soundness of this report. EPA accepts responsibility for all information presented and any errors contained in this document.

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1.0 Introduction

This report presents the methodology used by the U.S. Environmental Protection Agency (EPA) to estimate projections of greenhouse gas (GHG) emissions other than combustion-related carbon dioxide (CO₂) out to the year 2030. The sources of U.S. non-CO₂ GHG and non-energy CO₂ emissions are in the energy; industrial processes; solvent and product use; waste; agriculture; and land use, land-use change, and forestry sectors. This report describes the specific methods used to project emissions for each source category. EPA will generate the projections by applying this methodology within a data system designed specifically to project the non-CO₂ GHG emissions.

1.1 Background

The U.S. government provides projections of U.S. GHG emissions for international reporting purposes as part of U.S. Climate Action Reports (CARs) to the United Nations Framework Convention on Climate Change (UNFCCC). EPA has coordinated the production of these projections, which are assembled from projections produced by the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA), the U.S. Department of Agriculture (USDA), and EPA. EPA is responsible for estimating projections for the non-CO₂ GHG and non-energy CO₂ sources.

New international reporting requirements for biennial reports now require updates to the U.S. GHG emissions projections every two years, instead of every four years as in the past.

1.2 Sectors and Key Category Analysis

Table 1 lists the sectors and source categories that generate non-CO₂ GHG and non-energy CO₂ emissions. The sector list is based on the source categories characterized in the U.S. GHG Inventory. Because of the large number of sources, EPA developed source-specific projection methodologies for a limited set of source categories. The remaining categories use a generic projection methodology. Two criteria have been used to designate the sources for which specific projection methodologies were developed:

1. All source categories designated as "key categories" in the 2012 U.S. GHG Inventory
2. Additional source categories of special interest, such as due to the presence of mitigation programs

This document focuses on describing the source-specific methodologies used to project emissions. The generic projection approach used for other sources was to extrapolate emissions based on the historical trend over the previous 10 years. For sources where emissions increased over that time period, a linear extrapolation was used; for declining emissions, an exponential extrapolation was used. EPA used these different approaches to contain projections within reasonable bounds over the long projection time period (i.e., growth tends to come up against physical limitations and decline should not go below zero emissions).

Table 1. Non-CO₂ and Non-Energy CO₂ Projection Source Categories
Check Mark (✓) Indicates That Source-Specific Methodologies Were Developed

Sector	Source(s)	Key Categories	Non-Key Categories
Energy	✓ Coal mining	CH ₄	
	✓ Stationary combustion sources	CH ₄ , N ₂ O	
	✓ Natural gas systems	CH ₄ , non-energy CO ₂	
	✓ Petroleum systems	CH ₄	
	✓ Non-energy use of fuels	Non-energy CO ₂	
	Abandoned underground coal mines		CH ₄
	✓ Mobile combustion		CH ₄ , N ₂ O
	International bunker fuels		CH ₄ , N ₂ O
	Incineration of waste		N ₂ O, non-energy CO ₂
Industrial Processes	✓ Adipic acid production	N ₂ O	
	✓ Substitution of ozone-depleting substances	HFCs	
	✓ HCFC-22 production	HFCs	
	✓ Aluminum production	PFCs, non-energy CO ₂	
	✓ Electric transmission and distribution	SF ₆	
	✓ Cement production	Non-energy CO ₂	
	✓ Iron and steel production and metallurgical coke production	Non-energy CO ₂	CH ₄
	✓ Magnesium production		SF ₆
	Nitric acid production		N ₂ O
	Silicon carbide production		CH ₄ , non-energy CO ₂
	Ferroalloy production		CH ₄ , non-energy CO ₂
	✓ Semiconductor manufacturing		HFCs, PFCs, SF ₆
	Lime production		Non-energy CO ₂
	Limestone and dolomite use		Non-energy CO ₂
	Ammonia production		Non-energy CO ₂
	Urea consumption for non-agricultural purposes		Non-energy CO ₂
	Soda ash production and consumption		Non-energy CO ₂
	Petrochemical production		CH ₄ , non-energy CO ₂
	Carbon dioxide consumption		Non-energy CO ₂
	Titanium dioxide production		Non-energy CO ₂
Zinc production		Non-energy CO ₂	
Phosphoric acid production		Non-energy CO ₂	
Lead production		Non-energy CO ₂	
Agriculture	✓ Enteric fermentation	CH ₄	
	✓ Agricultural soil management	N ₂ O	
	✓ Rice cultivation	CH ₄	N ₂ O
	✓ Manure management	CH ₄	N ₂ O
	Field burning of agricultural residues		CH ₄ , N ₂ O
Waste	✓ Landfills	CH ₄	
	✓ Wastewater treatment (domestic)		CH ₄ , N ₂ O
	Wastewater treatment (industrial)		CH ₄
	Composting		CH ₄ , N ₂ O
Solvent and Product Use	N ₂ O product usage		N ₂ O
Land Use, Land-Use Change, and Forestry	✓ Forest fires (forest land remaining forest land)	CH ₄ , N ₂ O	
	Wetlands remaining wetlands		N ₂ O, non-energy CO ₂
	Cropland remaining cropland		Non-energy CO ₂
	Settlements remaining settlements		N ₂ O

37 1.3 General Approach

38 The basic approach used to project these emissions was based on using inventory methodologies to
39 estimate emissions in future years. EPA used information from the most recent U.S. GHG Inventory (EPA
40 2013) as the starting point for emissions and underlying activities. EPA projected changes in activity data
41 and emissions factors from that base year. For the current projections, EPA used the year 2011 for the
42 base year, drawn from the 2013 U.S. GHG Inventory. Activity data projections include macroeconomic
43 drivers such as population, gross domestic product, and energy use, and source-specific activity data
44 such as fossil fuel production, industrial production, or livestock populations and crop production.
45 Future changes in emissions factors were based on continuation of past trends and expected changes
46 based on implementation of policies and measures.

47 Key elements of the overall methodology are summarized below.

48 Activity Drivers

49 Unlike emissions inventories developed for past or present inventory years—which are typically based
50 upon actual measured or quantified activity data statistics—future year projections have no activity data
51 available, by definition. Instead, activity drivers are used to estimate future year activity levels.

52 Activity drivers serve as proxies, allowing the development of reasonable approximations of future year
53 activity from base year activity levels. For instance, the U.S. Census Bureau and other agencies have
54 developed reasonably accurate long-term population projections, based on past trends and a general
55 understanding of long-term demographic behavior. These long-term population projections can be used
56 to develop future year activity level estimates for source categories that use population-based activity
57 data (e.g., domestic wastewater treatment, landfills). Another example is the long-term energy
58 production and consumption projections developed by EIA in conjunction with the *Annual Energy*
59 *Outlook*. These energy projections are developed using a sophisticated model that seeks to accurately
60 represent all aspects of U.S. energy; they can be used to develop future year activity level estimates for
61 source categories that use energy-based activity data (e.g., non-energy uses of fossil fuels, natural gas
62 systems, petroleum systems). Additional source-specific activity drivers are discussed below in Section
63 2.0.

64 Scenarios

65 The methodologies discussed in this document describe a projection scenario including the effects of
66 currently implemented policies and measures, referred to in the UNFCCC context as a “with measures”
67 scenario. This type of scenario is also sometimes referred to as a reference, baseline, or business-as-
68 usual scenario, although the term “business-as-usual” can also refer to a scenario not including the
69 effects of policies. Within the international reporting context, countries are also encouraged to provide
70 a “without measures” scenario removing the effect of policies and measures, and an “additional
71 measures” scenario including planned policies and measures. These two alternative scenario types are
72 not addressed in this document.

73 The “with measures” scenario uses a central estimate for various activity drivers. Although the results of
74 applying these methodologies will be a single projection estimate, there is uncertainty in each element
75 of the projections. In some cases, activity driver projections provide low and high scenarios that could
76 be used to develop low and high sensitivity projection scenarios in the future.

77 **Policies and Measures**

78 The projection methodologies for each source include the effects of currently implemented policies and
79 measures (PAMs). Policies implemented after the production of projections would not be included
80 without changes to the methodology. Policies are included in various ways depending on the source.
81 Considered policies include both regulatory and voluntary programs, and both policies specifically aimed
82 at reducing GHGs, as well as policies with other main purposes that have indirect impacts on GHG
83 emissions.

84 EPA has included these effects in the projections in different ways depending on the source category
85 and the data available. In some cases, potential emissions are calculated based on activity data and
86 emissions factors, and then estimates of PAM-related reductions are used to reduce potential emissions
87 resulting in actual emissions. In other cases, the effects of longstanding policies and measures are
88 included within the calculation of aggregate emissions factors based on historical emissions and
89 activities. In yet other cases, estimates of reductions due to newly implemented policies and measures
90 are based on the specific provisions of policies. Lastly, the use of external activity data implicitly includes
91 the effects of policies modeled as part of those external projections. For example, EIA projections
92 include the effects of various energy and environmental policies in the *Annual Energy Outlook*
93 projections of fossil fuel production, so that when those projections are used to calculate fugitive
94 emissions, various policies are indirectly accounted for in these non-CO₂ and non-energy CO₂ projections.

95 The term “policies and measures” describes both regulatory requirements and voluntary programs.
96 PAMs may adjust the activity data, emissions factors, or calculated emissions. In many cases, regulatory
97 PAMs do not specifically target GHG emissions, but are cobenefits. Regulatory PAMs create reductions
98 due to mandated requirements; examples include applicable subparts of the New Source Performance
99 Standards (NSPS) and state-level regulations. Voluntary PAMs create reductions in response to various
100 incentives or motivating factors. Examples of voluntary PAMs include the Natural Gas STAR program, the
101 Landfill Methane Outreach Program, and incentives that promote renewable energy (e.g., tax credits,
102 low-interest loans, Renewable Portfolio Standards).

103 The implementation of PAMs throughout the projection time series must be carefully considered. Some
104 PAMs may simply be a certain reduction quantity or percent reduction that can be applied over the
105 entire time series. However, some regulatory PAMs are phased in over a number of years. One example
106 is a regulation that requires reductions for a certain type of equipment at some future date and

107 reductions for a different type of equipment at another future date. Another example is mandatory
108 reductions that only apply to new equipment; over time this new equipment with reductions would be
109 gradually incorporated into the overall equipment population as old equipment ages and is replaced.

110 **Technology Characterization and Change**

111 In general, base year emissions estimates represent the current state of technology and its associated
112 level of implementation within each source category. However, most of the long-term non-CO₂
113 projections do not address any potential future technological improvements in emissions control
114 technologies. Such improvements may occur in response to various environmental, economic, or social
115 drivers. Significant technological improvements will reduce actual future emissions below the projected
116 estimates; adjustments to the projection methodology may be required to address these technological
117 improvements.

118 **1.4 Quality Assurance and Quality Control**

119 The non-CO₂ projection system has been designed around the IPCC approach to create good quality
120 estimates of GHG emissions. The quality system has two main components: quality control and quality
121 assurance. The full IPCC definitions of quality control and quality assurance are as follows:

122 **Quality Control (QC)** is a system of routine technical activities to assess and maintain the
123 quality of the inventory as it is being compiled. It is performed by personnel compiling the
124 inventory. The QC system is designed to:

- 125 (i) Provide routine and consistent checks to ensure data integrity, correctness, and
126 completeness;
- 127 (ii) Identify and address errors and omissions;
- 128 (iii) Document and archive inventory material and record all QC activities. QC activities
129 include general methods such as accuracy checks on data acquisition and calculations,
130 and the use of approved standardised procedures for emission and removal calculations,
131 measurements, estimating uncertainties, archiving information and reporting. QC
132 activities also include technical reviews of categories, activity data, emission factors, other
133 estimation parameters, and methods.

134 **Quality Assurance (QA)** is a planned system of review procedures conducted by
135 personnel not directly involved in the inventory compilation/development process.
136 Reviews, preferably by independent third parties, are performed upon a completed
137 inventory following the implementation of QC procedures. Reviews verify that
138 measurable objectives were met, ensure that the inventory represents the best possible

139 estimates of emissions and removals given the current state of scientific knowledge and
140 data availability, and support the effectiveness of the QC programme.

141 Mechanisms to ensure **QC** are embedded in the non-CO₂ projections calculations in several ways. The
142 source-category specific spreadsheets have been designed to be transparent, for example: calculations
143 flow logically from the top of the sheet to the bottom; constants appear first, then source data are
144 listed; all relevant cells in the workbooks are color-coded for easy reference, indicating whether the cells
145 provide calculations, outputs, QC checks, or data input. The calculations make extensive use of lookup
146 functions to ensure that consistent unit conversions are used throughout. Data validation rules and
147 drop-down menus for source, activity, scenario, and unit names are used to ensure that only those for
148 which valid lookups exist within the database can be selected. Also, a QA worksheet is contained in each
149 source-category specific spreadsheet that contains both automated and manual QC checks.

150 **QA** will be implemented through a process of independent review of the both the workbooks and the
151 methodologies used to generate the projections.

152 **1.5 Uncertainty**

153 Uncertainties in projections combine the uncertainties in the estimation approaches used for the base
154 year inventory as well as uncertainties in anticipating changes in activity data and emissions factors over
155 the projection period.

156 Uncertainties in GHG inventories arise from the estimating activity data and the emissions factors. Some
157 sources of emissions are inherently more uncertain than others. For example, non-CO₂ emissions from
158 agriculture arise from natural processes and as such can be difficult to characterize. Emissions from soils
159 can depend on meteorology and soil type, in addition to the amount of fertilizer applied or the amount
160 and types of crops grown; emissions from livestock can change depending on the feed type. Emissions of
161 CO₂ from fossil fuel combustion are much easier to estimate and are therefore less uncertain, as long as
162 the composition of the fuel and the amount of fuel are both well known.

163 The uncertainty in total GHGs in the U.S. GHG Inventory is estimated to be -2 to +5 percent in 2011, at a
164 95 percent confidence interval. Since total GHG emissions are dominated by CO₂ from fuel combustion,
165 the overall uncertainty is low. However, for the non-CO₂ gases, and non-energy CO₂ sources, the
166 uncertainties are higher (e.g., +13 to -14 percent for CH₄, -9 to +41 percent for N₂O). The uncertainty
167 related to individual sources is higher still, and can vary significantly between sources. For example,
168 emissions from iron and steel production have relatively low uncertainty (-12 to +12 percent for CH₄)
169 while emissions from petroleum systems have high uncertainty (-24 to +149 percent for CH₄).

170 Projecting GHG emissions adds another layer of uncertainty. For example, changes in industry structure
 171 over time, the particular impacts of policies, changing weather and economic conditions all add
 172 variability to how future emissions will develop. Some indication of the degree of uncertainty related to
 173 projection variables can be gained by looking at the range of published scenarios for these factors. Some
 174 source documents, such as the EIA Annual Energy Outlook, present alternative scenarios which differ
 175 from their reference scenario regarding key variables. For example, the range between the low and high
 176 economic growth scenarios for GDP is -8.8 and +9.4 percent relative to the reference case; for the low
 177 and high oil and gas resource scenario natural gas production varies -13.6 to +18.1 percent.

178 In discussing the uncertainties for projections, it is useful to separate out the uncertainty in the GHG
 179 projection from the uncertainty inherent in estimating historical GHG emissions. The uncertainties
 180 related to historical inventories should be combined with the uncertainties related to projected activity
 181 data and emissions factors to account for the full potential for uncertainty in projected emissions. A
 182 quantitative uncertainty analysis has not been carried out for the current set of projections, but EPA
 183 plans to more thoroughly characterize uncertainty in future versions of these projections.

184 1.6 Equations

185 Calculations for each source throughout this document use a similar template wherein source emissions
 186 are projected by multiplying emissions factors by projected activity data. In many cases, the base year
 187 inventory uses more detailed activity data than is available for projections, and so an aggregate
 188 emissions factor is calculated by dividing historical emissions by historical activity data. In general there
 189 are sometimes minor differences in scope or estimates of base year activity data between the U.S. GHG
 190 Inventory and the data source used for projections. To ensure consistency with the historical inventory,
 191 the projected change in the activity data from the base year is applied to the base production level
 192 presented in the inventory.

$$Emissions_y = EF_{agg} \times InventoryActivity_b \times \left(\frac{ProjectedActivity_y}{ProjectedActivity_b} \right)$$

193 **Equation 1**

194 Where:

195	$Emissions_y$	=	Projected emissions in year y
196	EF_{agg}	=	Aggregate emissions factor
197	$InventoryActivity_b$	=	Historical activity data from U.S. GHG Inventory in base year b
198	$ProjectedActivity_b$	=	Activity estimate for base year b from projection data source
199	$ProjectedActivity_y$	=	Activity data projections for year y from projection data source
200	y	=	projected year
201	b	=	base year

202 **2.0 Source Methodologies**

203 Source-specific methodologies are presented in this section, by sector: energy; industrial processes;
204 agriculture; land use, land-use change, and forestry; and waste.

205 **2.1 Energy**

206 **Stationary Source Combustion**

207 **Source Description**

208 The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial,
209 and residential sectors represents the greatest share of U.S. GHG emissions. CH₄ and N₂O emissions
210 from stationary combustion sources depend on fuel characteristics, size, and vintage, along with
211 combustion technology, pollution control equipment, ambient environmental conditions, and operation
212 and maintenance practices. N₂O emissions from stationary combustion are closely related to air-fuel
213 mixes and combustion temperatures, as well as the characteristics of any pollution control equipment
214 that is employed. CH₄ emissions from stationary combustion are primarily a function of the CH₄ content
215 of the fuel and combustion efficiency.

216 Emissions projections estimated in this section include CH₄ and N₂O from stationary source combustion.
217 Combustion also results in CO₂ emissions, but those emissions are covered by energy-related CO₂
218 emissions projections beyond the scope of this report. This source category is included within IPCC
219 guidelines source subcategory 1A. CO₂ from non-energy use of fuels is covered in a separate projections
220 category, although the U.S. GHG Inventory (EPA 2013) discusses them together. Emissions from U.S.
221 territories are included.

222 **Methodology**

223 EPA calculated projected emissions from this source category by summing projections of emissions from
224 residential, commercial, industrial, and electric power sources. Each of these sources includes coal, fuel
225 oil, natural gas, and wood fuel combustion. Combustion in the U.S. territories was added separately. CH₄
226 and N₂O emissions for each category were calculated separately:

- 227 • Residential
 - 228 ○ Coal
 - 229 ○ Fuel oil
 - 230 ○ Natural gas
 - 231 ○ Wood and biomass
- 232 • Commercial
 - 233 ○ Coal
 - 234 ○ Fuel oil
 - 235 ○ Natural gas
 - 236 ○ Wood and biomass
- 237 • Industrial
 - 238 ○ Coal

- 239 ○ Fuel oil
- 240 ○ Natural gas
- 241 ○ Wood and biomass
- 242 ● Electric power
 - 243 ○ Coal
 - 244 ○ Fuel oil
 - 245 ○ Natural gas
 - 246 ○ Wood and biomass
- 247 ● U.S. territories
 - 248 ○ Coal
 - 249 ○ Fuel oil
 - 250 ○ Natural gas
 - 251 ○ Wood and biomass

252

253 As shown above, each sector was subdivided by fuel type, including coal, fuel oil, natural gas, and wood.

254 The CH₄ and N₂O emissions estimation methodology used in the U.S. GHG Inventory was revised in 2010

255 to use the facility-specific technology and fuel use data reported to EPA’s Acid Rain Program.

256 Residential, Commercial, and Industrial

257 EPA estimated projected CH₄ and N₂O emissions associated with stationary combustion from the

258 residential, commercial, and industrial sectors by multiplying consumption projections for each sector

259 and fuel from the U.S. Energy Information Administration, or EIA (EIA 2013)¹ by the Tier 1 default

260 emissions factors provided by the 2006 IPCC Guidelines (IPCC 2006), which were also used to calculate

261 emissions in the U.S. inventory. Future wood consumption projections for commercial and industrial

262 sectors were not available from the EIA; therefore, historical wood consumption data (by sector) from

263 EIA were extrapolated (based on the annual percent change over the previous 10 years) to estimate

264 future consumption through the end of the projection period. EPA then multiplied wood consumption

265 projections by sector-specific Tier 1 default emissions factors provided by the 2006 IPCC Guidelines to

266 estimate future CH₄ and N₂O emissions.

267 Electric Power

268 To project CH₄ and N₂O emissions from combustion in the electric power sector, EPA multiplied (for each

269 fuel type) projected U.S. electricity generation by an aggregate emissions factor based on historical CH₄

270 and N₂O emissions and historical electricity generation. Projected electricity generation came from EIA’s

271 *Annual Energy Outlook* (EIA 2013). EPA calculated aggregate emissions factors for each fuel source by

272 dividing historical emissions from electricity generation (by fuel source) from the EPA inventory by

273 historical generation from EIA over the most recent five years and averaging the results. As with the

274 residential, commercial, and industrial sectors, future wood consumption projections for the electric

275 power sector were not available from the EIA; therefore, historical wood consumption data from the EIA

¹ Sectoral information for U.S. territories (American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is not available from EIA. Based on the U.S. GHG Inventory, CH₄ and N₂O emissions from U.S. territories are negligible; therefore, fuel consumption in U.S. territories was not included in the stationary combustion emissions projections.

276 were extrapolated based on the annual percent change over the previous 10 years to estimate future
277 wood consumption through the end of the projection period.

278 The projection methodology for CH₄ and N₂O from electric power differs from that used in the U.S.
279 Inventory. The inventory uses a Tier 2 methodology for the electric power sector,² whereas all other
280 sectors for stationary combustion use a Tier 1 methodology. Specifically, the Tier 2 methodology for the
281 electric power sector uses electric-facility-specific technology and fuel use data reported under EPA's
282 Acid Rain Program.

283 **U.S. Territories**

284 Information on underlying combustion activity for the U.S. territories is not included in the *Annual*
285 *Energy Outlook*. Therefore, EPA calculated projections of CH₄ and N₂O emissions from combustion in the
286 U.S. territories by extrapolating emissions based on the annual percent change over the most recent 10
287 years.

² CH₄ and N₂O emissions for the electric sector from previous years listed in the U.S. GHG Inventory were also adjusted using the new Tier 2 methodology approach.

288 **Mobile Source Combustion**

289 **Source Description**

290 Mobile combustion produces GHGs other than CO₂, including CH₄, N₂O, and indirect GHGs including NO_x,
291 CO, and NMVOCs. As with stationary combustion, N₂O and NO_x emissions from mobile combustion are
292 closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution
293 control equipment. N₂O from mobile sources, in particular, can be formed by the catalytic processes
294 used to control NO_x, CO, and hydrocarbon emissions. CO emissions from mobile combustion are
295 significantly affected by combustion efficiency and the presence of post-combustion emissions controls.
296 CO emissions are highest when air-fuel mixtures have less oxygen than required for complete
297 combustion. These emissions occur especially in idle, low-speed, and cold start conditions. CH₄ and
298 NMVOC emissions from motor vehicles are a function of the CH₄ content of the motor fuel, the amount
299 of hydrocarbons passing uncombusted through the engine, and any post-combustion control of
300 hydrocarbon emissions (such as catalytic converters).

301 Emissions projections estimated in this section include CH₄ and N₂O from mobile source combustion.
302 Combustion also results in CO₂ emissions, but those emissions are covered by energy-related CO₂
303 emissions projections beyond the scope of this report. This source category is included within IPCC
304 guidelines source subcategory 1A.

305 **Methodology**

306 CH₄ and N₂O emissions from this source category are modeled using the Motor Vehicle Emissions
307 Simulator (MOVES), developed by EPA's Office of Transportation and Air Quality.³ Results were
308 calculated based on runs of the MOVES2010b, the latest version of the MOVES system, using national
309 default inputs. The MOVES2010b model estimates the vehicle population and activity data including
310 miles driven and number of starts for each vehicle source type using a variety of information sources, as
311 documented by EPA (2010). These projected activity estimates are then multiplied by appropriate
312 emissions rates. N₂O emissions are calculated directly, while CH₄ emissions are derived from emissions
313 rates for total hydrocarbons. The N₂O emissions rates and the CH₄/THC ratios are described in EPA
314 (2012d).

³ MOVES2010b and related information and documentation can be found online at
<<http://www.epa.gov/otag/models/moves/index.htm>>.

315 **Non-Energy Uses of Fossil Fuels**

316 **Source Description**

317 In addition to being combusted for energy, fossil fuels are consumed for non-energy uses (NEUs) in the
318 United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum
319 gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke
320 (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-
321 energy applications of these fuels are equally diverse, including feedstocks for the manufacture of
322 plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various
323 metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC
324 2006).

325 CO₂ emissions arise from NEUs via several pathways. Emissions may occur during the manufacture of a
326 product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally,
327 emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the
328 time series and across all uses, about 62 percent of the total carbon consumed for non-energy purposes
329 was stored in products, and not released to the atmosphere; the remaining 38 percent was emitted.

330 This emissions source covers CO₂ emissions from NEUs of fossil fuels. This corresponds to a part of IPCC
331 source 1A, as described in the U.S. GHG Inventory (EPA 2013).

332 **Methodology**

333 EPA calculated emissions projections for this source by multiplying base year CO₂ emissions from NEUs
334 of fossil fuels in the U.S. GHG Inventory by the growth in industrial energy consumption of feedstocks
335 and fuels usually used for non-energy purposes in the *Annual Energy Outlook* (EIA 2013). Growth in CO₂
336 from NEUs of fuels is assumed to be proportional to the total energy content of consumed energy
337 (excluding refining) of LPG feedstock, petrochemical feedstocks, asphalt and road oil, and natural gas
338 feedstocks (see the *AEO* table "Industrial Sector Key Indicators and Consumption").

$$Emissions_y = Emissions_b \times \left(\frac{NEU-Energy_y}{NEU-Energy_b} \right)$$

339 **Equation 2**

340 Where:

341 $Emissions_y$ = Projected emissions in year y

342 $Emissions_b$ = Emissions in the base year

343 $NEU-Energy_y$ = NEU energy in year y

344 $NEU-Energy_b$ = NEU energy in the base year

345 **Non-Energy Use of Fuels in the U.S. GHG Inventory**

346 For background, the calculation of emissions from non-energy use of fuels in the U.S. GHG Inventory is
347 described here for the purpose of understanding the emissions included in the base year. In the U.S.
348 GHG Inventory, EPA estimated the amount of carbon stored in products to determine the aggregate

349 quantity of fossil fuels consumed for NEUs. The carbon content of these feedstock fuels is equivalent to
350 potential emissions, or the product of consumption and the fuel-specific carbon content values. Both
351 the non-energy fuel consumption and carbon content data were supplied by the U.S. Energy Information
352 Administration (EIA 2013). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and
353 special naphtha were adjusted to account for net exports of these products that are not reflected in the
354 raw data from EIA. For the remaining NEUs, EPA estimated the quantity of carbon stored by multiplying
355 the potential emissions by a storage factor.

356 Coal Mining

357 Source Description

358 CH₄, which is contained within coal seams and the surrounding rock strata, is released into the
359 atmosphere when mining operations reduce the pressure above and/or surrounding the coal bed. The
360 quantity of CH₄ emitted from these operations is a function of two primary factors: coal rank and coal
361 depth. Coal rank is a measure of the carbon content of the coal, with higher coal ranks corresponding to
362 higher carbon content and generally higher CH₄ content. Pressure increases with depth and prevents
363 CH₄ from migrating to the surface; as a result, underground mining operations typically emit more CH₄
364 than surface mining. In addition to emissions from underground and surface mines, post-mining
365 processing of coal and abandoned mines also release CH₄. Post-mining emissions refer to CH₄ retained in
366 the coal that is released during processing, storage, and transport of the coal.

367 This emissions source covers fugitive CH₄ emissions from coal mining (including pre-mining drainage)
368 and post-mining activities (i.e., coal handling), including both underground and surface mining. This
369 corresponds to IPCC source category 1B1a, excluding emissions from abandoned underground mines
370 (which are included as a separate source category, corresponding to IPCC category 1B1a3).

371 Methodology

372 EPA calculated emissions projections for this source by summing emissions associated with underground
373 mining, post-underground mining, surface mining, and post-surface mining.

$$Emissions_y = \sum_s Emissions_{y,s}$$

374 Equation 3

375 Where:

376 s = Sources (underground, post-underground, surface, and post-surface mining)

377 $Emissions_{y,s}$ = Emissions in year y from source s

378

379 EPA projected emissions from each source by multiplying an aggregate emissions factor by projected
380 coal production (for underground or surface mining as appropriate). Projected reductions due to
381 recovery and use are then subtracted from potential emissions.⁴

⁴ Current CH₄ recovery and use projects apply to underground mining, but projects related to surface mining could be implemented in the future.

$$Emissions_{y,s} = EF_{agg,s} \times InventoryProduction_{b,s} \times \left(\frac{ProjectedProduction_{y,s}}{ProjectedProduction_{b,s}} \right) \times (1 - CH_4RecoveryUseFrac_s)$$

Equation 4

382

383 Where:

- 384 $EF_{agg,s}$ = Aggregate emissions factor associated with source s
 385 $InventoryProduction_{b,s}$ = Coal production associated with source s in the base
 386 year from the U.S. GHG Inventory⁵
 387 $ProjectedProduction_{y,s}$ = Projected coal production associated with the emissions
 388 source (e.g., either underground or surface mining) in year y
 389 $CH_4RecoveryUseFrac_s$ = Fraction of CH₄ recovered from source s

390 Emissions Factors

391 To calculate potential emissions from each category, EPA calculated an aggregate CH₄ emissions factor
 392 using historical CH₄ emissions and coal production data contained in the most recent U.S. GHG Inventory
 393 (EPA 2013). For example, , historical CH₄ liberated by underground mining was divided by the total
 394 underground coal production for the corresponding year. The aggregate emissions factor is the average
 395 of this ratio over the most recent five years. Similar calculations were performed for post-underground
 396 mining emissions, surface mining emissions, and post-surface mining emissions, using either historical
 397 underground or surface mining production data as appropriate.

398 The projection methodology differs from the estimation methodology used in the U.S. GHG Inventory.
 399 The inventory does not use emissions factors to calculate CH₄ emissions from underground mines. The
 400 U.S. GHG Inventory estimates total CH₄ emitted from underground mines as the sum of CH₄ liberated
 401 from ventilation systems (mine-by-mine measurements) and CH₄ liberated by means of degasification
 402 systems, minus CH₄ recovered and used. EPA estimated surface mining and post-mining CH₄ emissions
 403 by multiplying basin-specific coal production, obtained from EIA’s *Annual Coal Report* (EIA 2012), by
 404 basin-specific emissions factors.⁶

405 Coal Production Projections

406 EPA projected emissions using projections of underground, surface, and total coal production from the
 407 EIA *Annual Energy Outlook (AEO)* (EIA 2013). The 2013 AEO projects the total coal production for the
 408 United States, as well as the coal production by region, and by various characteristics including
 409 underground and surface mining (see AEO table “Coal Production by Region and Type”).

410 EIA provides historical regional coal production data broken out between underground and surface
 411 mining in its *Annual Coal Report* (EIA 2012). EPA collated and calculated the proportion of production,
 412 underground versus surface, for each year. (EPA determined the total underground mining coal

⁵ Because of slight differences between historical and projection datasets, values for production in the base year from each dataset do not cancel

413 production and the total surface mining coal production for the United States by summing the regional
414 totals for each year.) There has been a general trend toward increasing surface mining relative to
415 underground mining (EPA 2013).

416 **CH₄ Mitigation (Recovery and Use)**

417 EPA projected coal mine CH₄ mitigation by calculating the historical fraction of methane recovered in
418 relation to generation from underground mines, and applying that fraction to future generation. The
419 historical fraction was averaged over the most recent five years. Future mitigation was estimated by
420 applying the historical rate of recovery and use to projected potential emissions generated.

421 The U.S. GHG Inventory uses quantitative estimates of CH₄ recovery and use from several sources.
422 Several gassy underground coal mines in the United States employ ventilation systems to ensure that
423 CH₄ levels remain within safe concentrations. Additionally, some U.S. coal mines supplement ventilation
424 systems with degasification systems, which remove CH₄ from the mine and allow the captured CH₄ to be
425 used as an energy source.

$$CH_4RecoveryUseFrac_s = \sum_{y=b}^{b-4} \frac{CH_4RecoveryUse_{s,y}}{PotentialEmissions_{s,y}} / 5$$

426 **Equation 5**

427 Where:

428 *CH₄RecoveryUse_{s,y}* = Recovered emissions from source s in year y
429 *Potential Emissions_{s,y}* = Potential emissions from source s in year y
430 *b* = base year

431 **Natural Gas Systems**

432 **Source Description**

433 The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing
434 facilities, and over a million miles of transmission and distribution pipelines. CH₄ and non-combustion⁷
435 CO₂ emissions from natural gas systems are generally process-related, with normal operations, routine
436 maintenance, and system upsets being the primary contributors. There are four primary stages of the
437 natural gas system which are briefly described below.

438 **Production**

439 In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise
440 from the wells themselves, gathering pipelines, and well-site gas treatment facilities (e.g., dehydrators,
441 separators). Major emissions source categories within the production stage include pneumatic devices,
442 gas wells with liquids unloading, and gas well completions and re-completions (i.e., workovers) with
443 hydraulic fracturing (EPA 2013). Flaring emissions account for the majority of the non-combustion CO₂
444 emissions within the production stage.

445 **Processing**

446 In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting
447 in “pipeline-quality” gas, which is then injected into the transmission system. Fugitive CH₄ emissions
448 from compressors, including compressor seals, are the primary emissions source from this stage. The
449 majority of non-combustion CO₂ emissions in the processing stage come from acid gas removal units,
450 which are designed to remove CO₂ from natural gas.

451 **Transmission and Storage**

452 Natural gas transmission involves high-pressure, large-diameter pipelines that transport gas long
453 distances from field production and processing areas to distribution systems or large-volume customers
454 such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating
455 and turbine compressors, are used to move the gas throughout the U.S. transmission system. Fugitive
456 CH₄ emissions from these compressor stations and from metering and regulating stations account for
457 the majority of the emissions from this stage. Pneumatic devices and uncombusted engine exhaust are
458 also sources of CH₄ emissions from transmission facilities. Natural gas is also injected and stored in
459 underground formations, or liquefied and stored in above-ground tanks, during periods of lower
460 demand (e.g., summer), and withdrawn, processed, and distributed during periods of higher demand
461 (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these
462 storage facilities. Emissions from LNG import terminals are included within the transportation and
463 storage stage.

⁷ In this document, consistent with IPCC accounting terminology, the term “combustion emissions” refers to the emissions associated with the combustion of fuel for useful heat and work, while “non-combustion emissions” refers to emissions resulting from other activities, including flaring and CO₂ removed from raw natural gas.

464 **Distribution**

465 Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations,
466 reduce the pressure, and then distribute the gas through primarily underground mains and service lines
467 to individual end users.

468 **Coverage**

469 Projections for this source cover CH₄ and non-combustion CO₂ emissions from natural gas systems.
470 Combustion CO₂ emissions are covered by energy-related CO₂ emissions projections outside the scope
471 of this report. The corresponding source for natural gas systems in the 2006 IPCC guidelines is 1B2b.

472 **Methodology**

473 The methodology for natural gas emissions projections involves the calculation of CH₄ and CO₂ emissions
474 for over 100 emissions source categories across the four natural gas sector stages, and then the
475 summation of emissions for each sector stage. The calculation of emissions for each source of emissions
476 in natural gas systems generally occurs in three steps:

- 477 1. Calculate potential CH₄
- 478 2. Estimate reductions data associated with voluntary action and regulations
- 479 3. Calculate net emissions

480 EPA calculated potential CH₄ emissions from natural gas systems by summing the projections associated
481 with (1) production, (2) processing, (3) transmission and storage, and (4) distribution. In general, activity
482 data were projections of natural gas production and consumption from the Energy Information
483 Administration, or EIA (EIA 2013). Additional activity data for projections included liquefied natural gas
484 (LNG) imports, pipeline length, and number of service lines. Because the base year inventory emissions
485 explicitly include reductions due to voluntary and regulatory requirements, the projections also include
486 appropriate explicit mitigation projections as well. Emissions for each source were estimated using the
487 following equation:

$$NE_{s,y} = PE_{s,y} - VR_{s,y} - RR_{s,y}$$

488 **Equation 6**

489 **Where:**

- 490 $NE_{s,y}$ = Projected net emissions for source s in year y
- 491 $PE_{s,y}$ = Projected potential emissions for source s in year y
- 492 $VR_{s,y}$ = Projected voluntary reductions for source s in year y
- 493 $RR_{s,y}$ = Projected regulatory reductions for source s in year y

494 The sections below describe detailed calculations for projections of CH₄ from natural gas systems. Non-
495 combustion CO₂ emissions also result from natural gas systems, mainly from the production and
496 processing stages. In the production stage, non-combustion CO₂ mostly results from flaring. In the
497 processing stage, non-combustion CO₂ comes mostly from acid gas removal units, which are designed to
498 remove CO₂ from natural gas. EPA calculated projected non-combustion CO₂ emissions from the

499 production and processing stages by scaling emissions in the base year by the increase in projected
500 natural gas production in the *Annual Energy Outlook (AEO)* (EIA 2013).

501 **Production Stage**

502 The production stage includes a total of 35 emissions source categories. Regional emissions were
503 estimated in the base year inventory for the six supply regions (i.e., Northeast, Gulf Coast, Midcontinent,
504 Southwest, Rocky Mountain, and West Coast) for 33 of these sources.

505 *Potential Emissions*

506 EPA estimated future year potential emissions for the production stage using the following equation.

$$507 \quad PE_{s,y} = PE_{s,b} \times \left(\frac{Gas\ Production_y}{Gas\ Production_b} \right)$$

508 **Equation 7**

509 Where:

510 $PE_{s,y}$ = Projected future potential emissions for source s in year y

511 $PE_{s,b}$ = Estimated potential emissions for source s in base year b

512 $Gas\ Production_y$ = Projected natural gas dry production year y

513 $Gas\ Production_b$ = Estimated natural gas dry production for base year b

514 The natural gas dry production estimates were obtained from the *Annual Energy Outlook (AEO)*
515 Supplemental Tables published by EIA.⁸

516 *Voluntary Reductions*

517 Projections of voluntary reductions for the production stage were based on historical data reported by
518 industry to the Natural Gas STAR program for projects implemented to reduce emissions. Natural Gas
519 STAR tracks projects on an annual basis and assigns a lifetime of limited duration to each reduction
520 project; for purposes of the base year emissions inventory and the future year projections, the
521 reductions associated with each project were either considered to be a “one-year” project or a
522 “permanent” project based on sunset dates provided by the Natural Gas STAR program. Reductions
523 from “one-year” projects were typically from the implementation of new or modified practices, while
524 reductions from “permanent” projects tended to be from equipment installation, replacement, or
525 modification. In the base year emissions inventory and the future year projections, reductions for a
526 “one-year” project were limited to the project’s reported start year, while reductions for a “permanent”
527 project were assigned to the project’s reported start year and every subsequent year thereafter. Thus,
528 the reductions due to “permanent” projects gradually accumulated throughout the inventory time
529 series, while the reductions due to “one-year” projects were replaced every year.

530 The following production stage voluntary reductions were reported to Natural Gas STAR and applied to
531 individual sources in the emissions inventory:

⁸ References to the *AEO* Supplemental Tables in this methodology do not indicate year or table number because these will change every year.

- 532 • Completions for gas wells with hydraulic fracturing (one year)—perform reduced emissions
533 completions (RECs).
- 534 • Pneumatic device vents (one year)—reduce gas pressure on pneumatic devices; capture/use gas
535 released from gas-operated pneumatic pumps.
- 536 • Pneumatic device vents (permanent)—identify and replace high-bleed pneumatic devices; convert
537 pneumatic devices to mechanical controls; convert to instrument air systems; install no-bleed
538 controllers.
- 539 • Kimray pumps (permanent)—install/convert gas-driven pumps to electric, mechanical, or solar
540 pumps.
- 541 • Gas engines compressor exhaust (one year)—replace ignition/reduce false starts; turbine fuel use
542 optimization.
- 543 • Gas engines compressor exhaust (permanent)—convert engine starting to N- and/or CO₂-rich gas;
544 install automated air/fuel ratio controls; install lean burn compressors; replace gas starters with air
545 or N.

546 In addition to these reductions that were applied to specific individual sources in the emissions
547 inventory, there were reductions classified as “Other Production” that were applied to the overall
548 production stage emissions.

549 It was assumed that the percentage of voluntary reductions relative to potential CH₄ in the most recent
550 base year inventory for the production stage would remain constant in each subsequent future year.⁹ In
551 addition, implementation of the oil and natural gas New Source Performance Standards (NSPS)—
552 discussed further below—necessitates the reclassification of certain production reductions from
553 voluntary to regulatory.

554 *Regulatory Reductions*

555 As part of the regulatory reductions for the production stage, reductions due to existing NESHAP
556 requirements for dehydrator vents and condensate tanks without control devices were included in the
557 base year inventory. These reductions were carried forward in the future year projections.

558 In addition, the base year inventory accounted for state-level requirements in Wyoming and Colorado
559 for RECs. In the base year inventory, a national-level reduction was estimated by applying a 95 percent
560 REC reduction to the fraction of national emissions occurring in Wyoming and Colorado (i.e., 15.1

⁹ The assumption of a constant rate of voluntary reductions relative to the base year inventory for sources unaffected by regulatory changes is meant to simulate a constant level of effort toward voluntary reductions into the future. No enhancements to the voluntary program are assumed. This assumption is a source of uncertainty; due to the voluntary nature of the program, reduction levels can fluctuate based on participation and investment. Where new regulatory requirements apply to new and modified equipment, voluntary reductions are assumed to continue to apply to existing equipment, but no voluntary reductions are applied to new equipment. As a future improvement to these projections, EPA plans to develop an alternate methodology to model equipment turnover.

561 percent); this resulted in a national-level reduction of 14.35 percent for gas well completions and
562 workovers with hydraulic fracturing. These reductions were modified as described below.

563 The oil and natural gas NSPS for VOCs (EPA 2012a, finalized in 2012) significantly increased the amount
564 of regulatory reductions applicable to the production stage, resulting in substantial CH₄ emissions
565 reductions co-benefits. These reductions are not currently reflected in the 2013 U.S. GHG Inventory for
566 the base year 2011, but are projected for future years as discussed in detail below. The specific NSPS
567 requirements impact the following production stage sources with regard to VOC (and the associated
568 CH₄) emissions:

- 569 • Hydraulically fractured natural gas well completions
- 570 • Hydraulically refractured natural gas well recompletions
- 571 • New and modified high-bleed, gas-driven pneumatic controllers
- 572 • New storage tanks (with VOC emissions of 6 tons per year or more)
- 573 • New and modified reciprocating and centrifugal compressors at gathering and boosting stations

574 The impact of these requirements on the future year projections is discussed below. The specific
575 quantitative reductions calculated for these projections are based on information from the NSPS
576 *Background Technical Support Document for the Proposed Standards* (EPA 2011) and the *Background*
577 *Supplemental Technical Support Document for the Final New Source Performance Standards* (EPA
578 2012b), referred to collectively in this document as the NSPS TSD.

579 [Hydraulically Fractured Well Completions](#)

580 The NSPS requires the use of RECs (or “green completions”) for all new hydraulically fractured wells. A
581 phase-in period prior to January 1, 2015, also allows for the alternate use of a completion combustion
582 device (i.e., flare), instead of RECs. In addition, RECs are not required for exploratory “wildcat” wells,
583 delineation wells (i.e., used to define the borders of a natural gas reservoir), and low-pressure wells (i.e.,
584 completions where well pressure is too low to perform RECs); in these instances, emissions must be
585 reduced using combustion. Based on the NSPS TSD (EPA 2012b), EPA assumed for the purpose of these
586 projections a 95 percent reduction for both RECs and completion combustion.¹⁰

587 Although the base year inventory included a national-level reduction of 14.35 percent to account for the
588 required use of RECs in Wyoming and Colorado, there does not appear to be an appreciable difference
589 in emissions reductions resulting from the NSPS requirements and the state requirements in Wyoming
590 and Colorado. Therefore, for future year projections, the national-level reduction of 14.35 percent was
591 replaced with a 95 percent reduction for new hydraulically fractured well completions.

¹⁰ The NSPS TSD indicates that 90 percent of flowback gas can be recovered during an REC (based on Natural Gas STAR data) and that any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions. The NSPS TSD indicates that although industrial flares are required to meet a combustion efficiency of 98 percent, this is not required for completion combustion devices. Completion combustion devices (i.e., exploration and production flares) can be expected to achieve 95 percent combustion efficiency.

592 [Hydraulically Refractured Well Workovers](#)

593 The NSPS also requires the use of RECs for gas wells that are refractured and recompleted. The phase-in
594 period before January 1, 2015, is also applicable.¹¹ As with completions, a 95 percent reduction was
595 assumed for both RECs and completion combustion. This replaced the national-level reduction of 14.35
596 percent that was used in the base year inventory.

597 For both well completions and workovers (or refractured well completions) with hydraulic fracturing, in
598 conjunction with the NSPS, EPA removed REC-related reductions from the projected voluntary
599 reductions from the production stage to avoid double-counting. This removal was very straightforward,
600 since these REC-related reductions were calculated separately and then applied to the well completions
601 and workovers source in the base year inventory.

602 [New and Modified High-Bleed, Gas-Driven Pneumatic Controllers](#)

603 The NSPS also requires the installation of new low-bleed pneumatic devices (i.e., bleed rates less than or
604 equal to 6 standard cubic feet per hour) instead of high-bleed pneumatic devices (i.e., bleed rates
605 greater than 6 standard cubic feet per hour) with exceptions where high bleed devices are required for
606 safety reasons. The TSD indicates that a typical production stage high-bleed pneumatic device emits
607 6.91 tons of CH₄ per year and that replacing the high-bleed device with a typical low-bleed pneumatic
608 device would result in a reduction of 6.65 tons CH₄ per year; this is a reduction of 96.2 percent. The TSD
609 also indicates that only 51 percent of all pneumatic devices installed are continuous bleed natural gas
610 driven controllers. In addition, it is assumed that 20 percent of the situations where bleed pneumatic
611 devices are installed require a high-bleed device (i.e., instances where a minimal response time is
612 needed, large valves require a high bleed rate to actuate, or a safety isolation valve is involved) (EPA
613 2011). Based on this information, for the purpose of these projections EPA applied a national-level
614 reduction of 77 percent (i.e., 0.962×0.8) to each future year's annual increase in emissions from
615 pneumatic device vents in the production stage.

616 In conjunction with the NSPS, no removal of production stage voluntary reductions was required. The
617 reductions included in the base year inventory already occurred in the past and the associated effects
618 carry forward into the future or were unrelated to the requirements of the NSPS.

619 [New Storage Tanks](#)

620 The NSPS also requires that new storage tanks with VOC emissions of 6 tons per year or greater must
621 reduce VOC emissions by at least 95 percent, likely to be accomplished by routing emissions to a
622 combustion device or rerouting emissions into process streams. The TSD indicates that approximately 74
623 percent of the total condensate produced in the United States passes through storage tanks with VOC
624 emissions of 6 tons per year or greater (EPA 2011). Based on this information, for the purpose of these
625 projections EPA applied a national-level reduction of 70.3 percent (i.e., 0.95×0.74) to each future year's
626 annual increase in emissions from condensate storage tanks in the production stage.

¹¹ Use of RECs is not considered to be "modified" and would not trigger state permitting requirements, while use of flaring or completion combustion would be considered to be "modified."

627 In conjunction with the NSPS, no removal of production stage voluntary reductions associated with
628 storage tanks was required. The reductions included in the base year inventory already occurred in the
629 past and the associated effects carry forward into the future.

630 *New and Modified Reciprocating Compressors*

631 The NSPS requires the replacement of rod packing systems in reciprocating compressors at gathering
632 and boosting stations. There are two options for this replacement: every 26,000 hours of operation if
633 operating hours are monitored and documented, or every 36 months if operating hours are not
634 monitored or documented. The NSPS TSD estimated baseline emissions of 3,773 tons per year of CH₄ for
635 new reciprocating compressors used in the production stage; the TSD also estimated total reductions
636 from replacing the rod packing for these compressors as 2,384 tons per year of CH₄ (EPA 2011). Based
637 on this information, for the purpose of these projections EPA applied a national-level reduction of 63.2
638 percent to each future year's annual increase in emissions from gathering reciprocating compressors in
639 the production stage.

640 *Processing Stage*

641 The processing stage includes a total of 11 emissions source categories. EPA estimated the base year
642 inventory emissions for the processing stage at the national level, instead of at the region level, like the
643 base year inventory emissions for the production stage.

644 *Potential Emissions*

645 Because projections of future year processing activity were not available, EPA also used Equation 7 to
646 estimate future year potential emissions for the processing stage by assuming that the quantity of
647 processed natural gas would track closely with the quantity of produced natural gas.

648 As with the production stage, EPA used the natural gas dry production estimates from the table titled
649 "Lower 48 Natural Gas Production and Wellhead Prices by Supply Region" of the AEO Supplemental
650 Tables to develop future year processing stage emissions estimates.

651 *Voluntary Reductions*

652 Projections of voluntary reductions for the processing stage were based on historical data reported by
653 industry to the Natural Gas STAR program for projects implemented to reduce emissions (EPA 2012c).
654 The following processing stage voluntary reductions were reported to Natural Gas STAR and applied to
655 individual sources in the emissions inventory:

- 656 • Blowdowns/venting (one year)—recover gas from pipeline pigging operations; redesign
657 blowdown/alter ESD practices; reduce emissions when taking compressors offline; use composite
658 wrap repair; use hot taps for in-service pipeline connections; use inert gas and pigs to perform
659 pipeline purges.
- 660 • Blowdowns/venting (permanent)—rupture pin shutoff device to reduce venting.

661 In addition to these reductions that were applied to specific individual sources in the emissions
662 inventory, there were reductions classified as “Other Processing” that were applied to the overall
663 processing stage emissions.

664 It was assumed that the percentage of voluntary reductions relative to potential CH₄ in the most recent
665 base year inventory for the processing stage would remain constant in each subsequent future year.¹² In
666 addition, implementation of the oil and natural gas NSPS (discussed further below) necessitates the
667 reclassification of certain processing reductions from voluntary to regulatory.

668 *Regulatory Reductions*

669 The only regulatory reductions included in the base year inventory for the processing stage were
670 existing NESHAP requirements for dehydrator vents (EPA 2013). These reductions were carried forward
671 in the future year projections.

672 The oil and natural gas NSPS significantly increased the amount of regulatory reductions applicable to
673 the processing stage relative to the base year 2011 inventory estimates. The specific NSPS requirements
674 affect the following processing stage sources with regard to VOC (and the associated CH₄) emissions:

- 675 • Reciprocating compressors
- 676 • Centrifugal compressors
- 677 • New and modified high-bleed, gas-driven pneumatic controllers
- 678 • New storage tanks (with VOC emissions of at least 6 tons per year)

679 The impact of these requirements on the future year projections is discussed below.

680 *New and Modified Reciprocating Compressors*

681 The NSPS requires the replacement of rod packing systems in reciprocating compressors. There are two
682 options for this replacement: every 26,000 hours of operation if operating hours are monitored and
683 documented, or every 36 months if operating hours are not monitored or documented. The NSPS TSD
684 estimated baseline emissions of 4,870 tons per year of CH₄ for new reciprocating compressors used in
685 the processing stage; the TSD also estimated total reductions from replacing the rod packing for these
686 compressors as 3,892 tons per year of CH₄ (EPA 2011). Based on this information, for the purpose of
687 these projections EPA applied a national-level reduction of 79.9 percent to each future year’s annual
688 increase in emissions from reciprocating compressors in the processing stage.

689 *New and Modified Centrifugal Compressors*

690 The NSPS requires a 95 percent reduction in VOC emissions from centrifugal compressors with wet seal
691 systems, which can be accomplished through flaring or by routing captured gas back to a compressor
692 suction or fuel system, or switching to dry seal systems. The NSPS does not apply to centrifugal
693 compressors with dry seal systems, because they have low VOC emissions. A national-level reduction of
694 95 percent was applied to each future year’s annual increase in emissions from centrifugal compressors
695 with wet seals in the processing stage.

¹² This assumption is discussed in Footnote 7.

696 In conjunction with the NSPS, no removal of processing stage voluntary reductions was required. The
697 reductions included in the base year inventory already occurred in the past and the associated effects
698 carry forward into the future or were unrelated to the requirements of the NSPS.

699 **New and Modified High-Bleed, Gas-Driven Pneumatic Controllers**

700 The NSPS also requires that the VOC emissions limit for continuous-bleed, gas-driven pneumatic controls
701 at gas processing plants be zero. Accordingly, emissions from new pneumatic device vents in the
702 processing stage were set to zero.

703 **New Storage Tanks**

704 As described above in the production sector.

705 **Transmission and Storage Stage**

706 The transmission and storage stage includes a total of 37 emissions source categories: 25 associated
707 with natural gas transmission and storage and 12 associated with liquefied natural gas (LNG)
708 transmission and storage. The natural gas and LNG emissions were estimated at the national level.

709 *Potential Emissions*

710 Future year potential emissions for the natural gas sources and the six LNG storage sources within the
711 transmission and storage stage were estimated using the following equation:

712
$$PE_{s,y} = PE_{s,b} \times \left(\frac{Gas\ Consumption_y}{Gas\ Consumption_b} \right)$$

713 **Equation 8**

714 Where:

715 $PE_{s,y}$ = Projected future potential emissions for source s in year y

716 $PE_{s,b}$ = Estimated potential emissions for source s in base year b

717 $Gas\ Consumption_y$ = Projected national natural gas consumption in year y

718 $Gas\ Consumption_b$ = Estimated national natural gas consumption in base year b

719 The national natural gas consumption estimates were obtained from the table titled “Energy
720 Consumption by Sector and Source—United States” in the *AEO* Supplemental Tables. The specific
721 estimates used were for the “Natural Gas Subtotal” line item (including natural gas, natural gas-to-
722 liquids heat and power, lease and plant fuel, and pipeline natural gas) under “Total Energy
723 Consumption.”

724 Future year potential emissions for the six LNG import terminal sources within the transmission and
725 storage stage were estimated using the following equation:

726
$$PE_{s,y} = PE_{s,b} \times \left(\frac{LNG\ Imports_y}{LNG\ Imports_b} \right)$$

727 **Equation 9**

728 Where:

729	$PE_{s,y}$	=	Projected future potential emissions for source s in year y
730	$PE_{s,b}$	=	Estimated potential emissions for source s in base year b
731	$LNG Imports_y$	=	Projected LNG imports in year y
732	$LNG Imports_b$	=	Estimated LNG imports in base year b

733 The LNG import estimates were obtained from the table titled “Natural Gas Imports and Exports” of the
 734 AEO Supplemental Tables. The specific estimates used were for the “Liquefied Natural Gas Imports” line
 735 item.

736 *Voluntary Reductions*

737 Projections of voluntary reductions for the transmission and storage stage were also based on historical
 738 data reported by industry to the Natural Gas STAR program for projects implemented to reduce
 739 emissions. The following transmission and storage stage voluntary reductions were reported to Natural
 740 Gas STAR and applied to individual sources in the base year emissions inventory:

- 741 • Reciprocating compressors (one year)—replace compressor rod packing systems.
- 742 • Reciprocating compressors (permanent)—replace wet seals with dry seals.
- 743 • Pipeline venting (one year)—recover gas from pipeline pigging operations; use composite wrap
 744 repair; use hot taps for in-service pipeline connections; use inert gas and pigs to perform pipeline
 745 purges; use pipeline pump-down techniques to lower gas line pressure.
- 746 • Pneumatic devices (permanent)—identify and replace high-bleed pneumatic devices; convert
 747 pneumatic devices to mechanical controls; convert to instrument air systems.

748 In addition to these reductions that were applied to specific individual sources in the emissions
 749 inventory, there were reductions classified as “Other Transmission and Storage” that were applied to
 750 the overall transmission and storage stage emissions.

751 It was assumed that the percentage of voluntary reductions relative to potential CH₄ in the most recent
 752 base year inventory for the transmission and storage stage would remain constant in each subsequent
 753 future year.¹³ In addition, implementation of the oil and natural gas NSPS (discussed further below)
 754 necessitates the reclassification of certain reductions from voluntary to regulatory.

755 *Regulatory Reductions*

756 No regulatory reductions were previously included in the inventory for the transmission and storage
 757 stage.

758 The oil and natural gas NSPS includes requirements applicable to the natural gas transmission and
 759 storage stage for VOC reductions of at least 95 percent for new storage tanks with VOC emissions of 6
 760 tons per year or more.

¹³ This assumption is discussed in Footnote 7.

761 The impact of these requirements on the future year projections is discussed below.

762 *New Storage Tanks*

763 As described above in the production sector.

764 *Distribution Stage*

765 The distribution stage includes a total of 23 emissions source categories consisting of 10 city gate
766 sources, two customer meter sources, three vented sources, and eight pipeline leak sources. For all
767 sources, emissions were estimated at the national level.

768 *Potential Emissions*

769 Because future year distribution projections were not available, EPA estimated future year potential
770 emissions for the distribution stage (except for the pipeline leak sources) using Equation 3, assuming
771 that the quantity of distributed natural gas tracks closely with the quantity of consumed natural gas. The
772 natural gas consumption estimates were obtained from the table titled “Energy Consumption by Sector
773 and Source—United States” of the *AEO* Supplemental Tables. Sector-specific consumption estimates
774 were used. For most sources (i.e., all city gate, all vented, and the residential customer meter sources),
775 the “Natural Gas” line item under “Residential Consumption” was used. For the commercial/industry
776 sources, EPA used the summation of the “Natural Gas” line item under “Commercial Consumption” and
777 the “Natural Gas Subtotal” line item (including natural gas, natural gas-to-liquids heat and power, and
778 lease and plant fuel) under “Industrial Consumption.”

779 Unlike most other sources in the natural gas systems emissions inventory, projected pipeline leak
780 emissions in the distribution stage were not estimated using natural gas production or consumption
781 estimates. Instead, linear extrapolation of historical pipeline miles was used to project leak emissions
782 from distribution mains, while linear extrapolation of the historical number of service lines was used to
783 project leak emissions from services. Linear extrapolation was used because the historical statistics for
784 pipeline miles and number of services show fairly consistent behavioral trends over the entire time
785 series from 1990 to 2011. In particular, the historical statistics show a distinct trend toward the use of
786 plastic and away from other materials (i.e., cast iron, copper, unprotected steel, and protected steel).
787 Historical pipeline length data was drawn from the US GHG Inventory (EPA 2013), which draws pipeline
788 data from a variety of sources.

789 *Voluntary Reductions*

790 Projections of voluntary reductions for the distribution stage were based on historical data reported by
791 industry to the Natural Gas STAR program for projects implemented to reduce emissions. Unlike the
792 production, processing, and transmission and storage stages, no distribution stage voluntary reductions
793 reported to Natural Gas STAR were applied to individual sources in the emissions inventory. However,
794 there were reductions classified as “Other Distribution” that were applied to the overall distribution
795 stage emissions.

796 It was assumed that the percentage of voluntary reductions relative to potential CH₄ in the most recent
797 base year inventory for the transmission stage would remain constant in each subsequent future year.¹⁴

798 *Regulatory Reductions*

799 There were no requirements in the oil and gas NSPS that impact emissions from the distribution stage.

¹⁴ This assumption is discussed in Footnote 7.

800 **Petroleum Systems**

801 **Source Description**

802 CH₄ emissions from petroleum systems are primarily associated with crude oil production,
803 transportation, and refining. Each of these activities releases CH₄ to the atmosphere as fugitive
804 emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion.
805 Fugitive and vented non-combustion CO₂ emissions from petroleum systems are primarily associated
806 with crude oil production and refining operations but are negligible in transportation operations.

807 Production field operations currently account for the vast majority of CH₄ emissions and non-
808 combustion CO₂ emissions. The most dominant sources of CH₄ emissions within production field
809 operations, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high-
810 bleed pneumatic devices, oil tanks, natural-gas-powered low-bleed pneumatic devices, gas engines,
811 deep-water offshore platforms, and chemical injection pumps. Vented CO₂ associated with natural gas
812 emissions from field operations is the major source of emissions from production field operations. The
813 dominant sources of vented CO₂ emissions are oil tanks, high-bleed pneumatic devices, shallow water
814 offshore oil platforms, low-bleed pneumatic devices, and chemical injection pumps.

815 In the crude oil transportation sector, venting from tanks and marine vessel loading operations accounts
816 for the majority of CH₄ emissions. Fugitive emissions, almost entirely from floating roof tanks, account
817 for the remaining CH₄ emissions. CH₄ emissions from pump engine drivers and heaters were not
818 estimated due to lack of data.

819 Crude oil refining accounts for a small portion of total CH₄ emissions from petroleum systems because
820 most of the CH₄ in crude oil is removed or escapes before the crude oil is delivered to the refineries.
821 Within refineries, vented emissions account for the majority of CH₄ emissions, while fugitive and
822 combustion emissions account for the remainder. Refinery system blowdowns for maintenance and the
823 process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most
824 of the fugitive CH₄ emissions from refineries are from leaks in the fuel gas system. Non-combustion CO₂
825 emissions result from fugitive emissions released during asphalt blowing.

826 Projections for this source cover CH₄ and non-combustion CO₂ emissions from petroleum systems.¹⁵
827 Combustion CO₂ emissions are covered by energy-related CO₂ emissions projections, outside the scope
828 of this report. This section covers fugitive CH₄ emissions from wells producing both natural gas and oil
829 (“associated wells”), while fugitive CH₄ emissions from non-associated natural gas wells are covered in
830 the natural gas systems source. The corresponding source in the 2006 IPCC guidelines is 1B2a.

¹⁵ In this document, consistent with IPCC accounting terminology, the term “combustion emissions” refers to the emissions associated with the combustion of fuel for useful heat and work, while “non-combustion emissions” refers to emissions resulting from other activities, including flaring.

831 **Methodology**

832 Emissions from petroleum systems are calculated by summing the projections associated with
833 production field operations, crude oil transportation,¹⁶ and crude oil refining. Non-combustion CO₂
834 associated with crude oil production is negligible and not included. Activity data are projections of crude
835 oil production, import, export, and refining from the U.S. Energy Information Administration, or EIA
836 (2013). Aggregate emissions factors are calculated from historical emissions in the U.S. inventory
837 compared with historical activity data. Because historical inventory emissions include estimates of
838 mitigation activity, the projections implicitly include mitigation in line with past practice through the
839 emissions factor calculation.

$$Emissions = \sum Emissions\ by\ Source$$

840 **Equation 10**

841 **Production Field Operations**

842 In order to project CH₄ and non-combustion CO₂ emissions from petroleum production field operations,
843 EPA multiplied base year production from the U.S. GHG Inventory by the percent change in U.S. crude oil
844 production projections¹⁷ from EIA (2013) and aggregate emissions factors for CH₄ and non-combustion
845 CO₂ from historical petroleum production operations. EPA estimated the aggregate emissions factor by
846 dividing emissions associated with historical petroleum production field operations from the U.S. GHG
847 Inventory by the historical crude oil production data from the EIA for the corresponding years. The
848 emissions factor for future years is the averages of the aggregate emissions factors over the previous
849 five years.

$$Emissions_{production,y} = EF_{agg} \times InventoryProduction_b \times \left(\frac{ProjectedProduction_y}{ProjectedProduction_b} \right)$$

850 **Equation 11**

851 Where:

852 EF_{agg} = Calculated aggregate emissions factor

853 **Crude Oil Transportation**

854 Future CH₄ emissions associated with crude oil transportation are assumed to remain at same level as
855 the base year through the end of the projection period. This assumption is justified because crude oil
856 transportation activities account for less than 0.5 percent of total CH₄ emissions from petroleum
857 systems in the 2012 U.S. GHG Inventory, and CH₄ emissions associated with crude oil transportation
858 have remained approximately constant from 2005 to 2010. For these reasons, no detailed analysis of the
859 emissions from this sub-source was conducted.

¹⁶ Only CH₄ emissions projections for crude oil transportation are provided (non-combustion CO₂ emissions are negligible).

¹⁷ Projections include the amount of crude oil produced domestically in the United States and lease condensate. Liquid produced at natural gas processing plants is excluded.

860 **Crude Oil Refining**

861 CH₄ and non-combustion CO₂ emissions from crude oil refining are projected by multiplying refining
862 activity in the base year by the change in total crude oil supply projections (including imported crude oil)
863 and aggregate emissions factors based on historical emissions and refining activity. Total crude supply is
864 the total inputs to refining, expressed in the AEO as million barrels per day. The aggregate CH₄ and non-
865 combustion CO₂ emissions factors were estimated by dividing historical refining emissions data
866 contained in the U.S. GHG Inventory (EPA 2013) by U.S. refining data from EIA (2013) for the
867 corresponding years, and averaging over the most recent five years.

$$Emissions_{refining,y} = EF_{agg} \times InventoryRefining_b \times \left(\frac{ProjectedCrudeSupply_y}{ProjectedCrudeSupply_b} \right)$$

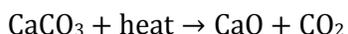
868 **Equation 12**

869 2.2 Industrial Processes

870 Cement Production

871 Source Description

872 Cement production is an energy- and raw-material-intensive process that results in the generation of
873 CO₂ from both the energy consumed in making the cement and the chemical process itself. Non-energy
874 CO₂ emissions from cement production are created by the chemical reaction of carbon-containing
875 materials (i.e., calcining limestone) in the cement kiln. While in the kiln, limestone is broken down into
876 CO₂ and lime, with the CO₂ released to the atmosphere. Specifically, during calcination, each mole of
877 CaCO₃ (i.e., limestone) heated in the clinker kiln forms one mole of lime (CaO) and one mole of CO₂:



878 Cement continues to be a critical component of the construction industry; therefore, the availability of
879 public and private construction funding, as well as overall economic conditions, has considerable
880 influence on cement production.

881 This source category covers process-related (non-combustion) CO₂ emissions from cement production.
882 This source category corresponds to IPCC source category 2A1. It does not cover emissions associated
883 with energy use in cement production, which are included in energy-related CO₂ emissions projections
884 beyond the scope of this report.

885 Methodology

886 Projected emissions from this source are calculating by multiplying (1) an emissions factor based on the
887 assumptions used for the 2013 U.S. GHG Inventory (EPA 2013) for lime fraction and cement kiln dust by
888 (2) base year clinker production and (3) the change in the cement value of shipments from the U.S.
889 Energy Information Administration's (EIA's) *Annual Energy Outlook (AEO)* (EIA 2013).

$$\text{Cement CO}_2 \text{ emissions} = \text{Emissions Factor} \times \text{InventoryClinker}_b \times \left(\frac{\text{ShipmentValue}_y}{\text{ShipmentValue}_b} \right)$$

890 **Equation 13**

891 Where:

892 *InventoryClinker_b* = Base year clinker production in U.S. Inventory

893 *ShipmentValue_y* = Cement value of shipments in year y

894 *ShipmentValue_b* = Cement value of shipments in the base year

895 Clinker Production Projections

896 Projections of cement production were not available; however, EIA does provide "value of shipments"
897 projections for the cement industry in the *AEO* reports. Therefore, the percent increase or decrease in
898 "value of shipments" was assumed to be approximately equivalent to the annual percent change in
899 production for the cement industry (with cement production in the most recent inventory serving as the

900 baseline). The change in value of shipments was multiplied by clinker production in the most recent year
901 of the U.S. GHG Inventory.

902 Projected clinker production was checked against two other data sources. The Portland Cement
903 Association provides projections of the annual change in cement consumption through 2017 based on
904 projections of macroeconomic data including housing starts. In addition to historical production values,
905 the USGS provides estimates of cement and clinker production capacity. Due to regular maintenance
906 and other common issues, plants are assumed to be limited to a practicable maximum capacity
907 utilization of 85%. The estimates of future production here were checked to ensure that they did not
908 exceed current practicable capacity utilization of existing production over the first five years of the
909 projection.

910 There are a number of uncertainties which arise from the chosen approach to projecting clinker
911 production. Historically, value of shipments have not been an accurate proxy for past production levels
912 due to price changes, indicating that future price changes may result in value of shipments diverging
913 from production. In addition, it is uncertain the extent to which this approach fully accounts for
914 technology trends towards using more cement additives, changes in environmental regulations affecting
915 cement plants and the possibility of increased clinker imports. Due to these uncertainties, EPA
916 considered an alternative extrapolation approach to estimating future clinker production. However,
917 extrapolation of production over five to ten years would result in a declining trend (as opposed to the
918 available data sources which indicate production increases) and extrapolating from the bottom of the
919 recession to the present would result in a projection highly sensitive to the rate of change from 2009-
920 2011, inappropriate for a long-term projection. The variations between the production projections
921 indicated based on choice of various assumptions indicate that this factor has an uncertainty of at least
922 20% for long-term projections. As a future improvement, EPA plans to work with sector experts to
923 ensure production projections account for the listed factors.

924 **Non-Energy CO₂ Emissions Factor**

925 The U.S. inventory uses an emissions factor based on long-term average production characteristics and
926 chemical properties, and the same emissions factor is used here for projections. The emissions factor is
927 the product of the average lime (CaO) fraction for clinker of 65 percent and a constant reflecting the
928 mass of CO₂ released per unit of lime, adjusted for cement kiln dust. This calculation yields an emissions
929 factor of 0.52 tons of CO₂ per ton of clinker produced. The following intermediate calculation yields an
930 emissions factor per ton of clinker.

$$EF_{clinker} = 0.65 \text{ tCaO/ton clinker} \times \left(\frac{44 \text{ g/mole CO}_2}{56 \text{ g/mole CaO}} \right) = 0.51 \text{ tons CO}_2/\text{ton clinker}$$

931 **Equation 14**

932 **Cement Kiln Dust**

933 During clinker production, some of the materials fails to be incorporated into the clinker and instead
934 exits the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). The
935 emissions attributable to the calcinated portion of the CKD are not accounted for by the calculation in

936 equation 14 non-energy CO₂ emissions factor. The IPCC recommends that these additional CKD non-
937 energy CO₂ emissions be estimated as 2 percent of the non-energy CO₂ emissions calculated from clinker
938 production. Therefore, EPA estimated total cement production emissions—including the emissions
939 assigned to CKD—according to the 2006 IPCC Guidelines (IPCC 2006).

$$EF_{agg} = EF_{clinker} \times 1.02 = .52 \text{ tons CO}_2/\text{ton clinker net of losses to cement kiln dust}$$

940 Equation 15

941

942 **Adipic Acid Production**

943 **Source Description**

944 Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings,
945 urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the
946 aliphatic dicarboxylic acids, which are used to manufacture polyesters. Adipic acid is produced through a
947 two-stage process during which N₂O is generated in the second stage. The first stage of manufacturing
948 usually involves the oxidation of cyclohexane to form a cyclohexanone/cyclohexanol mixture. The
949 second stage involves oxidizing this mixture with nitric acid to produce adipic acid. N₂O is generated as a
950 byproduct of the nitric acid oxidation stage and is emitted in the waste gas stream. Process emissions
951 from the production of adipic acid vary with the types of technologies and level of emissions controls
952 employed by a facility.

953 This source category covers N₂O emissions from the production of adipic acid. This category corresponds
954 to IPCC source category 2B3.

955 **Methodology**

956 EPA calculated projected emissions from this source category by multiplying (1) assumed constant
957 production of adipic acid from the base year by (2) an average emissions factor based on recent
958 historical emissions and production. This approach yields a projection of constant future emissions from
959 this source.

$$Emissions = EF_{avg} \times Adipic\ Acid\ Production_b$$

960 **Equation 16**

961 Where:

962 *Adipic Acid Production_b* = Production of adipic acid in the base year

963 *EF_{avg}* = Average emissions factor

964 Adipic acid production is different from many other source categories because there are a small number
965 of facilities. Four adipic acid plants were operating in the United States in 1990 (EPA 2013). By 1998, the
966 three largest plants had N₂O abatement technologies in place. The fourth plant, which did not have
967 controls for N₂O, ceased operation in April 2006. In 2009 and 2010, one of the remaining three plants
968 was not operational. In 2011, all three remaining plants were operational, but the abatement utilization
969 rate at the largest plant was much lower in 2011 than in 2010.

970 **Adipic Acid Production Projections**

971 Projections of adipic acid production were not available. In addition, due to the significant operational
972 changes to adipic acid production in the United States since 1990, a linear extrapolation of historical
973 adipic acid production was not representative of future trends. Based on expert opinion, it was assumed
974 that adipic acid production would be equivalent to the most recent U.S. GHG Inventory year and remain
975 constant.

976 **Emissions Factor**

977 In order to project N₂O emissions from adipic acid production, EPA estimated an aggregate N₂O
978 emissions factor by dividing historical emissions in the U.S. GHG Inventory by historical adipic volume
979 and averaging the results for recent years for which there have not been any plant closings or
980 construction. According to the 2013 U.S. inventory, a plant closed in 2006, so the emissions factor was
981 averaged over the most recent five years (2007–2011).

982 **Iron and Steel Production and Metallurgical Coke Production**

983 **Source Description**

984 The production of iron and steel is an energy-intensive process that also emits CO₂ and CH₄. Process-
985 related emissions occur at each step of production, from the production of raw materials to the
986 refinement of iron to the making of crude steel. The majority of CO₂ emissions from the iron and steel
987 production process come from the use of metallurgical coke in the production of crude iron (i.e., pig
988 iron) and from the consumption of other process byproducts (e.g., blast furnace gas, coke oven gas)
989 used for various purposes at the iron and steel mill, with lesser amounts emitted from the use of flux
990 and from the removal of carbon from pig iron used to produce steel.

991 Metallurgical coke is produced by heating coking coal in a coke oven in a low-oxygen environment. The
992 process drives off the volatile components of the coking coal and produces coal (metallurgical) coke,
993 resulting in CO₂ emissions and fugitive CH₄ emissions. Carbon-containing byproducts of the metallurgical
994 coke manufacturing process include coke oven gas, coal tar, coke breeze, and light oil.

995 According to the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006), the
996 production of metallurgical coke from coking coal is considered to be an energy use of fossil fuel and the
997 use of coke in iron and steel production is considered to be an industrial process source. Therefore, the
998 Guidelines suggest that emissions from the production of metallurgical coke should be reported
999 separately in the energy source, while emissions from coke consumption in iron and steel production
1000 should be reported in the industrial process source. However, the 2013 U.S. GHG Inventory (EPA 2013)
1001 estimates and approaches for both metallurgical coke production and iron and steel production are
1002 presented together because the activity data used to estimate emissions from metallurgical coke
1003 production have significant overlap with activity data used to estimate iron and steel production
1004 emissions. Further, some byproducts (e.g., coke oven gas) of the metallurgical coke production process
1005 are consumed during iron and steel production, and some byproducts of the iron and steel production
1006 process (e.g., blast furnace gas) are consumed during metallurgical coke production.

1007 This source category covers both CO₂ and CH₄ for iron and steel production (IPCC source category 2C1)
1008 and CO₂ for metallurgical coke. It does not include emissions from use of conventional fuels (natural gas,
1009 fuel oil, etc.) downstream of the iron and steelmaking furnaces (EPA 2013).

1010 **Methodology**

1011 EPA projected emissions from iron and steel and metallurgical coke production by multiplying (1) base
1012 year emissions from the U.S. GHG Inventory by (2) the projected change in energy-related emissions
1013 from the iron and steel industries over the projection period from the EIA's AEO.¹⁸ The AEO emissions
1014 estimates were not used directly because the coverage differs between the U.S. GHG Inventory and the
1015 AEO.

¹⁸ Projections of emissions in the AEO are not used for other non-CO₂ source categories because for many source categories emissions from energy use are not proportional to process emissions covered within the scope of the source category.

1016 Published projections of iron and steel and metallurgical coke production were not available from EPA
1017 or the U.S. Energy Information Administration (EIA) or industry trade associations; however, EIA does
1018 provide projections of “value of shipments,” energy use, and emissions from energy use through 2040
1019 for the iron and steel industry in the *Annual Energy Outlook (AEO)* reports (EIA 2013). Unlike many other
1020 industrial process source categories, which deal exclusively with process emissions, this source category
1021 involves a combination of energy-related and process emissions resulting from fuel use. Therefore, the
1022 percent increase or decrease in EIA projected emissions was assumed to be approximately equivalent to
1023 the change in production for the iron and steel industry (with the most recent year production of iron
1024 and steel serving as the baseline).

1025 To calculate CO₂ emissions and CH₄ emissions from iron and steel production in the U.S. inventory, EPA
1026 used production of various products (including sinter, direct reduced iron, pig iron, electric arc furnace
1027 steel, and basic oxygen furnace steel) to calculate associated emissions. For the purpose of projections,
1028 these more detailed product projections are not available.

1029

1030 **Aluminum Production**

1031 **Source Description**

1032 Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in many manufactured
1033 products, including aircraft, automobiles, bicycles, and kitchen utensils. The production of primary
1034 aluminum—as well as consuming large quantities of electricity—results in process-related emissions of
1035 non-energy CO₂ and two PFCs: CF₄ and C₂F₆.

1036 Non-energy CO₂ is emitted during the aluminum smelting process when alumina (aluminum oxide,
1037 Al₂O₃) is reduced to aluminum using the Hall-Heroult reduction process. The reduction of the alumina
1038 occurs through electrolysis in a molten bath of natural or synthetic cryolite (Na₃AlF₆). The reduction cells
1039 contain a carbon lining that serves as the cathode. Carbon is also contained in the anode, which can be a
1040 carbonaceous mass of paste, coke briquettes, or prebaked carbon blocks from petroleum coke. During
1041 reduction, most of this carbon is oxidized and released to the atmosphere as non-energy CO₂.

1042 This source category covers PFC and non-energy CO₂ emissions from aluminum production. It
1043 corresponds to IPCC source category 2c3. Emissions associated with electricity and other energy used in
1044 aluminum production are not included in this source category projection, but are included in energy-
1045 related CO₂ emissions projections beyond the scope of this report.

1046 **Methodology**

1047 EPA calculated projected emissions from this category by estimating production based on current
1048 capacity and expert judgement regarding existing facilities and planned capacity changes, and slowly
1049 declining emissions factors consistent with meeting international voluntary reduction goals.

1050 **Activity Data**

1051 For this projection, existing aluminum production was assumed to remain constant at the production
1052 rate at the end of the most recent year. Aluminum production changes as a result of broader economic
1053 trends. Year-to-year changes in production levels are due to variations in utilization rate of plants, and
1054 this projection assumes that no new plants are built and no currently operating plants are shut down.
1055 According to the U.S. GHG Inventory (EPA 2013), a significant amount of production was shut down
1056 between 2008 and 2009. By the end of 2012, most smelter capacity which was shut down in 2008-2009
1057 were restarted or the owners had announced that the closure had been made permanent (Bray 2013).
1058 The projections used the U.S. Aluminum Association’s production estimates for 2012, which are
1059 approximately 4 percent higher than 2011, although emissions have not yet been estimated for 2012 as
1060 part of the U.S. GHG Inventory. The Aluminum Association’s estimate of production rate at the end of
1061 2012 was used as the assumed production level for 2013 and beyond.

1062 Projections of aluminum production were not available from EPA or the U.S. Energy Information
1063 Administration (EIA); however, EIA does provide “value of shipments” projections through 2040 for the
1064 aluminum industry in its *Annual Energy Outlook* reports (EIA 2013). Based on low energy prices related
1065 to increasing natural gas production, EIA projects an increase in the value of shipments from the
1066 aluminum industry. The difference between the EIA projection and the assumption used for this
1067 projection reflects uncertainty in future industry production. EPA considered using EIA value of
1068 shipments projections as a proxy for aluminum production (as was done for several other sources) but
1069 rejected that option because the rapid increase in production implied by the EIA projections differed
1070 from the expectation of EPA and USGS sector experts regarding future production.

1071 **Emissions Factor**

1072 In order to project non-energy CO₂ emissions and PFC emissions from aluminum production, EPA
1073 estimated an aggregate non-energy CO₂ emissions factor and a PFC emissions factor using the historical
1074 aluminum production amounts and associated emissions contained in the U.S. GHG Inventory. The initial
1075 emissions factor was calculated by averaging the calculated aggregate emissions factors over 2010–
1076 2011, omitting emissions related to unusual disruption events.

1077 The global aluminum industry has agreed to a goal to reduce the average PFC emissions factor globally
1078 to the rate of the median plant by technology type (Marks and Bayliss 2010). Although the goal is stated
1079 on a global basis, for the purpose of this projection the U.S. industry was assumed to meet this goal in
1080 2020. Between 2011 and 2020, the PFC emissions rate for each technology type is assumed to change
1081 gradually from the averaged starting rate to the 2020 goal level. After 2020, emissions factors are
1082 assumed to remain constant.

1083 **Magnesium Production and Processing**

1084 **Source Description**

1085 The magnesium metal production and casting industry uses SF₆ as a cover gas to prevent the rapid
1086 oxidation of molten magnesium in the presence of air. SF₆ has been used in this application around the
1087 world for more than 25 years. A dilute gaseous mixture of SF₆ with dry air and/or CO is blown over
1088 molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of
1089 the SF₆ reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and
1090 magnesium fluoride. The amount of SF₆ reacting in magnesium production and processing is considered
1091 to be negligible; for historical inventory calculations, EPA assumed all SF₆ used to be emitted into the
1092 atmosphere (EPA 2013). Although alternative cover gases (such as AM-cover™ containing HFC-134a,
1093 Novec™ 612, and dilute SO₂ systems) can be used, many facilities in the United States are still using
1094 traditional SF₆ cover gas systems.

1095 This source category includes SF₆ emissions from magnesium manufacturing and processing plants. It
1096 corresponds to IPCC source category 2C4.

1097 **Methodology**

1098 Projections of emissions from this source assume that emissions will be flat over the projection period.
1099 Both the underlying level of magnesium production and processing and the average emissions per unit
1100 of production are projected to remain flat.

1101 **HCFC-22 Production**

1102 **Source Description**

1103 CHF₃ (also known as HFC-23) is a byproduct of the manufacture of chlorodifluoromethane (HCFC-22),
1104 which is primarily employed in refrigeration and air conditioning systems and as a chemical feedstock
1105 for manufacturing synthetic polymers. Once separated from HCFC-22, the HFC-23 may be released to
1106 the atmosphere, recaptured for use in a limited number of applications, or destroyed. Between 1990
1107 and 2000, U.S. production of HCFC-22 increased significantly as HCFC-22 replaced chlorofluorocarbons
1108 (CFCs) in many applications. Because HCFC-22 depletes stratospheric ozone, its production for non-
1109 feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act. Feedstock
1110 production, however, is permitted to continue indefinitely.

1111 Three HCFC-22 production plants were operating in the United States in 2011. Since 1990, five plants
1112 that did not capture or destroy HFC-23 have ceased operations, and one plant that captures and
1113 destroys the HFC-23 generated began to produce HCFC-22. Since the closing of the uncontrolled
1114 facilities, there has been a significant decline in HCFC-22 production and HFC-23 process emissions. HFC-
1115 23 emissions from the three HCFC-22 production plants still operating have also decreased since 1990
1116 due to the implementation of HFC-23 recovery, capture, and destruction techniques.

1117 This source category covers HFC-23 emissions produced as a byproduct of HCFC-22 production. It covers
1118 HCFC-22 production for both feedstock and non-feedstock (emissive) uses. It corresponds to IPCC source
1119 category 2E1.

1120 **Methodology**

1121 EPA calculated projected emissions from this source by multiplying (1) projected feedstock and non-
1122 feedstock HCFC-22 production by (2) an aggregate emissions factor based on historical emissions and
1123 production.

1124 **HCFC-22 Production Projections**

1125 Production of HCFC-22 for feedstock and non-feedstock uses are estimated separately. HCFC-22
1126 production for non-feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act,
1127 but feedstock production is permitted to continue indefinitely. To project non-feedstock production of
1128 HCFC-22, this analysis assumes that all U.S. allowances are used for HCFC-22 production. Feedstock
1129 production is assumed to increase at a steady rate of 5 percent per year based on global market
1130 research.

1131 For non-feedstock production, U.S. regulations require companies to hold allowances that are provided
1132 by EPA. It was assumed that all such allowances as distributed by regulation (76 FR 47451) were used for
1133 production in 2010–2011. The 2010 non-feedstock production is thus estimated to be 54.1 gigagrams
1134 (Gg). The non-feedstock production for 2011 is also assumed to equal the production allowances, or
1135 41.3 Gg.

1136 The allocations are provided to ensure U.S. compliance with the *Montreal Protocol on Substances That*
 1137 *Deplete the Ozone Layer*. Under the Montreal Protocol, the United States agreed to produce and
 1138 consume a set amount of HCFCs. In 2010–2014, the limit is 25 percent of the United States’ historical
 1139 baseline. In 2015–2019, the limit drops to 10 percent of the historical baseline. EPA assumed that
 1140 production in 2012–2014 is equal to allowances granted, which are lower than the number of
 1141 allowances provided in 2011 (76 FR 47451 and 78 FR 20004). EPA also assumed that the United States
 1142 uses its entire cap in 2015–2019 for the production of HCFC-22, or 27.7 Gg each year. As stated above,
 1143 the U.S. Clean Air Act requires all non-feedstock production to cease in 2020. This methodology
 1144 produces a conservative (higher) estimate of non-feedstock production for several reasons:

- 1145 • In past years, EPA has consistently provided production allowances below the maximum cap set by
 1146 the Montreal Protocol.
- 1147 • The cap applies to all HCFCs, not just HCFC-22. Thus any production of other HCFCs would reduce
 1148 the maximum HCFC-22 allowed to be produced under the Montreal Protocol cap.
- 1149 • Because at least one company holding production allowances does not produce HCFC-22 in the
 1150 United States, it is unlikely that every production allowance will be used.
- 1151 • Manufacturers may choose not to produce the exact maximum they are allowed to. Even if demand
 1152 for HCFC-22 exceeds the production allowances, that demand may be met by imported supplies,
 1153 chemical recovered from retired equipment, and stockpiles of previously produced chemical.

1154 **HCFC-22 Non-Feedstock Production Assumptions**

Year	Assumed HCFC-22 Production (Gg)
2012	22.8
2013	41.2
2014	36.0
2015–2019	27.7
2020 and after	0

1155
 1156 To determine the base year feedstock production, EPA subtracted the base year non-feedstock
 1157 production (as determined above) from the total base year production as shown in the U.S. GHG
 1158 Inventory. To project HCFC-22 production for feedstock uses, EPA assumed that feedstock production
 1159 increases 5 percent each year in accordance with the global production estimate outlined by Montzka et
 1160 al. (2010).

1161 **HFC-23 Emissions Factor**

1162 In order to project HFC-23 emissions from HCFC-22 production, EPA estimated an HFC-23 emissions
 1163 factor using the historical HCFC-22 production rates and associated emissions over the most recent
 1164 three years in the U.S. inventory. This period was chosen based on consistency in the emissions rate
 1165 over this period, avoiding changes in plant and mitigation system operation which would have

1166 significant effects on emissions rates. When performing this analysis on the 2013 U.S. GHG Inventory,
1167 over 2009–2011, EPA calculated the average emissions factor to be 0.0053 kilograms of HFC-23 emitted
1168 per kilogram of HCFC-22 produced.

1169 **Substitution of Ozone-Depleting Substances**

1170 HFC and PFC emissions from use of substitutes for ozone-depleting substances (ODSs) are projected
1171 using a detailed Vintaging Model, which tracks equipment sold, serviced, and retired each year to
1172 estimate historical and projected emissions. The model covers more than 60 end uses in
1173 refrigeration/air-conditioning, solvents, foams, fire extinguishing, and aerosols.

1174 **Source Description**

1175 HFCs and PFCs are used as alternatives to several classes of ODSs that are being phased out under the
1176 terms of the Montreal Protocol and the Clean Air Act Amendments of 1990. ODSs—CFCs, halons, carbon
1177 tetrachloride, methyl chloroform, and HCFCs—are used in a variety of industrial applications including
1178 refrigeration and air conditioning equipment, solvent cleaning, foam production, sterilization, fire
1179 extinguishing, and aerosols.

1180 The use and subsequent emissions of HFCs and PFCs as ODS substitutes have been increasing from small
1181 amounts in 1990. This increase was in large part the result of efforts to phase out CFCs and other ODSs
1182 in the United States. This trend is expected to continue in the short term, and it will likely continue over
1183 the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased
1184 out under the provisions of the Copenhagen Amendments to the Montreal Protocol and the subsequent
1185 Adjustment agreed in 2007 in Montreal. Improvements in the technologies associated with the use of
1186 these gases and the introduction of alternative gases and technologies, however, may help to offset this
1187 anticipated increase in emissions.

1188 This emissions source covers HFC and PFC emissions from use of substitutes for ODSs. End use sectors
1189 include refrigeration/air conditioning, aerosols, foams, solvents, and fire protection. This source
1190 corresponds to IPCC source category 2F. For a more detailed discussion of the source category and each
1191 of the end use categories, see the U.S. GHG Inventory chapter for this source (EPA 2013, p. 4-73).

1192 **Methodology**

1193 HFC and PFC emissions from use of substitutes for ODSs are projected using a detailed Vintaging Model
1194 of ODS-containing equipment and products. This is the same model used to calculate emissions for the
1195 U.S. GHG Inventory. More detailed information on its construction and data can be found in the Annex
1196 to the U.S. GHG Inventory, although a summary is provided below.

1197 The Vintaging Model estimates emissions from five ODS substitute end-use sectors: air-conditioning and
1198 refrigeration, foams, aerosols, solvents, and fire-extinguishing. Within these sectors, there are 60
1199 independently modeled end-uses. The model requires information on the market growth for each of the
1200 end-uses, a history of the market transition from ODS to alternatives, and the characteristics of each
1201 end-use such as market size or charge sizes and loss rates. As ODS are phased out, a percentage of the
1202 market share originally filled by the ODS is allocated to each of its substitutes.

1203 The model, named for its method of tracking the emissions of annual “vintages” of new equipment that
1204 enter into service, is a “bottom-up” model. It models the consumption of chemicals based on estimates
1205 of the quantity of equipment or products sold, serviced, and retired each year, and the amount of the

1206 chemical required to manufacture and/or maintain the equipment. The Vintaging Model makes use of
1207 this market information to build an inventory of the in-use stocks of the equipment and ODS and ODS
1208 substitute in each of the end-uses. The simulation is considered to be a “business-as-usual” baseline
1209 case, and does not incorporate measures to reduce or eliminate the emissions of these gases other than
1210 those regulated by U.S. law or otherwise common in the industry. Emissions are estimated by applying
1211 annual leak rates, service emissions rates, and disposal emissions rates to each population of
1212 equipment. By aggregating the emissions and consumption output from the different end-uses, the
1213 model produces estimates of total annual use and emissions of each chemical.

1214 The Vintaging Model synthesizes data from a variety of sources, including data from the ODS Tracking
1215 System maintained by the Stratospheric Protection Division and information from submissions to EPA
1216 under the Significant New Alternatives Policy program. Published sources include documents prepared
1217 by the United Nations Environment Programme Technical Options Committees, reports from the
1218 Alternative Fluorocarbons Environmental Acceptability Study, and conference proceedings from the
1219 International Conferences on Ozone Protection Technologies and Earth Technologies Forums. EPA also
1220 coordinates extensively with numerous trade associations and individual companies. For example, the
1221 Alliance for Responsible Atmospheric Policy; the Air-Conditioning, Heating and Refrigeration Institute;
1222 the Association of Home Appliance Manufacturers; the American Automobile Manufacturers
1223 Association; and many of their member companies have provided valuable information over the years.
1224 Some of the unpublished information that the EPA uses in the model is classified as confidential
1225 business information (CBI). The annual emissions inventories and projections of chemicals are
1226 aggregated in such a way that CBI cannot be inferred. Full public disclosure of the inputs to the Vintaging
1227 Model would jeopardize the security of the CBI that has been entrusted to EPA.

1228 **Semiconductor Manufacturing**

1229 **Source Description**

1230 The semiconductor industry uses multiple long-lived fluorinated gases in plasma etching and plasma
1231 enhanced chemical vapor deposition (PECVD) processes to make semiconductor products. The gases
1232 most commonly employed are CHF_3 , CF_4 , C_2F_6 , NF_3 , and SF_6 , although other compounds such as C_3F_8 and
1233 C_4F_8 are also used. The exact combination of compounds is specific to the process employed.

1234 A single 300-millimeter silicon wafer that yields between 400 to 500 semiconductor products (devices or
1235 chips) may require 100 or more distinct fluorinated-gas-using process steps, principally to deposit and
1236 pattern dielectric films. Plasma etching (or patterning) of dielectric films, such as SiO_2 and Si_3N_4 , is
1237 performed to provide pathways for conducting material to connect individual circuit components in
1238 each device. The patterning process uses plasma-generated fluorine atoms, which chemically react with
1239 exposed dielectric film to selectively remove the desired portions of the film. The material removed—
1240 along with undissociated fluorinated gases—flows into waste streams and, unless emissions abatement
1241 systems are used, into the atmosphere. PECVD chambers, used for depositing dielectric films, are
1242 cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to
1243 fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and
1244 chamber hardware. Undissociated fluorinated gases and other products pass from the chamber to
1245 waste streams and, unless abatement systems are employed, into the atmosphere. In addition to
1246 emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma
1247 processes into different fluorinated compounds which are then exhausted, unless abated, into the
1248 atmosphere. For example, when C_2F_6 is used in cleaning or etching, CF_4 is generated and emitted as a
1249 process byproduct. Besides dielectric film etching and PECVD chamber cleaning, much smaller quantities
1250 of fluorinated gases are used to etch polysilicon films and refractory metal films like tungsten.

1251 **Methodology**

1252 EPA estimated emissions from semiconductor manufacturing by estimating projected changes in
1253 production and changes in emissions factor per unit of area. EPA projected changes in production by
1254 extrapolating historical trends, but reducing the rapid growth rate in future years. Changes in emissions
1255 factor were estimated based on implementation of reduction technologies associated with progress
1256 toward the global commitment by the World Semiconductor Council. For the purpose of projections,
1257 EPA made separate calculations for manufacturers formerly partners in the EPA PFC Reduction/Climate
1258 Partnership for the Semiconductor Industry and manufacturers that have never participated in this
1259 program.

1260 **Activity Data**

1261 Semiconductor manufacturing is an expanding industry in the United States, both in terms of the
1262 number of facilities and the production levels achieved by the current facilities. Over time,
1263 semiconductor devices have gradually become more complex, requiring more layers and more complex
1264 processes to manufacture. Complex devices with many layers require more steps involving fluorinated
1265 gases.

1266 Two metrics for semiconductor production are commonly used. The first, silicon area, represents the
1267 total area of silicon wafers produced. The second metric is total manufactured layer area (TMLA). TMLA
1268 represents the total area of all layers produced, or the silicon area multiplied by the number of layers of
1269 the devices manufactured. In 2011, TMLA was approximately 8.5 times higher than silicon area demand,
1270 meaning that the average device produced in the United States had about 8.5 layers. These projections
1271 use TMLA as the activity data basis for projections. The World Semiconductor Council reduction goal is
1272 expressed on a silicon area basis.

1273 Activity growth, in terms of TMLA, can occur without a new fab being built. The capacity of a fab is
1274 measured in terms of the number of chips it can produce, which is a function of both number of wafers
1275 processed (i.e., the silicon consumed) and the number of die pieces produced per wafer (i.e., the
1276 number of individualized chips cut, or diced, out of a wafer). Growing demand for a product can be met
1277 by shrinking die size (which is accomplished by growing circuits vertically, or increasing the number of
1278 layers), which also improves performance and functionality.

1279 EPA estimated future TMLA by extrapolating historical growth, but at a declining rate. This assumes no
1280 future recessions or fab closures that would have a major impact on U.S. production activity. The U.S.
1281 industry TMLA growth rate in 2012 was set to the average growth rate seen from 2004 to 2011, 12
1282 percent. The growth rate was then set to decline out through 2020 to 5 percent. Linear interpolation
1283 was used between 2012 and 2020 to determine annual growth rates. After 2020, the growth rate was
1284 assumed to be 5 percent per year.

1285 For the purpose of estimating emissions, production activity must be allocated between companies that
1286 have participated in the voluntary partnership program and non-partners. From 2004 to 2011, partner
1287 companies accounted for an average of 80 percent of TMLA production. EPA assumed that the
1288 percentage of production owned by these companies will gradually grow from 80 percent in 2012 to 85
1289 percent in 2020 because all new fabs known to be under construction are by manufacturers that have
1290 participated in the partnership program.

1291 **Emissions Factors**

1292 EPA projected future emissions rates by incorporating estimated emissions rates of new facilities
1293 starting production, assuming constant emissions rates among former partner manufacturers and
1294 introduction of emissions reduction technologies at the remaining non-partner manufacturers.

1295 The U.S. GHG Inventory bases emissions estimates of former partner companies on emissions reports
1296 submitted as part of the voluntary program (EPA 2013). Over the past decade, emissions rates among
1297 these companies have dropped substantially on a TMLA basis along with the uptake of a variety of
1298 technologies to reduce emissions such as NF₃ remote clean. Former partner companies were not
1299 assumed to implement further reduction measures at existing facilities over the projection period. EPA
1300 estimated new facilities' emissions rates based on emissions from a recently opened fab using best
1301 mitigation practices.

1302 Non-partner companies have not reported their emissions through the voluntary program, and
1303 historically EPA has assumed that these manufacturers have emissions equivalent to partner rates
1304 before the introduction of the voluntary program. New information on the emissions from all large
1305 manufacturers is now available through the Greenhouse Gas Reporting Program, but this information
1306 has not yet been incorporated into inventory estimates. Incorporating these data is a planned
1307 improvement to the inventory and these projections, and is likely to reduce estimated emissions rates
1308 among non-partners. For these projections, EPA has assumed that non-partners are also implementing
1309 reduction technologies, but on a delayed timeline compared to non-partners. Non-partners are assumed
1310 to achieve an emissions rate in 2020 equivalent to the partner emissions rate in 2011.

1311 The World Semiconductor Council has set a new emissions intensity goal for 2020 that requires a 30
1312 percent decrease in emissions intensity, or emissions per surface area of silicon produced (to 0.22
1313 kilograms of CO₂ equivalent per square centimeter). Area produced is not the same as TMLA, which
1314 takes into account the number of layers on devices manufactured. The more layers on a device, the
1315 more fluorinated-GHG-using steps it takes to manufacture that device (i.e., more layers of film have to
1316 be deposited, that film has to be etched, and the deposition chambers need to be cleaned more often
1317 with more use). Due to uncertainty regarding how the global emissions intensity goal might affect U.S.-
1318 specific emissions, these projections do not assume that the U.S. industry achieves the global intensity
1319 goal.

1320 **Electrical Transmission and Distribution**

1321 Because SF₆ is used as an electrical insulator, it can be emitted when transmission and distribution
1322 equipment leaks or is repaired. To project SF₆ emissions from electrical transmission and distribution,
1323 EPA extrapolated historical growth in transmission line mileage, assumed constant emissions rates
1324 among non-Partner utilities, and declining emissions rates among partner utilities.

1325 **Source Description**

1326 The largest use of SF₆, both in the United States and internationally, is as an electrical insulator and
1327 interrupter in equipment that transmits and distributes electricity. The U.S. electric power industry has
1328 used the gas since the 1950s because of its dielectric strength and arc-quenching characteristics. It is
1329 used in gas-insulated substations, circuit breakers, and other switchgear. SF₆ has replaced flammable
1330 insulating oils in many applications and allows for more compact substations in dense urban areas.

1331 Fugitive emissions of SF₆ can escape from gas-insulated substations and switchgear through seals,
1332 especially from older equipment. The gas can also be released during equipment manufacturing,
1333 installation, servicing, and disposal. Since 1990, SF₆ emissions have decreased significantly in the United
1334 States. Two trends contributed to this decrease: a sharp increase in the price of SF₆ during the 1990s and
1335 a growing awareness of the environmental impact of SF₆ emissions through programs such as EPA's SF₆
1336 Emission Reduction Partnership for Electric Power Systems.

1337 This source category includes SF₆ emissions from the operation of electric transmission and distribution
1338 systems and emissions from the manufacture of electrical equipment. This corresponds to IPCC source
1339 category 2F7.

1340 **Methodology**

1341 EPA calculated projected emissions from this source by multiplying (1) projected transmission miles
1342 based on extrapolation of past rates of change by (2) projected emissions per mile of transmission line
1343 based on assumptions regarding future reduction activities. Different calculations are performed for
1344 groups of utilities based on participation in the EPA SF₆ Emissions Reduction Partnership for Electric
1345 Power Systems, and based on the size of the utility.

$$SF_6Elect\&D_{y,u} = EF_{y,u} \times TransMiles_y$$

1346 **Equation 17**

1347 Where:

1348 $SF_6Elect\&D_{y,u}$ = Projected SF₆ emissions for utility group *u* in year *y*

1349 $EF_{y,u}$ = Emissions factor for utility group *u* in year *y*

1350 $TransMiles_y$ = Transmission miles in year *y*

1351 **Activity Data**

1352 Transmission miles are defined as the miles of lines carrying voltages above 34.5 kilovolts (EPA 2013).
1353 EPA calculated the projected change in transmission miles by averaging the annual percent change over

1354 the period of 1999 to the base year for four utility groups: (1) all utilities with more than 10,000 miles of
 1355 lines; (2) all utilities with less than 10,000 miles of lines; (3) partner utilities with more than 10,000 miles
 1356 of transmission lines; and (4) partner utilities with less than 10,000 miles of lines. Non-partner utilities’
 1357 transmission projections were based on subtracting partner mileage from the total for the groups above
 1358 and below 10,000 miles of lines. Based on the 2013 U.S. GHG Inventory (EPA 2013), transmission miles
 1359 have increased 0.2% per year among all utilities with less than 10,000 miles of transmission lines,
 1360 increased 4.0% per year for all utilities with more than 10,000 miles of transmission lines and decreased
 1361 1.7% per year among Partner utilities with less than 10,000 miles of transmission lines. Growth rates for
 1362 partner and non-Partner utilities in each size category are listed in the summary table below.

1363 **Emissions Factor**

1364 EPA estimated emissions factors for future years based on assumptions about reduction activities for
 1365 each utility group and based on the previous reduction trend over the 1999 to 2011 period.

1366 For non-Partners, EPA assumed the emissions rate per transmission mile to stay constant through the
 1367 projection period. Based on the U.S. GHG Inventory (EPA 2013), the 2011 emissions rates per
 1368 transmission mile are 0.34 kilograms of SF₆ per transmission miles and 0.58 kilograms of SF₆ per
 1369 transmission mile for non-Partners with less than 10,000 miles of transmission lines and greater than
 1370 10,000 miles of transmission lines, respectively.

1371 For Partner utilities, EPA extrapolated total emissions based on continuation but slowing of historical
 1372 trends over the 2004–2011 time period. Based on the 2013 U.S. GHG Inventory, the average year-to-
 1373 year percent change over this time period was 9 percent. These projections assume that the downwards
 1374 emissions trend will continue, but at half the historical rate, resulting in a 4.5 percent decrease in total
 1375 emissions per year. For completeness, EPA back-calculated an emissions rate for each year, which
 1376 results in an emissions factor which decreases by 6.4 percent per year, slower than the historical
 1377 emissions factor decrease of 10.2 percent per year over the 1999–2011 time period.

1378 **Activity Data and Emissions Rate Assumptions**

Utility Group	Transmission Miles		Emissions Rate	
	Methodology	Calculation	Methodology	Calculation
Partners, <10,000 miles of transmission lines	Extrapolate average growth rate over 1999–2011	1.7% decrease per year	Reduce total emissions at half historical rate	-6.4% per year
Partners, >10,000 miles of transmission lines		3.2% increase per year		
Non-Partners, <10,000 miles of transmission lines	Subtract partner miles from total	0.6% increase per year	Constant	0.34 kg SF ₆ /mile
Non-Partners, >10,000 miles of transmission lines		6.4% increase per year	Constant	0.58 kg SF ₆ /mile

1379

1380

1381 **2.3 Agriculture**

1382 **Enteric Fermentation**

1383 **Source Description**

1384 CH₄ is produced as part of normal digestive processes in animals. During digestion, microbes residing in
1385 an animal’s digestive system ferment food. This microbial fermentation process, referred to as enteric
1386 fermentation, produces CH₄ as a byproduct, which can be exhaled or eructated by the animal. The
1387 amount of CH₄ produced and emitted by an individual animal depends primarily upon the animal’s
1388 digestive system and the amount and type of feed it consumes.

1389 Ruminant animals (e.g., cattle, buffalo, sheep, goats, and camels) are the major emitters of CH₄ because
1390 of their unique digestive systems. Non-ruminant animals (e.g., swine, horses, and mules) also produce
1391 CH₄ emissions through enteric fermentation, although they emit significantly less CH₄ on a per-animal
1392 basis.

1393 In addition to the type of digestive system, an animal’s feed quality and feed intake affect CH₄ emissions.
1394 In general, lower feed quality and/or higher feed intake leads to higher CH₄ emissions. Feed intake is
1395 positively correlated to animal size, growth rate, and production (e.g., milk production, wool growth,
1396 pregnancy, or work). Therefore, feed intake varies among animal types as well as among different
1397 management practices for individual animal types (e.g., animals in feedlots or grazing on pasture).

1398 This source category covers CH₄ emissions from enteric fermentation from livestock. It corresponds to
1399 IPCC category 4A. Included livestock categories are beef cattle, dairy cattle, horses, swine, sheep, goats,
1400 American bison, mules, burros, and donkeys.

1401 **Methodology**

1402 EPA projected CH₄ emissions from enteric fermentation by summing projections associated with beef
1403 cattle, dairy cattle, swine, sheep, goats, horses, American bison, mules, burros, and donkeys. For each
1404 animal type, projected emissions are based on projected animal populations and aggregate emissions
1405 factors (Equation 18). The aggregate emissions factors are based on average emissions in the U.S. GHG
1406 Inventory (EPA 2013). Projected animal populations come from U.S. Department of Agriculture (USDA)
1407 long-term projections (USDA 2013), where available, and extrapolation of trends where projections are
1408 unavailable. The sources of projected livestock population data are summarized in the table below.

$$\sum_1^n \left(EF_n \times Inventory Population_{n,b} \times \frac{Projected Population_{n,y}}{Projected Population_{n,b}} \right)$$

1409 **Equation 18**

1410 Where:

- 1411 *n* = Animal type *n*
1412 *EF_n* = Emissions factor for livestock type *n*
1413 *b* = base year

1414

Summary of Calculations by Animal Type

Animal Type	Population Projection	Projected Emissions Factor
Dairy cattle	<i>USDA Long-Term Agricultural Projections to 2022 (USDA 2013) and extrapolation</i>	Aggregate emissions factor, extrapolated
Beef cattle	<i>USDA Long-Term Agricultural Projections to 2022 (USDA 2013) and extrapolation</i>	Aggregate emissions factor, extrapolated
Swine	<i>USDA Long-Term Agricultural Projections to 2022 (USDA 2013) and extrapolation</i>	Fixed
Sheep	Historical extrapolation	Fixed
Goats	Historical extrapolation	Fixed
Horses	Assumed constant	Fixed
American bison	Assumed constant	Fixed
Mules, burros, and donkeys	Assumed constant	Fixed

1415

1416 Activity Data

1417 Projected animal populations come from a combination of USDA projections and extrapolations of
1418 trends.

1419 *USDA Long-Term Agricultural Projections* provide projections over a 10-year period for various
1420 agricultural information including livestock populations for dairy cattle, beef cattle, and swine. They also
1421 provide production weight for poultry, which is used for projection purposes as a proxy for the number
1422 of poultry. Because the projections in this report extend over a longer period than the USDA projections,
1423 EPA extrapolated livestock populations over the rest of the projection period by applying the same
1424 average percent change between the base year and the end of the USDA projection period to the end of
1425 the USDA projections.

1426 Projected animal populations are not available for sheep, goats, horses, American bison, mules, burros,
1427 and donkeys. In the case of sheep and goats, EPA extrapolated projected future animal populations by
1428 applying the average percent change over the last 10 years of the U.S. inventory to the population in the
1429 base year. The populations of horses, American bison, mules, burros, and donkeys make up a very small
1430 portion of the emissions from this source, and were assumed to remain constant over the projection
1431 period.

1432 The U.S. GHG Inventory uses a more detailed set of beef and dairy populations to estimate livestock
1433 emissions, and therefore the projections presented here do not use identical methodology to estimate
1434 emissions from cattle as the inventory. To estimate CH₄ emissions, the inventory relies on EPA's Cattle
1435 Enteric Fermentation Model (CEFM), which is based on recommendations provided in IPCC guidelines.
1436 The CEFM uses information on population, energy requirements, digestible energy, and CH₄ conversion
1437 rates to estimate CH₄ emissions. The inventory methodology is more detailed than the methodology for
1438 projections; it uses additional activity data not available for projections, such as counts for younger
1439 replacement dairy and beef cattle of various ages. For example, instead of the "dairy cattle" and "beef
1440 cattle" groupings, the inventory uses 10 different cattle subpopulations based on age:

1441

<u>Dairy cattle</u>	<u>Beef cattle</u>
<ul style="list-style-type: none"> • Dairy cows • Dairy replacements (7–11 months) • Dairy replacements (12–23 months) 	<ul style="list-style-type: none"> • Bulls • Beef cows • Beef replacements (7–11 months) • Beef replacements (12–23 months) • Steer stockers • Heifer stockers • Feedlot cattle

1442

1443 To ensure that projected animal populations have comparable coverage and composition to historical
 1444 populations, EPA calculated projected populations by applying the percent increase in the projection
 1445 data to the inventory livestock population in the base year.

1446 **Emissions Factors**

1447 For the U.S. GHG Inventory, emissions factors for dairy and beef cattle are modeled within the CEFM
 1448 and depend on a variety of factors including energy requirements, digestible energy, and CH₄ conversion
 1449 rates. For the purpose of projections, EPA calculated an aggregate emissions factor for each year by
 1450 dividing total emissions associated with dairy and beef cattle, and dividing by the corresponding
 1451 population. These aggregate emissions factors have gradually increased over time. Under the
 1452 assumption that emissions per head of cattle are likely to continue to increase in the future, the
 1453 projections assume that the emissions factors for dairy and beef cattle gradually increase at a slowing
 1454 rate over the first 10 projection years, and remain constant after that time through the end of the
 1455 projection period.

1456 For sheep, goats, horses, swine, mules and asses, and American bison, the U.S. GHG Inventory uses fixed
 1457 emissions factors that are representative of typical animal sizes, feed intakes, and feed characteristics in
 1458 developed countries. The projections use the same emissions factors, listed in the table below.

1459

Emissions Factors for Other Animal Types

Livestock Type	Emissions Factor (kg CH₄/head/year)
Sheep	8
Goats	5
Horses	18
Swine	1.5
Mules and asses	10.0
American bison	82.2

1460

1461 **Manure Management**

1462 **Source Description**

1463 The management of livestock manure can produce anthropogenic CH₄ and N₂O emissions. When
1464 livestock or poultry manure is stored or treated in systems that promote anaerobic conditions (e.g., as a
1465 liquid/slurry in lagoons, ponds, tanks, or pits), the decomposition of materials in the manure produces
1466 CH₄. For non-liquid-based manure systems, moist conditions (which are a function of rainfall and
1467 humidity) can create areas of anaerobic conditions and associated CH₄ production. Ambient
1468 temperature, moisture, and manure storage or residency time affect the amount of CH₄ produced
1469 because they influence the growth of the bacteria responsible for CH₄ formation.

1470 Direct N₂O emissions are produced as part of the nitrogen cycle through the nitrification and
1471 denitrification of the organic nitrogen in livestock dung and urine. Specifically, direct N₂O emissions
1472 occur when the manure is first handled aerobically and then anaerobically. These emissions are most
1473 likely to occur in dry manure handling systems that have aerobic conditions, but also contain pockets of
1474 anaerobic conditions due to saturation. Indirect N₂O emissions are produced when nitrogen is lost from
1475 the system through volatilization or through runoff and leaching. Runoff losses would be expected from
1476 operations that house animals or store manure in a manner that exposes them to weather. (EPA 2013)

1477 This source category covers CH₄ and N₂O emissions from manure management systems. It corresponds
1478 to IPCC source category 4B. (Emissions associated with pasture, range, and paddock and daily spread
1479 systems are covered in the agricultural soil management source category.) Emissions in this category
1480 include manure from dairy and beef cattle, swine, sheep, goats, poultry, and horses.

1481 **Methodology**

1482 EPA calculated emissions projections from manure management systems by summing projections of
1483 emissions associated with dairy cattle, beef cattle, swine, sheep, goats, poultry, and horses.

1484

$$Emissions_y = \sum EF_{agg_{n,y}} \times InventoryPopulation_{n,b} \times \left(\frac{ProjectedPopulation_{n,y}}{ProjectedPopulation_{n,b}} \right)$$

1485 **Equation 19**

1486 Where:

- 1487 $EF_{agg_{n,y}}$ = Aggregate emissions factor for animal type n in year y
1488 $InventoryPopulation$ = Historical livestock populations from U.S. GHG Inventory
1489 $ProjectedPopulation$ = Projected populations from USDA Long-Term Agricultural
1490 Projections
1491 y = projected year y
1492 b = base year

1494 **Emissions Factors**

1495 EPA calculated the aggregate emissions factor for past years for each animal type by dividing historical
1496 CH₄ and N₂O emissions associated with each animal type by the livestock populations. The U.S. GHG

1497 Inventory presents these aggregate emissions factors for historical years for CH₄ from manure
 1498 management (EPA 2013).

1499 The aggregate emissions factor used for projections was calculated differently for different animal types.
 1500 In the cases of dairy cattle and swine, changes in animal size and greater use of liquid systems have led
 1501 to an increasing trend in emissions from manure management per animal. To capture this trend, EPA
 1502 extrapolated projected aggregate emissions factors for these animals based on the average percent
 1503 change over the previous 10 years. For beef cattle, sheep, goats, poultry, and horses, no clear trend is
 1504 present and the aggregate emissions factor used for projections was the average of the previous five
 1505 years, to smooth out year-to-year variations.

1506 **Livestock Populations**

1507 Projections of dairy cattle, beef cattle, and swine are available as part of the USDA Long-Term
 1508 Agricultural Projections, in terms of 1,000 head (USDA 2013). Projections of young chicken production in
 1509 million pounds are available as well, which is assumed to be proportional to livestock populations. Long-
 1510 term projections are not available for sheep, goats, or horses; EPA extrapolated these from historical
 1511 populations or assumed that they were constant.

1512 **Summary of Projection Calculations by Animal Type**

Animal Type	Projection	Projected Aggregate Emissions Factor
Dairy cattle	USDA population projections, extrapolation	Extrapolated
Beef cattle	USDA population projections, extrapolation	Average of last five years
Swine	USDA population projections, extrapolation	Extrapolated
Sheep	Historical extrapolation	Average of last five years
Goats	Historical extrapolation	Average of last five years
Poultry	USDA production projections, extrapolation	Average of last five years
Horses	Assumed constant	Average of last five years

1513

1514 **Rice Cultivation**

1515 **Source Description**

1516 All rice grown in the United States is grown in flooded fields. When fields are flooded, aerobic
1517 decomposition of organic material gradually depletes most of the oxygen present in the soil, causing
1518 anaerobic soil conditions. Once the environment becomes anaerobic, CH₄ is produced through anaerobic
1519 decomposition of soil organic matter by methanogenic bacteria. Factors that influence CH₄ emissions
1520 from flooded rice fields include fertilization practices (especially the use of organic fertilizers), soil
1521 temperature, soil type, rice variety, and cultivation practices (e.g., tillage, seeding, and weeding
1522 practices).

1523 This source category covers CH₄ emissions from rice cultivation. It corresponds to IPCC source category
1524 4C.

1525 **Methodology**

1526 Projected emissions from this source are calculated by multiplying (1) an aggregate emissions factor
1527 based on historical emissions per area by (2) base year area harvested from the U.S. GHG Inventory by
1528 (3) projected change in area of harvested rice in the U.S. from base year to the projection year from
1529 USDA long-term projections.

$$Emissions = EF_{agg} \times InventoryAreaHarvested_b \times \left(\frac{ProjectedHarvestedArea_y}{ProjectedHarvestedArea_b} \right)$$

1530 **Equation 20**

1531 Where:

1532 EF_{agg} = Aggregate emissions factor

1533 y = Projection year y

1534 b = Base year

1535 **Activity Data**

1536 The U.S. Department of Agriculture (USDA) Long-Term Agricultural Projections report (USDA 2013)
1537 contains projections of rice area planted, rice area harvested, rice yield per acre, total production, and
1538 various economic information such as imports and exports. The report generally projects U.S. rice
1539 production for Arkansas, California, Louisiana, Mississippi, Missouri, and Texas over a 10-year period.
1540 The U.S. GHG Inventory (EPA 2013) includes Florida and Oklahoma as well; because it adds production
1541 from these two states, there are slight differences in the coverage of historical area used for the
1542 inventory and area projections. To avoid problems cause by these differences, EPA applied the growth
1543 rate in the projection to the base year emissions data.

1544 EPA used rice area harvested for these projections. Projections in this report extend past the 10-year
1545 projection window presented in the USDA long-term projections report, so EPA extrapolated the
1546 projections over the remainder of the projection period by assuming that rice area harvested remained
1547 constant after the end of the period covered by USDA projections. Over the historical period, harvested

1548 rice area has fluctuated between about 1.2 and 1.6 million hectares based on shifting market conditions,
1549 making rice more or less valuable relative to other crops. Year-to-year variation has exceeded overall
1550 trends.

1551 **Emissions Factor**

1552 To calculate an aggregate emissions factor for kilograms of CH₄ per hectare of rice harvested, EPA
1553 divided historical emissions by area of harvested rice over the most recent five years of the U.S. GHG
1554 Inventory and averaged the results.

$$EF_{agg} = \left[\sum_{y=b-5}^b \left(\frac{Emissions_y}{RiceAreaHarvested_y} \right) \right] / 5$$

1555 **Equation 21**

1556 Where:

1557 EF_{agg} = Aggregate emissions factor

1558 b = Base year

1559 **Agricultural Soil Management**

1560 **Source Description**

1561 N₂O is produced naturally in soils through the microbial processes of nitrification and denitrification. A
1562 number of agricultural activities increase mineral nitrogen availability in soils, thereby increasing the
1563 amount available for nitrification and denitrification, and ultimately the amount of N₂O emitted.

1564 Direct increases occur through a variety of management practices that add or lead to greater release of
1565 mineral nitrogen to the soil, including fertilization; application of managed livestock manure and other
1566 organic materials such as sewage sludge; deposition of manure on soils by domesticated animals in
1567 pastures, rangelands, and paddocks; production of nitrogen-fixing crops and forages; retention of crop
1568 residues; and drainage and cultivation of organic cropland soils. Other agricultural soil management
1569 activities, including irrigation, drainage, tillage practices, and fallowing of land, can influence nitrogen
1570 mineralization in soils and thereby affect direct emissions. Indirect emissions of N₂O occur through
1571 volatilization and subsequent atmospheric deposition of applied/mineralized nitrogen, as well as surface
1572 runoff and leaching of applied/mineralized nitrogen into groundwater and surface water.

1573 This source category includes direct and indirect N₂O emissions from croplands and grasslands. This
1574 source category corresponds to IPCC source category 4D.

1575 **Methodology**

1576 To project N₂O emissions from agricultural soil management, EPA allocated base year emissions from
1577 this source to subcategories associated with various activity drivers, and then using changes in the
1578 projections of those activity drivers from the base year to scale the base year inventory emissions. The
1579 activity drivers identified are (1) nitrogen from synthetic fertilizer use, (2) residues from crop production,
1580 and (3) livestock manure (both managed and unmanaged pasture, range, and paddock).

1581

$$Emissions_{s,y} = Emissions_{s,b} \times \left(\frac{Activity_{s,y}}{Activity_{s,b}} \right)$$

1582 **Equation 22**

1583 **Where:**

1584 $Emissions_{s,y}$ = N₂O emissions for source *s* in year *y*

1585 $Activity_{s,y}$ = Activity driver associated with source *s* in year *y* (kg N)

1586

1587 The U.S. inventory divides emissions using the following categories:

1588 1. Direct N₂O emissions

1589 ○ Cropland soils

1590 ■ Mineral soils

1591 ● Synthetic fertilizer

1592 ● Organic amendment

- 1593 • Residue N
- 1594 • Mineralization and asymbiotic fixation
- 1595 ▪ Organic soils
- 1596 ○ Grassland soils
 - 1597 ▪ Synthetic fertilizer
 - 1598 ▪ Pasture, range and paddock (PRP) manure
 - 1599 ▪ Managed manure
 - 1600 ▪ Sewage sludge
 - 1601 ▪ Residue N
 - 1602 ▪ Mineralization and asymbiotic fixation
- 1603 2. Indirect N₂O emissions
 - 1604 ○ Land type
 - 1605 ▪ Cropland, grassland, forest land, settlements
 - 1606 ○ Emissions type
 - 1607 ▪ Volatilization and atmospheric deposition
 - 1608 ▪ Leaching/runoff

1609 For the purpose of projections, emissions subcategories are aggregated as indicated in the table below
 1610 for association with various activity data drivers:

1611

Inventory Subcategory	Activity Data Driver for Projections	Projection Source
Direct emissions from synthetic N fertilizer use on mineral cropland soils and grassland soils	Fertilizer use	Extrapolation of historical usage
Direct emissions from organic N amendments on mineral cropland soils and direct emissions from PRP manure N and managed manure N on grasslands	Livestock production	USDA projections of livestock production and populations (USDA 2013)
Direct emissions from crop residue N on mineral cropland soils and grasslands	Crop production	USDA projections of crop production (USDA 2013) multiplied by default IPCC 2006 factors for dry matter and N content (IPCC 2006)
All other direct emissions (mineralization and asymbiotic fixation on mineral soils, organic soils, and sewage sludge; mineralization and asymbiotic fixation on grasslands)	None	Held constant
Indirect emissions total	Direct emissions (less mineralization and asymbiotic fixation)	Proportional to sum of direct emissions calculations for synthetic fertilizer, organic amendments, crop residue N, and other except mineralization and asymbiotic fixation

1612

1613 **Synthetic Fertilizer Use**

1614 EPA calculated projected synthetic fertilizer use by calculating the average percent change in historic
1615 synthetic fertilizer use over the previous 10 years and applying that percentage change over the
1616 projection period. The U.S. GHG Inventory (EPA 2013) includes data used for past emissions inventories
1617 on synthetic fertilizer nitrogen added to major and non-major crops, which EPA summed for this
1618 calculation.

1619 Synthetic fertilizer use projections are not available from USDA as part of the Long-Term Agricultural
1620 Projections, although crop production and other projections are available. Synthetic fertilizer use
1621 projections are provided by the Food and Agricultural Policy Research Institute at Iowa State University
1622 (FAPRI 2011), but were not used directly for these projections. These projections are used as a
1623 comparison to the historical extrapolation. Another alternative source for projecting nitrogen fertilizer
1624 usage is examining historical trends in crop production and fertilizer use and extrapolating those
1625 individual trend relationships.

1626 **Nitrogen from Crop Residues**

1627 Projected nitrogen from crop residues is calculated using (1) projected production amounts and
1628 harvested acreage of various crop types from USDA long-term projections and (2) default factors from
1629 IPCC 2006 guidelines for harvested annual dry matter yield, ratios of above- and below-ground residue
1630 to harvested yield, and nitrogen contents of above- and below-ground residue (IPCC 2006). Standard
1631 bushel weight factors convert bushel production to weight measures. The Tier 1 equation from the IPCC
1632 guidelines is used to calculate nitrogen from crop residues.

1633 Crop production projections are available from USDA long-term projections for corn, sorghum, barley,
1634 oats, wheat, soybeans, rice, cotton, and sugar. The inventory calculates emissions associated with both
1635 major and non-major crops. Major crops make up more than 90 percent of U.S. cropland, so the
1636 production trend for major crops is taken to represent the overall trend for the purpose of N₂O
1637 emissions projections associated with crop residues.

$$N_{CropResidues} = \sum_{crops} [Harvested_c \times (R_{ag,c} + N_{ag,c} \times R_{bg,c} + N_{bg,c})]$$

1638 *adapted from IPCC (2006), Equation 11.7a*
1639 **Equation 23**

1640 Where:

- 1641 *c* = Crop type
1642 *H_c* = Harvested annual dry matter yield for crop *c*
1643 *R_{ag,c}* = Ratio of above-ground dry matter residues to harvested yield for crop *c*
1644 *N_{ag,c}* = N content of above-ground residues for crop *c*
1645 *R_{bg,c}* = Ratio of below-ground dry matter residues to harvested yield for crop *c*
1646 *N_{bg,c}* = N content of below-ground residues for crop *c*

1647 The IPCC 2006 guidelines describe Tier 1 equations and default factors to calculate average crop residue
1648 from different crop types using dry matter fractions, above- and below-ground ratios of residues to dry
1649 matter fraction of harvested product, and nitrogen content of above- and below-ground residues. In
1650 addition to major crop types, default factors are provided for individual crop types. These default factors
1651 are found in table 11.2 of the IPCC 2006 guidelines.

1652 **Nitrogen from Livestock Manure**

1653 Projected nitrogen from livestock manure applied to croplands and grasslands (through either managed
1654 or unmanaged pathways) is calculated using (1) USDA projections of various livestock populations and
1655 (2) default factors for nitrogen excretion and typical animal mass from the IPCC (2006) guidelines.

1656 Projected livestock populations are used consistent with the assumptions detailed in the manure
1657 management source category methodology. (Dairy, beef, swine, and poultry populations are from USDA
1658 Long Term projections; other animal type populations are extrapolated, and horse populations are
1659 assumed to be constant.) Default excretion rates for the various animal types are multiplied by the
1660 projected animal populations to estimate manure from livestock. The proportion of manure generation
1661 added to each crop type and cropland versus grassland is assumed to be constant.

1662 2.4 Land Use, Land-Use Change, and Forestry

1663 CH₄ and N₂O Emissions from Forest Fires

1664 Source Description

1665 GHG fluxes occur due to changes within and conversions between certain land-use types, such as forest
1666 land, cropland, grassland, settlements, and wetlands.

1667 The GHG flux from *Forest Land Remaining Forest Land* is reported under the 2006 IPCC Guidelines (IPCC
1668 2006) using estimates of changes in forest carbon stocks, non-CO₂ emissions from forest fires (CH₄ and
1669 N₂O), and the application of synthetic fertilizers to forest soils. This section focuses on the non-CO₂ GHG
1670 emissions associated with forest fires (both wildfires and prescribed fires). Changes in forest C stock are
1671 beyond the scope of this report.

1672 Methodology

1673 EPA projected CH₄ and N₂O emissions from forest fires by multiplying projected forest hectares burned
1674 by historical average carbon density factors, default IPCC combustion rates, and ratios of CH₄ and N₂O
1675 emissions to CO₂ emissions. Projections of area burned are drawn from an average of several model
1676 estimates from research in press (Mills et al. n.d.).

1677 Projections of Forest Fires

1678 Wildfire projections for the lower 48 states were estimated using modeling results from Mills et al.
1679 (n.d.). This analysis applied the MC-1 dynamic global vegetation model with climate projection data
1680 from two general circulation models (GCMs) and three emissions scenarios (“business as usual” and two
1681 exemplary global GHG mitigation policies). MC-1 provides gridded results at varying spatial and
1682 temporal scales that can inform plant and leaf types, nutrient movement, and vegetation disturbance by
1683 wildfire. MC-1’s fire model simulates wildfire’s occurrence, its behavior, and some of its ecosystem
1684 effects.¹⁹ The fire model calculates the fraction of a half-kilometer-by-half-kilometer cell’s area that is
1685 burned over different lengths of time (e.g., annually, multi-year periods) as a function of the simulated
1686 rate of fire spread and the amount of time since the last fire event. The corresponding area burned in a
1687 cell is then calculated by multiplying the fraction burned by the cell area. MC1 output was adjusted to
1688 exclude the proportion of any cell assumed to be in developed or agricultural land use types.²⁰

¹⁹ While the MC1 fire model is meant to simulate natural fire dynamics, human activity (specifically fire suppression policies) clearly has had a dramatic impact on recent fire frequency and intensity. The fire model accounts for this by incorporating a fire suppression adjustment, which assumes that 95 percent of fires that would have otherwise naturally occurred have been suppressed. For the remaining unsuppressed fires, the methodology assumes that those above a defined fireline intensity burn 95 percent of affected areas. While this rule does not capture the subtleties of 20th century fire suppression, it can reproduce patterns of historical fires in the United States reasonably well. It is also important to note that proactive fire suppression (e.g., prescribed fires) and other management activities were not modeled in the analysis (Mills et al. n.d.).

²⁰ Developed lands were projected using the Integrated Climate and Land Use Scenarios (ICLUS; Bierwagen et al. 2010) model. Using the U.S. population projections described in Paltsev et al. (n.d.), the ICLUS model generated county-level population projections at five-year intervals between 2000 and 2100. The spatial allocation submodel

1689 Mills et al. estimated the acreage burned in the lower 48 states from wildfires, aggregated both by
1690 region and national total, using two GCMs under a “business as usual” or reference scenario. These
1691 GCMs were selected to reasonably bound the future variation in mean temperature and precipitation in
1692 the United States. The two GCMs—CCSM-30 and MIROC-MED—comparatively project a generally
1693 cool/wet (although still warmer than the baseline) and hot/dry future climate, respectively, for the
1694 lower 48.

1695 The acreage burned through in the lower 48 states from prescribed fires and from wildfires in Alaska
1696 was not available. Therefore, the average acreage burned for the five most recent inventory years,
1697 specifically regarding prescribed fires in the lower 48 and all wildfires in Alaska, was determined and
1698 assumed to remain constant through 2035.

1699 **Carbon Emitted**

1700 Estimates for carbon emitted²¹ include emissions from wildfires in both Alaska and the lower 48 states,
1701 as well as emissions from prescribed fires in the lower 48 states only (based on expert judgment that
1702 prescribed fires only occur in the lower 48 states). EPA applied the IPCC (2006) default combustion
1703 factor of 0.45 for “all ‘other’ temperate forests” in estimating C emitted from both wildfires and
1704 prescribed fires. Mills et al. provide total area burned (not just forest) and so the average ratio of forest
1705 area to total area burned over the previous five years was applied, resulting in projections of forest area
1706 burned.

1707 As stated in the U.S. GHG Inventory (EPA 2013), the emissions factors for the three categories of forest
1708 fires are:

- 1709 • Wildfires in the lower 48 states: 31.7 to 34.4 megagrams carbon per hectare
- 1710 • Wildfires in Alaska: 63.3 to 64.4 megagrams carbon per hectare
- 1711 • Prescribed fires in lower 48 states: 11.4 to 11.7 megagrams carbon per hectare

1712 For the projections, the average of each emissions factor was used. It was assumed that these emissions
1713 factors remain constant through the end of the projection period.

within ICLUS then applied the county projections into developed and undeveloped lands in the future at a resolution of 1 square kilometer. Pixels were designated as “developed” if they contained more than one housing unit per 40 acres, or if the pixel was pre-established in ICLUS as being commercial/industrial land. Pixels with less than one housing unit per 40 acres were classified as “undeveloped.” Agricultural areas were derived from the 2001 National Land Cover Database (USGS 2003), and assumed static for the entirety of the study period—thus using current agricultural land use to screen out areas that are currently intensively managed. The agricultural and developed lands layer was combined with the coarser-resolution data from MC1 (0.5° × 0.5° / ~1,600 km² resolution) to determine the proportion of land types within the MC1 cell. Mills et al. (n.d.): (1) recognized that agricultural land use patterns will likely change significantly in the future, but found that credible and spatially explicit estimates were limited; (2) recognized that while agricultural areas contribute significantly to terrestrial C storage, the focus of this paper is on carbon and wildfire dynamics in natural areas; and (3) recognized that carbon dynamics in agricultural areas are more appropriately analyzed using other models developed specifically for these systems.

²¹ Carbon emitted = emissions factor (in megagrams carbon per hectare) multiplied by hectares burned.

1714 **Conversion Factors**

1715 To estimate CO₂ emissions, EPA multiplied total carbon emitted by the C to CO₂ conversion factor of
1716 44/12 and by 92.8 percent, which is the estimated proportion of carbon emitted as CO₂. Projections of
1717 carbon emitted from forest fires are drawn from an average of several model estimates from research in
1718 press (Mills et al. n.d.).

$$E_{CH_4,y} = E_{C,y} \times 92.8\% \times \left(\frac{44}{12}\right) \times ER_{CH_4,y}$$

1719 **Equation 24**

1720 **Where:**

1721 $E_{CH_4,y}$ = Total annual CH₄ emissions from forest fires for year y

1722 $E_{C,y}$ = Total annual C emissions from forest fires for year y

1723 92.8% = Estimated proportion of C emitted as CO₂

1724 44/12 = Molecular weight ratio of CO₂ to C

1725 $ER_{CH_4,y}$ = Emissions ratio of CH₄ to CO₂ for year y

1726

$$E_{N_2O,y} = E_{C,y} \times 92.8\% \times \left(\frac{44}{12}\right) \times ER_{N_2O,y}$$

1727 **Equation 25**

1728 **Where:**

1729 $E_{N_2O,y}$ = Total annual N₂O emissions from forest fires for year y

1730 $E_{C,y}$ = Total annual C emissions from forest fires for year y

1731 92.8% = Estimated proportion of C emitted as CO₂

1732 44/12 = Molecular weight ration of CO₂ to C

1733 $ER_{N_2O,y}$ = Emissions ratio of N₂O to CO₂ for year y

1734

1735 Default emissions ratios between CH₄, N₂O, and CO₂ are calculated based on emissions factors for
1736 burning of forests. Default emissions rates for forests other than tropical forests are 1,569 grams of CO₂,
1737 4.7 grams of CH₄, and 0.26 grams of N₂O per kilogram of dry matter.²²

²² Table 2.5 within Section 2.4 of Volume 4, Chapter 2, of the 2006 IPCC inventory guidelines.

1738 **2.5 Waste**

1739 **Landfills**

1740 **Source Description**

1741 Municipal solid waste (MSW) placed in a landfill is initially decomposed by aerobic bacteria. After the
1742 oxygen has been depleted, the remaining waste is available for consumption by anaerobic bacteria,
1743 which break down organic matter into substances such as cellulose, amino acids, and sugars. These
1744 substances are further broken down through fermentation into gases and short-chain organic
1745 compounds that form the substrates for the growth of methanogenic bacteria. These CH₄-producing
1746 anaerobic bacteria convert the fermentation products into stabilized organic materials and biogas
1747 consisting of approximately 50 percent biogenic CO₂ and 50 percent CH₄, by volume, with less than 1
1748 percent non-methane organic compounds and trace amounts of inorganic compounds. Significant CH₄
1749 production typically begins one or two years after waste disposal in a landfill and continues for 10 to 60
1750 years or longer as the degradable waste decomposes over time (EPA 2013).

1751 CH₄ emissions from landfills are a function of several factors, including (1) the total amount of waste in
1752 MSW landfills, which is related to total waste landfilled annually; (2) the characteristics of landfills
1753 receiving waste (i.e., composition of waste-in-place, size, climate); (3) the amount of CH₄ that is
1754 recovered and either flared or used for energy purposes; and (4) the amount of CH₄ oxidized in landfills
1755 instead of being released into the atmosphere.

1756 This source category covers fugitive CH₄ emissions from landfills. It corresponds to IPCC source category
1757 6A1.

1758 **Methodology**

1759 EPA calculated emissions projections for this source by (1) projecting potential emissions from MSW
1760 landfills, (2) adding potential emissions from industrial landfills, and then (3) subtracting CH₄ recovered
1761 from gas-to-energy projects or flared CH₄ and (4) subtracting oxidized CH₄.

$$E_{tl,y} = (PE_{ml,y} + PE_{il,y} - E_{r,y}) \times (1 - Ox)$$

1762 **Equation 26**

1763 **Where:**

- 1764 $E_{tl,y}$ = Projected total annual CH₄ emissions from landfills for year y
- 1765 $PE_{ml,y}$ = Potential emissions from MSW landfills for year y
- 1766 $PE_{il,y}$ = Potential emissions from industrial landfills for year y
- 1767 $E_{r,y}$ = Annual CH₄ emissions recovered for year y
- 1768 Ox = Percent oxidation (%)

1769 **MSW Landfills**

1770 EPA projected potential CH₄ emissions from MSW landfills using the integrated form of the first order
1771 decay (FOD) model, which uses the procedures and spreadsheets from IPCC (2006) to estimate CH₄

1772 emissions from solid waste disposal. EPA used a form of the FOD model that incorporates a time delay
1773 of six months after waste disposal before the generation of CH₄ begins. FOD models assume that landfill
1774 CH₄ generation is at its peak shortly after initial placement. The input parameters required for the FOD
1775 model equations are:

1776 • **The mass of waste disposed of each year.** The historical amount of “MSW landfilled” and “waste in
1777 place” were taken from the U.S. GHG Inventory (EPA 2013). To project annual landfill waste
1778 generation and disposal data for the United States through the end of the projection period, EPA
1779 compared historical MSW disposal rates to landfills and the U.S. population, resulting in per capita
1780 rates of landfill MSW disposal. EPA took historical MSW disposal rates for the United States from the
1781 U.S. GHG Inventory and historical U.S. population data from the U.S. Census Bureau for the
1782 corresponding years (U.S. Census 2011). Based on the historical trend, EPA assumed the per capita
1783 rate of landfill MSW disposal for the projections to be the average of the last four years of the most
1784 recent U.S. GHG Inventory.

1785 To project the annual MSW disposed of in landfills each year, EPA multiplied the per capita rate of
1786 landfill MSW disposal by the projected U.S. population data from the U.S. Census Bureau (U.S.
1787 Census 2012). Per capita waste disposal was assumed to remain constant over the projection period.

1788 • **The degradable organic carbon (DOC).** The DOC (fraction, gigagrams carbon per gigagram of waste)
1789 was assumed to remain constant at the value presented in the most recent U.S. GHG Inventory
1790 through the end of the projection period.

1791 • **The CH₄ generation potential (L₀) and rate constant (k).** The CH₄ generation potential (L₀ in cubic
1792 meters of CH₄ per megagram of waste) and rate constant k (per year) are assumed to remain
1793 constant at the values presented in the most recent U.S. GHG Inventory.

1794 **Industrial Landfills**

1795 It has been determined that over 99 percent of the organic waste placed in industrial landfills originated
1796 from two industries: food processing (meat, vegetables, fruits) and pulp and paper (EPA 1993).

1797 Therefore, the CH₄ emissions from industrial landfills were projected based on the estimated change in
1798 production for both sectors. Specifically, the EIA provides “value of shipments” projections for the food
1799 and paper industries in the *Annual Energy Outlook (AEO)* reports (EIA 2013). The annual percent
1800 increase or decrease in “value of shipments” was assumed to be approximately equivalent to the annual
1801 percent change in production for the two industries.²³ The most recent inventory year served as the
1802 baseline for the CH₄ emissions projections.

²³ As discussed in the 2013 U.S. GHG Inventory, not all of the items produced from the food processing and pulp and paper industry are deposited in a landfill. Research into waste generation and disposal in landfills for the pulp and paper industry indicated that the quantity of waste landfilled was about 0.050 megagrams per megagram of product compared to 0.046 megagrams per megagram product for the food processing industry (Weitz and Bahner 2006). However, since the historical CH₄ emissions from industrial landfills contained in the 2013 U.S. GHG Inventory already account for this, EPA did not apply the ratio directly to future projections. EPA also assumed a constant emissions factor for projection purposes.

$$PE_{il,y} = PE_{il,b} \times \left(\frac{VS_{fp,y}}{VS_{fp,b}} \right)$$

Equation 27

1803

1804 Where:

- 1805 $PE_{il,y}$ = Potential emissions from industrial landfills for year y
 1806 $PE_{il,b}$ = Potential emissions from industrial landfills for base year b
 1807 $VS_{fp,y}$ = Value of shipments for food and paper industries for year y
 1808 $VS_{fp,b}$ = Value of shipments for food and paper industries for base year b

1809 Note that the CH₄ emissions from industrial landfills for the most recent year addressed in the U.S. GHG
 1810 Inventory serves as the baseline year for the emissions projections.

1811 **Recovered CH₄ from Gas-to-Energy and Flaring**

1812 The U.S. GHG Inventory accounts for CH₄ emissions avoided (i.e., recovered) due to landfill-gas-to-energy
 1813 (LFGTE) projects and flaring. To project recovered CH₄ emissions, EPA extrapolated the historical percent
 1814 of CH₄ generation recovered (as stated in the most recent U.S. GHG Inventory) through the end of the
 1815 projection period. EPA then subtracted these recovered CH₄ emissions from the total annual CH₄
 1816 emissions projected from MSW landfills. The projected recovery and flaring ratio will be cross-checked
 1817 against more detailed landfill-level modeling to ensure that it properly reflects industry practices and
 1818 regulatory requirements.

1819 **Oxidized CH₄ from Landfills Prior to Release to Atmosphere**

1820 A portion of the CH₄ escaping from a landfill oxidizes to CO₂ in the top layer of the soil. The amount of
 1821 oxidation depends upon the characteristics of the soil and the environment. Similar to the U.S. GHG
 1822 Inventory, it was assumed that 10 percent of the CH₄ generated (minus the amount of gas recovered for
 1823 flaring or LFGTE projects) was oxidized in the soil. The factor of 10 percent is consistent with the value
 1824 recommended in the IPCC (2006) revised guidelines for managed and covered landfills, and was
 1825 therefore applied to the estimates of CH₄ generation minus recovery for both MSW and industrial
 1826 landfills.

1827 **Domestic Wastewater Treatment**

1828 **Source Description**

1829 The treatment of domestic wastewater can result in CH₄ and N₂O emissions. Wastewater from domestic
1830 sources²⁴ is treated to remove soluble organic matter, suspended solids, pathogenic organisms, and
1831 chemical contaminants. Wastewater treatment is conducted either on site, most commonly through the
1832 use of septic systems or package plants, or off site at centralized treatment systems.

1833 CH₄ is produced when organic matter is degraded under anaerobic conditions. The principal factor in
1834 determining the CH₄ generation potential of wastewater is the amount of degradable organic material in
1835 the wastewater.

1836 N₂O can be generated by the further treatment of domestic wastewater during nitrification and
1837 denitrification of the nitrogen present, usually in the form of urea, ammonia, and proteins. The principal
1838 factor in determining the N₂O generation potential of wastewater is the amount of nitrogen in the
1839 wastewater.

1840 This source category covers CH₄ and N₂O from domestic wastewater treatment systems. This
1841 corresponds to IPCC source category 6B2 (or IPCC 2006 category 4D1). For the purpose of projections,
1842 CH₄ emissions from industrial wastewater treatment are treated as a separate source (IPCC category
1843 6B1 or 4D2 in 2006 categories). No source-specific methodology was developed for industrial
1844 wastewater treatment, so the default extrapolation approach was used for that source.

1845 **Methodology**

1846 Projected emissions from this source category were calculated by summing emissions from various
1847 waste treatment systems: onsite/septic systems, centrally treated aerobic systems, centrally treated
1848 anaerobic systems, and emissions from anaerobic digesters. The total amount of waste is based on
1849 projections of population growth, while the portion of waste attributable to various streams is based on
1850 extrapolating historical trends. The methodology contained in the U.S. GHG Inventory (EPA 2013) was
1851 used as the basis for projecting non-CO₂ GHG emissions (CH₄ and N₂O) from domestic wastewater
1852 treatment.

1853 **Domestic Wastewater CH₄ Emissions**

1854 CH₄ emissions can arise from lack of containment or gas collection on septic systems, aerobic systems
1855 that are not well managed or that are designed to have periods of anaerobic activity (e.g., constructed
1856 wetlands), anaerobic systems (anaerobic lagoons and facultative lagoons), and anaerobic digesters
1857 when the captured biogas is not completely combusted. In order to account for these potential CH₄
1858 emissions sources, these projections use five pathways for domestic wastewater treatment:

- 1859
- On site (septic systems)

²⁴ As with the U.S. GHG Inventory, EPA assumed that domestic wastewater includes wastewater from household use, as well as any commercial and non-hazardous industrial wastewater that is collected by centralized treatment systems.

- 1860 • Centrally treated aerobic systems (with and without primary sedimentation)
- 1861 • Centrally treated anaerobic systems (with and without primary sedimentation)

1862
1863

1864 While anaerobic digestion is not considered a “pathway,” it is an optional treatment process for sludge
1865 after it has gone through a centrally treated aerobic or anaerobic system. Therefore, the CH₄ produced
1866 by anaerobic digesters is included in the U.S. GHG Inventory as well as in the emissions projections.

1867 *Onsite (Septic Systems)*

1868 CH₄ emissions from septic systems were estimated in the U.S. GHG Inventory by multiplying the United
1869 States population by the percent of domestic wastewater treated in septic systems and a septic system-
1870 specific emissions factor (10.7 grams CH₄/capita/day). To estimate future CH₄ emissions from septic
1871 systems, EPA used (1) projected population from the U.S. Census Bureau (U.S. Census 2012) and (2) the
1872 percent of domestic wastewater treated in septic systems/onsite (historical data extrapolation; EPA
1873 2013).

$$E_{ss,y} = \frac{POP_y \times WW_{os,y} \times EF_{ss} \times 365.25}{10^9}$$

1874 Equation 28

1875 Where:

- 1876 $E_{ss,y}$ = Total annual CH₄ emissions from onsite septic systems for year y (Gg)
- 1877 POP_y = U.S. population for year y (people)
- 1878 $WW_{os,y}$ = Fraction of domestic wastewater treated onsite (i.e., in septic systems) for year y
1879 (%)
- 1880 EF_{ss} = Septic system-specific emissions factor (grams CH₄/person/day)
- 1881 365.25 = Days per year
- 1882 10^9 = Conversion factor (g to Gg)

1883

1884 *Centrally Treated Aerobic Systems and Anaerobic Systems*

1885 The total BOD content of influent domestic wastewater is assumed to be constant throughout the
1886 central treatment pathways. Therefore, CH₄ emissions are proportional to the allocation of wastewater
1887 to each central treatment pathway. For the centrally treated systems, CH₄ emissions were estimated in
1888 the U.S. GHG Inventory using the generalized equation below. The emissions factors/correction factors
1889 (EF) and the percent of BOD removed for each pathway distinguish the CH₄ generation potential
1890 between aerobic, anaerobic, and with/without primary treatment.

$$E_{ct,y} = BOD_{tot,y} \times \sum_j [WW_{j,y} \times (1 - \%R_{j,y}) \times EF_{j,y}]$$

1891 Equation 29

1892 Where:

- 1893 $E_{ct,y}$ = Total annual CH₄ emissions from centrally treated systems (aerobic and anaerobic)
1894 for year y
1895 $BOD_{tot,y}$ = Total produced BOD for year y
1896 $WW_{j,y}$ = Fraction of wastewater treated through pathway j for year y
1897 $\%R_{j,y}$ = Fraction of BOD removed through pathway j for year y
1898 $EF_{j,y}$ = CH₄ emissions factor for pathway j for year y
1899 J = Wastewater treatment pathways: onsite, centrally treated aerobic and anaerobic,
1900 with or without primary sedimentation
1901

$$BOD_{tot,y} = POP_y \times BOD_{pc,y} \times 365.25$$

1902 Equation 30

1903 Where:

- 1904 $BOD_{tot,y}$ = Total produced BOD for year y (kg)
1905 POP_y = U.S. population for year y (people)
1906 $BOD_{pc,y}$ = Per capita BOD production for year y (kg BOD/person/day)
1907 365.25 = Days per year

1908 To estimate future CH₄ emissions from centrally treated systems, EPA projected the following variables:

- 1909 • The U.S. population for each year (U.S. Census 2012).
1910 • The percent of domestic wastewater collected (historical data extrapolation; EPA 2013).
1911 • The percent of centralized wastewater treatment using aerobic versus anaerobic systems (historical
1912 data extrapolation; EPA 2013).
1913 Other factors, such as emissions factors, were held constant from the most recent inventory year.

1914 *Anaerobic Digesters*

1915 CH₄ emissions from anaerobic digesters were estimated in the U.S. GHG Inventory by multiplying the
1916 wastewater influent flow to centrally treated systems that have anaerobic digesters, the amount of
1917 biogas generated by wastewater sludge treated in anaerobic digesters, the proportion of CH₄ in digester
1918 biogas, and the destruction efficiency associated with burning the biogas in an energy/thermal device.

1919 To estimate future CH₄ emissions from anaerobic digesters, the following variable was projected:

- 1920 • The influent wastewater flow to centrally treated systems with anaerobic digesters (historical data
1921 extrapolation; EPA 2013).
1922

$$E_{ad,y} = WW_{ad,y} \times \left(\frac{DG_{pc,y}}{WW_{pc,y}} \right) \times 0.0283 \times BG \times 365.25 \times \rho_{CH_4} \times (1 - DE) \times (1/10^9)$$

1923 Equation 31

1924 Where:

- 1925 $E_{ad,y}$ = Total annual CH₄ emissions from anaerobic digesters for year y (Gg)
1926 $WW_{ad,y}$ = Wastewater influent flow to POTWs with anaerobic digesters (gallons)
1927 $DG_{pc,y}$ = Per capita digester gas produced per day (ft³/person/day)
1928 $WW_{pc,y}$ = Per capita wastewater flow to POTW per day (gallons/person/day)
1929 0.0283 = Conversion factor (ft³ to m³)
1930 BG = Proportion of CH₄ in biogas
1931 365.25 = Days per year
1932 ρ_{CH4} = Density of CH₄ (662 g/m³)
1933 DE = CH₄ destruction efficiency from flaring or burning in engine
1934 $1/10^9$ = Conversion factor (g to Gg)

1935

1936 **Domestic Wastewater N₂O Emissions**

1937 N₂O emissions from domestic wastewater were estimated in the U.S. GHG Inventory using the 2006 IPCC
1938 Guidelines (IPCC 2006). The IPCC methodology includes calculations for the N₂O emissions associated
1939 with wastewater effluent discharged to aquatic environments and total N₂O emissions from centralized
1940 wastewater treatment plants (with and without nitrification/denitrification). Due to high uncertainty of
1941 measures of N₂O from septic systems, estimates of N₂O emissions from septic systems were not
1942 included in the U.S. GHG Inventory or these projections (EPA 2013).

1943 *Effluent Discharge*

1944 N₂O emissions from effluent discharge are based on annual, per capita protein consumption (kilograms
1945 of protein per person per year). For the U.S. GHG Inventory, the amount of protein available to be
1946 consumed was estimated based on per capita annual food availability data and the protein content of
1947 that particular food, and then adjusted using a factor to account for the fraction of protein actually
1948 consumed. Any nitrogen removed with sludge, and therefore not discharged to aquatic environments,
1949 was not included.

1950 In the U.S. GHG Inventory, N₂O effluent emissions were calculated by multiplying the U.S. population
1951 using central treatment systems (minus the percent of the U.S. population served by biological
1952 denitrification systems) by the annual per capita protein consumption with correction factors, and
1953 subtracting the amount of nitrogen removed with sludge. To estimate future N₂O emissions (2011 to
1954 2035) from effluent discharge, EPA projected the following variables:

- 1955 • The U.S. population for each year (U.S. Census 2012).
- 1956 • The U.S. population that is served by biological denitrification (historical data extrapolation; EPA
1957 2013).
- 1958 • The percent of the U.S. population using central treatment systems/plants (historical data
1959 extrapolation; EPA 2013).

- 1960 • Annual per capita protein consumption (average of most recent five years).
- 1961 • The amount of nitrogen removed with sludge (assumed to remain constant).

$$N_2O_{eff,y} = \left\{ \left[\left((POP_y \times F_{tp,y}) - (0.9 \times POP_{dn,y}) \right) \times Pro_y \times N_{Pro} \times F_{nc} \times F_{ic} \right] - N_{s,y} \right\} \times EF_{eff} \times (44/28) \times (1/10^9)$$

1962 Equation 32

1963 Where:

- 1964 $N_2O_{eff,y}$ = Projected total annual N₂O emissions from wastewater effluent discharged to
- 1965 aquatic environments for year y (Gg)
- 1966 POP_y = U.S. population for year y (people)
- 1967 $F_{tp,y}$ = Fraction of population using wastewater treatment plant for year y (%)
- 1968 0.9 = Fraction of nitrogen removed by denitrification systems
- 1969 $POP_{dn,y}$ = Population that is served by biological denitrification for year y (%)
- 1970 Pro_y = Annual per capita protein consumption for year y (kg/person/year)
- 1971 N_{Pro} = Fraction of nitrogen in protein (kg N/kg protein)
- 1972 F_{nc} = Factor for non-consumed protein added to wastewater
- 1973 F_{ic} = Factor for industrial and commercial co-discharged protein into sewer system
- 1974 $N_{s,y}$ = Nitrogen removed with sludge for year y (kg N/year)
- 1975 EF_{eff} = Emissions factor from effluent (kg N₂O-N/kg sewage-N produced)
- 1976 44/28 = Molecular weight ratio of N₂O to N₂
- 1977 $1/10^6$ = Conversion factor (kg to Gg)

1978 *Central Treatment Systems/Plants*

1979 N₂O emissions from centralized treatment systems include plants that have nitrification/denitrification
 1980 as part of their treatment process, as well as plants that do not. EPA calculated N₂O emissions from
 1981 plants that have nitrification/denitrification by multiplying the U.S. population served by biological
 1982 denitrification, an IPCC emissions factor, and a factor for industrial and commercial protein co-
 1983 discharged into the sewer system. For N₂O emissions from plants that do not have
 1984 nitrification/denitrification, EPA multiplied the remainder of the U.S. population that uses central
 1985 treatment systems by an IPCC emissions factor and the same factor for industrial and commercial
 1986 protein co-discharged into the sewer system. To estimate future N₂O emissions (2011 to 2035) from
 1987 central treatment systems, EPA projected the following variables:

- 1988 • The U.S. population for each year (U.S. Census 2012).
- 1989 • Fraction of the U.S. population using central treatment plants (historical data extrapolation; EPA
 1990 2013).
- 1991 • U.S. population that is served by biological denitrification (historical data extrapolation; EPA 2013).

$$\begin{aligned}
 N_2O_{pl,y} &= N_2O_{nd,y} + N_2O_{wond,y} \\
 &= \{POP_{dn,y} \times EF_{id} \times F_{ic} \times (1/10^9)\} + \{[(POP_y \times F_{tp,y}) - POP_{dn,y}] \times F_{ic} \times EF_{nid}\} \\
 &\quad \times (1/10^9)
 \end{aligned}$$

1992 Equation 33

1993 **Where:**

- 1994 $N_2O_{pl,y}$ = N₂O emissions from centralized wastewater treatment plants for year y (Gg)
- 1995 $N_2O_{nd,y}$ = N₂O emissions from centralized wastewater treatment plants with
- 1996 nitrification/denitrification for year y (Gg)
- 1997 $N_2O_{wond,y}$ = N₂O emissions from centralized wastewater treatment plants without
- 1998 nitrification/denitrification for year y (Gg)
- 1999 $POP_{dn,y}$ = Population that is served by biological denitrification for year y (%)
- 2000 EF_{id} = Emissions factor for plant with intentional denitrification (g N₂O/person/yr)
- 2001 F_{ic} = Factor for industrial and commercial co-discharged protein into sewer system
- 2002 POP_y = U.S. population for year y (people)
- 2003 $F_{tp,y}$ = Fraction of population using wastewater treatment plant for year y (%)
- 2004 EF_{nid} = Emissions factor for plant with no intentional denitrification (g N₂O/person/yr)
- 2005 $1/10^9$ = Conversion factor (g to Gg)

2006

2007 The equations and factors presented in this section are based on those presented within the wastewater

2008 treatment section of the U.S. GHG Inventory, and more information can be found there.

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