

ISSUE BRIEF 1

**BY THE NUMBERS: GREENHOUSE GAS
EMISSIONS AND THE FOSSIL-FUEL
SUPPLY CHAIN IN THE UNITED STATES**

DANIEL S. HALL

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SUMMARY

This issue brief presents information on greenhouse gas (GHG) emissions in the United States to provide background for the design of a domestic climate policy. It starts by detailing current U.S. GHG emissions, including breakdowns of emissions by greenhouse gas and by economic sector. Following that, patterns of production, distribution, and use of fossil fuels in the U.S. economy are examined to estimate the number of sources that would potentially be regulated under a domestic climate policy.

- Current, annual U.S. GHG emissions total more than 7 billion metric tons of carbon dioxide equivalent (CO₂e) (emissions for 2005 totaled 7.26 billion metric tons CO₂e). Emissions have been growing by about 1 percent per year since 1990. CO₂ is the primary greenhouse gas, accounting for more than four-fifths of U.S. GHG emissions; the remaining 16 percent is composed of methane, nitrous oxide, and various fluorinated gases.
- The sectors with the largest emissions are electricity generation (33 percent) and transportation (28 percent). The primary drivers of emissions in these sectors are coal-burning for electricity generation and oil use for transportation.
- Almost all U.S. CO₂ emissions are generated by the combustion of fossil fuels. Because CO₂ emissions from fossil fuels can be calculated directly and accurately based on the carbon content of the fuel, there is flexibility about *where* in the fossil-fuel supply chain to regulate CO₂ emissions. Although it is often assumed that regulation of CO₂ would occur “at the smokestack” (that is, at the point of emissions), the ability to calculate emissions based on carbon content means that regulation can be accomplished at any point from fossil-fuel production (“upstream”), to processing or distribution (“midstream”), to actual end use (“downstream”).
- There are typically fewer upstream producers, or midstream processors and/or distributors, than there are downstream users. This is particularly true for oil and natural gas, which have a very small number of processing and distribution facilities (that is, oil refineries and natural gas processors or pipeline distributors) and a very large number of end users (for example, automobiles and homes).
- Regulating CO₂ emissions at upstream or midstream entities would facilitate the inclusion of virtually all fossil-fuel emissions in a market-based (tax or cap-and-trade) climate policy. Such regulation would likely involve fewer than 3,000 sources: around 1,000 entities for coal (either coal mines or large coal-burning facilities); and another 500–700 each for oil and natural gas (including refineries, natural gas processors, and importers/exporters). A purely downstream approach that regulates only large stationary emitters (primarily electricity generators and industrial sources) would likely involve about 10,000

entities and cover about half of U.S. fossil-fuel emissions. Merging this approach with midstream coverage of transportation fuels (refineries and importers) would add the same 500–700 entities and net about another third of these emissions, thus covering 80 percent of U.S. fossil-fuel emissions (or about two-thirds of total U.S. GHG emissions). Issue Brief #4 on the scope and point of regulation provides further discussion on the policy issues surrounding where to regulate emissions.

- Emissions of non-CO₂ GHGs come from a variety of sectors and activities, and are often widely dispersed. Although smaller in percentage terms, non-CO₂ emissions are important in discussions of climate policy because they often account for a substantial share of projected near-term emission reductions. Options for including these gases in a climate policy are discussed further in Issue Briefs #14 and #15, on non-CO₂ gases and offsets respectively.

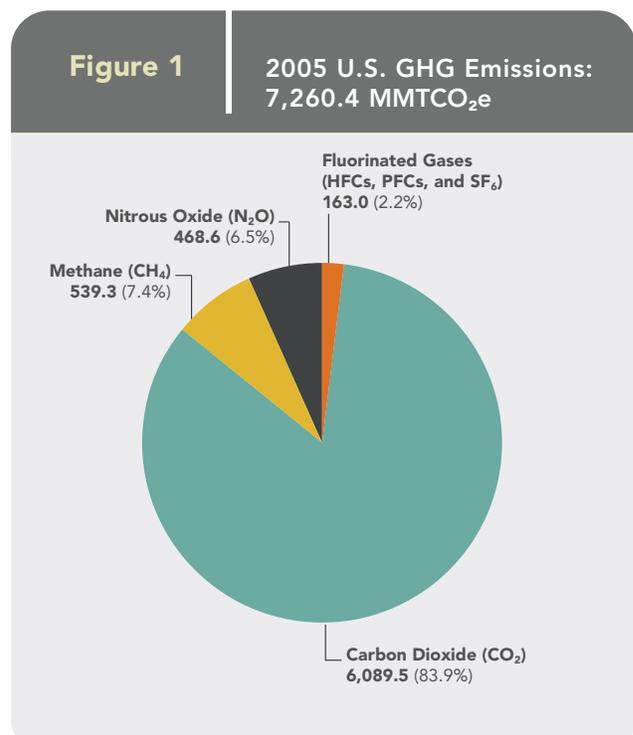
U.S. Greenhouse Gas Emissions

The U.S. Environmental Protection Agency (EPA)¹ calculates that GHG emissions in the United States in 2005 totaled 7,260.4 million metric tons of carbon dioxide equivalent (MMTCo₂e).^{2,3,4}

Figure 1 shows U.S. GHG emissions in 2005, broken down by type of gas. Figure 2 depicts the trend in U.S. emissions since 1990.

U.S. CO₂ emissions have been growing on average at about 1.2 percent per year since 1990. Methane (CH₄) emissions have fallen slightly (by about 0.8 percent annually) since

1990 while nitrous oxide (N₂O) emissions rose slightly in the mid-90s but have since returned to 1990 levels. Emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆)—referred to sometimes collectively as the fluorinated (F) gases, or the high global warming potential (GWP) gases—have risen at a 4 percent average annual rate since 1990.



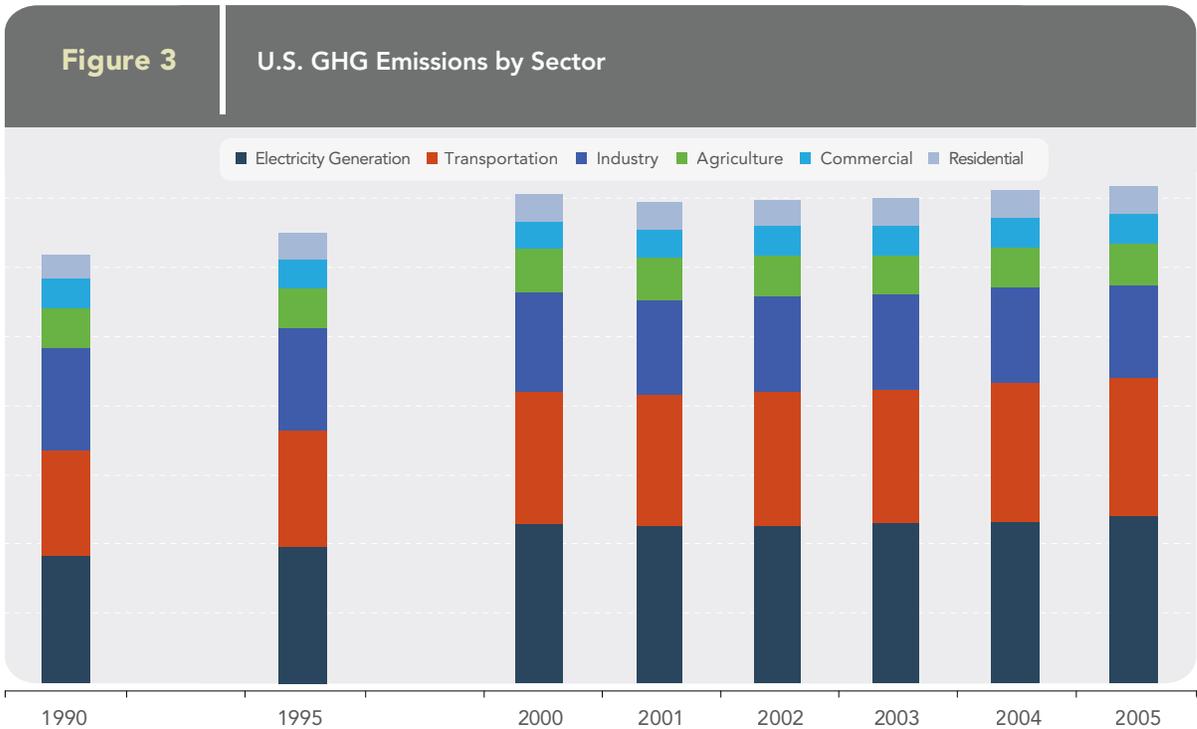
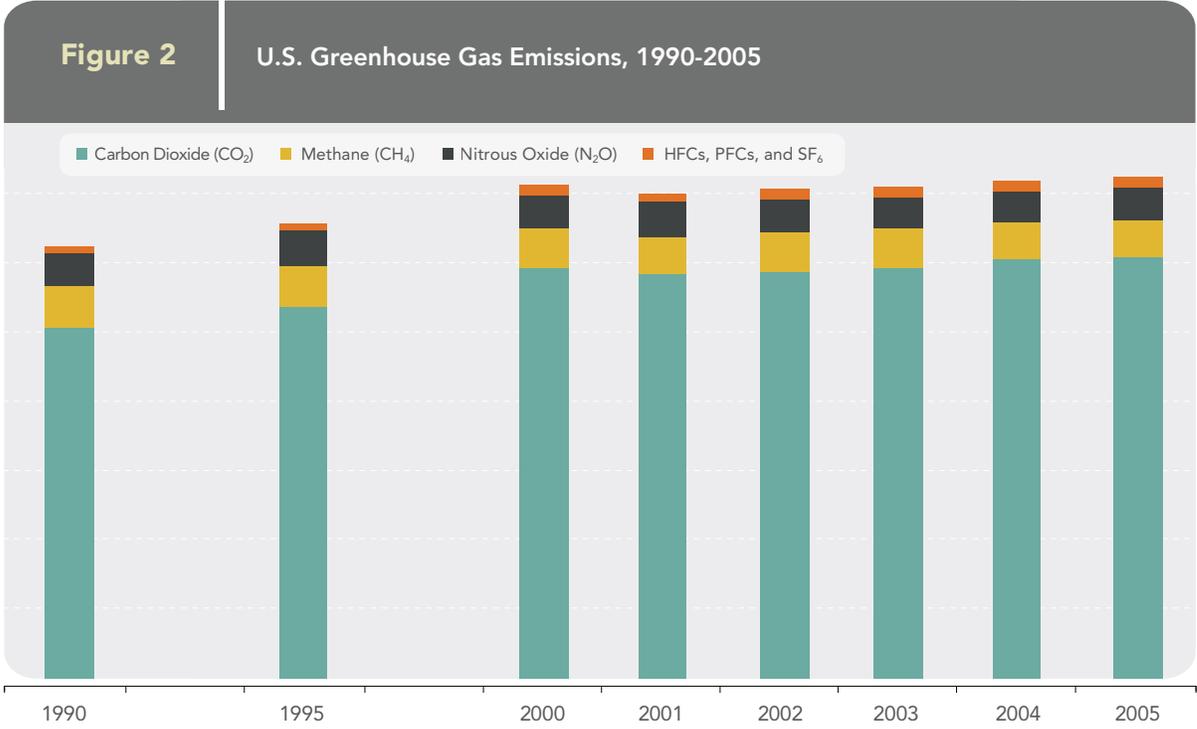
1 Both the EPA and the Department of Energy's Energy Information Administration (EIA) release detailed reports on U.S. GHG emissions annually, most recently in April 2007 and November 2006 respectively. Reported emissions are similar in the two reports, but there are systematic differences. The most recent EIA study reports (preliminary) 2005 emissions of 7,147.2 MMTCo₂e, about 1.6 percent lower than the current EPA report. Comparing reported annual emissions from previous years, the EPA estimates are consistently higher than those of EIA: for 2000–2004, the EPA figure is higher by 2.3 percent on average (165 MMTCo₂e), with a range of 1.4–2.8 percent; for 1990 emissions—frequently used as a historical baseline—the EPA reports emissions of 6242.0 MMTCo₂e, while the EIA reports 6112.8 MMTCo₂e (a difference of 2.1 percent). The major difference in the methodologies employed by the two agencies is in accounting for nitrous oxide (N₂O) emissions, especially from agricultural soil management; the higher EPA estimates for N₂O emissions account for approximately 90 percent of the difference in emissions estimates reported by these two sources. There are also smaller—and approximately offsetting—differences in estimates for CO₂ and methane (CH₄) emissions. The EPA reports higher industrial process CO₂ emissions (e.g., from iron and steel production), while the EIA estimates higher CH₄ emissions, primarily from landfills, natural gas systems, and manure management. This paper uses the EPA report, largely because it provides greater disaggregation for certain sectors. The annual EPA report is available at <http://epa.gov/climatechange/emissions/usinventoryreport.html> while the EIA report is available at <http://www.eia.doe.gov/environment.html>.

2 Several units are used to measure and report GHG emissions; this report uses one of the most common: million metric tons of CO₂ (Metric tons are spelled tonnes in British English.) Some studies report emissions in teragrams (Tg), which are identical to million metric tons (1 Tg = 1 MMT). Another common measure (used more frequently in Europe) is gigatonnes of carbon (GtC). One Gt = 1 billion metric tons = 1,000 MMT; including the conversion from carbon (C) to carbon dioxide (CO₂), 1 GtC = 3.67 x 10³ MMTCo₂.

3 The use of CO₂-equivalent (CO₂e) units allows comparison between various GHGs based on their contribution to the warming effect of the atmosphere. CO₂-equivalence is calculated by multiplying the weight of the gas by a factor called its global warming potential, or GWP. Carbon dioxide itself has a GWP of 1; the GWP for other gases depends on the strength of their warming effect and their residence time in the atmosphere. This means that there are different GWPs for different time horizons. The most commonly used GWPs are based on a 100-year time horizon. Methane, for example, has a 100-year GWP of 21; thus 1 metric ton of methane emissions is reported as 21 tCO₂e emissions. The GWPs used in the EPA emissions report are the 100-year GWPs from the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report; these are also the factors required for international reporting under the UN Framework Convention on Climate Change. An updated set of 100-year GWPs was published in the IPCC Third Assessment Report; some studies—including the EIA emissions report—use these in reporting. Although the two sets of GWPs are very similar, their differences may partially account for small differences in reported emissions among various sources.

4 Estimates of uncertainty are included for all emissions in Annex 7 of the EPA report. The 95 percent confidence interval (CI) for total U.S. emissions is 7,170.3–7,635.0 MMTCo₂e, or -1 percent to +5 percent of the central estimate of 7,260.4 MMTCo₂e. By gas, the uncertainty is smallest in percentage terms for CO₂ emissions (-2 percent to +5 percent), with progressively higher uncertainties for the fluorinated gases (-6 percent to +16 percent), methane (-10 percent to +16 percent), and nitrous oxide (-16 percent to +24 percent). In general, uncertainties tend to be lower when emissions arise from centralized production activities (as with fossil fuels or the fluorinated gases) and/or are associated with smaller numbers of point sources (as with most CO₂ process emissions); these uncertainties are typically within +/-10 percent. Higher uncertainties are frequently associated with emissions from distributed activities (e.g., methane from natural gas systems) and/or fugitive sources (such as landfill methane or nitrous oxide from agricultural soils), and can be +/-40 percent. While smaller sources tend to have higher relative uncertainties, the largest source of absolute uncertainty is the largest source of emissions: fossil-fuel combustion accounts for 80 percent of U.S. GHG emissions (5,751 MMTCo₂e), and, with a 95 percent CI of -2 percent to +5 percent, has an absolute uncertainty of about 400 MMTCo₂e. Thus, this source of emissions accounts for most of the uncertainty in the overall emissions estimate.

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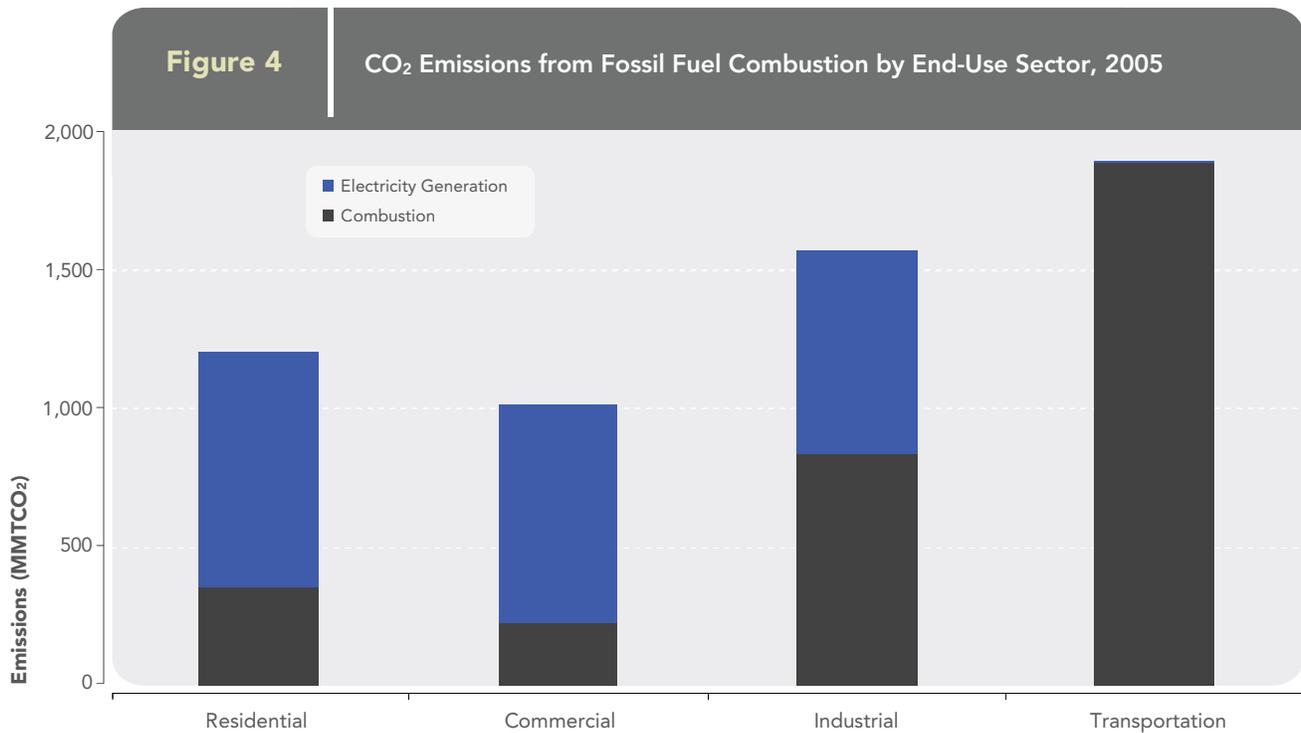


Figure 3 shows these same emissions totals again, but broken down by economic sector rather than gas. Electricity generation accounts for one-third of total emissions.⁵ Transportation is the second-largest category, accounting for 28 percent of U.S. GHG emissions. Industry accounts for about 19 percent of total emissions. Agriculture, the commercial sector, and the residential sector each account for 5–8 percent of total emissions. Electricity generation and transportation have accounted for the majority of emissions growth since 1990, with emissions from these sectors growing at an average annual rate of about 1.8 percent. Emissions from primary energy consumption in the residential and commercial sectors, by contrast, have grown more slowly—at average annual rates of 0.5 percent and 0.2 percent, respectively. Agricultural emissions have remained essentially unchanged since 1990, with growth averaging just 0.1 percent per year. Industrial emissions, meanwhile, have declined by almost 0.6 percent per year since 1990.

The following sections look in more detail at emissions of specific gases, starting with CO₂ and then moving to non-CO₂ GHGs.

⁵ Note that emissions from the electric power sector vary regionally across the United States, e.g., the southeastern U.S. tends to have more coal-fired generation and hence larger electric-sector emissions. This point is discussed in greater detail in Issue Brief #11 on the electricity sector.

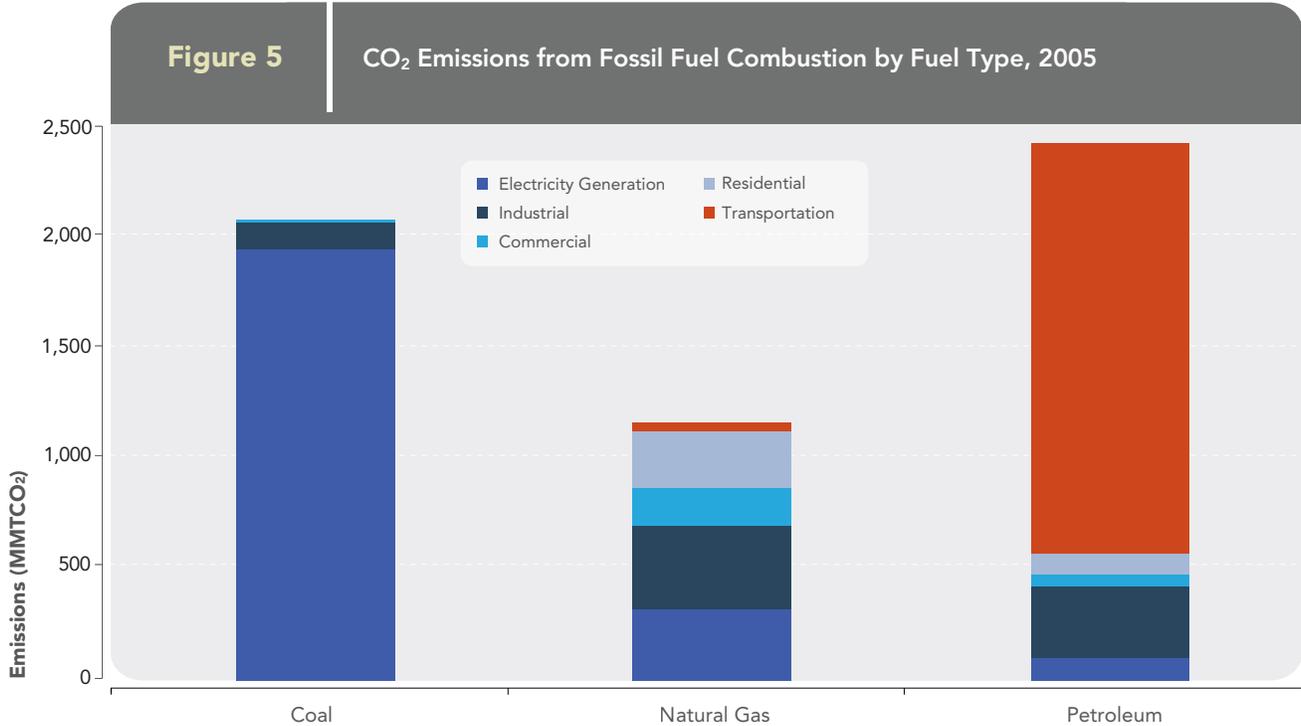
Carbon Dioxide Emissions

Emissions of CO₂ constitute about 84 percent of total U.S. GHG emissions. Of this emitted CO₂, the vast majority (5,751 MMTCO₂, or 94.4 percent) comes from the combustion of fossil fuels. Figure 4 breaks these emissions down by sector for the year 2005, with total emissions from electricity generation (at 2,381 MMTCO₂) apportioned to end-use sectors. Among end-use sectors (that is, after apportioning the electric-sector contribution), transportation accounts for the largest single share of U.S. fossil-fuel emissions—about 31 percent of the total. Industry accounts for approximately 26 percent of fossil-fuel emissions;⁶ residential and commercial energy users account for 19.8 percent and 16.7 percent, respectively.

Figure 5 shows fossil-fuel emissions by fuel type with different colors indicating sector and with electricity emissions again distributed among end-use sectors. This breakdown reveals that petroleum use—with total annual CO₂ emissions of 2,487 MMT—accounts for the largest share of emissions among fuels, with most emissions coming from dispersed use of fuels for transportation, rather than from operational emissions at large facilities. Emissions from coal total 2,094 MMTCO₂, almost entirely from electricity generation. Emissions from

⁶ Agricultural emissions are included with industrial sector emissions in Figures 4 and 5.

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the use of natural gas are spread relatively evenly between electricity generation, industry, and commercial and residential users, with 1,170 MMTCO₂ emitted in 2005.

The pie chart in Figure 6 disaggregates transportation sector emissions. Passenger vehicles (cars and light-duty trucks) account for almost two-thirds (61 percent) of CO₂ emissions from transportation. Of these emissions, the vast majority—around 90 percent—come from household vehicle use, with commercial use comprising the remainder.⁷ Shipping makes up about a quarter of emissions, mostly from trucks. Aircraft are the other significant contributor, with about 10 percent of total transportation emissions.

Although much smaller contributors than fossil-fuel combustion, other sources of CO₂ within the economy account for approximately 4.7 percent of total U.S. GHG emissions. Figure 7 breaks these emissions out by source, indicating that nearly half come from non-energy uses of fossil fuels where some of the carbon is stored

in a product and some is emitted. Emissions can occur during the manufacture of some products, such as plastics and rubber, or over a product's lifetime, as occurs with transportation lubricants or industrial solvents. The industrial sector accounts for most other non-energy CO₂ emissions, particularly process emissions from cement manufacture and iron and steel production.

Non-CO₂ Greenhouse Gas Emissions

Non-CO₂ gases compose about 16 percent of U.S. GHG emissions as measured in CO₂-e terms based on their 100-year GWP. Although smaller than the contribution from CO₂ in percentage terms, non-CO₂ emissions are important in discussions of climate policy because they often account for a substantial share of projected emissions reductions, particularly in the near term.⁸ The potential for including non-CO₂ emissions in a mandatory federal market-based program varies. Some are fugitive emissions that might only be included as offsets (for example, methane emissions from

⁷ This percentage was calculated from an EIA report on household vehicle energy use, based on 2001 survey data from the U.S. Department of Transportation. (EIA, 2005. *Household Vehicles Energy Use: Latest Data & Trends*, DOE/EIA-0464(2005), EIA: Washington, DC. Available at http://www.eia.doe.gov/emeu/rctcs/nhts_survey/2001/index.html and accessed on August 16, 2007.)

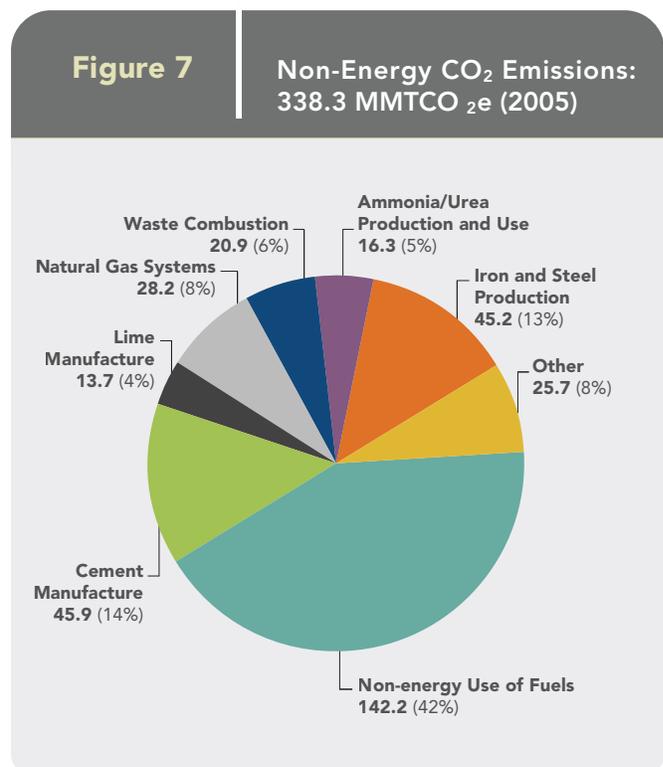
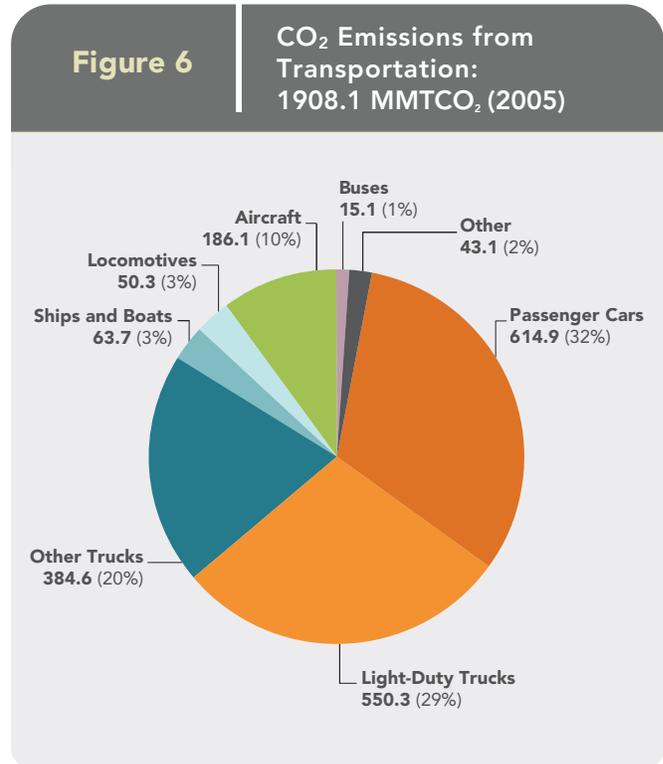
⁸ For example, an EIA analysis from March 2006 that considered a range of cap-and-trade proposals found that with modest near-term GHG permit prices (\$8–\$24 (2004 dollars) per tCO₂e in 2020), reductions in other GHGs (i.e., those besides energy-related CO₂) would account for 25–55 percent of total emissions reductions in 2020, despite composing only about 6 percent of regulated emissions in the reference scenario. (EIA, 2006. *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals*, SR/OAIF/2006-01, EIA: Washington, DC.)

landfills and nitrous oxide emissions from agricultural soil management); others, especially industrial gases, could be included relatively easily.⁹

The next three figures depict sources of emissions of the three major types of non-CO₂ GHGs: methane, nitrous oxide, and the fluorinated gases. Methane emissions fall broadly into three categories: waste, agriculture, and fossil-fuel sources. Landfills and wastewater treatment account for about 30 percent of methane emissions. Another 30 percent comes from agricultural activities; most of this is from the digestive gases of livestock, particularly ruminant animals (cattle, sheep, goats, etc). Various fossil-fuel systems account for just over one-third of methane emissions. Natural gas systems account for the largest portion of this share, largely as a result of fugitive emissions from throughout the natural gas system (production, processing, transmission, and distribution). Coal mining and petroleum systems also contribute methane emissions, principally from production activities (coal seams and oil field operations).

Nitrous oxide is produced naturally in soils through the microbial processes of nitrification and de-nitrification. These processes are amplified by agricultural activities—such as fertilization, which adds mineral nitrogen to soils—which produce more than three-fourths of anthropogenic N₂O emissions. Nitrous oxide is also formed as a byproduct of ordinary combustion processes, with emissions determined by fuel characteristics; combustion parameters, such as temperature and air-fuel ratio; and pollution control equipment. Emissions are also influenced by the processes used in catalytic converters to control nitrogen oxides, carbon monoxide, and hydrocarbon emissions, making mobile sources—particularly passenger vehicles—the second-largest contributor to nitrous oxide emissions (although emissions from this source have been falling since the late 1990s as improvements have been made in vehicle pollution-control technology).

The fluorinated gases (HFCs, PFCs, and SF₆) account for the smallest share of CO₂-e emissions, although they have very high GWP and are growing more quickly than other non-CO₂ GHGs. Most emissions from this group of gases are associated with their use as substitutes for ozone depleting substances (ODSs). Under the Montreal Protocol and the 1990 Amendments to the Clean Air Act, the United States is phasing out the use of ODSs. Unfortunately, the HFCs and PFCs that are being used instead—while they do not deplete



⁹ See Issue Briefs #14 and #15, on nontraditional GHGs and offsets, for further discussion of policy options for these types of emissions.

Figure 8

**Methane (CH₄) Emissions:
539.3 MMTCO₂-e (2005)**

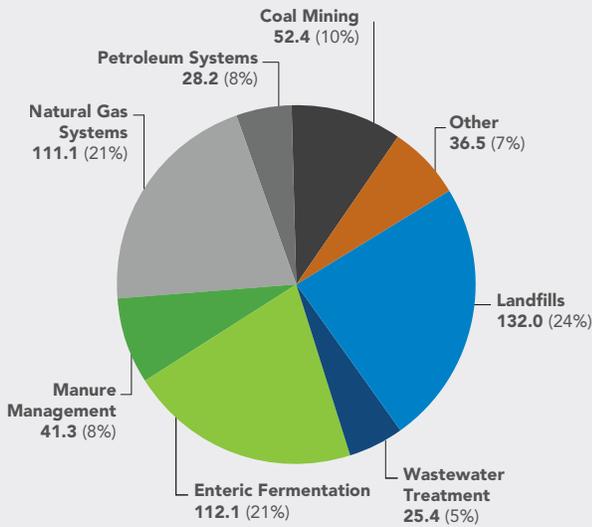
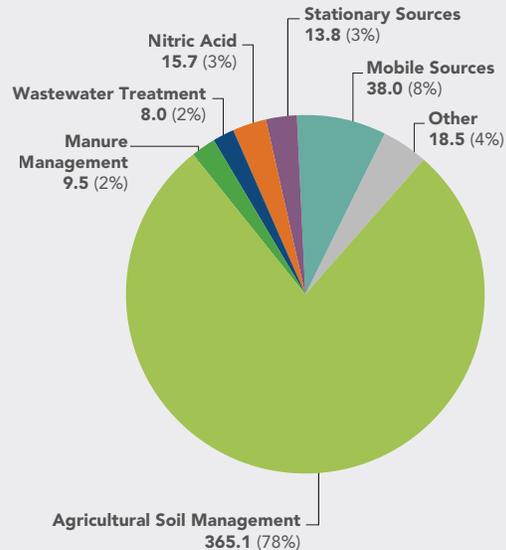


Figure 9

**Nitrous Oxide (N₂O) Emissions:
468.6 MMTCO₂-e (2005)**



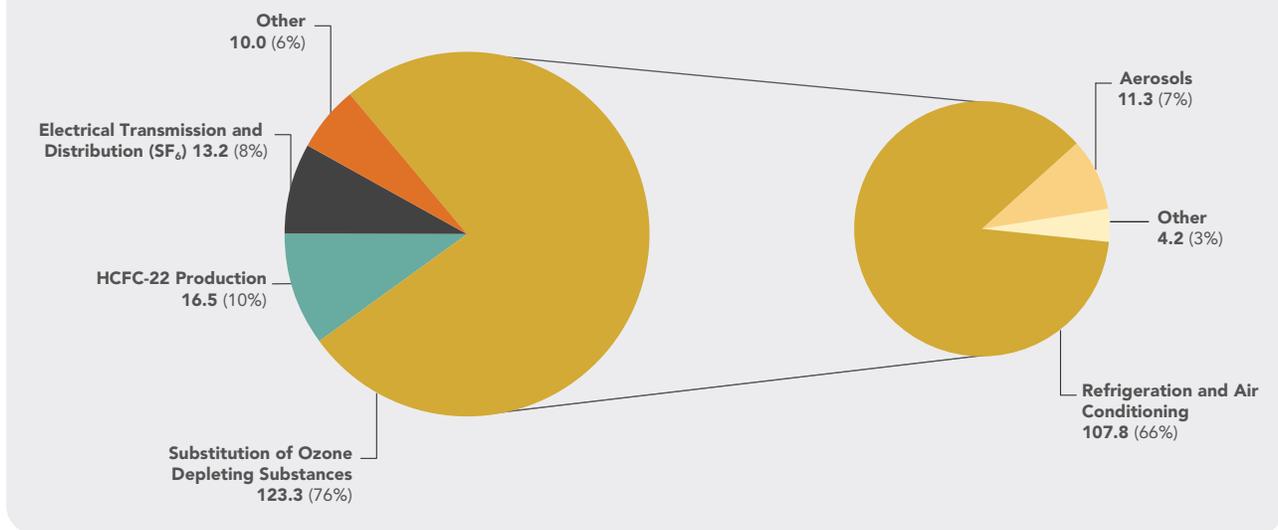
the ozone layer—are potent greenhouse gases.¹⁰ As shown in Figure 10, the bulk of HFC and PFC emissions come from the use of fluorinated gases for refrigeration and air conditioning; many of these emissions result from accidental leakage, particularly in smaller mobile systems such as motor vehicle air conditioners and refrigerated transport units. Smaller contributions also come from the use of fluorinated gases as aerosol propellants and as solvents in some industrial processes. Emissions of ODS substitutes have risen steadily in the last few years and are projected to continue increasing. On the other hand, emissions related to HCFC-22 production are falling, as this gas was a temporary substitute for some ODSs, but is now itself being phased out in the United States. Other emissions arise from production and use of SF₆, a gas that serves as an insulator and interrupter in equipment that transmits and distributes electricity. Most SF₆ emissions are fugitive releases, such as leaks from gas-insulated substations through equipment seals or releases during servicing or disposal activities. Emissions from these activities have been gradually falling since 1990 due to increased SF₆ prices and growing awareness of the environmental impact of the gas.

Number and Type of Carbon Dioxide Sources

The remainder of this issue brief examines in some detail the number of facilities involved in different stages of fossil-fuel production, processing, distribution, and use. As noted at the outset, this information is relevant because—unlike other types of emissions—CO₂ from fossil-fuel combustion can be directly and accurately estimated by multiplying the carbon content of the fuel by the volume of fuel consumed. This calculation can be performed at any point after fuels are produced, giving policymakers the flexibility to regulate emissions at different points in the fossil-fuel supply chain.

We emphasize data on the number, size, and type of facilities involved at different stages because it may be impossible to directly regulate very large numbers of small sources—such as homes and cars—without a high cost in terms of measuring, monitoring, and verifying emissions. By contrast, moving regulation upstream to facilities that supply these small sources may allow regulators to capture the vast majority of emissions throughout the economy while monitoring a much smaller number of facilities. Except where particular constraints exist, the market signal to reduce emissions—via a

¹⁰ Most of the ODSs being phased out by the Montreal Protocol are also potent GHGs.

Figure 10**Emissions of Fluorinated Gases: 163.0 MMTCO₂-e (2005)**

price on CO₂ emissions—would be transmitted to virtually all downstream users.¹¹ The latter point is important: the United States will only achieve the most emission reductions at the lowest cost to the economy if all actors in the chain of energy supply and use face the same incentive to reduce emissions.

In the discussion that follows, we distinguish between upstream, midstream, and downstream facilities or sources. Upstream facilities are fuel-production operations, such as coal mines, or natural gas and oil producers. Midstream facilities are intermediate fuel processors, including oil refiners, transporters, and pipeline operators. Downstream entities are end-users of fuel and include the facilities where emissions actually occur, such as electric power generators, industrial users, or households and automobiles.¹² As noted above, emissions can be calculated for upstream, midstream, or downstream facilities based on the carbon content of the fuel that is produced, processed, or consumed, rather than being directly measured (at the downstream smokestack). The next three sections discuss the number and size of upstream,

midstream, and downstream facilities, respectively.

Upstream Facilities

Upstream facilities include both producers and importers of fossil fuels. Figures 11 and 12 show the distribution of U.S. producers of fossil fuels. In the case of coal, about 500 mines account for 95 percent of U.S. production, while the top 1,000 mines account for 99.5 percent of production. In total, there are about 1,400 coal mines in the United States.¹³ By contrast, there are more than 15,000 companies producing crude oil and natural gas domestically. As with coal, however, production is concentrated among the largest companies: the top 500 producers account for 90–93 percent of U.S. production.¹⁴

In addition to production facilities, upstream regulation would have to account for imports. Coal imports are very small relative to domestic production—less than 3 percent.¹⁵ Natural gas imports are larger, making up about one-fifth of U.S. consumption.¹⁶ Most of these are pipeline imports from

11 See Issue Brief #4 on scope and point of regulation for further discussion of constraints that may exist on the ability to pass costs from upstream suppliers to downstream users.

12 Note that the same facility could confront different compliance obligations depending on the point of regulation. For example, if CO₂ were regulated at midstream based on fuel input, an oil refinery would be responsible for submitting allowances or paying taxes on the carbon content of its refining throughput as well as its direct emissions. Under downstream regulation based on actual emissions, the same refinery would be responsible only for its own direct emissions.

13 EIA Coal Production Data Files, 2005. Available at <http://www.eia.doe.gov/cneaf/coal/page/database.html>. Accessed August 16, 2007.

14 EIA, 2006. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2005 Annual Report, Appendix A, Operator Level Data*, DOE/EIA-0216(2005), EIA: Washington, DC.

15 EIA, 2007. *Quarterly Coal Report October–December 2006*. DOE/EIA-0121 (2006/04Q). EIA: Washington, DC. Coal imports were on average about 2.3 percent of domestic production from 2001–2006. Coal exports were about 4.2 percent of U.S. production from 2001–2006.

16 EIA, 2007. *U.S. Natural Gas Imports and Exports: Issues and Trends 2005*, EIA: Washington, DC. Exports of natural gas from the U.S. represent less than 4% of domestic production, with most of this being pipeline

Figure 11

Distribution of U.S. Coal Production (2005)

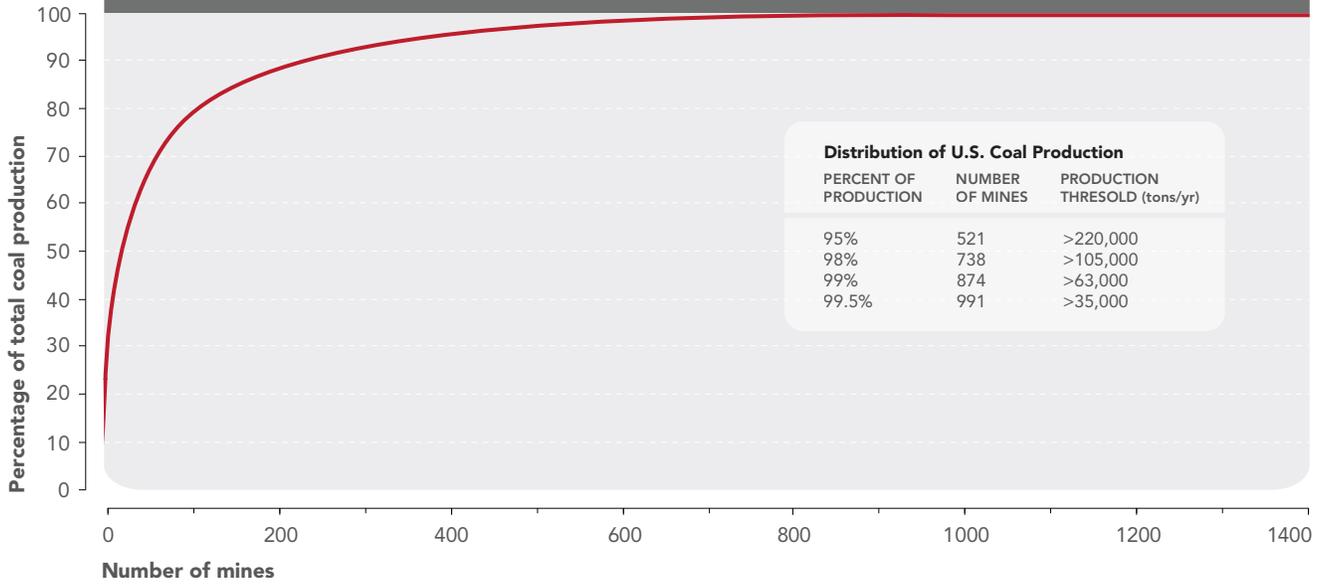
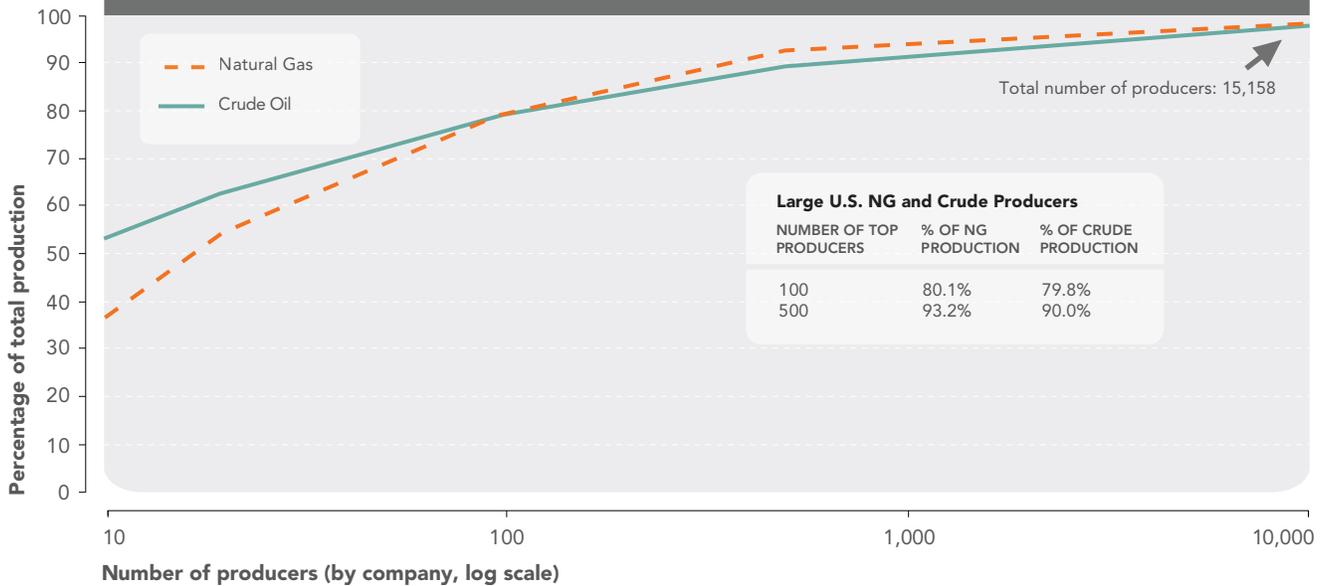
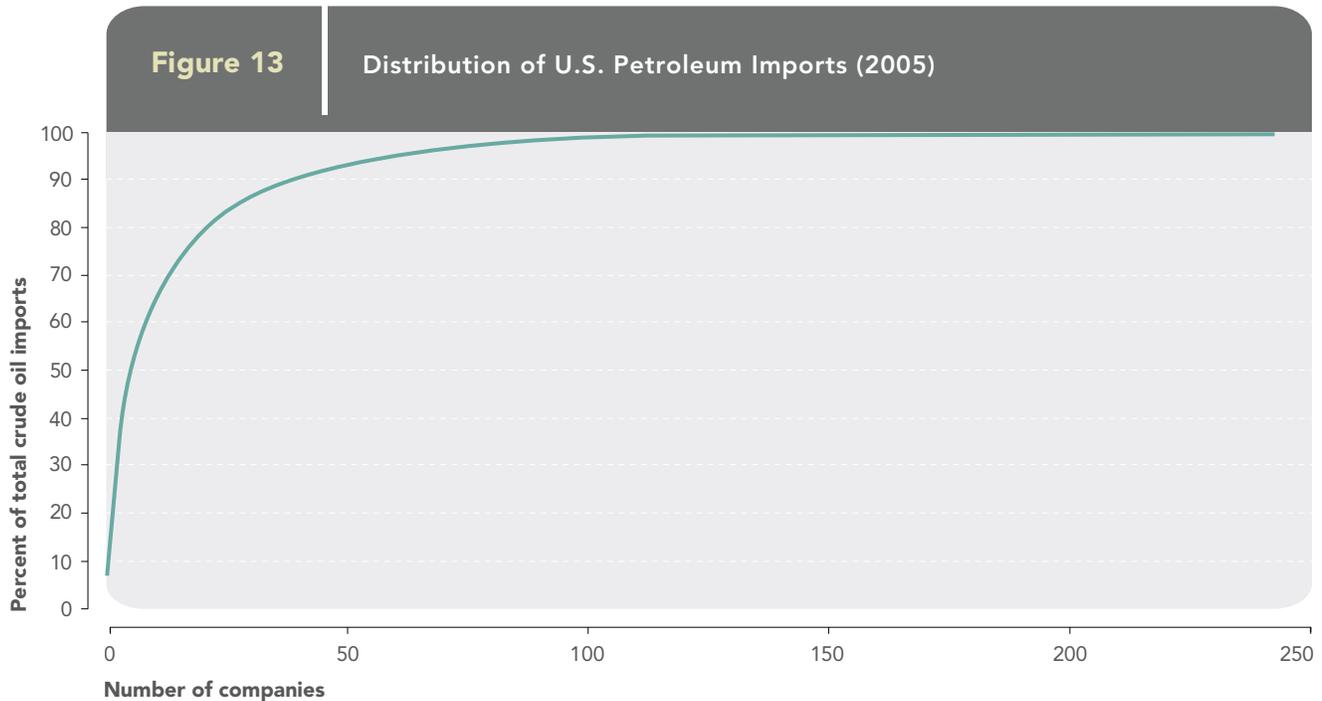


Figure 12

Distribution of U.S. Natural Gas and Crude Oil Production (2005)





Canada and Mexico, with the last 15 percent of imports (3 percent of total U.S. natural gas supply) being liquid natural gas (LNG). Slightly more than 100 companies are involved in natural gas pipeline import/export.¹⁷ Five companies imported LNG to the U.S. in 2005.¹⁸ Unlike coal or natural gas, imports exceed U.S. production in the case of petroleum. Figure 13 shows the distribution of U.S. petroleum imports—both crude and refined—by company; less than 250 companies account for all imports, with about 100 companies making up 99 percent of the total.¹⁹

Midstream Facilities

Although in theory, transmission facilities could be regulated (whether oil and gas pipelines or coal shippers), most proposals for midstream regulation focus on processors. Further, the emphasis is on oil and natural gas, since coal is typically not processed between production and use.

Figure 14 shows U.S. crude oil refining capacity as of January 1, 2006 for the approximately 150 refineries in operation at

that time.²⁰ This figure depicts capacity rather than actual throughput because firm-level data on throughput are not available. Because the utilization of operable capacity for refineries has averaged over 90 percent for the last five years, however, capacity data provide a reasonable proxy for throughput.²¹ Imports of refined petroleum products, which composed about 25 percent of total U.S. petroleum imports in 2005, would also need to be regulated in a midstream system.²² Figure 13 includes these refined products; although a detailed breakdown is not given, the figure indicates that fewer than 250 companies import petroleum products, whether refined or crude.

Natural gas processing plants are in some respects analogous to oil refining facilities, although they receive less attention. Processing plants take raw natural gas from the wellhead and process it into standard pipeline-quality natural gas, removing oil, water, natural gas liquids (NGLs), and contaminants (such as sulfur). Figure 15 shows processing capacity for the approximately 570 natural gas processing facilities in the

17 U.S. Dept. of Energy, Authorizations to import/export natural gas, 2005. <http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders-2005.html> Accessed August 24, 2007.
 18 EIA, 2007. *U.S. Natural Gas Imports and Exports: Issues and Trends 2005*, EIA: Washington, DC.
 19 Figure 13 data from the EIA, *Company Level Imports of Petroleum*, 2005. http://www.eia.doe.gov/oil_gas/petroleum/data_publications/company_level_imports/cli_historical.html Accessed August 16, 2007.

20 EIA, 2006. *Refinery Capacity Report 2006*, EIA: Washington, DC. http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcap_historical.html Accessed August 16, 2007.
 21 EIA, 2007. *EIA Petroleum Navigator*, U.S. Total Weekly Inputs, Utilization & Production. The average weekly percent utilization of refinery operable capacity from August 2002 to July 2007 was 90.5 percent. File available at http://tonto.eia.doe.gov/dnav/pet/pet_pnp_wiup_dc_nus_w.htm Accessed August 27, 2007.
 22 EIA, 2007. *EIA Petroleum Navigator*, U.S. Weekly Imports & Exports. Imports of petroleum products (i.e., all non-crude oil imports) were 24.8% of total 2005 imports. File available at http://tonto.eia.doe.gov/dnav/pet/pet_move_wkly_dc_NUS-200_mbbld_w.htm Accessed August 27, 2007.

continental United States.^{23,24} Natural gas imports would also have to be accounted for under a midstream system, since pipeline and LNG imports are rarely processed by U.S. processing facilities. As noted previously, about 100 companies are involved in importing natural gas.

Downstream Sources

There are a much larger number and variety of downstream fossil-fuel users compared to either midstream or upstream fuel producers or processors. In addition to traditional large point sources of emissions, such as electric generating units or manufacturing plants, downstream sources include much smaller fuel users such as commercial buildings, automobiles, and home furnaces. There are an enormous number of these small sources in the U.S. economy, including nearly 200 million personal vehicles in the United States.²⁵ Out of the almost 110 million households in the country, nearly 70 million use natural gas; fuel oil or liquid propane gas (LPG) are used in about 9 million each; and kerosene is used in about 3 million.²⁶ There are fewer commercial buildings—under 5 million—about half of which use natural gas; another half million each use fuel oil or propane.²⁷ All told there are roughly 300 million small downstream sources in the U.S. economy, primarily homes and personal vehicles.

The remainder of our discussion focuses on large downstream sources and, in particular, on downstream sources in the electric utility and industrial sectors. These sectors accounted for just over half (52 percent) of total U.S. GHG emissions in 2005 (see Figure 3). Legislative proposals that opt for regulating downstream sources typically target these large emitters; if emissions from small sources are included, they are typically regulated upstream or midstream (for example, through crude oil producers/importers or refiners).

Figure 16 depicts the distribution of CO₂ emissions from the electric power sector.²⁸ Emissions are presented by facility for the approximately 3,000 facilities in the United States that use fossil-fuel-based generation.²⁹ The 800 largest emitting facilities account for 95 percent of electric power sector emissions. Nearly two-thirds of all fossil-fuel generating

facilities emit more than 10,000 metric tons annually; together these large facilities account for more than 99.9 percent of electric utility emissions. Of the roughly 3,000 fossil-fuel-based electric generating facilities in the United States, around 900 burn coal. Given that electricity generation accounts for more than 90 percent of U.S. coal use (see Figure 5), it would appear that the number of upstream facilities for coal (coal mines) is roughly equal to the number of downstream facilities (coal-burning electric generating units). Finally, note that these data do not include electricity generation at industrial- and commercial-sector plants.³⁰

The other major category of large downstream sources consists of industrial facilities, particularly manufacturing. Manufacturing accounts for 84 percent of energy-related CO₂ emissions in the industrial sector.³¹ (The rest arise from agriculture, construction, fisheries, forestry, and mining.) The discussion below summarizes information about energy-related CO₂ emissions from manufacturing.

According to the U.S. Census Bureau, which conducts a nationwide economic survey every five years, the U.S. manufacturing sector in 2002 consisted of approximately 350,000 establishments employing more than 14 million people.³² EIA reports that direct CO₂ emissions from the manufacturing sector in 2002 were approximately 860 MMTCO₂.³³ (This total includes emissions from on-site fossil-fuel-based electricity generation, but does not include net electricity purchases from the electric power sector.) EIA provides data for about 30 different categories of manufacturing operations,³⁴ which together account for more than 90 percent of manufacturing sector energy-related CO₂ emissions, but does not provide any information about the distribution of emissions across individual facilities. To obtain a rough estimate of the distribution of manufacturing emissions sources by size, we use data from the Census Bureau economic survey, which provides disaggregated data on manufacturing employment, with firms grouped by number of employees.³⁵ Assuming emissions within each manufacturing category are proportional to employment, we develop an estimate of the distribution of emissions among firms. Thus, for example, if there are 8 firms in the largest employment size group of a particular type of manufacturing, and they account for 30 percent of employment within that manufacturing category, we

23 EIA, 2006. *Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market*. EIA: Washington, DC. Although Alaska has four natural gas processing plants with more than 8 billion cubic feet per day of combined processing capacity (about 12 percent of the U.S. total), almost none of the natural gas extracted in Alaska enters any transmission system. Rather, it is re-injected into reservoirs.

24 Figure data provided on request by EIA.

25 EIA, 2005. *Household Vehicles Energy Use: Latest Data & Trends*, DOE/EIA-0464(2005). EIA: Washington, DC.

26 EIA, 2001. *2001 Residential Energy Consumption Survey, Housing Characteristic Data Tables HC1: Housing Unit Characteristics*. EIA: Washington, DC.

27 EIA, 2006. *2003 Commercial Building Energy Consumption Survey, Building Characteristic Tables, Table B22: Energy Sources, Number of Buildings*. EIA: Washington, DC.

28 EIA, *Form EIA-906 and EIA-920 Databases*, http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html Accessed August 16, 2007.

29 "Facilities" are defined by unique EIA plant identification numbers. In practice this means that a facility is considered the sum of all the generating units at a physical plant location.

30 Note that on-site industrial electric generation is included in the discussion of the industrial sector that follows.

31 EIA, 2006. *Energy-Related Carbon Dioxide Emissions in U.S. Manufacturing*, DOE/EIA-0573(2005), EIA: Washington, DC.

32 Data on number of establishments and employee size came from U.S. Census Bureau, 2002 Economic Census. Data retrieved with American FactFinder.

33 EIA, 2006. *Energy-Related Carbon Dioxide Emissions in U.S. Manufacturing*, DOE/EIA-0573(2005), EIA: Washington, DC.

34 Manufacturing operations are categorized by the North American Industrial Classification System (NAICS).

35 Employment data are also categorized by NAICS, and are reported using ten employment size divisions, ranging from establishments with one to four employees to those with 2,500 employees or more.



Figure 14

**Distribution of U.S. Refining Capacity
(2006, Atmospheric Crude Oil Distillation)**

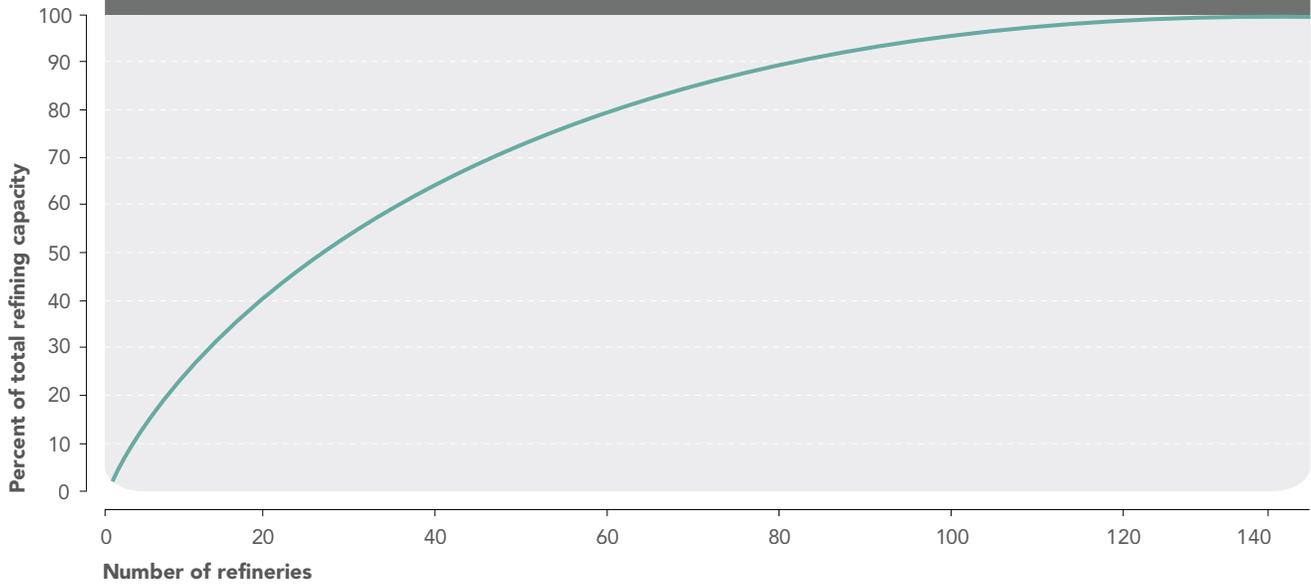


Figure 15

**Distribution of U.S. Natural Gas Processing Capacity
(2006, Lower 48 States)**

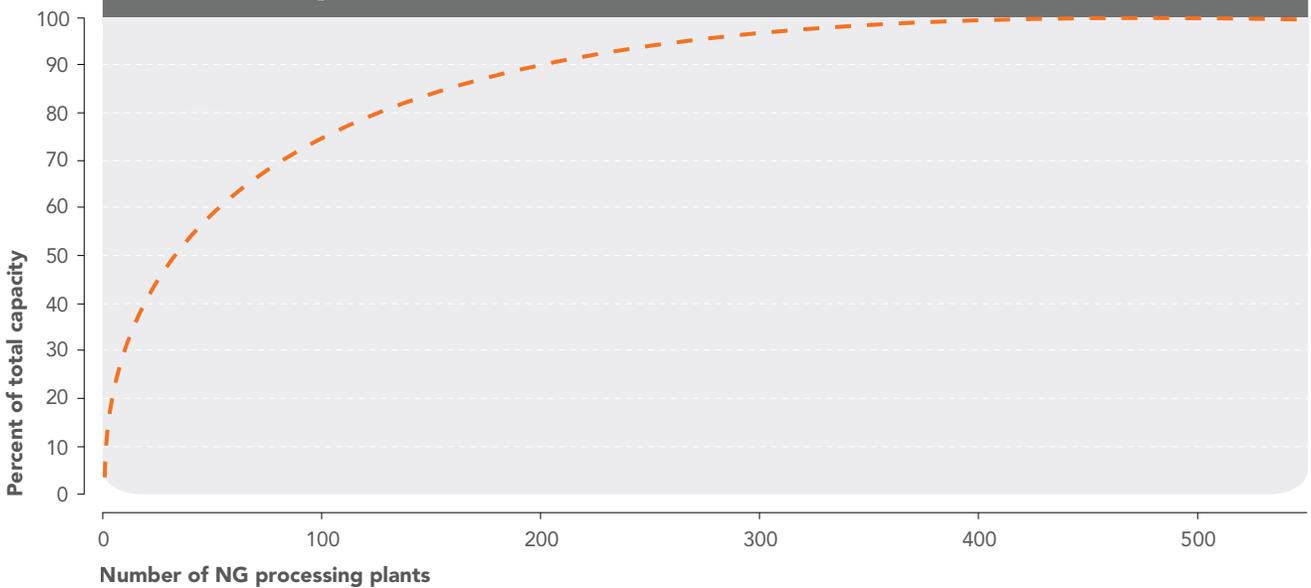


Figure 16

Distribution of CO₂ Emissions from Electric Power Sector Generating Facilities (2005)

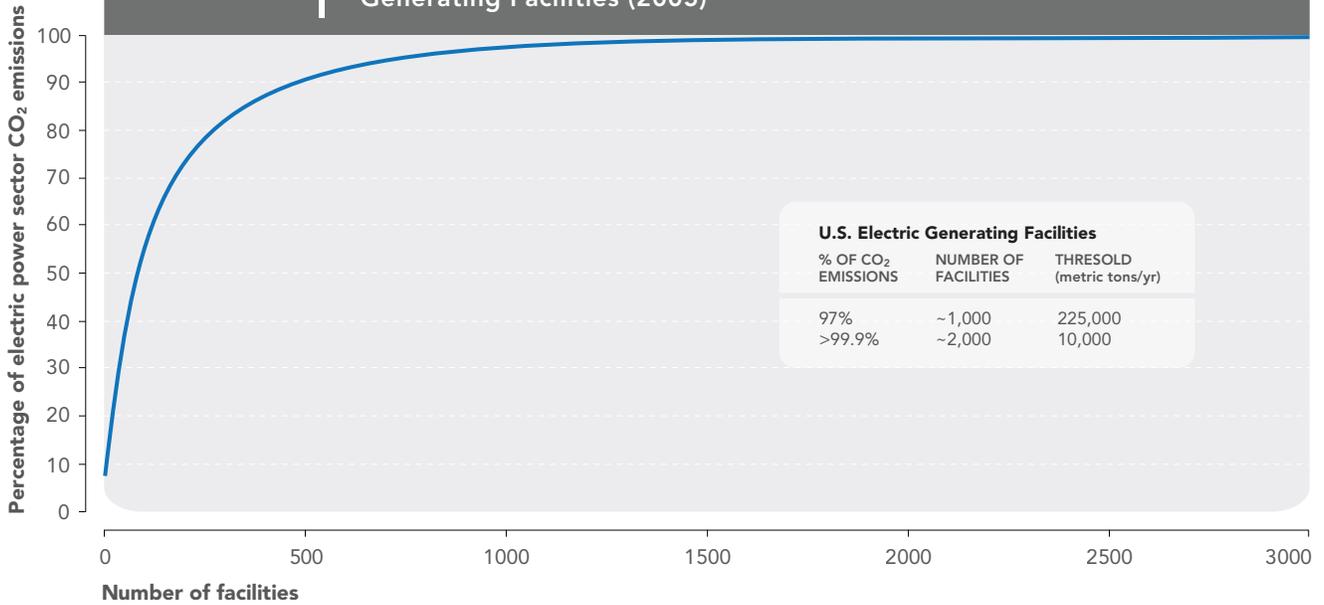
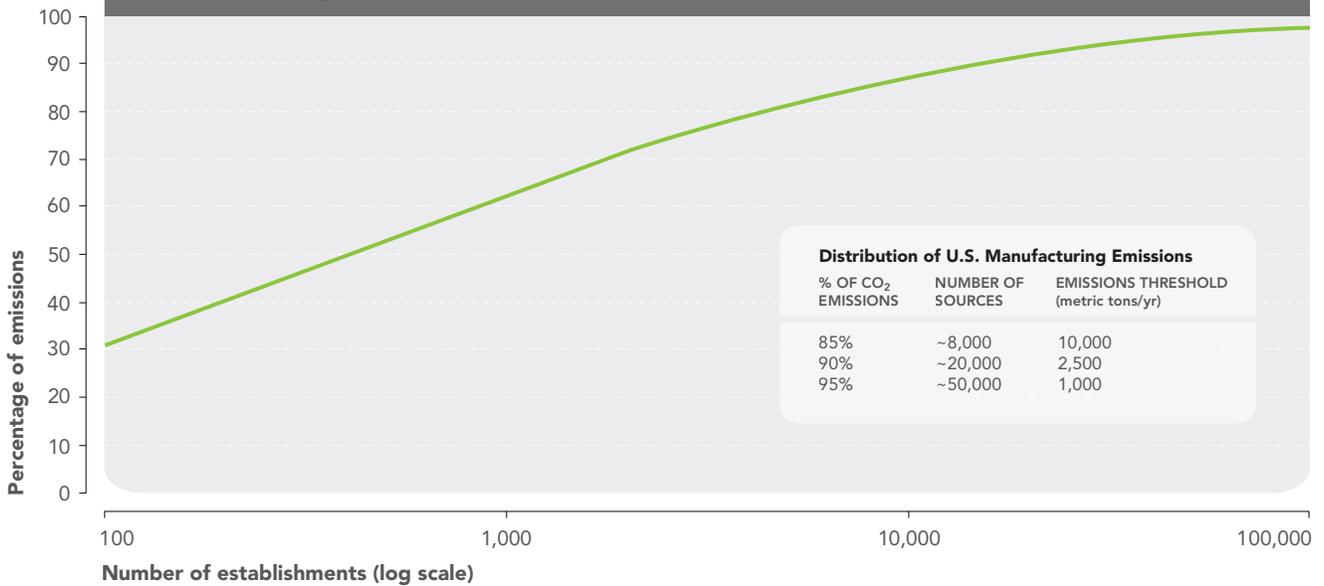


Figure 17

Distribution of Energy-Related CO₂ Emissions from U.S. Manufacturing in 2002 (estimate based on employment as a proxy emissions measure)



assume they account for 30 percent of the energy-related CO₂ emissions reported by EIA for that type of manufacturing.³⁶ The resulting estimate of emissions distribution is very rough, but should be sufficient to provide policymakers with a useful approximation of the number of manufacturing sources that might be involved in domestic regulation.

Figure 17 shows the result of this analysis. It suggests that the 10,000 largest firms account for around 85 percent of manufacturing CO₂ emissions. Achieving coverage of more than 95 percent of manufacturing emissions would likely involve more than 50,000 sources.

Conclusion

As suggested at the outset, regulating a relatively small number of upstream or midstream facilities—fewer than 3,000—would capture the vast majority of economy-wide CO₂ emissions and pass incentives for mitigation to a much larger number of downstream emission sources (paying attention to certain constraints). Focusing only on downstream regulation, the analysis presented here suggests that a system covering the 10,000 largest sources might capture about half of national CO₂ emissions (all electric generation emissions and most manufacturing CO₂ emissions). A third option would be a hybrid system, which would regulate large downstream sources while also capturing emissions from smaller downstream sources (such as cars and buildings) by regulating on the basis of fuel throughput at midstream or upstream entities. This approach could work well for regulating CO₂ emissions from the transport sector, where a small number of refineries and importers serve virtually the entire sector.

When regulating some types of sources (such as wellheads in an upstream system or industrial facilities in a downstream system) it will likely be necessary to establish cut-offs, whereby smaller entities are excluded. The figures in this section help provide a sense of the trade-off between increasing coverage on the one hand and limiting the number of regulated facilities—and associated administrative costs—on the other.³⁷ For some categories of sources, such as oil refineries and coal mines (or coal-burning electric generating units), there are few enough facilities that they could all be included.

³⁶ The approximately 30 categories for which EIA details emissions comprise around 70,000 establishments, or about 20 percent of all manufacturing establishments. This analysis divides these manufacturing establishments into roughly 300 bins (30 categories by 10 employment size groups). The other 280,000 establishments—accounting for less than 9 percent of manufacturing energy-related CO₂ emissions—are included in the analysis in an “all others” category with the same 10 employment size divisions.

³⁷ Note that the relative contribution to overall emissions from small sources could change under long-term regulation depending on the stringency of emissions targets and program coverage. This is discussed in further detail in Issue Brief #4 on scope and point of regulation.