Title

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by

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An Appendix to the Report "A Lifecycle Emissions Model (LEM): Lifecycle Emissions from Transportation Fuels, Motor Vehicles, Transportation Modes, Electricity Use, Heating and Cooking Fuels, and Materials"

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INTRODUCTION

Fossil fuel production results in emissions of CH_4 because some leakage of natural gas, which is mostly CH_4, occurs through natural gas production, oil production, and coal mining. In the case of natural gas production, the magnitude of these emissions depends primarily on the age and state of maintenance of the production equipment. For oil production, CH_4 emissions vary depending on the amount of gas in the oil field and the manner in which unrecovered gas is disposed of. For coal mining, emissions depend on many factors, including the amount of natural gas present in the mine area, the depth of the mine, and the condition in which the mine is abandoned, among other factors.

METHANE EMISSIONS FROM NATURAL GAS PRODUCTION

Small amounts of natural gas are lost from production fields, transmission lines, and distribution systems. Natural gas leaks from joints and compressor stations throughout the natural-gas system. Gas also leaks, or is vented, from instruments that operate on gas, from valves opened to drain liquids from pipelines, and on occasion from overpressure valves[1]. Gas may be vented from buildings during construction, or emitted during the purging of pipelines (AGA, 1989a) , but intentional venting probably accounts for a minority of losses.

In the past few years, as part of efforts to account for sources and sinks of greenhouse gases, several organizations and researchers have estimated leakage from natural gas systems.[2] Most of the studies done to date agree on two key points. First, total gas loss to the atmosphere from wellhead to end-use consumer, in modern, well-maintained systems, is probably less than 2% of total gas throughput (Table E-1).[3] Second, losses in old or poorly maintained systems can be quite a bit higher. For

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[1]Some gas permeates through the walls of plastic pipes, but the rate, 0.26 ft^3/day-mile (Spriggs, 1988), is insignificant.

[2]The Energy Information Administration publishes estimates of "unaccounted for" gas, but this is an account-balancing item, not an estimate of actual gas losses to the atmosphere. "Unaccounted for" gas is the imbalance between the sum of the components of gas supply and the sum of the components of gas disposition. The imbalance is created by variations in reporting practices, metering, meter adjusting, and other factors, including gas losses. Because it is strictly an accounting term, unaccounted for" gas can be and actually has been *negative* (EIA, 1989c; this simply means that the estimated disposition exceeded estimated supply). Obviously, the amount of gas actually lost to the atmosphere cannot be negative.

[3]Staff at the U. S. Energy information Administration (EIA) believe that gas leaks are less than 0.5% total of total deliveries (McCarrick, 1990) . The International Workshop on Methane Emissions from Natural Gas Systems, Coal Mining, and Waste Management Systems (1990) comes to essentially the same conclusion.

example, Hogan et al. (1991) believe that leakage in the [former] Soviet Union is about 6%,[4] and estimates in Mitchell et al. (1990) indicate even higher loss rates for older systems in Britain designed originally to carry city gas (which is mostly carbon monoxide and hydrogen) rather than natural gas (which is mostly CH_4). There is some disagreement, however, on the total leakage from existing national and regional systems, which comprise parts and subsystems of varying ages and quality. Most gas companies believe that total losses are relatively low, but others (e.g., Mitchell, et al., 1990) believe that the older parts of the gas networks can raise the average loss rate substantially. Generally, there is little reliable information on not only leaks from older systems, but also the amount of gas carried in older systems.

Table E-1 summarizes several recent estimates of gas loss from production, transmission, and distribution systems. An EPA study (1993) for the U.S. Congress estimated emission factors for "model," or representative facilities at each stage of the natural gas system (for example, natural gas processing-plants, or transmission pipelines) then multiplied these emission factors by "activity factors," (e.g., gas throughput, or miles of pipeline), and aggregated the results for the entire U.S. system. They also made emission projections for the years 2000 and 2010. The results of the study, which are broadly consistent with other recent, though but generally less disaggregated studies, are also shown in Table E-1.

However, a recently completed, multi-year, detailed study by Radian Corporation, for the Gas Research Institute (GRI) and the U. S. EPA (EPA/GRI, 1996; see also Kirchgessner et al., 1997) estimates somewhat higher leakage rates than do earlier studies (Table E-1). The Radian study concluded that CH_4 emissions from the natural gas industry were 314 BCF in 1992 (EPA/GRI, 1996) . This figure corresponds to about 1.4% of gross natural gas production, and suggests that natural gas systems contributed about 19% to the total anthropogenic CH_4 emissions in the U.S. in 1992 (EPA/GRI, 1996) . The study estimated fugitive (leaked), vented (intentional) and combustion emissions of methane from all of the components and activities (e.g., pneumatic devices, dehydrator glycol pumps, and "blow and purge") of gas production, processing, transmission and storage, and distribution. It found that about 48% of total natural gas industry emissions were the result of fugitive losses during the transmission and storage segment and the distribution segment (EPA/GRI, 1996) . Each of these two categories accounted for nearly 75 BCF of CH_4 emitted in 1992 and the only other category with comparably high emissions was identified as the 54 BCF of CH_4 vented during the production segment (EPA/GRI, 1996).

The EPA/GRI study, as updated by EIA (1998) and EPA (1999) (see Table E-1), clearly is the best ever done for the U. S., but it is likely that a good deal of uncertainty in estimates of natural gas leakage rates remains. For example, Shorter et al. (1997) used a tracer gas, SF_6, to estimate the leakage from gas plants, separator stations, wells,

[4]However, the Alphatania Group (1989) believes that only 0.5% to 1.2% of gas throughput leaks from the gas systems in the former Soviet Union.

storage fields, compressor stations, metering stations, high-pressures stations, and vaults, and found that for many sources the leakage rate (L/min) varies over 2 or 3 orders of magnitude. (In the EPA/GRI study, tracer gas measurements were used to characterize emissions from meters and pressure regulating stations [Harrison et al., 1996].) See Table E-1 and notes for a complete summary of the results of this study.

METHANE EMISSIONS FROM OIL PRODUCTION

Background

Many fields contain both natural gas and crude oil. Some of these fields contain mostly crude oil, and are developed in order to sell the oil. When the oil at these fields is produced, small amounts of the associated natural gas are produced also. If the gas cannot be collected and sold economically, it must be disposed of. There are three ways to dispose of unmarketable associated gas: re-inject it into the producing field, burn it (called "flaring"), or simply vent it to the atmosphere. Re-injected gas for the most part does not enter the atmosphere, so it is of no concern in an analysis of emissions of greenhouse gases. However, venting the gas releases it in its original state, as CH_4, higher alkanes, CO_2, N_2, and H_2S, and flaring the gas produces CO_2 and unburned hydrocarbons, including some CH_4.

Several sources, including the United Nations, the Organization of Petroleum-Exporting Countries, the energy agencies of national governments, and major international gas companies, estimate the amount of gas vented and flared locally, regionally, and worldwide. The U.S. Energy Information Administration (EIA) analyzes the quality of these data and publishes its "best-estimates" in its *International Energy Annual* (EIA, annual) . From 1983 to 1994, 3 to 4 trillion cubic feet (TCF) of gas were vented or flared worldwide every year (EIA, *International Energy Annual,* various years). In 1983, 3.85 TCF of gas, or about 7% of dry gas production, were vented or flared, and in 1992 the figure was 3.83 TCF, or 5.1% of dry gas production (EIA, 1994a) . It appears that some of the previously vented and flared gas now is being re-injected: the quantity of gas re-injected has increased from 5.41 TCF in 1983 to 8.90 TCF in 1992 (EIA, 1994a) and 10.4 TCF in 1994 (EIA, 1996d) . Worldwide, venting and flaring probably will decline as natural gas increases in value and is re-injected, used domestically, or exported. The United Nations projects that in the year 2010 venting and flaring will be half of what it was in 1987 (United Nations, n.d.) [5]. Major gas-producing developing countries are expected to use associated gas to help fuel industrial development (ICF, 1990a; IEA, 1989) .

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[5] For example, Nigeria (West Africa), the largest flarer of gas in the world, "has stated policies encouraging alternatives to flaring," including using the gas domestically or exporting it. Similarly, Algeria (Mediterranean) is planning to increase its re-injection of gas to enhance oil recovery (ICF, 1990a).

The EIA data indicate that the amount of venting or flaring varies considerably around the world. In order to estimate venting or flaring emissions attributable to U.S. *consumption* of petroleum (as opposed to US *production* of crude oil), one must know the rate of venting or flaring in the all the countries that produce oil used directly (as crude oil) or indirectly (as petroleum products) by the U.S. One way to calculate this rate is to divide the world into regions. Then estimate the amount of gas vented or flared per unit of oil produced in each region, and multiply each of the regional rates by the amount of oil that the U.S. gets, directly or indirectly from the region. We do this in the main report.

Emissions of vented and flared not included in the EIA statistics

It is important to note that the EIA collects its venting and flaring data from state agencies in the U.S., and from foreign governments. The state offices report venting and flaring from all onshore oil wells, and venting and flaring from State but not Federal offshore oil wells. The EIA's estimates of venting and flaring in the U.S. are based entirely on the state data[6], and therefore do not include venting and flaring from Federal offshore oil wells (McCarrick, 1990) .

However, the EIA estimates can be supplemented with data from the Minerals Management Service (MMS) on venting and flaring from Federal offshore oil wells. In 1990, in the Gulf of Mexico, 48 SCF of gas were vented or flared from oil wells per barrel of crude oil produced (Nixdorff, 1991) . Since production from Federal offshore oil wells in the Gulf of Mexico typically is more than 90% of total Federal offshore oil production (Minerals Management Service, 1992) , one can assume that this 48 SCF/bbl rate applied to all Federal offshore oil wells in 1990. From 1970 to 1991, Federal offshore production was 10% to 12% of total U. S. oil production (Minerals Management Service, 1992) . With these two statistics -- the amount of gas vented or flared per bbl of offshore production, and the offshore production as a fraction of total production -- we can calculate total venting and flaring from offshore oil production. We do this in the main report.

It should be noted that it is possible that some gas is vented underwater and not reported. Sackett and Barber (1988) state that in the 1970s, it was common to vent natural gas underwater at offshore oil-producing platforms. Sea Technology (1974) and Brooks et al. (1977) cite large estimates of vented and flared gas in 1973 and 1974 (about 150 SCF/bbl), and Brooks et al. (1977) argue that most of this was vented underwater. However, the MMS data discussed above show much less venting and flaring in 1990 (48 SCF/bbl). The question, then, is this: has offshore venting and flaring declined dramatically since the early-to-mid 1970s, or are the MMS data not as complete as the

[6]The state data may have serious shortcomings: they apparently are based not on measurements or engineering calculations of the amount of gas actually vented or flared, but rather on estimates of unaccounted for gas or of some other quantity (Harrison, 1992) . If this is true, then the amount of gas actually vented or flared might be quire different than the amount reported by the EIA . Unfortunately, no other estimates are available.

data sources cited in Sea Technology (1974) and Brooks et al. (1977)? The answer appears to be the former, because Sea Technology (1974) cites the Department of the Interior (probably the U.S. Geological Survey), and Brooks et al. (1977) cite a personal communication from the U.S. Geological Survey. As well, the MMS took over the task of collecting venting and flaring data from the Geological Survey Nixdorff, 1991). Therefore, all the data probably come from the same source, and show that venting and flaring have declined. (Note, too, that the MMS data come from oil companies, who are supposed to report *all* venting and flaring.)

Thus, it probably is reasonable to assume that the EIA data and the MMS data together cover nearly all of the sources of vented or flared gas in the U.S. Unfortunately, the picture is much less clear for the rest of the world. The EIA has reported that it does not know if the sources it uses to estimate venting and flaring emissions in other countries are reliable or complete. We suspect that in many cases the data are not reliable, and that venting and flaring is significantly under-reported in many parts of the world. In the main report, we use our judgment to adjust for this likely under-reporting.

Vented versus flared gas

Finally, in order to calculate the greenhouse effect of vented and flared gas, the aggregate measure "vented or flared" must be disaggregated to the amount vented (venting releases mainly CH_4, and smaller amounts of NMHCs and CO_2) and the amount flared (flaring produces mainly CO_2, with smaller amounts of CH_4 and NMHCs). Although none of the documents cited above separate the proportion vented from the proportion flared, it is widely believed that most “vented or flared” gas actually is flared. The Office of Oil and Gas at the EIA expect that at least 95% of all vented or flared gas to be actually flared. They point out that the term "vented or flared" is something of an anachronism, dating from a time several years ago when a fair amount of gas really was vented (McCarrick, 1990) . In fact, unmarketable, associated gas must be flared (if not re-injected), to destroy toxic compounds in the raw gas and to prevent the accumulation of an explosive concentration of natural gas. Releasing toxins into the atmosphere from the raw gas can also be complete be avoided if the raw gas is re-injected. Generally, gas can be vented only when a very small amount is released in a remote location with strong winds, and these situations are relatively rare. The EPA (1993) cites a draft report by Radian Corporation that estimates that at least 96% of the total reported venting and flaring actually is flared rather than vented.

However, there are several other factors to consider. First, as mentioned above, Sackett and Barber (1988) and Brooks et al. (1977) believe that in the 1970s, a large fraction of offshore waste gas was vented underwater. Brooks et al. (1977) state that "the [offshore] petroleum industry considers venting preferable" to flaring, for several reasons (p. 378) and note that, in 1974, the U.S. Geological Survey estimated that 70% of offshore vented or flared gas actually was vented. In support of this, Brooks et al. (1977) also found a high concentration of CH_4 and other hydrocarbons in Gulf waters.

Second, in addition to venting and flaring emissions, there also are fugitive gas emissions from oil production fields. The EPA (1993) estimates that fugitive CH_4 emissions could have been as high as 0.022 Tg (about 1.2 billion cubic feet) in 1990, or roughly 1% of reported venting and flaring emissions in the U.S. However, the EPA's best guess is that fugitive emissions were much less than this. They also note that fugitive emissions have been declining.

Third, industry sources have reported that flares often are not nearly 100% effective, and thereby emit a significant amount of unburned gas. For example, industry sources cited in Barns and Edmonds (1990) believe that total CH_4 emissions due to both venting and incomplete combustion in flares are 20% of total reported venting or flaring emissions. Unfortunately, there are no data on the average effectiveness of flares, or the amount of unburned CH_4 emitted from flares.

In addressing these issues, we assume that 4% of the EIA-reported venting or flaring emissions from onshore oil production is vented rather than flared. Next, we assume that fugitive emissions are equivalent to an additional 1% of reported venting and flaring, as venting. Then, we assume that flares are 95% effective, so that an additional 5% (0.96 x [1-0.95]) of onshore venting or flaring emissions effectively is "vented," as unburned gas. Therefore, the total effective venting rate for onshore oil production is 4% (direct venting) + 1% (fugitive emissions) + 5% (unburned gas from flares) = 10% of reported venting or flaring. Regarding underwater venting from offshore oil production, there are two possibilities: either the fraction of vented gas has declined considerably, as implied by the EIA, or else there is still a large amount of perhaps clandestine venting underwater. We take a middle ground, and assume that underwater venting has declined somewhat, from the 70% level estimated by the USGS for 1974, to 30% in 1987 and thereafter. We also assume that gas vented underwater eventually enters the atmosphere.

The onshore vented fraction and the offshore vented fraction must be combined. In 1987, 21 BCF of gas was vented or flared from offshore State and Federal oil leases (based on 48 SCF/offshore-bbl, from above, and 437 million bbl produced from state and Federal offshore leases, according to the MMS [1992]), and 121 BCF was vented or flared from onshore fields (124 BCF from onshore + State offshore production, as reported by the EIA, less my estimate of 3 BCF from the offshore State leases, which are included in the 21 BCF estimate). If 10% of onshore gas was effectively vented, and 30% of offshore gas was vented, then overall, about 13% of total (onshore plus offshore) vented or flared gas was effectively vented, in the U.S. in 1987.

Vented vs. flared in other countries

This 13% venting rate applies to crude oil produced in the U.S., but it does not necessarily apply to all the oil consumed in the U.S. because the U.S. imports roughly half of the oil that it uses, and the percentage of gas that is vented rather than flared will vary from country to country. In the main report, as part of the calculation of the average venting or flaring rate attributable to U.S. oil use, we assume venting percentages for each of the regions of the world. We assume in industrialized countries

the percent of vented or flared gas that is vented (or not burned in flares) is the same as in the U.S. However, we assume that in other countries, particularly in Africa, the percentage vented is higher -- perhaps as high as 20% -- because of looser regulations and enforcement and poorly functioning equipment. (Ideally, we would estimate separate "vented" fractions for onshore and for offshore production, and then weight these by the share of onshore and offshore production for each country, but data on onshore vs. offshore production are not readily available.) With these assumptions about the fraction vented or incompletely flared, and with separate CEFs assigned to each compound or class of compounds emitted (CH_4, CO_2, and NMHCs), one can calculate the CO_2-equivalent impact of gas emissions associated with the use of oil in the U.S.

METHANE EMISSIONS FROM COAL MINING

The processes that produce coal -- called "coalification" -- also produce methane and other gases. Some of this coalbed gas is stored in the coal bed itself. However, coalification produces much more gas than the coal itself can store. This excess gas migrates into the surrounding rock and sand strata, forming the "traditional" natural gas deposits mined by the natural gas industry. The formation of a ton of anthracite may generate 6,000 cubic feet of CH_4, and the formation of a ton of very high rank coal may generate up to 27,000 cubic feet (Ayers and Kelso, 1989; Thakur, et al., 1996) .

The gas retained in coalbeds ranges from a negligible quantity up to about 900 cubic feet per ton. The rate of gas release from coal mining, depends on several factors: the age, depth, and structure of the coalbed; the mining technique; and the rank and quality of the coal. Gas production increases with the depth of the mine and the rank of the coal (the higher the fixed carbon content of the coal, the higher the CH_4 content) (Deul and Kim, 1988; Kuuskra and Brandenburg, 1989) . Underground mines produce an order of magnitude more gas per ton of coal than do surface mines.

Most of the gas in mined coal is released when coal is depressurized to atmospheric pressure as it is exposed. Most of the remaining gas is released when the coal is cleaned, crushed, and prepared for final use. A small amount of gas remains in the prepared coal and is burned with the coal. In order to estimate the impact on climate of gas produced as a result of coal mining, we must know the rate of release of coalbed gas per ton of coal mined, and the fate of the released gas. Released coalbed gas may be:

i) Mixed with air and vented to the atmosphere.
ii) Collected, drained, and flared.
iii) Collected, drained, and sold as a fuel.[7]

[7]A small amount of the methane released by a coal-producing mine can be captured and used as a fuel at the mine. However, statements and data in Deul and Kim (1988), ICF (1990b), and DeLuchi (1991)

Compared to flared gas, vented gas has a greater impact on climate because a mole of CH_4 has a greater warming potential than does a mole of CO_2 and the gas recovered and used as a fuel can be viewed as a co-product of mining that may displace the production and use of other fossil natural gas. (If the methane marketed from coal mining displaces other fossil natural gas one-for-one, then it has no net impact on climate.) Thus, we estimate the CO_2-equivalent impact of emissions from coal mining as follows:

$$CBG_{CO_2} = (CBGR - CBGC - CBGF) \cdot \left(\sum_i MF_i \cdot CEF_i \right) + (CBGC \cdot (1 - DF) + CBGF) \cdot MF_C \cdot 3.664$$

$$CBGR = CBGRT_U \cdot P_U + CBGRT_S \cdot P_S$$

$$LET:$$

$$CBGC = CBGR \cdot K1$$

$$CBGF = CBGR \cdot K2$$

where:

CGB_{CO2} = the CO_2-equivalent impact of atmospheric emissions of coalbed gas.

CBGR = coalbed gas released by coal mining (but not necessarily emitted to the atmosphere).

CBGC = released coalbed gas that is captured and used as a fuel (see the discussion below).

DF = the fraction, of gas marketed as a fuel, that displaces other natural gas production and use (1-DF is the fraction that represent new net consumption) (see the main report).

CBGF = released coalbed gas that is flared rather than simply vented to the atmosphere (assumed, in the absence of any actual data, to be 5% of CBGR; i.e., K2 = 0.05).

MF_i = the mass fraction of gas i in coalbed gas (see the discussion of the composition of coalbed gas, below).

CEF_i the CO_2-equivalency factor for gas i (see the main report).

MF_c = the carbon weight fraction of coalbed gas (calculated from data on the composition of coalbed gas, discussed below).

3.667 = the ratio of the weight of CO_2 to C.

$CBGRT_u$ = the rate of release of coalbed gas per ton of coal from underground mines (see the discussion below).

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indicate that the amount of methane used as fuel at the mine is a minuscule fraction of the total amount produced and vented.

$CBGRT_S$ = the rate of release of coalbed gas per ton of coal from surface mines (see the discussion below).

P_u = coal production from underground mines (estimated from EIA historical data and projections for coal production (EIA, 1996b; EIA, 1994c)).

P_S = coal production from surface mines (estimated from EIA historical data and projections for coal production (EIA, 1996b; EIA, 1994c)).

In the following, we will discuss coalbed-gas releases from underground and surface mines, the fate of released gas, and the composition of the gas.

Coalbed gas releases from coal mining

Detailed estimates of total CH_4 releases from coal mining have been made only recently. Most estimates made in the 1980s, including those by Bolle et al. (1986) , Crutzen and Gidel (1983) and Rasmussen and Khalil (1984) were based on articles by Ehhalt and Schmidt (1978) and Ehhalt (1974) , which, in turn, referred to a NASA study by Hitchcock and Weschler (1972) . The NASA report used an estimate from Koyama (1963), which appears to be an original work. However, Koyama (1963) was concerned mainly with CH_4 from paddy fields; he estimated CH_4 emissions from coal mining in a one-sentence calculation in which he assumed that coal fields produce CH_4 at a rate of 21 cm^3/g of coal mined (p. 3973). This unredeemed, unelaborated, 1963 assumption was propagated through the literature for nearly three decades.

Recently, however, several original and detailed estimates have been made. (Note that most of the following are estimates of emissions to the atmosphere, not releases due to coal mining; as presented above, emissions are equal to releases less amounts captured and used as a fuel.) In 1990, ICF (1990b) estimated emissions from coal mining and use for every state in the U.S., as a function of the amount of coal mined, the mining technique, and the CH_4 content of the coal. The CH_4 content of the coal was estimated using data on the CH_4 content of various classes of coal, and the amount of coal production by class of coal. They also estimated emissions worldwide. They estimated that in 1987 coal mining resulted in emissions of 368 BCF of CH_4 in the U.S., and 2494 BCF worldwide, or about 400 SCF-CH_4/ton-produced in the U.S., and 492 SCF-CH_4/ton-coal-produced worldwide. They estimate that CH_4 emissions from coal mining worldwide will increase from 3788 to 4262 TCF by the year 2000 due partly to increasing coal production, together with an assumed increasing average mine depth, a factor that results in higher emissions per ton of coal produced.

In 1993, the EPA updated and expanded the ICF work, to estimate releases and emissions of coalbed gas in 1988. They used general assumptions to estimate releases from surface mines, but actually estimated releases from each underground mine in the U.S. They also estimated that 12 BCF of the released coalbed gas was captured and sold to gas companies in 1988. We have divided their estimates of total CH_4 emissions by

their estimates of total coal production, to produce a national average emission factor, shown in Table E-2.

Using an approach based on direct analysis of the CH_4 in 137 coal samples, Kirchgessner et al. (1993) estimated 1989 global CH_4 emissions from underground coal mines by developing two sets of regression equations. The first set of equations relates the total residual and desorbed CH_4 in a coal sample to its heating value, depth, moisture content, and fuel ratio (i.e. the ratio of fixed carbon to volatile matter). Two separate equations were estimated: one for coals with a heating value below 34,680 J/g and another for coals with a heating value above this value (the value was chosen based on a clear break-point in a graph of CH_4 content versus heating value). These equations are as follows:

(HV<34,680 J/g) $IS = 0.0159\ D + 2.2781/M^2 - 2.228$
(HV>34,680 J/g) $IS = 0.0136\ D + 0.0015\ HV + 2.6809\ FR - 56.4901$

where:

HV = coal heating value in J/g.
IS = in-situ residual + desorbed gas (cubic meters CH_4/tonne of coal).
D = depth in meters.
M = percent moisture content.
FR = fuel ratio (fixed carbon/volatile matter).

The estimation of these two equations produced R-squared values of 0.56 and 0.71 respectively (only variables that could be retained with 95% or greater confidence were included). The remaining step in estimating the total in-situ CH_4 content of the coal was to add a factor to account for the CH_4 "lost" between the time the coal was sampled and when it was placed in the sampling canister. Using data from various studies, lost gas factors were estimated for each of seven coal ranks: these factors ranged from 0.05 for high volatile bituminous, to 0.20 for medium-volatile bituminous. The total in-situ CH_4 content of the coal was then taken as the sum of residual, desorbed, and lost CH_4 Kirchgessner et al. (1993).

The second regression equation estimated by Kirchgessner et al. (1993) relates total mine shaft and gob well emissions of CH_4 to annual coal production, total CH_4 content of unmined coal, and a dummy variable based on the product of coal production and in-situ CH_4 content. This equation is as follows:

$$ME = 1.08\ 10^{-7}\ (CP \times IS) + 31.44 - 26.76\ (DV)$$

where:

ME = total emissions of CH_4 from mine shafts and gob wells (10^6 meters per year).
CP = annual coal production in tons per year.
IS = total CH_4 content of unmined coal (cubic meters CH_4/ton of coal).
DV = dummy variable (1 if coal production x in-situ CH_4 content < $7.6x10^6$, 0 if coal production x in-situ CH_4 content > $7.6x10^6$).

The R-squared value for this equation is 0.59, which indicates that nearly 60 percent of the variation in mine CH_4 emissions can be explained by these independent variables. Using these regression equations and the assumptions that 6.9 Tg/year of CH_4 are emitted globally from surface mines and 2.7 Tg/yr. are emitted globally from coal handling operations (assumptions based, respectively, on a single study of surface mine emissions and the unsupported assumption that 25 percent of the CH_4 in mined coals is released after the coal leaves the mine), a final estimate for 1989 global CH_4 emissions from surface and underground mining operations of 45.6 Tg (or 63,469 10^6 m^3) was obtained (Kirchgessner, et al., 1993) . The estimate for U.S. underground mines is shown in Table E-1, along with other estimates based on earlier studies.

The EIA's (1995b, 1997) analysis of emissions of greenhouse gases in the United States uses data from the EPA (1993) report and from other recent sources to estimate CH_4 emissions from coal mining. They estimate releases from surface mines and underground mines, and the amount of the release gas that is captured and used. Table E-3 presents details from their analysis. Table E-2 shows the EIA estimate for 1988, for comparison with the EPA's estimate. The EIA estimate for 1988 falls between the EPA's low and high estimates for 1988.

Finally, in 1992 the Coal Industry Advisory Board (CIAB) estimated global emissions of CH_4 from coal mining, based on 1990 production data (see Table 7 for the estimate for U.S. mines). The study estimated total CH_4 emissions from mining activity in ten countries, as well as the amount of coalbed CH_4 that can potentially be recovered. Thakur et al. (1996) report the results of this study, as well as estimating the amount of CH_4 actually recovered and used in 1994. According to the CIAB study, coal mining operations in China released the most CH_4, with emissions of over 405 BCF, compared to about 190 BCF emitted in the U.S. (Thakur et al., 1996). Meanwhile, actual recovery and use rates varied substantially among countries in 1994, with Germany, Austria, and Czechoslovakia having the highest use rates (relative to total emissions) of about 20-25%, the U.S. next with about 18% of total emissions recovered and used, and other countries following with usage rates of 5% to 10% (Thakur et al., 1996).

Our assumptions

We use the recent EIA (1995b, 1997, and more current estimates from the series) estimates of methane releases from coal mines, because they distinguish underground-

mine releases from surface mine releases (Table E-3), and clearly distinguish releases from emissions. For example, we provide separate estimates of the parameters CBGR and CBGC in our equation above. We start with their estimates of CBGRTu and CBGRTs in 1993, and then assume that CBGRTu increases 0.2%/year, on account of underground mines becoming deeper as the shallower coal is exhausted. (Recall that releases increase with depth.) We assume that CBGRTs remains constant.

Fate of methane releases from coal mines

Most released coalbed gas simply is mixed with air and ventilated to the surface. By law, the vented gas must contain less than 1% CH_4 (Kim, 1990), a concentration that is too dilute to burn. This coalbed gas may be counted as a net GHG emission from coal mining.

However, as noted above, some released coalbed gas is recovered and used as a fuel. Table E-3 shows the amount of released coalbed gas the EIA estimates to have been recovered through 1993. The amount of gas recovered has increased in recent years, and is expected to continue to increase. We assume that the amount of released gas that is recovered and used as a fuel increases by 3%/year[8].

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[8]U.S. coalbeds contain about 400 TCF of CH_4, of which at least 90 TCF are recoverable (Ayers and Kelso, 1989; Black, 1990, 1994). Under ideal conditions, 60 to 70 percent of the CH_4 from a coalbed can be recovered and used, but under more typical conditions the usable percentage is in the range of 30 to 40 percent (Thakur et al., 1996). However, some CH_4 that is recovered cannot be economically utilized, even for cogeneration or on-site heating, and is therefore vented after recovery. Thakur et al. (1996) suggest that while CH_4 recovery could reach 30% to 40% of total emissions, perhaps only 50% of the recovered CH_4 will actually be utilized.

Coalbed CH_4 research and development has grown considerably in recent years, and several large CH_4 recovery projects are operating, near-operating, or planned (Ayers and Kelso, 1989; Kuuskra and Brandenburg, 1989; Schraufnagel et al., 1990). In 1988, only 28 BCF of CH_4 were recovered from U.S. coalbeds and marketed, mostly in Alabama, Colorado, and New Mexico (EIA, 1989d). In 1989, 80 BCF were recovered and marketed, again mainly in Alabama, Colorado, and New Mexico (EIA, 1990A). However, in 1992 550 BCF, or over 3% of total natural gas supply, were recovered (Black, 1994), and in 1994 over 900 BCF were recovered (EIA, 1995c) some of the increase owing to methane recovery at four extremely gassy mines in Virginia (EPA, 1995c). By the year 2000, U.S. production could reach 1500 BCF (Petroleum Energy & Intelligence Weekly, 1992).

Still, there are several obstacles to large-scale development of coalbed methane. First, it is difficult to find highly permeable, productive spots in coal fields (Schraufnagel et al., 1990). Second, gas recovery is expensive. The recent rapid development of coal-bed methane was spurred by a 90cents/CF tax credit, which expired after 1992. The expiration of this credit apparently has dampened interest in producing coalbed methane, because fewer wells are being drilled in most basins. High gas prices or another public subsidy would spur interest again (Black, 1994). Third, environmental regulations -- for example, regarding the disposition of coproduced water -- might be restrictive (Schraufnagel et al., 1990). For these and other reasons, coal companies are reluctant to get involved . Petroleum & Energy Intelligence Weekly (1992) sums up the situation best: "...worldwide interest heralds a rich future for CBM, though it likely will take several more years before the true potential of many of these areas can be accurately gauged. And almost every region sports unique problems -- including scant finances, creaky

Composition of coalbed gas

In most analyses of greenhouse-gas emissions, coalbed gas is assumed to be 100% CH_4. However, coalbed gas does contain small amounts of other compounds, such as C_2H_6 and CO_2, which have different CEFs from that of CH_4. Typically, about 80 to 95 percent of coalbed gas is CH_4; the remainder being trace quantities of ethane, propane, butane, carbon dioxide, hydrogen, oxygen, nitrogen, and helium (Thakur et al., 1996). In this analysis we estimate the composition of coalbed gas, based on data in Deul and Kim (1988) (they show the composition of coal gas from 7 coalbeds) and multiply the mass of each compound emitted by its CEF.

METHANE EMISSIONS FROM HYDROPOWER RESERVOIRS

Flooded land at hydropower facilities can produce greenhouse-gas emissions, as inundated soils and organic matter degrade and their carbon content becomes mineralized to CO_2 and CH_4. (These emissions are analogous to emissions of CO_2 and CH_4 from natural processes in pristine lakes and wetlands.) The emissions, in grams-CO_2 equivalent/kWh-generated, can be estimated simply as the product of the emission rate per unit area (g-CO_2-equivalent/ha), and the areal intensity of power generation (ha/kWh). However, it is difficult to estimate any sensible average worldwide or U. S. emission rate, because areal emissions have been measured at a few sites (Gagnon and van de Vate, 1997). Also, the real intensity of generation can vary by orders of magnitude, from 1 to 1000 kW/ha or more (Ogden and Nitsch, 1993; Moreira and Poole, 1993)[9].

One study conducted on hydroelectric reservoirs in the boreal region of northern Quebec revealed that, over a two year period, emission fluxes of CH_4 to the atmosphere ranged from 5 to 10 mg/m^2/d. This study also concluded emission fluxes of CO_2

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infrastructure, and political uncertainty. But with the political status of gas rising steadily throughout the world, expect a bigger CBM push on an even more far-ranging basis" (p. 15).

An important clarification: the amount of "recoverable" coalbed gas discussed in this footnote is not the same as the amount of *released* gas that is recovered and used as a fuel. The latter refers to the recovery of gas that is released as a result of mining, whereas the former refers to the recovery of any gas from any coalbed, whether mined or not. The estimates in this footnote include recovery of gas from beds that either are unminable (because the coal is too deep, as in the San Juan Basin of Colorado), or are so gassy that they will not be mined unless the gas is removed. Hence the estimates of recoverable coalbed gas greatly exceed the estimates of the amount of gas released by mining and then recovered.

[9]It appears however that most plants are in the range of 4 to 40 kW/ha. The historical average in Brazil is 22 kW/ha (Moreira and Poole, 1993). The LaGrande complex in Quebec apparently produces 15-25 kW/ha (our estimate based on Gagnon and van de Vate, 1997). In the World Bank database, the range is from 4 kW/ha for small plants, to 30 kW/ha for large plants (Gagnon and van de Vate, 1997). In the U. S., the average capacity factor is 10-kWh/day/kW (EIA, 1996b) or about 40%.

ranged from 500 to 1100 mg/m^2/d (Duchemin, et al., 1995; see also Gagnon and van de Vate, 1997). Interestingly, emissions were found to be independent of the nature of the flooded substrate and the amount of time elapsed since inundation. Emissions of CH_4 were governed mainly by oxidation and advection processes in the water column. The authors conclude that the measured emission levels are significant, but much lower per unit of energy produced than those from thermal power plants[10]. In support of this, Gagnon and van de Vate (1997) estimate that the gross emissions from the Quebec reservoirs correspond to 34 g-CO_2-equivalent emissions of CO_2 and CH_4 per year.

Delmas et al. (2001) estimate that "gross" CH_4 emissions average about 2000 tonnes/year over 50 years from a 115 MW dam in tropical French Guinea. The dam has a typical output of about 560 gWh per year, so the emission rate per unit energy is about 4 g-CH_4/kWh. The CO_2 emission rate appears to be at least one order of magnitude higher.

Gagnon and van de Vate (1997) review the state of knowledge as of 1996, and speculate that the worldwide average might be on the order of 20 g-CO_2-equivalent/kWh-hydropower, including emissions from construction, which appear to be on the order of 5 g/kWh.

The studies and estimates cited above are of "gross" emission rates, without a deduction for the background or natural rate of emission in the absence of the hydropower reservoir. There is some indication that the emissions net of the no-hydro background are slightly less than the "gross"emissions.Kelly et al. (1997) measures emissions before and after flooding an experimental reservoir in Canada, and found that the emissions before flooding were an order of magnitude smaller than the emissions after flooding. If the emissions would have stayed at the pre-flood level had the reservoir not been flooded, then the net emission rate of interest -- the difference between post-flood emissions and what emissions would have been had there been no flooding -- is close to the measured post-flood ("gross") rate. In the Kelly et al. (1997) project, the experimental area, a boreal forest wetland of 17 ha, emitted approximately -200 mg/m^2/d CO_2 and 3 mg/m^2/d CH_4 before flooding, and 2000 mg/m^2/d CO_2 and 53 mg/m^2/d CH_4 after flooding. (The un-flooded wetland was a net CO_2 sink; hence the negative emission rate before flooding.) However, Delmas et al. (2001)

[10]This conclusion might not be correct as regards methane emissions. The data cited here and in Gagnon and van de Vate (1997) indicate emissions of 0.01 to 1.0 g-CH_4/kWh and 1 to 1,000 g-CO_2/kWh from hydropower plants, with central estimates of 0.1 g-CH_4/kWh, and 20 g-CO_2/kWh. Fossil fuel plants emit 0.001 to 0.110 g-CH_4/kWh and 500 to 1000 g-CO_2/kWh (calculated from data developed for this model, assuming a 34% generation efficiency). Thus, CH_4 emissions from hydropower plants might be comparable to or even greater than CH_4 emissions from fossil-fuel plants (per kWh), although CO_2 emissions will be less. However, this conclusion must be tempered by at least two considerations: i) one should deduct from the "gross" hydropower emission rate the "background" rate of emissions that would have been generated by un-inundated soil and riverbed; and ii) emissions from an existing hydropower plant are independent of the amount of power actually generated.

measured emissons from a tropical reservoir in French Guineau and estimaed that "net" emissions were 15 – 42% less than "gross"emissions (p. 999).

St. Loius et al.(2000) review data available in 2000 and estimate gross and net fluxes of CO_2 and CH_4 from surface reservoirs globally: 7 to $15 \cdot 10^{14}$ g/yr of CO_2, and about $0.7 \cdot 10^{14}$ g/yr CH_4. (The gross fluxes are similar to the net fluxes.) Assuming that only 50% of the total is from reservoirs that would not have been built were the production of hydropower not desired, and given $0.7 \cdot 10^{14}$ kWh of hydropower produced in 1999, the result is about 8 g CO_2/kWh and 0.5 g CH_4/kWh.

Clearly, before any definitive conclusions are drawn regarding overall greenhouse gas emissions from hydroelectric reservoirs, more research is needed on emissions from reservoirs in different latitudes, on emissions from areas with different soil and fauna characteristics, on relative emissions from inundated versus non-inundated areas, and on seasonal variations in emissions.

Nevertheless, on the basis of information presented above, and in Gagnon and Van de Vate (1997), we assume average "net" emissions of 0.3 g-CH_4/kWh, and 5 g-CO_2/kWh, excluding emissions from construction, which in our analysis are not accounted for any power generation facilities. We recognize that the estimates of Delmas et al. (2001) are at least an order of magnitude higher.

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TABLE E-1: RECENT SURVEYS, STUDIES, OR ESTIMATES ON THE RATE OF LEAKING NG TRANSMISSION AND DISTRIBUTION SYSTEMS

Organization (Reference)	NG lost, % of delivered NG			Comments
	Prod.	*Trans.*	*Dist.*	
Canadian Gas Association (1990)	0.25	0.018-0.082	0.03	Estimate for Canadian companies
Alphatania Group (1989)[a]	0 to 0.20	0 to 0.13	0.03 to 0.30	Survey of 28 companies worldwide
Arthur D. Little (1989)	0.53			Estimate for worldwide production
European gas companies[b]		0.005	<1.00	Higher loss in old dist. lines
Germany (Okken, 1990)	0.50			
PG&E (Cottengim, 1989)[c]		------ 0.14 -----		Mostly distribution losses
SoCal Gas (Mehskati, 1993)[d]		------ 0.12 -----		Mostly distribution losses
American Gas Association (1989a)[e]		0.0-6	0.28	Survey of U.S. NG companies
British Gas (Wallis,1991)			<1.00	Mainly from old cast-iron pipes
Swedegas (in Svensson, et al., 1991)	-------- < 1.00 --------			
Mitchell et al. (1990)		----- 0-0.5 ------		Post-1969 NG pipes in Britain
Mitchell et al. (1990)		---- 1.9 -10.8 ----		All NG pipes in Britain
EPA (1993)[f]	0.32	0.28	0.09	Detailed estimate for U.S. in 1990
EPA (1993)[f]	0.31	0.22	0.07	Year-2000 projection, high-gas use
Gas Research Inst. (in Lamb et al., 1995)	-------- 1.0 to 2.0 --------			For U.S. facilities
Radian Int'l LLC for EPA/GRI (1996)[g]	0.55	0.54	0.39	Detailed estimate for U.S. in 1992
EPA (1999) and EIA (1998) update[h]	0.52	0.54	0.38	Detailed revision of EPA/GRI (1996)

Notes:

[a] The Alphatania Group (1989), a consulting firm to the natural gas industry, asked for information on CH_4 leaks from "41 selected companies and organizations closely concerned with natural gas operations worldwide" (p. 3). They received responses from 28. The figure for distribution losses is for new systems; they estimated that up to 1% of throughput leaks from old distribution systems. This study was cited by the Canadian Gas Association (1990) and Wilson (1990).

[b] Communication from personnel at gas companies to Okken and Kram (1989) .

[c] Cottengim et al. (1989) call this the "most comprehensive analysis of unaccounted-for gas ever undertaken". The study investigated leakage (both intentional and unintentional), theft, metering inaccuracies, and accounting problems, for the PG&E transmission and distribution system in 1987. Intentional losses, such as from purges and valve operations, were determined from historical records and field surveys. Unintentional leaks from distribution systems were estimated for different categories of distribution pipe by field tests of different kinds of leaks. The transmission system was assumed to leak at "the highest conceivable rate". Losses from unintentional ruptures were estimated by multiplying an average (apparently historical) loss rate per rupture by the number of ruptures in 1987. Unintentional losses from distribution systems were 0.06% of the total; unintentional losses from transmission systems were 0.005%; losses from ruptures of any kind of system were 0.01%; losses from instrument usage, facility blow and purge gas, gas sampling, drip operations, relief valve operations, and miscellaneous operations were 0.065%. Actual losses were only 9% of all unaccounted for gas; the biggest source of unaccounted for gas was inaccuracies in orifice meters.

[d] SoCal Gas estimated the following "unaccounted for" (that is, not accounted for in normal gas accounting) gas losses to the atmosphere in 1991 (all units in MCF [one thousand cubic feet]): 15,580 from major and minor leakage from transmission systems; 58,039 from leakage from compressor packing seals on reciprocating and rotary compressors; 59,912 from pneumatic instruments, gas sampling and analysis, facility blow and purge gas, drip purging operations, and turbine engine starts; 622,160 from underground leaks from distribution systems; and 182,502 from unreported damage to distribution systems, for a total of 938,193 MCF (Meshkati, 1993). In addition, there were accounted-for losses from the transmission system and from major damage to the distribution system, and unaccounted for losses from natural-gas storage fields. We estimate that these additional losses were about 30% of the 938,193 estimated "unaccounted for" gas losses. The grand-total gas lost to the atmosphere was thus about 1.2 BCF, or 0.12% of the 1.048 TCF of sales by SoCaL Gas in 1991.

[e] The transmission companies claimed to be confident with their estimates; the distribution companies were less confident. (Leaks in high-pressure transmission lines are easier to identify than leaks in low-pressure distribution lines.) Shortly before this study, the AGA was estimating total leakage to be in the range of 0.2 to 0.3% (AGA, 1989b) .

[f] The column "Production" in this table includes leakage from field production, gas processing plants, and storage systems, among which leakage from field production is by far the largest emission source. Engine exhaust is not included here.

[g] The complete results of this study, in BCF methane emitted in 1992 in the U.S., are as follows (from EPA/GRI, 1996):

Natural Gas Emission Type	Production Segment (BCF)	Gas Processing Segment (BCF)	Transmission and Storage Segment (BCF)	Distribution Segment (BCF)	Total Natural Gas Industry (BCF)
Fugitive	24.0	24.4	72.1	74.7	195.2
Vented	53.8	5.1	33.0	2.2	94.2
Incomplete combustion	6.6	6.9	11.4	N/A	24.9
Total	84.4	36.4	116.5	77.0	314

In the GRI/EPA study, fugitive emissions are unintentional releases of methane from equipment leaks at sealed surfaces, and from underground pipes. Vented emissions are intentional releases of methane from pneumatic devices, dehydrators, chemical injection pumps (a minor source), and blowing and purging. Combustion emissions result from incomplete combustion of methane in burners, flares, and engines (mainly engines). In our estimation of the percentage leakage rate (discussed next), we exclude emissions from incomplete combustion, because we account for these emissions separately with an emission factor for CH_4 from compressor engines. (The total emissions implied by our CH_4 emission factors for natural gas engines, in the main report are consistent with GRI/EPA's estimates of emissions from incomplete combustion.)

The authors state that their final 1992 U.S. loss estimates of 1.4% of gross and 1.6% of net natural gas produced are believed accurate to within ±0.5%.

In 1992, the U. S. consumed 19,540 BCF of natural gas (EIA, 1996a) . Thus, we estimate that leakage from the production and processing segments = 0.55% of total NG consumption; leakage from transmission and storage (which we call transmission), 105/19540 = 0.54%; and leakage from distribution, 77/19540 = 0.39%.

Note that this study estimated emissions of methane only. Most likely, minor amounts of other constituents of natural gas, mainly ethane, nitrogen, and carbon dioxide, were lost along with the methane.

[h] Recently, the EIA (1998) and the EPA (1999) refined the EPA/GRI (1996) estimates for 1992 by using better data on numbers of wells, miles of pipeline, gas throughput, and so on. The ratio of the EIA (1998) to the original EPA/GRI (1996) estimates are: 0.92 for recovery, 1.0 for processing, 0.99 for transmission and storage, and 0.97 for distribution.

TABLE E-2: ESTIMATES OF METHANE EMISSIONS FROM U.S. COAL MINING

	10^9 SCF[a] CH_4	*10^6 ton coal*	*SCF-CH_4 /ton-coal*	*Year*
EIA (1995b)	220.2	950	231.7	1988
EPA (1993) low	172.3	950[b]	181.3	1988
EPA (1993) high	271.4	950[b]	285.7	1988
EPA (1993) low	193.1	1,125[b]	171.7	2000
EPA (1993) high	339.3	1,375[b]	246.8	2000
Kirchgessner et al.(1993)	193.2[c]	356[c]	542.7[c]	1989
CIAB (in Thakur et al., 1996)	190.9	931[d]	205.1	1990

n.e. = not estimated; SCF = standard cubic foot of gas; CIAB = Coal Industry Advisory Board; ton = English short ton (2000 lbs). The estimates here are of emissions, which do not necessarily equal releases. (In principle, emissions are equal to releases less quantities captured and used as a fuel.)

[a] The EPA (1993), the EIA (1995b), and Kirchgessner et al. (1993) report emissions in 10^{12} grams (teragrams). To obtain cubic feet of CH_4 we used the EPA's (1993) conversion factor of 52.2 billion cubic feet per teragram (19.2 g/SCF). Thakur et al. (1996) report emissions in millions of tons, which we then convert to cubic feet using 1,016,000 grams per ton and 19.2 grams per cubic foot.

[b] These amounts were taken from a graph in the EPA (1993) report.

[c] These figures are for underground mine production only. Kirchgessner et al. (1993), lacking sufficient data for a sophisticated analysis of emissions from surface mines, make the assumption that average emissions of CH_4 from surface mines are 1 cubic meter per ton of coal, or about 35 cubic feet per ton. Multiplying this emission factor by surface mine production and adding to the total shown for underground mines produces a result similar to the EPA (1993) 'High' estimate. Also, the reported estimate for underground mines in 1989 is very close to the EIA- based estimate for underground mines in 1989 (Table E-3).

[d] Thakur et al. (1996) report a 1990 U.S. coal production breakdown of 384 Mt from underground mines and 547 Mt from surface mines, for a total of 931 Mt.

TABLE E-3. EIA ESTIMATES OF METHANE RELEASES AND ATMOSPHERIC EMISSIONS FROM COAL MINING 1987-1996

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Methane released from underground mines (10^{12} g)	3.86	4.07	4.11	4.42	4.18	4.19	3.52	3.91	3.99	3.92
Methane released from surface mines (10^{12} g)	0.42	0.43	0.45	0.47	0.46	0.46	0.46	0.49	0.50	0.50
Methane recovered and sold (10^{12} g)	-0.25	-0.25	-0.25	-0.25	-0.25	-0.37	-0.48	-0.49	-0.50	-0.50
Methane recovered and sold (10^{9} SCF)	-13.1	-13.1	-13.1	-13.1	-13.1	-19.3	-25.1	-25.6	-26.1	-26.1
Methane recovered as fraction of gas released	-0.06	-0.06	-0.05	-0.05	-0.05	-0.08	-0.12	-0.11	-0.11	-0.11
Production from underground mines (10^{6} short tons)	372.9	382.2	393.8	424.5	407.2	407.2	351.1	399.1	396.2	407.7
Production from surface mines (10^{6} short tons)	545.9	568.1	586.9	604.5	588.8	590.3	594.4	634.4	636.7	655.2
Release rate from underground mines (SCF/ton)	540.3	555.9	544.8	543.5	535.8	537.1	523.3	511.4	525.7	501.9
Release rate from surface mines (SCF/ton)	40.2	39.5	40.0	40.6	40.8	40.7	40.4	40.3	41.0	39.8
Average emission rate (SCF/ton)[a]	229.0	233.5	229.4	235.4	230.1	224.0	193.2	197.5	201.6	192.5

From the EIA (1995b, 1997). SCF = standard cubic feet. The EIA reports amounts released or recovered in sold in teragrams; I convert this to SCF using the EPA's (1993) conversion factor of 52.2 billion cubic feet per teragram.

[a] Emissions are equal to releases less quantities recovered and sold.