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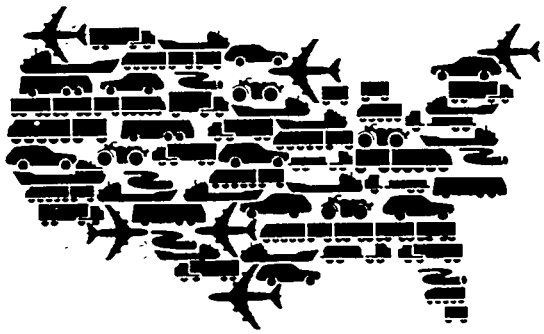
ANL/ESD/TM-22, Vol. 2

Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity

Volume 2: Appendixes A-S



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ANL/ESD/TM-22, Vol. 2

Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity

Volume 2: Appendixes A-S

by M.A. DeLuchi*

Center for Transportation Research, Energy Systems Division,
Argonne National Laboratory, 9700 South Cass Avenue, Argonne, Illinois 60439

November 1993

Work sponsored by
United States Department of Energy,
Assistant Secretary for Energy Efficiency and Renewable Energy,
Office of Transportation Technologies,
Assistant Secretary for Policy, Planning and Program Evaluation,
Office of Environmental Analysis,
United States Department of Transportation and California Department of Transportation,
University of California Transportation Center

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*DeLuchi is affiliated with the Institute of Transportation Studies, University of California, Davis.

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Acknowledgments

This report has benefited from reviews by (in alphabetical order): Frank Black, U.S. Environmental Protection Agency; Gene Ecklund, U.S. Department of Energy; Diane Fisher, Environmental Defense Fund; David Hall, Kings College, London; Tom MacDonald, California Energy Commission; Terry Renner, Amoco Oil Corporation; Dan Santini, Argonne National Laboratory (ANL); Mai Nguyen-Misra, U.S. Environmental Protection Agency; and Stefan Unnasch, Acurex Corporation. I am grateful to Carol Wouters, Florence Henning, and Marita Moniger at ANL for editing this document, and I especially thank Dan Santini for his management skills in overseeing the publication of this report.

Most of the research for this report was supported by a dissertation grant from the University of California Transportation Center, which is funded through the U.S. Department of Transportation and the California Department of Transportation. The U.S. Department of Energy provided funds for the research, review, editing, and publication process, through its Office of Transportation Technologies, which is in the Office of Energy Efficiency and Renewable Energy, and the Office of Environmental Analysis, which is in the Office of Policy, Planning and Program Evaluation.

The estimates made within this report are my own and do not necessarily represent values that are endorsed by any of the reviewers or sponsoring organizations.

Appendix A:

Review of General Methods

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A.1 The General Method: What Should and What Can Be Done

The point of comparing greenhouse gas emissions from different fuels is to determine the difference in emissions that would result from choosing one fuel over another and to compare the emissions from the chosen fuel with those representing the status quo. To estimate the greenhouse effect from using an alternative fuel instead of gasoline, one must define a baseline scenario in which gasoline is used and no alternative fuels are used, and compare it with a scenario in which alternative fuels and less gasoline are used. In principle, this process is not quite as straightforward as it sounds because choosing an alternative fuel would not necessarily result in a one-for-one substitution of the alternative fuel for gasoline, with no other changes occurring.

The problem is that using X gallons of any alternative fuel would do more than just displace the production and consumption of X gallons of gasoline. First, there would be price effects: the use of an alternative fuel would reduce the demand for gasoline, which would reduce the price of gasoline, which would thereby increase demand for gasoline by inducing more travel. (Of course, if the alternative fuel were to displace all gasoline and were to be the same price as gasoline, this situation would not occur.) Technically, the extra greenhouse gas emissions from the induced travel should be assigned to the alternative-fuel policy since these emissions would hypothetically not have occurred had the alternative-fuel policy not been adopted. On the other hand, the use of an alternative fuel could have countervailing price effects. For example, the use of domestic gas to make compressed natural gas (CNG) would raise the price of gasoline; higher prices should induce conservation and therefore reduce greenhouse gas emissions in other gas-using sectors.

Second, a change in gasoline demand will change refinery operations, and because all products (including gasoline) come from a single input (crude oil), a change in the output of one product would affect the price and quantity of other products. These changes in price and output of other refinery products (diesel fuel, jet fuel, residual fuel, etc.) would affect the use of these products and thus change greenhouse gas emissions. Again, these changes in greenhouse gas emissions should be assigned to the alternative-fuel policy.

Third, the alternative fuel would have different performance and range characteristics than gasoline, and these differences would probably affect how and how much people would travel. This change in travel would, in turn, affect emissions of greenhouse gases, and these changes in emissions should be assigned to the use of the alternative fuel, in comparison with the gasoline "business-as-usual" scenario.

One could find more indirect effects. Because petroleum is such an important part of the U. S. economy, a change in the price and availability of petroleum would have repercussions throughout the economy: it would affect fuel choice, energy conservation, the substitution of capital for labor, and so on.

Modeling the macroeconomic effects of fuel substitution is beyond the scope of this analysis. I have limited my effort to an engineering-type analysis, which assumes, in effect, that using X-miles-worth of alternative fuel B means not using, distributing, refining, transporting, and recovering X-miles-worth of gasoline and crude. This simplification should not be viewed as a poor attempt at macroeconomic projection, but rather as an answer to the question, "What would be the effect of a net elimination (after all the macroeconomic and consumer adjustments) of X-miles-worth of gasoline production and use and a net increase in X-miles-worth of production and use of alternative fuel B?" I think it is useful to have an answer to this question, even if the conditions that will make it realistic are not specified. The answer is useful because at very large levels of alternative fuel use, the dominant effect on energy use and emissions is likely to be first-order displacement of gasoline.

A.2 Structure of the Greenhouse Gas Emissions Model

I use a detailed energy use and emissions model to calculate emissions of carbon monoxide (CO), methane (CH_4), nitrous oxide (N_2O), nonmethane organic compounds (NMOCs), nitrogen oxides (NO_x), and carbon dioxide (CO_2) from the use of gasoline, diesel, methanol, natural gas (CNG and liquefied natural gas [LNG]), ethanol, electric, liquefied petroleum gas (LPG), and hydrogen (liquid hydrogen [LH_2] and hydride) vehicles. The basic output of the model is given in grams of CO_2-equivalent emissions per mile of travel by the vehicle. "CO_2-equivalence" refers to the combining of emissions of all the different gases into a single index, a procedure which is explained in Appendix O. The result for electricity is given in grams of CO_2-equivalent emissions per kilowatt-hour (kWh) of electricity delivered to end users and is embedded in the result for transportation fuels.

In virtually all cases, the model calculates grams of CO_2-equivalent emissions from stage s (e.g., oil recovery) of the fuel-production-and-use cycle from use of fuel f (e.g., diesel fuel), per mile of travel, as follows:

$$G_{s,f} = En_{s,f} \times Em_{s,f} \times M \qquad (A.1)$$

where:

$G_{s,f}$ = CO_2-equivalent emissions from stage s of the cycle for fuel f, in grams per mile of travel;

$En_{s,f}$ = energy use efficiency measure, in 10^6 Btu of process energy used at stage s of the cycle for fuel f, per 10^6 Btu of fuel f available to end-users;

$Em_{s,f}$ = CO_2-equivalent emissions, in grams per 10^6 Btu of process energy used at stage s of the cycle for fuel f; and

M = fuel available to the transportation sector, in 10^6 Btu per mile of travel.

Total greenhouse gas emissions per mile for the cycle for fuel f are simply the sum of the $G_{s,f}$ for all s, plus emissions from material manufacture and assembly. I discuss materials further in Appendix P.

The calculation of $En_{s,f}$, $Em_{s,f}$, and M is the main work of the model. The resultant $G_{s,f}$ values are shown in Table 9 in Volume 1 of this report. Table 3 in Volume 1 shows the values for En for the various fuels, and Table 6 in Volume 1 shows Em values. Table A.1 shows energy use in 10^6 Btu/mi for the alternative fuels relative to gasoline in the base case. Each of these is discussed in more detail next.

The one exception to the general calculation method represented by Equation A.1 is the calculation of CO_2 emissions from a natural gas-to-methanol or coal-to-methanol plant. In this

TABLE A.1 Relative Mile/10^6 Btu Fuel Economy of Alternative-Fuel Vehicles, Base Case

Gasoline vehicle (arbitrarily set to 1)	1.000
Diesel fuel vehicle (arbitrarily set to 1)	1.000
Methanol *mixture* in gasoline vehicle application[a]	1.150
Methanol in diesel vehicle application	0.970
NG in gasoline vehicle application	1.068
NG in diesel vehicle application	0.835
EV in gasoline vehicle application (EV energy from outlet)	3.473
Hydrogen (hydride) in gasoline vehicle application	1.062
Hydrogen in diesel vehicle application	0.947
Ethanol in gasoline vehicle application	1.140
Ethanol in diesel vehicle application	0.940
LPG in gasoline vehicle application	1.089
LPG in diesel vehicle application	0.849

[a] I assume that the relative efficiency of the methanol vehicle is proportional to the methanol volume content of the mixture.

Note: These values are calculated from the data in Table 2 in Volume 1 of this report.

case, CO_2 emissions are calculated as the difference between carbon in the input feedstock and carbon in the output fuel rather than as the product of an emission factor and a process-energy-consumption figure. However, emissions of non-CO_2 greenhouse gases from the plant and off-site emissions from the generation of electricity consumed by the plant are calculated as per Equation A.1. This calculation is explained in more detail in Appendix J on methanol.

A.2.1 Calculation of $E_{n,s}$: Process Energy per Unit of Fuel Energy Made Available to Consumers

The use of process energy at a stage of the cycle (e.g., feedstock recovery) per unit of fuel made available to the transportation sector is calculated in one of two ways, depending on the fuel. For coal and natural gas (NG), there are enough data on supply and disposition and the use of process energy at each stage of the extraction-to-use cycle to allow one to calculate, historically, how much of what kind of process energy is used at each stage and, for a given amount of fuel produced, how much ends up being available for end use in transportation. Thus, if one knows, for example, that in the United States in 1987, (1) X energy units of coal were produced, (2) Y energy units of coal were used to produce the electricity used at coal mines, and (3) Z units of energy of any kind (including the coal) were used in coal mining operations, then one knows that $Z/(X - Y)$ units of energy were consumed per unit of coal energy available for end use.

For methanol, hydrogen, ethanol, and synthetic natural gas (SNG), there are no such aggregate historical data on energy flows because these are quite minor fuels; consequently, the calculation must be done differently. For petroleum and uranium, there are aggregate data on the amount of process energy used at some of the stages of the cycle, but the cycles and outputs are more complex than those for NG and coal, and it is not possible to simply and directly calculate the amount of energy used at a stage of the process per unit of product fuel made available for end users.

So, for all fuels other than coal and NG including natural gas liquids (NGLs), the model first calculates the amount of process energy used to produce a unit of energy from that process, which is not necessarily the same as process energy per unit of fuel energy available to the transportation sector. The two will be different (i.e., the amount of fuel produced at any stage of the fuel-extraction-and-use system will not equal the amount that comes out of the system and is available to highway users) if, at any point in the entire fuel-extraction-and-use system, the fuel is used to process or transport itself. For example, the amount of SNG available to the highway transportation sector will be less than the amount produced if the gas is shipped via pipeline, because gas-fired pipeline compressors will consume some of the gas to run themselves, and electric-motor-driven compressors will probably draw some power from gas-fired stations. This "own use" must be accounted for.

The simplest way to account for "own use" is to multiply one ratio (process energy at stage X to energy produced at stage X) by another ratio (energy produced at stage X to energy ultimately available for consumption in the transportation end-use sector). For example, if fuel

system F uses $P_1 \times 10^6$ Btu of energy (none of which is from fuel F) to produce 1.0×10^6 Btu of F, and it uses $P_2 \times 10^6$ Btu of energy (all of which is from fuel F) to distribute 1.0×10^6 Btu of F, then the ratio of production energy to fuel available for *consumption* (call this ratio E_1) can be calculated as explained in the following steps.

1. Given that the ratio of the amount of fuel F consumed in the distribution stage to the amount of F out of the distribution stage (and available for consumption) is P_2:1, the ratio of F energy consumed in the distribution stage to F energy into the distribution stage (before consumption in the distribution stage) is $P_2/(1 + P_2)$.

2. The above ratio means that distribution consumes $P_2/(1 + P_2)$ units of every 1.0 unit of F out of the production stage and into the distribution stage, a fact that, in turn, means that $1.0 - P_2/(1 + P_2)$ units of F make it out of the distribution stage and are available for consumption, given 1.0 unit out of the production stage.

3. Consequently, E_1 — the ratio of F energy produced to F energy available for consumption — is $1/[1 - P_2/(1 + P_2)]$.

4. This expression simplifies to $1 + P_2$, and thus

$$E_1 = P_1 \times (1 + P_2).$$

The correct expression or the energy intensiveness of distribution, E_2, is simply P_2, since it was assumed that no own use occurs after the distribution stage.

If P_2 was given in terms of energy into the production stage (so that P_2 was the amount of energy required to distribute 1.0 unit of F, where the 1.0 included the amount P_2), then $E_1 = P_1/(1 - P_2)$, and $E_2 = P_2/(1 - P_2)$. This method is used to calculate own use for gasoline, diesel, and residual fuel.

In general, it can be shown that if P_i units of F are used to produce 1.0 unit of F at stage i (so that the 1.0 unit output from stage i and does not include the P_i), then:

$$E_i = P_i \times (1 + P_{i+1}) \times (1 + P_{i+2}) \times (1+P_{i+3}) \ldots$$

for linear systems with no loops or feedbacks.

A final note on own use: If a tanker truck delivering fuel X also burns fuel X itself (e.g., a diesel-burning, diesel-carrying truck), then whether or not the truck's use of fuel X must be counted as own use at the fuel distribution stage depends on where the truck gets its fuel. If it fills

up at service stations that are served by trucks, the truck's consumption of X must be counted as own use because, at some point, some other truck carries the fuel that the truck in question uses. Thus, in this case, if a diesel truck carries Y gallons of diesel fuel, about 0.99Y actually are available to end users outside the petroleum fuel system, because about 0.01Y will be used by other diesel-carrying trucks. However, if diesel-carrying trucks get their fuel at bulk terminals not served by trucks (bulk terminals are served primarily by pipelines and ships), none of the diesel carried by tanker trucks is used by the trucks themselves; all of it goes outside the system. Therefore, there is no own use to consider at the distribution stage.

Regardless of where the tanker gets its fuel, the tanker's use of fuel X must be counted as own use in all the preceding stages for fuel X (feedstock recovery and transport, refining, fuel distribution to the bulk terminal), because the fuel must be made, processed, etc. All that is at issue here is whether, in calculating the Btu of process energy/Btu of end-use energy intensity of the truck distribution stage, all or only nearly all of the fuel carried by a tanker counts toward Btu of end-use energy.

In practice, tanker trucks probably refuel at both service stations and storage terminals. In the analysis of the petroleum-fuel cycle, it was simplest to count all petroleum fuel consumed at the distribution stage as own use. To achieve consistency, I followed the same for own use of the other fuels at the distribution stage. Adopting a more complicated convention, in which some trucks use bulk terminals and some use service stations, would have no noticeable effect on the result: the grand total grams per mile figures would change by less than 0.01%.

I use many sources of data to calculate the amount and kind of energy used at each stage of the fuel production and use cycle. I discuss these sources and their use in the appendixes for particular fuels. Table 3 in Volume 1 shows the base-case calculated at 10^6 Btu of process energy/10^6 Btu of fuel to consumers used in this analysis. Table 5 in Volume 1 shows the breakdown of process energy, by type, at each stage of the fuel production and use cycle.

I have chosen to calculate process energy efficiencies or intensities (e.g., the energy requirements of coal mining or petroleum refining) from original data rather than finished estimates in the literature, because there are no comprehensive, up-to-date, detailed, and original estimates. One widely cited source (Aerospace Corporation, 1982, which is cited by DeLuchi et al. in *Transportation Fuels and the Greenhouse Effect*, 1987; Unnasch et al., 1989; and Ho and Renner, 1990) took its estimates of process efficiency for the NG cycle and for coal mining and preparation from a 1980 U. S. Department of Energy (DOE) report (Mertes and Hurwicz, 1980) and its estimate of the efficiency of the petroleum cycle from a 1979 Society of Automotive Engineers (SAE) paper (Alternate Fuels Committee, 1979). The 1979 SAE paper shows single efficiency numbers for each step of the petroleum cycle, with no details or references. The 1980 DOE report shows amounts and types of energy used at each stage of the fuel cycles: the data for petroleum refineries were taken from Haynes (1976, which is used as a source for this report, too); the data on energy use in the nuclear power cycle were from Rotty et al. (1975, also used here); the data for coal were from a 1976 research report; and the source of the NG data is not clear. Because more recent and disaggregated (and probably more reliable) primary data are available, I have calculated efficiencies and fuel use from scratch.

A.2.2 Calculation of $Em_{s,f}$: Grams of CO_2-Equivalent Emissions per 10^6 Btu of Process Energy Used

This is calculated as:

$$Em_{s,f} = \sum_e (Gr_e \times S_{e,s,f})$$

where:

$Em_{s,f}$ = CO_2-equivalent emissions, in grams, per 10^6 Btu of process energy used at stage s of the cycle for fuel f;

Gr_e = CO_2-equivalent emissions, in grams, from energy user e (e.g., train, tanker, pipeline compressor engine, tractor, coal-fired power plant) per 10^6 Btu of fuel consumed by energy user e; and

$S_{e,s,f}$ = total amount of energy consumed at stage s by energy user e, divided by total process energy consumed by all energy users, for the cycle for fuel f (in other words, S_e is the share of e of total process energy used at stage s).

The energy share data, $S_{e,s,f}$, are generally from the same sources that tell the total amount of process energy used at each stage of the cycle (amount of energy and kind of energy are usually reported together).

Grams of CO_2-equivalent emissions from each energy user are calculated from data on (1) the carbon and energy characteristics of the fuel used, (2) emissions of non-CO_2 greenhouse gases, and (3) emissions from the production, processing, and distribution of the process fuel itself. Table A.2 shows the calculated Gr_e.

$$Gr_e = CO2 + FC + \sum_i (G_i \times EF_i)$$

where:

CO2 = direct emissions of CO_2 from fuel combustion per 10^6 Btu of fuel consumed,

G_i = emissions of non-CO_2 greenhouse gas i (CH_4, N_2O, CO, or NMOCs) per 10^6 Btu of fuel consumed,

TABLE A.2 Greenhouse Gas Emissions from Trains, Trucks, Tankers, Pipelines, Tractors, Compressors, Wells, Engines, etc., Including Emissions from Making the Fuel, in Grams per 10^6 Btu of Fuel Input to the Device (except as noted)

Data	Diesel Trains[a]	Fuel Oil Tanker	Diesel Scrapers	Wheeled Loaders	Off-Road Trucks	Gasoline Tractor	Diesel Tractor[b]	Well Equip.	Gasoline Engine	Diesel Engine	Diesel Truck[c]	Methanol Truck[c]	Ethanol Truck[c]
Input													
CH_4	15.4	15.2	6.2	14.1	4.3	69.7	19.9	3.3	73.6	12.3	4.3	2.1	2.0
N_2O	2.0	2.0	2.0	2.0	2.0	10.0	2.0	2.0	10.0	2.0	2.6	2.5	2.4
NMHCs	147.5	136.4	87.7	150.6	64.1	513.4	218.2	42.5	689.4	133.5	88.9	220.3	187.3
CO	212.8	303.0	276.9	322.9	404.1	12112.1	389.2	425.2	14,638.6	333.9	466.4	545.5	528.7
NO_x	605.6	818.2	846.5	1051.5	936.5	561.0	1,095.6	1,635.3	379.0	1,535.3	348.3	337.8	327.4
Calculated results													
CO_2 combustion	71,566	74,188	71,678	71,386	71,558	47,872	71,053	71,595	4,333	71,428	NS	NS	NS
Non-CO_2	27,395	36,040	36,374	45,573	40,055	68,851	48,405	67,807	71,207	64,727	NS	NS	NS
Indirect energy[d]	15,0121	110,243	NE	NE	NE	NE	NE	NE	NE	NE	55,186	55,186	55,186
Making the fuel	15,964	15,474	15,964	15,964	15,964	24,956	15,964	15,964	24,956	15,964	15,964	0	0
Grand total	265,405	235,945	124,016	132,923	127,577	141,679	135,422	155,366	139,497	152,119	159,926	135,173	71,021

Data	Refinery Gas[e]	NG Turbine	NG Engine	Ethanol Plant[f]	Oil Refinery[g]	NG to MeOH[h]	Coal to MeOH[i]	Gasify Wood[j]	Wood Boiler[k]	Coal Boiler	NG Boiler	Oil Boiler	Petrol. Coke[l]
Input													
CH_4	1.3	11.2	723.5	0.2	0.4	0.4	8.3	1.8	8.1	0.7	1.3	3.0	0.0
N_2O	2.0	2.0	2.0	0.0	1.0	0.5	1.6	0.4	2.0	4.0	2.0	2.0	4.0
NMHCs	1.2	0.6	38.3	49.1	13.2	0.2	83.3	8.5	38.0	1.5	1.2	0.8	3.0
CO	15.4	49.9	187.5	42.5	8.8	1.4	7.2	60.5	271.6	13.0	15.4	15.2	30.1
NO_x	54.0	131.5	1451.5	0.0	2.8	66.9	55.6	16.9	76.1	2,27.6	54.0	152.4	225.9
Calculated results													
CO_2 combustion	56,029	53,509	51,223	0	496[m]	0[n]	0[n]	0[o]	0[o]	95,059	53,588	75,100	99,363
Non-CO_2	2,823	6,221	74,073	317	584	2,835	3,525	965	4,329	10,329	2,824	6,792	10,312
Indirect energy[d]	NE	9,133	9,133	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE
Making the fuel	0	11,115	11,115	NA	NA	NA	NA	NA	NA	9,060	11,115	15,474	NA
Grand total	58,851	79,978	145,544	317	1,079	2,835	3,525	965	4,329	114,449	67,527	97,366	109,676

Footnotes on next page.

TABLE A.2 (Cont.)

[a] The new Clean Air Act Amendments direct EPA to promulgate emission standards for locomotives and study whether emissions from other off-road sources should be controlled (EPA, *CAA*, 1990). I have assumed that emissions from locomotives will be reduced by 50% from the AP-42 level. I have not assumed reductions for any other sources.

[b] Diesel tractors are a proxy for all farm equipment (the actual factors are very close).

[c] The input emission factors are calculated from the data of Table B.2, to ensure internal consistency. For methanol and ethanol trucks, a zero is shown under "making the fuel," because I assume that (1) methanol-burning or ethanol-burning trucks deliver only methanol or ethanol, never diesel fuel, and (2) as discussed in the text above (with regard to the variable "FC" and double-counting, total greenhouse gas emissions from an energy user (such as a truck) include *only* direct combustion emissions and not fuel production and delivery emissions, if the fuel used by the energy user (in this case, the methanol or ethanol used by the truck) and the fuel being "processed" by the energy user (in this case, the fuel being carried by the truck) are the same. If one were to assume that methanol-burning trucks did deliver diesel fuel, however, one would have to include emissions from the production and distribution of the methanol used by those trucks *here*, because that production and distribution would not otherwise be accounted for in the crude-to-gasoline (or diesel) cycle of which the methanol-burning truck would now be a part.

[d] Emissions from energy used to build and maintain trains, tankers, trucks, and pipelines.

[e] I assume the same emission factors as those for natural-gas-fired industrial boilers.

[f] These are all emissions *other* than those from fuel combustion (which are calculated separately). Data are in units of g/10^6 Btu of products *output* from the plant. CH_4 emissions are from distillation and dehydration, and are calculated from data in USDOE, *Energy Technologies and the Environment* (1988). I assume that N_2O and NO_x emissions are produced only by fuel combustion; hence, zeros are shown here (this assumption is consistent with data shown in Sperling, 1988, and the DOE *Handbook*, 1983). CO and NMHC emissions calculated from data in Sperling (1988). I assume that the NMHC figure includes any ethanol emissions. See Appendix K.

[g] These are all emissions other than those from fuel combustion (which are calculated separately). Data are in units of gm/mmBtu of products *output* from the plant. Data on CO, NO_x, and NMHC emissions are based on the analysis in DeLuchi (1991), which uses AP-42, NEDS, NSPS, and other data to estimate controlled emissions in the year 2000. NMHC emissions include fugitive emissions, with controls. See Appendix M. Methane emissions are based on data from the Texas Air Control Board (1990), the South Coast Air Quality Management District (1990), and the EIA's *Petroleum Supply Annual*. See Appendix M. N_2O is my estimate.

[h] CO, NO_x, and NMHC emission factors are from Intech (1990). Those for N_2O and CH_4 are my estimates. See Appendix J. NO_x emissions from methanol plants are relatively high, perhpas becuase of the high temperature of steam reforming, about 1500°F. Low-temperature processes or processes using pure oxygen would have lower emissions.

[i] NMHC and NO_x factors are from Sperling (1988) for various gasification technologies. The CO factor is from Chadwick et al. (1987) for Texaco gasification. I estimate N_2O emissions from fuel combustion by using the emission factor for coal-fired industrial boilers and assuming that 20% of the input coal feed goes to the boilers (Paul, 1978; Salmon, 1986). I then assume that N_2O emissions from non-uel combustion processes are equal to emissions from fuel combustion. CH_4 emissions are estimated to be 10% of NMHC emissions. This estimate may be conservative, because CH_4 emissions from coal-burning power plants are more than 10% of NMHC emissions (Table D.4).

TABLE A.2 (Cont.)

[j] The NO_x emission factor is based on data in Sperling (1988; 10-190 g/10^6 Btu), the DOE *Handbook* (1983; 18 g/10^6 Btu), and DOE *Energy Technologies and the Environment* (1988; 53 g/10^6 Btu). All other emission factors, X_p, are estimated by scaling this NO_x factor by the ratio X_p/NO_x for wood boilers.

[k] All emission factors except the N_2O factor are from AP-42 for wood and waste boilers. These factors are used to estimate emissions from lignin combustion, in the wood-to-ethanol process. The NO_x emission rate shown here is well below the lowest NSPS for any industrial steam-generating unit (0.30 lb/10^6 Btu). The N_2O factor is my estimate. See Appendix K.

[l] Petroleum coke. From AP-42, third edition (1977). The latest edition does not have coke emission factors.

[m] This is CO_2 emissions from control of CO emissions from catalytic crackers. CO_2 emissions from the combustion of fuels used by the refinery (e.g., refinery gas, or fuels used to generate electricity) are calculated elsewhere, as the product of the amount of fuel used and the fuel's greenhouse gas emission factor. I assume no CO_2 is simply lost from crude. See Appendix H on petroleum for details.

[n] CO_2 emissions from the methanol plant are calculated elsewhere, as the difference between the carbon in the input feedstock and the carbon in the output fuel. See Appendix J for details. CO_2 emissions from the generation of any electricity used by the plant are calculated elsewhere, from data on the amount and kind of electricity used and electricity generation emission factors.

[o] Wood burners and ethanol plants do emit CO_2, but if the plant runs exclusively on biomass (and purchased electricity is ignored), all the CO_2 originally came from the atmosphere and so is not a net emission. Emissions from generation of any purchased electricity are counted separately.

Sources and notes: The CH_4, CO, and NMHC emission factors are from AP-42 and other EPA sources, except as noted. See the other appendixes for details. N_2O emissions from all sources that use diesel or fuel oil are assumed to be the same as N_2O emissions from fuel-oil power plants. Other N_2O emission factors are estimated on the basis of data discussed in Appendix N. With biofuels, the calculation of CO_2-equivalent emissions from CH_4, CO, and NMHCs includes a CO_2 credit; that is, the warming effect of the carbon removed as CO_2 via photosynthesis is deducted from the warming effect of the carbon emitted as CO, CH_4, or NMHC.

NA means not applicable, either because the emissions are not due to fuel use (e.g., emissions from some process areas in petroleum refineries) or because emissions from making the fuel are counted elsewhere. NE means not estimated. NS means that values are not shown here (but can be estimated from values in Table B.2).

EF_i = greenhouse-effect equivalency factor between CO_2 and non-CO_2 greenhouse gas i (Appendix O), and

FC = CO_2-equivalent emissions from fuel recovery, transport, processing, etc., per 10^6 Btu of fuel used by energy user e.

Data on the G_i are from the U. S. Environmental Protection Agency's (EPA's) *Compilation of Air Pollutant Emission Factors, Fourth Edition* (AP-42) and other EPA reports, and are discussed in Appendix M on emissions of methane and Appendix N on emissions of nitrous oxide and the appendixes on particular fuels.

The equivalency factors, EF_i, are derived in Appendix O.

The fuel-cycle emissions, FC, associated with the use of the process fuel, are calculated simply as FC = $\sum_s$, except end use $[En_{s,f} \times Em_{s,f}]$. To avoid double counting, FC is not included in the calculation of Gr_e if e uses fuel f. For example, suppose that it takes X energy units of coal and Y energy units of diesel fuel to produce all the crude oil, including the crude oil used to produce the Y units of diesel fuel, used in a particular year. To calculate the greenhouse gas emissions associated with this production of crude oil, I count emissions from the use of the coal, plus emissions from the recovery and transport of the coal, plus direct emissions from the use of the diesel fuel. However, I do not add emissions from the use of energy to recover the crude used to make the diesel fuel because, as just stated, that energy has already been accounted for: it is the coal and the diesel fuel itself. In other words, in steady state, Y units of diesel and X units of coal will yield all the crude needed, including the crude for the diesel fuel. So the energy used to recover the diesel does not need to be added; it has already been included in the coal and the diesel itself. Only direct emissions from combustion of the diesel should be counted. (There is additional energy required to refine the crude into the diesel used to recover the crude, but that energy is fully accounted for in the refining stage. In other words, in the refinery energy-use and emissions calculation, I start with that amount of energy required to refine all products, including products used to recover crude and refine crude. So, emissions from refineries that produce the diesel should not be added to direct diesel emissions in oil recovery because they are accounted for in the refinery stage.)

Note that there is a circularity here: Gr_e depends on FC, which depends on $Em_{s,f}$, which depends on Gr_e. This circularity is handled by iterative calculations in the model.

Finally, direct or combustion emissions of CO_2 are calculated simply as:

$$CO_2 = (C - C_i) \times 3.6666$$

where:

C = carbon, in g/10^6 Btu of fuel, and

C_i = carbon emitted as CH_4, CO, or NMOCs per 10^6 Btu of fuel.

Additional calculations, which I will not detail, are required to determine C and C_i.

A.2.3 Calculation of 10^6 Btu/Mile Efficiency of Vehicles

This last component is calculated first for gasoline and diesel vehicles, from miles-per-gallon (mpg) data input by the user. It is then calculated for the alternative-fuel vehicles, from data on the weight and thermal efficiency of alternative-fuel vehicles relative to gasoline and diesel-fuel vehicles. The calculation for the alternative-fuel vehicles (AFVs) is:

$$1/M_i = (1 + T_i)/(1 + Wf \times W_i/W_p) \times (MPG_p/D_p)$$

where:

M_i = efficiency of AFV i in 10^6 Btu/mi;

T_i = thermal efficiency advantage or disadvantage of fuel i when compared with petroleum fuel p,

Wf = % decrease in fuel economy per 1% increase in vehicle weight,

W_i = extra weight of AFV, i, compared with petroleum-fuel vehicle p,

W_p = total driving weight of petroleum-fuel vehicle,

MPG_p = efficiency of petroleum-fuel vehicle p in mpg, and

D_p = density of petroleum fuel p in 10^6 Btu/gal.

The estimation of these factors is discussed in Appendix B. Table A.1 shows base-case, calculated mi/10^6 Btu factors relative to gasoline and diesel.

A.2.4 Other Calculations

Sources of greenhouse gases not associated with the use of energy in the fuel production and use cycle are discussed here. The model includes detailed calculations of venting, flaring, or leaking of gas (mostly methane) from coalbeds, oil wells, and NG systems (Appendix M). It also calculates emissions from the manufacture and assembly of materials used to make vehicles (Appendix P). I examine, but do not include in the quantitative base-case results, energy used to make fuel production facilities, such as power plants and petroleum refineries (Appendix P). I include a rough estimate of the energy used to build, clean, repair, and maintain tankers, trains, trucks, and pipelines. I ignore the energy used to make the iron foundry that makes the steel for the, say, coal-fired power plant that provides power to the electric vehicle (and similarly for other third-order processes).

A.3 Higher Versus Lower Heating Values

In the literature and in personal communications, I find a growing concern about whether one should use higher or lower heating values for particular fuels in particular applications. This concern stems from the observation that the higher heating value, which includes the heat of condensation of water vapor, is not available to automotive engines because the water does not condense in the engine. On the face of it, this observation seems to suggest that one should use the lower heating value for transportation fuels.

I prove here that in a properly done analysis, the heating value does not matter at all; in fact, any heating value (higher, lower, or otherwise; indeed, any real number) for any fuel will always produce the same result. The concise demonstration of this proof is straightforward. Because the primary data used in this sort of analysis are never in thermal heating units (Btu or joules) but always in what I call "physical" units (grams, meters, miles, pounds, cubic feet, gallons, liters, and tons), and because the ultimate output is in grams per mile, it follows that one can do the entire analysis without ever using thermal heating units. If one does introduce a heating value, it must cancel out at some point, since there is no heating unit in grams per mile.

Let us explore this proof in more detail. What, ultimately, are the basic data — the ultimate observations — regarding the uses and characteristics of fuels? They are given in units such as tons of coal, barrels of oil, and standard cubic feet (SCF) of gas (where "standard" is defined unambiguously); pounds of carbon per pound of fuel and moles of carbon per moles of fuel; miles driven; and kilowatt-hours of electricity consumed. All these units are precisely, uniquely, and unambiguously defined. One can conduct the analysis entirely in these terms, without ever introducing a heating value. For example, let us consider emissions from the electric vehicle (EV) fuel cycle in which a coal-fired power plant generated power. We first need basic U. S. Bureau of the Census data on the amount of energy (in barrels of oil, SCF of natural gas, gallons of gasoline, and so on) required to produce one ton of coal. We can get data from EPA emission tests on how many grams of CO, NMOCs, NO_X, and CH_4 are emitted from burning a barrel of oil, SCF of gas, gallon of gasoline, etc., in a particular application. If we also get data on the carbon content (in pounds per barrel, pounds per SCF, etc.) of these fuels, we can calculate the amount of CO_2

emitted from burning these fuels to produce a ton of coal. By converting the non-CO_2 greenhouse gases to CO_2 equivalent emissions (Appendix O) and adding them to the CO_2 emissions, we get the CO_2-equivalent emissions of greenhouse gases emitted per ton of coal produced.

We can follow the same procedure for the coal transport stage, by using data on how many gallons of diesel fuel a train uses to transport one ton of coal one mile, how many miles the coal is transported, how much non-CO_2 greenhouse gases in grams per gallon is emitted from the train, and how much carbon is in the diesel fuel. The result is CO_2-equivalent emissions per ton of coal transported.

At the power plant stage, the fundamental item of data is not the efficiency of the power plant as a percentage but rather the observation that underlies the efficiency number: kilowatt-hour out per ton of coal in. On the basis of this kWh/ton value, pounds of emissions of non-CO_2 greenhouse gases per ton of coal input (EPA's basic emission unit), and pound of carbon/pound of coal, we can calculate CO_2-equivalent emissions. Now, however, they are in g/kWh produced from the ton of coal. All estimates in g/ton of coal can be converted into estimates in g/kWh out.

Finally, at the vehicle stage, the fundamental measurement is kilowatt-hour consumed at the outlet per mile of travel by the vehicle. If we want to derive the mi/kWh figure from the fuel economy value for a comparable gasoline vehicle, we simply compare the mi/kWh data for EVs with mpg data for the comparable gasoline vehicle (which is what I do here). With this mi/kWh figure, one can convert all estimates in g/kWh to g/mi. We now have an answer in grams of CO_2-equivalent emissions per mile of travel by the vehicle, without having ever used a thermal heating value.

Of course, if we want to display intermediate results in a common energy currency, we would have to introduce heating values. At some point, however, the heating values would cancel out. For example, let us return to the EV/coal power plant case. Suppose we want to show, as intermediate results, the amount of process energy (diesel fuel, NG, etc.) required to mine or transport one energy unit of the feedstock (coal, in this case). We would have to convert the ratio of SCF of NG per ton of coal to Btu of NG per Btu of coal, using Btu per SCF and Btu per ton values. If we were to work with these Btu/Btu values throughout the calculation (as I do here), we would have to apply a gram per 10^6 Btu of NG emission factor to the NG use in order to calculate emissions. But this g/10^6 Btu figure itself is calculated as the product of g/SCF and SCF/Btu data, so that the Btu/SCF cancels out.

g of CO_2 from NG/Btu of coal produced = (g/Btu of NG) × (Btu of NG/Btu of coal produced)
= [(g/SCF of NG) × (SCF of NG/Btu of NG)] × [(Btu of NG/SCF of NG) × (SCF of NG/ton of coal) × (ton of coal/Btu of coal)]
= (g/SCF of NG) × (SCF of NG/ton of coal) × (ton of coal/Btu of coal)
= g/Btu of coal.

This calculation procedure shows the cancellation of the heating value expression. The basic g/10^6 Btu unit (Table 6 in Volume 1) is calculated from g/Btu (Table 6 in Volume 1) and Btu/Btu (Table 4 of Volume 1) figures, as shown in the top line above. These figures, in turn, are built from heating values (SCF of NG/Btu of NG), the SCF of NG/ton of coal rate (e.g., the raw data from the U. S. Bureau of the Census), and the g/SCF of NG emission rate (from the EPA), as shown in the second line above. However, the SCF of NG/Btu of NG figure appears in the numerator and the denominator of the second line and hence cancels out the third line. Thus, in terms of the final g/Btu of coal result (last line), it does not matter what SCF of NG/Btu of NG heating value is used. (Of course, the heating value does matter in the calculation of the intermediate energy ratio in the second line.)

In the example above, Btu of coal is left in the denominator, but only because the calculation has not been carried through to g/mi. At some point (namely, at the power plant), one will have to convert back to physical units, using Btu-coal/ton-coal, and at this point the heating values for coal cancel.

In summary, two things are clear:

- In principle, the entire g/mi calculation can be made without using a single heating value.

- If one chooses to introduce heating values to express intermediate results on energy units but still begins and ends the calculation with nonheating value physical units and uses physical units as the primary data at all steps, it does not matter what heating values are used. The grams per mile results will be the same because the heating values must cancel out. (Of course, the intermediate energy ratios depend on the heating values chosen, but the point is that the final figure of interest, grams per mile, does not.)

It is also clear that if an analyst uses somebody else's Btu/ton-mile, energy-efficiency, or mi/10^6 Btu figures rather than physical units as input data for the calculation and does not check to see how these figures were calculated, the heating value used to calculate the Btu/ton-mile, etc., might not be the same as the heating value the analyst has used to get back to physical units. In this case, there will be an error (inconsistency) in the calculation.

The conclusion, then, is that one either should do the entire calculation from scratch by using physical units or make sure that any energy efficiency values used as input were calculated from the same heating values used throughout the rest of the calculation.

I have done this here. For example, I used physical emission factors for power plants, trains, ships, cars, refineries, etc., from EPA's AP-42. For power plant thermal efficiency (Btu/kWh), I used DOE's Energy Information Administration (EIA) values, which are calculated from the same higher heating values I use here. For the transport stage, I used Rose's (1979)

Btu/ton-mile values, which again are based on the same heating values I use. I calculated the relative efficiency of electric vehicles using mi/kWh data and mpg data for comparable cars. Whenever possible, I calculated relative thermal efficiency of internal combustion engine vehicles from physical units (e.g., SCF/mi versus mpg).

A.4 Carbon Dioxide Recovery and Disposal

It is possible to remove CO_2 from flue gas (or even separate the carbon from the rest of the fuel before combustion) and dispose of the carbon. I mention a few such schemes or analyses here.

The best discussions are provided by Shell International Petroleum (1990) and Hendriks et al. (1990). They show that most of the CO_2 can be recovered from coal-fired and gas-fired power plants and integrated gasification combined-cycle (IGCC) plants and disposed of in depleted natural gas fields at relatively modest cost (resulting in a $0.01-0.03 increase per kilowatt-hour of electricity).

Steinberg (1989) has described a HYDROCARB process for producing pure particulate carbon and a hydrogen-rich gas from carbonaceous raw materials. The raw material is hydrogenated to produce a methane-rich gas, which is thermally cracked to carbon particles and hydrogen gas. Minerals, oxygen, sulfur, and fuel nitrogen are removed. The hydrogen gas can be used as ordinary hydrogen fuel. The carbon black can be mixed with oil or water and used in conventional combustion applications, at a cost competitive with the current costs of petroleum distillates, or it can be stored as a solid as a way of sequestering or removing carbon.

The difficulty with the notion of CO_2 removal is disposal. Two disposal sinks have been suggested: drained gas fields and the deep ocean. However, not only are both of these finite sources, it is not clear that disposal in the deep ocean is permanent and otherwise ecologically neutral. In fact, it is likely that it is neither permanent nor neutral; the deep waters of the ocean reach the surface eventually, and it is not unlikely that at least some biological processes are related in some way to the CO_2 concentration of the deep ocean.

The message I am stating here is that making something and then trying to dispose of it is not the same as not making the thing in the first place. From a greenhouse perspective, a CO_2-disposal scheme should not be considered in the same light as, say, a solar energy scheme. Disposal schemes should not be seen as CO_2-elimination schemes.

Appendix B:

Emissions from Vehicles; Spills, Leaks, and Other Losses of Fuel; and Heavy-Duty and Light-Duty Emission Factors Combined

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Emissions from Vehicles; Spills, Leaks, and Other Losses of Fuel; and Heavy-Duty and Light-Duty Emission Factors Combined

B.1 Overview of CO_2 Emissions from Vehicles

Carbon dioxide (CO_2) emissions per mile are a function of the amount of fuel consumed per mile, the carbon content of the fuel, and the amount of the fuel carbon that is fully oxidized. The model calculates gram-per-mile (g/mi) CO_2-equivalent emissions from input and calculated data on the mi/10^6 Btu efficiency of the vehicles, the percent carbon in the fuel, the energy heating value of the fuel, the density of the fuel, and emissions per mile of non-CO_2 greenhouse gases. CO_2 is also produced by combustion of engine oil. This appendix analyzes the efficiency of alternative-fuel vehicles (AFVs) relative to petroleum internal combustion engine vehicles (ICEVs), emissions of non-CO_2 greenhouse gases, and emissions of CO_2 from engine oil. Fuel characteristics are discussed in Appendix C.

B.2 Relative Thermal Efficiency and Weight of Alternative-Fuel Vehicles

The model calculates CO_2 fuel emissions for baseline gasoline- and diesel-fuel vehicles, given the characteristics of the fuels and the efficiency of the vehicles. CO_2 emissions for the alternatives are calculated relative to the petroleum-fuel baseline by using data on the energy and carbon characteristics of the alternative fuels and the efficiency of the alternative-fuel vehicles relative to the gasoline- or diesel-fuel vehicles. The relative efficiency is a function of the relative thermal efficiency of the alternative fuel and the relative weight of the AFV. Recall from Appendix A on the review of general methods that:

$$1/M_i = (1 + T_i)/(1 + Wf \times W_i/W_p) \times (MPG_p/D_p)$$

where:

M_i = 10^6 Btu/mile efficiency of AFV, i;

T_i = thermal efficiency advantage or disadvantage of fuel, i, compared with petroleum fuel, p;

Wf = % decrease in fuel economy per 1% increase in vehicle weight;

W_i = extra weight of AFV, i, compared with petroleum-fuel vehicle, p;

W_p = total driving weight of petroleum-fuel vehicle;

MPG_p = miles-per-gallon (mpg) fuel economy of petroleum-fuel vehicle, p; and

D_p = 10^6 Btu/gallon density of petroleum fuel, p.

- *Thermal Efficiency (T_i).* Methanol, natural gas (NG), ethanol, and hydrogen can all be used more efficiently than gasoline in spark-ignition engines. However, with the possible exception of hydrogen, they are generally less efficient in single-fuel, heavy-duty engines than is diesel fuel. (The efficiency of electric vehicles relative to the efficiency of gasoline vehicles is calculated differently.) Below, in separate paragraphs for each fuel, data on T_i are reviewed.

- *Extra Weight (W_i).* The extra weight, W_i, is a function of relative fuel storage, range, power, and luggage-space requirements. These factors are analyzed for each fuel in the paragraphs below.

- *Decrease in Fuel Economy as a Function of Weight (Wf).* Several studies indicate that a 10% increase in vehicle weight causes a 5-7% decrease in efficiency, all else being equal. The calculation in DeLuchi et al. (1987) arrives at a 7% decrease for each 10% increase. Bussman's (1990) statistical analysis of U. S. Environmental Protection Agency (EPA) test data on fuel economy and vehicle weight shows that a 10% increase in weight leads to a 5.1% decrease in mpg. Amann (1990) finds that a 10% increase in weight causes a 5.7% decrease in efficiency for a fleet of cars with automatic transmissions, and Bleviss (1988) concludes that a 10% reduction in weight yields a 5.7-6.7% improvement in 55/45 combined-cycle economy. Here, I assume a 6% decrease in vehicle fuel efficiency for each 10% increase in weight.

- *Fuel Economy (MPG_p) and Driving Weight (W_p).* The mpg of the petroleum vehicle is an input variable that drives the rest of the calculation. The mpg of the base-case petroleum vehicle is meant to be the in-use, average mpg over the life of the vehicle in all driving conditions. This measure is comparable to the EPA's estimate of in-use combined city/highway mpg. I have assumed that in 2000, light-duty passenger vehicles less than five years old will average about 30 mpg in city/highway driving (on reformulated gasoline) and heavy-duty vehicles less than five years old will average about 6 mpg. These values are broadly consistent with several projections of fleet average and new-car fuel city/highway economy (EIA, *Assumptions for the Annual Energy Outlook 1990*, 1990; Energy and Environmental Analysis, 1989; Millar et al., 1985). (I specify "less than five years old" because, by 2000, most alternative-fuel vehicles will be less than five years old.) I emphasize, though, that the base-case mpg figures used here are not projections and have no special significance;

they are merely points of reference. In sensitivity analyses, I examine the effects of assuming different baseline mpgs.

All of the alternatives, except the electric vehicle (EV), are compared with the gasoline vehicle in combined city/highway driving (30 mpg). The electric vehicle is compared against the gasoline vehicle in city driving only because EVs will not be used for long highway trips. My analysis of EPA fuel economy tests indicates that a gasoline vehicle that gets 30 mpg for in-use city/highway driving gets about 24.5 mpg for in-use city driving. Therefore, the EV is compared with the baseline gasoline vehicle at 24.5 mpg (the same weight as in the 30 mpg case).

The base-case gasoline vehicle uses reformulated gasoline and has a range of 350 mi.

Given this baseline, petroleum-vehicle mpg, the model calculates the weight of the gasoline-fuel vehicle by using a statistical (descriptive) relationship between weight and fuel economy. By using a 905-vehicle sample from the EPA's 1990 mpg certification test results, Wang (1991) has estimated the following relationship:

$$W_p = 6675.54 - 167.57M_{p,u} + 1.49(M_{p,u})^2$$

$$R^2 = 0.800$$

$$\text{F statistic} = 1923.7$$

where:

W_p = inertial test weight of the petroleum-fuel vehicle (curb or empty weight plus 300 lb), in pounds, and

$M_{p,u}$ = the unadjusted, 55/45 EPA-certified fuel economy of the petroleum-fuel vehicle.

I have assumed that $M_{p,u}$ is equal to the in-use lifetime fuel economy divided by 0.8, where 0.8 represents a 20% difference between unadjusted EPA fuel economy and in-use values. Ross (1989) suggests that the EPA's 15% adjustment factor may be too low because of increasing congestion and other factors; the EIA, *Assumptions for the Annual Energy Outlook 1990*, uses a 20% adjustment factor. Refer to Table 2 in Volume 1 for base-case values.

As mentioned above, the weight and efficiency of the AFV are calculated relative to the baseline values for the petroleum-fuel vehicles. In other words, we are interested in the difference between the actual weight and efficiency of the AFV and the weight and efficiency of the petroleum-fuel vehicle that would have been bought or used instead. This point is quite important: the actual weight and efficiency of the AFV, which are a function of its actual performance and

range, are the relevant factors — not the weight and efficiency that the AFV would have if it had the same performance and range as the comparable petroleum-fuel vehicle. One should not estimate greenhouse gas emissions from performance- and range-equivalent vehicles if, in fact, the AFVs will not have the same performance and range.

Again, the actual weight and efficiency of the AFV, which are a function of its actual performance and range, should be compared with the weight and efficiency of the petroleum-fuel vehicle that would have been bought instead. These two factors are related, but not in a straightforward way. Consider range: for electric, hydrogen, and NG vehicles, increasing the range is very costly; for the comparable gasoline vehicle, it is virtually free and of little consideration, up to 300-400 mi. In the foreseeable future, EVs simply will not be built to have the 350-mi range that gasoline vehicles have, and gasoline-vehicle manufacturers will not try to sell gasoline vehicles with a very short range. This situation will occur because virtually no one would be willing to pay the extra cost (in dollars, handling, performance, and lost luggage space) of increasing the range of an EV to 350 mi, but virtually everyone is willing to pay the utterly trivial cost difference between a gasoline vehicle with a 100-mi range and one with a 350-mi range. Thus, EVs will have a much shorter range than the gasoline vehicles that would have been built in their stead. To model EVs with the same range as gasoline vehicles would yield inaccurate results.

The same sort of argument applies to compressed natural gas vehicles (CNGVs), especially dual-fuel vehicles, hydrogen vehicles, and fuel-cell vehicles. Most of these vehicles will not have the same range as the gasoline vehicle. Indeed, consumers will get less utility out of the AFV because of this fact, but it is important to note that this reduced utility has no obvious effect on greenhouse gas emissions. In a cost-benefit analysis, this lost utility is critical, but in a greenhouse gas analysis, it is irrelevant because the greenhouse gas emissions are determined by the physical characteristics of the vehicles and how the vehicles are driven, not by consumer utility. (Consumer utility determines market potential, and short-range vehicles may have a limited market. This situation is, however, irrelevant to the per-mile emissions of the short-range vehicles that are actually sold and used.)

With respect to performance (which bears indirectly on relative efficiency), the situation is structured analogously, but the results are different because there is less difference between the total cost (financial and nonfinancial) of increasing the power of an AFV and the total cost of increasing the power of a petroleum-fuel vehicle than there is between the cost of increasing the range of an AFV and the cost of increasing the range of a petroleum-fuel vehicle. Hence, it is possible that a vehicle manufacturer, had it not made a CNGV, would have made either (1) a gasoline vehicle with the same size engine and better performance than the CNGV, or (2) a gasoline vehicle with a smaller engine and the same performance, or (3) both kinds of vehicles (the gasoline vehicle with the same size engine will have better performance, in part, because it will weigh less). Furthermore, had the CNGV not been available, the consumer might have picked either kind of gasoline vehicle. The outcome will depend on how much more a bigger engine costs in the CNGV than in the gasoline vehicle (where cost includes effects on efficiency and range) and the consumer demand for power.

To put this in different terms: the power and especially the range supply-cost curves (where all costs are included) are different for different vehicles, so the consumer choice (the intersection of the consumer demand curve and the supply curve) will depend on the kind of vehicle. (One could also argue, plausibly, that the demand for power and range is a function of the type of vehicle, but this violates orthodox microeconomic theory.)

The preceding discussion is important because the results of this analysis definitely indicate that alcohol vehicles have a performance and range advantage over all other AFVs, and it might be tempting to correct the greenhouse-gas estimates to a performance- and range-equivalent basis. As just argued, such a correction would be wrong. The better performance and range of alcohol and petroleum-fuel vehicles make these vehicles more marketable, but these factors do not directly affect the difference in per-mile greenhouse gas emissions between these vehicles and the worse-performing AFVs that are actually sold. We are interested in greenhouse gas emissions from vehicles as they will likely be sold, and some AFVs will be sold with inferior performance and range.

B.2.1 Methanol Light-Duty Vehicles: Thermal Efficiency

The higher octane number, wider flammability limits, faster flame speed, and higher heat of vaporization of methanol, as compared with gasoline, will allow for a higher compression ratio, shorter burn time, and leaner-burn engine, and they can theoretically increase the fuel efficiency of a methanol light-duty (LD) engine by 25% or more, compared with gasoline (EPA, *Analysis of the Economic and Environmental Effects of Methanol as an Automotive Fuel*, 1989; DeLuchi et al., 1988; Sapre, 1988; Chevron, 1985). This theoretical potential has nearly been realized in recent tests with second-generation, lean-burn, optimized M100 vehicles from Toyota and Nissan, which have demonstrated efficiency gains of 12% and 19% relative to gasoline (Hellman and Piotrowski, 1990).*

Therefore, it is reasonable to assume that fully optimized, lean-burn, M100 vehicles with a high compression ratio can be 20% or more efficient than comparable gasoline vehicles. Most of this efficiency advantage is a result of their higher compression ratio and leaner operation compared with gasoline. However, the higher compression ratio and the leaner operation increase tailpipe emissions of nitrogen oxides (NO_x), all else being equal. The higher compression ratio increases

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* EPA tests (Hellman and Piotrowski, 1990) indicated that the Nissan methanol vehicle was 33% more efficient than the comparable gasoline vehicle provided by Nissan (the methanol and gasoline vehicle weighed the same and had the same gear ratio, but the methanol vehicle was more powerful). However, Nissan stated that it had done things to improve the efficiency of the methanol vehicle that perhaps could, in principle, have been done to the gasoline vehicle (things like using a low-friction piston design and low-friction engine oil). Nissan calculated that if one excluded the effect of these changes and counted only changes unique to the use of methanol (such as a higher compression ratio and leaner operation), the M100 vehicle would be 19% more efficient than the gasoline vehicle.

The issue is not settled, though, because Nissan implied that some of the changes it made to the methanol vehicle (but did not consider in arriving at its 19% efficiency advantage) may, in fact, be easier to make to methanol vehicles than gasoline vehicles.

the temperature in the combustion chamber, so engine-out NO_X emissions increase, and lean operation renders the reduction catalyst virtually useless. Given that the new Clean Air Act Amendments have mandated an 0.40 g/mi NO_X standard be phased in beginning in 1994 (EPA, *CAA*, 1990), the question becomes: can an advanced methanol vehicle have both a high compression ratio and lean operation (and thus be much more thermally efficient than a gasoline vehicle) and still meet an 0.40 g/mi NO_X standard?

Preliminary evidence indicates that it will be difficult for lean-burn methanol vehicles with a high compression ratio to meet the 0.40 g/mi, in-use 50,000-mi standard. In the recent EPA tests, the advanced lean-burn Toyota (11:1 compression ratio) emitted 0.49 g/mi NO_X at low mileage, and the advanced lean-burn Nissan (12:1 compression ratio) emitted 0.56 g/mi, also at low mileage (Hellman and Piotrowski, 1991). These vehicles will emit more in-use, and more at 50,000 mi. A lean-burn M100 vehicle (11.5:1 compression ratio) tested by Toyota emitted 0.40 g/mi at 0 mi but deteriorated to 0.70 g/mi at 30,000 mi (Tsukasaki et al., 1990). A lean-burn Toyota Corolla demonstrated low NO_X emissions (0.31 g/mi) at low-mileage (Yasuda et al., 1989), but NO_X emissions at high-mileage were not determined (this vehicle uses two catalytic converters). A lean-burn Toyota Camry emitted very high NO_X levels when run lean (CARB, 1988).

Current evidence indicates that methanol engines may have to forego either lean operation or a high compression ratio in order to meet an 0.40 g/mi NO_X standard. They will probably give up lean operation rather than the high compression ratio because running lean increases NO_X emissions much more than does increasing the compression ratio (the NO_X reduction catalyst, which in effect is trying to increase the concentration of oxygen in the exhaust stream, does not function in an oxygen-rich, or lean, regime), and because the high compression ratio also boosts power, whereas lean operation decreases power.

If methanol vehicles must operate at a stoichiometric air-fuel mixture in order to satisfy the 0.40 g/mi standard, they will forego a substantial part of the potential 20-30% efficiency gain. Chevron (1985) estimates that lean-burn alone improves fuel efficiency by 10%, so that a methanol vehicle operating at stoichiometric will be 10-20% more efficient than a comparable gasoline vehicle (rather than 20-30% more efficient). In support of this statement, I note that first-generation, non-lean-burn methanol vehicles generally have been less than 10% more efficient than their gasoline counterparts (DeLuchi et al., 1988; McGill and Hillis, 1988).

The Clean Air Act Amendments of 1990 require the EPA to study the cost and necessity of tightening tailpipe standards further, to perhaps 0.20 g/mi in the case of NO_X. It is very unlikely that a lean-burn methanol or gasoline vehicle will be able to meet a 0.20 g/mi in-use NO_X standard at 50,000 mi.

Finally, note that even if lean-burn methanol vehicles can meet a 0.40 g/mi NO_X standard, they will have a lean-burn efficiency advantage over gasoline vehicles only if gasoline vehicles cannot also operate lean and still meet the 0.40 g/mi NO_X standard, or if gasoline vehicles do not operate as lean as methanol vehicles (which is likely because of the lower lean limit of methanol

engines). It will be harder for lean-burn gasoline vehicles than for lean-burn methanol vehicles to meet the 0.40 g/mi NO_x standard because methanol's lower flame temperature, shorter burn time, higher latent heat of evaporation, and leaner lean limit result in lower engine-out emissions. (These factors probably more than compensate for the higher engine-out NO_x emissions caused by the higher compression ratio of the methanol vehicle.)

Preliminary studies indicate that it will be very difficult for lean-burn gasoline vehicles to meet a 0.40 g/mi standard. Diwell et al. (1988) tried to reduce NO_x emissions from lean-burn gasoline engines by maximizing NO_x reduction during rich transients and sustaining some NO_x reduction during lean steady-state operation. However, the catalyst converted only 10% of NO_x emissions during lean operation; overall, it reduced NO_x emissions only 20-30% compared with uncontrolled emissions — not nearly enough to bring emissions down to 0.40 g/mi. Held et al. (1990) experimented with different catalyst materials and selective catalytic reduction with lean-burn operation and converted up to 45% of NO_x emissions, but they concluded that NO_x emissions from lean-burn gasoline engines could not be brought to the level of emissions from a current stochiometric gasoline engine (meeting a 1.00 g/mi standard).

In summary, for a methanol vehicle to be 20+% more efficient than a gasoline vehicle, the methanol vehicle must be able, and the gasoline vehicle unable, to operate lean and still meet a 0.40 g/mi, in-use, 50,000-mi NO_x standard, and possibly a 0.20 g/mi NO_x standard. This situation is improbable, because it will be hard for both vehicles (albeit harder for the gasoline vehicle) to meet the standard and run lean. Therefore, I assume a base-case efficiency improvement of 15% for advanced, dedicated, non-lean-burn M100 vehicles meeting a 0.40 g/mi NO_x standard.

However, because relative fuel efficiency is such an important yet still uncertain variable, I consider higher and lower values in the scenario analyses. The higher value corresponds to a scenario in which advanced lean-burn vehicles are able to meet a stringent in-use NO_x standard and gasoline vehicles cannot.

B.2.2 Light-Duty Methanol Vehicles: Relative Weight

The relative weight of methanol vehicles will depend on how manufacturers and consumers handle the different range and power potential of methanol vehicles.

Consider power first. It is well-established, theoretically and in practice, that methanol LD vehicles will be about 15% more powerful than their gasoline counterparts because of the higher octane number and higher latent heat of vaporization of methanol (DeLuchi et al., 1988; Sapre, 1988). How these factors determine the weight difference between the methanol and the gasoline vehicle depends on whether the manufacturer would have built and sold a gasoline vehicle with the same size and weight engine (the gasoline vehicle performs worse than the methanol vehicle) or a vehicle with a larger engine providing equal performance. According to one manufacturer, the larger engine providing equal performance would weigh about 50 lb more than the methanol

engine. Hence, the potential power increase with methanol could result in either no change in vehicle weight or a 50-lb difference. If one believes that consumer demand is completely independent of industry offering and advertising (i.e., that consumers should have the same demand for power in the with-methanol and without-methanol scenarios), the 50-lb difference scenario is correct (the methanol vehicle weighs 50 lb less).

However, methanol vehicles will not go as far as gasoline vehicles on a gallon of fuel. If manufacturers build methanol vehicles to have the same range as the gasoline vehicles they would have built (i.e., if consumers are willing to pay for the small extra cost of maintaining gasoline-vehicle-type range in a methanol vehicle), the methanol vehicle tank will be about 50-60 lb heavier than the gasoline vehicle tank when full (Table 2 in Volume 1 of this report) and 30-40 lb heavier on average (assuming that the tank is 60% full and accounting for the constant extra weight of the tank itself).

Thus, there are four possible outcomes: two engine outcomes (the methanol engine weighs the same or is 50 lb lighter), permutated with 2 tank outcomes (the methanol tank weighs the same or is 30-40 lb heavier). I believe that it is most likely that methanol vehicles will be about 20 lb lighter than the gasoline vehicles that would have been sold instead. This 20-lb decrease will improve fuel economy by about 0.5%. This 0.5% is well within the uncertainty of the 15% thermal efficiency advantage estimated above, so it can be ignored.

B.2.3 Flexible-Fuel Methanol/Gasoline Vehicles

Flexible-fuel vehicles will show much less of an efficiency gain when they run on methanol, because their engines cannot be fully optimized for methanol. I assume a gain of 5% in the base case, because of the faster flame speed, lower flame temperature, and higher heat of vaporization of methanol.

B.2.4 Methanol Heavy-Duty Vehicles

Methanol can be used in heavy-duty (HD) engines in two basic ways: (1) with diesel fuel in an essentially unmodified, dual-fuel, diesel engine; or (2) in a modified, spark-assisted or spark-ignited, monofuel, methanol, HD engine (IEA, *Substitute Fuels for Road Transport*, 1990).

Dual-fuel engines must use mostly diesel fuel at start-up and part load because of the poor autoignition properties of methanol (unless excellent ignition-enhancing compounds for methanol are found). Because dual-fuel engines rely partly on petroleum, they are not as attractive from an energy security or environmental standpoint and are probably, at most, an interim step toward single-fuel engines. For these reasons, most research is focusing on methanol-only, heavy-duty engines. Accordingly, I do not establish and estimate a case explicitly for dual-fuel methanol heavy-duty vehicles (HDVs). However, the efficiency of methanol use in dual-fuel HDVs is likely

to be similar to the efficiency of methanol use in advanced, spark-assisted, monofuel methanol HDVs, and so the best case for spark-assisted methanol HDVs can be viewed as the base case for dual-fuel methanol HDVs.

Although most current-technology, spark-assisted methanol HDVs are less efficient (in some cases much less efficient) than their diesel HD counterparts primarily because of the lower compression ratio of spark-assisted engines compared with that of compression-ignition diesel engines (New York City, 1989; DeLuchi et al., 1988; Santini et al., 1989; King and Bol, 1988), the technology is still developing, and further engine optimization will improve thermal efficiency. Researchers expect improved methanol HDVs to be nearly as thermally efficient as diesel vehicles, except perhaps at low speeds in start-stop city driving (IEA, *Substitute Fuels for Road Transport*, 1990; Santini et al., 1989). The U. S. Department of Energy (DOE, 1990) projects that methanol HDVs will be only 3-5% less efficient than HD diesel vehicles. In support of these projections, Eberhard et al. (1990) recently reported that a 1988 glow-plug Detroit Diesel Corporation (DDC) methanol engine was roughly as efficient as its diesel counterpart in transient testing, and the International Energy Agency (IEA, 1990) reported that a German MAN stratified-charge, spark-ignited methanol engine is 5% more efficient than a comparable diesel engine.

If diesel-fuel vehicles have to use a trap oxidizer, the back pressure will reduce efficiency and improve the relative efficiency of the methanol vehicle. NO_x control down to the new CAA standard may also reduce efficiency.

On the basis of these considerations and the assumption that methanol is used heavily in buses (the new CAA amendments call for low-polluting fuels in buses), I assume that methanol HDVs will be almost, but not quite, as efficient as diesel HDVs, on average.

Finally, I assume that HD methanol vehicles will weigh the same as their HD diesel counterparts.

B.2.5 Natural Gas Light-Duty Vehicles: Thermal Efficiency

Natural gas's very high octane number (which allows for a high compression ratio), wide flammability limits (which permit lean operation), and gaseous state (which reduces fuel consumption during cold-start) can give it a large efficiency advantage when used in dedicated light-duty vehicles (LDVs) (DeLuchi et al., 1988, and EPA, 1990, *Analysis of the Economic and Environmental Effects of Compressed Natural Gas as a Vehicle Fuel*, Volume 1). However, NG has a slower flame speed than gasoline, which means that the heat release from NG combustion is more "spread out" over the piston stroke and less concentrated at or near top dead center, where the heat release is used most effectively. This factor reduces thermal efficiency. The use of fast-burn combustion chambers may be able to compensate partially for this.

Thus, a fully-optimized, lean-burn, fast-burn dedicated natural gas vehicle (NGV) with a very high compression ratio will be more thermally efficient than a stoichiometric gasoline vehicle, although probably not as efficient as a methanol vehicle. The thermal efficiency advantage could be as high as 20% (DeLuchi et al., 1988). Indeed, some engine tests with NG have shown large increases in thermal efficiency. Most vehicle tests have not; however, no advanced, lean-burn, fast-burn, electronically controlled vehicles have been built. The IEA (*Substitute Fuels for Road Transport*, 1990) estimates that NGVs should be 13.3% more efficient than gasoline vehicles, in part because of higher efficiency at warm-up.

The key issue, as with methanol, is the effect of the tight new NO_x standard on efficiency. It probably will be at least as hard for lean-burn, high-compression-ratio NGVs to meet an 0.40 g/mi, in-use 50,000-mi NO_x standard as it will be for methanol vehicles: the longer burn time and higher compression ratio of NG engines will increase engine-out emissions compared with those of methanol engines. Therefore, I assume in the base case that NGVs cannot operate lean. However, no one has built an optimized, lean-burn, fast-burn, low-NO_x engine (with, say, only a moderately increased compression ratio and with extensive use of exhaust-gas recirculation), and it is not impossible that an NGV could retain a substantial efficiency advantage and still meet the NO_x standard. I consider this possibility in a scenario analysis (as I do with methanol).

However, it is not even clear if an optimized NGV can operate at stoichiometry (as opposed to slightly rich) and with a high compression ratio (CR) and still meet the 0.40 g/mi standard. NGVs may have to forego a very high CR (and sacrifice performance and efficiency) to reduce engine-out NO_x, and NGVs may have to operate slightly rich to make the reduction catalyst more effective. (An NGV tested by Gabele [1990] had to be run slightly rich to reduce NO_x emissions because the NGV did not produce enough reactive hydrocarbons to aid reduction over the catalyst.) An NGV operated slightly rich and with the same CR as a gasoline vehicle would not be more efficient than a gasoline vehicle and could be less efficient, depending on the play of the opposing factors: rich operation and burn time (which is affected by chamber design) on the one hand, and warm-up efficiency on the other.

The lack of fully optimized, low-NO_x NGVs and the wide range of opposing theoretical considerations make it very difficult to estimate the relative efficiency of an NGV. In the base case, I assume that advanced, dedicated CNGVs will operate at stoichiometry, with a high-compression ratio and fast-burn combustion chamber and will achieve a 10% thermal efficiency advantage while meeting the 0.40 g/mi NO_x standard. Liquefied natural gas vehicles (LNGVs) will be slightly more efficient because of the cooling effect of liquefied natural gas (LNG).

B.2.6 Natural Gas Vehicles: Relative Weight

The extra weight of LD NGVs is a function of three factors: (1) the relative weight of the fuel storage equipment, (2) the relative weight of the extra vehicle structure needed to support the tanks or extend the vehicle to preserve trunk space, and (3) the relative weight of the engine.

Table 2 in Volume 1 documents the assumptions used here regarding the weight of the compressed natural gas (CNG) and LNG storage system. Fiberglass-wrapped aluminum tanks providing a 250-mi range in a high-mileage vehicle using CNG will weigh more than 100 lb more than the gasoline tank they replace (DeLuchi et al., 1988). Kevlar wrap would reduce the weight but would increase the cost. An LNG system would be only 50 lb heavier than an equal-range gasoline tank, which is one of several advantages of using LNG as a fuel.

Note that the weight of the NG storage system is a function of the assumed range of the vehicle. Because the weight of the CNGV is sensitive to the range, I consider lower and higher ranges in a scenario analysis.

The CNGVs will either have less trunk space than the comparable gasoline vehicles or they will be extended, and thus made heavier, to accommodate the CNG tanks. I expect that CNGVs will have less trunk space (again, this will affect their marketability, but not their relative greenhouse gas emissions). LNG systems do not have so great a disadvantage in this regard since they are half the size of CNG systems for a given range and weigh about the same as methanol tanks (DeLuchi et al., 1988).

The CNG storage system weight factor in Table 2 in Volume 1 includes the weight of mounting brackets and modest structural reinforcement to the vehicle.

The last weight factor in the LD NGV analysis is the engine. It appears that a fully optimized, single-fuel LD CNG engine with a very high compression ratio, fast-burn chamber, and improved breathing characteristics will be at least as powerful as an equal-weight gasoline counterpart (DeLuchi et al., 1988). However, overall performance is a function of weight as well as vehicle power, and CNGVs will weigh about 5% more than gasoline vehicles. Thus, CNGVs will, in the best case, offer performance comparable to the gasoline vehicle with a similar weight engine. In any case, the dedicated, optimized CNGV is not likely to perform so much worse than the gasoline vehicle that it would be worth worrying about what size gasoline engine would have been built and bought in the no-CNG scenario. Thus, in the base case, I assume no significant weight difference on the engine side.

However, if the CNGV cannot use a very high compression ratio because of the tight new NO_x standard, the difference in power may become significant enough that the purchaser might have bought a gasoline vehicle with a significantly smaller engine, had he not bought the CNGV. I consider this in a scenario analysis.

The LNGVs have another advantage: less fuel storage weight for the engine to compensate for, on the one hand, and an inherently more powerful engine because of the charge-condensing effect of cold LNG, on the other. Therefore, it is possible that an LNG engine could be slightly lighter than a gasoline engine providing the equal acceleration. In the base case, I assume no extra weight in the engine compartment for LD LNGVs.

B.2.7 Dual-Fuel Natural Gas/Gasoline Vehicles

I assume that dual-fuel NG/gasoline vehicles will be as thermally efficient on NG as a dedicated gasoline vehicle on gasoline (i.e., no efficiency gain or loss). I assume that a vehicle has a 150-mi range on CNG and estimate the weight increase accordingly.

In the base case for dual-fuel, I do not make any adjustments for the lower power of dual-fuel vehicles on CNG because dual-fuel vehicles will most likely have less power when on CNG and be used by people who are willing to tolerate the power loss in order to be able to use CNG. (If this were a cost-benefit analysis, it would be important to account for the power loss, but in a greenhouse analysis, it is not important (if people simply are tolerating the power loss) because, as discussed above, emissions depend on the performance characteristics of the vehicles actually sold and used, not on consumer valuation of the characteristics.)

It could be argued, however, that the consumers who use dual-fuel CNG vehicles would have bought a dedicated gasoline vehicle that would have been much less powerful than the actual gasoline version of the dual-fuel vehicle, and hence that the dual-fuel vehicle would have a bigger, heavier engine than the gasoline vehicle they would have bought. This argument would be true if three conditions were met: (1) if the consumer were choosing between a dual-fuel vehicle and a dedicated gasoline vehicle (because if the consumer were deciding whether to convert a vehicle he or she already bought, and if he or she had not considered conversion at the time of purchase, then the engine size would be the same whether the consumer ends up with a dual-fuel vehicle or not); (2) if the dedicated gasoline vehicle were to come with a range of engine sizes, with all else being equal; and (3) if the consumer was not willing to pay much for extra power in a dedicated gasoline vehicle. In this scenario, the dual-fuel engine would be heavier than the dedicated engine that would have been bought. I consider this in a scenario analysis.

Finally, I note that it is not reasonable, in any case, to model the dual-fuel CNG vehicle to have the same range on CNG that the comparable dedicated gasoline vehicle has on gasoline. The dual-fuel CNG vehicle simply will not have the same range on CNG, and the greenhouse gas emissions from the gasoline vehicle that would have been bought (or remain unconverted) are not sensitive to range (see discussion above).

B.2.8 Compressed Natural Gas Heavy-Duty Vehicles

In spark-ignition, heavy-duty engines, CNG can be used in place of either gasoline in spark-ignition HDVs or diesel-cycle HDVs. A CNG spark-ignited HDV will be more thermally efficient than a spark-ignition HDV primarily because of the higher compression ratio possible on CNG. However, a CNG spark-ignited HDV will be less thermally efficient than a comparable diesel-cycle engine because the diesel cycle uses a higher compression ratio. In a recent analysis, the EPA (1990, *Analysis of the Economic and Environmental Effects of Compressed Natural Gas as a Vehicle Fuel*, Volume 2) projects that an optimized, lean-burn, spark-ignited NG HD engine will be 25% less thermally efficient than a comparable diesel-cycle engine. However, other

investigators estimate a lower efficiency loss: Goetz et al. (1988) report an 18% drop with bus engines, Lawson (1988) reports a loss of 10-20% for a Cummins L10, and unpublished EPA data indicate a loss of 13%. Similarly, Rele and Seppen (1990) and Klimstra (1990) remark that gas engines are 15% less efficient than diesel engines.

Natural gas, like methanol, can be used with diesel fuel in dual-fuel HD engines. Diesel fuel is used to start the engine and is the primary fuel at part load. Because of this reliance on diesel fuel, dual-fuel NG HDVs are not as attractive as single-fuel, spark-ignited NG HDVs with respect to environmental considerations or energy security. Most work in the United States is on the single-fuel use of NG in HDVs. Consequently, I do not establish and estimate a case for dual-fuel NG HDVs. However, assuming that the efficiency of NG use in dual-fuel HDVs will be similar to the best-case efficiency of NG use in optimized single-fuel engines, the best case for single-fuel NG HDVs can be viewed as the base case for dual-fuel NG HDVs.

For a heavy-duty NG vehicle, the change in weight due to redesigning and resizing the engine for an alternative fuel would be so small, relative to total vehicle weight, it would be insignificant. Therefore, I have ignored the weight differences associated with HD engines. For CNG heavy-duty vehicles, I have included the effects of the extra weight of the storage tanks. If LNG is used (LNG is a perfectly viable fuel for HDVs) the weight increase will be as it is inconsequential as it is with methanol.

B.2.9 Ethanol Vehicles: Relative Thermal Efficiency and Weight

Ferchak and Pye (1981, Part II) cite seven studies that show that a gallon of ethanol can drive a vehicle as far as a gallon of gasoline. This implies that ethanol use is about 45% more thermally efficient than gasoline use, a figure which seems improbably high, even for fully optimized vehicles (I have not consulted the original references). Lynd (1989) cites several studies that estimate a 23-40% advantage for methanol and, in more recent work, reports that ethanol is expected to be slightly less efficient than methanol. Wyman and Hinman (1990) cite vehicle tests that indicate an advantage of about 20%.

Recently, the EPA (1990, *Analysis of the Economic and Environmental Effects of Ethanol as an Automotive Fuel*) analyzed the relative efficiency of ethanol engines and concluded that ethanol vehicles should show nearly the same overall efficiency improvement over gasoline that methanol vehicles show, up to 30%. Methanol will have a slight 1-2% absolute advantage over ethanol: the stoichiometric combustion of methanol results in a higher post-combustion pressure than does the stoichiometric combustion of ethanol because of the greater number of gaseous moles formed by methanol combustion. I follow the EPA and Lynd (1989) and assume that ethanol vehicles are nearly as thermally efficient as methanol vehicles. I also assume that, like methanol vehicles, ethanol vehicles will weigh roughly the same as the gasoline vehicles they replace. I also assume that ethanol will be similar to methanol in heavy-duty applications.

B.2.10 Electric Vehicles

B.2.10.1 General Information

The mile/10^6 Btu energy consumption of electric vehicles is calculated as:

$$E_{ev} = E_g \times E_b \times E_r \times W \times R_p$$

where:

E_{ev} = mi/10^6 Btu efficiency of the electric vehicle (counting from the outlet, using 3412 Btu/kWh);

E_g = mi/10^6 Btu efficiency of the gasoline vehicle;

E_b = energy out/energy in efficiency of the battery;

E_r = energy out/energy in efficiency of battery recharging;

W = factor to account for the extra weight of the electric vehicle;

R_p = mi/10^6 Btu battery-to-road energy consumption of the EV divided by the mi/10^6 Btu gasoline-tank-to road energy consumption of the ICEV in urban driving when the weight difference between the EV and the ICEV is netted out .

These variables are treated as follows:

The variable E_g is calculated from the baseline mpg of the gasoline vehicle (24.5 mpg in city driving, not 30 mpg in combined city/highway driving).

The variables E_b and E_r depend on the battery; typical values for sodium/sulfur batteries are 0.75 and 0.92 (DeLuchi et al., 1989; Auxer, 1991). The effect of varying these is considered in sensitivity analyses. (For example, developers of the Na/S battery project higher performance and efficiency values for the year 2000 than those used here.) For general discussions of advanced batteries, see DOE (1990), Shemmans et al. (1990), Sera et al. (1990), and DeLuchi et al. (1989).

Continual shallow discharging of batteries may reduce their efficiency (USDOE, August 1990). Hence, if most EV owners recharge their batteries after driving only a few miles, if advanced batteries lose efficiency after repeated shallow discharging, and if there is no technical

way to prevent the loss of efficiency due to shallow discharges, then average battery efficiency may be less than is estimated here. I consider this situation in a scenario analysis.

The variable W is calculated from the extra weight of the vehicle and the factor relating extra weight to efficiency. The extra weight is calculated from data on the energy density of the battery and the desired range. A separate EV model is used for this calculation; some details of this model are given in DeLuchi et al. (1989). The resultant extra weight is shown in Table 2 in Volume 1.

The variable R_p, which is the ratio of mi/10^6 Btu vehicle energy consumption in urban driving, is an important variable. The best way to estimate it is to compare the mi/10^6 Btu efficiency of EVs with that of comparable ICEVs, netting out the effect of weight (which is captured separately by W). Because the greenhouse standing of EVs relative to ICEVs depends so much on the relative energy consumption of the EV and the ICEV, one must analyze R_p as carefully as possible. Table B.1 shows such a detailed analysis of R_p, calculated as:

$$R_p = (EV_{eff} \times (0.4 + 0.6EV_{wt}/ICEV_{wt})/3412)/(mpg/125{,}000)$$

where:

EV_{eff} = mi/kWh energy consumption from the battery terminals (Table B.1),

0.6 = 6% increase in efficiency for each 10% decrease in weight,

EV_{wt} = test weight of the EV (Table B.1),

$ICEV_{wt}$ = test weight of the ICEV (Table B.1),

3412 = Btu/kWh,

mpg = fuel economy of comparable gasoline vehicle (Table B.1), and

125,000 = Btu/gal of gasoline.

I choose my base-case value of $R_p = 5.7$ (for city driving) on the basis of the results in Table B.1. I study the effect of changing this variable in sensitivity analyses. An R_p of about 5.7 is consistent with an ICEV engine-and-drivetrain efficiency of 14% and an EV motor-and-drivetrain efficiency of about 80%, which are typical values (see note o, Table B.1).

In the base case, I compare the efficiency of EVs in urban driving with the efficiency of ICEVs in urban driving because EVs are likely to be used primarily for short trips in urban or

TABLE B.1 Ratio of Energy Consumption of Electric Vehicles to Energy Consumption of Comparable Internal Combustion Engine Vehicles for City Driving

EV					ICEV				Result (R_p)	
	Energy Cons. (mi/kWh)					Energy Use				
Type of EV	Battery	Outlet	Test[a]	Test Wt.\ Battery Wt.	Vehicle Comparable to EV	Test Wt.	mpg	Test	Vehicle Efficiency EV/ICEV	Notes
ELVEC-EV	(4.13)	2.79	SAE D	3,600\992	Subcompact	2,300	33.0	FUDS	6.1	b
Audi	2.30	1.38	City	4,630\1,100	Audi 100	3,500	16.8	City	6.0	c
ETV-1	3.41	- -	FUDS	3,960\1,090	'79 Ply. Horizon	2,500	27.6	FUDS	6.1	d
ETV-2	3.14	- -	FUDS	3,920\1,066	'79 BMW 320i	2,750	26.0	FUDS	5.6	e
Yr 2000 EV	(4.63)	3.33	SAE D	2,560\400	Year 2000 ICEV	2,110	35.6	FUDS	5.4	f
City STROMer	3.51	2.07	SAE C	3,671\ --	'85 VW Golf GTI	2,500	28.3	FUDS	5.8	g
Griffon van	(1.66)	1.03	Urban	6,775\2,500+	'84 GMC vans	4,200	17.5	FUDS	4.8	h
4-seat BMW	(3.73)	2.35	ECE	3,600\584	'86 BMW 3 series	3,100	27.0	Comb.	5.6	i
ETX-I	2.99	- -	FUDS	3,800\1,237	'83 Ford Escort	2,500	28.0	FUDS	5.1	j
ETX-II	2.5	- -	FUDS	4,500\1,100	'88 Ford Aerostar	3,500	18.0	FUDS	6.0	k
G-van	1.77	- -	SAE D	7,780\2,540	'89 GM G-van	4,750	17.0	FUDS	5.3	l
TEVan	3.31	- -	FUDS	4,948\1,770	'89 T115 minivan	3,500	23.0	FUDS	6.6	m
DSEP	2.58	- -	FUDS	5,300\1,600	'89 stretched T115	3,850	20.0	FUDS	5.8	n
Average:									5.7	
Average without highest and lowest values:									5.7	
Ratio based on component-by-component efficiency:									5 to 6	o

EV battery efficiencies shown in parentheses were calculated by dividing the reported efficiency from the outlet by the combined efficiency of the charger and the battery, as reported in the reference.

Battery weight is included so that one can check if EV test weight less battery weight is close to ICEV test weight, which it should be.

[a] FUDS is the Federal Urban Drive Schedule, which is used by the EPA to measure "city" fuel economy. I use the unadjusted EPA city fuel economy, for proper comparison with the unadjusted SAE test results. The SAE cycles are urban test cycles designed specifically for EVs. The SAE D cycle has higher average speed and power than the FUDS, but lower maximum speed and power. The SAE C cycle is less demanding than the SAE D cycle. The European ECE cycle is a composite of FUDs and the U. S. highway cycle

TABLE B.1 (Cont.)

[b] EV characteristics from an EV simulation model called "ELVEC" (Hamilton, 1980). The ICEV and EV were assumed to have equal payload volume, payload, and acceleration times. The EV is assumed to have a range of 100 miles in a the SAE J227a/D cycle. Hamilton (1980) gives 2.79 from the outlet, including regenerative braking, and specifies 0.90 charger efficiency and 0.75 battery efficiency. Weight and efficiency of ICEV as specified by Hamilton.

[c] EV data from Mueller and Wouk (1980, SAE #800204), who reported 1.38 mi/kWh from the outlet in what apparently was a test in urban traffic. They calculate energy use from the batteries by assuming a combined 60% efficiency for the battery and the charger. The fuel economy for the Audi ICEV was reported in Mueller and Wouk (1980, SAE #800109), for driving in city traffic. It is not clear if the vehicle had regenerative braking.

[d] ETV-1 data from Kurtz (1981). Weight and efficiency of Horizon ICEV from 1979 EPA emissions and fuel economy test data, with the following adjustment: the ETV-1 had exceptionally low aerodynamic drag. I assume that if the Horizon ICEV had the same low coefficient of drag, fuel economy the city cycle would have been 15% higher than as measured by the EPA in 1979 (24 mpg). The ETV-1 was 11% more efficient in the SAE D cycle than the FUDS cycle. Efficiency estimate for ETV-1 accounts for about 13% energy returned to battery by regenerative braking.

[e] ETV-2 data from AiResearch (1981). The ETV-2 used a flywheel to improve acceleration and increase range. Energy from regenerative braking went to the flywheel rather than the battery. In the SAE D cycle, the ETV-2 achieved 3.64 mi/kWh, 16% better than in the FUDS. The authors state that the ETV-2 was comparable to a BMW 320i; I assume 1980 model year and use 1980 EPA test results for weight and fuel economy. The 1979 BMW ICEV weighed the same as the 1980 model but achieved only 18 mpg in the city cycle test.

[f] All ICEV and EV data from ELVEC and EVWAC computer simulations, by General Research Corporation (Carriere et al., 1982). EV and ICEV have same acceleration. EV uses a Lime/Fe-S battery and has 150-mi range. EV and ICEV have same acceleration and interior capacity. Carriere et al. specify 3.33 mi/kWh from the outlet, including regenerative braking, and 0.72 combined battery and charger efficiency. They gave curb weights of 2,260 lb (EV) and 1,810 lb (ICEV); I assume that efficiency data were reported with an additional 300-lb test payload, as used by the EPA and by Hamilton (1980b), who also used ELVEC.

[g] EV data from Driggans and Whitehead (EVS88-018, 1988). The STROMer was built from a Golf CL. However, EPA data are available only for the Golf GTI. I assume 1985 model year. Efficiency data include energy returned by regenerative braking.

[h] Griffon data from Driggans and Whitehead (EVS88-039, 1988). The Griffon is a Bedford van, and the EPA does not report test data for Bedford vans. I assumed that the Griffon is comparable to 1984 GMC vans and used 1984 EPA weight and fuel economy test results. Griffon efficiency figure includes regenerative braking. The battery weight is modules only; it does not include auxiliaries or tray. The test cycle is the TVA's urban cycle. The Griffon was 27% more efficient in the SAE C cycle. Data in reference indicate that combined battery/charger efficiency was 62%.

TABLE B.1 (Cont.)

[i] EV data from Angelis et al. (1987), who expect the EV to achieve 190 Wh/km in the ECE cycle, from the outlet, with an additional 75 Wh/km required for battery heating. I assume a combined battery and charger efficiency of 0.63 for Na/S batteries. Regar (1987) reports that the vehicles being tested are converted BMW series 3 cars; I use EPA weight and fuel economy data for 1986 BMW series 3 vehicles. Since the ECE is a combination of FUDS and the highway cycle, I use the unadjusted EPA combined mileage result. The 3,300 lb given by Angelis et al. for calculating energy consumption appears to be curb weight; I have assumed they added 300 lb test weight for the actual efficiency calculation. The BMWs have regenerative braking (Haase, 1987), which apparently was included in the efficiency goal.

[j] ETX-I data from MacDowell and Crumley (1988). The ETX-I was stated to be comparable to a Mercury LN7 or Ford Escort; I used EPA weight and fuel economy results for a 1983 Escort. EPA test weight of 2,500-lb (2,200-lb curb weight plus 300-lb payload weight) is consistent with 2,224 curb weight reported by Ford and GE for the ICEV, before it was converted to the ETX-I. ETX-I data include split regenerative braking.

[k] ETX-II data from Stokes et al. (1988) and Patil and Davis (1988). The efficiency figure for the ETX-II is a goal and appears to include regenerative braking. However, it is not clear if this includes energy required to heat the Na/S battery. The ETX-II will be built from a Ford Aerostar van; I use 1988 EPA fuel economy and weight data for the Aerostar. The fuel economy for 1987 was 20 mpg.

[l] G-van characteristics from Hamilton (October 31, 1988); test weight is curb weight plus test payload. Electricity consumption data from computer simulations run by Hamilton (October 31, 1988). Accounts for regenerative braking. Hamilton's simulation of energy consumption over the C cycle (the value shown is for the D cycle) was extremely close to the consumption measured for the C cycle at the TVA test track.

[m] TEVan characteristics from Hamilton (October 31, 1988); test weight is curb weight plus test payload. Electricity consumption data from computer simulations run by Hamilton (October 31, 1988). Accounts for regenerative braking. Simulation results are close to Chrysler projections. I used mpg and weight results for the Chrysler Caravan.

[n] DSEP characteristics from Hamilton (October 31, 1988); test weight is curb weight plus test payload. Electricity consumption data from computer simulations by Hamilton (October 31, 1988). Accounts for regenerative braking. I used mpg and weight results for the heavy Chrysler Caravan, since the DSEP is a heavier version of the TEVan.

TABLE B.1 (Cont.)

° Based on the following data:

For advanced EVs with ac motors:

Source	Gosden (1990)	Falt et al. (1990)	Fenton & Sims
Drive cycle	SAE J227a-C	A city cycle?	SAE J227a-D
Efficiency			
Auxiliary power	0.938	--	incl. below
Controller	0.967	0.98	
Inverter	incl. above	0.97	0.96
Motor	0.890	0.89	0.88
Drivetrain	0.953	0.90	0.89
Total once-through	0.769	0.74	
Regenerative braking	1.155	1.041*	
Overall net	0.888	0.770	

* Assuming 80% battery efficiency.

The regenerative braking factor is equal to one plus the fraction of energy into the controller that is returned all the way back through the system to the controller.

Note that these figures are from city-cycle tests. Over a high-speed highway test cycle (45 mph and above), the net efficiency of the electric powertrain falls slightly, because there is no regenerative braking. The motor and controller are about as efficient at a steady speed of 45 mph as over the urban cycle, according to Fenton and Sims (1990). The combined city/highway net efficiency of the EV is 75-82%.

The gas-tank-to-road efficiency of year-2000 ICEVs will be about 15% in the city cycle and 17% in the combined city/highway cycle (HHV basis; An and Ross, EEA, 1990; Falt et al., 1990). Hence, the electric powertrain (battery to road) is 5-6 times more efficient than the ICE powertrain (gasoline tank to road) in city driving, and 4-1/2 to 5 times more efficient in combined city/highway driving.

suburban areas. These base-case results for urban driving do not apply to combined city/highway driving because the electric powertrain is slightly less efficient in high-speed highway driving than it is in urban driving because of the lack of regenerative braking, whereas the ICEV is more efficient at higher loads (see Table B.1, note o). For combined city/highway driving, the R_p is about 4.7. I use this value in a scenario analysis (Table 12 of Volume 1).

Because of the importance of R_p, one should ask if, in the future, R_p will be the same as the average R_p in Table B.1. Because of two broadly counterbalancing factors, which will be discussed next, I conclude that R_p is likely to remain the same in the future.

1. On the one hand, there is more opportunity to improve the efficiency of internal combustion engine (ICE) drivetrains than electric drivetrains. Current ICEs are very inefficient at part load, whereas electric motors are more than 90% efficient over typical drive cycles. A concerted effort to improve the drivetrain efficiency of both EVs and ICEVs is likely to reduce the advantage enjoyed by EVs.

2. On the other hand, vehicle designers and manufacturers have more incentive to improve the efficiency of EVs because improved efficiency pays off more for EVs than for ICEVs. (Improved efficiency will increase the performance and range of any vehicle.) However, consumers may think it is much more important to "squeeze" more miles and power out of an EV than an ICEV (assuming diminishing marginal returns to greater range and power). If this situation is true, manufacturers will find it worthwhile to do things to the EV body, drivetrain, interior, tires, and air conditioning (A/C) system and load (A/C is discussed more below) that they would not have done to the ICEV. The all-out attempt to make the GM Impact as efficient as possible clearly supports this hypothesis. (Some of the features of the Impact, such as a streamlined underside and reduced frontal area, cannot be applied to ICEVs because of the exhaust and muffler equipment on the underside and the radiator in the front.)

B.2.10.2 Air Conditioning

The energy-use ratio calculated here (R_p) is based on standard EPA and Society of Automotive Engineers drive-cycle tests, during which A/C is apparently not used. However, the use of A/C should not, in principle, significantly change the energy-use ratio calculated here, except perhaps in a way that favors EVs, as mentioned above and explained below. The calculations in Table B.1 indicate that it takes roughly six times more Btu of gasoline from the tank than electricity from the battery to provide a mile's worth of engine or motor output. In other words, in general, the electric motor uses six times less energy per unit of any kind work than does the ICEV. Assuming that the power demand for A/C is the same for both EV and ICEV vehicles (regardless of how the power is supplied), the A/C system in the EV should use about six times fewer Btu per unit of cooling provided than the A/C system in the ICEV. In short, the use of A/C increases the work that an ICE or electric motor must do but does not change the amount of energy required to produce a unit of any work.

The foregoing statement is true if the power demand for A/C is the same in the EV and the ICEV. This situation may not be the case because of the great impetus to reduce the power demand of A/C in EVs. The diversion of gasoline or battery energy to the A/C system reduces the range of either vehicle; this reduction is unimportant in an ICEV but is fairly serious in an EV, which has a limited range. Consequently, researchers are searching for ways to reduce the power demand of A/C systems for EVs (Schwarz, 1990; Tamura and Ikeda, 1990). Some methods of reducing power demand, such as reducing heat flow into the vehicle, may be applied to an EV but not to an ICEV because, as just noted, it is not as important to improve the range of an ICEV. If this happens, A/C systems in EVs will use less energy than A/C systems in ICEVs, and the EV powertrain will be even more efficient than the ICEV powertrain when the A/C is used.

B.2.11 Liquefied Petroleum Gas Light-Duty Vehicles: Relative Efficiency and Weight

Liquefied petroleum gas (LPG, which is primarily propane) is similar to NG as an engine fuel. It has a higher octane rating than gasoline, which permits the use of a higher compression ratio in a dedicated vehicle (which in turn improves efficiency), and it does not need enrichment at start-up, which saves fuel during the cold-start portion of a drive cycle. LPG has wider flammability limits than gasoline, so vehicle operation can be leaner and more efficient (Bechtold and Timbario, 1983), if a lean-burn liquefied petroleum gas vehicle (LPGV) can meet the 0.40 g/mi NO_x standard. Although a lean-burn LPG vehicle should have an easier time meeting the 0.40 g/mi NO_x standard than a lean-burn NG vehicle because of the faster flame speed and lower octane rating of LPG (which will reduce, directly or indirectly, emissions out of the engine), it will still be very difficult for a lean-burn LPG vehicle to satisfy the new standard. I assume, in the base case, that lean burn cannot be used with LPG.

Vehicles that run on LPG should be about as thermally efficient as NGVs. LPG has a lower octane rating and narrower flammability limits than NG, but LPG has a faster flame speed, which improves efficiency (Bechtold and Timbario, 1983). These properties will probably balance each other out. Both fuels should be more efficient than gasoline during cold start.

Fleming and Bechtold (1982) estimate that optimized LPG vehicles should be about 8% more thermally efficient than gasoline vehicles. The Western Liquid Gas Association (1990) implies that propane vehicles are 5-25% more efficient than gasoline vehicles. Webb (1990) assumes a 10-14% improvement for optimized monofuel propane LDVs over gasoline vehicles. I assume they have the same thermal-efficiency advantage as CNG.

Because of their heavier fuel tanks, LPG vehicles are slightly heavier than comparable gasoline vehicles. The extra weight of the LPG vehicle is calculated in Table 2 in Volume 1; the effect of this extra weight on vehicle efficiency is calculated by assuming a 6% decrease in efficiency for each 10% increase in weight. I ignore any differences in engine power and weight.

B.2.12 Liquefied Petroleum Gas Heavy-Duty Vehicles

Because of the lower compression ratio used in the spark-ignition vehicles, LPG HD, spark-ignition vehicles are less efficient than HD diesel, compression-ignition vehicles. Goetz et al. (1988) measured thermal efficiency to be 13% lower in an LPG bus engine than the diesel version of the same engine. Rele and Seppen (1990) remarked that gas engines are about 15% less efficient than diesel engines. Turner et al. (1990) reported even greater losses in thermal efficiency, 25-30%, for a HD propane GMC and W-star truck compared with a diesel Mack truck driven under similar conditions, but part of the thermal efficiency loss may have resulted from differences between the engines. I assume the thermal efficiency loss relative to heavy-duty diesel vehicles (HDDVs) is the same as that of HD CNG vehicles.

B.2.13 Hydrogen Vehicles: Relative Thermal Efficiency and Weight

The thermal efficiency and weight data in Table 2 in Volume 1, for both light- and heavy-duty vehicles, are determined on the basis of the analysis in DeLuchi (1989). The very large efficiency advantage of hydrogen vehicles is primarily due to the extremely wide flammability limits of hydrogen, which permit ultra-lean operation. Hydrogen vehicles may be able to run lean and meet an 0.40 g/mi NO_x standard. The reason is because NO_x emissions from the engine (i.e., engine-out emissions) decrease continuously with an increasing air/fuel ratio, and, at some ultra-lean point, engine-out emissions will be below 0.40 g/mi. (See Das, 1990; Wolpers et al., 1988; and DeLuchi, 1989, for a discussion of the prospect of near-zero NO_x emissions from hydrogen vehicles.) Hydrogen vehicles alone may be able to operate at such an ultra-high air/fuel ratio. An optimized hydrogen vehicle might be designed for ultra-lean operation at steady load, with engine-out NO_x emissions of less than 0.40 g/mi and stoichiometric operation under high load to provide extra power for acceleration. NO_x emissions from high-load operation could be controlled by a reduction catalyst since the air/fuel mixture under high load would be stoichiometric. The base-case values in Table 2 in Volume 1 assume that hydrogen vehicles will be significantly more efficient than gasoline vehicles and still meet an 0.40 g/mi NO_x standard by running ultra-lean at constant load. The weight changes with hydrogen use are discussed in DeLuchi (1989).

B.2.14 Fuel Cell Vehicles

A fuel cell is a device that converts the chemical energy in hydrogen to electrical energy. The conversion occurs when a porous and electrically conductive electrode (the anode) takes electrons away from hydrogen molecules. The electrons constitute an electric current that provides work against a load, such as an electric traction motor. In a proton-exchange-membrane (PEM) fuel cell, the stripped hydrogen (a proton) is transferred from the anode to the opposite electrode, the cathode, by a proton-conducting material called an electrolyte. At the cathode, the stripped hydrogen combines with atmospheric oxygen and the electrons (which now have done their work) to form water. The reactions at the electrodes are facilitated by catalysts, which, in the case of the PEM fuel cell, are made of a noble metal such as platinum.

Fuel cells are classified primarily by the kind of electrolyte they use. At least two kinds of fuel cells, phosphoric-acid and alkaline, are commercially available. However, phosphoric-acid fuel cells are expensive and too bulky and heavy to be used in LDVs, and alkaline fuel cells are too susceptible to poisoning by atmospheric CO_2 at the cathode (the air electrode) to be used easily in terrestrial applications. Consequently, researchers are developing other advanced fuel cells for vehicles, including PEM fuel cells (also called solid-polymer-electrolyte fuel cells), molten-carbonate fuel cells, and solid oxide fuel cells. In this analysis, I assume that a PEM fuel cell is used.

The hydrogen fuel used by a fuel cell can be stored on board the vehicle as hydrogen or effectively stored in a hydrocarbon, such as methanol or NG, which is decomposed by an on-board reformer to hydrogen and carbon monoxide (CO). I consider both hydrogen and methanol storage. Hydrogen can be produced by many processes from many hydrogen-containing compounds; I consider gasification of biomass and solar electrolysis of water. I assume that the hydrogen is stored as a metal hydride. For methanol, I consider gasification of biomass, gasification of coal, and reforming of NG.

Because fuel cell vehicles (FCVs) are the furthest from commercialization and the least well-characterized vehicle technologies analyzed here, I do not calculate their relative overall efficiency in detail and do not have a separate column for them in Table 2 in Volume 1. Rather, I model reformed-methanol FCVs by making appropriate changes to the relative efficiency data and emissions data pertaining to methanol vehicles in the model. I model hydrogen FCVs by making parallel changes to the input data pertaining to hydrogen FCVs.

DeLuchi et al. (1991a, 1991b) developed a detailed cost and performance model for FCVs that use methanol or hydrogen. Their literature review and analysis indicate that hydrogen-powered FCVs would be two to three times more thermally efficient than gasoline ICEVs on a mile/10^6 Btu basis. I conservatively assume that hydrogen-powered FCVs would be about 2.2 times more thermally efficient than gasoline ICEVs. Methanol-powered FCVs would be about 15% less efficient than hydrogen FCVs because of the energy requirements of reforming. The thermal efficiency advantage of FCVs over diesel ICEVs would be somewhat less than their advantage over gasoline ICEVs because diesel engines are more efficient than gasoline engines.

The thermal efficiency advantage of fuel cells is adjusted to account for the extra weight of the FCVs. The methanol FCV is assumed to weigh 100 lb more than the gasoline ICEV and 300 lb more than the diesel ICEV. The weight of the hydrogen FCV is calculated based on the amount of hydride required for a 200-mi range in a LDV and a 300-mi range in a HDV.

Fuel-cell vehicles using pure hydrogen would emit only water. They simply could not emit CO, nonmethane organic compounds (NMOC), methane (CH_4), or CO_2 because there would be no source of carbon, not even a lubricant. Moreover, low-temperature fuel cells do not emit NO_x because the temperature is far below that required for NO_x formation. Consequently, in the case of a hydrogen FCV, I assume no vehicular emissions of CH_4, CO, nitrous oxide (N_2O), NO_x, NMOC, and CO_2.

Fuel cell vehicles using reformed methanol would have minor emissions of CO and NO_x from the reformer and minor evaporative emissions of the stored methanol. I assume that there would be no tailpipe emissions of CH_4, NMOC, CO, or N_2O; no emissions of CO_2 as a result of the combustion of lubricating oil; only 0.01 g/mi of NO_x emissions from the reformer on LDVs; and only 0.02 g/mi of NO_x emissions from the reformer on HDVs. Evaporative emissions of NMOC from methanol vehicles are calculated automatically as a function of the overall fuel efficiency of the vehicle. Emissions of CO_2 from the reforming of fuel are calculated on the basis of the carbon content of the fuel and the overall efficiency of fuel use.

I can only crudely approximate emissions from the manufacture of materials in FCVs. I assume that the materials breakdown in an FCV, excluding the fuel storage system, would be the same as the breakdown in an ICEV. This obviously is not correct because the powertrain in an FCV would be very different from that in an ICEV. Unfortunately, there are no data available to make an accurate characterization. I assume that the methanol FCV would weigh 100 lb more than the comparable gasoline LDV and 300 lb more than the comparable HDV. The weight of the hydrogen FCV is calculated by assuming hydride storage, an LDV range of 200 mi, and an HDV range of 300 mi.

B.2.15 Gasoline Versus Diesel Vehicles

Diesel fuel vehicles emit fewer greenhouse gases per mile than do gasoline vehicles because diesel vehicles are more efficient and it takes less energy to refine crude to diesel than to gasoline. Until recently, however, policymakers have not viewed diesel vehicles as an alternative to gasoline vehicles, primarily because diesel vehicles typically have had relatively high particulate matter (PM), sulfur-oxide, and NO_x emissions. However, recent EPA regulations limit the sulfur content of diesel fuel to 0.05% (Federal Register, August 21, 1990), and the Clean Air Act of 1990 (CAA) sets limits on PM and NO_x emissions (1.0 g/mi NO_x at 50,000 mi, and 0.08 g/mi PM at 50,000 mi) (EPA, *CAA*, 1990). Diesel-fuel vehicles, then, may be clean enough to be considered an alternative to gasoline vehicles.

To compare the CO_2-equivalent emissions of diesel and gasoline vehicles, one must specify the fuel economy, weight, and (CO, NMOC, CH_4, N_2O, and NO_x) emissions of the two kinds of vehicles. Turbocharged, indirect-injection, diesel-fuel vehicles have 25-30% better fuel economy than their gasoline counterparts (Bleviss, 1989; Energy and Environmental Analysis, 1988; Millar et al., 1985; Sekar et al., 1984; Barnes-Moss and Scott, 1976). Direct-injection, turbocharged diesels have a 40-45% fuel economy advantage (Energy and Environmental Analysis, 1990, 1988). Diesel engines also weigh about 100 lb more than spark-ignition engines (Energy and Environmental Analysis, 1990).

The fuel economy increases cited above are determined on the basis of unadjusted mpg fuel economy. The in-use fuel economy advantage of diesels may be even greater because diesel vehicles may perform closer to their unadjusted ratings than do gasoline vehicles (Duleep, 1991).

However, the use of trap oxidizers to control PM emissions will reduce the efficiency of diesel vehicles. I assume that these factors cancel each other out.

Emission factors for light-duty diesel vehicles (LDDVs) are in Section B.3.2.

B.2.16 Summary

The weight and efficiency assumptions used in this analysis and discussed above are shown in Table 2 in Volume 1. The basic input data are the desired range, the weight of the fuel storage tank per pound of fuel, and the relative thermal efficiency. With these data, the model first calculates the amount of fuel needed to satisfy the range requirement. Then the model calculates the tank size that will be needed for the calculated amount of range. It then sums the weight of the fuel and tank and compares it with the weight of the gasoline or diesel-fuel system. It calculates the relative weight and the relative efficiency factor due to the relative weight. It combines the relative-weight efficiency factor and the relative thermal-efficiency factor to give overall relative efficiency. The advantage of this approach is that the vehicle range is explicitly included as a variable; there is no cheating on weight (and thus efficiency and greenhouse gas emissions) by hiding assumptions about range. (This approach also introduces circularity into the calculation since the amount of fuel required to satisfy a given range depends on the efficiency of the vehicle, but the efficiency depends in part on the weight of the fuel. The model solves these circularities by iteration.)

B.3 NMOC, NO_x, and CO Emissions from Vehicles

Emissions of CO, NMOC, and NO_x from vehicles contribute to the greenhouse effect indirectly by affecting the concentration of ozone and methane. (CH_4 and N_2O emissions, which affect climate directly, are analyzed in Appendixes M and N.) Also, as discussed below, one must know vehicular CO and NMOC emissions to calculate CO_2 emissions because vehicular carbon emissions as CO_2 are calculated as the total amount of carbon available in the fuel, minus the amount of carbon emitted as NMOC and CO.

To estimate NMOC, NO_x, and CO emissions from petroleum-fuel vehicles, I begin with the output of MOBILE4, the EPA's detailed computer emissions model. MOBILE4 can be set to estimate composite, fleet-average emission factors for light-duty gasoline vehicles (LDGVs) and HDDVs in the year 2020. I program MOBILE4 for the year 2020 rather than 2000 because the MOBILE4 fleet includes a few old, uncontrolled vehicles, and because AFVs will replace only relatively new, tightly controlled vehicles. Then I adjust the MOBILE4, year-2020 output to account for those requirements of the new CAA that cannot be incorporated easily into MOBILE4.

In the following section, I discuss how I adjust the emissions results of MOBILE4 and the California version of MOBILE4 to reflect the new CAA requirements. I then estimate emissions from alternative-fuel vehicles, considering the clean-fuel emissions standards of the CAA (which,

by and large, are the same as the standards for gasoline and diesel vehicles) and data on emissions from AFVs relative to emissions from petroleum-fuel vehicles.

B.3.1 Heavy-Duty Diesel Vehicles

The MOBILE4 emission factors for HDDVs fully incorporate the 1994 HDV standards that were adopted prior to the CAA Amendments of 1990. The CAA left the hydrocarbon (HC) and CO standards intact but lowered the NO_X standard from 5.0 to 4.0 g/brake-horsepower-hour (bhp). However, the MOBILE4 g/mi emission factors translate to less than 4.0 g/bhp, so that no adjustment is necessary to account for the lowering of the NO_X standard. Hence, the MOBILE4 factors for HDDVs can be used to represent year-2000 emissions from HDDVs under the new CAA (Tables B.2 and B.3). There are no evaporative emissions from HDDVs because of the extremely low volatility of diesel fuel.

B.3.2 Light-Duty Diesel Vehicles

Under the new CAA, LDDVs have the same CO and NMOC standards as gasoline LDGVs. The new NO_X standard for LDDVs, 1.0 g/mi, is higher than the standard for gasoline vehicles. MOBILE4 projects that (1) CO emissions from LDDVs will be well below the CO standard, (2) NO_X emissions will be very close to the standard, and (3) NMOC emissions will exceed the 0.25 g/mi standard (see Table B.3). Therefore, I use the MOBILE4 projections of CO and NO_X emissions. (The ratio of NO_X emissions from LDDVs to NO_X emissions from LDGVs equals the ratio of the NO_X standard for LDDVs to the NO_X standard for LDGVs.) For N_2O, I use the estimate from Table N.1 in Appendix N. Finally, I assume that LDDVs will emit the same level of NMOC as LDGVs since both will certify to the same standard, and both will have to use some form of control to meet the standard. (The MOBILE4 projections do not take account of the new NMOC standard.)

B.3.3 Heavy-Duty Alternative-Fuel Vehicles

For two reasons, I assume that alternative-fuel HDVs will emit as much as NO_X as diesel HDVs. First, HD AFVs face the same 4.0 g/bhp NO_X standard. Although it will be easier for some vehicles and fuels to meet the standard (e.g., easier for methanol than for diesel fuel), all vehicles will either have to sacrifice performance and fuel economy or add emission control equipment in order to meet the standard. In other words, all vehicles must in some sense pay for meeting the NO_X standard, which means that manufacturers will not try to go much below the standard (unless EPA allows credits for doing so).

TABLE B.2 Lifetime Average Vehicle Emissions, Input and Calculated Data (g/mi)

Emission	Gasoline		Diesel	Methanol/LD[b]	Methanol/HD[c]	NG/LD	NG/HD	EVs[d]
	Standard	Reformulated[a]						
In actual g/mi:								
CH_4[e]	0.05	0.05	0.10	0.03	0.05	1.20[f]	3.00[f]	0.00
N_2O[g]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.00
Upstream evaporative NMOC[h]	0.13	0.13	0.01	0.06	0.38	0.00	0.00	0.00
Vehicle evaporative NMOC[i]	0.30	0.30	0.00	0.13	0.86	0.00	0.00	0.00
Tailpipe NMOC	0.40	0.34	2.05	0.43	4.00	0.22	0.60	0.00
Total NMOC[j]	0.83	0.77	2.06	0.62	5.25	0.22	0.60	0.00
CO	7.21	6.13	10.78	7.21	13.00	3.60	7.00	0.00
NO_x as NO_2	0.45	0.45	8.05	0.45	8.05	0.45	8.05	0.00
CO_2 from oil[k]	2.00	2.00	4.00	2.00	4.00	1.00	2.00	0.00
CO_2 from EV heater[l]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CFCs[m]	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031
CO_2 from fuel[n]	275.45	268.52	1,651.41	214.64	1,495.41	195.51	1,463.94	0.00
In CO_2-equivalent g/mi:								
CFCs[m]	220.37	220.37	220.36	220.37	220.36	220.37	220.36	220.37
CH_4, CO, N_2O, NO_x, NMOCs	67.02	63.16	396.66	60.75	406.69	72.45	426.64	0.00
Total without CFCs[o]	344.47	333.68	2,052.07	277.39	1,906.10	268.95	1,892.58	0.00
Total with CFCs[p]	564.85	554.05	2,272.43	497.76	2,126.46	489.32	2,112.94	220.37
For biofuels case (total g/mi):[q]								
Without CFCs				51.40	386.01	64.44	408.92	
With CFCs				271.77	606.38	284.81	629.29	

TABLE B.2 (Con't)

	Hydrogen/LD	Hydrogen/HD	Ethanol/LD[r]	Ethanol/HD[r]	LPG/LD	LPG/HD
In actual g/mi:						
CH_4[e]	0.005	0.005	0.03	0.05	0.05	0.10
N_2O[g]	0.000	0.060	0.06	0.06	0.06	0.06
Upstream evaporative NMOC[h]	0.00	0.00	0.03	0.19	0.02	0.10
Vehicle evaporative NMOC[i]	0.00	0.00	0.06	0.42	0.00	0.00
Tailpipe NMOC	0.040	0.040	0.32	4.00	0.22	1.80
Total NMOC[j]	0.04	0.04	0.40	4.60	0.24	1.90
CO	0.70	0.100	7.21	13.00	5.50	9.00
NO_x as NO_2	0.45	8.05	0.45	8.05	0.45	8.05
CO_2 from oil[k]	2.000	4.000	2.00	4.00	1.50	3.00
CO_2 from EV heater[l]	0.000	0.000	0.00	0.00	0.00	0.00
CFCs[m]	0.031	0.031	0.031	0.031	0.031	0.031
CO_2 from fuel[n]	0.00	0.00	0.00	0.00	226.72	1,695.56
In CO_2-equivalent g/mi:						
CFCs[m]	220.37	220.36	220.37	220.36	220.37	220.36
CH_4, CO, N_2O, NO_x, NMOCs	20.65	340.25	49.03[s]	385.38[s]	55.35	388.16
Total without CFCs[o]	22.65	344.25	51.03	389.38	283.57	2,086.72
Total with CFCs[p]	243.02	564.61	271.40	609.75	503.94	2,307.09

[a] Reformulated gasoline, as specified in Appendix C. This is used as the base-case gasoline here.

[b] Emissions shown are for M100. For methanol/gasoline mixtures, the model calculates evaporative emissions and methane emissions as a function of the methanol proportion.

[c] Assumes 100% methanol.

[d] Emissions from vehicle only. Other fuel-cycle emissions calculated elsewhere.

[e] See Appendix M, for discussion of sources and data.

TABLE B.2 (Con't)

[f] Emissions from a CNGV. An LNGV has additional minor methane emissions from boil-off.

[g] See Appendix N for discussion of sources and data.

[h] Emissions of nonmethane organic compounds (including alcohols) from bulk terminals, refineries, loading and unloading, tankers, ships, stage I refueling, and so on. Uses data of Table 4 in Volume 1. See this Appendix for data and sources. Any alcohol emissions are included at their full mass (i.e., the NMOC g/mi emissions shown do not exclude alcohols or the oxygen in alcohols, nor do they convert alcohols to some "organic-material equivalent"). However, in converting NMOC to CO_2-equivalent mass emissions, only the carbon weight of the NMOC is counted, to properly account for the relative reactivity of NMOC (see Appendix O). I assume that evaporative emissions have the same carbon content as the fuel itself (Table C.1).

[i] Hot-soak, running loss, and refueling emissions. See this Appendix for discussion. Alcohol emissions counted at full mass. However, in converting NMOC to CO_2-equivalent mass emissions, only the carbon weight of the NMOC is counted, to properly account for the relative reactivity of NMOC (see Appendix O). I assume that evaporative emissions have the same carbon content as the fuel itself (Table C.1).

[j] Sum of upstream evaporative emissions, vehicular evaporative emissions, and tailpipe evaporative emissions. NMOCs include alcohol emissions, at full mass. However, in converting NMOC to CO_2-equivalent mass emissions, only the carbon weight of the NMOC is counted, to properly account for the relative reactivity of NMOC (see Appendix O).

For NMOC emissions from vehicles and other combustion sources, I make the following assumptions about the carbon content of NMOC emissions:

	C in NMOC	Explanation
Current gasoline	0.866	Same as fuel itself
Reformulated gasoline	0.833	Same as fuel itself
Diesel fuel	0.858	Same as fuel itself
Methanol	0.400	Almost all methanol (0.375); a few HCs
Ethanol	0.550	Almost all ethanol (0.522); a few HCs
Gaseous fuels	0.800	Ethane is typical (CH_4 counted separately)
Coal	0.600	Same as fuel itself
Wood	0.500	Same as fuel itself

[k] Estimated based on NMOC emissions from hydrogen vehicles and an analysis of oil consumption.

[l] Currently, EVs use oil-powered heaters. However, it is possible that high-temperature batteries could provide heat. I assume no fuel is burned to provide heat in the vehicle.

TABLE B.2 (Con't)

[m] See Appendix Q for methods and sources.

[n] Calculated by carbon-balance method. See this Appendix for details.

[o] The sum of CO_2 from fuel, CO_2 from oil, and the CO_2-equivalent of CH_4, N_2O, CO, and all NMOC. NMOC converted to CO_2-equivalent based on the carbon content of the NMOC. See Appendix O.

[p] Sum of CO_2-equivalent emissions from fuel use and CO_2-equivalent emissions of CFCs.

[q] Emissions if methanol and NG are made from biomass; equal to the CO_2 equivalent of emissions from the combustion of engine oil (assuming that engine oil is made from fossil-fuels), plus the CO_2-equivalent of CH_4, CO, NMOC, and N_2O emissions, less a CO_2 credit for the carbon in CH_4, CO, and NMOC (i.e., the greenhouse effect of an emission of CH_4 from a biofuel is equal to the difference between CH_4 and CO_2, because the carbon is taken from the atmosphere as CO_2 and returned as CH_4).

[r] Assumes 100% ethanol.

[s] With the CO_2 credit for carbon removed by photosynthesis, as per note q.

TABLE B.3 MOBILE4 Fleet-Average, Year-2020, g/mi Emission Factors[a]

Pollutant	LDGVs[b]	LDGT1[b]	HDGV[b]	LDDV	HDDV
Total HC[c]	1.01	1.11	2.77	0.52	2.13
Exhaust NMOCs	0.59	0.78	1.33	0.50	2.03
CH_4	0.05	0.07	0.18	0.02	0.10
Evaporative HC[d]	0.38	0.26	1.27	0.00	0.00
CO	7.21	9.08	16.53	1.45	10.78
NO_x	0.92	1.13	4.26	1.10	8.05
California NO_x[e]	0.56	0.84	4.28	1.08	8.33
N_2O[f]	0.06	0.06	0.06	0.054[g]	0.06

LDGV = light-duty gasoline vehicle; LDGT1 = light-duty gasoline truck, class 1; HDGV = heavy-duty gasoline vehicle; LDDV = light-duty diesel vehicle; HDDV = heavy-duty diesel vehicle.

[a] Assumed in-use summertime RVP of 8.05, stage-II (pump) and on-board refueling controls, and inspection and maintenance and anti-tampering programs (but with no check for lead in the tailpipe).

[b] These results are for a low-RVP but otherwise unreformulated gasoline. The gasoline vehicles would have lower CO and tailpipe NMOC emissions on reformulated gasoline.

[c] Evaporative emissions plus NMOC tailpipe emissions plus methane emissions. Total may not equal sum of components because of independent rounding.

[d] Hot-soak + diurnal (0.13 g/mi) + refueling (0.02 g/m) + running loss (0.23 g/mi) emissions.

[e] The result of the running the California version of MOBILE4, CALI4, for the year 2020.

[f] From Tables B.2 and N.1.

[g] Based on tests of one vehicle (Table N.1).

Second, the MOBILE4 g/mi NO_x estimate for HDDVs is consistent with measurements and projections of NO_x emissions from HD AFVs (Sperling and DeLuchi, 1991; EPA, Economic and Environmental Analyses of Alternative Fuels, 1990). Thus, the MOBILE4 HDDV NO_x emission estimate probably will be representative of emissions from all vehicles.

The new CAA directs the EPA to promulgate standards for ultra-low-emission vehicles (ULEVs) and zero-emission heavy-duty vehicles (ZEVs). I assume here that the ULEV and ZEV standards will not have any significant effect by the year 2000. Also, under the new CAA, clean-fuel HDVs weighing between 8,500 and 26,500 lb must meet a lower combined NO_x and NMOC standard. I do not consider this requirement.

The CO and HC standards are not constraining for HDDVs and are not likely to be constraining for HD AFVs that meet the NO_x standard. I estimate CO and tailpipe NMOC emissions from alternative-fuel HDVs, relative to diesel-fuel HDVs, on the basis of the review in Sperling and DeLuchi (1991). I assume there will be lean-burn, spark-ignition NGVs. In support of this, the EPA (*Analysis of the Economic and Environmental Effects of Compressed Natural Gas as a Vehicle Fuel, Volume II*, 1990) projects that lean-burn HD NGVs will meet the HD emission standards relatively easily.

There will be small amounts of evaporative emissions from HD ethanol and alcohol vehicles. I calculate these by scaling the g/mi evaporative-emission rate from LDVs by the ratio of the mi/10^6 Btu efficiency of LDVs to the mi/10^6 Btu efficiency of HDVs. This method assumes that evaporative emissions are a function of fuel use and, hence, fuel economy. The calculation of g/mi evaporative emissions from LDVs is discussed below.

B.3.4 Light-Duty Vehicles Using Unreformulated Gasoline

The new CAA Amendments and recent EPA regulations mandate a lower Reid vapor pressure (RVP) for gasoline; lower NO_x and NMOC certification standards; 100,000-mi in-use standards; controls on vehicle refueling; reformulated gasoline; and, in most ozone nonattainment areas, inspection and maintenance (I&M) programs (EPA, *CAA*, 1990). MOBILE4 has variables to represent RVP, on-board and pump-side controls on refueling, and inspection and maintenance programs; but not tailpipe standards, gasoline composition, or in-use testing requirements (although the California version of MOBILE4 can be used to estimate the effects of a lower NO_x standard, as discussed below). Table B.3 shows the results of running MOBILE4 for the year 2020, programmed with the new RVP standards, onboard and pump-side (Stage-II) refueling controls, and inspection and maintenance parameters.

California has a 0.40 g/mi 50,000-mi NO_x standard, with an option to meet an 0.70 g/mi standard and a lower CO standard. Hence the California version of MOBILE4 provides an approximation of the newly mandated federal NO_x standard. The California version estimates in-use emissions of 0.56 g/mi NO_x for the year 2020 (Table B.3).

The results from MOBILE4 must be adjusted to capture the effects of those aspects of the CAA that cannot be modeled. The California NO_x result, which is based on a 50,000-mi certification standard and assumes that a small portion of vehicles certify under an 0.70 g/mi standard, must be reduced to account for the imposition of in-use standards and the absence of the 0.70 g/mi option in the new CAA. The new CAA Amendments require that vehicles meet the 0.40 g/mi, 50,000-mi certification standard in use, as well as during certification, and they require that vehicles meet the 0.60 g/mi in-use standard at 100,000 mi. Accordingly, I assume a fleet-average emission rate of 0.45 g/mi in 2000.

The current MOBILE4 CO emission rate should be reduced to account for the imposition of the in-use standards (3.4 g/mi at 50,000 mi and 4.2 g/mi at 100,000 mi) and the new cold-temperature CO standard. There is evidence, however, that MOBILE4 substantially underestimates CO emissions from vehicles by inadequately accounting for so-called "superemitters." I assume that these countervailing factors cancel each other, and I use the current MOBILE4 year-2020 output without adjusting it.

The NMOC tailpipe emission rate must be adjusted to reflect the lower tailpipe standard (0.25 g/mi NMOC, down from 0.39 at present) and the imposition of the in-use standards. I assume exhaust NMOC emissions of 0.40 g/mi, down from the 0.59 value in MOBILE4's year-2020 projection. (As discussed below, MOBILE4 probably does not dramatically underestimate NMOC emissions.)

Evaporative emissions from conventional gasoline vehicles will probably be slightly lower than the amount projected by my runs of MOBILE4. These runs incorporate the new RVP, refueling, and I&M regulations but not the new CAA mandate to further control vehicular evaporative emissions (EPA, *CAA*, 1990). This mandate will lead to a revision of the evaporative emissions test and standard and will reduce running losses. Therefore, I assume that total evaporative emissions will be slightly lower than those predicted by MOBILE4: 0.30 g/mi rather than 0.38 g/mi.

B.3.5 Vehicles Using Reformulated Gasoline

The new emission standards discussed above apply to vehicles that use conventional gasoline (vehicles must be certified to meet the standards on conventional gasoline). The CAA specifically states that reformulated gasoline must either contain no more than 25% aromatics or provide a 15% reduction in emissions of volatile organic compounds (VOC) and toxics based on the emissions from a baseline gasoline vehicle, whichever is more stringent (EPA, *CAA*, 1990; the baseline is to be defined by the EPA later). Thus, a vehicle using reformulated gasoline will emit fewer VOC than a vehicle using conventional gasoline. In the base case in which I assume the use of reformulated gasoline, I assume a 15% reduction in emissions of VOC and CO and no change in NO_x emissions (compared with a vehicle using conventional gasoline). These assumptions are consistent with the requirements of the CAA and with preliminary emission comparisons and projections (Boekhaus et al., 1990; U. S. GAO, 1990; Wall Street Journal, 1990; Piel, 1989).

Because of the wording of the CAA and because gasoline vehicles must certify to the new CAA standards on conventional gasoline, reformulated-gasoline vehicles will produce lower emissions than conventional-gasoline vehicles. In effect, reformulated-gasoline vehicles are required to meet a lower VOC standard than conventional-gasoline vehicles and a lower CO standard than any other LDV.

B.3.6 Alternative-Fuel Light-Duty Vehicles

Alternative or clean-fuel vehicles must meet emission standards of 0.125 g/mi for NMOC, 3.4 g/mi for CO, and 0.4 g/mi for NO_X. (These are Phase I standards for vehicles up to 5,750 lb, which apply through the year 2001.) The NO_X and CO standards are the same as those for gasoline vehicles; the NMOC standard is half. I estimate emissions from methanol, CNG, and hydrogen vehicles relative to emissions from gasoline and diesel-fuel vehicles, considering both these clean-fuel standards and the emissions data reviewed in Sperling and DeLuchi (1991) and other sources.

B.3.6.1 Nitrogen Oxides

I assume that all single-fuel, optimized ICEVs will emit the same level of NO_X because the new NO_X standard, which is the same for all vehicles, will be difficult enough for all vehicles to meet that none will emit significantly below the standard (e.g., see discussion above, about the difficulty of meeting the NO_X standard with lean burn). However, a flexible-fuel methanol or ethanol vehicle should emit less NO_X than a comparable dedicated gasoline vehicle, assuming that the same NO_X standard applies to flexible-fuel vehicles (FFVs) on gasoline and dedicated gasoline vehicles, because an FFV will emit less NO_X when running on alcohol because of alcohol's lower flame temperature, faster flame speed, and higher latent heat of vaporization (Sperling and DeLuchi, 1991).

B.3.6.2 Carbon Monoxide

I assume that methanol, ethanol, LPG, and NG vehicles must operate near stoichiometry to meet the NO_X standard (see discussion above). Thus, these vehicles will have to forego the large CO and NMOC emissions benefits of very lean operation (the stoichiometry of a hydrogen engine has little effect on CO and NMOC emissions since in hydrogen vehicles these are produced only from combustion of engine oil). Therefore, I assume that no AFV will achieve huge CO reductions when compared with a gasoline vehicle.

However, CO emissions are also a function of the how well the fuel mixes with air and how fully the fuel is vaporized at cold start. Alcohol-fuel vehicles have no comparative advantages in these areas, so they can be expected to emit as much CO as conventional gasoline vehicles (at

stoichiometry). Emissions data clearly support this assumption (Sperling and DeLuchi, 1991). Indeed, alcohol vehicles may have higher CO emissions during cold start because of the low vapor pressure of ethanol and methanol. Therefore, I assume that alcohol vehicles emit as much CO as conventional-gasoline vehicles.

Since reformulated gasoline is intended to produce less CO than conventional gasoline, and because conventional-gasoline and alcohol-fuel vehicles will certify to the same standard and probably will emit the same amount CO, reformulated gasoline will result in less CO emissions than will alcohol. Boekhaus et al. (1990) make a similar assumption.

I assume that NG vehicles will emit somewhat less CO than conventional- and reformulated-gasoline vehicles, even at stoichiometry, because of reduced CO emissions at start up and because, if a CNG vehicle operates even slightly lean, CO emissions drop dramatically. However, I do not assume the very low CO emissions levels associated with uniformly lean operation on CNG.

If NGVs must operate slightly rich to meet the NO_X standard, they will produce at least as much CO as the conventional gasoline vehicle. I consider this in a scenario analysis.

I assume that LPG vehicles emit only slightly less CO than do gasoline vehicles and slightly more than NGVs on the basis of data and statements in Bechtold and Timbario (1983), WLGA (1988), CARB (1989), and Goetz et al. (1988, for bus engines).

B.3.6.3 Nonmethane Organic Compounds: Tailpipe Emissions

The standard for NMOC emissions from the tailpipe of clean-fuel vehicles is half that for gasoline vehicles. In its 1989 rules for methanol vehicles, the EPA established that NMOC emissions from methanol vehicles were to be represented by converting the actual, full weight of all the organic emissions to the mass amount of gasoline-vehicle emissions with the same total carbon (where gasoline emissions are assumed to contain 86.6% carbon) (Federal Register, April 11, 1989). Applied to the new CAA standards, this convention means that methanol vehicles must certify to a 50%-lower carbon-emission standard. I assume, then, that methanol vehicles will emit half the total carbon from the tailpipe that conventional (gasoline) vehicles do. Thus, (1) if gasoline vehicles emit 0.40 g/mi NMOC from the tailpipe (see above; on conventional, not reformulated, gasoline), and (2) if the organic emissions from methanol vehicles are 40% carbon (most of the organic emission is methanol, which is 37.5% carbon, but there is a small amount of hydrocarbons emitted, with a much higher carbon content), methanol vehicles will emit 0.43 g/mi of total organics. This assumption is quite consistent with emissions data from methanol vehicles (Sperling and DeLuchi, 1991) and the EPA's projection (1989, *Analysis of the Economic and Environmental Effects of Methanol as a Automotive Fuel*).

I follow the same convention in estimating NMOC emissions from ethanol, NG, and LPG vehicles: 50% lower carbon emissions compared with conventional gasoline. My assumptions regarding the carbon content of organic emissions from these vehicles are shown in the notes to Table B.2. The resulting NMOC g/mi emission for NG is consistent with expected results for optimized vehicles (Sperling and DeLuchi, 1991).

The NMOC input data in Table B.2 (e.g., 0.315 g/mi for ethanol and 0.43 g/mi for methanol) show the full weight of NMOC emissions (carbon, hydrogen, and oxygen). However, in converting these emissions to CO_2-equivalents, only the carbon weight is counted because the amount of CO_2 and ozone formed from NMOC is a function of the carbon content (see Appendix O).

B.3.7 Vehicles Using Liquid Fuels: Evaporative NMOC Emissions

In general, evaporative emissions from vehicles, vehicle refueling, and product distribution and storage are proportional to the true vapor pressure (TVP) of the liquid, amount of liquid, molecular weight of the vapors, and the extent and effectiveness of emission controls. The use of emission controls, in turn, is determined in part by the stringency of the evaporative emissions standard for the particular fuels. Given g/gal evaporative emissions from gasoline, g/gal evaporative emissions from methanol and ethanol vehicles can be estimated by comparing the TVP and molecular weights of methanol and ethanol to those of gasoline for a given level of control. (Grams-per-gallon evaporative emissions from gasoline vehicles and gasoline-vehicle refueling can be inferred from the data in Table B.2; g/gal gasoline evaporative emissions from upstream processes are discussed below.)

New EPA rules will reduce the RVP of gasoline to 7.8 or 9.0 during five months (May-September) (Federal Register, June 11, 1990); the rest of the year, RVP will be about 11.5. The year-round average will be about 10 (DeLuchi et al., 1991; recall that in a greenhouse-gas analysis, year round, national averages are of interest). Assuming a national-average, year round temperature of 60°F (based on data in the U. S. *Statistical Abstract*), the year-round national-average TVP of gasoline will be 5.2 (EPA, 1985, AP-42). At 60°F, the TVP of methanol is 1.4; of ethanol, 0.6 (EPA, AP-42). This means that molar evaporative emissions from 1 gal of methanol will be 26% of the molar emissions from 1 gal of gasoline. Molar emissions from ethanol will be 12% of molar emissions from gasoline. Since the molecular weight of methanol vapor is 48% of the molecular weight of 10-RVP gasoline vapor, and the molecular weight of ethanol vapor 70% of it, g/gal methanol evaporative emissions will be 13% and g/gal ethanol emissions will be 8% of g/gal gasoline evaporative emissions, at a given level of control.

To determine final, in-use evaporative emissions from alcohol vehicles and systems relative to gasoline, one must project the level of control of evaporative emissions from the alcohol system, compared with the control of the gasoline system. The level of control will be determined in part by emission standards, which the EPA sets by considering both the cost and benefits of emission

control. I have not attempted to quantify these costs and benefits here; rather, I touch briefly on a few of the issues.

Presently, the evaporative emission standard for methanol vehicles is 2 g of gasoline-equivalent hydrocarbons per test (2 g/test) (Federal Register, April 11, 1990). This, like the tailpipe standard, is meant to result in equivalent carbon emissions (the gasoline-vehicle evaporative emissions standard also is 2 g/test). One could argue from this that evaporative carbon emissions from methanol vehicles will be the same as those from gasoline vehicles and (per mile, not per gallon) because manufacturers will take advantage of methanol's lower evaporative potential by cutting the cost of evaporative emission-control equipment to the point that methanol vehicles just meet the standard. The EPA explicitly acknowledges this tradeoff between control cost and emissions in its analysis for the standards (Federal Register, April 11, 1990).

The argument thus far is that methanol vehicles will produce as much hot-soak, diurnal, and running-loss evaporative VOC as gasoline vehicles. However, most of the in-use evaporative emissions from gasoline vehicles are a result of the failure of the evaporative emission control system, most typically, overloading of the canister. A failed methanol evaporative-control system will clearly produce fewer VOC than a failed gasoline control system because of the lower TVP and molecular weight of methanol. Also, in order to pass the 2 g/test standard, methanol vehicles may have to have emission controls that are nearly as effective as those for gasoline vehicles because in a new vehicle, uncontrollable background sources of VOC, such as upholstery, emit almost 2 g/test. This means that evaporative emissions from the fuel must be virtually eliminated (Federal Register, April 11, 1989).

I weigh these factors qualitatively and assume that g/gal emissions of VOC from methanol vehicles are 26% of the g/gal emissions from gasoline vehicles and that g/gal evaporative emissions from ethanol vehicles are 16% of those from gasoline vehicles — about twice the rate one would expect if alcohol vehicles had the same degree of control as gasoline vehicles.

The situation with vehicle refueling is also uncertain, although probably less so. If methanol vehicles are built with the same on-board refueling controls as gasoline vehicles, as is likely, the full evaporative emissions-reduction potential of methanol refueling will be realized. It is possible, but seems unlikely, that the EPA will relax the refueling control requirement for methanol vehicles. I assume the same on-board controls.

There are similar cost/emission tradeoffs associated with upstream evaporative emissions. At all stages, the basic question is: will the much lower evaporative emissions potential of alcohol vehicles translate into reduced emissions, reduced control costs, or some combination of both? Because of the difficulty of quantifying this tradeoff and because the tradeoff will result in different outcomes for different stages of the fuel marketing system, I simply assume that methanol vehicles will have 26% of the g/gal emissions of gasoline vehicles and that ethanol vehicles will have 16% (twice the rate one would expect if alcohol and gasoline vehicles had the same level of control at every stage).

Both evaporative and tailpipe NMOC emissions from alcohol/gasoline mixtures depend in a nonlinear way on the concentration of alcohol. When doing alcohol/gasoline scenario analyses, I use EPA (*Analysis of the Economic and Environmental Effects of Methanol as an Automotive Fuel*, 1989) estimates of evaporative and tailpipe emissions from methanol FFVs (for ethanol as well) and Sapre's (1988) data on evaporative and tailpipe emissions from methanol and gasoline blends.

The NGVs and EVs have no fuel-related evaporative emissions. I do not include background emissions of VOCs from vehicle upholstery and paint for three reasons. First, and most importantly, the EPA has apparently excluded such background emissions in its MOBILE4 program because MOBILE4 shows zero evaporative emissions from diesel-fuel vehicles. I therefore assume that background emissions are not included in the gasoline vehicle totals. Second, background emissions are hard to quantify and change greatly over the life of the vehicle. Third, background emissions are probably relatively small (on the order of 0.1 g/mi average) over the life of the vehicle. They amount to about 1 g/mi of CO_2-equivalent emissions or 0.2% of total life-cycle CO_2-equivalent emissions.

B.3.8 Questions about MOBILE4

Recently, researchers compared emissions measured from vehicles on the road with emissions predicted by early EPA and California models and found that the models (e.g., MOBILE3 and EMFAC7C) can greatly underestimate actual on-road emissions of CO and NMOC (Ingalls et al., 1989; Pierson et al., 1990). Ingalls et al. (1989) found that on-road HC emissions were 1.4 to 6.9 times higher than the emission factors calculated by the California Air Resources Board's EMFAC7C; CO emissions were 1.1 to 3.6 times higher; and NO_x emissions were 0.6 to 1.4 times higher. These factors are generally consistent with the results of other on-road emission studies (Pierson et al., 1990). It appears that MOBILE3 and EMFAC7C do not account adequately for emissions from poorly tuned, poorly maintained, and tampered-with vehicles and emissions from overloaded HC evaporative canisters. Neither one of these models estimates running evaporative losses.

The most recent EPA model, MOBILE4, does include running losses as well as a more sophisticated treatment of evaporative emissions in general and appears to predict HC emissions much better than its predecessor, MOBILE3 (Pierson et al., 1990). MOBILE4 is currently the best emissions model available. It probably underpredicts CO emissions; its performance with respect to HC emissions is not well known. However, the inaccuracies in MOBILE4 probably do not have a significant effect on absolute emissions of CO_2-equivalent greenhouse gases and probably would not have a significant effect on relative emissions from HC-burning vehicles since the inaccuracies are likely to be the same for all such vehicles. If MOBILE4 does greatly underestimate HC and CO emissions, the reductions in greenhouse gas emissions from hydrogen and electric vehicles will be slightly higher than the greenhouse gas reductions estimated here since these vehicles do not emit much CO and NMOC.

B.4 Carbon Balance

The greenhouse gas emissions model, by accounting for all carbon emitted by vehicles, produces an exact estimate of CO_2 emissions from fuel combustion. It calculates total fuel carbon into the engine per mile and then subtracts the portion of the fuel carbon that is emitted as CO, NMOC, or CH_4. The remaining carbon is calculated as being fully oxidized to CO_2.

The model accounts for the fact that a portion of the total tailpipe emissions of CO, NMOC, and CH_4 come from lubricating oil, not from fuel. The model asks for total tailpipe emissions in the federal test procedure and for the percentage of this total that results from the burning of fuel rather than the burning of lubricating oil. Thus, the model multiplies total CO, NMOC, and CH_4 emissions per mile by the percentage due to fuel and then deducts the carbon content of these calculated fuel-based CO, NMOC, and CH_4 emissions from total fuel carbon into the engine per mile. The calculated remaining carbon reveals fuel-based CO_2 emissions.

B.5 Oil Consumption

Some of the lubricating engine oil is burned in the engine and forms CO_2, CO, CH_4, and NMOC. The model asks for an estimate of g/mi CO_2 emissions from oil consumption. I make this estimate on the basis of data on CO_2 emissions from hydrogen vehicles since all CO_2 from hydrogen engines comes from the oil. These CO_2 emissions appear to be between 1 and 16 g/mi, with values above 2 g/mi indicating excessive oil consumption (DeLuchi, 1989). This result suggests an average estimate of 1-2 g/mi. As a check, I estimate that about one quart of oil should be burned every 3,000 mi. This corresponds to about 1 g/mi of CO_2 emissions, assuming 3,100 g/gal and 86% carbon. In the model, I entered 2 g/mi for gasoline LDVs rather than 1 g/mi to account for poorly tuned cars and nonrecycled oil (which eventually oxidizes to CO_2). I have arbitrarily assumed twice as much oil-derived CO_2 per mile from HDVs as from LDVs.

Oil analyses of the Federal Methanol Fleet indicate that engine wear may be higher with methanol than with gasoline; otherwise, there are no abnormal trends (McGill and Hillis, 1988). King and Bol (1988) found that oil consumption in HD methanol vehicles is the same as in diesel counterparts. Therefore, I assume no difference in the rate of oil consumption between methanol (and ethanol) and petroleum-fuel vehicles and hence use the same CO_2 g/mi rate.

Since it is likely that oil will last much longer in NGVs (DeLuchi et al., 1988), I assume that CO_2 emissions from engine oil in NGVs are half those in methanol and gasoline vehicles. LPG vehicles, too, are expected to consume less oil (Fleming and Bechtold, 1982). Recently, Turner et al. (1990) compared the oil consumption in propane and diesel trucks. They measured substantially lower oil consumption in the propane trucks. EVs do not consume oil.

B.6 Leaks and Emissions from Storing, Transferring, and Distributing Fuel

Fuel is lost during production, storage, and distribution. For example, gasoline evaporates, leaks, and spills when it is delivered to service stations, stored at bulk terminals, carried by tankers or tank trucks, and transferred between storage facilities and tankers and trucks. NG leaks from field production facilities, transmission lines, distribution lines, and probably CNG stations. Liquid hydrogen boils and evaporates when it is transferred between containers.

Fuel lost to the atmosphere affects the greenhouse calculation in two ways. First, all fuels, with the exception of hydrogen, are direct or indirect greenhouse gases. Second, the loss of fuel increases the amount of fuel that must be sent through the system to deliver a net unit to the motorist, which in turn increases emissions from fuel production and transport per unit of fuel that actually makes it to the end-user. Both of these effects must be accounted for.

Table 4 in Volume 1 shows the data necessary to estimate fuel losses from both of the effects mentioned above. The table shows, among other things, the fraction of gaseous fuel that leaks from the production and distribution system and the fraction of liquid fuel that evaporates during production, distribution, and storage. With this information, one can calculate the direct greenhouse effect of the loss, per unit of fuel actually delivered, and the make-up effect of the lost fuel. The direct greenhouse effect of the loss is converted to g/mi CO_2-equivalent emissions and incorporated into Table B.2. The make-up effect is expressed as a multiplication factor and is built into the model at various points.

The estimates in Table 4 of Volume 1 of leaks of NG from production and distribution systems are discussed and documented in Appendix M. This section discusses the estimates of the losses of liquids and liquefied gases.

B.6.1 Losses of Gasoline and Alcohols

Evaporative losses, in grams, are a function of the volatility of the fuel, molecular weight of the vapor, and degree of control used. DeLuchi et al. (1991) analyzed the loss from the gasoline system for the year 2000, taking into the account the emission control requirements of the new CAA Amendments and assuming the low-RVP gasoline required in recent EPA legislation. The result is about 4 g/gal for a fairly tightly controlled gasoline-marketing system. The evaporative loss rate for diesel and residual fuels is essentially zero because they have such low RVPs (EPA, 1985, AP-42). The evaporative loss rate for alcohol vehicles is estimated relative to the rate for gasoline vehicles, considering the lower TVP and lower molecular weight of alcohols but also accounting for the possibility of less stringent emission controls (so the alcohol system still will produce much lower evaporative emissions but also save on emission control costs; see discussion above).

In calculating upstream emissions from the use of methanol/gasoline mixes, the model assumes that methanol and gasoline are delivered in separate streams and not mixed until the motorist mixes them in the fuel tank. Thus, the g/mi nonvehicular NMOC emission rate for methanol vehicles is equal to the gasoline g/mi rate multiplied by the gasoline fraction, plus the pure methanol g/mi rate multiplied by the methanol fraction. This method is correct for estimating upstream emissions from mixes used by FFVs but not quite accurate for estimating emissions from M85 because M85 is blended before it gets to the service station. The model will be inaccurate to the extent that upstream evaporative emissions from delivery of an M85 mixture are different from the emissions from a gasoline stream weighted 85% and a methanol stream weighted 15% (this weighted average is what the model calculates). This difference is inconsequential.

The net greenhouse impact of evaporative emissions from biofuels is calculated as the gross impact of the evaporated fuel carbon, less a credit for the carbon (as CO_2) originally removed from the atmosphere by the plant from which the biofuel was made.

Evaporative emissions that occur after the fuel is metered at the dispensing pump are not included in the calculation of the make-up effect, end-use is considered to have occurred after the fuel is metered to the vehicle. Any evaporative loss that occurs after the fuel is dispensed to the vehicle affects the mpg efficiency of the vehicle because the "g" in "mpg" is measured as the fuel is dispensed, but it does not affect the amount of fuel that must be delivered to the pump. Put another way, the make-up effect of evaporative losses that occur after the pump is accounted for in the mpg figure itself; the greater the loss, the lower the mpg figure. However, one must still account for the direct, atmospheric effects of the evaporative emissions of NMOC and the boil-off losses of LNG. This accounting is in Table B.2 ("Vehicular evaporative emissions;" the estimation of this is discussed above).

B.6.2 Boil-off Losses of Liquefied Gases

If a liquid hydrogen (LH_2) vehicle is not used for a few days or an LNG vehicle is not used for more than a few weeks, the liquid fuel stored on the vehicle will warm up, boil off, and vent from the vehicle. (If the vehicle is driven before the vapor pressure reaches the venting point, the vapor will be burned in the engine, and the vapor pressure will be reduced.) This fuel is lost permanently and must be made up all the way back to the fuel production stage. The vaporized LNG is also a greenhouse gas. Because LNG vehicles can sit for a long period of time before they vent (DeLuchi et al., 1988), it is not likely that much fuel will be lost this way. I assume that 0.05% of the fuel will be vented from LNG vehicles. On average, LH_2 vehicles have a much shorter period before they vent because LH_2 is much colder (DeLuchi, 1989); I assume an average loss of 1%. I assume the same for LPG as for LNG.

A liquefied gas also will partially vaporize when it is transferred from a production facility to a tanker truck, from a tanker truck to a service station tank, or from a service station tank to a vehicle tank, if the transfer lines and containers are warmer than the liquid. However, these vapors will not be vented to the atmosphere but will instead be recovered and sent to back to the original

container and eventually put to some use. Thus, vaporized and recovered gas will not be lost or have to be made up by increased gas production. Also, the vaporized liquid will not be a direct greenhouse gas since it will never reach the atmosphere. However, the vaporization of the liquid during transfers affects energy use and greenhouse gas emissions; it reduces the amount of liquid that reaches the motorist per unit of liquefaction energy at the plant and, hence, increases liquefaction energy requirements per unit of liquid gas actually delivered to the motorist. This effect must be accounted for.

Since LNG is likely to be made at service stations (DeLuchi et al., 1988), the only transfer of liquid will occur when it is transferred from the station to the vehicle. Because of this fact, and because of the relatively high temperature of LNG, I assume that vaporization losses will not be more than 1%.

By contrast, LH_2 will probably be made at large centralized facilities and, in many cases, will be transferred three times (production plant to truck, truck to station, and station to vehicle) before it reaches the vehicle. At least 10% of the LH_2 will vaporize at each stage if the lines and tanks are warm; if they are cold, about 5-7% will vaporize (DeLuchi, 1989; private communications from LH_2 suppliers). On average, around 16% of the LH_2 will boil off. Overall, about 84% of the originally liquefied LH_2 will reach the vehicle as LH_2. If advanced technology requires 0.26 Btu-electric to produce a Btu of LH_2 out of the liquefier (Blazek et al., 1986), it will take 0.26/0.84 = 0.31 Btu-electric to deliver a Btu of LH_2 to the motorist. This figure is entered in Table 3 of Volume 1.

B.7 Composite LDV/HDV Methanol Emission Factor

An alternative fuels program is likely to involve both heavy-duty and light-duty vehicles. For example, the 1994 heavy-duty vehicle NO_x and PM emission standards may force the use of methanol or NG. AFVs fare worse against HDDVs than they do against LDVs. Consequently, the aggregate effect of an alternative fuels package depends on the amount of heavy-duty diesel vehicle miles traveled (VMT) affected and the amount of light-duty gasoline VMT affected. Although VMT by HDDVs is very small compared to VMT by gasoline LDVs, HDDVs emit several times more greenhouse gases per mile, which means that the use of alternative fuels in HDDVs can significantly influence the aggregate greenhouse effect of an alternative fuels program.

The aggregate g/mi emissions of an alternative-fuel, heavy-duty, and light-duty fleet can be calculated as:

$$A_e = D_e \times D_m + L_e \times L_m$$

where:

A_e = aggregate g/mi emission factor for alternative-fuel vehicles that replace the gasoline and diesel-fuel fleet;

D_e = g/mi emissions from alternative-fuel HDVs that replace diesel vehicles;

D_m = VMT by alternative-fuel HDVs that replace diesel vehicles, divided by VMT by the whole alternative-fuel fleet;

L_e = g/mi emissions from alternative-fuel LDVs that replace gasoline vehicles; and

L_m = VMT by alternative-fuel LDVs that replace gasoline vehicles, divided by VMT by the whole alternative-fuel fleet.

The variable A_e can then be compared with the similar aggregate factor calculated for the gasoline and diesel fleet to determine the percentage change in g/mi emissions that result from the alternative fuels program continue. To make this calculation, one must determine current and future D_m and L_m for the gasoline and diesel-fuel vehicle fleet. Table B.4 shows that in 1987, diesel-fuel heavy-duty trucks and buses accounted for about 4.5% of all highway VMT, and gasoline-powered autos and light-duty trucks accounted for about 92% of all highway VMT. (The remaining VMT was by medium-duty and diesel LDVs, which I assume are less likely to use alternative fuels.) Overall, diesel-fuel vehicles, including medium- and light-duty vehicles, accounted for about 6% of total VMT. The VMT share of HDDVs is likely to increase because VMT by HDVs is likely to grow slightly faster than VMT by LDVs (EIA, *Assumptions for the Annual Energy Outlook 1990*, 1990; Millar et al., 1985) and because diesel's share of the HDV market may increase even further (EIA, *Assumptions for the Annual Energy Outlook 1990*, 1990).

The data in Table B.4 and the discussion above indicate that if policy mandates that alternative fuels displace gasoline in light-duty applications (autos and trucks) and diesel fuel in heavy-duty bus and truck applications, 5-6% of the VMT will be miles that would have been traveled by diesel vehicles and 94-95% will be miles that would have been traveled by gasoline vehicles. If the alternative fuels are used in both light- and medium-duty trucks, the diesel share of displaced VMT will increase slightly. In the base-case analysis, I assume that of the total VMT displaced by alternative fuels, 94% of the VMT being displaced will be gasoline VMT and 6% will be diesel VMT. There is a considerable difference between the percentage change for alternative-fuel LDVs only and that for light- and heavy-duty vehicles combined, even with only 5% of the VMT by HDVs.

TABLE B.4 VMT by Type of Vehicle and Fuel, 1987 U. S. Data

Fuel and Vehicle	Consumption (10^9 gal)[a]	Average mpg[b]	VMT (10^9 mi)[c]	VMT (%)[d]
Gasoline				93.55
Automobiles	69.72	19.26	1342.8	69.8
Buses	0.498	5.89	2.9	0.15
Trucks	40.08	(11.3)[e]	453.6	23.6
Light trucks	30.72	(13.9)[e]	426.0	22.1
Heavy trucks			13.5	0.7
Diesel				6.11
Automobiles	1.06	19.26	20.4	1.1
Buses	0.682	5.89	4.0	0.21
Trucks	15.16	(6.11)[e]	92.6	4.8
Heavy trucks			83.0	4.3

[a] From *Transportation Energy Data Book* (Davis et al., 1989).

[b] From *Highway Statistics* (USDOT, 1988). The average mpg figures are for all autos and buses; I assume diesel and gasoline vehicles of each class have the same efficiency.

[c] For autos and buses, VMT is calculated as product of total fuel consumed and average mpg, by class.

VMT for trucks is calculated differently. The *1982 Truck Inventory and Use Survey* (USDOT, 1985) reports VMT by weight class and type of fuel, for 1982. In billions of VMT, the numbers are 377.3 (all trucks), 310.1 (all gasoline trucks), 291.2 (light gasoline trucks), 9.19 (heavy gasoline trucks), 63.3 (all diesel trucks), and 56.6 (heavy diesel trucks) ("heavy" is the sum of values for "light-heavy" and "heavy-heavy"). No disaggregated data are available for 1987; however, in 1987, all trucks traveled 551.9 billion miles (USDOT, *Highway Statistics*, 1988; which follows the *Truck Inventory...* classification system). I have scaled the 1982 disaggregated data by the ratio of 551.9/377.3.

[d] Percent of total 1.924 trillion highway VMT in 1987 (USDOT, *Highway Statistics*, 1988). The sum of VMT percentages is slightly less than 1.00 because a small percentage (about 0.4%) of VMT is by LPG vehicles.

[e] Back-calculated from data on fuel consumed and scaled VMT, as a check. These values are reasonable: Most diesel-using trucks are heavy vehicles, averaging between 5 and 6 mpg, whereas most gasoline-using trucks are light vehicles, averaging between 10 and 15 mpg.

Appendix C:

Fuel Specifications and the Fate of Fuel Carbon

Appendix C:

Fuel Specifications and the Fate of Fuel Carbon

The grams of carbon dioxide (CO_2) emitted per mile of travel are equal to the efficiency of combustion (expressed in 10^6 Btu/mi) multiplied by the (oxidized) carbon (C) energy content of the fuel (expressed in grams of C converted to CO_2 per 10^6 Btu of fuel energy). Consequently, to calculate the emissions of greenhouse gases per mile, one must know the amount of carbon in the fuel per unit of the energy of the fuel. This value can be calculated for each fuel from data on fuel characteristics.

Tables C.1-C.3 show the fuel characteristics used in this study. All the characteristics are variable in the model, so they can be changed if better data become available. Unless otherwise noted, all numbers represent higher heating values (HHVs).

The choice of heating-value convention (higher or lower) is immaterial if one does the analysis properly. Strictly speaking, properly calculated g/mi results are completely (exactly or mathematically, not just "roughly") independent of the choice of heating value because heating values cancel out entirely. This is discussed more in Appendix A.

C.1 Crude Oil and Petroleum Products

The important characteristics of petroleum products are mass density, HHV, and carbon content. Different petroleum products (diesel fuel, gasoline, residual fuel, etc.) have different energy and carbon characteristics, so they must be specified differently. There also are differences among grades of the same kind of fuel, among different types of gasolines (e.g., premium unleaded and regular unleaded), and different grades of diesel fuel and residual fuel oil; however, these variations are relatively minor and are not considered here.

C.1.1 Crude Oil

The Energy Information Administration (EIA) and the American Petroleum Institute (API) specify the HHV and the density of crude oil (Table C.1). Gaines and Wolsky (1981) show that the carbon content of crude oil ranges between 83% and 87%, with most crude oils containing about 85.6% carbon. They also show that crude oil consists mainly of alkanes (including cycloalkanes), with a very small amount of aromatics. By comparison, gasoline contains a much smaller amount of alkanes and a much larger amount of aromatics (refining converts some of the alkanes to aromatics and other compounds). Since aromatics have a higher carbon to hydrogen

TABLE C.1 Characteristics of Fuels

Fuel	Higher Heating Values[a]		Density[b]	Carbon[c]	Sulfur
Domestic crude oil	0.1381 × 10^6 Btu/gal	5.800 × 10^6 Btu/bbl	3,191 g/gal	0.855	
Residual fuel oil	0.1497 × 10^6 Btu/gal	6.287 × 10^6 Btu/bbl	3,575 g/gal	0.858	
Diesel fuel	0.1387 × 10^6 Btu/gal	5.825 × 10^6 Btu/bbl	3,192 g/gal	0.858	
Petroleum coke	0.1434 × 10^6 Btu/gal	6.024 × 10^6 Btu/bbl	4,321 g/gal	0.900	
Marketable coke		6.024 × 10^6 Btu/bbl		0.900	
1987 gasoline	0.1251 × 10^6 Btu/gal	5.253 × 10^6 Btu/bbl	2,791 g/gal	0.866	0.0003
Reformulated gas	0.1222 × 10^6 Btu/gal	5.132 × 10^6 Btu/bbl	2,749 g/gal	0.833	0.0003
Methanol	0.0645 × 10^6 Btu/gal[d]		2,996 g/gal[e]	0.375[f]	
Ethanol	0.0846 × 10^6 Btu/gal[g]		2,988 g/gal[e]	0.522[f]	
Generic coal		21.340 × 10^6 Btu/ton		0.610[h]	0.0131[i]
Coal to power		20.923 × 10^6 Btu/ton		0.600[h]	0.0099[i]
Coal to methanol		21.340 × 10^6 Btu/ton		0.610[h]	0.0131[i]
Hydrogen	7,470 g/10^6 Btu	338.000 Btu/SCF[j]		0.00	
LPG for refineries[k]	0.0920 × 10^6 Btu/gal	3.863 × 10^6 Btu/bbl	2,053 g/gal		
NGLs		3.812 × 10^6 Btu/bbl[l]			
Electricity		3,412 Btu/kWh			
Steam		1,200 Btu/lb[m]			
Petroleum products		5.395 × 10^6 Btu/bbl[n]	6.68 bbl/ton		
Other refinery oil		5.825 × 10^6 Btu/bbl			
Oven-dried wood		8,350 Btu/lb			

[a] Values are from EIA's *Monthly Energy Review*, for the year 1988, unless otherwise noted. Where 10^6 Btu/gal and 10^6 Btu barrel are both shown, the former is calculated from the latter assuming 42 gal/bbl.

[b] From EIA *International Energy Annual* (1989), unless otherwise noted.

[c] Values for petroleum products from various sources, including Rose and Cooper (1977), Gaines and Wolfsky (1981), Francis and Peters (1983), Marks (1982), Rotty and Masters (1985), EPA mpg and emissions certification data, and my analysis of the composition of gasoline (see text and Table C.2).

TABLE C.1 (Cont.)

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[d] Calculated from combustion enthalpy. Consistent with value in *Transportation Energy Data Book* (Davis and Hu, 1990).

[e] From CRC, *Handbook of Chemistry and Physics* (1975).

[f] Calculated from chemical composition.

[g] From Davis et al., *Transportation Energy Data Book* (1989).

[h] Chosen to match heating value, using EIA, *Coal Data: A Reference* (1989) data.

[i] The EIA projects that under the new CAA, coal used by utilities will contain 0.99% sulfur in the year 2000 (EIA, *Improving Technologies*, 1991). The EIA also projected that the sulfur content would be 1.31% in the absence of the new CAA; I use this value to represent the sulfur content of coal used in nonutility applications.

[j] Calculated from combustion enthalpy and ideal gas law.

[k] For LPG used by and made by refineries. I have used the HHV of propane, because virtually all of refinery LPG production is propane. LPG as a vehicular fuel is specified in Table C.3.

[l] EIA's *Natural Gas Annual* (1989) gives essentially the same result.

[m] Lacey and Stroud (1983) use 1,700 Btu/lb; Gaines and Wolsky (1981) use 1,100; TRW (1980) uses 1,333.

[n] For 1989 The HHV of product i multiplied by refinery output of product i, summed for all products, then divided by total refinery barrel output (from EIA, *Annual Energy Review*, 1990).

TABLE C.2 Analysis of Petroleum Products

Class of Compound	Carbon Fraction[a]	Density (g/L)[b]	HHV (kJ/g)[c]	Gasoline, volume fractions						Diesel	
				ARCO EC-1[d]	ARCO No-Lead[d]	Summer Grade[e]	Winter Grade[e]	Yearly Average[f]	Reform-ulated[g]	In-Use Fuel[h]	Test Fuel[h]
C_{12}-C_{20} alkanes[i]	0.850	780.0	47.3							0.770	0.880
C_4-C_{12} alkanes[j]	0.843	700.0	47.9						0.60		
C_5-C_{12} alkanes[k]	0.840	680.0	48.1	0.507	0.437	0.486	0.641	0.55		0.000	0.000
Aromatics[l]	0.900	870.0	42.7	0.209	0.336	0.444	0.298	0.35	0.20	0.213	0.105
Napthenes	0.857	770.0	46.7	0.109	0.089	0.000	0.000	0.00	0.00	0.000	0.000
Alkenes[m]	0.857	770.0	47.5	0.120	0.123	0.070	0.061	0.10	0.05	0.017	0.015
Ethanol	0.521	789.0	29.9	0.000	0.000	0.000	0.000	0.00	0.00	0.000	0.000
ETBE	0.705	747.0	40.2	0.000	0.000	0.000	0.000	0.00	0.00	0.000	0.000
MTBE	0.681	746.0	40.1	0.055	0.000	0.000	0.000	0.00	0.15	0.000	0.000
Calculated (g/L)				736.9	766.8	770.7	742.1	755.5	744.4	799.0	789.3
Calculated (kJ/g)				46.31	46.06	45.35	46.18	45.86	45.49	46.24	46.77
Calculated (C fraction)				0.8477	0.8641	0.871	0.862	0.866	0.833	0.861	0.856
Calculated (10^6 Btu/gal)				0.1225	0.1257	0.1232	0.1225	0.1243	0.1215	0.1389	0.1363
Reported (C fraction)				0.849		0.869	0.857			0.858	0.864
Reported (g/L)				737.4	760.3	757.0[n]	739.0[n]			836.9	811.8

"Calculated" values are calculated by me, using the compositional data and HHV, density, and C fraction data of the table. "Reported" values are those co-reported with the compositional data (see notes below).

[a] For alkanes, carbon fraction is for compounds in the middle of the range; for alkenes and napthenes, carbon fraction based on atomic formula C_nH_{2n}.

[b] From the *CRC Handbook of Chemistry and Physics* (1975), for compounds representative of the class of compounds shown. Values for MTBE and ETBE are from Baur et al. (1990).

TABLE C.2 (Cont.)

[c] From the *CRC Handbook of Chemistry and Physics* (1975), for compounds representative of the class of compounds shown. Value for MTBE calculated by multiplying the LHV given in Baur et al. (1990) by the ratio of the HHV of methanol to the LHV of methanol; value for ETBE calculated analogously, using LHV in Baur et al. (1990).

[d] Composition and reported C and g/L data from Boekhaus et al. (1990). Composition data are weight fractions, not volume fractions. EC-1 is ARCO's reformulation for leaded gasoline.

[e] Compositon and reported C and g/L data from Braddock (1981).

[f] My estimate, based on data in Boekhaus et al. (1990), U. S. Government Accounting Office (1990), Stump et al. (1989), Sigsby et al. (1987), Braddock et al. (1986), and Braddock (1980).

[g] My estimate, based on reformulations now being tested or proposed (EIA, *The Motor Gasoline Industry*, 1991; Boekhaus et al., 1990; Piel, 1989; see also Appendix H). The EIA (*The Motor Gasoloine Industry*, 1991) states that the petroleum industry thinks of reformulated gasoline as having 20% aromatics, 5% olefins, and 2% oxygen. "Interim" reformulations already on the market have an aromatics content of 20-25% and an oxygen content of 1.0-2.5% (Peyla, 1991), and "final" refomulations are expected to have more oxygen and less aromatics. For example, among the several reformulations being tested at ARCO, one with only 10% aromatics is one of the most promising (Babikian, 1991). The composition estimated here is between the composition of the interim reformulations, and the 10% aromatics-composition being tested by ARCO.

The reformulation specified here has more oxygen than is required under the new Clean Air Act, and less aromatics than may be required. There are several reasons why the final versions of reformulated gasoline are likely to go beyond the 25% aromatics/2%oxygen requirements of the CAA (the 25% requirement is actually one of two options). First, California is likely to require a considerably more stringent reformulation, and other states may follow California's lead. Second, the CAA states that the reformulated gasoline must meet the more stringent of two options: (1) contain no more than 25% aromatics or (2) provide a 15% reduction in emissions of VOC and toxics. It is likely that the second option will prove more stringent and that reformulated gasoline will have to contain less than 25% aromatics to satisfy it. Third, the EPA may limit aromatics to 20% or less. Fourth, the CAA grants credits for making a reformulated gasoline with less aromatics or more oxygen than is required (EPA, *Clean Air Act Amendments*, 1990). And fifth, as discussed above, the oil industry appears to be working towards more severe reformulations than the minimum required by the CAA (probably for the reasons enumerated here).

[h] Compositional and reported C and g/l data from Dietzmann et al. (1980). "In-use fuel" is national average for DF-2. Test fuel is DF-1 emissions test fuel.

[i] Range of alkanes in diesel fuel.

TABLE C.2 (Cont.)

[j] Range of alkanes in gasolines in current gasoline. I consider heptane to be the representative compound.

[k] Range of alkanes in gasolines in reformulated gasoline. I assume that RVP regulations eliminate butane, and that this changes the representative compound to octane.

[l] Includes napthenes, except for the ARCO data.

[m] Typically called "olefins" in the literature.

[n] These are values for commercial grade gasoline, which is not the same as "in-use" gasoline. Braddock shows lower densities for actual, in-use gasoline.

TABLE C.3 Analysis of Raw Natural Gas, Pipeline Natural Gas, Coal-Bed Gas, Refinery Gas, and LPG

Feature	HHV[a] (kJ/mole)	Summation factor[b]	Input Gas Volume Fractions				
			Raw NG[c]	Pipeline[d]	Coal Bed[e]	Refinery[f]	LPG
CH_4	890.650	0.0490	0.840	0.925	0.964	0.420	0.000
C_2H_6	1,560.690	0.1015	0.050	0.040	0.002	0.420	0.000
C_3H_8	2,219.170	0.1530	0.023	0.010	0.000	0.020	0.950
C_4H_{10+}	2,877.400	0.2112	0.026	0.010	0.000	0.010	0.050
CO_2	0.000	0.0670	0.028	0.005	0.010	0.010	0.000
N_2	0.000	0.0224	0.021	0.010	0.024	0.000	0.000
H_2	285.830	NA	0.000	0.000	0.000	0.100	0.000
H_2S	562.010[g]	0.1000[h]	0.012	0.000	0.000	0.010	0.000
H_2O	0.000	0.1000[h]	0.000	0.000	0.000	0.010	0.000
Compressibility factor			0.997	0.997	0.998	0.995	0.976
Density (g/liter)[i]			0.809	0.720	0.682	0.903	1.877
Density (g/SCF)			22.919	20.391	19.305	25.585	53.149
HHV (kJ/standard liter)[i]			39.315	38.419	35.305	46.702	94.345
HHV (Btu/SCF)			1,055.545	1,031.512[j]	947.898	1,253.880	2,533.051
HHV (g/10^6 Btu)			21,713	19,768	20,366	20,405	20,982
HHV (10^6 Btu/bbl)							
Carbon weight fraction[k]			0.696	0.740	0.707		
Sulfur weight fraction				0.000007[l]			

[a] Higher heating values (HHVs) at 298 K are based on "new recommendations" reported by researchers at the National Bureau of Standards and the Texas A&M Thermodynamics Research Center (Garvin et al., 1986).

[b] Used to calculate the compressibility factor, which, in turn, is meant to account for nonideal gas behavior.

[c] Compositon calculated from composition of pipeline gas and data on the amount of nonhydrocarbon gases and NGLs removed (EIA, *Natural Gas Annual*, 1989).

[d] Composition based in part on data of Table C.4.

[e] Composition from Deul and Kim (1988). See Appendix M.

TABLE C.3 (Cont.)

[f] See discussion in this appendix and Table C.5.

[g] Value for H_2S is heat of formation of $SO_2 + H_2O - H_2S$.

[h] I estimated summation factors for H_2O and H_2S assuming they had 0.99 compressibility factors.

[i] Calculated using a modified form of the ideal gas law as given in van der Lugt (1986). The modification uses the compressibility factors, shown in the table; compressibility factors are calculated from summation factors, also shown in this table.

[j] Calculated from composition; composition adjusted so that result matches HHV reported in EIA's *Annual Energy Review* (1990).

[k] Calculated from composition of gases.

[l] From EPA's AP-42.

ratio than alkanes, the carbon content of crude should be less than that of current gasoline. Below, I show that the current gasoline is about 86.6% carbon. Thus, the carbon contents used here are mutually consistent.

Gasoline and diesel fuel, unlike methanol, ethanol, hydrogen, and methane, are a mixture of many compounds with different carbon contents. Hence, the carbon content of petroleum products will vary as a function of their precise compositions. In the following sections, I analyze the characteristics of current gasoline, reformulated gasoline, and diesel fuel as a function of composition.

C.1.2 Current Gasoline

Table C.2 calculates the HHV, density, and carbon content of gasoline, given its composition, and it also shows the reported measurements of HHV and density. The results and data show that gasoline contains between 86% and 87% carbon, has an HHV of 122,000-126,000 Btu/gal, and has a density of 740-771 grams per liter (g/L). In Table C.2, the calculation of carbon content is likely to be more accurate than the calculations of density and HHV, because the calculations of density and HHV assume that the overall density is equal to the average of the density of the components, which is not exactly accurate because of interactions among components. The carbon content is the most important value because it directly determines CO_2 emissions.

The reported and calculated carbon contents of Table C.2 agree with data from several other sources. The U. S. Environmental Protection Agency (EPA) assumes that gasoline hydrocarbon emissions, on the average, can be represented as $CH_{1.85}$ (*Federal Register*, April 11, 1989), which is 86.6% carbon. Ho (1989) of Amoco also represents gasoline as $CH_{1.85}$. Rose and Cooper (1977) estimate that British gasoline is 85.0-88.5% carbon. The EPA certification emission measurements of carbon monoxide (CO), hydrocarbon (HC), and CO_2 emissions per mile and the corresponding mile-per-gallon (mpg) fuel economies, consistently indicate a carbon content of between 86.2% and 86.8%.

In summary, it is well established (by compositional analysis, reported carbon content, and back-calculation from emissions data) that gasoline is about 86.6% carbon. I use this value to represent current gasoline.

The EIA states that gasoline has a density of 737 g/L. Braddock (1981) reports that the national average summer fuel density is 744 g/L and the national average winter fuel density is 735 g/L, which gives a year-round average of 739 g/L; this is very close to the EIA value. Because these two sources agree and because the densities of Table C.2, which are higher, are probably not that accurate (because of the failure to account for molecular interactions between the components of gasoline), I use the EIA value for current gasoline.

The EIA estimates that gasoline has a HHV of about 125,100 Btu/gal. This value is within the range of Table C.2. I use this value for current gasoline.

C.1.3 Reformulated Gasoline

Table C.2 calculates the characteristics of a reformulated gasoline. I have reformulated gasoline by reducing its content of aromatics, olefins, and butane, increasing its content of alkanes, and adding methyl tertiary butyl ether (MTBE), as is widely expected (see Appendix H). This results in a lower carbon content and 10^6 Btu/gal density, as would be expected, given the addition of oxygenates and the elimination of some high-carbon, high-energy aromatics. These results are supported by ARCO's report that EC-1 has a lower carbon content and volumetric density than the baseline leaded gasoline (Boekhaus et al., 1990).

The reformulated gasoline of Table C.2 has less carbon, a lower HHV, and a lower density than current gasoline (compare calculated results for "yearly average" gasoline to "reformulated" gasoline in Table C.2). In this analysis, I represent reformulated gasoline by multiplying the attributes of the current baseline gasoline (density, carbon content, and heating value) by the ratio of calculated attribute for reformulated gasoline to the calculated attribute for current gasoline, instead of using the calculated absolute attributes for reformulated gasoline in Table C.2, because the calculation method in Table C.2 more accurately represents the change from current to reformulated gasoline than it represents the absolute characteristics of reformulated gasoline. Reformulated gasoline is used in the base-case analyses.

C.1.4 Diesel Fuel

The EIA uses an HHV of 138,700 Btu/gal, and a density of 843.2 g/L. Dietzmann et al. (1980) report that nationally, diesel fuel averages 836.9 g/L. By using the Dietzman data on the composition of this national average diesel fuel, I calculate that it has an HHV of 138,900 Btu/gal (Table C.2). All of these estimates are extremely close; I use the EIA values.

Dietzmann et al. (1980) report a national average carbon content of 85.8%. They note that the carbon content of the diesel fuel used in EPA emissions tests is a bit higher, at 86.4%. (To check this, I back-calculated the carbon content of the diesel fuel used in EPA certification tests, given the EPA data on CO, HC, and CO_2 g/mi emissions and mpg fuel economy, and found it to be between 86% and 87%). Therefore, I use 85.8%.

Low-sulfur diesel fuel should have essentially the same carbon content, density, and heating value as current diesel fuel. Reducing sulfur from 0.25% to 0.05%, by weight, cannot change the overall density and carbon content of diesel fuel by more than 0.2%, unless the HC portion of diesel is reformulated as well. By contrast, the reformulation of gasoline will change its

characteristics by 3-4%. Thus, any change in the characteristics of diesel fuel is likely to be negligible and one order of magnitude smaller than the changes in the characteristics of gasoline.

C.2 Natural Gas and Liquefied Petroleum Gas

To calculate greenhouse gas emissions from the end-use of natural gas, one must know the heating value, density, and carbon content of pipeline gas. To calculate the greenhouse impact of venting and flaring raw gas, one must know the heating value, density, carbon content, and composition of raw or uncleaned gas. Of course, the composition of pipeline gas is related to the composition of raw gas (pipeline gas is raw gas with certain amounts of nonhydrocarbon gases and natural gas liquids removed).

The heating value, density, and carbon content of raw and pipeline natural gas depend on its composition. Natural gas is a mixture of several gases, including hydrocarbons, CO_2, nitrogen (N_2), water (H_2O), and hydrogen sulfide (H_2S). These component gases have different heating values, densities, and carbon contents; consequently, the overall heating value, density, and carbon content of natural gas all depend on the proportions of the components. The greenhouse model used here takes detailed input data on the composition of pipeline gas and calculates the composition of raw gas from those data and from the data on the quantities and kinds of gases removed from raw gas.

The pipeline gas composition used in the model is specified in Table C.3. I chose this pipeline gas composition in accordance with the results of a detailed national survey of gas quality, as reported in Weaver (1989) and shown in Table C.4, to end up with an aggregate HHV equal to the U. S. national average HHV as reported by the EIA (*Annual Energy Review 1989*, 1990). The Aerospace Corporation (1982) reviewed old national data on gas quality and arrived at a national average composition similar to that found in Table C.4.) The aggregate heating value of the mixture shown in Table C.4 is very close to the EIA's average heating value, so only minor adjustments are needed to arrive at a composition with the EIA's HHV.

The raw gas composition (which is used, as explained above, to estimate the greenhouse impact of venting and flaring raw gas) is calculated from the input data on the composition of pipeline gas and from data on the amount and kind of HC gases and natural gas liquids removed from raw gas (EIA, *Natural Gas Annual*, 1989). This calculation ensures that all the data used here are mutually consistent. The calculated raw gas composition is very similar to the composition of raw gas reported in a Canadian study: 86.2% methane (CH_4), 2.9% C_2, 1.6% C_3, 2.6% C_{4+}, 2.9% CO_2, 2.9% H_2S, and 1.8% N_2 (Webb and PPS, 1983).

I use one specification of the composition of natural gas for all end uses. Although the composition of natural gas varies among regions, it does not appear to vary systematically among end uses. For example, the natural gas consumed by utilities has the same heating value as the natural gas consumed by residences and industry (EIA, *Annual Energy Review*, 1990; EIA, *Cost and Quality of Fuels*, 1989).

TABLE C.4 Average Mole Percent of Constituents of Natural Gas, from a Survey of 115 Gas Distribution Companies in the United States[a]

Compound	Mole %
CH_4	92.21
C_2H_6	3.78
C_3H_8	0.91
C_4H_{10} and up	0.61
CO_2	0.59
N_2	1.84
H_2	0.01
O_2	0.05

[a] As shown in Sierra Research (1989).

The energy density and carbon weight fraction of LPG are also calculated from input volumetric shares of individual gases (primarily propane and butane). The base case mixture is shown in Table C.3.

C.3 Coal-Bed Gas

See discussion in Appendix M.

C.4 Refinery Gas

Refinery gas, which is a mixture of paraffins and other gases stripped from crude oil, provided half of the total fuel energy used by refineries in the U. S. in 1988 (EIA, *Petroleum Supply Annual*, 1989). The composition, and hence the heating value and the carbon fraction, varies not only from unit to unit in a refinery (Table C.5) but also over time in the same unit. However, intra-unit intertemporal variation is small when compared with inter-unit variation. Catalytic reformers, which convert the alkanes in petroleum to the higher-octane products needed in gasoline, produce a hydrogen-rich off-gas because alkanes have a higher H:C ratio than aromatics, olefins, and other high-octane compounds. Crackers, on the other hand, break down large molecules into smaller ones and do not produce much hydrogen. In fact, some forms of cracking consume hydrogen. For example, the breaking of a C_8H_{18} alkane into two C_4H_{10} alkanes increases total hydrogen. Hydrocracking is done in the presence of hydrogen.

TABLE C.5 Volumetric (mole) Composition of Refinery Gas from Various Processes in Percentages

	Composition by Process and Source (%)								
	Catalytic Reforming			Catalytic Cracking			Hydrodealkylation	"Average"	
Type of Gas	A	B	C	D	D	E	A	E	F
Hydrogen	65-90	80+	73.91	8-20	10.4	16.99	40-65	34.65	40
C_1 (methane)	4-10		12.57	20-45	22.2	31.06	20-35	20.54	19
C_2 (ethane)	4-10		6.78	10-35	12.9	26.28[b]	0-5	25.81[b]	16
C_3 (propane)	2-6		3.71	2-8	21.2	8.27[b]	0-2	7.35[b]	
C_4 (butane)	2-5		1.83	0-8	30.0	2.77[b]	0-1	4.34[b]	
Others[c]	0-5		1.20	0-9	3.5	14.63	0-1	7.31	
1988 mbd capacity[d]	Reforming			Catalytic cracking					
World	8,419			10,091					
U. S.	3,715			5,368					

A = Banks and Isalski (1987), B = Lowder (1989), C = Tomlinson and Finn (1990), D = Wiseman (1986), E = Guerra et al. (1979), and F = weighted average calculated in this study.

[a] Calculated from the data of this table, assuming 75% H_2, 10% CH_4, and 7% C_2 from catalytic reforming units, assuming 15% H_2, 25% CH_4, and 22% C_2 from catalytic cracking units, and weighting catalytic reforming off-gas by 41% and catalytic cracking off-gas by 59% (the weighting factors are based on the 1988 capacity shown here).

[b] Includes alkenes.

[c] Others for source C is C_5+. Others for source A is C_5+, aromatics, water, and acid gases. Others for source D is H_2S. Others for source E is CO_2, CO, O_2, and higher alkanes and alkenes.

[d] From EIA, *International Energy Annual* (1989).

Table C.5, drawn from data from several sources, quantifies the composition of refinery off-gas from various units. Using these data, I have estimated an average, or weighted, composition of refinery gas by weighting the off-gas from catalytic crackers and catalytic reformers in proportion to the 1988 worldwide and U. S. daily capacity of each of kind of unit (see footnote a to Table C.5). Of course, the ratio of the capacity of catalytic crackers to the capacity of reformers does not necessarily equal the ratio of the amount of gas produced by crackers to the amount of gas produced by reformers (which is what we want to know) because there is an intervening variable, namely the unit of off-gas produced per barrel of product run. Despite this fact, I hope my calculation is serviceable as an approximation of the amount of off-gas from each unit. This calculated average is consistent with the average specified by Guerra et al. (1979; reference "E" in Table C.5 here).

The amount of off-gas produced does not necessarily equal the amount burned as a fuel; some of it is used as a chemical feedstock. Typically, much of the hydrogen off-gas from the reformer is used in the hydrotreating unit (Berger and Anderson, 1979), which, among other things, converts olefins to paraffins which requires a substantial amount of hydrogen (paraffins have a higher H:C ratio than olefins). The higher alkanes and alkenes, C_{3s} and C_{4s}, from catalytic crackers are used in the alkylation units to produce high-octane gasoline components (Wiseman, 1986). The subtraction of hydrogen and C_{3+} alkanes from refinery gas leaves predominantly methane and ethane. This composition is different than the weighted composition of off-gas produced.

How much hydrogen is and will be removed from refinery gas? The answer depends on the hydrogen needs of the refinery, the ability of the refinery to recover the hydrogen, and the ability of the refinery to burn a hydrogen-rich off-gas. On the one hand, refineries cannot strip all the hydrogen from the off-gas (EIA, *Refinery Evaluation Modeling System*, 1984), so they have developed turbines that run on hydrogen-rich reformer off-gas (Lowder, 1989). On the other hand, refineries are likely to recover hydrogen more vigorously in the future because although they will be producing less of it internally, they will have a greater need for it. They will be producing less because gasoline reformulation will force them to curtail use of the reformer, which is a main source of hydrogen. They will need more because reformulation will require increased hydrocracking and hydrotreating.

My assumption about the composition of refinery gas, which is based on the foregoing analysis and discussion of the production and disposition of refinery off-gas, is shown in Table C.3. The HHV of this composition, calculated by the model and shown in Table C.3, compares well with the heating values in the literature, including those used by the EIA and the API. The EIA uses an old Bureau of Mines estimate of 6 10^6 Btu/bbl as the volumetric energy content of refinery gas, which, when combined with API's 3,600 ft^3/bbl (American Petroleum Institute, *Basic Petroleum Data Book*, Washington, D.C. [1989]) value, yields 1,666.7 Btu per standard cubic foot (SCF). The API (1976) relies on data in Maxwell (1950), who assumes that refinery gas is a mixture of paraffins, hydrogen sulfide, and inert gases, with an HHV ranging from 1,000 to 2,000 Btu/SCF. Finally, Berger and Anderson (1979) state that the heating value of refinery gas averages 1,500 Btu/ft^3.

In the future, the composition of refinery gas will change because changes in the quality of the input crude oil and in the demand for products will change the usage and operating characteristics of refinery units. The use of lower quality, heavier crude oil will increase the use of cracking units; the need to boost octane will increase the use of reformers. Because it is not clear toward which direction the composition will change, I assume that it will be the same in the year 2000.

C.5 Coal

The CO_2 emissions per unit of coal energy are approximately equal to the coal's carbon weight per unit of energy (C/Btu) multiplied by 3.666 (C to CO_2). (I say "approximately" because a tiny portion of the carbon is not burned to CO_2 and because sulfur scrubbing can result in additional CO_2 emissions, depending on the process and sorbent used). The carbon content per Btu is never reported as such; one must calculate it from the reported carbon weight percent and the Btu/lb heating value. In doing this calculation, one point should be kept in mind: the carbon weight percentage and the HHV must be estimated on the same basis ("as received," "moisture free," or "moisture and ash free").

The specifications of a coal, including its Btu/lb heating value and weight percentage of carbon, depend on whether the coal is analyzed with or without ash and moisture. The coal can have both moisture and ash (usually coal as received at the facility has both moisture and ash), ash but no moisture (moisture-free [MF], or dry coal; I use this as the analytical basis), or neither moisture nor ash (moisture-and-ash-free [MAF], or dry ash-free [DAF] coal). An analysis of the carbon, nitrogen, hydrogen, oxygen, and sulfur content of MAF coal is called an ultimate analysis. Because neither moisture nor ash contains carbon or is combustible, the C/Btu value of a coal is independent of the analysis basis. Therefore, the carbon percentage and Btu/lb must be measured on the same basis (MAF, MF, or as-received), but it does not matter which basis is used.

In addition to being independent of the analysis basis, the C/Btu value of the coal is almost independent (to within about 5%) of the rank of the coal, when anthracite is excluded (Table C.6). As shown in Table C.6, virtually all coal contains 17,000-18,000 Btu/lb of carbon. (Note that the sources of Table C.6 are in very close agreement with one another.) As the heating value increases, the carbon content also increases, about proportionately. Winschel (1990) on the basis of an analysis of 504 North American coals, reports values that are within 1-3% of those of Table C.6. The unweighted average of the Table C.6 data, excluding anthracite, is about 17,600 Btu/lb of C; the average of the Winschel data set is about 17,400 Btu/lb. Since anthracite is such a negligible percentage of U. S. production, the Btu/C (and hence C/Btu) value of U. S. coal, for practical purposes, can be assumed to be nearly constant. This assumption is important, because it eliminates the need for analyzing scenarios on the basis of the composition of coal.

TABLE C.6 Btu per Pound of Carbon in Coal

Rank of Coal	EIA *Coal Data* (1989)	Smith & Smoot (1990)	Hensel[a]
Anthracite	16,194		16,538
Low-volatile bituminous	17,299	17,174	17,341
Medium-volatile bituminous	17,536		17,472
High-volatile A	17,901	17,671	17,952
High-volatile B	17,940		17,757
High-volatile C	18,104	17,938	17,658
Subbituminous A	17,618		17,352
Subbituminous B	17,820		17,175
Subbituminous C	16,950	16,973	16,901
North Dakota lignite	17,250		17,093

All analyses based on ultimate, MAF basis.

[a] As cited in Smith and Smoot (1990).

The greenhouse model accepts three different kinds and uses of coal: coal for electric utilities, coal for coal-to-methanol plants, and coal for other consumption. I specify the carbon content and heating value so that they are mutually consistent (i.e., result in Btu/lb-C of value equal to that for subbituminous A coal).

Appendix D discusses the conversion of sulfur to CO_2 as a result of scrubbing. In the base case, I use the national-average sulfur content projected by the EIA for 2000 (EIA, *Improving Technology*, 1991). The EIA projects that the Clean Air Act (CAA) will induce greater use of low-sulfur coal; hence, the coal used by utilities will have a lower sulfur content (on average) than it does today.

C.6 Proper Accounting of the Fate of Fuel Carbon

In most combustion applications, nearly all of the carbon in an HC fuel (95-99%) is fully oxidized to CO_2 in the combustion chamber or in the hot exhaust, flue, or stack gases. The remaining fuel carbon leaves the tailpipe or stack as CO, CH_4, nonmethane hydrocarbons (NMOCs), or soot (carbon), or is deposited in the combustion device as carbon. The non-CO_2 carbonaceous emissions eventually oxidize in the atmosphere to CO_2 (the soot remains as carbon). However, before they oxidize to CO_2, CO and NMOCs participate in an atmospheric chemistry that affects the concentration of greenhouse gases. NMOC and NO_x emissions are instrumental in ozone formation chemistry; CO emissions increase the residence time of methane by reacting with $OH^{\bullet}$ and reducing its ($OH^{\bullet}$) availability as a sink for methane (methane and tropospheric ozone are greenhouse gases). Methane emissions contribute directly to the greenhouse effect.

Consequently, it is not accurate to treat all fuel carbon as directly converting to CO_2 (even though all of it eventually does become CO_2) because of the intermediate stage of some carbon as CO, NMOC, or CH_4. Nor is it correct to treat all fuel carbon as oxidizing to CO_2 and then factor in CH_4 emissions, because this procedure double-counts some fuel carbon, once as CO_2 and again as CH_4. This analysis treats emissions of non-CO_2 organic gases correctly and in detail. First, emissions of CO, NMOC, and CH_4 are input into the model by using the best available emission factors (mostly from the EPA). The carbon content of these CO, NMOC, and CH_4 emissions is deducted from the total carbon content of the fuel consumed; the carbon remaining in the fuel is then assumed to be emitted as CO_2. Then NMOC, CO, and CH_4 (and N_2O and NO_x) emissions are converted to CO_2-equivalent emissions by a procedure (described in Appendix O), that accounts for the lifetime of the gases, their radiative adsorption strength, their eventual oxidation to CO_2, and chemical interactions. The CO_2-equivalents are added to actual CO_2 emissions.

Appendix D:

Electricity Generation and Use

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Electricity Generation and Use

D.1 Conventions of the Analysis

The use of electricity does not produce emissions of any kind at the actual point of end use. Likewise, the distribution of electricity does not produce greenhouse gases, aside from probably minor amounts of nitrous oxide (N_2O) from corona discharge (see Appendix N; I have included this N_2O here) and ozone from ionization of oxygen by the magnetic field. However, the combustion of fossil fuels used to generate electricity produces CO_2 and other greenhouse gases.

The fact that electricity energy consumption can be measured at the point of end use, as power consumption by utility customers, or at the point of generation, as fuel consumption by utilities, can cause serious confusion. About three times more energy (in Btu) is consumed by power plants than is made available to customers (in the definitional Btu equivalent of kilowatt-hours). Thus, when one is talking about electricity consumption or the energy-equivalent of electricity, it is important to be clear about whether one is measuring electricity consumption at the point of end use (3,412 Btu/kWh) or in fuel inputs to electricity consumption. For example, if an article says that compressing natural gas (NG) takes five units of energy for every 100 units of compressed natural gas (CNG) produced and that compressors use electricity, I will calculate roughly three times greater emissions of greenhouse gases if I assume the article means five units of end-use electricity rather than five units of fuel energy input to the generating plant. I will do so because five units of end-use electricity consumption requires about 15 units of fuel energy input, and it is fuel use at the plant, not end use, that produces the greenhouse gases. If the article does not tell me where it measures those five units, I must guess.

Unfortunately, there is no agreement about where electricity consumption should be measured, and writers use both measures, sometimes without explanation. Here, when I speak of 10^6 Btu of electricity or power or of the proportion of total energy that is supplied by electricity, I always mean electricity at the point of consumption, at 3,412 Btu/kWh, unless I definitely state otherwise. Thus, when I write that NG compression requires five energy units of power for every 100 energy units of CNG produced, I mean that 5 Btu of electricity (0.001465 kWh) are consumed by the compressor for every 100 Btu of CNG produced (at 3,412 Btu/kWh). I refer to these Btu as "Btu-electric," and the electricity consumption as "power" or "end-use consumption." I refer to Btu input to the power plant as "Btu-thermal." (Occasionally I discuss how I have converted someone else's measurement at the point of generation to a value at the point of use and, for these discussions, I need to distinguish the different ways of measuring Btu of electricity.)

I chose this convention for practical purposes. There is no universally correct conversion from Btu of fuel input to Btu (kWh) of electrical energy output; the conversion rate, or heating value (Btu/kWh), depends on the efficiency of electricity generation. This rate varies with technology, operating conditions, and so on. Consequently, if one chooses a particular heating

rate — say, 10,000 Btu/kWh — and later decides that it should be different, one has to go back and change every expression involving electricity consumption. On the other hand, if one expresses electricity consumption at the point of end use — 3,412 Btu/kWh — and treats generation efficiency as a separate variable, then one can change generation efficiency without ever changing electricity consumption.

To return to an example: suppose that 15 kWh of electricity produce 10^6 Btu of CNG. By my convention, the efficiency of compression is $15 \times 3{,}412/1{,}000{,}000 = 5.12\%$. This efficiency ratio stays the same regardless of whether electricity generation is 20% efficient or 40% efficient, so I could use it throughout my analysis and never change it, even if I were to change my assumptions about the efficiency of generation 100 times. On the other hand, if I were to express electricity in terms of Btu thermal, I would have to change the efficiency ratio every time I changed my assumption about electricity generation efficiency: at 11,000 Btu/kWh, efficiency would be $15 \times 11{,}000/1{,}000{,}000 = 16.5\%$, but at 9,000 Btu/kWh, the answer would be 13.5%. With either convention, changing the efficiency assumption would change the results, but with the Btu-thermal convention, changing the efficiency assumption would require one to change the expression of the efficiency or amount of electricity use. My convention avoids this.

Of course, I do not ignore greenhouse gas emissions from power generation. I calculate these in the normal course of tracing energy use back from the point of consumption through the point of generation to the point of feedstock recovery. Generation efficiency comes into play in the calculation of emissions from power plants and is a variable in the model.

D.1.1 Internal Use of Power by Electric Power Plants

A portion of the total power produced by the generators at a power plant is used by the plant itself for lighting, equipment, and so on. I account for this internal use by using net generation efficiency — 10^6 Btu of power out of the plant per 10^6 Btu of fuel into the plant — in all calculations in the model. All Energy Information Administration (EIA) electricity statistics are calculated on the basis of net generation.

D.2 Greenhouse Gas Emissions from the Use of Electricity

To calculate greenhouse gas emissions due to electricity use for a particular process (e.g., petroleum refining), one must know the (1) amount electricity consumed at the point of use per unit of product or service provided; (2) grams of greenhouse gases emitted per unit of electricity delivered to the process for each fuel; (3) percentage of each kind of electricity — coal, nuclear, gas, or oil-based — produced by utilities in each city or region or country contributing to the process; and (4) contribution of each city or region or country to the total process.

Formally:

$$T_p = EL_p \times \sum_{f,r} \left[G_f \times E_{f,r} \times P_{p,r} \right]$$

where:

T_p = total greenhouse gas emissions from electricity use, in grams per unit of process p (e.g., p could be petroleum refining);

EL_p = electricity use by process p, in 10^6 Btu of end-use electricity per unit of process p;

G_f = greenhouse gas emissions from fuel f per unit of electricity consumed;

$E_{f,r}$ = fraction of total electricity generation in region r provided by fuel input f;

$P_{p,r}$ = fraction of total output of process p done in region r;

f = fuel index: electricity generation by coal, oil, nuclear, or natural gas; and

r = any city, state, or country with process p.

This calculation assumes that electricity use by process p is the same in every region r. The EL_p and $P_{p,r}$ are analyzed in the appendixes pertaining to the particular process; for example, the amount of electricity used by refineries and the regional or city shares of total U. S. petroleum refining are discussed in the appendix on petroleum. This appendix examines $E_{f,r}$ (the breakdown of electricity generation by fuel type in cities, states, and countries) and G_f (greenhouse gas emissions from fuel f per unit of electricity consumed). It also tabulates all the $P_{v,r}$ calculated in the other appendixes and estimates the mix of power used to recharge EVs nationwide.

D.2.1 Electricity Mix in Cities and Regions of the United States

The EIA's *Annual Outlook for Electric Power 1990* (1990) reports 1988 net utility generation by type of fuel and projects net utility generation by type of fuel for 2000 for each of 10 U. S. federal regions. (Net generation is the amount of electricity made available to the grid; it is total electricity generated by a power plant less the amount used by the plant itself.) The EIA regional projections exclude nonutility generation. However, the EIA estimates that in the United States in 2000, sales from nonutilities to utilities will amount to only 3.3% of total national generation by utilities. Thus, even though nonutilities use proportionately more gas and nonfossil

energy than do utilities, their contribution is so small that including them, if it were possible, would not change the national (or probably any regional) average generation mix.

The North American Electric Reliability Council (NERC, 1989) also reports and projects net utility generation by fuel type, for 20 NERC regions. Its "net" generation includes electricity used for pumped hydro storage; the EIA's "net" does not. NERC regions are not the same as the EIA's federal regions.

The EIA also reports net generation by fuel type for every electric utility in the United States (computer printout available from the EIA; EIA, March 5, 1990). These highly disaggregated data, in conjunction with information on the service area of utilities *(Electrical World*, 1988), can be used to estimate the generation mix used to supply any particular U. S. city or region.

There are thus two kinds of data on electricity mixes in the United States: (1) regionally aggregated projections and (2) current utility-by-utility use. Ideally, for this sort of analysis, one would use year-2000 projections by particular cities, with adjustments for electricity trading. Unfortunately, these data probably do not exist for every city of interest and certainly are not readily available in a single document. One must either use the year-2000 projections for regions or try to calculate the actual mix for each city in 1988 from the EIA data and the Electrical World data. The advantage of the former data set is that it is a set of projections, and the modeling effort here is intended to extend them to 2000. The disadvantage, and it is a serious one, is that there can be considerable difference between an average regional mix and the mix used by particular cities within the region. The second approach provides city-specific data but not projections. I feel that the difference between the current mix and the year 2000 mix is less than the difference between regional projections and city-specific projections. I choose to calculate city-specific electricity mixes for the United States. The data and results are shown in Table D.1 and Table 7 in Volume 1.

The city-by-city, average electricity mix calculated here is only an approximation of what is desired, which is the future, marginal mix used by specific industries (located in the cities whose electricity mixes are calculated). The problems are that a particular industry within a city may not draw power in proportion to the current average electricity mix supplied to the city, and that the city's generating mix may change in the future. Moreover, the method used here to account for electricity trading is extremely simplified, accounting only for trading between neighboring utilities with large interties (see note a, Table D.2).

However, these discrepancies are probably not huge. For example, NERC (1989) projects that the regional generation shares by fuel type in 1998 will be within 10% (relative percentage points) of the shares for 1989 for most fuels and regions. This projection suggests that city-by-city generation mixes will not change more than 10% over the next 10 years. Regarding power trade, the EIA (*Electric Trade in the United States 1986*, 1990, p. 8) notes that "most bulk power

TABLE D.1 Electricity Mix and Activity Shares in U. S. Cities

U. S. City	Generation by Type of Fuel[a]				City's Share[b] of Total U. S. Activity				
	Coal	Nuclear	NG	Oil	Petroleum Refining	Auto Making	Uranium Enriching	Charging EVs	Making Ethanol
New York, NY	0.169	0.393	0.145	0.260		0.011			
Los Angeles, CA	0.312	0.245	0.331	0.053	0.082	0.008			
Chicago, IL	0.213	0.777	0.004	0.006	0.045	0.026			
Philadelphia, PA	0.200	0.519	0.007	0.221	0.041	0.006			
San Francisco, CA	0.000	0.195	0.446	0.050	0.044	0.009			
Houston, TX	0.314	0.117	0.564	0.005	0.230				
Dallas, TX	0.515	0.000	0.480	0.005		0.009			
Detroit, MI	0.892	0.087	0.009	0.012		0.197			
Boston, MA	0.000	0.000	0.110	0.890		0.009			
Washington, D.C.	0.877	0.000	0.007	0.116		0.000			
St. Louis, MO	0.695	0.267	0.000	0.002		0.091			
Pittsburgh, PA	0.307	0.691	0.002	0.000					
Baltimore, MD	0.378	0.550	0.012	0.058		0.018			
Minneapolis, MN	0.595	0.370	0.005	0.004	0.014	0.016			
Atlanta, GA	0.793	0.192	0.000	0.003		0.029			
Newark, NJ	0.135	0.645	0.114	0.112	0.022	0.007			
Cleveland, OH	0.634	0.358	0.000	0.008	0.027	0.120			
San Diego, CA	0.000	0.000	0.788	0.212					
Miami, FL	0.000	0.421	0.233	0.347					
Denver, CO	0.584	0.034	0.021	0.001					
Seattle area, WA	0.066	0.091	0.020	0.003	0.026	0.000			
Phoenix, AZ	0.461	0.522	0.015	0.000					
New Orleans, LA	0.071	0.305	0.617	0.007	0.148				0.030
Kentucky	0.987	0.000	0.001	0.002		0.038	0.88		0.020
Gulf coast, MI	0.954	0.000	0.043	0.003	0.021				
Tennessee	0.883	0.040	0.001	0.003		0.012			0.050
Virginia	0.518	0.430	0.002	0.058		0.013			0.050
Wisconsin	0.762	0.220	0.002	0.002		0.025			
Oklahoma	0.502	0.000	0.498	0.000	0.021				
Kansas	0.793	0.179	0.024	0.004	0.020				0.020
Illinois	0.743	0.234	0.001	0.003	0.024				0.500
Iowa	0.723	0.159	0.052	0.009					0.190
Indiana	0.784	0.138	0.065	0.005					0.050
Ohio	0.784	0.138	0.065	0.005					0.060
Other U. S.[c]	0.570	0.195	0.094	0.055	0.115	0.056		1.0000	0.030

[a] From an EIA computer printout of electricity generation by fuel type for every U. S. utility in 1988 (EIA, data transmittal, March 1990), and information in Electrical World's *Directory of Electric Utilities* (1988) on which utilities serve which cities and states (see Table D.2) (except as noted). EIA electricity generation data are always net, not gross, generation.

[b] The calculation of these shares is discussed in the appendices covering the particular topic, e.g., nuclear power or oil.

[c] Projected U. S. average electricity mix, year 2000 (EIA, *Annual Outlook for U. S. Electric Power 1989*, 1989).

TABLE D.2 Cities and States and the Utilities Servicing Them

City/State	Utility Servicing The Service Or State[a]
New York, NY	Consolidated Edison of New York, with major interties with Niagara Mohawk and Public Service Electric and Gas
Los Angeles, CA	Refineries are in Southern California Edison (SCE) service area (Torrance, Carson, El Segundo, Long Beach...). SCE has four major ties with Los Angeles Department of Water and Power (LADWP).
Chicago, IL	Commonwealth Edison serves Chicago and vicinity (refineries at Wood River probably are served by Illinois Power Company; at Robinson, by Central Illinois Public Service Company; and at Hartford, by Union Electric Company)
Philadelphia, PA	Philadelphia Electric (Philadelphia and vicinity; includes Marcus Hook refineries)
San Francisco, CA	Pacific Gas and Electric (Northern California)
Houston, TX	Houston Power and Light serves Houston, Galveston, Baytown, Deer Park; Texas-New Mexico Power[b] serves Sweeney and Texas City; Gulf States serves Port Arthur and Beaumont; Central Power & Light serves Corpus Christi
Dallas, TX	Texas Utilities Electric (Dallas and Vicinity)
Detroit, MI	Detroit Edison (Detroit, Dearborn, Ann Arbor, Warren...)
Boston, MA	Boston Edison (Boston and vicinity)
Washington, DC	Potomac Electric Power Company
St. Louis, MO	Union Electric (same UEC as in Illinois)
Pittsburgh, PA	Duquesne Light (Pittsburgh and vicinity)
Baltimore, MD	Baltimore Gas and Electric (Baltimore and vicinity)
Minneapolis, MN	Northern States Power (virtually all of Minnesota)
Atlanta, GA	Georgia Power (virtually all of Georgia)
Newark, NJ	Public Service Electric and Gas, with major interties with Jersey Central Power and Light
Cleveland, OH	Cleveland Electric Illuminating
San Diego, CA	San Diego Gas and Electric (San Diego and vicinity)
Miami, FL	Florida Power and Light (covers a lot of Florida)
Denver, CO	Public Service Company of Colorado[c] (covers most of Colorado); they get about 35% of their power from the Western Area Power Administration (WAPA), which supplies only hydro power.
Seattle area, WA	Puget Sound Power and Light[d] (covers Seattle area, but not Seattle; includes Ferndale and Anacortes refineries)
Phoenix, AZ	Arizona Public Service (covers virtually all of Arizona)
New Orleans, LA	Louisiana Power and Light and Gulf States Utilities
Kentucky	Louisville Gas and Electric, Kentucky Power, Kentucky Utilities, Big River
Gulf coast, MI	Mississippi Power, serves the Gulf area
Tennessee	Tennessee Valley Authority (sells to municipal systems)
Virginia	Virginia Electric and Power (biggest of 3 majors)
Wisconsin	Wisconsin Electric Power, Wisconsin Power and Light
Oklahoma	Public Service Company of Oklahoma, Oklahoma Gas and Electric
Kansas	Served mostly by municipal utilities (I picked four Kansas utilities)
Illinois	Illinois Power, Union Electric, and Central Illinois Public Service

See next page for footnotes.

TABLE D.2 (Cont.)

[a] From Electrical World's *Directory of Electric Utilities* (1988). For each city, the electricity mix is calculated from the aggregate mix of all the utilities named in association with the city, except as noted. The utilities named are the major ("home") utility servicing the particular city, plus any utilities that have interties with the home utility amounting to at least 25% of the capacity of the home utility.

[b] Texas-New Mexico Power imports most of its power. I have not included either its own generation or its imports, since it is a small contributor to the total.

[c] I have assumed that Public Service of Colorado bought an additional 7 million mWh of hydro from WAPA.

[d] Puget Sound buys most of its power, from many sources. Rather than try to calculate the mix of electricity purchased by Puget Sound, I used the power mix for the Northwest Region in 1988, as reported by the EIA's *Annual Outlook for U. S. Electric Power* (1989).

transfers involve neighboring utilities whose systems are directly interconnected." The calculation used here accounts crudely for transfers between directly connected utilities. Thus, unless the industries considered here consume a much different power mix than that of the cities in which they are located, the use of current, city-by-city, average electricity mixes (with some accounting for trading) may not be terribly inaccurate.

D.2.2 Electricity Mixes in Other Countries

Electricity generation in other countries is important because other countries make products used by the United States (e.g., gasoline, automobiles, and enriched uranium). Table D.3 shows country-by-country electricity generation mixes. For International Energy Agency (IEA) countries, the data are projected mixes in 2000 (IEA, *Energy Policies and Programmes of IEA Countries*, 1989); for non-IEA countries, the data are actual generation mixes in 1988 (IEA, *World Energy Statistics and Balances*, 1990). Details are given in the notes to Table D.3.

Note that electricity generation by fuel type in a particular country (which is what is shown in Table D.3) may not be precisely the same as electricity consumption by fuel type (which is what we want to know) because of international electricity trading. However, there is not much international trade in electricity. Virtually all countries in the world generate at least 90% of their electricity requirements, and many countries generate essentially all of it (EIA, *International Energy Annual*, 1989). In 1985 and 1986, the United States imported less than 2% of its electricity, and almost all of it was imported from Canada (EIA, *Electric Trade in the United States 1986*, 1990. Imports will continue to be less than 2% of total electricity sales for the foreseeable future (EIA, *Annual Outlook for U. S. Electric Power 1990*, 1990). Hence, I ignore international electricity imports and exports.

TABLE D.3 Electricity Mix and Activity Shares in Other Countries

Country	Generation by Type of Fuel[a]				City's Share[b] of Total U. S. Activity				
	Coal	Nuclear	NG	Oil	Petroleum Refining	Auto Making	Uranium Enriching	Charging EVs	Making Ethanol
Algeria	0.000	0.000	0.885	0.079	0.011				
Angola	0.000	0.000	0.000	0.262	0.001				
Argentina	0.036	0.109	0.279	0.273	0.000				
Australia	0.807	0.000	0.064	0.018	0.001				
Bahamas[b]	0.000	0.000	0.000	1.000	0.002				
Belgium	0.371	0.563	0.009	0.061	0.003				
Brazil[c]	0.015	0.000	0.000	0.035	0.005	0.002			
Canada	0.182	0.161	0.026	0.036	0.014	0.091			
China	0.690	0.000	0.002	0.108	0.001				
Colombia	0.079	0.000	0.178	0.006	0.002				
Ecuador	0.000	0.000	0.000	0.146	0.000				
France	0.073	0.703	0.006	0.015	0.001	0.001	0.120		
Germany	0.500	0.331	0.057	0.040	0.003	0.001			
Greece	0.722	0.000	0.053	0.106	0.001				
India	0.694	0.026	0.011	0.031	0.002				
Indonesia	0.204	0.000	0.012	0.568	0.001				
Italy	0.290	0.000	0.265	0.235	0.003	0.000			
Japan	0.186	0.384	0.165	0.142	0.000	0.165	0.000		
South Korea	0.232	0.469	0.122	0.135	0.000	0.017			
Kuwait	0.000	0.000	0.814	0.186	0.001				
Mexico	0.078	0.000	0.088	0.587	0.003	0.006			
Netherlands	0.430	0.236	0.243	0.021	0.004		0.000		
N. Antilles	0.000	0.000	0.000	1.000	0.002				
Nigeria	0.000	0.000	0.607	0.101	0.000				
Norway	0.000	0.000	0.075	0.003	0.001				
Peru	0.000	0.000	0.016	0.192	0.002				
Puerto Rico[d]	0.000	0.000	1.000	0.000	0.001				
Romania	0.416	0.000	0.238	0.195	0.003				
Saudia Arabia	0.000	0.000	0.469	0.531	0.007				
Singapore	0.000	0.000	0.000	1.000	0.002				
Soviet Union	0.261	0.127	0.332	0.133	0.001				
Spain	0.426	0.254	0.000	0.106	0.003				
Sweden	0.028	0.427	0.005	0.020	0.000	0.004			
Syria	0.000	0.000	0.069	0.683	0.001				
Trinidad and Tobago	0.000	0.000	0.999	0.001	0.002				
United Kingdom	0.704	0.177	0.006	0.086	0.019				
Venezuela	0.000	0.000	0.249	0.142	0.016				
Virgin Islands[d]	0.000	0.000	0.800	0.200	0.000	0.010			
Yugoslavia	0.566	0.049	0.024	0.051	0.000	0.000			
Rest of world[e]	0.500	0.050	0.100	0.100	0.003	0.001			

See next page for footnotes.

TABLE D.3 (Cont.)

[a] The IEA's *Energy Policies and Programmes of IEA countries* (1989) projects fuel *inputs* to electricity generation in IEA countries — Austria, Australia, Belgium, Canada, Germany, Greece, Italy, Japan, Norway, Spain, Sweden, and the United Kingdom — in the year 2000. Because the ratio of electricity-energy out to fuel-energy in is different for different fuels, the future generation mix by fuel type, which is what we want to know, is not necessarily the same as the future input mix by fuel type, which is what the IEA projects. Therefore, I have converted the IEA fuel-input projections to generation projections, using country-by-country conversion efficiencies.

For all non-IEA countries except Puerto Rico, the Bahamas, and the Virgin Islands, the data of this Table are actual generation shares in 1988, according to the IEA (*World Energy Statistics and Balances*, 1990). For Puerto Rico, the Bahamas, and the Virgin Islands, see notes b and d.

IEA electricity generation shares are based on "gross" rather than "net" generation — that is, they include electricity used internally by power plants — and also include non-utility generation. By contrast, the EIA data used in Table D.1 are based on net generation, and do not include non-utility generation. Technically, these differences should be reconciled. Ideally, in calculating generation shares, one would exclude electricity used internally by power plants, because this electricity is not available to outside fuel-production-and-use cycles. On the other hand, one should include any generation by nonutility generators that actually is sold to the grid. However, both these adjustments are more trouble than they are worth, so I have not bothered with them.

[b] The United Nations *1987 Energy Statistics Yearbook* (1989) reports that in 1987, the Bahamas generated all its electricity from fossil fuels (the *Yearbook* does not give a breakdown by individual fuels). I assume that oil was 100% of the fuel input to power plants, because the Bahamas do not produce or import coal or natural gas, and do not import electricity, but do import a lot of crude oil, which they refine for export (EIA, 1989; UN, 1989).

[c] In 1986 biomass provided 19% of the thermal input to power generation in Brazil (United Nations, 1988). I do not count biomass because biomass combustion does not produce net CO_2.

[d] The breakdown for Puerto Rico is based on the type of main generator in Yabucao, where the main refinery is (generator type from Electrical World). The breakdown for the Virgin Islands is based on the type of generator in St. Croix, where the main refineries are (generator type from Electrical World).

[e] Mix is my assumption.

D.2.3 Mix of Power Supplied to Generic Electricity Users

It is not possible or worthwhile to specify fuel inputs to electricity generation for every use of electricity in this analysis. For example, oil pipelines and, to a much lesser extent, gas pipelines use electricity to run compressors. However, the compressors are located all over the country and do not use much electricity, so the fuel input to the electricity they use is not likely to be significantly different than the national average mix and is not very important, anyway. Other users of generic electricity in this report are methanol and biofuel plants, coal and uranium mines, oil and gas wells, and nuclear conversion and fabrication plants.

For generic users of power, I use the mix of electricity that the EIA projected for 2000 (EIA, *Improving Technology*, 1991). This projection accounts for the effect on fuel choice of the new Clean Air Act (CAA) limits on emissions of sulfur oxides (SO_x) and nitrogen oxides (NO_x).

The generic power emission factors, like the process-specific electricity emission factors, account for the energy used to recover, transport, and process the fuel used by the power plant (Table D.4). Both generic and specific power factors are adjusted to avoid double counting the energy consumed by the pollutants emitted from the equipment used to recover and transport the

TABLE D.4 Complete Fuel-Cycle Emissions of Greenhouse Gases from Electricity Generation

Emissions from Fuel Combustion at the Power Plant ($g/10^6$ Btu fuel input to power plant)	Power-Plant Fuel						
	Coal	Fuel Oil	Natural-Gas Boiler	Natural-Gas Turbine	Nuclear Power[a]	Methanol (from natural gas)	Hydrogen (from nuclear power)
CH_4[b]	0.7	0.9	0.1	15.7	0.0	0.7	0.0
N_2O[c]	4.0	2.0	2.0	2.0	0.0	2.0	2.0
NMHC[b]	1.5	2.3	0.6	2.8	0.0	4.0	0.0
CO[b]	13.0	15.2	17.6	50.6	0.0	15.0	0.0
NO_x[d]	227.6	152.3	120.9	90.8	0.0	100.0	115.0
SO_x[e]	418.5	239.9	0.3	0.3	0.0	0.3	0.0
CO_2	95,512[f]	75,101	53,590	53,489	0.0	63,837	0.0
CO_2-equivalent emissions ($g/10^6$ Btu fuel input to plant, 100-yrs)							
From power plant[g]	105,841	81,860	59,069	58,196	3,165[h]	68,497	5,180
From upstream[i]	9,060	15,474	9,934[j]	9,934[j]	14,566	41,487[k]	19,862[l]
Total	114,901	97,334	69,002	68,129	17,731	109,984	25,042
Fuel-cycle CO_2-equivalent emissions							
100-yr case $g/10^6$ Btu generated[m]	348,820	306,081	210,501	207,838	17,731	333,285	62,606
g/kWh delivered[n]	1,297	1,138	784	774	69	1,239	235
20-year case g/kWh delivered	1,737	1,416	1,032	995	101	1,643	379
500-year case g/kWh delivered	1,184	1,067	721	717	60	1,156	165

[a] Nuclear is expressed in $gm/10^6$ Btu of output or generated electrical energy.

[b] These emissions are not controlled. Coal, oil, and gas emissions data from EPA's AP-42.

[c] From various EPA and other documents. See Appendix N.

TABLE D.4 (Cont.)

[d] Controlled emissions, equal to uncontrolled emission factors multiplied by emission control reduction factors. Uncontrolled, g/10^6 Btu NO_x emissions are calculated from AP-42. I estimated uncontrolled factors for methanol and hydrogen, based on fuel properties compared to natural gas.

As discussed in the text, I assume a 50% reduction in NO_x emissions from coal-and gas-fired boilers, and a 25% reduction from oil-fired boilers.

[e] Controlled emissions, equal to uncontrolled emission factors multiplied by emission control reduction factors. Uncontrolled emissions calculated from sulfur content of fuel. I assume a 50% reduction in SO_x emissions from coal- and oil-fired plants.

[f] Includes CO_2 from scrubbing SO_x.

[g] Emissions of CO_2 plus the CO_2-equivalent of emissions of CH_4, N_2O, NMHCs, CO, and NO_x.

[h] Complete fuel-cycle CO_2-equivalent emissions from standby generators and auxiliary boilers using diesel fuel. See Appendix I.

[i] Complete CO_2-equivalent greenhouse-gas emissions from feedstock recovery and transport and fuel production and delivery (g/10^6 Btu delivered to power plants). The values are from Table 6.

[j] This value is smaller than the value for NG in Table 6 because the value in Table 6 includes leaks of NG from a low-pressure distribution system, whereas the value here doe not (I assume that NG power plants are not connected to low-pressure distribution systems).

[k] The methanol-to-power system is the same as the methanol-to-vehicles system, except that there is no truck distribution of methanol to power plants, and a greater percentage of methanol moves by pipeline than in the methanol-to-vehicles case. Recall that the base case assumes that 75% of the methanol is made from remote natural gas.

[l] From uranium processing, for hydrogen from nuclear power. Hydrogen from solar power would produce no emissions here.

[m] Based on the generation efficiencies of Table 7.

[n] Assuming that electricity transmission and distribution is 92% efficient (U. S. national average; EIA, *Annual Energy Review*, 1990), and generates 0.011 gram N_2O per kWh delivered, from the corona discharge from high-voltage transmission lines (App. N).

feedstock, in certain cases. For example, in the analysis of greenhouse gas emissions from coal mining, electricity use at coal mines is multiplied by a generic emission factor, which assumes that a portion of the power supplied to the mine is from coal-fired plants. Unadjusted, this generic life-cycle emission factor would include emissions from equipment used to mine and transport coal sent to the coal-fired power plant supplying the coal mine. However, these emissions from equipment used to mine and transport coal are already fully accounted for in the U. S. Bureau of the Census's tally of fuels used in coal mining. In other words, emissions from the use of fuels to mine and deliver coal to the coal-fired plant are calculated in the feed recovery and feed transport stage, so including these emissions in the generic electricity emission factor would be double counting. The coal part of the generic electricity factor should, in this case, include only emissions from the power plant. (Of course, the natural-gas, oil, and nuclear part of the generic emission factor should include emissions from feed recovery and transport because these are not included in the coal-cycle analysis.)

Now, if the example were about electricity consumed by NG field equipment, the generic electricity emission factor would be adjusted differently — by subtracting emissions from NG recovery and transport. Specific emission factors are adjusted in the same way. For example, in calculating emissions from electricity used by petroleum refineries, emissions from tankers used to transport oil to power plants supplying refineries are not counted because all emissions from tankers are already included under in feed transmission or product distribution.

D.2.4 Mix of Fuel Used to Generate Power to Recharge Electric Vehicles

The national generating mix used by electric vehicles (EVs) will depend on the regional distribution of vehicles, timing and demand for recharging power, operating and maintenance costs and availability of power plants, and other factors. The mix used to recharge EVs will most likely not be the simple (24-hour) national average electricity mix. For example, incremental use of gas and oil, which are intermediate-load and peaking fuels, will be determined in part by when EV owners start recharging their vehicles. If they start recharging their vehicles right after work, the first few hours of recharging will coincide with the afternoon and evening peak and increase demand on oil- and gas-fired plants. On the other hand, most nuclear power base-load plants will not be available for recharging because they already are being operated at full capacity because of their low operating costs and high capital costs.

Several reports have estimated the marginal power mix for EVs. Hamilton (May 1988) cites a 1982 study by General Research Corporation that estimates that if EV owners were to start recharging their vehicles between 5:00 and 7:00 p.m. in 2000, the vehicles would draw 60% of their power from coal-fired plants, 27% from oil-and gas-fired plants, and 1% from nuclear plants. If recharging were begun later and timed to finish at 6:00 a.m., the mix would be 74% coal, 14% oil and gas, and 4% nuclear.

Recently, the EPA (*Analysis of the Economic and Environmental Effects of Electricity as an Automotive Fuel*, 1990) estimated the marginal mix of electricity used to meet the incremental demand for power due to EV recharging in 10 regions of the United States, for 2010 and 2020 for two recharging scenarios. Its analysis is based on earlier work done by General Research Corporation (1982), which used national models of electricity generation to estimate the marginal electricity supply for EVs. The EPA estimates show that coal-fired plants will be used to meet 34-51% of the demand for recharging power, oil-fired plants, 17-24%; gas-fired, 30-40%; and nuclear, 0.1%. More oil and gas will be used when recharging starts at 5:00 p.m. than when it is timed to finish at 6:00 a.m. These estimates may be skewed toward gas and oil and away from nuclear power and coal because, in 1980, utilities used more oil and gas and less coal and nuclear power than they are projected to use in 2000 (EIA, *Annual Energy Review 1989*, 1990; EIA, *Annual Outlook for U. S. Electric Power 1990*, 1990).

Finally, Dowlatabadi et al. (1990) calculated regional marginal power mixes for EVs on the basis of projected available capacity. They found that there was virtually no excess nuclear

generating capacity, a small amount of excess coal-fired capacity, and a large amount of excess oil- and gas- fired capacity.

Although there are large quantitative differences between these studies, they agree qualitatively on two main points:

1. Very little nuclear power will be used to recharge EVs because nuclear power plants are already operating at capacity.

2. A large portion of EV recharging energy will be supplied by gas- and oil-fired plants because they are relatively underutilitized and are used for peaking capacity. Furthermore, an increasing number of combined-cycle, gas-fired plants will be built in the future.

Thus, the EV recharging mix uses more gas and oil and much less nuclear power than the projected national-average, 24-hour mix.

On the basis of these considerations, I assume that coal supplies 50% of the marginal demand; gas, 30%; oil, 15%, and nuclear power, 2%. This assumption is close to the mix assumed in EPA's year-2010 "6:00 a.m. recharge-finish" scenario (see above). Scenario analyses report the results for EVs using the average power mix of different cities (Table 12).

D.2.5 Emissions of Greenhouse Gases per Unit of Electricity Generation

Emissions per unit of electricity generation are calculated as emissions per unit of fuel burned divided by the efficiency of generation. Emissions per unit of fuel burned are equal to the sum of: (1) CO_2-equivalent of emissions of methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO), nonmethane organic compounds (NMOCs), and NO_x per unit of fuel burned; (2) CO_2 emissions from the fuel; and (3) CO_2 emissions from scrubbing sulfur.

Table D.4 shows emissions of greenhouse gases per unit of fuel energy input (g/10^6 Btu), for the base-case efficiency assumptions for conventional electricity-generating technologies. Table D.5 shows the quality of the EPA emission factors used in Table D.4. Table D.6 shows efficiency and emission factors for advanced electricity-generating technologies, and Figure D.1 shows the best and worst cases for advanced electricity-generating technologies compared with conventional coal technologies. Table D.7 shows greenhouse-gas emissions per unit of electricity end use (g/kWh delivered to users) for both conventional and advanced electricity-generating technologies. These figures are complete fuel-cycle, end-use emission factors and can be used to estimate greenhouse gas emissions from the use of electricity in any sector. Fuel-cycle emissions are essentially directionally proportional to net generation efficiency. Table D.8 shows the contribution of individual greenhouse gases to CO_2-equivalent emissions from power plants and from upstream processes.

TABLE D.5 Quality of the EPA's AP-42 Emissions Data

Data	VOC	NMVOC	CO	NO_x	SO_x	PM	PM_{10}
Coal boiler	A	A	A	A	A	A	C
Gas boiler	C	C	A	A	A	B	—
Oil boiler	A	A	A	A	A	A	C
Wood boiler	D/E[a]	D	C	B	B	C	E
Gas or oil turbine	B	—	B	B	B	B	—

"—" = not determined. A is the highest quality (most reliable), E is the lowest.

[a] The methane factor was rated "E," the nonmethane factor, "D."

D.2.5.1 Emission Factors for CH_4, N_2O, CO, NMOCs, and NO_x

The CO and NMHC emissions data in Table D.4 are uncontrolled emission factors from the EPA's *Compilation of Air Pollutant Emission Factors* (AP-42 1985, 1988 supplement), otherwise known as AP-42, the best and most widely cited source of estimates of emissions from power plants and other point sources. I have used emission factors for uncontrolled power plants because at present there are no controls for CO and NMOCs in power plants.

The CH_4 emissions data are also from AP-42 and are calculated as the difference between total and nonmethane hydrocarbon emissions. Data on emissions of N_2O are from EPA and other documents and are discussed in Appendix N.

The new CAA Amendments (CAAA) set a goal of a 2-million-ton (1,814-Gg) reduction in total national NO_x emissions when compared with 1980 levels. In 1980, electric utilities emitted 6,370 Gg of NO_x, which was 63% of total NO_x emissions from fuel combustion (10,113 Gg) and 30% of total national emissions of NO_x (EPA, NEDS, 1990). The CAAA do not specify reductions for the utility sector but does set emissions levels for some types of coal-fired plants, which are based on reductions provided by low-NO_x burner technology (EPA, *CAA*, 1990). It appears that uncontrolled NO_x emissions from coal-fired plants will be reduced by roughly 50%.

The CAAA do not obligate the EPA to reduce NO_x emissions from oil-and gas-fired plants. However, the EPA and individual states may do so anyway. Presently, utility NO_x emissions from NG-fired plants are 30-35% below uncontrolled levels, and from oil-fired plants, 0-10% (EIA, *Annual Outlook for U. S. Electric Power 1990*, 1990; EPA, AP-42 1985 and 1988; EPA NEDS, 1990).

TABLE D.6 Efficiency and Emissions of Advanced Power-Generation Technologies

Plant Type	Net Efficiency (%, HHV)	Emissions ($g/10^6$ Btu input)					
		CH_4	N_2O	NMOCs	CO	NO_x	SO_x
NG combined cycle[a]	45	15.7	2.0	2.8	51	91	0.3
ISTIG[b]	47	15.7	2.0	2.8	51	45	0.3
CRISTIG[c]	52	15.7	2.0	2.8	51	10	0.3
CG/gas-turbine plant[d]	42	0.7	4.0	1.5	2.0	43	34
Coal FBC[e]	36	0.7	200	1.5	2.0	120	94
BIG/ISTIG[f]	42	0.7	4.0	1.5	2.0	43	n.e.
CG/MCFC[g]	50	0.1	1.0	1.0	1.0	10	1.0
NG/MCFC[h]	57	0.5	1.0	1.0	1.0	3.0	0.3
BIG/MCFC[i]	50	0.1	1.0	1.0	1.0	10	n.e.

n.e. = not estimated

[a] Natural-gas combined-cycle power plant.

Efficiency: In a combined cycle, the hot exhaust gases from the turbine raise steam that is used in a steam turbine to generate electricity. Several sources report that commercially available, advanced combined-cycle gas turbines are 45% efficient (U. S. Congress, 1991; EIA, *Electricity Supply*, 1991; Williams and Larson, 1989, 200-MW plants).

Emissions: In its analysis for the National Energy strategy, the EIA (*Electricity Supply*, 1991) assumes that current combined-cycle plants emit 205 $g/10^6$ Btu NO_x. This is about twice the rate assumed here for a simple gas turbine in the year-2000. NO_x emissions from combined cycles can be reduced to much lower levels than this, but at some cost in efficiency (Williams and Larson, 1989). I assume that an emission rate of 91 $g/10^6$ Btu (Table D.4), could be achieved at no significant cost in efficiency. The emission factors for the other pollutants also are assumed to be the same as for a simple-cycle turbine (Table D.4).

[b] Intercooled-steam-injected gas turbine.

Efficiency: In ISTIG, the hot turbine exhaust gases raise steam, like in the combined cycle, but the steam, instead of being used in a steam turbine, is injected into the fuel combustor to increase power output and efficiency. There also is an intercooler between compression stages. ISTIGs are expected to be 47 to 48% efficient (Williams and Larson, 1989, 114-MW GE turbine; EIA, *Electricity Supply*, 1991).

TABLE D.6 (Cont.)

Emissions: In its analyses for the National Energy Strategy, the EIA (*Electricity Supply*, 1991) projects emissions of 45 g/10^6 Btu NO_x for gas ISTIG on line in the year 2000. This is 50% of the rate projected here for gas-turbines in the year 2000. Williams and Larson (1989) estimate that NO_x emissions from a ISTIG system would range from 5 to 285 g/10^6 Btu, depending on the molar steam-to-fuel ratio in the primary combustion zone.

Emissions would be twice this for a plain STIG system. However, they state that the low-end of the range probably is an underestimate. They further note that if NO_x were controlled to below 25 ppm (about 45 g/10^6 Btu — the level projected by the EIA), CO emissions would rise sharply (e.g., at about 20 ppm NO_x, CO is about 70 ppm. Therefore, I assume a NO_x emission rate of 45 g/10^6 Btu. The emission factors for the other pollutants are assumed to be the same as for a simple-cycle turbine (Table D.4).

[c] Chemically-recuperated ISTIG.
In a CRISTIG, some of the turbine exhaust heat and some steam would be used to reform the fuel into H_2, CO, and CO_2. This could further improve the efficiency. They estimate NO_x emissions of 0.5 to 14 g/10^6 Btu, although the low-end, according to them, probably is an underestimate. I assume 10 g/10^6 Btu NO_x. The emission factors for the other pollutants are assumed to be the same as for a simple-cycle turbine (Table D.4).

[d] Coal-gasification/gas-turbine power plant.

Efficiency: Miller (1990) of DOE assumes 42% for an unspecified coal/IGCC (integrated-gasification combined-cycle power plant). The EPRI TAG (U. S. Congress, 1991) recommends 37% for an unspecified coal/IGCC. The EIA (*Electricity Supply*, 1991) assumes 43% for an unspecified system on line in the year 2000. Spencer et al. (1986) believe that the efficiency of the oxygen-blown/Texaco-gasifier IGCC system (like the one at Cool Water, California) can be increased to 38%. Barnett and Teagen (1991) indicate a target of 50-52% efficiency by the year 2000 for an unspecified IGCC. A GE study cited by Williams (1989) suggested that replacing the oxygen-blown Texaco gasifier and combined-cycle power plant with an air-blown Lurgi fixed-bed gasifier and an ISTIG would improve the efficiency to 42.1%.

Emissions: Wolk and Holt (1988) report emissions of 43 g/10^6 Btu NO_x and 2 gm/10^6 Btu CO from the Cool Water plant using Illinois #6 coal. There are no CO_2 emissions from sulfur control, because sulfur is removed by absorption in dimethyl ether polyethylene glycol. Farooque et al. (1990) report that an advanced oxygen-blown coal/IGCC with in-bed desulfurization using zinc ferrite would emit 134 g/10^6 Btu NO_x and 11 g/10^6 Btu SO_x. In its analyses for the National Energy Strategy, the EIA (*Electricity Supply*, 1991) assumed emissions of 45 g/10^6 Btu NO_x for an unspecified coal/IGCC system on line by the year 2000. Barnett and Teagen (1991) show a target of 14 g/10^6 Btu NO_x for an unspecified IGCC in the year 2000. I use the CO, NO_x, and SO_x emission factors reported for the Cool Water Plant, and assume that emission factors for the other pollutants would be the same as those for a conventional coal-fired plant (Table D.4).

[e] Fluidized-bed combustion coal plant.

Efficiency; The EPRI Technical Assessment Guide (U. S. Congress, 1991) and Miller (1990) assume an efficiency of 36%.

Emissions: The EIA (*Electricity Supply*, 1991) assumes NO_x emissions of 120 g/10^6 Btu. I assume that CO, CH_4, and NMOC emissions would be the same as from conventional coal-fired plants. I calculate the amount of CO_2 produced from limestone injection to remove 90% of SO_x (Makansi, 1991). Based on Makansi's (1991) statements

TABLE D.6 (Cont.)

that N_2O from FBC plants can be 1-2 orders of magnitude greater than N_2O from pulverized-coal-fired boilers, due to the low temperature of combustion, I assume that N_2O emissions would be 50 times greater than from conventional coal-fired power plants.

[f] Biomass integrated-gasification steam-injected gas-turbine.

Efficiency. Larson and Williams (1990) report an efficiency of 32.5% for the GE LM-5000 BIG/STIG, when the feed has 15% moisture content. However, they state that "there is no obvious reason why the gasification efficiency of biomass would not be at least as high as the better-documented estimate for coal" (p. 159). They also state that the technology for coal-based gasification is largely transferable to systems based on biomass, and moreover, that biomass systems would require less developmental effort, because biomass is more reactive and hence easier to gasify than, and contains virtually no sulfur (which means that no sulfur-removal technology would be needed). In accordance with the belief that a BIG/STIG system would be at least as efficient as a coal system, Williams (1989) assumes an efficiency of 42% (see note pertaining to efficiency of coal gasification systems).

Emissions: I assume the same emissions (except of SO_x) as from a coal-gasification/gas-turbine plant.

[g] Coal-gasification molten-carbonate fuel-cell power plant.

Efficiency: Miller (1990) of USDOE assumes 50% for gasification/fuel cell on coal. In its analyses for the National Energy Strategy, the EIA (*Electricity Supply*, 1991) assumes 60% efficiency. According to Rastler (1990), EPRI's goal for a 200-250 MW coal gasification/MCFC plant is 50% efficiency. Farooque et al. (1990) report the results of a detailed design and economic analysis done by Energy Research Corporation: 45.1% net efficiency for a 238-MW MCFC with oxygen-blow Texaco gasification with cold-gas cleanup; 47.1% net efficiency for a 209-MW MCFC with an oxygen-blown KRW gasification with hot-gas cleanup.

Emissions: The EIA assumes 4.5 g/10^6 Btu NO_x. Zegers (1990) projects that coal MCFCs and NG MCFCs will emit 1.7 g/10^6 Btu NO_x, and cites emissions from "experimental fuel cells" of 0-13 g/10^6 Btu NO_x and 0 HCs, but the experimental data probably do not refer to internal-reforming MCFCs. Barnett and Teagen (1991) project emissions of about 7-8 g/10^6 Btu for fuel cells generically. EPRI's goals for a 200-250 MW coal/MCFC plant are 13 g/10^6 Btu NO_x, SO_x of 0.7 g/10^6 Btu (Rastler, 1990). Farooque et al. (1990) report the results of a detailed design and economic analysis done by Energy Research Corporation: NO_x emissions of 0 and SO_x emissions of 4 g/10^6 Btu from a 238-MW MCFC with oxygen-blow Texaco gasification with cold-gas cleanup; and 13 g/10^6 Btu NO_x and 0.4 g/10^6 Btu SO_x from a 209-MW MCFC with oxygen-blown KRW gasification with hot-gas clean up. Sulfur control for Texaco-MCFC would be done with a zinc ferrite sorbent, so there would be no CO_2 emissions (Williams and George, 1990). Given these data, I assume 10 g/10^6 Btu NO_x, and very low emissions of other pollutants.

[h] Natural-gas molten-carbonate fuel cell power plant.

Efficiency: The EPRI TAG (U.S. Congress, 1991) recommends an efficiency of 53% for dispersed, advanced MCFCs using natural gas. Miller (1990) assumes an efficiency of 55% for a generic fuel cell operating on methane. In its analyses for the National Energy Strategy, the EIA (*Electricity Supply*, 1991) assumes an efficiency of 68% (this may include cogeneration) for a generic fuel cell. Doi et al. (1990) report 51% efficiency for a 5-MW natural-gas fired MCFC. Goldstein (1990) cites a design for a 22 MW MCFC NG-plant

TABLE D.6 (Cont.)

with an efficiency of 57%. EPRI projects 55-57% efficiency for 2-5 MW "market-entry" natural-gas based systems (Rastler, 1990).

Emissions: The EIA assumes 4.5 g/10^6 Btu NO_x. Zegers (1990) projects that coal MCFCs and NG MCFCs will emit 1.7 g/10^6 Btu NO_x, and cites emissions from "experimental fuel cells" of 4-30 g/10^6 Btu HC and 18-31 g/10^6 Btu NO_x, but the experimental data probably do not refer to internal-reforming MCFCs, which would have lower emissions. Barnett and Teagen (1991) project emissions of about 7-8 g/10^6 Btu for fuel cells generically. Hashimoto (1990) reports that less than 2 ppm (3-4 g/10^6 Btu) NO_x were measured in the exhaust gas of a Westinghouse 5-kW natural-gas fueled solid-oxide fuel cell. A design cited by Goldstein (1990) projects zero NO_x emissions, less than 5 g/10^6 Btu CO, less than 3 g/10^6 Btu HCs, and 0.1 g/10^6 Btu SO_x. EPRI projects no emissions of NO_x, CO, or SO_x for a 2-5 MW "market-entry" NG MCFC system (Rastler, 1990). Given these data, I assume 3 g/10^6 Btu NO_x, and very low emissions of other pollutants.

[i] Biomass-gasification/molten-carbonate fuel cell. I assume the same efficiency and emissions (except of SO_x) as in the case of a coal-gasification MCFC.

Here, I assume that in 2000, NO_x emissions from coal-fired and gas-fired plants will be 50% below uncontrolled levels and NO_x emissions from oil-fired plants will be 25% below uncontrolled levels. Applying these reductions to AP-42 uncontrolled emission factors and multiplying by projected fuel inputs to electricity plants in 2000 (EIA, *Annual Outlook for U. S. Electric Power 1990*, 1990) result in a total of 5,363 Gg NO_x from utilities in 2000. This is about 1,000 Gg less than utilities generated in 1980. Hence, my assumptions are consistent with the CAA goal of a roughly 2000-Gg reduction in NO_x emissions from all sectors.

Although not all AP-42 estimates are of high quality, the estimates for power plants are probably quite reliable, and even though they are averages, they probably closely approximate emissions from most power plants. Table D.5 shows how the EPA rates the quality of the factors; an "A" rating means that many the emission factor is supported by many (say, more than 10) source tests of high technical quality; an "E" rating means that the factor is based on one observation of questionable quality. Coal, gas, and oil factors have high ratings.

The emission factors for gas- or oil-fired turbines are slightly different than the emission factors for boilers. The EPA's AP-42 has emission factors for both kinds of units. In 1988, 6.5% of total gas-fired utility generation was from gas turbines (or engines) and 3.5% of total oil-fired utility generation was from turbines (or engines). The gas-turbine generation was 0.6% of total U. S. generation, and the oil-fired turbine was 0.2% (EIA, *Electric Power Annual*, 1989). Because so little electricity is generated from oil-fired turbines, I ignore them here and assume their generation under oil-fired boilers. I would ignore gas-fired turbine generation, too, except that it is slightly larger and is expected to increase substantially in the future. I assume that in 2000, 25% of gas-fired generation will be by gas turbines.

TABLE D.7 Complete Fuel-Cycle Emissions of Greenhouse Gases from Electricity Generation in Grams of CO_2-Equivalent Emissions per Kilowatt-Hour Delivered to End Users, as a Function of Net Generation Efficiency

Generation Scenario[a]	Coal	Oil	NG Boiler	NG Turb./ Other	Nuclear	Methanol (from NG)	Biomass
With 100-year factors[b]							
1. 32% efficiency	1,335	1,132	803	793	69	1,278	
2. 35% efficiency	1,220	1,032	734	725	83	1,162	
3. 38% efficiency	1,123	949	676	668	22	1,073	
4. 38%, low emissions	1,079	917	653	650		1,049	
5. 40% efficiency	1,067	900	643	634		1,018	
6. 40%, low emissions	1,025	871	620	617		1,000	
7. NG combined cycle				565			
8. Fluidized-bed combustion	1,768						
9. Gasification/gas turbine	949						107
10. ISTIG				526			
11. CRISTIG				466			
12. Molten-carbonate fuel cell	781		419				74
With 500-year factors[b]							
1. 32% efficiency	1,219	1,061	738	735	60	1,174	
2. 35% efficiency	1,114	968	675	672	72	1,072	
3. 38% efficiency	1,025	890	621	618	17	986	
4. 38%, low emissions	1,010	879	612	612		991	
8. Fluidized-bed combustion	1,470						
9. Gasification/gas turbine	904						76
10. ISTIG				495			
12. Molten-carbonate fuel cell	751			403			57
With 20-year factors[b]							
1. 32% efficiency	1,779	1,407	1,055	1,016	100	1,689	
2. 35% efficiency	1,625	1,283	964	929	118	1,541	
3. 38% efficiency	1,496	1,175	888	855	38	1,399	
4. 38%, low emissions	1,328	1,059	799	788		1,323	
8. Fluidized-bed combustion	2,098						
9. Gasification/gas turbine	1,400						205
10. ISTIG				639			
12. Molten-carbonate fuel cell	890			476			130

All values include 3 g/kWh CO_2-equivalent of N_2O from corona discharge. However, this could be as high as 61 g/kWh (Appendix N). Emissions from the construction of power plants are not included; these probably would amount to 2-5 g/kWh. All efficiencies are net generation efficiencies based on higher heating values.

TABLE D.7 (Cont.)

[a] Generation scenarios are as follows:

1. Fossil-fuel plants: efficiency of 32% for all plants (approximately the current U. S. national average). Emissions of non-CO_2 greenhouse gases from fossil plants as in Table D.4. 92% distribution efficiency. Methanol made from primarily remote natural gas (as in Table D.4).

   Nuclear power: The base-case, "no-new-orders" scenario (projected energy-use values for 1990-2010), which uses the base-case values of Table I.3 for SWU/MWh-generated, tons U_3O_8/GWh-generated, and MWh-enrichment/MWh-generated. Emissions from standby generators are as in base case here (Table D.4).

2. Fossil-fuel plants: 35% efficiency; all else as in scenario 1. This is the projected average efficiency of new fossil-electric plants expected to be ordered between now and the year 2000 (EIA, *Annual Outlook for U. S. Electric Power 1990*, 1990).

   Nuclear power: new-capacity, low-efficiency scenario: SWU/MWh-generated, tons U_3O_8/GWh-generated, and MWh-enrichment/MWh-generated are at the 1977-1988 levels (Table I.3), which embody a lower burn-up rate, and more initial loadings, than do the projected 1990-to-2010 base-case levels. The energy requirement of mining and milling is at the 1982 value, which is much higher than the base-case 1987 value used here (see Table I.1). All else as in scenario 1.

3. Fossil-fuel plants: 38% efficiency; all else as in scenario 1.

   Nuclear power: U-AVLIS or gas-centrifuge enrichment, which use 1/20 the energy of gaseous diffusion; all else as in scenario 1.

4. Fossil-fuel plants: 38% efficiency; SO_x and NO_x emissions are 50% of the levels of Table D.4. All else as in scenario 1.

5. Fossil-fuel plants: 40% efficiency; all else as in scenario 1. This is the likely economical thermal efficiency limit for coal, oil, and gas boilers (Gilbert Associates, 1985; Encor America, 1986).

6. Fossil-fuel plants: 40% efficiency, SO_x and NO_x emissions are 50% of the levels of Table D.4. All else as in scenario 1.

7-12. Advanced-technology scenarios: efficiency and emissions as in Table D.6; all else as in scenario 1.

[b] Using the CO_2-equivalent factors of Table 8, for the time horizon indicated.

TABLE D.8 CO_2-Equivalent Emissions of Individual Greenhouse Gases from Power Plants and Upstream Processes in Grams per Kilowatt-Hour Delivered

Source	Coal Boiler	Fuel Oil Boiler	NG Boiler	NG Turbine	Nuclear Power
Upstream processes[a]					
CH_4	65.7	7.9	16.3	16.3	2.7
N_2O	0.4	5.3	0.7	0.7	0.7
NMOCs	0.4	3.3	1.1	1.1	.0
CO	0.3	1.5	0.4	0.4	0.1
NO_x	5.9	20.6	21.9	21.9	4.6
CO_2	29.3	141.8	72.0	72.0	45.9
All non-CO_2 gases	72.8	38.7	40.4	40.4	8.1
Upstream Total	102.0	180.5	112.4	112.4	54.0
Power plants[b]					
CH_4	0.1	0.2	0.0	3.6	0.1
N_2O[c]	16.3	10.0	9.8	9.8	3.3
NMOCs	0.1	0.3	0.1	0.3	0.1
CO	0.4	0.5	0.6	1.7	0.1
NO_x	102.5	71.0	54.7	41.1	4.9
CO_2	1075.4	875.9	606.3	605.2	6.5
All non-CO_2 gases	119.5	82.0	65.2	56.4	8.4
Power plant total	1194.8	957.9	671.5	661.6	14.9
Power plant + upstream					
Non-CO_2 gases	192.2	120.7	105.6	96.8	16.6
CO_2	1104.6	1017.7	678.3	677.2	52.4
Grand total[d]	1296.9	1138.4	783.9	774.0	69.0

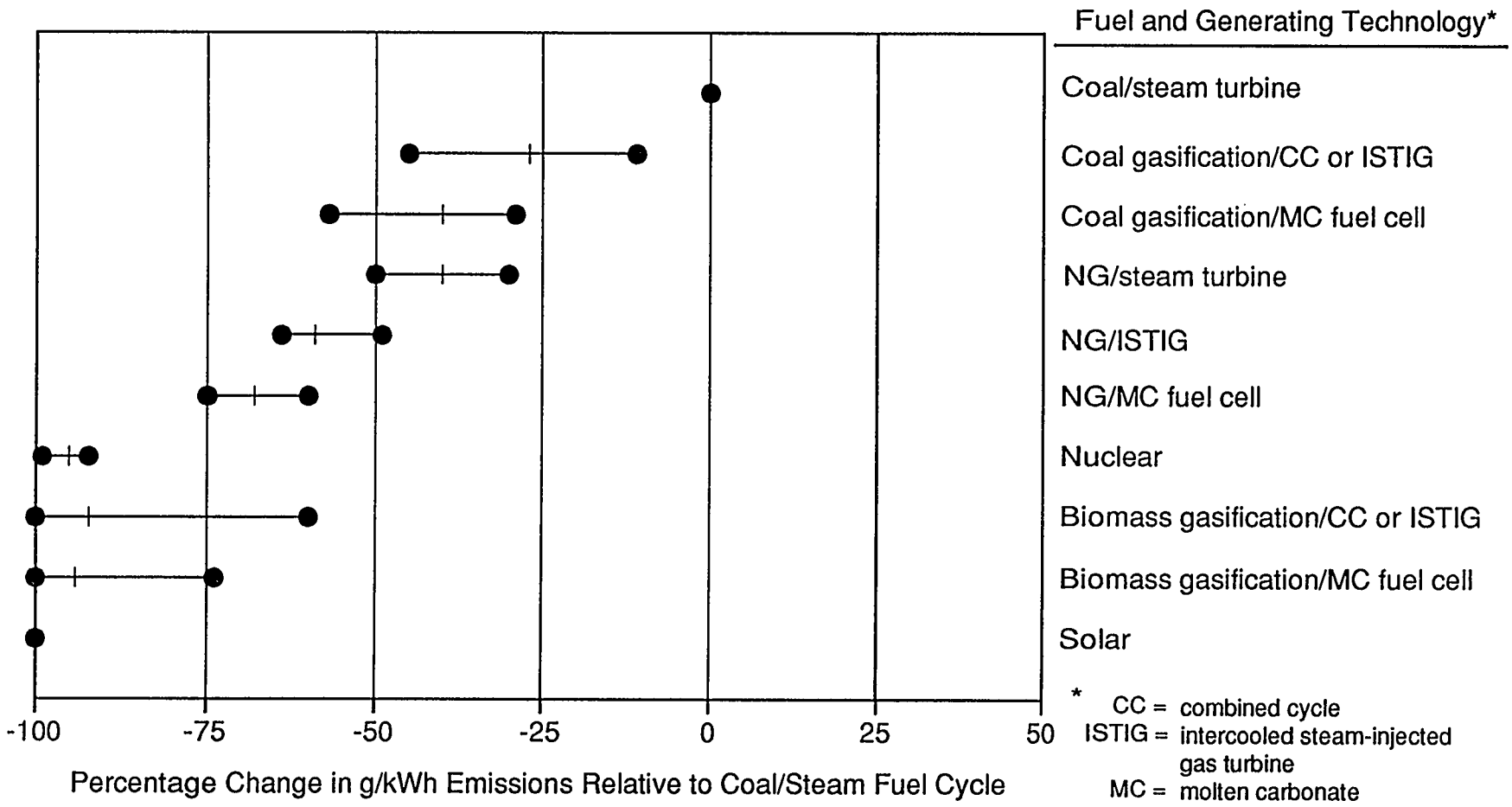
Units are grams of CO_2-equivalent emissions per kWh delivered to end users. Assumes 92% distribution efficiency. Includes N_2O emissions from corona discharge from high-voltage transmissions lines (Table D.4). Based on 100-year time horizon (Table 8).

[a] Feedstock recovery, transport, etc. Based on g/10^6 Btu values of Tables 6 and D.4.

[b] Operating at the base-case efficiency levels (Table 7).

[c] Includes N_2O formed by corona discharge from high-voltage transmission lines.

[d] Same as bottom-line totals of Table D.4.



Notes: Each line shows the range of results, from the most favorable to the least favorable, for the fuel cycle listed to its right. The results are expressed as a percentage change in CO_2-equivalent emissions relative to the baseline coal/steam fuel cycle of Table D.7. Emissions from the manufacture and assembly of facilities are not included. The solid circle at the left end of the range marks the most favorable case, which is the greatest percentage reduction or least percentage increase. The solid circle at the right end of the range marks the least favorable case, which is the least percentage reduction or greatest percentage increase. The solid tick between the circles represents the base-case value, which is my best estimate. The ranges shown include comparisons under all three time horizons (20 years, 100 years, and 500 years). Sources: Tables D.4 and D.7 and Figure D.1.

FIGURE D.1 Spans between the Most and Least Favorable Emission Results for Various Electricity-Use Fuel Cycles

Each line shows the range of results, from the most favorable to the least favorable, for the fuel cycle listed to its right. The results are expressed as a percentage change in CO_2-equivalent emissions relative to the baseline coal-steam fuel cycle of Table D.7. Emissions from the manufacture and assembly of facilities are not included. The solid circle at the left end of the range marks the most favorable case, which is the greatest percentage reduction or least percentage increase. The solid circle at the right end of the range marks the least favorable case, which is the least percentage reduction or greatest percentage increase. The solid tick in between the circles represents the base-case value, which is my best estimate. The ranges shown include comparisons under all three time horizons (20 years, 100 years, and 500 years). The base-case percentage change is based on the data of Tables D.4 and D.7 The best and worst cases are described next. The description mentions only those variables that change away from their base-case values (e.g., as in Table D.6 and elsewhere); all other variables retain their base-case values.

Coal-gasification combined-cycle (CC) or intercooled steam-injected gas turbine (ISTIG).

Best case: 45% efficiency; 14 g/10^6 Btu NO_x from power plant; 250 standard cubic feet (SCF) of methane per ton of coal mined.

Worst case: 36% efficiency; double the emission factors of Table D.6.

Coal-gasification molten-carbonate (MC) fuel cell.

Best case: 55% efficiency; zero emissions from power plant; 250 SCF methane/ton coal mined.

Worst case: 45% efficiency; double CO, NMOC, N_2O emission factors of Table D.6; 13 g/10^6 Btu NO_x.

Natural gas ISTIG.

Best case: 47% efficiency; NO_x, NMOC, CH_4 and N_2O emission factors of Table D.6 reduced by 50%; natural gas does not go to a natural-gas liquids (NGL) plant.

Worst case: 42% efficiency; 91 g/10^6 Btu NO_x; all natural gas goes to a NGL plant; 1% gas leakage from gas transmission.

Natural gas MC fuel cell.

Best case: 60% efficiency; zero emissions from power plant; natural gas does not go to a NGL plant.

Worst case: 50% efficiency; double the emission factors of Table D.6; all natural gas goes to a NGL plant; 1% gas leakage from gas transmission.

Nuclear power.

Best case: Uranium enrichment laser-isotope separation or gas centrifuge; U. S. average power mix used by enrichment plants.

Worst case: Scenario 2 from Table D.7.

Biomass-gasification CC or ISTIG

Best case: The one-time increase in the standing stock of carbon (CO_2) in biomass, as a result of permanently replacing crops or grasses with trees, offsets decades of fuel cycle-CO_2 emissions, including emissions from the manufacture and assembly of facilities and equipment. See Appendix K for details.

Worst case: 36% efficiency; double the emission factors of Table D.6; all biomass acreage is fertilized; add 2000 lb/acre lime; 0.015 g of N evolved as N_2O per g of N fertilizer; wood yield of 5 tons/acre; energy required for planting and harvesting 25% higher than in base case; add 0.10 Btu-energy (mainly as oil)/Btu-power to account for energy embodied in facilities and equipment. See Appendixes K, N, and P for details.

FIGURE D.1 (Cont.)

Biomass-gasification MC fuel cell

Best case: The one-time increase in the standing stock of carbon (CO_2) in biomass, as a result of permanently replacing crops or grasses with trees, offsets decades of fuel cycle-CO_2 emissions, including emissions from the manufacture and assembly of facilities and equipment. See Appendix K for details.

Worst case: 45% efficiency; double the CO, NMOC, N_2O emission factors of Table D.6; 13 g/10^6 Btu NO_x; all biomass acreage is fertilized; add 2000 lb/acre lime; 0.015 g of N evolved as N_2O per g of N fertilizer; wood yield of 5 tons/acre; energy required for planting and harvesting 25% higher than in base case; add 0.10 Btu-energy (mainly as oil)/Btu-power to account for energy embodied in facilities and equipment. See Appendixes K, N, and P for details.

FIGURE D.1 (Cont.)

D.2.5.2 CO_2 Emissions from Fuel Combustor

Emissions of CO_2 from fuel combustion are calculated from data on the carbon and energy content of the fuel and the amount of fuel carbon emitted as CO, CH_4, and NMOCs rather than CO_2. The carbon in CO, CH_4, and NMOCs is subtracted from the total carbon available in the fuel (per energy unit of the fuel); the remainder is assumed to burn fully to CO_2.

About 90% of the oil used by electricity-generating utilities is residual fuel oil; the remainder is distillate oil (North American Electric Reliability Council, 1989). For simplicity, I have assumed that all oil used in power generation is residual fuel oil. Since distillate and residual fuel have roughly the same amount of carbon per unit energy, and distillate fuel oil contributes only 0.5% of total input to electricity generation, this simplification is acceptable.

D.2.5.3 CO_2 Emissions from Scrubbing Sulfur

In the United States, Japan, and western Europe, new coal-fired plants must control emissions of sulfur oxides (SO_x). A common way to desulfurize flue gases is to introduce calcium-containing ions into a solution of sulfur ions (from the flue gas); the calcium combines with the sulfur to form gypsum (Glamser et al., 1988). If the source of the calcium is calcium carbonate ($CaCO_3$), the process releases CO_2: the carbon in the carbonate is converted to CO_2 in the ratio of one mole of CO_2 produced for every mole of sulfur scrubbed, or removed from the flue gas stream (Jons et al., 1987; Glamser et al., 1988):

$$CaCO_3 + SO_2 + 1/2H_2O \rightarrow CaSO_3 \times 1/2H_2O + CO_2$$

These additional CO_2 emissions must be assigned to coal-burning plants that desulfurize with calcium carbonate (or, in general, with any carbon-releasing compound).

However, calcium can be introduced in other compounds, such as calcium hydroxide ($Ca(OH)_2$). With this method, no extra carbon is added, so no extra CO_2 can be formed. In fact, researchers have found that if such a calcium sorbent is recycled, it can pick up CO_2 from the air and form calcium carbonate, which results in a net reduction in CO_2 emissions (Withum et al., 1988).

Although calcium carbonate is the most common sorbent, there are many other sorbents and scrubbing methods, some that produce CO_2 (e.g., sodium carbonate) and some that do not (e.g., the "Wellman-Lord" process, which uses a sodium-sulfite scrubbing solution) (USDOE, *Energy Technologies and the Environment*, 1988). CO_2 emissions from flue-gas desulfurization, then, depend on the type of sorbent used and the amount of sulfur removed.

In this analysis, I calculate CO_2 emissions from SO_2 control as follows:

$$CO2 = H \times Sw \times Sr \times Ca \times 1.375$$

where:

CO2 = grams of CO_2 emitted from scrubbing, per 10^6 Btu of coal burned;

H = higher heating value of coal, g/10^6 Btu (Table C-1);

Sw = weight fraction of sulfur in coal (0.013; Table C-1);

Sr = fraction of sulfur removed from coal, on average, in the year 2000 (about 0.50; estimated below);

Ca = fraction of sulfur removal done by using $CaCO_3$ or another CO_2-producing sorbent (about 0.50 in 1983; USDOE, *Energy Technologies and the Environment*, 1988); and

1.375 = ratio of the molecular weight of CO_2 to sulfur (44:32; one mole of CO_2 is produced for each mole of sulfur removed).

With regard to the estimation of Sr, the fraction of sulfur removed from coal, in 2000 in the United States, only about 20% of the sulfur is removed from coal at present (EIA, *Electric Power Annual, 1988*), but new plants are required to remove up to 90% of the sulfur (some clean-coal generation techniques, such as fluidized-bed combustion, also may use limestone to remove SO_x). The new CAA Amendments place a cap on utility emissions of 8.9 million tons (8,074 Gg) by 2000 (EPA, *CAA*, 1990). The EIA (*Annual Outlook for U. S. Electric Power 1990*, 1990) projects 18.951 quads of coal input, 6.334 quads of natural gas input, and 2.175 quads of oil input to power plants in 2000. Assuming that the g/10^6 Btu SO_x emission rate from oil-fired plants is

one-half that of coal-fired plants and that NG plants emit no sulfur, the maximum year-2000 m/10^6 Btu emissions from coal-fired plants can be calculated as:

$$8{,}074 \times 10^9 = X \times (18.951 \times 10^9) + X/2 \times (2.175 \times 10^9)$$

where:

8,074 = maximum, year 2000, Gg SO_X emissions from utilities,

X = g/10^6 Btu SO_X emission rate from coal-fired plants,

18.951 = quads of input to coal-fired plants, and

2.175 = quads of input to oil-fired plants.

The solution to this is 403 g/10^6 Btu for coal-fired plants and 201 g/10^6 Btu for oil-fired plants. This represents roughly a 50% reduction from uncontrolled levels (based on low-sulfur coal) for coal-fired plants.

D.2.6 Efficiency of Power Plants

The efficiency (heat rate) of fossil-fuel power plants has remained at around 32% since the mid-1960s (EIA, *Monthly Energy Review*; Encor-America [for EPRI], 1986). For economic and operating reasons, utilities have not bought more efficient plants since that time. However, it is possible that higher efficiency plants may be attractive in the near future. The Electric Power Research Institute (EPRI) and others estimate that advanced fossil plants will have a heat rate of around 8,500-9,500 Btu input/kWh output, or 36-40% (Gilbert Associates [for EPRI], 1985; Encor-America [for EPRI], 1986; Balzhiser and Yeager, 1987).

The EIA (*Annual Outlook for U. S. Electric Power 1990*, 1990) has projected the efficiency of coal-, oil-, and gas-fired plants for 2000. The EIA assumes that existing fossil-fueled plants will operate with the efficiency they showed from 1982 and 1987 (32-33%), that new steam plants will be from 33-36% efficient, and that new combined-cycle plants will be from 41-47% efficient. Combining these assumptions with assumptions about the rate of construction of new plants, the EIA projects fuel consumption and electricity generation for 2000. I use their projections in Tables 7 and D.4.

Table D.7 shows total fuel-cycle CO_2-equivalent emissions at several levels of efficiency.

D.2.7 New Electricity-Generating Technologies

The emission factors in Table D.4 and the base-case efficiency assumptions used here are representative of current-technology utility boilers and simple-cycle turbines. However, researchers are developing cleaner, more efficient gas- and coal-fired technologies, including combined-cycle gas turbines, intercooled steam-injected gas turbines (ISTIG), coal-integrated-gasification/advanced-gas-turbine plants, fluidized-bed combustors, and coal-integrated-gasification/molten-carbonate fuel-cell plants. In addition, gasification/turbine and gasification/fuel cell technologies can be used with biomass instead of coal. Table D.6 shows the efficiency of and emissions from these plants. These technologies are included not because they are expected to make a substantial contribution to electricity generation by 2000, but rather to show the longer-run potential for reducing emissions from the use of electricity.

D.3 Emissions of Greenhouse Gases from Hydro, Geothermal, Wind, Biomass, and Solar Power from U. S. National Power Mixes in 2000

In calculating emissions from the use of electricity for various national or regional processes (e.g., refining petroleum and compressing natural gas) in 2000, this analysis ignores any emissions of greenhouse gases from the use of renewable energy sources (hydro, geothermal, wind, biomass, and solar power) on the assumption that these emissions are so small, they are unimportant. In this section, I justify this assumption.

D.3.1 Wind, Solar, and Hydro Power

The operation of wind, solar-thermal, photovoltaic, and hydro generating facilities produces no emissions of any kind. The construction of these facilities and the manufacture of the materials used to make them produce only small amounts of greenhouse gases (see Appendix P). The vehicles and equipment used by plant employees and administrators produce only trivial amounts of greenhouse gases. For example, a fleet of 50 company vehicles, each driven 15,000 mi/yr will produce about 600,000 kg of CO_2-equivalent gases, less than 0.01% of the yearly life-cycle CO_2-equivalent emissions from a 1000-MW coal-fired power plant operating at 70% capacity. Hence, it is reasonable to assume that solar, hydro, and wind power emit but a very small amount of life-cycle greenhouse gases.

D.3.2 Geothermal Power

Geothermal fluids can contain dissolved CO_2, CH_4, NMHCs, and sulfur gases. Sulfur species can affect global climate by forming aerosols and affecting cloud albedo. Underground, under high temperature and pressure, these species remain dissolved in the liquid. When the fluid

is withdrawn to provide heat to make steam to drive a turbine, however, the fluid's temperature and pressure drop, and compounds that do not condense under atmospheric conditions are emitted to the atmosphere as gases (OECD, 1988). These emissions can vary greatly; they depend on the location, recovery technology, and control technology. It would seem that the average total greenhouse gas emissions from geothermal facilities should be at least one order of magnitude less than the emissions from fossil-fuel power plants (per megawatt). The Organization for Economic Cooperation and Development (OECD) states that "CO_2 emissions dominate the gaseous emissions in most geothermal fields, though [the] overall level per unit power is usually much less than from a fossil fuel plant" (OCED, 1988, p. 69). Otherwise, the operation of a geothermal plant should produce essentially no greenhouse gases. Emissions from the construction and operation of vehicles and equipment should also be very few, as discussed above.

Although geothermal power production can emit greenhouse gases — perhaps roughly as much as from the nuclear-power production cycle — geothermal power contributed less than 1% of the total U. S. electricity generation in 1988, and it is projected to contribute only about 1% in 2000 (Table D.9). The longer-term potential is greater, but not more than 5% of total U. S. electricity generation in 2030. Given that geothermal plants will generate about 1% of U. S. power and assuming that greenhouse gas emissions from geothermal plants do not constitute more than 10% of those from fossil-fueled power plants, the exclusion of geothermal power from the formal analysis probably understates life-cycle greenhouse-gas emissions from EVs by about 0.1% and understates emissions from other alternative-fuel cycles (which use much less electricity) by about 0.01%. These effects are insignificant and can be ignored.

D.3.3 Biomass

Current-technology biomass-fired power plants probably emit the full range of greenhouse gases, including CO_2, CH_4, N_2O, NMOC, and NO_x. However, the CO_2 emitted from biomass combustion is not a net release to the atmosphere since the carbon in the biomass comes originally from CO_2 in the atmosphere, via photosynthesis. The greenhouse impact of the non-CO_2 gases is about one order of magnitude smaller than that of CO_2 (from fossil-fueled plants).

The production, processing, and transport of biofuels also can produce small, but not trivial, amounts of greenhouse gases (see Appendix K). Likewise, emissions from the construction of biofuel generating plants are probably small, but not insignificant.

Unpublished runs of the emissions model indicate that the sum of non-CO_2 greenhouse gas emissions from the combustion of biofuels in current-technology plants, plus all greenhouse gas emissions from the production, processing, and transport of biofuels, probably amounts to 15-25% of the fuel-cycle emissions from fossil-fuel power plants. While these per-kWh emissions are significant, electricity generation from biofuels accounted for less than 2% of the total generation in 1988 and is projected to account for only 2-3% by 2000 (Table D.9). Moreover, virtually all biomass power is produced by small power producers and cogeneration facilities, not

TABLE D.9 Current and Projected Electricity Generation from Renewable Energy, Percent of Total Utility and Nonutility Electricity Generation

Power	1988[a,b]	2000	2010[a,c]	2030
Hydro	10.6	8.96	7.19-8.47	4.78-6.97
Geothermal	0.69	0.79-1.05	1.06-1.69	1.23-5.05
Biomass	1.71[d]	2.63-2.90	3.39-4.02	3.00-3.96
Solar and wind	~0.00	0.53-1.59	3.17-8.47	9.15-36.07

From USDOE, *The Potential of Renewable Energy* (1990). Ranges shown are high and low estimates. The low estimates are for the "business as usual" scenario; the high estimates are for the "RD&D intensification, without intermittent constraints" scenario.

[a] The reference gives total energy input to electricity generation for the years 1990 and 2030, and apparently assumes that energy input to electricity generation grows at a constant annual rate of 2.2% between 1990 and 2030. I calculate the energy input for 1988, 2000, and 2010 by applying the 2.2% growth rate to the given figure for 1990.

[b] These values can be compared with the EIA's (*Annual Review of Energy, 1989*) estimate of the percent of total utility (not including nonutility) generation in 1989 by renewables: 9.50% hydro, 0.34% geothermal, 0.07% biomass, and 0.0001% solar and wind.

It appears that biomass value here is half wood, and half waste. The EIA's *Estimates of Biofuels Consumption in the United States During 1987* shows that utilities consumed 8.6×10^{12} Btu of wood only (waste excluded) in 1987; the *Annual Energy Review 1989* reports that utilities generated $1,477 \times 10^{6}$ kWh from wood and waste in 1987. The $1,477 \times 10^{6}$ kWh of output would require about 16×10^{12} Btu of input, or about twice the input of wood alone.

[c] These values can be compared with the EIA's (*Annual Outlook for U. S. Electric Power 1990*, 1990) projections of the percent of utility and nonutility generating capacity in the year 2000 that will be renewable: 7.69% hydro (9.85% if pumped storage hydro and other storage capacity is included); 0.65% geothermal (58% utility, 42% nonutility); 2.18% biomass (6% utility, 94% nonutility); and 1.08% solar and wind (31% utility, 69% nonutility).

[d] Klass (1990) reports 8,624.8 MW of biomass-fueled electricity-generating capacity in the U. S. as of December 31, 1987. This was about 1.2% of total generating capacity in 1987 and 1988. However, data in Klass (1990) indicate that biomass-fired capacity is more fully utilized than other capacity, so that biomass probably supplied around 1.66% of total generation in the U. S. in 1987 and 1988. This figure is consistent with the DOE estimate shown in this Table.

Klass's (1990) data also indicate that roughly half of the biomass capacity is wood-fired, and that less than 5% of total biomass electric generation is by utilities.

by utilities (notes to Table D.9). Most of this nonutility generation is used on-site; according to Klass (1990), "total production should be substantially more than the excess sold to utilities" (p. 20). Thus the total biomass-fueled power available to the grid (and ultimately to other fuel-production processes, such as petroleum refining) probably will be less than 1% of the total generation. This amount is small enough to ignore for the purpose of calculating emissions from future mixes of power that are likely to be used for various processes.

D.3.4 Summary

The amount of greenhouse gases emitted from the construction of renewable-fuel power plants, from the operation of utility or fleet vehicles, and from the use of energy in utility buildings is quite small and can be ignored. Solar, hydro, and wind power plants have no other emissions. The geothermal and biomass electric fuel cycles emit some greenhouse gases, but because total biomass and geothermal electricity generation available to the grid will only be on the order of 2% of total available electricity, these emissions can be ignored.

Appendix E:

Energy Use by Trains, Trucks, Ships, and Pipelines

Appendix E:

Energy Use by Trains, Trucks, Ships, and Pipelines

E.1 Overview

Emissions of greenhouse gases (in grams) from fuel transport, per mile of travel from the vehicle, can be calculated as:

$$G = E \times F \times V$$

where:

G = grams of greenhouse gases per mile of travel by the vehicle;

E = emission rate of the transport mode (train, ship, truck, or pipeline), in g/10^6 Btu of fuel consumed by the mode;

F = fuel consumption rate of the transport mode, in 10^6 Btu of fuel consumed per 10^6 Btu of product or feedstock delivered; and

V = efficiency of the vehicle, in mi/10^6 Btu of fuel consumed by the vehicle.

This appendix discusses the calculation of F, which is the fuel consumption rate of trains, trucks, ships, and pipelines carrying coal, oil, petroleum products, natural gas (NG), ethanol, or methanol. The fuel consumption rate for the transport of biomass feedstocks (wood or corn) is discussed in the appendix on biofuels. The base-case values I use are meant to be for the year 2000.

Note that F is measured as 10^6 Btu of fuel consumed in transport divided by 10^6 Btu of fuel consumed by highway vehicles. The calculation of the denominator, fuel consumed by highway vehicles, is a separate matter that is discussed in the appendixes on particular transportation fuels in the sections on net end-use consumption. The calculation of the numerator, fuel consumed by the transport mode, is the subject of this appendix.

The numerator, F, fuel consumed by transport modes, is calculated as

$$\text{Btu/ton–mile} \times \text{ton–miles}$$

where ton–miles is either given or is calculated as the product of tonnage and mileage.

Table E.1 shows the basic data and results of the calculation of energy used by pipelines, trucks, trains, and ships transporting coal, crude oil, petroleum products, methanol from wood, methanol from coal, methanol from NG, and ethanol from corn and wood. The calculations for coal, crude oil, and petroleum products are based in part on actual data from 1987. The calculations for methanol and ethanol are necessarily hypothetical because there are no aggregate data on movements of these commodities (because so little is moved compared with coal and petroleum). I have estimated the movements of methanol and ethanol on the basis of rough ideas about where the plants would be located, where the markets would be located, and what modes of transport would be most economical (see Appendixes J and K).

Data on Btu per ton–mile are taken from Tables E.2 and E.3. Ton–mile data are taken or calculated from various sources as discussed in the text and the notes to the tables.

In the following paragraphs, I discuss some methodological issues that deal with the estimation of energy use by fuel transport modes.

E.2 Handling of Empty Backhauls

The correct expression of Btu per ton–mile energy intensity is:

$$E/(T \times M)$$

where:

E = total Btu used by the mode of transport, including that used for auxiliary power and all on-board power, and energy used for the backhaul (if the carrier returns empty);

T = total product tonnage, which does not include the weight of fuel used by the transport mode; and

M = distance the tonnage was actually carried (not including the backhaul distance).

Total tonnage should include only the weight of product discharged from the carrier; the weight of the fuel used to drive the carrier should not be counted. (The tonnage estimates in the Army Corps's *Waterborne Commerce* [various years] do not count bunker fuels, so they are correct for my purposes.) If the carrier returns empty, the energy used on the backhaul must figure

TABLE E.1a Calculation of Quads of Energy Used to Transport Coal, Crude Oil, and Petroleum Products in the Year 2000

Movement by Transport Mode	Coal	Crude Oil	Oil Products[a]
Rail			
1,000 tons	622,873		
Average miles	530		
Ton-miles	3.30×10^{11}	9.29×10^{8}	2.04×10^{10}
Btu/ton-mile	270	516	516
Quads used	0.089	0.000	0.011
Domestic water			
1,000 tons	171,094		
Average miles	447		
Ton-miles	7.65×10^{10}	4.23×10^{11}	1.48×10^{11}
Btu/ton-mile	500	184	197
Quads used	0.038	0.078	0.029
International water			
1,000 tons			
Average miles		9,552	5,126
Ton-miles		2.15×10^{12}[(b)]	4.11×10^{11}
Btu/ton-mile		114	114
Quads used	0.000	0.246	0.047
Pipeline			
1,000 tons	5		
Average miles	300		
Ton-miles	1.50×10^{6}	3.52×10^{11}[(b)]	2.45×10^{11}
Btu/ton-mile	600	75	95
Quads used	0.000	0.026	0.023
Road			
1,000 tons	146,356[c]		
Average miles	60[d]		
Ton-miles	9.94×10^{9}	2.40×10^{9}	1.25×10^{11}[(e)]
Btu/ton-mile HDDVs	2,072	1,704	1,816
Quads used	0.021	0.004	0.227
Total quads used	0.148	0.355	0.337
Btu-transport/ Btu-end use	--------	See Table 3	--------

See next page for footnotes.

TABLE E.1a (Cont.)

The values for 1,000 tons and average miles are actual or estimated 1987 values, except as noted. The values for ton-miles are either calculated here as the product of tons and miles, or, where these are not shown in the table, were given directly. See appendixes pertaining to individual fuels for details on the sources and derivations of these numbers. All values for Btu/ton-mile are estimates for the year 2000, as explained in this appendix.

NS = calculated but not shown.

[a] All petroleum products, including coke, asphalt, tar, road oil, LPG, etc.

[b] The calculated value for 1987 has been adjusted to reflect the probable increase in imports by the year 2000. See Appendix H.

[c] Includes weight of ash transported for disposal. See Appendix F.

[d] Average of coal haul and ash haul.

[e] Rough estimate, based on data for 1982. See Appendix H.

TABLE E.1b Assumptions Used to Calculate the Energy Required to Transport Methanol, Ethanol, and LPG

Movement by Transport Mode	Methanol from NG	Methanol from Coal	Methanol from Wood	Ethanol from Corn	Ethanol from Wood	LPG
Rail						
1,000 tons	2,000	30,000	55,000	70,000	55,000	4,000
One-way miles	400	800	600	600	600	600
Btu/ton-mile	516	516	516	516	516	516
Quads used	0.00041	0.0124	0.0170	0.022	0.0170	0.0012
Domestic water						
1,000 tons	40,000	45,000	55,000	20,000	55,000	0
One-way miles	800	800	800	600	800	0
Btu/ton-mile	197	197	250	300	250	197
Quads used	0.0063	0.0071	0.0110	0.004	0.0110	0.0000
International water						
1,000 tons	75,000	0	0	0	0	5,000
One-way miles	5,500	0	0	0	0	10,000
Btu/ton-mile	114	114	150	150	150	114
Quads used	0.047	0.000	0.000	0.000	0.000	0.006
Pipeline						
1,000 tons	40,000	60,000	10,000	1,500	10,000	95,000
One-way miles	500	800	500	500	500	600
Btu/ton-mile	95	95	95	95	95	90
Quads used	0.002	0.005	0.000	0.000	0.000	0.005
Road						
1,000 tons	100,000	100,000	100,000	100,000	100,000	100,000
One-way miles	100	75	100	250	100	150
Btu/ton-mile HDDVs	1,816	1,816	1,816	1,816	1,816	2,000
Quads used	0.018	0.014	0.018	0.045	0.018	0.030
1,000 tons produced[a]	100,000	100,000	100,000	100,000	100,000	100,000
Net quads end use[b]	1.95	1.95	1.95	2.57	2.57	4.32
Total quads used[c]	0.074	0.038	0.047	0.071	0.047	0.042
Btu-transport/ Btu-end use[d]	0.0378	0.0193	0.0239	0.0275	0.0182	0.0097

See appendixes pertaining to individual fuels for derivations of the numbers. The numbers for methanol and ethanol are my assumptions for a hypothetical distribution system, scaled to a hypothetical level of production (see notes below, and Appendixes J and K).

TABLE E.1b (Cont.)

[a] For methanol and ethanol, I have arbitrarily chosen these values; they are meant to be the hypothetical level of production of methanol or ethanol. This arbitrarily chosen production level is a reference point: relative to it, I have estimated the amount of methanol and ethanol hypothetically distributed by train, ship, and pipeline. Note that since the final results are expressed per unit, as total distribution energy per unit of fuel energy delivered to the consumer, the absolute magnitude of the starting point is irrelevant. One would get the same ratio if the starting production point, and all the tonnages estimated relative to it, were 13 times higher or 4.4 times lower.

See the section on methanol transport, at the end of the appendix on methanol (Appendix J) for details.

[b] Equal to total tons produced multiplied by quads/ton, minus quads of fuel used by trucks to transport the fuel (own use).

[c] Sum of quads used for rail, ship, pipeline, and truck transport.

[d] Total quads used divided by quads of end use.

TABLE E.2 Estimates of Btu/Ton-Mile for Various Modes and Commodities

Commodity Transported and Reference	Mode of Transport			
	Truck	Train	Water	Pipeline (Btu-power)
Coal				
USDOE (1983)[a]	1,342-2,683	348[b]	615	574[c]
CRS (1977)[d]	2,518-2,800	536-791	540-680	
Banks (1977)				534[e]
ANL (1982)	2,134	489	481	897[f]
Rose (1979)	2,590		450	
Petroleum products				
Hooker et al. (1980)			480[g]	92; 106[h]
ANL (1982)	2,235	526	408	90[i]
Kurak (1989)				60-120[j]
Banks (1977)				108[k]
My estimate for 1987	1,900[l]			
Rose (1979)	2,270	860		
Crude oil				
ANL (1982)	2,134	665	408	75[m]
Interhome (1989)				< 200[n]
Banks (1977)				63[k]
Rose (1979)	2,130			
Generic petroleum				
CRS (1977)[o]	2,400	750	500	1,850
ORNL (1989)				87[p]
BAH (1977)			212	
Generic (any commodity)				
ORNL (1989)	1,898[q]	474[r]	402[s]	
USDOT (1988)		445[t]		
USDOE (1983)			331[u]	
Penner (1978)	1,950[v]			
Rotty et al. (1975)	2,720	550		
Forest or wood products				
Rose (1979)[w]	2,770	960		
Farm products				
Rose (1979)[x]	2,680	680		

See next page for footnotes.

TABLE E.2 (Cont.)

USDOE (1983) = *Energy Technology Characterizations Handbook.* CRS (1977) = U.S. Congressional Research Service, *National Energy Transportation.* ORNL (1989) = Oak Ridge National Laboratory, *Transportation Energy Data Book,* Davis et al.; ORNL estimates are total energy use by mode divided by total ton-miles by mode for 1987. ANL (1982) = Argonne National Laboratory, *Baseline Projections of Transportation Energy Consumption by Mode: 1981 Update,* Millar et al.; some of Argonne's estimates may be derived from Rose, 1979. USDOT (1988) = *National Transportation Statistics,* 1986 data. OGJ = *Oil and Gas Journal.* BAH (1977) = Booze, Allen, & Hamilton, *Energy Use in the Marine Transportation Industry, Volume II, Task I — Industry Summary.*

Values shown do not include "indirect" energy used to build and maintain transportation systems. However, this energy is accounted for in the final results.

Keep in mind that the estimates shown in the table were made at different times, and energy intensity changes over time.

[a] Their numbers are drawn from other sources published in the mid to late 1970s but are not referenced individually. For the truck, the higher estimate assumes that nothing is carried on the return trip.

[b] Unit coal train.

[c] Includes slurry preparation, pipeline pumping, and dewatering facilities.

[d] From a study by the Missouri Pacific Railroad Traffic Research Division.

[e] An estimate of electricity use by the Black Mesa pipeline. Includes electricity used to pump up the water mixed with the coal (29 Btu-electric per ton-mile of coal, assuming the electric pump is 64% efficient), electricity used to prepare and pump coal slurry mixture (275 Btu-electric per ton-mile of coal, including energy used to grind coal and taking advantage of the downhill drop on the Black Mesa line), and electricity used to deslurrify the coal (231 Btu-electric per ton-mile of coal). I have not included the energy required to reduce the moisture content of the coal, because (1) Banks does not specify the source of this energy and (2) I assume waste heat could be used. ORNL gives 2,765 Btu-thermal per ton-mile, based on the same study by Banks. I cannot produce an estimate of 2,765 from the Banks data.

[f] Recorded as 0 in ANL's Appendix B but estimated to be 2,990 Btu thermal on p. 139. ANL projected that if more coal slurry pipelines are built, the average length of haul will increase and energy intensity will decrease. I converted to Btu-electric by using ANL's 30% electricity generation and distribution efficiency.

TABLE E.2 (Cont.)

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[g] Based on a careful analysis of coastal tankers (20,000-80,000 dwt) plying the U.S. Gulf Coast/Northeast Coast route. Hooker reports that the average energy intensities of coastal tankers for one firm in 1975 were much higher: 635 Btu/ton-mile.

[h] The result of a very detailed analysis of electricity consumption by Colonial (first number) and Plantation (second number) pipelines in 1977.

[i] I converted from ANL's value of 300 Btu-thermal by using ANL's 30% electricity generation and distribution factor.

[j] In 1988, Texas Eastern shipped 160 million barrels of petroleum products from the Gulf Coast to the Midwest and Northeast via pipeline. They spent $21.1 million on electricity to run the pipelines, which was $6 million less than they would have spent had they not made the system more efficient in 1986. Starting with the unoptimized, original, less efficient system ($27.1 million for electricity — I consider the optimized system to be representative of future, not current, industry averages) and given 6.72 cents/kWh (apparently their average power cost), and assuming 7 barrels/ton, the result is 60,000 Btu/ton. If the average haul was 1,000 miles (the length of their line from Baytown Texas to Lebanon Ohio), the intensity was 60 Btu/ton-mile. If the average haul was 500 miles (about the average length for petroleum products in the U.S., according to USDOT (1988), the energy intensity was 120 Btu/ton-mile. Based on Btu-electric.

[k] Banks estimated kWh/ton-mile as:

$$(E_e/E_p)/(BM/D)$$

where:

E_e = dollar expenditures on power used by oil pipeline compressors, as reported by pipeline companies to the Interstate Commerce Commission (ICC);

E_p = average price of electricity in $/kWh, based on interviews with pipeline companies;

BM = barrel-miles of shipments, as reported to the ICC; and

D = average density of crude or product mixture, in barrels/ton.

The industry average for crude pipelines was 0.0184 kWh/ton-mile. One company provided Banks with an estimate of 0.0316 for its operations. The industry average for product pipelines was 0.0250 kWh/ton-mile, with three companies reporting 0.0208, 0.0261, and 0.0572 kWh/ton-mile.

TABLE E.2 (Cont.)

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[l] According to a person in the gasoline delivery business, trucks typically carry 8,800 gallons of gasoline. If the truck gets 4 mpg loaded, and returns the same distance empty at 8 mpg, the result is 1,916 Btu/ton-mile for any distance (assuming the truck uses diesel fuel). The round-trip average fuel economy would be 5.3 mpg, which was the value in 1987 for heavy-heavy diesel trucks (Davis and Hu, 1991). I assume 6.0 mpg for the year 2000.

[m] I converted to Btu-electric from ANL's listed value of 250 Btu thermal, using ANL's 30% electricity generation and distribution efficiency.

[n] Interprovincial Pipeline (1989) states that their pipeline system pumping power capacity exceeds 750,000 kW. In 1988, Interprovincial moved 1.507 million barrels per day (Interhome, 1989). Thus the maximum possible energy intensity for the system (if the system operated at maximum capacity 100% of the time) would have been 200 Btu-electric per ton-mile. Undoubtedly, average power usage for 1988 was less than the maximum capacity, and so energy intensity was less than 200 Btu-ton/mile.

[o] A claim by the American Waterways Operators (p. 262). The value for pipelines is probably Btu-thermal.

[p] Btu-electric; I converted from the given value of 270 Btu/ton-mile, Btu-thermal, assuming electricity generation and distribution efficiency of 32.3%. The 270 Btu per ton-mile was from J.N. Hooker, *Oil Pipeline Energy Conservation and Efficiency*, ORNL-5697, Oak Ridge National Laboratory, Tennessee (1981). Edition 9 gave 280 Btu per ton-mile.

[q] Energy use data from the Census's *Truck Inventory and Use Survey 1982*, and ton-mile data from Transportation Policy Associates, *Transportation in America*, 6th Edition, Washington, D. C., Supplement, November (1988).

[r] For class 1 freight railroads in 1986. The value for 1988 is 434. Calculated from data in EIA's *Petroleum Marketing Monthly, June 1988*, and publications by the Association of American Railroads. I show the 1986 value for comparison with USDOT's 1986 value (note t).

[s] For general waterborne commerce, based on energy-use and ton-mile data from the EIA's *Petroleum Marketing Monthly, June 1988*, the Army Corp's *Waterborne Commerce*, and other sources.

[t] For class 1 freight railroads in 1986; from *Railroad Ten-Year Trends* by the Association of American Railroads. The year-by-year Btu/ton-mile figures for railroads in *National Transportation Statistics* are about 10% lower than those in the *Transportation Energy Data Book* (1989). The two sources show the same year-by-year ton-mile figures but different Btu figures.

[u] For an LNG tanker of 63,460 dwt capacity. I assume a one-way haul of 8,000 miles. Year not specified; references used are from mid to late 1970s.

TABLE E.2 (Cont.)

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[v] For a five-axle combination diesel truck averaging 5.64 mpg and carrying an average load of 13 tons. Based on data from FHWA.

[w] For 1976/77. Year 2000 values would be 2,216 for truck and 499 for trains, based on a 20% reduction for trucks, 1977-2000, and a 48% reduction for trains, 1976-2000.

[x] For 1976/77. Year 2000 values would be 2,144 for truck and 354 for trains, based on a 20% reduction for trucks, 1977-2000, and a 48% reduction for trains, 1976-2000.

TABLE E.3 Detailed Estimates of the Btu/Ton-Mile Energy Intensity of Petroleum Tankers

	A	B	C	D	E	F	G	H	I	J[d]
Reference	dwt (long tons)	Shaft-Power (hp)	Type of Power Plant	Speed (knots)	Fuel at Sea (long tons)	Fuel/d in Port	One-Way Distance (miles)[a]	In Port (days)[b]	dwt Payload /dwt[c]	Btu/ ton-mi[d]
BAH (1977)[e]	40,000	12,000	Steam turbine	15.5	22				0.96	355^
BAH (1977)[f]	14,766	4,000	Steam & diesel		7				0.96	540^
BAH (1977)[g]	3,937	1,500							0.96	650^
Marks (1982)	161,000	10,072		11.5	60	20	5,750	5	0.98*	105
Marks (1982)	500,000	81,500		16	419.16	133[h,*]	6,900*	6 *	0.96*	176
Marks (1982)	250,000	51,500		16	265.01	84[h,*]	6,900*	5 *	0.95*	223
Marks (1982)	19,500			14	28	5	6,900*	4[i,*]	0.93*	342
Marks (1982)	50,000	16,700		16	85.97	27[h*]	6,900*	4 *	0.93*	362
Chem Systems (1988)	250,000		Direct-drive diesel	12	37.5	7.5	6,900*	2	0.99*	39
Chem Systems (1988)	100,000		Direct-drive diesel	12	32.5	7.5	6,900*	2	0.98*	85
Chem Systems (1988)	40,000		Direct-drive diesel	12	27.5	7.5	6,900*	2	0.96*	184
Chem Systems (1988)	150,000		Steam turbine	16.5	140	15*	6,900*	2 *	0.96*	180
Chem Systems (1988)	30,000		Direct-drive diesel	16.5	70	7.5*	6,900*	2 *	0.90*	482
LNG:										
Chem Systems (1988)	125,000 m^3	Steam turbine	18.5	60/90[j]	40	5,500	3	NA	0.059[k]	

BAH = Booze, Allen, & Hamilton, *Energy Use in the Marine Transportation Industry, Volume II, Task I — Industry Summary* (1977). Rose (1979) uses the BAH data, and ANL (1982) appears to use Rose to estimate the energy intensity of marine transport.

* My assumption or calculation, relying at least in part on numbers not given in the reference. Unasterisked data are given in the reference or can be calculated from data in the reference.

^ As given in the reference.

[a] Statute miles. I assume round-trip mileage is twice one-way mileage. I assume 6,900 statute miles (6,000 nautical miles) because 12,000 nautical-mile round trips are common and because using one distance in all cases shows the importance of ship design variables.

[b] Per round trip.

TABLE E.3 (Cont.)

[c] The percentage of the total weight carried (dwt): cargo, water, mail, fuel, stores, crew, baggage, product that is payload (crude oil or petroleum products). I calculate this by subtracting from dwt 1.5 times the amount of fuel required for a 10,000-nautical-mile one-way trip, at the given operating speed, with a 10% margin; the 1.5 accounts for nonfuel, noncargo weight (water, crew, etc.) ($I = 1 - [(1.5 \times 10{,}000 \times 1.1 \times E)/(D \times 24)]/A$; letters refer to column headings above).

[d] I calculate this as the sum of fuel used in port and at sea for the whole round trip, divided by the product of one-way mileage and payload tonnage. Payload tonnage is equal to dwt multiplied by the payload percentage. The calculation is:

$$J = [(E \times 2 \times G/(D \times 24 \times 1.15) + F \times H) \times 42 \times 10^6 \text{ Btu/ton}]/(A \times I \times G)$$

where the letters refer to the column headings above.

My calculations assume that the tanker returns empty at the same rate of fuel consumption as on the loaded leg. If the tanker carries another product on the return trip, then the energy intensity allocated to petroleum would be a bit more than half (a bit more, because of the additional port-time for loading and unloading the second cargo).

[e] Coastal tanker.

[f] Great Lakes dry-bulk carrier.

[g] Great Lakes tanker.

[h] I assume fuel use in port is equal to the shaft horsepower x lb-fuel/shaft-horsepower-hour x 0.0039, following BAH (1977). The fuel consumption rate can be calculated from the data in the Table to be 0.42 lb/shaft-horsepower hour ($2{,}000 \times E/24 \times B$; where E and B are column headings above).

[i] Given as a 3-day layover plus 12 hours per port stop. I assume one port stop per one-way trip.

[j] 90 long-tons/day of boil-off gas (0.17% boil-off/day), and 60 long-tons/day of fuel oil.

[k] Btu-fuel/Btu-LNG delivered. Calculated from formula in Chem Systems (1988). Equal to 0.021×10^6 Btu-fuel oil/10^6 Btu-LNG delivered (including fuel in port), plus 0.038×10^6 Btu-NG/10^6 Btu-LNG delivered. It appears that they assume that the tanker burns NG on the return trip.

in total modal energy consumption. If the carrier moves another product on the return trip, the energy used on the backhaul should not be assigned to the first product. For most of the products and modes analyzed here, the carrier returns empty. Ninety-one percent of the cars that carry coal return to the mine empty (Rose, 1979); oil tankers generally return to the loading port empty (Booz, Allen and Hamilton, 1977), although there is a small trend toward hauling water back to the producing country, and trucks generally return empty unless they can find a return product compatible with the first. Methanol tankers will also return empty (Chem Systems, 1988). Pipelines, of course, do not have return trips. On the other hand, in calculating ton-miles, only the miles the product actually moved, not the mileage of empty backhauls, should be counted.

I have intended to express all estimates of energy intensity (Btu/ton–mile) according to this convention. However, in several cases, the data are not detailed enough for me to determine if the energy intensity has been calculated as I want it to be. For example, it is often not clear if auxiliary power (e.g., for ships) has been counted or if only motive energy has been counted. However, I assume that auxiliary power is generally small when compared with motive power, so that any inconsistency in accounting for it will have little effect.

A potentially more important issue is whether the reference source I use has counted the energy required for empty backhauls. With a few exceptions, the sources I use appear to count the energy for backhauls. In the U. S. Department of Energy's (DOE's) *Energy Technology Characterizations Handbook*, the estimates for coal transport by train and barge appear to count the energy used for return trips (they give annual energy requirements for many round trips per year). It is not clear if the *Handbook* energy estimate for liquefied natural gas (LNG) tankers includes the backhaul because the book assumes only one trip per year of unspecified length . The estimate for truck transportation of coal includes energy used on the return trip, but it counts return mileage in the estimate of ton-miles, which is a mistake if nothing is carried on the return trip. The estimates from Davis et al. (1989), the U. S. Department of Transportation (1988), and Millar et al. (1982) all include energy used for backhauls because they estimate total energy consumption for a mode. The basis of the estimates reported by the U. S. Congressional Research Service (1977) is not clear.

E.3 Energy Intensity Now and in the Future

Table E.2 shows several estimates of the energy intensity of rail, water, pipeline, and truck transport. The estimates differ because the references use different primary data sources, different base years (energy intensity generally improves over time), and different assumptions about backhauls. For a given mode, the energy intensity will depend on the fuel or feedstock carried, because the weight and design of the container, possibility of returning with another commodity, circuitry of the route, design of the vehicle, length of the train, and other factors depend on the feedstock or fuel carried and affect energy intensity (Rose, 1979).

In this report, I specify the energy intensity for each fuel carried and mode of transport by using data in Rose (1979), the *Transportation Energy Data Book* (Davis and Hu, 1991), and other

sources (Table E.2). I also include an estimate of indirect energy consumption, which is the energy used to maintain and build transport systems by using data in Rose (1979). Rose (1979) and Davis and Hu (1991) use the same higher heating valves (HHVs) used here.

E.3.1 Railroads

Rose (1979) calculates the energy intensity of rail transport in detail for coal, petroleum, wood, farm products, and many other commodities. I take his commodity-specific Btu/ton-mile estimates for 1976 (based on his "great-circle miles") and scale them downward by the ratio of projected year-2000 average rail intensity to actual year-1976 average rail intensity. Rose's unscaled (1976) estimates are shown in Table E.2; my scaled year-2000 projections are shown in Table E.1.

The average, overall energy intensity of Class 1 railroads has declined monotonically since 1976, from 677 to 434 Btu/ton–mi in 1988 (Davis and Hu, 1991). The Energy Information Administration (EIA) attributes this largely to legislation, called the Staggers Rail Act, that gave railroads incentives to invest in efficiency (EIA, *Energy Consumption and Conservation Potential*, 1990). According to the EIA, the railroads have nearly exhausted the sorts of efficiency improvements encouraged by the Staggers Act. However, other sorts of efficiency improvements are available.

The energy intensity of trains is likely to decline further during the 1990s as rising fuel prices give operators incentive to reduce fuel consumption. At a meeting in 1982, experts from industry and DOE identified many fuel-saving measures then available to railroads, including education of engineers and dispatchers, closer attention to fuel metering and fuel security, reduction of empty freight-car miles, and elimination of unnecessary idling (Saricks et al., 1984). Industry and literature sources estimated that many of these measures could reduce fuel consumption by 5-15%. Railroads adopted some of these measures in the 1980s, but some have not been taken. I assume that energy intensity will continue to decline, although at a slower rate than in the 1970s.

The EIA (*Energy Consumption and Conservation Potential*, 1990) projects that the energy intensity of railroads will decline between 0.3% (reference case) and 0.9% (high conservation case) per year from 1990 to 2010. I assume a decline of 0.6%/yr through 2000. This decline results in 404 Btu/ton–mi in 2000, a reduction of 40.3% from 1976.

Rose calculated that, in 1976, the specific energy intensity for coal transport by rail was 450 Btu/ton–mi, but for other products it was much higher. Rose's implicit overall average energy intensity for all commodities is probably close to 677 Btu/ton–mi (coal is the main commodity carried by railroads). Accordingly, I multiply all of Rose's (1979) specific energy intensities for individual commodities by 0.597. The results are shown in Table E.1.

Switching from diesel to locomotives powered by overhead electricity would reduce energy consumption 50-70% but would require more capital than the industry is likely to be able to afford for many years (Saricks et al., 1984).

E.3.2 Trucks

Rose (1979) also calculates, in detail, the energy intensity of truck transport for coal, crude oil, petroleum products, forest products, farm products, and many other commodities. Again, I take his commodity-specific Btu/ton–mile ("great-circle mile") estimates, which I assume are for 1977, and scale them downward by the ratio of projected year 2000 average truck intensity to actual year 1976 average truck intensity. Rose's unscaled (1977) estimates are shown in Table E.2; my scaled year 2000 estimates are shown in Table E.1.

The fuel economy of heavy-heavy diesel trucks improved by about 10% from 1977 to 1987, although the overall mpg of all combination trucks remained nearly constant during the same period (Davis and Hu, 1991; USDOT, *National Transportation Statistics*, 1988; FHWA, *Highway Statistics 1987*, 1988). The lack of overall improvement by combination trucks appears to be due to a decrease in the fuel economy of gasoline and liquefied petroleum gas medium and light-heavy trucks, which cancels the improvement in the fuel economy of heavy-heavy trucks. Here, the fuel economy of heavy trucks is relevant because heavy trucks will carry transportation fuels and feedstocks.

There is a lot of room to improve the fuel economy of heavy trucks in intercity transport. Bertram et al. (1983) lists some 60 measures that are based on a review of the literature and discussions with industry representatives. The authors and industry participants agreed that it was most important to motivate drivers and vehicle owners to drive and maintain vehicles fuel-efficiently (e.g., eliminate unnecessary idling, stay under 55 mph, and perform regular maintenance). Many of these measures, behavioral and technical, offer fuel savings of 5-10%. The EIA (*Energy Consumption and Conservation Potential*, 1990) lists several technologies that could improve fuel economy, including low-heat rejection (adiabatic) engines, improved radial tires, and the use of ceramics.

The EIA (*Energy Consumption and Conservation Potential*, 1990) estimates that the fuel economy of heavy diesel trucks will grow between 0.57% (reference case) and 1.3% (high-conservation case) per year, from 1990 to 2010. I assume it will grow 0.95%/yr from 1987 to 2000. This results in 6 mpg by 2000, up 13% from the 1987 value, and up 25% from the 1977 value. This 25% improvement in fuel economy translates to a 20% reduction in energy intensity. Thus, I multiply all of Rose's (1979) Btu/ton–mile figures for individual commodities by 0.80. The results are shown in Table E.1.

E.3.3 Pipelines

The energy intensity of a pipeline is a function of the flow rate, viscosity of the liquid, pipeline diameter, efficiency of the motors, and other factors. The estimates of the energy intensity of pipeline transport are of reasonably good quality and are in generally good agreement for individual commodities (Table E.2). Included in Table E.2 are several estimates based on actual energy consumption of pipelines as well as engineering estimates. Hooker et al. (1980) estimates electricity consumption by pipeline compressors as a function of route configurations, product density, route mileage, and other factors.

The efficiency of pipeline systems can be improved by using more efficient electric motors and by computerizing systems operations (Banks and Horton, 1977). The numbers used for the year 2000 in Table E.1 reflect modest efficiency gains over the values of Table E.2.

E.3.4 Ships

The Btu/ton–mile energy intensity of a ship is a function of ship size, design, type of power plant, and speed. These characteristics are quite different for petroleum tankers than for coal-carrying barges. There also are significant differences in these characteristics (and hence in energy efficiency) among different types of petroleum tankers. For example, bigger tankers are more efficient than smaller tankers; in fact, energy intensity decreases faster than carrying capacity increases as one moves from small 20,000 dead-weight ton (dwt) products carriers to ultra-large crude carriers, because horsepower/dwt decreases with increasing dwt. Similarly, diesel-fuel, direct-drive engines consume 10-40% less fuel per shaft horsepower-hour (hp-h) than steam-turbine engines and other types of power plants (Rose, 1979; Marks, 1982). Different types of ships travel at different speeds, and because water is considerably more dense than air, fuel consumption is much more sensitive to speed in marine transport than in land transport. Traveling faster than the economically optimal speed of 12 knots (kn) increases fuel consumption dramatically — A general rule of thumb is that a 10% reduction in operating speed reduces energy consumption by about 20% (Rose, 1979). The overall energy intensity of a ship is also a function of the length of the haul and the time spent in port. (Energy use in port is counted here.)

Thus, to estimate the energy use in water transport of petroleum, one must do more than merely distinguish between tankers and barges. One must also specify the size, engine technology, and traveling speed of the vessels. One then must know the energy efficiency of each kind of vessel and the mix of the kinds of vessels.

Table E.3 shows the energy intensity of ships as a function of ship characteristics. For each data source in the table, the data from are arranged from least to greatest energy intensity (Btu/ton–mile). For example, the first three entries under "Chem Systems" show the effects of decreasing dwt at constant technology and speed, as do the three entries under "Marks" for 16 kn. The fourth entry under "Chem Systems" shows that a large, steam-turbine driven vessel traveling at 16.5 kn requires as much fuel/ton–mile as a much smaller, slower, direct-drive vessel, the

advantage in size having been canceled by the higher speed and less efficient technology. The last entry under "Chem Systems" shows that increasing the speed from 12 to 16.5 kn more than doubles the energy consumption (compare 30,000 dwt and 40,000 dwt tankers). The effect of speed is illustrated also by the "Marks" data: the size advantage of the 50,000 dwt tanker over the 19,500 dwt tanker is nullified by the higher speed of the larger vessel.

Table E.4 shows the mix of the world tanker fleet. Most of the world's large tankers were built between 1974 and 1978; since then, the building boom has slowed considerably (OPEC, 1989). In fact, the average dwt was slightly lower in 1988 than it was in 1983. It is likely, though, that it will increase again in the future because the number of large tankers laid up has declined steadily since 1984 (OPEC, 1989).

E.3.5 Energy Intensity of Future Waterborne Commerce

Tankers have become more efficient over the last 20 years, primarily as a result of the use of direct-drive diesels in place of steam-driven engines. Tanker efficiency may also have improved through using less powerful engines (perhaps made possible by less air and water resistance) and traveling at slower speeds. For example, in 1989, Chevron ordered four 150,000 dwt tankers from Japanese companies (to be delivered in 1991-1992), each with a 18,900 service hp diesel engine providing a service speed of 15 kn (OGJ, March 6, 1989); in 1974, a "typical" 150,000 dwt tanker had 26,500 hp, according to Champness and Jenkins (1985), and 20,000 hp, according to Booz, Allen, and Hamilton (1977).

Tankers will probably continue to become more efficient, especially if fuel prices rise. In 1981, Bertram and Saricks (1981) tabulated and analyzed more than 60 fuel-savings measures for marine transportation derived from literature reviews and discussions with industry representatives. They concluded that slower ship speeds, improvements in hull trim, proper maintenance and adjustment of propellers, proper engine tuning, and motivating the crew to be fuel efficient could reduce energy consumption by 7-30%. Although these measures were compiled in 1981, most of them appear to be applicable today. For example, a new 236,604-dwt Japanese crude carrier has a slim hull designed to minimize water resistance and reduce wave-making, an aerodynamic superstructure, and an efficient new propeller design, which reduces fuel consumption by 20% compared with very large crude carriers (VLCCs) built in 1987, and 50% compared with 1982 VLCC models (OGJ, February 13, 1989).

Therefore, it seems reasonable to assume that new ships will be moderately more efficient than current tankers. However, fleet-average efficiency will only improve slowly because of the very long lifetime of tankers. The EIA's *Energy Conservation and Consumption Potential* (1990) projects only a small increase in fleet-average efficiency in its high conservation case because of the long lifetime of tankers and because fuel costs are only a small portion of total operating costs.

TABLE E.4 World Tanker Fleet, Distribution of dwt, 1983 and 1988

Data	1983[a]	1988[b]
Percentage by dwt class		
10,000-49,999	15.1	15.9
50,000-99,999	17.5	19.2
100,000-199,999	14.9	17.2
200,000-319,999	42.0	37.2
320,000+	10.4	9.4
Number of ships	3,115	2,923
Average dwt	90,900	85,300
U. S. fleet average dwt	57,000	

[a] 1983 data from Champness and Jenkins (1983).

[b] 1988 data from OPEC (1989).

When fuel bills were soaring in the early 1980s, there was talk of outfitting ships with sails (*Petroleum Encyclopedia*, 1983; Bertram and Saricks, 1981). While this tactic theoretically offered considerable potential to reduce fuel consumption, the idea appears to have lost favor as fuel prices dropped. I do not consider it here.

Overall energy consumption by tankers depends on the length of haul as well as on the Btu/ton–mile efficiency. Significantly longer or shorter hauls could significantly increase or decrease total energy consumption. However, because of the complexity and variability of the flow of oil, it is virtually impossible to predict changes in the average length of haul. One might assume with some confidence that U. S. oil production will decline over the next 20 years and that imports will increase, but to use these assumptions to predict future movements of crude and products requires additional assumptions, including (1) who will export crude to United States, (2) how much crude will be exported, (3) where crude will be refined, (4) where the refined imported crude will be consumed, (5) who will export the refined crude product to the United States, (6) how much crude will be exported, and (7) where in the United States the crude will go. Influencing these outcomes will be such things as changes in port capacities.

A scenario in which the United States continues to import large amounts of crude from Mexico, Canada, and Venezuela (EIA, *Petroleum Supply Annual,* 1988) is quite different from one in which the United States imports more from the Middle East. I do not consider this scenario further; instead, for simplicity, I assume the same mix of exporting countries will exist in the

future. I do, however, assume that more oil will be imported in 2000 more than it is today, from the same mix of countries. This assumption will not change the average length of haul, but it will increase the total tonnage moved and hence increase total energy used by tankers (see Appendix H for more discussion).

On the basis of data in Tables E.3 and E.4, I establish future petroleum and methanol and ethanol fleets. The characteristics of these are shown in Table E.5. Values for Btu/ton–mile are calculated from these data and input into Table E.1. For crude oil and petroleum-product tankers, I have assumed values closer to the Btu/ton–mile figure for direct-drive, relatively efficient ships operating at a fuel-saving speed of 12 kn (Table E.3). I assume that domestic product tankers are generally smaller than domestic crude tankers and that vessels in domestic service are smaller than vessels in international service. The numbers I have chosen result in an average total dwt value for the fleet that is consistent with the data in Table E.4.

In the base case, I assume that methanol is shipped in a fleet of tankers with the same characteristics as the fleet of tankers now shipping crude oil and petroleum products internationally. This assumption presumes a relatively large demand for methanol. I assume that biofuels will typically be transported in tankers slightly smaller (and therefore slightly less efficient) than tankers used for fossil fuels, because biofuel-production plants generally will produce less energy than will petroleum refineries. Finally, I note that the Btu/ton–mile intensity of coal transport by water, via barge, is much higher than it is for petroleum transport, as indicated by the data in Table E.2. My assumption is shown in Table E.1.

E.4 Indirect Energy Use

The Btu/ton–mile intensities calculated and used here do not include the energy used to build and maintain vehicles and transportation systems or the energy embodied in materials. However, such indirect energy consumption is a real part of a fuel production and use cycle and must be counted. Rose (1979) cites a source that estimates indirect energy use as a percentage of direct energy use. For ships, indirect energy consumption is 85.7% of direct energy consumption; for pipelines, 7.1%; for trains, 116.7%; and for trucks, 42.9%. (This figure for trucks is broadly consistent with my estimate in Appendix P that the energy required to make and assemble the materials of a truck is 10-15% of direct energy use when one considers that the energy in materials and for assembly is only a portion of total, indirect energy.) I use these percentages here.

I assume that most of this indirect energy is used to make steel or concrete or is in the form of oil used by vehicles and maintenance and construction equipment. On the basis of this assumption and data on input of energy by type for steel and concrete production (Hudson, 1982; Sapp, 1980), I assume that the source for indirect energy represents 50% coal, 20% NG, 20% oil, and 10% electricity.

TABLE E.5 Calculated and Assumed Characteristics of Ships in This Report

dwt Class	Calculated Relative Payload	Input Btu/ ton-mile[a]	Input Relative Distance[b]	Input Fraction of Ships in Each dwt Class[d]					
				Methanol[c] Domestic	Methanol Int'l.	Crude Domestic	Crude Int'l.	Products Domestic	Products Int'l.
30,000	1.000	300	1.000	0.150	0.020	0.100	0.020	0.150	0.020
60,000	2.000	240	1.000	0.350	0.050	0.250	0.050	0.350	0.050
90,000	3.000	180	1.100	0.400	0.130	0.450	0.130	0.400	0.130
120,000	4.000	150	1.200	0.100	0.200	0.200	0.200	0.100	0.200
150,000	5.000	120	1.200	0.000	0.300	0.000	0.300	0.000	0.300
200,000	6.667	90	1.300	0.000	0.200	0.000	0.200	0.000	0.200
250,000	8.333	70	1.300	0.000	0.100	0.000	0.100	0.000	0.100
300,000	10.000	50	1.300	0.000	0.000	0.000	0.000	0.000	0.000
Calculated fleet average Btu/ton-mile[e]				197	114	184	114	197	114

[a] From the data of Table E.3. See text.

[b] Reflects longer hauls for larger ships.

[c] Applies also to ethanol tankers plying inland waterways.

[d] See text for discussion.

[e] Input to Table E.1.

I calculate greenhouse gas emissions from the use of indirect energy by multiplying total direct energy use for each mode and commodity (Table E.1) first by the indirect-energy percentage for each mode (above), then by the energy-input share factors (50% coal, 20% NG, 20% oil, 10% electricity), and finally by the fuel-cycle grams of CO_2-equivalent/10^6 Btu process-fuel emission factor for each kind of energy input (Table 6 in Volume 1).

Appendix F:

Coal

Appendix F:

Coal

F.1 Overview and Objective

In the United States, coal is mined in underground and surface mines in the East, primarily in Appalachia, and in surface mines in the Rocky Mountain states. Electric generating utilities in the eastern part of the country consume most of the coal produced in the United States.

Trucks move coal from the face of the coal seam to cleaning plants, rail tipples, or barge loading facilities, and to some small consumers located near the mine. Most coal, however, is moved long distances by rail, typically from the mine to a large electric generating facility. Coal accounts for about 50% of all tonnage moved by rail.

The coal energy-use cycle is relatively simple to analyze. Energy is used in coal mining and preparation and in rail transport to large end users. There is no product refining and distribution, as with oil, and no joint production, as with natural gas and natural gas liquids. The U.S. Bureau of the Census data on energy used in mining, the Energy Information Administration (EIA) data on coal production and consumption, and the data on energy used to transport coal are reasonably complete and straightforward.

The objective is to determine the amount and kind of energy used to mine, transport, process (if relevant), and distribute (if relevant) the fuel, per energy unit of fuel, made available to end users outside the fuel-production system. In the following sections, I discuss components of these process-energy/net-energy-for-consumption ratios from coal: the amount and kind of energy used to mine coal in 1982 and 1987, the amount and kind of energy used to transport coal in 1987, and the amount of coal made available to end users in 1987 and 2000.

F.2 U. S. Bureau of the Census Data on Energy Used to Recover Coal, Oil, Gas, and Uranium

Every five years, the U. S. Bureau of the Census surveys industries, manufacturers, transportation, and other sectors of the U. S. economy. These surveys report the amount and value of products from each industry, and the amount, value, and kind of fuels (including electricity) used by each industry. The most recent survey was conducted for 1987. I have calculated 1982 and 1987 energy-use by the coal, uranium, oil, and gas industries, using the final U. S. Bureau of the Census survey data (USDOC, *Census of Mineral Industries, Fuels and Electric Energy Consumed*, 1985 and 1990).

Several problems arise in calculating energy use from the survey data. First, the Census Bureau withholds fuel consumption data for some sub-activities in the industries. In a few instances this is done because the data are poor, but most often the data are withheld because only one company was involved in the activity and the Census Bureau cannot disclose data about an individual firm. These data have to be estimated. I discuss particular difficulties as they arise for particular fuels (see notes to the tables in pertinent appendixes).

Second, some companies do not report detailed data on fuel use, and some small companies are not surveyed. The Census Bureau estimates the value, but not the quantity or types, of the fuel used by these companies (this is called undistributed fuel; electricity apparently is not included). If one assumes that the energy used by the companies that did not report detailed data or were not surveyed, comprised fuels in the same proportions as did the energy used by companies that reported detailed data, then one can scale up the amount of reported fuel use by the ratio of the total value of all fuels (the estimated value of undistributed fuels plus the reported value of detailed fuels) to the value reported for detailed fuels. An indication that this is assumption is reasonable is that the 10^6 Btu/$ value the Census Bureau uses for undistributed fuels is very close to the value implicit in my assumption.

Similarly, the census estimates the value, but not the quantity, of a small proportion of total production (e.g., tons of coal) by mineral industries. The total quantity of production (reported plus unreported production) can be estimated by scaling reported production by the ratio of total value to reported value.

Third, the Census Bureau lumps Liquefied Petroleum Gas (LPG), coke, wood, and other minor fuels together into an "other" category, and reports the cost of these other fuels, but not their energy content. To calculate greenhouse gas emissions, one must convert this expenditure on other fuels to a physical or energy amount of a specific kind of fuel. I do this in several steps. First, I convert the dollars spent on other fuels into energy units by using the Census Bureau's 10^6 Btu/$ factor for other fuels (Table F.1). Then, I scale this estimate of other fuels by the factor, discussed above, that accounts for undistributed fuels. Finally, on the assumption that most of the other fuels are LPG or coke and so would have an average carbon content similar to that of diesel fuel, I assign the energy embodied in other fuels to diesel fuel. (I note, too, that the Census Bureau 10^6 Btu/$ factor for other fuels is close to the Census Bureau's 10^6 Btu/$ factor for diesel fuel.) Since, in most cases, industries consume only small amounts of other fuels, minor errors in estimating greenhouse gas emissions from other fuels are tolerable.

Fourth, the Census does not always cover every activity related to the industry. For example, the coal mining survey covers mining, preparation, coal cleaning, and coal mining services (which perform such things as overburden removal), but does not appear to include reclamation services. I have ignored such errors of omission on the assumption that they are unimportant.

TABLE F.1 Data Used to Adjust Census Data on Energy Used to Recover Coal

SIC area	$ Purchased Fuels[a] per $ Distributed Fuels[c] 1982	$ Purchased Fuels[a] per $ Distributed Fuels[c] 1987	$ All Products[b] per $ Distributed Products[d] 1982	$ All Products[b] per $ Distributed Products[d] 1987
Bituminous coal mining	1.049	1.332	1.087	1.086
Anthracite coal mining	(use rates for bituminous)	--	1.063	1.060

Also: 0.137×10^6/$ of other fuels 1982 (value used by the Census) and 0.161×10^6 Btu/$ of other fuels 1987 (value used by the Census).

Sources: Publications from the U. S. Department of the Commerce, Bureau of the Census: *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985); *1987 Census of Mineral Industries, Coal Mining* (1990).

[a] The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies not surveyed (the Census estimated the value for these companies) and by companies that did not report how much of each kind of fuel they used.

[b] The total dollar value of all products (crude oil, dry gas, NGLs, uranium ore, etc.) of all companies engaged in the activity, including products from companies not surveyed (the Census estimated production for these companies), and products from companies that did not classify or detail their products (e.g., did not state what kind of coal they produced).

[c] The dollar value of the fuels purchased by companies that reported the amount of each kind of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only total cost of purchased fuels, with no breakdown or details.

[d] The dollar value of products of those companies that reported the amount and kind of each product.

Fifth, some estimates are not disaggregated sufficiently for my purposes. For example, the survey reports energy used by metal mining services, but does not disaggregate the services or the energy by the type of metal mining (e.g., uranium, iron, bauxite, etc.). More seriously, energy use in oil and gas extraction is reported together. Fortunately, there are plausible ways to disaggregate these values, as I discuss in appendixes pertaining to particular fuels, such as Appendix H (petroleum), Appendix G (natural gas), and Appendix I (nuclear energy).

F.3 Energy Used to Mine and Prepare Coal

Table F.2 shows the results of my analysis of the U.S. Bureau of the Census survey of energy use in coal mining. The analysis indicates that very little energy is used to mine and prepare coal — less than 1% of the energy available in the coal (Table F.3).

F.3.1 Comparison with Other Data

The Census Bureau data can be compared with engineering estimates of energy use in the U.S. Department of Energy's (DOE's) *Energy Technology Characterizations Handbook* (1983). The DOE *Handbook* gives diesel and electricity requirements for reference eastern underground mines and eastern and western surface mines. These per-mine values can be scaled up to total underground, western surface, and eastern surface coal production in the United States in 1982, and checked against the Census Bureau figures (I assume that western underground mines, which the DOE did not characterize, have the same energy requirements as eastern underground mines). As shown below, these scaled-up values are very close to the Census Bureau data used here.

According to the Energy Information Administration's (EIA's) *Coal Production — 1992* (EIA, 1983), 337.010×10^6 ton of coal was produced at underground mines in the U. S. (mostly in Appalachia), 248.068×10^6 ton at surface mines west of the Mississippi, and 247.446×10^6 ton at surface mines in the East. Scaling up the DOE *Handbook* (1983) figures to these national production levels yields:

	Underground	East Surf.	West Surf.	Total
Electricity, 10^6 kWh	13,233	1567	23	14,823
Diesel, 10^3 barrels	307	17,800	2,506	20,613
Total quads				0.171
Total quads from 1982 Census, used here				0.150

The total energy figures are reasonably close. The DOE *Handbook* 1983 figures include coal preparation but not beneficiation, which is treated separately. Since it is not clear if beneficiation is included in the Census Bureau data (the Standard Industrial Classification of coal mining does not mention it specifically) and to what extent the process is used, I have ignored it.

TABLE F.2 Energy Used to Mine and Clean Coal

Fuel Used	1982 Units	1982 Energy (%)	1987 Units	1987 Energy (%)
Crude oil (10^3 bbl)	0.0	0.00	0.0	0.00
Diesel (10^3 bbl)[a]	11,955.9	46.50	13,272.0	47.58
Residual (10^3 bbl)	1,606.0[b]	.74	1,246.6	4.82
Natural gas (10^9 ft^3)	0.8	0.58	1.5	0.93
Coal (10^3 tons)	378.3	5.39	446.0	5.86
Electricity (10^6 kWh)	5,300.6[c]	34.86	7,458.2[c]	36.66
Gasoline (10^6 gal)	66.4	5.55	43.7	3.36
Other (10^6 $)	4.2	0.38	7.9	0.78
Total energy (quads)	0.150	100.00	0.162	100.00
USDOC production totals (10^6 tons)	853.8		931.9	
EIA production[c] totals (10^6 tons)	838.1		918.8	

Sources: See those listed for Table F.1.

[a] I assigned half of the diesel fuel used in coal mining to scraping equipment and half to loading equipment by using EPA AP-42 emission factors for each (Table A.1).

[b] The use of residual fuel in anthracite mining in 1982 was not disclosed. I estimated this by multiplying diesel fuel use in anthracite mining by the ratio of residual fuel use to diesel fuel use in bituminous and lignite mining.

[c] Coal mines generated and sold an undisclosed amount of electricity in 1982 and 1987. These electricity sales should be subtracted from the amount purchased. I estimated electricity sales in coal mining by using data on electricity purchased and sold in all mineral industries.

[d] From EIA, *Coal Production* (1983, 1988). The correct Census figure to compare with the EIA data is the sum of reported net tonnage shipments of all coal (lignite, bituminous, and anthracite) and coal not specified by kind (n.s.k.). Coal n.s.k. is coal whose value but not weight was reported to the Census. According to the Minerals Branch of the Census, the amount of coal n.s.k., as a percentage of reported net shipments, is roughly equal to the value of n.s.k coal as a percentage of the value of all reported net tonnage — about 10% (Roy Frank, October 12, 1989).

TABLE F.3 Coal Production and Consumption Sheet

Item	1982	1987
Production (10^3 tons)[a]	853,766	930,996
Own use (10^3 tons)[b]	4,606	5,261
Net consumption (10^3 tons)[c]	849,160	925,735
Net consumption (quads)	18.12	19.76
Production/consumption[d]	1.0054	1.0057
Production efficiency[e]	0.0083	0.0082

[a] From Table F.2.

[b] The amount of coal used at coal mines, as shown in Table F.2, plus the amount of coal used at electricity plants supplying power to coal mines, assuming coal mines draw from the national average power mix. Does not include coal used to make electricity used by refineries making diesel fuel used by trains to deliver coal, and similar third-order own use, because the amount is negligible.

[c] Production minus own use.

[d] The ratio of coal produced to coal available to end users. This ratio is used to convert methane emissions per ton of coal produced to methane emissions per ton of coal to end users. See Appendix M.

[e] Total energy used at coal mines, as shown in Table F.2, divided by quads of net consumption.

Note, too, that the amount of coal production reported to the Census Bureau is about the same as the amount reported to the EIA (Table F.2). This agreement indicates that the Census Bureau data are fairly reliable.

F.4 Energy Used to Transport Coal

The amount of energy used to transport coal is the sum of the amount used by trains, trucks, ships, and coal slurry pipelines (see Table E.1). Trucks and trains use diesel fuel, ships use residual fuel oil, and slurry pipelines use electricity. For each of these modes, the total amount of energy consumed is equal to the Btu/ton-mile energy intensity of the mode multiplied by total coal tonnage carried by the mode and the average length of haul. Btu/ton-mile data are compiled in Table E.2 and discussed in Appendix E. In this section, I calculate the amount of coal hauled by each mode and the average length of shipment.

F.4.1 Tons of Coal Shipped, by Mode

I use data from the EIA's *Coal Distribution* (1988), which reports coal tonnage shipped by rail, water and truck, as stated by coal distributors themselves. I have counted all coal distributed domestically, coal distributed to the Canadian border, and all secondary forms of transportation (the mode of shipment to lakes, rivers, or coastal ports). For coal exported overseas, I count shipment to the U. S. coast, but not beyond.

Pipeline tonnage data are from the *Transportation Energy Data Book* (Davis and Hu, 1991) for the Black Mesa pipeline, which is the only coal slurry pipeline operating. (*Coal Distribution* [1988] lumps pipeline tonnage with tramway and conveyor belt tonnage.)

The EIA's *Coal Distribution* estimates of tons of coal exported and tons of coal produced in the United States are consistent with the figures reported in the EIA's *Annual Review of Energy*. The 1987 *Coal Distribution* estimate of tons of coal shipped by rail (counting rail as both a primary and a secondary means of transportation) agrees to within better than 5% with the estimate in the Federal Railroad Administration's (USDOT, 1987) *1987 Carload Waybill Statistics*. (The *Waybill Statistics* are independent samples of railroad commodity movements.) The railroad data in the *Coal Distribution* report thus appear to be quite reliable.

Waterborne Commerce of the United States, Calendar Year 1986 (U. S. Department of Army, 1987) reports a significantly larger tonnage of coal moved on lakes and rivers than does the EIA. This discrepancy is probably due to different definitions and categories. The two sources agree on tons of coal exported overseas.

F.4.2 Average Length of Haul

The EIA does not report mileage data for coal movement by rail. However, the *1987 Carload Waybill Statistics* (U. S. DOT, 1989) reports both tons and ton-miles of coal movement by rail. As noted above, the USDOT tonnage estimates agree with the EIA's tonnage estimates, which suggests that it is consistent to calculate the average length of haul from the *Waybill Statistics* and apply it to the EIA data. The result is 490 mi in 1987 (478 mi in 1982).

The Clean Air Act's (CAA)'s) limits on sulfur emissions from coal-fired plants will likely induce the greater use of low-sulfur western coal (EIA, *Improving Technology*, 1991; they estimate that the share of Western coal will increase from about 40% to about 50%, due to the CAA). On average, western coal fields are located further from power plants than are eastern coal fields, and hence the greater use of western coal will increase the average length of haul by rail. Therefore, I assume that the average haul in 2000 is somewhat longer than at present.

Waterborne Commerce of the United States (U. S. Department of Army, 1988, 1989) reports that coal was shipped an average of 446 mi by water in 1987 and 456 in 1986. The DOE

Handbook (1983) assumes 190 mi one-way for eastern barges and 400 mi one-way for western barges. I use 450 mi (it is probably the best raw data available).

The DOE *Handbook* (1983) assumes 60 mi round-trip per coal-delivery truck. I will use this value.

The Black Mesa coal slurry pipeline is 273 mi long, according to the *Transportation Energy Data Book*, and USDOT's *National Energy Transportation Study* (1980). I have assumed a length of 300 mi to account for the coal shipped by tramway and conveyor belt.

For comparison, The *National Energy Transportation Report* (U. S. CRS, 1977) reports average miles of coal haul for railroads, water, and road as 300, 480, and 50-75 (p. 62).

My assumptions for Btu/ton-mile, tonnage, and average length of haul are shown in Table E.1.

F.4.3 Energy Used to Dispose of Coal Ash

In the United States, coal contains about 10% ash by weight, on average (EIA, *Coal Data, 1989*). The ash does not burn and must be gathered up and disposed of. In addition, the sludge from flue-gas desulfurization units must be disposed of. In 1984, U. S. electric utilities generated about 69 10^6 ton of coal ash and 16 10^6 ton of FGD sludge, for a total of 85 10^6 ton (EPA, *Wastes from the Combustion of Coal...* 1987). In the greenhouse gas emissions model, this quantity is approximated as the product of the weight of coal and the ash weight fraction.

However, relatively little waste is trucked off site for disposal; most generating stations dispose of or recycle their waste on site (EPA, *Wastes from the Combustion of Coal...*, 1987). I assume that this disposal occurs at essentially no additional energy cost, and so multiply the quantity of waste generated by a small factor representing the quantity disposed off site. Moreover, the small amount of waste shipped off-site probably goes to the nearest landfill, mine, or surface impoundment. I assume 50 mi round trip by the disposal trucks.

F.5 Coal Available for Consumption, and Production and Transportation Efficiency

The calculation of the amount of coal made available to end users is straightforward: it is equal to the amount of coal produced, less the amount used at coal mines and at coal-fired power plants supplying electricity to the coal-production and transportation cycle. This is shown in Table F.3. In the case of coal, there are no losses or product transformations to account for.

Total energy used in coal mining divided by total coal energy available to end users for 1982 and 1987, is shown in Table F.3. Note that the ratios for 1982 and 1987 are virtually identical. Total energy used in coal transportation divided by total coal energy available to end users for 1987 is shown in Table E.1.

Table F.3 also shows the ratio of coal produced to coal available to end users. This ratio is used to convert methane emissions per ton of coal produced to methane emissions per ton of coal to end users (see Appendix M).

Appendix G:

Natural Gas and Natural Gas Liquids

Appendix G:

Natural Gas and Natural Gas Liquids

G.1 Overview

Raw natural gas (NG) is a mixture of hydrocarbons, water, nitrogen (N_2), carbon dioxide (CO_2), and often sulfurous compounds. The proportions of these compounds vary considerably from place to place, from nearly pure methane to mostly inert compounds (CO_2, nitrogen, and water) and contaminants. NG is found onshore and offshore by itself in gas-only fields and in association with petroleum. The Gulf Coast states produce most of the NG in the United States.

To be shipped in a pipeline and used as a fuel, NG must be separated from any co-produced liquids and purged of undesirable components. This processing involves several steps. First, the NG is separated from any liquids such as water, crude oil, and hydrocarbon condensate. The higher-weight alkanes (ethane, propane, and butane) are condensed, collected, and sold separately as fuels, because they typically have more value when they are separated than when they are components of an NG mixture. The NG is dried of water vapor, which can promote corrosion or lead to the formation of ice-like compounds called hydrates, which can plug gas lines. Finally, toxic and corrosive compounds, such as hydrogen sulfide (H_2S), and those without energy value, such as N_2 and CO_2, are removed (Kumar, 1987).

Natural gas recovery, cleanup, and transmission require energy (typically the NG itself), and the use of this energy produces greenhouse gases. Natural gas clean-up can release CO_2 and methane (CH_4); in addition, small amounts of CH_4 leak from fields and pipelines.

G.2 Energy Used to Lift and Process Natural Gas

There are two annual sources of information on the amount and kind of energy used to recover and process NG: the Energy Information Administration (EIA's) *Natural Gas Annual* and the U. S. Bureau of the Census's *Census of Mineral Industries, Fuels and Electric Energy Consumed.* The EIA form, EIA-176, which is sent to all companies involved in any phase of the NG business, records the amount of NG used in lease operations (field operations, such as drilling, heating, dehydrating, and compressing gas) and plant operations (removing nonhydrocarbon gases and natural gas liquids from the raw NG. See any *Natural Gas Annual.* The amount used for plant operations includes NG used as a fuel, NG lost, and NG vented or flared. I assume that very little NG is lost or vented and subsume this amount under my estimate of leakage from gas production.) From the responses given on survey form EIA-176, the EIA estimates the national total consumption of NG as lease and plant fuel. The EIA's results for 1982

and 1987 are shown in Table G.1. The EIA does not report the use of fuels other than NG. It also is not clear if some of the lease NG consumed was for oil production instead of NG production.

The U. S. Bureau of the Census reports the amount and kind of energy used to recover both NG and crude petroleum and the amount and kind of energy used to clean NG and produce natural gas liquids (NGLs) (Table G.2). The census does not report energy used by NG production separately from the energy used to produce both oil and NG. For a general description of the U. S. Census data, see Appendix F. Thus, associated with the EIA data is the problem of excluded energy sources and perhaps the problem of separating the oil and NG. Associated with the census data is the problem of separating the oil and the NG.

I use the U. S. Census data and then apportion process energy among petroleum, NG, and NGLs on the basis of the following observations:

First, it is likely that virtually all of the NG reported to the U. S. Bureau of the Census as being used to lift NG or oil was in fact used to lift or reinject NG. I infer this because the Bureau's estimate of the amount of NG used in oil and gas field operations is close to the EIA's estimate of the amount of NG used in field operations, and the EIA data probably refer to NG-lifting and NG-reinjecting operations only. The EIA survey (form EIA-176) is sent to NG producers and the survey is about gas, not oil, so the EIA feels that most, if not all, of the lease gas was used to produce or reinject gas, not oil (McCarrick, February 13, 1990). (There are no data on gas use by companies that produce only gas.) In any case, only a quarter of U. S. gas comes from wells that also produce oil (EIA, *Natural Gas Annual*, 1990), so most of the responding firms probably produce mostly or only gas.

The second observation is that energy used to reinject NG should in most cases be assigned to oil production because gas is reinjected mainly to pressurize oil wells and enhance oil recovery. If a producer intends to market gas from a field, it will not reinject any of the gas being produced, except in exceptional circumstances.

The EIA data clearly indicate that reinjected gas should be assigned to oil production. In states that do not produce any gas from oil wells (i.e., in states that produce gas only from gas-only wells), no gas is used for repressuring (EIA, *Natural Gas Annual 1989*, 1990). This situation is true for every state producing little or no gas from oil wells, including states that produce a lot of gas from gas-only wells. Gas is used for repressuring only in states that produce gas from oil wells.

In the United States most of the gas repressuring occurs in Alaska. In fact, in Alaska, virtually all associated gas is reinjected (EIA, *Natural Gas Annual 1989*, 1990) because there is no market for the gas. The data from Alaska suggest that producing and reinjecting associated natural gas require more energy (lease gas) than is required for producing gas for marketing: field operators in Alaska consumed 9.654 standard cubic feet (SCF) of lease gas per 100 SCF of all

TABLE G.1 Natural Gas and Natural Gas Liquid Production and Use Data

Item	USC 82[a]	EIA 82[b]	USC 87[a]	EIA 87[b]
Natural gas (NG) data				
Dry NG produced (10^9 ft^3)	17,908.9	17,758.0	16,844.7	16,536.0
Residue gas from NGL plants (10^9 ft^3)	11,198.4	13,193.2	10,219.3	11,685.9
Lease fuel (10^9 ft^3)[c]	324.4	386.1	458.5	481.8
NGL plant fuel (10^9 ft^3)[d]	471.4	515.4	390.3	408.1
Pipeline fuel (10^9 ft^3)	597.0*	597.0	519.0*	519.0
Unaccounted for loss (10^9 ft^3)[e]	474.7*	474.7	358.9*	358.9
Pipeline power (10^6 kWh)	2,377.2*	2,377.2	2,066.6*	2,066.6
NG for own-use power (10^9 ft^3)[f]	15.5*	15.5	12.7*	12.7
Net NG for end use (10^9 ft^3)[g]	16,104.2	15,847.6	15,165.3	14,815.5
Net NG for end use (quads)	16.6	16.3	15.6	15.3
Natural gas liquid (NGL) data				
Total NGL (10^6 bbl)	725.4	561.9	709.0	580.7
HHV[h] of NGL (quads)	2.77	2.14	2.70	2.21
Summary statistics				
10^9 ft^3 delivered gas[j]/10^9 ft^3 gas for end use	1.087	1.096	1.091	1.096
10^9 ft^3 dry gas produced/10^9 ft^3 gas for end use	1.112	1.121	1.111	1.116
Btu NG produced/Btu NGL + NG produced	0.870	0.895	0.865	0.885
Btu recovery energy/Btu NG + NGL	0.019	0.023	0.025	0.028
Btu production energy/Btu NG produced	0.022	0.026	0.019	0.021
Btu production energy/Btu NGL produced	0.035	0.035	0.031	0.030
Transmission energy[k]/Btu gas for end use	0.038	0.038	0.035	0.035
Btu compression or liquefaction energy per Btu CNG or LNG produced:				0.050[l]
Factor to account for NG used in liquefaction or compression:				1.027[m]

* The Census does not report this, so I have used data from the DOE Energy Information Administration (EIA).

[a] From the following publications from the U. S. Department of the Commerce, Bureau of the Census: USC 82 = *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985); USC 87 = *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); *1987 Census of Mineral Industries, Crude Petroleum and Natural Gas* (1990); *1987 Census of Mineral Industries, Natural Gas Liquids* (1990); and *1987 Census of Mineral Industries, Oil and Gas Field Services* (1990).

[b] EIA 82 = *Petroleum Supply Annual 1982* (1983), and EIA 87 = *Petroleum Supply Annual 1987* (1988).

[c] Fuel used at NG field operations.

TABLE G.1 (Cont.)

[d] Fuel used at NGL removal plants.

[e] Includes transmission and distribution leaks and losses. The reader will note that these are not the figures reported by the EIA. The EIA UAF figure is the difference between total supply and total consumption; I am interested in the difference between supply and consumption, excluding imports, exports, and storage additions and withdrawals. I have adjusted the UAF accordingly.

[f] Amount of natural-gas used at NG-fired generating plants supplying electricity to NG producers and pipelines. Calculated by multiplying total electricity consumption at NG field operations, NGL plants, and NG pipelines by the fraction supplied by NG-fired power plants.

[g] Equal to dry production minus NG used for lease fuel, plant fuel, and pipeline fuel; minus NG used by power plants supplying the NG system; and minus UAF gas. Does not account for NG used to compress or liquefy NG; that is accounted for separately. Excludes imports, because energy used to produce and transmit imports has not been counted. Excludes storage changes, on the assumption that in the long run, there should be no net change in storage.

[h] A weighted average calculated by the EIA, based on the amount and heating value of the constituents (butane, propane, ethane, pentanes plus plant condensate).

[i] These summary values are slightly different in the case of NG to methanol, because pipelines serving methanol plants will consume less fuel because of the shorter shipping distance. This reduction in pipeline energy affects all statistics, because it increases the amount of gas available for end use.

[j] Delivered gas is equal to net for end use plus lease, plant, pipeline, and own-use gas.

[k] The energy value of pipeline gas plus the energy value of electricity used by electric pipeline compressor stations. In the case of NG to methanol, this value is adjusted to account for the shorter shipping distance.

[l] Based on the data of Table G.6.

[m] Accounts for NG used to liquefy or compress NG.

gross withdrawals, whereas operators in the rest of the country used 2.372 SCF of lease gas per 100 SCF withdrawn (EIA, *Natural Gas Annual 1989*, 1990). In Alaska, 79.5% of gross gas withdrawal was reinjected and 20.0% was marketed; in the rest of the United States, 4.7% was reinjected and 92.7% was marketed. On the basis of these data, and assuming that the energy requirement of reinjection in Alaska is representative of the national average requirement, one can calculate the amount of lease gas used for reinjection and the amount of lease gas used to lift gas that is marketed:

$$2.372 = 0.047X + 0.927Y$$

$$9.654 = 0.795X + 0.200Y$$

TABLE G.2 Energy Used to Recover Raw Natural Gas and at Natural Gas Liquid Plants

	Natural Gas Recovery[a]				Natural Gas Liquid Plants[b]			
	1982		1987		1982		1987	
Fuel Used	Units	Energy (%)	Units	Energy (%)	Units	Energy (%)	Units	Energy (%)
Crude oil (10^3 bbl)	1742.8	2.52	602.4	0.68	0.0	0.00	0.0	0.00
Diesel (10^3 bbl)	4584.3	6.66	3169.0	3.61	29.2	0.03	5.3	0.01
Residual (10^3 bbl)	731.9	1.15	251.4	0.31	0.0	0.00	0.0	0.00
Natural gas (10^9 ft^3)	324.4	83.47	458.5	92.45	471.4	97.04	390.3	97.58
Coal (10^3 tons)	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
Electricity (10^6 kWh)	2391.4[c]	2.04	1884.0[c]	1.26	3327.5[d]	2.27	2690.4[d]	2.22
Gasoline (10^6 gal)	113.2	3.53	52.5	1.28	6.3	0.16	1.6	0.05
Other (10^6 $)	18.4	0.63	13.2	0.41	18.6	0.51	3.5	0.14
Total quads used	0.401		0.512		0.501		0.413	

Sources: See Table G.1.

[a] Energy used to recover raw natural gas. Energy apportioned between oil and gas using assumptions of Table G.4 (discussed in text above).

[b] Energy used at NGL facilities.

[c] Oil and gas producers generated and sold a small amount of electricity in 1982. I have subtracted this amount from the total amount of electricity purchased. The Census did not disclose the amount sold in 1987; I have estimated sales in 1987 by using data on electricity purchased and sold in all mineral industries.

[d] NGL plants sold a small amount of electricity in 1982 and 1987. I have deducted this from the amount purchased.

where:

X = SCF of lease gas used/SCF of gas reinjected and

Y = SCF of lease gas used/SCF of gas marketed.

On the basis of these U. S. data, X = 11.65 SCF/100-SCF-reinjected and Y = 1.97 SCF/100-SCF-marketed. This result indicates that 286 billion cubic feet (BCF) of gas, or 44.5% of total lease gas, was used for reinjection in the United States, given 641 BCF of total lease gas used in 1989 (EIA, *Natural Gas Annual 1989*, 1990). Thus, if the use of lease gas is a function of the amount reinjected and the amount marketed, and if the rate of using lease gas is the same in Alaska as it is in the rest of the country, one should assign 44.5% of total lease-gas use to oil production.

Of course, one could argue that conditions in Alaska are unusual and that elsewhere, much less lease fuel is required to reinject an SCF of gas. In this case, one might assume that only Alaskan lease-gas consumption should be assigned to oil recovery. (Alaskan gas operations consumed 29% of all lease gas used in the United States in 1989. One could argue that an even lower percentage should be assigned to oil production. Thus, it appears that 25-45% of lease-gas use in the United States should be assigned to oil production. In the base case, I assign 35% of total gas consumption to oil and 65% to production.

Since the assignment of the use of lease fuel to oil production is a function of the amount of gas reinjected and since the United States imports much of its oil, it is important to determine if the rate of reinjection in the countries that export oil to the United States is significantly different than the U. S. rate of reinjection. Using EIA (*International Energy Annual*, 1989) and United Nations (U.N., no date) data on reinjection, I have calculated the weighted average SCF of reinjected oil/bbl if oil exported to the U. S. rate for all U. S. imports. (The calculation is analogous to the calculation of weighted average venting and flaring per barrel, which is shown in Table M.7.) Countries that export oil to the United States reinject at a rate of about 600 SCF/bbl oil exported to the U. S.; the U. S. rate is about 630. Hence, there is no significant difference.

The third and final observation is that, according to the EIA (McCarrick, February 13, 1990) and Lieberman (1987), NG field equipment and processing plants use only a very small amount of electricity relative to the amount of gas they use. In support of this on, I have found that electricity use is only 2% of the total energy used at processing plants owned by interstate pipeline companies. Webb and PPS Ltd. (1983) show that power use is about 5% of total gas and power use by an NGL plant. My assumptions and results are shown in Tables G.2 and G.4.

Table G.1 compares EIA and U. S. Bureau of the Census survey estimates of the production and NG consumption of NG at NGL plants and NG facilities in 1982 and 1987. (The NGL data in the *Natural Gas Annual* and the *Petroleum Supply Annual* come from the same

TABLE G.3 An Estimate of the Amount of Electricity and Gas Used as Process Fuel by Interstate Pipeline Companies

Item[a]	Cost (10^6 $)[a]	My Assumption ($/unit of energy)[b]	Energy (quads)	Percent of Total Energy
For products extraction				
Fuel[d]	31.02	2.04/10^3 ft^3	0.0157	98.0
Power	4.48	0.048/kWh	0.000318	2.0
For transmission				
Gas fuel	375.89	2.04/10^3 ft^3	0.190	97.6
Other fuel & power[e]	65.48	0.048/kWh	0.00465	2.4

[a] From *EIA's Statistics of Interstate Natural Gas Pipeline Companies* (1988).

[b] Gas price is average price paid by interstate pipeline companies for gas from producers, gatherers, and/or processing plant operators, in 1988 (EIA's *Natural Gas Annual*). Electricity price is 1988 average retail price to industrial customers (EIA's *Monthly Energy Review*).

[c] Calculated here from energy expenditures and energy price. I assume 1,032 Btu/SCF for natural gas. The calculation of energy is just an intermediate step in the calculation of energy shares; the energy figures do not represent total process energy use by the natural gas industry or by natural gas pipelines.

[d] I assume all natural gas.

[e] I assume all electric power.

survey.) Table G.2 shows the Bureau's data on specific fuels used by NGL plants. The two sources agree quite closely on total dry gas production, energy used by NGL plants, and energy used in field operations in 1987. They do not agree as well on total production by NGL plants and energy used in field operations in 1982. I have used values in the middle of the ranges of the two sets of data.

Webb and PPS Ltd. (1983) show that an NGL plant in Canada uses about 0.021 Btu of gas and electricity per Btu of dry gas and NGLs produced, with about 95% of the input energy being gas. The data in Table G.1 show that about 0.034 Btu of NG is used to produce 1 Btu of NG and NGL, which is reasonably close to the Canadian data.

TABLE G.4 Data Used to Adjust Census Data on Energy Used to Recover Feedstocks

SIC area	$ Purchased Fuels[a] per $ Distributed Fuels[c] 1982	$ Purchased Fuels[a] per $ Distributed Fuels[c] 1987	$ All Products[b] per $ Distributed Products[d] 1982	$ All Products[b] per $ Distributed Products[d] 1987
Oil and gas extraction	1.136	1.111	1.123	1.125
Oil and gas field services	1.138	1.422	Not used	Not used
Natural gas liquids	1.009	1.039	1.003	1.004

Other assumptions:

0.650 fraction of NG used by oil and gas production assigned to NG (my estimate; see discussion in text).
0.050 fraction of all other oil and gas production energy assigned to NG (my estimate; see discussion in text).
0.400 fraction of energy used by drilling services assigned to NG (my estimate; see discussion in text).
0.161×10^6 Btu/dollar of "other" fuels, 1987 (value used by the Census)
0.137×10^6 Btu/dollar of "other" fuels, 1982 (value used by the Census)

Sources: See Table G.1.

[a] The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies not surveyed (the Census estimated the value for these companies) and fuels used by companies that did not report how much of each kind of fuel they used.

[b] The total dollar value of all products (crude oil, dry gas, NGLs, uranium ore, etc.) of all companies engaged in the activity, including products from companies not surveyed (the Census estimated production for these companies) and products from companies that did not classify or detail their products (e.g., did not state what kind of coal they produced).

[c] The dollar value of the fuels purchased by companies that reported the amount of each kind of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only total cost of purchased fuels, with no breakdown or details.

[d] The dollar value of products of those companies that reported the amount and kind of each product.

G.2.1 Emissions from the Manufacture of Concrete Used in Gas Recovery

Mueller (1990), by using data in the DOE *Handbook* (1983), calculates nontrivial emissions from the manufacture of concrete used to plug gas wells. However, the DOE *Handbook* made a mistake in its calculation of the value used by Mueller; it divided total concrete consumption by oil output in one year instead of over the 20-year life of the field. The correct concrete application factor is 20 times smaller than the one used by Mueller, which results in negligibly small emissions.

As in the case of oil, emissions from the manufacture of the steel used at gas fields are quite a bit greater than emissions from the manufacture of concrete, although they are still small. Table P.6 shows total emissions from the manufacture of steel and concrete as a function of total gas produced over the life of the field.

G.2.2 Assigning Recovery and Processing Energy to NG and NGL

The energy required to lift raw NG and separate the NGLs from the dry NG must be assigned to both products. The correct way to do this depends, in the first place, on the policy being evaluated. Suppose we are evaluating the greenhouse effects of choosing whether or not to make compressed natural gas (CNG) or liquefied natural gas (LNG) fuels. If we choose to make the NG-based fuels, we will incur all the emissions from the energy used to lift and process the gas, but (relative to not making the NG-based fuels), we will avoid the emissions associated with the manufacture and use of whatever energy products would have replaced the NGLs coproduced with the NG. Thus, we should assign to NG production and processing all the emissions from raw gas production and processing, minus the emissions that would have occurred had the NGLs not been available as a result of the decision to make NG-based transportation fuels.

To correctly calculate this NGL credit, we would have to model the supply and demand of NGLs and NGL substitutes and determine what energy would be used if the NGLs (from the use of CNG and LNG) were not available. There are many counterfactuals: refineries could produce more LPG; NGL plants could further fractionate gas to produce more NGL (which would require the increased production of an NG-substitute to make up for the decline in pipeline gas); other fuels, not derived from NG, could be used instead of NGLs; the smaller supply of NGL could raise its price and reduce demand and use, compared with the CNG/LNG case; and so on. (The situation would be reversed if an LPG policy were being evaluated.)

Such modeling is beyond scope of this project. I use a simpler, though less conceptually correct, method of assigning raw gas production and processing energy to both NG and NGL. I treat NGL as a generic energy product that is completely substitutable for NG, and evenly assign the energy required to produce a unit of NG or NGL to both products on the basis of energy

content. This production energy intensity is then adjusted separately for each product (NG, NGL) to account for "own use" ("own use" is explained in Appendix A):

$$PE_{ng} = Le/(P_{ng} + P_{ngl}) \times (P_{ng}/C_{ng})$$

where:

PE_{ng} = Btu of production energy per Btu of net NG energy consumed,

Le = total Btu used to produce raw gas (Table G.2),

P_{ng} = Btu of dry gas produced (Table G.1),

P_{ngl} = Btu of NGL produced (Table G.1), and

C_{ng} = Btu of NG consumed by end users (Table G.1).

For NGL, the calculation is the same, except that P_{ng}/C_{ng} is replaced by P_{ngl}/C_{ngl}, where C_{ngl} is Btu of NGL consumed by end users.

The calculation of the energy required to process NG in order to produce dry gas and NGL is not quite as straightforward because not all raw gas needs to be processed. In this analysis, the energy used at NGL plants is assigned to both NG and NGL. The resultant figure is the processing energy intensity for all NGLs. This figure is then weighted by the fraction of dry NG that has been processed (60-70% in the United States, a value that is dropping as more dry gas fields are discovered) to arrive at the processing energy for NG. Finally, these figures are adjusted to account for own use.

$$PR_{ng} = Pe/(Pr_{ng} + Pr_{ngl}) \times (Pr_{ng}/P_{ng}) \times (P_{ng}/C_{ng})$$

where:

PR_{ng} = Btu of processing energy per Btu of net NG energy consumed,

Pe = total Btu used at NGL plants (Table G.2),

Pr_{ng} = Btu of dry gas produced by NGL plants (Table G.1),

Pr_{ngl} = Btu produced by NGL plants (Table G.1),

P_{ng} = Btu of dry gas produced (Table G.1) (this cancels out), and

C_{ng} = Btu consumed by end users (Table G.1).

In general, the method of assigning production and processing energy to both NG and NGLs will be exactly, rather than approximately, correct, to the extent that the amount and kind of energy used to lift and process NG and NGLs, as calculated here, are the same as the amount and kind of energy that would have been used to make substitutes for the NGLs coproduced with the NG, had these NGLs not been available. Since NGLs and NG can substitute for each other in many applications (U. N. 1987), this assumption may be reasonably accurate.

G.2.3 Mix of Electricity and Fuels Used at NGL Plants

Table G.2 shows the amount of electricity consumed by NGL plants. I have assumed that NGL plants are located near petroleum refineries, so the plants use electricity generated from the same mix of fuels as the electricity used by refineries.

G.2.4 CO_2 Vented from Gas Processing Plants

Natural gas in the ground contains CO_2, hydrogen sulfide (H_2S), and other nonhydrocarbon gases. These gases are toxic or noncombustible; hence, they must be reduced to an acceptable level before the gas may be shipped to end users. The CO_2 separated at gas processing plants is either vented to the atmosphere or injected into an oil field to repressurize the field and enhance oil recovery. If it is vented, it is a greenhouse gas emission attributable to NG production (assuming that it would not otherwise leak naturally). CO_2 is reinjected if oil fields are nearby, if there is enough CO_2 to enhance oil recovery, and if oil prices are high enough to support enhanced oil recovery. It is vented if the amount of CO_2 is very small, if no oil fields are nearby, or if enhanced oil recovery is uneconomical.

These emissions of CO_2 from NG processing plants (aside from the CO_2 emissions from process energy used by those plants) are not great. There are only a few fields with very high levels of CO_2 or H_2S (Okken and Kram 1989; McCarrick 1990), and, as noted above, some of the CO_2 produced by these fields is reinjected. In the United States in 1988, the total amount of all nonhydrocarbon gases removed from raw gas was about 4.4% of marketed gas production (EIA, *NGA*; based on production and nonhydrocarbon release data for the states that reported both). The largest releases are in Wyoming, and are mainly attributable to a large gas field owned by Exxon, that is two-thirds CO_2. This 4.4% figure includes other gases besides CO_2 and does not account for reinjected CO_2. I assume that half of the nonhydrocarbon gases are CO_2 (on the basis of an Okken and Kram, 1989, estimate that the worldwide mean CO_2 content is 2%) and that 85% of the CO_2 is vented. I then assign this CO_2 emission to both dry NG production and NGL production.

As noted above, my input assumptions for 2000 follow the 1987 U. S. Bureau of the Census data (see also the section here on future energy use).

G.2.5 Emissions from Sulfur Removal

Recall that the use of carbonate to scrub sulfur oxides (SO_x) from the flue gas of a coal-fired power plant produces CO_2 (Appendix D). One might ask, then, if the removal of sulfur from NG produces CO_2. Sulfur is found in NG in the form of H_2S. If the concentration of H_2S exceeds certain limits, the H_2S must be separated from the rest of the NG and removed by absorbing the H_2S in an amine solution (EPA, AP-42, 1985 and 1988; amine absorption accounts for more than 95% of H_2S removal. Amine absorption does not itself produce any greenhouse gases. However, the eventual disposition of the sulfur in the separated H_2S may produce a minor amount of CO_2. The acidic waste gas from the amine process can be vented, burned, or, most commonly, sent to a sulfur recovery or sulfuric acid plant (EPA, AP-42, 1985 and 1988). Burning produces sulfur dioxide (SO_2); venting SO_2 releases H_2S (EPA, AP-42, 1985 and 1988).

Thus far, the sulfur-removal process produces no greenhouse gas emissions (aside from the use of process energy, which is considered separately here). If the H_2S is sent to a sulfuric acid plant, most of the sulfur will be converted to sulfuric acid (H_2SO_4), but a small amount will remain in the tail gas. New Source Performance Standards (NSPS) limit the amount of SO_2 in the tail gas of H_2SO_4 plants (EPA, AP-42, 1985 and 1988). The SO_2 emissions are reduced either by increasing the efficiency of conversion of SO_2 to H_2SO_4 or by scrubbing SO_2 in sodium sulfite/bisulfite. Neither process produces CO_2 directly.

However, if the H_2S is sent to a sulfur recovery plant (called a Claus plant), there is a small probability that minor amounts of CO_2 will be produced. There are three options for controlling SO_2 emissions from Claus plants to meet NSPS for SO_2: (1) scrub the SO_2; (2) increase the conversion of H_2S to elemental sulfur; or (3) convert the sulfur gas to H_2S and recover the sulfur (EPA, AP-42, 1985 and 1988). Some forms of the third option use carbonate (e.g., the Stretford process), but it appears that the carbonate solution is regenerated without net emissions of CO_2 (USDOE, *Energy Technologies and the Environment*, 1988). Option 2 does not produce CO_2. However, some forms of scrubbing (option 1) appear to use a carbonate process that produces CO_2.

The result of this is that total CO_2 emissions due to sulfur removal, per unit of NG delivered, will be very small. To illustrate this point, note that, typically raw NG contains about 1% sulfur by volume, and about 99% of this sulfur ends up as elemental sulfur or H_2SO_4 (EPA, AP-42, 1985 and 1988). Of the remaining sulfur, only a portion will pass through scrubbers that generate CO_2. CO_2 emissions from sulfur control probably amount to less than 0.00005 moles per mole of methane, which translates to roughly 3 g/10^6 Btu less than 0.005% of fuel-cycle emissions.

G.2.6 Liquefied Petroleum Gas from Refineries

Refineries produce some LPG (mostly propane), although considerably less than NGL plants produce. The calculation of greenhouse gas emissions from refinery-produced LPG follows the calculation for other petroleum products (up through the fuel production stage) and is explained in Appendix H.

The final g/10^6 Btu and g/mi emission factors for LPG are equal to emissions from NGL-derived LPG, weighted by the fraction of propane and butane from NGL plants and the fraction of propane and butane in the fuel, plus the same weighting from refinery-derived propane and butane. In 1987, NGL plants produced 60.8% of total (refinery + NGL plant) U. S. propane and 72.3% of total U. S. normal and isobutane (EIA, *PSA*, 1988). The base-case LPG composition is shown in Table C.3. On the basis of these figures and the base-case composition shown in Table C.3, NGL plants produced 61.4% of the base-case LPG components and refineries produced 38.6%. I use these values in the base case, and I test different values in sensitivity analyses.

It is appropriate to provide a note on LNG, synthetic natural gas (SNG), and pipeline imports here. In 1989, imports of LNG were only 0.2% of the total NG supply; SNG provided 0.85% of total supply (EIA, *The Outlook for Natural Gas Imports*, 1991; EIA, AOOG, 1990). The EIA projects that LNG imports will increase to 3-4% of the total NG supply in 2000, while SNG will account for only 0.6% of the total supply. LNG imports will ultimately be limited by the political difficulty of expanding LNG terminal capacity, which at present is only about 1 trillion cubic feet (TCF) (EIA, *The Outlook for Natural Gas Imports*, 1991; EIA, *Annual Outlook for Oil and Gas*, 1990).

This information suggests that if the natural gas vehicle (NGV) spawned increment in demand for NG is supplied by the current distribution of sources (domestic, SNG, pipeline imports, and LNG), less than 5% of NG for motor vehicles will come from LNG or SNG. Of course, it is possible that the incremental NG demand due to NGVs will be supplied primarily by LNG, but this prospect does not seem too likely, given that the demand for LNG may be constrained by terminal capacity and is likely to reach this limit without NGVs (EIA, *Outlook for Natural Gas Imports*, 1991). It is more likely that the NG used by NGVs will come from increased domestic production and increased pipeline imports.

Nevertheless, I include an NG-from-LNG scenario here, primarily because it is relatively easy to model. Liquefaction requires 0.10 10^6 Btu/10^6 Btu NG (Chem Systems, 1988; EIA, *The Outlook for Natural Gas Imports,* 1991). Transport requires 0.059 Btu/Btu LNG delivered (64% of this fuel use is NG; 36% is fuel oil) for a 12.81-day, 5,500-mi one-way trip (Chem Systems, 1988). See Table E.3 here; 5,500 mi is the transport distance used in the methanol-from-NG analysis.) Regasification requires 0.025 Btu/Btu of gas (EIA, 1991). On the basis of these data and proper accounting for the extra "own use" (see Appendix A) of NG for liquefaction, one can calculate the energy requirements and emissions of cycle for NGV that use foreign LNG.

G.3 Energy Used to Transport Natural Gas

Natural gas is transported across the United States in high-pressure transmission lines. The compressors located along these lines are primarily powered by gas-fueled reciprocating engines and gas turbines; a few are driven by electric motors. The engines, turbines, and power plants supplying electricity to the electric motors all have different emission factors. For example, gas engines emit considerably more CH_4, carbon monoxide (CO), and nonmethane hydrocarbons (NMHC) than gas turbines (EPA, AP-42, 1985 and 1998). Consequently, aggregate greenhouse gas emissions from NG transmission depend on the total amount of gas consumed by turbines, total amount consumed by engines, and the amount of electricity consumed by electric motors. In this section, I calculate the total amount of gas consumed by turbines and engines together, the breakdown between turbines and engines, and the total amount of electricity consumed.

G.3.1 Total Amount of Gas Consumed by Pipeline Compressors

Each year's EIA's *Natural Gas Annual* reports the quantity of gas consumed as a pipeline fuel, as determined by the EIA from responses on its survey form, EIA-176. These data are shown in Table G.1 for 1982 and 1987. (The EIA data on energy use by pipelines agree with data in the 1983 DOE *Handbook*). Unfortunately, the EIA does not estimate the breakdown between gas engines and turbines or the amount of electricity consumed by the very few electric compressors. In fact, there are no aggregate national data on the split among gas turbines, gas engines, and electric motors. To obtain this information, I surveyed NG transmission companies.

G.3.2 Breakdown between Engines and Turbines

Most pipeline compressor units are reciprocating engines, because engines are more efficient than turbines over a wider load range, and most pipelines must operate over a wide load range. Lieberman (1987, p. 112) states that turbines are a "sizable minority" of field and transmission compressor stations, but does not give a number. Kind (1989) has reported that the main transmission line of El Paso Natural Gas, a major interstate carrier, has 46 gas-turbine-driven centrifugal compressors and 223 reciprocating-engine-driven compressors, but he did not report the share of horsepower (relative energy use by turbines and engines depends on the relative horsepower and on the horsepower-hours).

To get a quantitative estimate of the national situation, I contacted five major interstate pipeline companies that serve different regions of the United States and asked them to tell me the percentage of total installed compressor horsepower in their system provided by turbines, reciprocating engines, and electric motors. The results are shown in Table G.5. On the basis of these data, I estimated the national breakdown between engines and turbines, by horsepower.

TABLE G.5 Energy Use by Gas Turbines, Gas Reciprocating Engines, and Electric Motors, on Transmission Pipelines

Pipeline Company or Source	1989 % Horsepower from:			1988 % of U. S. Total of:[a]	
	Turbines	Engines	Electric	TCF Moved[b]	Compressors
Natural Gas Pipeline of America (pers. comm., 1990)	~15	~85	<1	6	3
Tennessee Gas Pipeline & others[c] (pers. comm., 1990)	~25	~75	0	7	4
El Paso Natural Gas (Quinn, 1990)[d]	50	41	9	7	4
Enron (pers. comm., 1990)[e]	17	83	<1	9	13
Transcontinental Gas Pipe Line (pers. comm., 1990)[f]	14	83	4	9	3
National estimate by ORNL (Davis et al., 1989)	---------- 94		6[g]	100	100
My national estimate, from Table G.3	---------- 92		8[h]	100	100
National estimate, by Banks (1977)	---------- 96		4[i]	100	100

"pers. comm." = personal communication.

[a] From OGJ, November 27 (1989), for 1988. Some of these statistics are also in the EIA's *Statistics of Interstate Natural Gas Pipeline Companies.*

[b] Based on the statistic, "gas transported for others" (OGJ, November 27, 1989). TCF = trillion cubic feet.

[c] Also Midwestern Gas Transmission, East Tennessee Natural Gas, and Channel Industries.

[d] As of May 31, 1989: turbines = 324,188 hp; engines = 268,091; electric = 61,300.

[e] Horsepower shares include Northern Natural Gas, Florida Gas Transmission, Houston Pipeline, and Transwestern Pipeline. Compressor and gas delivered shares do not include Houston Pipeline.

[f] 1989 system totals = 979,519 horsepower, 4.279 billion hp-h. Electric-motor driven compressors = 37,500 hp, 131 million hp-h. Gas turbines = 133,000 hp, 458 million hp-h. Rest is reciprocating engine. Also, 39.768×10^9 ft^3 were used by compressors at 8.279 SCF/hp-h. The breakdown by horsepower-hour, as opposed to horsepower, was 10/88/3, which indicates that the reciprocating engines were actually used more. However, this probably cannot be generalized to all companies, since turbines can be used for baseload (e.g., El Paso Natural Gas) as well as for peaking.

TABLE G.5 (Cont.)

[g] Based on this, they estimate that electricity use by electric-motor-driven compressors is about 1.5% (Btu-electric basis) of the Btu of gas consumed by gas-powered compressors.

[h] Based on the assumption that electric-motor-driven compressors are four times more efficient than gas-powered compressors on an end-use energy basis. This appears to be what ORNL (above) assumes.

[i] Banks estimates that 4-5% of compressors are electrically driven.

The statistics in the table refer to installed horsepower. To convert installed horsepower by type of compressor to gas consumed by type of compressor (which is the unit of I want), one must know horsepower-hours by type of compressor and fuel consumption per horsepower-hour by type of compressor. For simplicity, I have assumed that the national ratio of installed turbine horsepower to installed engine horsepower is a reasonable approximation of the ratio of horsepower-hours.

Turbines can be used to meet both baseload (e.g., in the El Paso Natural Gas System) and peaking (e.g., Transcontinental Gas Pipe Line) requirements, so there is no reason to assume that turbine horsepower is used more or less than reciprocating-engine horsepower. To convert the engine/turbine ratio of horsepower-hours of compressor output to a ratio based on gas consumption, I use the EPA's conversion factors of 7.14 SCF of gas/hp-h for engines and 9.52 SCF of gas/hp-h for turbines. Transcontinental (personal communication, 1990), which has mostly engines, used 8.279 SCF/hp-h for its system in 1989, which is consistent with the EPA assumptions. The results of this analysis are shown in Table G.5, in which I estimate the breakdown between turbines and engines in NG transmission.

G.3.3 Electricity Used by Electric-Motor-Driven Compressors

In Table G.3, I estimate the proportion of gas to electricity as pipeline energy on the basis of financial reports of NG pipeline companies. That estimate, converted from an energy basis to a horsepower basis, is then compared with two other estimates of the proportion of total horsepower supplied by gas and electricity (Table G.5).

The data of Table G.5 indicate that electric motors account for about 5% of the installed horsepower of compressors. Assuming that electric motors are four times more efficient than gas-powered compressors on an end-use basis, about 1.3% of the total energy consumed by pipelines (counting electricity at 3,412 Btu/kWh) would be electricity. This result is entered in Table G.5 as a proxy for the year 2000 (as explained below, energy intensity by 2000 is likely to be close to that in 1987).

G.3.4 Modes Used to Transport Liquefied Petroleum Gas

In the United States, most of the LPG is produced in Texas, Oklahoma, Louisiana, and New Mexico (EIA, *PSA,* 1990). Very little LPG is moved by rail or ship; virtually all of it is moved at some point by pipeline and truck (USDOT and USDOE, 1980). Pipeline networks fan out from the Gulf Coast and Southwest to the Midwest and East. In 1976, 90.6% of the LPG used in the United States was shipped by pipeline-truck combination, 3.4% by truck alone, 4.6% by combination pipeline-rail, 0.9% by rail alone, and 0.5% by tanker or barge (USDOT and USDOE, 1980). However, it is likely that more LPG is moved by ship or barge today than it was in 1976. In 1987, about 4% of the total LPG supply was imported from countries other than Canada (about 10% of total supply was imported, but 58% of the imports came from Canada,

presumably by pipeline and truck) (EIA, *PSA*). On the basis of these considerations, I assume that 5% of the total LPG production moves by ocean-going tanker (I assume that this LPG comes from Algeria, which is the main source, aside from Canada, of imported LPG), 95% moves by pipeline at some point, 4% moves by rail at some point, and 100% moves by truck at some point (because the final distribution leg to the end user always is by truck). My assumptions are shown in Table E.1.

G.4 Energy Requirements of CNG Compression and LNG Liquefaction

To be stored on board a vehicle, NG must be either compressed to high pressure or liquefied. Both of these operations require energy in the form of electricity for compressors and NG for small liquefiers.

The electricity requirements of compressors depend on the amount of work the compressor must do on the gas; the amount of work depends on the difference between the pipeline inlet pressure at the station and the delivery pressure to the vehicles. Table G.6 shows the estimated actual energy requirements of CNG compressors; these estimates are consistent with the theoretical data estimated (1989) by Ho. Generally, less energy is required at a higher inlet pressure, which means that the difference between the station being located on a high-pressure trunk line or a low-pressure distribution line is somewhat important. In the base case, I assume compression from low-pressure distribution lines to high-pressure (3,600 psi) cascade storage bottles for fast-fill stations because if a CNG station is to be successful, it will have to be "fast-fill" and be located in an urban area.

Greenhouse gas emissions from electricity use by CNG compressors depend on the efficiency of electricity generation and the fuels used by electricity plants supplying the compressors. In the model, the electricity mix used by compressors is a separate variable, so it can be specified independently of the generic and other electricity mixes. I test different fuel mixes in sensitivity analyses.

In the LNG case, I assume that the gas is liquefied at the station (at the point of dispensing to consumers) by skid-mounted, self-powered liquefiers, rather than at large, central liquefaction facilities that transport LNG to service stations. The manufacturers of the small, on-site NG liquefiers report that the liquefiers consume about 0.2×10^6 Btu of NG from the pipeline for every 10^6 Btu of LNG produced (calculated from data in Cryogas Engineering, 1986, and Kennedy, 1987). If a small amount of the LNG vaporizes and must be reliquefied before it is delivered to the motorist, the energy requirement per unit delivered to the motorist will be slightly higher. If the liquefier is set up on a high-pressure gas line, the gas consumption can be reduced to 0.15×10^6 Btu/10^6 Btu (Constable et al., 1989). The effect of LNG boiloff and vaporization is discussed in Appendix B.

TABLE G.6 Compression Requirements of CNG Stations

Station Location	Inlet Pressure (psi)	Car Tank Pressure (psi)	Capacity (SCFM)	10^6 Btu-Power/ 10^6 Btu-CNG	Reference
Canada	175	3,000	65	0.015	Topaloglu (1984)
Pacific Rim	20-70	2,400	70[a]	0.055[b]	UN (1984)
New Zealand	5	3,000	60	0.073[c]	Abram et al. (1980)
U. S.		2,400	100	0.033	Bechtold et al. (1983)
New Zealand	50	3,000	176	0.027[c]	Abram et al. (1980)
New Zealand	300	3,000	265	0.021[c]	Abram et al. (1980)
U. S./Canada	--	2,200-3,200	--	0.03-0.05[d]	LaFrenz et al. (1981)
Sacramento, CA		3,000		0.026[e]	Elston (1990)

"--" = not specified. SCFM = standard cubic feet per minute. In the U. S., most inlet pressures are 5 psig or less.

[a] The reference stated that the station actually delivers 2,000 GJ per month. I back-calculated the capacity based on the assumption that the station operates at 60% capacity.

[b] I calculated this based on the assumption that in New Zealand (where the station was located) electricity is \$17.50/10^6 Btu (1983 U. S. \$).

[c] I calculated this from cost data in the reference. I assumed that the cost units in the reference were given in 1979 New Zealand dollars, and I calculated power consumption by using the 1979 conversion rate of \$1.1 NZ = \$1 U.S. and based on the 1979 cost of power in the U. S. being \$12.10/10^6 Btu.

[d] Data in reference given in \$-electricity/10^6 Btu-CNG. I assumed \$16/10^6 Btu-power (1980 U. S. \$), which was the average 1980 commercial sector price.

[e] Reported data were compression electricity cost of \$0.05/therm, electricity price of about \$0.065/kWh, and 100,000 Btu/therm of gas.

G.5 Calculation of NG Available to the Transportation Sector

As discussed in Appendix A, to calculate greenhouse gas emissions from the use of a fuel, one must know the amount and kind of process energy consumed per unit of the fuel made available for a particular use. For any particular fuel, this ratio depends on how that fuel is ultimately used. For example, in the case of NG, it takes a certain amount of energy to deliver a unit of NG to a power plant or to an LNG service station. However, the power plant can use all of the gas delivered to it to provide electricity; the LNG service station must use a portion of the delivered gas to liquefy the remainder, so less gas is available to cars than is available to power plants for a given amount of production. Because of this difference, one must calculate two separate energy/end-use ratios: one for transportation sector uses of gas and one for electricity-generating and industrial uses.

Table G.1 shows the NG supply and disposition sheet used to calculate the amount of NG available for end use per unit of energy used to produce and transmit NG. As just noted, two ratios must be calculated: one for transportation and one for all other end uses. In Table G.1, the efficiency figures "production energy/NG+NGL for end use" and "transmission energy/net for end use" are for the electricity and industrial sectors; they do not account for gas used to make CNG or LNG. These intensities are used to figure g/10^6 Btu emissions from the use of NG by power plants or industry. The g/10^6 Btu factor in Table G.6 is calculated on the basis of these factors.

To account for the use of gas to make CNG or LNG, one first calculates the ratio of the gas used to make CNG or LNG plus the CNG or LNG produced to the CNG or LNG produced, by using the data on the amount and kind of energy used to compress or liquefy gas. Then one multiplies the figures "production energy/NG+NGL for end use" and "transmission energy/net for end use" by this ratio to arrive at "production energy/NG+NGL for transportation end use" and "transmission energy/net for transportation end use". This energy intensity is then used to calculate greenhouse gas emissions per mile. A similar accounting is made for the loss, if any, of LNG due to boil-off.

G.5.1 LPG

For LPG, there are only two ways in which net consumption can differ from production: some produced LPG will leak and evaporate and some may be used by LPG-burning trucks to distribute LPG. In the base case, I assume a very low LPG leakage and evaporation rate; I also assume that no LPG delivery trucks use LPG themselves.

G.6 Future Energy Use in the Natural Gas Industry

G.6.1 Development of Unconventional Reserves

Presently, almost all of the NG used in the United States comes from conventional on-shore and off-shore deposits. However, a good deal of NG is located in so-called unconventional sources, such as tight sands and coal seams. As the wellhead price of NG rises, it will become increasingly economical to develop unconventional reserves (see AGA 1985). The EIA (AOOG, 1990) projects that the production of unconventional gas will increase to 2.70 TCF in 2000, or 12% of the total supply. It typically requires more energy to bring up unconventional reserves because the NG is located deeper, flows slower, is trapped or chemically bound, and so on. Therefore, if the price of NG rises and unconventional reserves are tapped, the amount of energy required to produce gas in the United States will rise. On the other hand, higher prices (and tighter environmental standards) may encourage the use of more efficient technologies, some of which are discussed next.

G.6.2 Past and Future Improvements in Technology and Efficiency

Since 1973, the ratio of NG used by pipeline compressors to NG produced has remained essentially constant at about 3%. The ratio of NG used as lease and plant fuel to NG produced has fluctuated between 5% and 7% (EIA, *Natural Gas Supply Annual*, various years). If the fraction of NG compressors powered by purchased electricity has remained near zero, and if the average length of shipment of NG has not changed appreciably, these EIA data imply that the efficiency of recovery and transmission has not improved. This lack of improvement may be, in part, be a result of operators replacing reciprocating engines with less efficient gas turbines, a trend the EPA observed in the mid-1970s (in EPA, AP-42, sheets dated April 1976).

However, tight nitrogen oxides (NO_x) emission standards and rising fuel prices will likely induce the use of more efficient production and transmission technologies in the future. For example, simple-cycle turbines, combined-cycle turbines, and lean-burn engines emit much less NO_x than do the common reciprocating engines (they also emit less CO, CH_4, and NMHC), and they can meet strict new NO_x emission standards that regular engines cannot. Of these, combined-cycle gas turbines and lean-burn engines also happen to be more efficient than the common, older engines. Rising wellhead prices, which the EIA projects through 2000 (EIA, *Annual Energy Outlook 1990*, 1990) will provide further incentive to use fuel-efficient technologies.

A combined cycle improves efficiency by using the thermal energy in the exhaust gases from the gas turbine, energy which is wasted in a simple-cycle turbine to raise steam in a boiler that then drives a steam turbine. In 1978, a report done for DOE said that the use of combined-cycle turbines would be the best way to improve the efficiency of the gas transport system (Banks and Horton, 1978). This technology is now starting to be used: a combined-cycle turbine at the Messina compression station on the Trans-Mediterranean pipeline has increased both efficiency and power output by 30% (Cocchi et al., 1989). Combined-cycle systems may be attractive wherever gas is expensive enough or wherever the need for power is great enough to justify the capital cost of adding the steam recovery system and if the steam system can be designed to follow variations in the turbine load.

Lean-burn engines operate at a higher air/fuel ratio and use less fuel per horsepower-hour than engines operating nearer to stoichiometry. As noted above, tight NO_x standards as well as higher fuel prices may force the use of lean-burn engines.

In the past few years an increasing number of pipeline companies have automated portions of their operations (see issues of the *Oil and Gas Journal.*) The development of sophisticated but relatively inexpensive software for monitoring and controlling pipeline performance in the face of rising power, labor, and fuel costs has made automation economically attractive. In 1986, Panhandle Eastern Pipe Line Co. expected to reduce its compressor fuel bill 15-20% as a result of automating key mainline compressor stations (Smith, 1986). Another compressor-engine control system reduced fuel consumption by 5% per year (*Oil and Gas Journal*, October 26, 1987).

G.6.3 Conclusion

The development of unconventional reserves will increase energy use in the NG industry, but this increase will be at least partially offset by the use of more efficient recovery and transmission technology. In the base case, I use 1987 energy use statistics to represent the year 2000 because energy-intensive production from unconventional reserves still will be a small percentage of total supply and because of the potential for counterbalancing efficiency improvements in production and transmission. Nevertheless, in a scenario analysis, I examine the effect of a 25% relative increase in the energy intensity of producing domestic gas.

Appendix H:

Petroleum

Appendix H:

Petroleum

H.1 Overview

Petroleum is the largest single energy source in the United States, accounting for over 40% of U. S. energy consumption (EIA, *Annual Energy Review 1989*, 1990). The highway transportation sector is almost 100% dependent on petroleum fuels, gasoline, and diesel fuel.

In the United States, most crude oil is produced in Alaska and on the Gulf Coast. Crude oil flows by water from Alaska to the West Coast and the Gulf, and from the Gulf to the East Coast or up the Mississippi. Gulf Coast refineries send petroleum products by water to the East Coast, and up the Mississippi and Ohio rivers. Products also flow by pipeline from the Gulf Coast to the East Coast. For larger volumes of crude oil, pipeline transport is cheaper and more efficient than water transport (USDOT and USDOE, 1980; USCRS, 1977).

The United States imports about half the oil (crude + products) it uses (EIA, *Annual Energy Review 1989*, 1990). Crude and products are imported from countries around the globe, including Canada, Mexico, Venezuela, Saudi Arabia, and Nigeria. In a greenhouse gas analysis, it is important to know where imported oil comes from because this determines how far, on average, the oil must be shipped, and this in turn determines energy use, and hence greenhouse gas emissions.

H.2 Energy Used in Oil Recovery

In this section, I analyze the amount and kind of energy used to produce crude oil, and I discuss the method used to allocate this energy to gasoline, diesel, residual fuel, and liquefied petroleum gases (LPG).

H.2.1 Overview of the Census Data

This subsection discusses the energy-use data reported by the U. S. Bureau of the Census of Mineral Industries. Appendix F on coal has a general description of the U. S. Bureau of the Census data.

The censuses of oil and gas production and oil and gas field services report energy used in oil and gas exploration, drilling, production, well closure, and related activities (see the Standard

Industrial Classification and Table H.1). Fuel use is reported for oil and gas producers and oil and gas field services, together, not separately, for the oil and gas industries. This joint consumption must be assigned to oil and gas production separately. I apportion these totals to oil and gas using the factors shown in Table H.2. As indicated in the table, I assign to natural gas production most of the gas used by oil and gas producers combined because natural gas producers use gas as their process fuel almost exclusively. The gas use that is assigned to oil production is primarily lease gas burned to provide energy to reinject associated gas used for repressurization of oil wells (see Appendix G).

I assign nearly all petroleum and electricity use to oil production, based on the analysis and data in Appendix G indicating that natural gas (NG) production uses very little electricity. I assign to oil somewhat more than half of the energy used by oil and gas field services since there are more oil than gas wells (EIA, *Annual Review of Energy 1989*, 1990) and oil is sought more actively than gas. Balancing this somewhat is that gas wells are more expensive than oil wells, according to the Energy Information Administration (EIA).

H.2.2 Comparison of the Census Energy-Use Estimates with Data from Other Sources

The DOE *Handbook* (1983) estimates that the energy used to produce oil in the lower 48 states onshore is 1.5% of the energy in the crude produced, with about half the energy requirement being diesel fuel used for development drilling and half electricity used by pumps. For offshore production, the figure is 9%, with fuel for drilling making up the bulk of the consumption. These two figures can be combined for comparison with the U. S. Bureau of the Census estimate: in 1987, all wells onshore and offshore in the lower 48 states produced 2.33 10^9 bbl of oil (*Petroleum Supply Annual 1987*); in the entire United States, offshore wells produced 366 10^6 bbl of oil, including lease condensate (Department of Interior, 1989). This indicates an average energy requirement of 2-3% of the energy value of crude, according to the DOE *Handbook*, which is consistent with the figure estimated from U. S. Bureau of the Census data.

Actual operating data for the S.H. Loe Oil Corporation are also consistent with these estimates. Before 1987, the company, which operates 148 stripper wells, used 450,000 kWh of purchased power to produce 8,100 bbl of oil, an efficiency (based on Btu-electric) of 3.3% (Spears, 1988). To reduce power costs, the company switched to NG to generate its own power on site; it used about 2,500 10^6 Btu of NG and reduced electricity consumption to 52,500 kWh. The resulting end-use consumption is higher than before (5.7% versus 3.3%), but the overall process efficiency, counting energy used to generate electricity, is considerably lower. Generating power on-site can thus be considered as an efficiency-improving technology in the future.

Note that I use the calculated U. S. energy intensity of petroleum recovery as representative of the energy intensity of recovering all crude, including foreign crude imported by the United States.

TABLE H.1 Energy Used to Explore and Drill for Oil

Fuel	1982 Units	1982 Energy (%)	1987 Units	1987 Energy (%)
Crude oil (10^3 bbl)	32,905.3	28.71	11,445.2	12.97
Diesel (10^3 bbl)	13,954.4	12.23	8,785.7	10.00
Residual (10^3 bbl)	5,861.3	5.54	605.5	0.74
Natural gas (10^9 ft^3)	181.7	28.19	249.4	50.28
Coal (10^3 tons)	0.0	0.00	0.0	0.00
Electricity (10^6 kWh)	33,385.4[a]	17.13	26,180.7[a]	17.46
Gasoline (10^6 gal)	270.4	5.09	166.0	4.06
Other (10^6 $)	151.3	3.12	142.8	4.49
Total energy (quads)	0.665	100.00	0.512	100.00
Total production (USDOC[b]) (10^6 bbl)	3,187.3		3,216.3	
Total production (EIA[c]) (10^6 bbl)	3,156.7		3,047.4	

Sources: The following publications from the U. S. Department of the Commerce, Bureau of the Census: *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985); *1987 Census of Mineral Industries, Crude Petroleum and Natural Gas* (1990); and *1987 Census of Mineral Industries, Oil and Gas Field Services* (1990).

Energy apportioned to oil and gas as per Table H.2 and the discussion in Appendix G.

Note that the oil production reported by the USDOC agrees with the production reported by the EIA to within 1% for 1982 and 6% for 1987, which gives confidence in the energy use figures of the Census.

[a] Oil and gas producers generated and sold a small amount of electricity in 1982. I have subtracted this amount from the total amount of electricity purchased. The Census did not disclose the amount sold in 1987; I have estimated sales in 1987 using data on electricity purchased and sold in all mineral industries.

[b] The correct USDOC total is reported production plus oil's share of oil and gas not specified by kind (n.s.k.). In calculating oil production from the Census data, I have assumed that oil's share of the reported value of oil and gas n.s.k. is equal to oil's share of the total value of oil and gas that is specified by kind (63.5% in 1987; according to the Bureau of the Census, this is a reasonable assumption [Roehl 1989]) and that a barrel of oil specified by kind has the same average value as a barrel of oil n.s.k.

[c] EIA, *Petroleum Supply Annual* (1983, 1988).

TABLE H.2 Data Used to Adjust Census Data on Energy Used to Recover Feedstocks

SIC Area	$ Purchased Fuels[a]/ $ Distributed Fuels[c] 1982	$ Purchased Fuels[a]/ $ Distributed Fuels[c] 1987	$ All Products[b]/ $ Distributed Products[d] 1982	$ All Products[b]/ $ Distributed Products[d] 1987
Oil and gas extraction	1.136	1.111	1.123	1.125
Oil and gas field services	1.138	1.422	Not used	Not used

0.350 fraction of NG used by oil and gas production assigned to oil (my estimate; see text for discussion).

0.950 fraction of all other oil and gas production energy assigned to oil (my estimate; see text for discussion).

0.600 fraction of energy used by drilling services assigned to oil (my estimate; see text for discussion).

0.137×10^6 Btu/$ of other fuels, 1982 (value used by the Census).

0.161×10^6 Btu/$ of other fuels, 1987 (value used by the Census).

Sources: See Table H.1.

[a] The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies not surveyed (the Census estimated the value for these companies) and fuels used by companies that did not report how much of each kind of fuel they used.

[b] The total dollar value of all products (crude oil, dry gas, NGLs, uranium ore, etc.) of all companies engaged in the activity, including products from companies not surveyed (the Census estimated production for these companies), and products of companies that did not classify or detail their products (e.g., did not state what kind of coal they produced).

[c] The dollar value of the fuels purchased by companies that reported the amount of each kind of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only total cost of purchased fuels, with no breakdown or details.

[d] The dollar value of products of those companies that reported the amount and kind of each product.

H.2.3 Efficiency of Oil Recovery in the Future

The overall average energy intensity of oil recovery is a function of the quality of crude oil, the location of the crude, and the recovery technology. Heavier crude requires more recovery energy than lighter crude; offshore oil requires more recovery energy than onshore oil, and enhanced oil recovery requires more energy than conventional recovery. The balance among these factors will be determined by oil price, quality, and availability; environmental regulations; energy policy; and the state of recovery technology.

The EIA's *Annual Outlook for Oil and Gas 1990* (AOOG, 1990) projects that offshore oil production will remain relatively constant through 2010. This assumes that the moratoria on drilling off the Pacific Coast will be lifted eventually; if they are not, total offshore production will probably decline.

The EIA also projects that production by enhanced oil recovery will remain fairly constant at about 0.5×10^6 Bd, or about 3% of total petroleum supply, through 2010, due to their forecast of fairly low prices. If the price of crude rises higher than expected, production from enhanced oil recovery could be higher.

Both foreign and domestic crudes are expected to continue to get heavier. This will slightly increase energy requirements.

Overall, it seems that the energy intensity of oil recovery will not increase appreciably by year 2000 and even beyond. Any small increases because of lifting of heavier crudes can probably be countered by efficiency improvements. Therefore, in the base case, I assume that the energy intensity of recovery in 2000 is the same as the calculated value for 1987.

H.2.4 Emissions from the Manufacture of Concrete Used to Plug Oil Well Holes

According to the DOE *Handbook* (1983), 1.1 lb of concrete is used to plug dry oil well holes per barrel of oil produced from onshore primary oil fields (the drilling success rate assumed in the DOE report is about right, according to EIA data). Applying an emission factor for concrete production (Table P.3, note f; the factor includes emissions from $CaCO_3$ —> CaO), and accounting for differences between the density of crude and the density of products and for own use of petroleum, one can calculate g/mi emissions attributable to this use of concrete for gasoline, diesel fuel, and residual fuel oil. The result turns out to be trivial: about 0.1 g/mi CO_2-equivalents. I have not included this amount in the final results because it is so small. There are greater, but still quite minor, greenhouse-gas emissions from the manufacture of the steel used to build oil wells. The energy used to make both the concrete and the steel, as a fraction of total oil produced over the lifetime of the field, is shown in Table P.6.

H.2.5 Allocation of Oil Recovery Energy to Products

To understand how one should allocate to products the energy used to recover (and transport) crude oil, one must understand very generally how crude is transformed into products. I will describe the transformation of crude to products, first in terms of mass and then in terms of volume, and from this I will show how the energy used to recover and transport crude should be allocated to products.

Let us start with the ton (2000 lb) as the basic unit of crude oil. Suppose that anywhere from 30 to 60% of each unit of crude is suitable for making gasoline, and the rest (40-70%) is suitable for distillates, kerosene, residual fuel, and other products. Suppose, also, that no mass inputs other than crude go into any product. All of these assumptions, with the exception of the last, which will be lifted shortly, are roughly realistic.

Suppose that in the base case, we have 10 units (tons) of crude, each producing 50% (one-half ton) of gasoline and 50% (one-half ton) of other fuels, for a total of 5 tons of gasoline and 5 tons of other fuels. Now, suppose that the use of an alternative fuel reduces demand for gasoline by 1 ton and demand for distillates by 1 ton. What happens to crude input? Obviously, crude input is reduced by 2 tons (each of the 2 tons would have produced one-half unit, or 1 ton, of gasoline and one-half unit, or 1 ton, of distillate).

But what if demand only for gasoline is reduced by 1 ton? The refinery now has to make 4 tons of gasoline and 5 tons of other products. It could continue to make 50% of each ton of crude into gasoline and 50% into other products, use 10 units (tons) of crude, and simply throw out the unneeded 2 half-units of crude that would have gone to make the one unit (ton) of gasoline no longer needed. But that would be unnecessarily wasteful. Instead, the refinery will change the ratio of gasoline to other fuels drawn from each unit to reflect the new overall demand ratio. It will input 9 units of crude and extract from each unit, four-ninths (44.4%) gasoline, and five-ninths (55.5%) other products (recall that this yield ratio can vary, within limits defined by crude quality, refinery operating conditions, and other costs). Thus, the displaced unit of gasoline will displace exactly one unit of crude.

The result is that, in any case (within the limits of the capability of the refinery to adjust crude yields to reflect product demand ratios), the loss of 1 ton of product implies the loss of 1 ton of crude, given conservation of mass and assuming no inputs other than crude (I ignore mass lost as pollution because it is a very small fraction of the input mass). This means that one assigns recovery energy to products on a mass basis, not a volume basis.

The one-to-one equivalency is in mass terms, not volume terms, because mass, not volume, is conserved. Thus, if the gasoline-producing half-ton of crude has a volume of X barrels, the gasoline produced from it may be more or less than X barrels, depending on the density of gasoline relative to crude. As it turns out, gasoline is less dense than crude (the ratio of the density of gasoline to the density of crude is 0.874) because the molecules of crude input to gasoline are disintegrated and rearranged and recombined to take up more space as gasoline than as

crude. This means that it takes less than one barrel of crude to produce one barrel of gasoline. This is a somewhat important fact because gasoline and crude production and consumption are almost always discussed in volume terms, not mass terms, and the volume change in going from crude to gasoline is over 10%. So, if one is working with gasoline gallons, one must at some point convert to grams in order to allocate to gasoline the energy used to recover and transport crude oil.

Now, to make this picture more realistic, one needs to account for refinery inputs other than crude. There are two additional kinds of inputs to account for: 1) unfinished oils, which end up in a range of products, and 2) inputs to gasoline: butanes, pentanes and higher, alcohols, motor gasoline blending components, and other hydrocarbons (I ignore other inputs to aviation gasoline). Because the unfinished oils presumably come from crude oil, have a density similar to that of crude, are used to make a range of products (as is crude), and, in any case, are a small input compared to crude (less than 5%, in volume terms), it is reasonable to treat them as if they were crude oil.

The point thus far is that to calculate the energy used to recover the crude that is used to make a barrel of any product except gasoline, one can multiply the energy required to recover a barrel of crude by the ratio of the density of the product to the density of the crude. (Of course, one can work in mass units from the start, using grams of crude, kg/g, etc.)

The situation is somewhat different with gasoline. The non-crude inputs to gasoline are less like crude than is unfinished oil, and are a slightly larger input, accounting for about 7% of the weight of finished gasoline (taking 2,000 g/gal for butanes and pentanes, 2,897 g/gal for gasoline blending components as naphtha, 3,000 g/gal for other hydrocarbons and alcohol, 2,791 g/gal for finished gasoline, and using input and production data from the EIA's *Petroleum Supply Annual*). This means that crude accounts for 93% of the weight of gasoline and, given that 1 ton of crude takes up 87.4% of the space of 1 ton of gasoline, and that 0.82 bbl of (the gasoline-making part of) crude goes toward a barrel of gasoline. The rest of the gasoline barrel comes from non-crude inputs and from the increase in volume resulting from rearranging the crude inputs.

Ideally, one would assume first that 0.82 bbl of crude makes a barrel of gasoline, calculate the energy required to recover the crude-based portion of gasoline, and then separately calculate the energy required to produce the non-crude components. I do this in a simplified way: I assume that the alcohol portion of the gasoline additives methyl tertiary butyl ether (MTBE) and ethyl tertiary butyl ether (ETBE) come from sources other than crude, but that the rest of the MTBE and ETBE and all other gasoline additives come from crude. I have separated the alcohol component of MTBE and ETBE because these are quite different from gasoline, and because the model can calculate emissions from the production of the alcohols (this is discussed further below, in connection with reformulated gasoline). I assume that, in effect, the rest of the gasoline blending components come from crude (or, what amounts to the same assumption, that the true feedstock for gasoline blending components, if it is not crude, has the same density and takes as much energy per barrel to recover as does crude oil).

There are further complications. As a result of a change in product demand, refineries may use a different slate of crudes that will require more or less energy to recover and transport than the original slate. Moreover, the marginal energy required to make a unit of product depends on the product demand ratio. I ignore these complications.

Thus, I allocate recovery energy by using density ratios for each product; formally:

$$Er_{p,i} = O_p \times (D_p/Dc) \times (Te_i/(Cr) \times H_p$$

where:

$Er_{p,i}$ = the amount of energy, i, required to recover the crude needed to make an energy unit of product, p, available to consumers;

O_p = the own-use factor for product, p (see Appendix A, and below);

D_p = the density of product, p (EIA data; Table C.1);

D_c = the density of crude oil (EIA data; Table C.1);

Te_i = total energy type, i, required to recover crude in the United States (Table H.1);

Cr = the volume of crude recovered (associated with the use of energy, Te_i (Table H.1); and

H_p = the volumetric heating value of product, p (EIA data; Table C.1).

In the case of reformulated gasoline, D_p is equal to grams of crude-derived gasoline per liter of reformulated gasoline. It is calculated as:

$$D_{p,g\text{-}c} = D_{p,rg} - MTBE \times 0.3386 \times D_m - ETBE \times 0.425 \times D_e$$

where:

$D_{p,g\text{-}c}$ = grams of crude-derived gasoline per total liter of reformulated gasoline,

$D_{p,rg}$ = total g/L density of reformulated gasoline (Table C.1),

MTBE = MTBE volumetric fraction of reformulated gasoline,

0.3386 = effective methanol volumetric fraction of MTBE,

D_m = g/L density of methanol (Table C.1),

ETBE = ETBE volumetric fraction of reformulated gasoline,

0.425 = effective ethanol volumetric fraction of ETBE, and

D_e = g/L density of ethanol (Table C.1).

With the assumption that the energy intensity of oil recovery outside the United States is the same as the U. S. intensity, and the assumption that any non-crude components of products effectively come from crude, the single value calculated here can be used for all products, imported and domestic, consumed in the United States.

This calculation is done for each kind of energy, i, used to recover crude. The $Er_{p,i}$ for each kind of energy is multiplied by the g/10^6 Btu emission factors for that kind of energy to yield emissions of greenhouse gases per unit of product energy available to consumers. This is summed over all the kinds of energy to produce total emissions of greenhouse gases from crude recovery, per energy unit of product, p, available to consumers.

H.3 Greenhouse Gas Emissions from Refineries

The U. S. Environmental Protection Agency (EPA) reports total national emissions of carbon monoxide (CO), nitrogen oxides(NO_x) and volatile organic compounds (VOCs) (NMHCs) from petroleum refineries (*National Air Pollutant Emission Estimates*, 1990). The total is equal to emissions from the use of refinery fuels (LPG, NG, refinery gas, etc.) plus emissions from refinery process areas and equipment (catalytic crackers, valves and pumps, etc.). The EPA's calculation of emissions from process units accounts for the national average use of emission controls, which is determined from emissions data reported by refineries to states and then to the EPA. I have reproduced the EPA's method here.

Total emissions from refineries are calculated as:

$$E_r = GG_f + GG_{pa} + CO2_{co}$$

where:

E_r = emissions from refineries;

$GG2_f$ = CO_2-equivalent emissions from fuels consumed for process energy (e.g., refinery gas);

GG_{pa} = CO_2-equivalent of CO, NMHC, methane (CH_4), NO_x, and nitrous oxide (N_2O) emissions from all refinery process areas other than fuel combustion (e.g., fluid catalytic crackers and blowdown systems); and

$CO2_{co}$ = CO_2 emissions from refinery process units as a result of burning CO to CO_2.

By far, the largest component of E_r is GG_f.

H.3.1 Emissions of Greenhouse Gases from Boiler Fuels

The CO_2-equivalent emissions from fuel use are calculated from data on the amount and carbon content of fuels consumed by refineries (EIA, *Petroleum Supply Annual*; Tables H.4 and C.1 in this report) and emissions of non-CO_2 gases from industrial boilers (Table A.2). The CO, NMHC, and CH_4 emission factors in Table A.2 are uncontrolled emission factors for industrial boilers (EIA, AP-42). The NO_x emission factor is calculated by assuming that by 2000, 47% of boilers will meet recent New Source Performance Standards (NSPS) for NO_x from industrial steam-generating units, and 53% of boilers will be uncontrolled at the AP-42 rate (see DeLuchi, 1991, for details). The N_2O emission factor is the same as for utility boilers.

I have not developed emission factors for all 13 refinery fuels shown in Table H.4. To simplify, I have lumped them into six groups, as can be seen in Table 5, and have applied the most representative emission factor to each group. Thus, refinery use of NG, LPG, and steam is added together and multiplied by the total CO_2-equivalent emission factor for NG-fired industrial boilers (Table A.2; I use NG because NG is by far the dominant fuel of the three); use of still gas and hydrogen is added together and multiplied by the refinery gas emission factor (Table A.2); coal and coke are added and multiplied by the petroleum coke factor (Table A.2; coke consumption is much greater than coal consumption); and residual fuel and crude oil are added and multiplied by the emission factor for fuel oil-fired industrial boilers. Use of diesel fuel is multiplied by the diesel engine factor, and use of electricity is multiplied by the electricity-use factor specifically for refineries. With refinery gas, I have assumed that emissions of CH_4, NMHCs, and CO are the same as from NG-fired industrial boilers (refinery gas is mostly methane).

These CO_2-equivalent emissions from fuel use are allocated to products according to the amount of fuel required to make each product. The allocation of refinery energy to particular products is discussed later.

TABLE H.3 Petroleum Supply, 1987[a]

Item	10^3 bbl	10^6 kg
Refinery production		
Gasoline	2,497,019	292,706
Diesel	996,119	133,544
Residual fuel	323,201	48,529
NGLs and LRGs	163,703	
All products[b]	5,338,657	725,115
Imports		
Gasoline	140,204	
Diesel	93,176	
Residual fuel	206,138	
NGLs and LRGs	73,290	
All products[b]	731,437	
Field production		
Gasoline	123	
Diesel	516	
Residual fuel	0	
NGLs and LRGs	580,714	
All products[b]	605,612	
Total production		
Gasoline	2,637,346	309,155
Diesel	1,089,811	146,104
Residual fuel	529,339	79,480
NGLs and LRGs	817,707	
All products[b]	6,675,706	906,718
Refinery crude input	4,691,783	628,802
Other input	400,000	
Crude input/refinery production		
Gasoline	1.879	
Diesel	4.710	
Residual fuel	14.517	
NGLs and LRGs	28.660	
All products[b]	0.879	
All input/refinery production	0.954	

Source: EIA *Petroleum Supply Annual* (1988).

[a] This table is not mentioned in the text until Section H.8 on page H-44.

[b] All products includes asphalt, tar, petroleum coke, unfinished oils, LPG, and more.

TABLE H.4 Refinery Energy Use

Fuel	1981 Units	1981 Energy (%)	1989 Units	1989 Energy (%)
Crude oil (10^3 bbl)	399	0.09	24	0.00
Diesel fuel (10^3 bbl)	1,960	0.46	429	0.09
Residual oil (10^3 bbl)	26,656	6.77	11,733	2.61
LPG (10^3 bbl)	6,617	0.98	11,962	1.55
Natural gas (10^3 ft^3)	650,875	27.12	612,948	22.38
Refinery gas (10^3 bbl)	178,970	43.38	241,935	51.38
Marketable coke (10^3 bbl)	1,398	0.34	1,234	0.26
Petroleum coke (10^3 bbl)	55,346	13.47	77,444	16.51
Coal (10^3 tons)	1,059	0.93	172	0.13
Electricity (10^6 kWh)	33,044	4.55	31,621	3.82
Steam (10^6 lb)	24,575	1.19	29,210	1.24
H_2 (10^3 SCF)	0	0.00	0	0.00
Oils and other (10^3 bbl)	3,054	0.72	124	0.03
Total energy use (quads)				
Energy used	2.48	100.00	2.83	100.00
Process energy/product energy	8.92		9.46	

Source: EIA, *Petroleum Supply Annual* (1982, 1990).

TABLE H.4a Refinery Energy Intensity, 1981-1989, Btu-Used/Btu-Produced[a]

1981	1982	1983	1984	1985	1986	1987	1988	1989
0.0892	0.0916	0.0935	0.0914	0.0921	0.0957	0.0943	0.0949	0.0946

[a] This table is not mentioned in the text until Section H.6 on page H-34.

Refinery energy intensity calculated as:

$$Re = Er / (Ro \times Hr)$$

where:

- Re = Btu-refinery energy/Btu-refinery output
- Er = energy used by refineries, 10^6 Btu (EIA, *PSA*, 1982-1990)
- Ro = refinery output, bbl (EIA, *PSA*, 1982-1990)
- Hr = weighted average HHV (10^6 Btu/bbl) of refinery output, calculated as:
- Hr = $(Hp \times P - Hi \times I + He \times E)/(P - I + E)$
- Hp = weighted average HHV of total petroleum products supplied in the U. S. (EIA, AER, 1990)
- P = total supply of petroleum products (EIA, AER, 1990)
- Hi = weighted average HHV of imports (EIA, AER, 1990)
- I = total imports (EIA, AER, 1990)
- He = weighted HHV of exports (EIA, AER, 1990)
- E = total exports (EIA, AER, 1990)

H.3.2 Emissions of Non-CO_2 Greenhouse Gases from Other Process Areas

DeLuchi (1991) calculates emissions of NMHCs, CO, and NO_x from all refinery operations excluding fuel combustion by using the method the EPA uses in calculating emissions for its National Emissions Data System (NEDS). The calculation assumes year-2000 controls of NO_x and fugitive HC emissions. These emissions factors are used here.

Emissions of CH_4 from non-fuel-use process areas are calculated by subtracting fuel-use CH_4 emissions from total, refinery-wide emissions. The calculation of emissions from fuel use is explained above. Total, refinery-wide emissions data are from the Texas Air Control Board (1990) and the South Coast Air Quality Management District (1990). The result is grams of methane emissions from particular refineries; this is converted to g/106 Btu by using data on the capacity of the refineries whose methane emissions were reported (EIA, PSA). See Appendix M for a more complete explanation.

I estimate N_2O emissions relative to N_2O emissions from utility boilers, considering the possibility that fluidized-bed combustors may emit relatively high amounts of N_2O (see Appendix N).

These process-area emissions of non-CO_2 greenhouse gases are then allocated separately to gasoline, diesel, and residual fuel, by using data in DeLuchi (1991). The allocation of process-area emissions is very similar to the allocation of fuel use, which is discussed below.

H.3.3 Emissions from Control of CO from Catalytic Crackers

I calculate CO_2 emissions from control of CO from catalytic crackers by estimating uncontrolled CO emissions by using AP-42 emission factors for catalytic crackers, and data in Thrash (1990) on national capacity of different kinds of catalytic crackers), subtracting from this actual CO emissions (as reported by the EPA), and converting the difference (controlled CO) to CO_2. The same could be done for controlled HC emissions, but the calculation is complicated by the fact that only one form of hydrocarbon (HC) control (flaring) converts HCs to CO_2. HC recovery, which reduces fugitive HC emissions and emissions from oil/water separation, does not produce CO_2. For simplicity, I assume that HC control does not produce CO_2.

H.3.4 Emissions from Sulfur Control

Recall that the use of carbonate to scrub oxides of sulfur (SO_x) from the flue gas of a coal-fired power plant produces CO_2 (Appendix D). One might ask, then, if the removal and control of sulfur at petroleum refineries produces significant amounts of CO_2.

Petroleum refineries have sulfur recovery plants that convert the H_2S in refinery gas streams to elemental sulfur. As discussed in Appendix G, H_2S sulfur plants probably produce only trivial amounts of CO_2. I ignore this source.

However, recent NSPS limit sulfur emissions from fluid catalytic cracking units (FCCUs) (Federal Register, August 17, 1989). The EPA expects that refiners will be able to meet the standards by using scrubbers, catalytic reduction, or low-sulfur feed. Presently, sodium scrubbers are used to control SO_x emissions from FCCUs.

The NSPS for FCCUs require that add-on control devices, such as scrubbers, reduce SO_x by 90%. Using a simple refinery emission model described in DeLuchi (1991), I have calculated that by the year 2000, control of SO_2 emissions from FCCUs will reduce SO_2 emissions by 0.756 g/gal of gasoline produced and 0.691 g/gal of diesel fuel produced, if all FCCUs that control SO_x achieve a 90% reduction over AP-42 uncontrolled emission levels. If half of the SO_2 is controlled by scrubbers that generate one mole of CO_2 per mole of SO_2 removed, then 0.52 g of CO_2 will be emitted per gallon of gasoline and 0.48 g of CO_2 per gallon of diesel fuel. At 30 mpg, this amounts to less than 0.005% of fuel-cycle CO_2-equivalent emissions. I ignore it here.

Recently, a dry carbonate-based scrubber has been installed on a petroleum coke calciner in a refinery in Colorado (Brown et al., 1990). This scrubber produces 2 mol of CO_2 for every 1 mol of SO_2 removed. The authors note that the scrubber could be used to remove SO_2 from the flue gas of FCCUs or fluid cokers, as well. Since SO_2 emissions from petroleum coke processes are less than from FCCUs, CO_2 emissions from the control of these SO_2 emissions will be negligible.

H.3.5 Emissions from Electricity Use

Emissions from electricity use from refineries are calculated by multiplying emissions from each type of power plant by refinery use of electricity from each type of plant. This is discussed in more detail later.

H.3.6 Emissions of CO_2 from Non-Fuel Sources

It is possible that some of the carbon in the input crude ends up neither as carbon in a product nor carbon in a refinery fuel, but is simply lost as CO_2. Presumably, though, the amount is very small: the purpose of refining is to separate and rearrange components of the crude, and the products contain about as much carbon as does the input crude. A rough carbon balance check, based on national crude input, product output, and carbon composition, shows that carbon input and output are very nearly equal. I assume that there is no significant loss of carbon as CO_2.

H.4 Calculation of Energy Used in Petroleum Refining, and Allocation to Products

H.4.1 Overall Energy Consumption

Petroleum refineries report energy consumption by type of fuel in the EIA's "Annual Refinery Report," and the EIA publishes the results in the *Petroleum Supply Annual* (Table H.4). These are the most detailed data available. The electricity consumption data reported by the EIA agree with the electricity consumption data reported in the Manufacturing Energy Consumption Survey (MECS) and the Annual Survey of Manufactures (ASM), and the overall-energy-consumption data in the Petroleum Supply Annual agree with the data in the MECS (after the energy used as a feedstock for nonfuel products is deducted from the MECS total). I use the EIA *Petroleum Supply Annual* data. The data for 1981 and 1989 are shown in Table H.4. Note that I assume that the U. S. refinery energy consumption data are representative of all refineries, including those overseas, that supply the United States with products.

H.4.2 Allocation to Particular Products

Refineries produce a wide range of products, from jet fuel to tar, and the energy consumption of refineries must be allocated to these products. The simplest course would be to assume that the energy consumed by a refinery per barrel of product is the same for all products. An argument in favor of this approach (besides its appealing simplicity) is that the major energy users in a refinery (crude distillation and cracking) produce multiple products. Getting to the bottom of the barrel (residual fuel oil and tar) requires removing the top of the barrel (butanes and light naphthas), and so the energy of separation or cracking should be assigned to all products in proportion to output. However, several energy consuming processes, such as reforming, alkylation, and isomerization, produce only one product (gasoline, in this case) and it would not be reasonable to allocate this energy to all refinery output. A product-by-product accounting is required. Here, I consider two approaches, one based on models of refinery of operation, the other based on energy consumption of major refining processes. After estimating the amount of energy required to make current gasoline and diesel fuel, I discuss how the reformulation of these fuels is likely to affect refinery energy consumption by 2000.

H.4.2.1 The Modeling Approach to Allocating Refinery Energy Use

As discussed in the Appendix A, to correctly estimate the energy required to refine gasoline, one would have to estimate energy use by refineries in "with gasoline" and "without gasoline" scenarios. The "with gasoline" scenario would project energy use by refineries producing a mix of products similar to the current mix. The "without gasoline" scenario would project energy consumption by refineries producing considerably less gasoline, under the presumption that an alternative fuel is displacing some gasoline demand. The difference in energy

use by refineries in these two scenarios would be the correct energy consumption to assign to gasoline. Unfortunately, it is difficult to estimate how refineries will respond to a change in demand because refineries have several options: they can change the yield from a particular kind of crude; change refining processes, pathways, additives, etc.; change the mix of crudes they use; and in the long-run, invest in new technology.

Consequently, this approach to estimating refinery energy consumption requires a detailed model of refinery operations. Lawrence et al. (1980) modeled energy consumption of a modern, self-sufficient refinery (one that generates its own electricity) as a function of the ratio of gasoline production to distillate (diesel fuel, jet fuel, kerosene, and residual fuel) production (G/D), and the mean octane number of the gasoline. The refinery produces 76 mbd (thousand barrels per day) of gasoline and diesel fuel and about 75 mbd of other products. They found that if the change in the G/D ratio was high and the octane was low, less energy was required to produce gasoline.

By using data in Lawrence et al. (1980), energy requirements at 86 octane for the difference between G/D = 1.6 and 0.7 can be calculated by:

$$71Ga_{1.6} + 5De_{1.6} + 75R_{1.6} = 66; \quad O_{1.6} = 0.44$$

$$48Ga_{0.7} + 28De_{0.7} + 75R_{0.7} = 58; \quad O_{0.7} = 0.39$$

where:

Ga = energy required to make gasoline (10^9 Btu/10^3 bbl);

De = energy required to make diesel (10^9 Btu/10^3 bbl);

R = energy required to make the rest of the products (10^9 Btu/10^3 bbl);

O = energy required to make all products (10^9 Btu/10^3 bbl); and

numerical subscript (such as 0.7) = the G/D ratio.

If one assumes that $R_{1.6} = R_{0.7}$, and the same for Ga and De, then:

$$Ga = 0.35 + De$$

$$De = 0.54 - R$$

If R and De are roughly equal, then De = R = 0.27, and Ga = 0.62. This implies that the amount of energy required to refine a barrel of gasoline is about 12.8% of the energy in the barrel, and for diesel, about 5.0% (it appears that they use lower heating values for the energy value of refinery fuels, so I have used lower heating values for products in calculating these percentages).

At 90 octane, and G/De of 1.6 and 1.3, the results are:

$$Ga = 0.80 + De$$

$$De = 0.29 - R$$

which results in an energy requirement of 19.5% for gasoline and 2.7% for diesel fuel. (This difference between gasoline and diesel may be too large. Note that if all the energy used by refineries in 1988 was assigned only to gasoline — and gasoline output was only 45% of total refinery energy output in 1988 — the intensity would be 21%; see data in Table H.4. It seems unlikely that virtually all of the energy of the refinery is going to produce less than half of the product slate.) Thus, according to their model, refining a barrel of gasoline requires between 12.8% and 19.5% of the energy in the barrel, depending on octane and G/D ratio, for a refinery consuming about 9% of the energy value of all products, on average.

Ideally, one would specify the marginal energy requirements of gasoline and diesel manufacture at specific octanes and G/D ratios. However, this is beyond the scope of this project. I assume one overall average energy intensity.

H.4.2.2 The Allocation by Process Area Approach to Allocating Refinery Energy Requirements

A second way to assign refinery energy to particular products is to allocate the energy consumed by major refining processes to the output of those processes. Again, Lawrence et al. (1980) provide enough data to do this calculation. They show energy consumption by 10 major refining areas, as a function of the mean octane rating of the gasoline and the ratio of gasoline production to distillate production. Haynes (1976) also analyzes energy consumption by type of refining process and type of energy used fuel; his breakdown of refining areas is not quite the same as that of Lawrence et al.

In Table H.5 I show how Haynes and Lawrence et al. assign energy to various refining units. I then allocate energy use in each refining area to gasoline, diesel, and residual oil, according to the extent to which each area is used to produce each kind of product. (The allocation and explanations are shown in Table H.5.) With these data, along with the figure for the total energy used by refineries per unit of product energy output (Table H.4) and data on products and product output distributions (EIA *Petroleum Supply Annual*), it is easy to calculate the refinery energy required produce gasoline, diesel, and residual fuel. The results are shown in Table H.6.

TABLE H.5 Allocation of Products and Refinery Energy Use to Process Areas in a Refinery

	Allocation of Refinery Energy[a]		Product Allocation to Area[b]		
Product Allocation to Area[b]	Lawrence et al.	Haynes	Gasoline	Dist.	Residual
Crude distillation	0.276	0.364	0.454	0.302	0.070
Catalytic cracking	0.314	0.065	0.550	0.365	0.085
Thermal cracking		0.033	0.454	0.302	0.070
Hydrocracking		0.044	0.541	0.359	0.000
Desulfurization	0.020	0.454	0.302	0.070	
Hydrotreating		0.085	0.541	0.359	0.000
Alkylation	0.065	0.069	1.000	0.000	0.000
Reforming	0.191	0.225	1.000	0.000	0.000
Coking	0.038	0.032	0.541	0.359	0.000
Visbreaking		0.007	0.000	1.000	0.000
Propylene concentration	0.050		0.000	0.000	0.000
Gas oil refractionation	0.000		0.000	1.000	0.000
Isomerization	0.042	0.002	1.000	0.000	0.000
Hydrogen		0.025	0.541	0.359	0.000
Finishing and other	0.003	0.055	0.454	0.302	0.070
Total (as a check)	0.999	1.006			

[a] Energy used in a particular process area divided by total refinery energy use.

[b] The fraction of total energy use in each process area assigned to gasoline, diesel, and residual fuel. I assigned the energy used by crude separation (atmospheric or vacuum distillation) to all refinery products, fuels and nonfuels, in proportion to refinery energy output, because all products go through crude separation first. Catalytic and thermal cracking likewise produce multiple products; thermal cracking, which in some cases produces nonfuel products, is assigned to all products (fuel and nonfuel) in proportion to outputs, whereas catalytic cracking is assigned to all fuel products in proportion to output. Alkylation, reforming, and isomerization, which produce high-octane gasoline components, are assigned entirely to gasoline (See Haynes, 1976; Lawrence et al., 1980; Wolsky and Gaines, 1981; EIA, *Petroleum Supply Annual,* and *The U. S. Petroleum Refining Industry in the 1980s*). Hydrocracking produces gasoline, distillates, butane, and LPG, and hydrotreating usually is done to middle distillates (Haynes, 1976; Wolsky and Gaines, 1981; EIA *Petroleum Supply Annual*), so I assign 90% of the energy consumed by hydrogen production and hydrogen-consuming processes to gasoline and distillate production. Cokers (a type of thermal cracker) produce gasoline, distillates, and coke, and gas oil refractionation is used to separate distillates (Lawrence et al., 1980). Visbreaking (a form of thermal cracking) is assigned to distillates (Haynes, 1976; Wolsky and Gaines, 1981; EIA, *Petroleum Supply Annual*).

TABLE H.6 Estimates of Refinery Energy Use, Btu-Process-Energy/Btu-Product

	Estimates for Standard Gasoline						Used Here	
Product	1	2	3	4	5	6	Standard	Reformulated
Gasoline	0.128-0.195	0.130	0.132	0.150	0.128-0.161	0.136	0.145	0.182
Diesel	0.027-0.050	0.068	0.073	0.041	0.064	0.022	0.058	0.065
Residual	0.025-0.046	0.064	0.050	0.033	- -			0.045
LPG		0.062	0.048		0.172	0.027		0.054[a]

All results adjusted to be consistent with total energy use by current refineries. All results on HHV basis, counting electricity as Btu-electric. The results based on references 1-5 have not been adjusted to account for the CAA Amendments in the U. S. that reduce the sulfur content of diesel and the RVP of and reactivity of gasoline. The values used here do no include the energy required to make the methanol component of added MTBE. That energy is accounted for separately. However, the values used here are meant to include any energy required to synthesize MTBE from methanol and isobutylene.

1 = My calculation using modeling results of Lawrence et al. (1980).

2 = My calculation using energy allocation to refining area by Lawrence et al. (1980).

3 = My calculation using energy allocation to refining area by Haynes (1976).

4 = Mertes and Huscwiz (1980), using data in Haynes (1976).

5 = White et al. (1982). I have reduced the numbers shown in their paper by 6%, to scale overall refinery energy requirements (per barrel of crude) down to 1987/88 levels. The low end refers to regular, the high end to premium gasoline.

6 = Craig et al. (1991).

[a] Includes energy for liquefaction. Based on rough allocation of process energy use (details not shown).

White et al. (1982) combine both approaches: they use a linear programming model to calculate energy consumption at each process area, and then they allocate process-area energy requirements to specific products by determining mass flow and separation across the particular unit and the ultimate fate of the mass. They modeled a modern refinery producing the gasoline and diesel fuel using crude oil that was expected to be marketed in the late 1980s. The results were similar to those in Lawrence et al. (1980): regular gasoline = 13.6%, premium gasoline = 17.1%, diesel fuel = 6.8%, and LPG = 18.3%. Note: the value for LPG is probably too high.

H.4.3 Other Sources of Information

Gaines and Wolsky (1981) compare seven estimates (including that of Haynes) of Btu of energy used by a refinery process per barrel of feed to the process. For most processes in refineries, the average of the seven estimates is within 20% of the Haynes value, which lends credibility to the Haynes allocation.

Mertes and Huscwiz (1980) do a calculation similar to mine, using the data in Haynes. They calculate the amount of diesel, residual fuel, LPG, NG, refinery gas, coke, and electricity used to make diesel fuel, residual fuel, and gasoline. The results are shown in Table H.7.

Recently, Craig et al. (1991) have allocated refinery energy to gasoline, diesel, and LPG based on process-area energy requirements reported in Sittig (1978). Their results are shown in Table H.6. Their value for gasoline is consistent with the results of the other studies discussed here; the value for diesel fuel is somewhat low. The Craig et al. value for LPG is almost one order of magnitude smaller than that of White et al. (1982). My own calculation results in a value closer to that of Craig et al. (My assumption for LPG is shown in Table H.6.)

Mertes and Huscwiz scaled values (see note d to Table H.7) are consistent with the output of Lawrence et al.'s refinery model and with the allocation of energy use by area to the three products, using Lawrence et al.'s data and Haynes' data. The results of the various ways of estimating energy requirements by product are shown in Table H.6.

H.4.4 Effect on Refinery Energy Consumption of Making Low-Sulfur Diesel Fuel

The final calculation of the energy required to make diesel fuel 2000 must reflect recent EPA regulations that will reduce the sulfur content of diesel fuel from 0.25% to 0.05% and cap the aromatic content at 35% (Federal Register, August 21, 1990). The reduction of sulfur content, by hydrodesulfurization (or hydrotreating), will require higher operating temperatures, more hydrogen, more waste gas treatment, and more sulfur recovery, and these will increase refinery energy requirements.

TABLE H.7 An Estimate of Amount and Type of Energy Used by Refineries to Produce Diesel Fuel, Residual Fuel, and Gasoline, 10^6 Btu Energy/10^6 Btu Product

Process Energy Source	Diesel Fuel		Residual Fuel		Gasoline	
	Btu/Btu[a]	%[b]	Btu/Btu[a]	%[b]	Btu/Btu[a]	%[b]
Diesel	0.000539	1.1	0.0005643	1.5	0.001830	1.1
Residual oil	0.00365	7.7	0.003595	9.5	0.01302	7.5
LPG	0.0005392	1.1	0.0005643	1.5	0.001830	1.1
Natural gas	0.01977	41.8	0.01390	36.7	0.06884	39.8
Coke	0.004974	10.5	0.003369	8.9	0.02378	13.8
Refinery gas	0.01381	29.2	0.01361	35.9	0.04924	28.5
Electricity	0.00399	8.4	0.002281	6.0	0.01432	8.3
Totals	0.04727	100.00	0.037884	100.00	0.17286	100.00
Total scaled to current refinery use[d]	0.041		0.033		0.150	

Source: Mertes and Huscwiz (1980).

[a] Btu of process energy used per 10^6 Btu of product.

[b] % of total process energy requirements.

[c] Btu-electric.

[d] Mertes and Huscwiz modeled refineries as consuming more energy than current refineries actually do. I have scaled down their total 10^6 Btu-process-energy/10^6 Btu-product estimates by the ratio of current refinery energy use to their assumed refinery energy use. Specifically, Mertes and Huscwiz assumed that the refinery produced in the ratio of 426×10^6 Btu of gasoline, 331×10^6 Btu of distillates, and 108×10^6 Btu of residual oil. This indicates a weighted average energy consumption of 10.8% of the energy value of the products, a factor about 1.15 higher than the current national average. Dividing their original results by 1.15 (to scale the results to current national average) yields energy intensities (10^6 Btu-fuel/10^6 Btu-product) of 4.1% for diesel, 3.3% for residual fuel, and 15% for gasoline.

Dutch researchers have estimated that an 0.05% sulfur cap will increase total refinery energy consumption by 0.8 to 1.0×10^6 t/yr at the 95 refineries in the 12 EEC countries (van Paassen et al., 1988). In the EEC, petroleum refineries mainly use refinery gas and residual oil as process fuels (IEA, *Energy Statistics of OECD Countries*, 1990), so the extra $0.8\text{-}1.0 \times 10^6$ t of process fuel amounts to 0.037-0.047 quad (using the g/10^6 Btu values for residual fuel, Table C.1, and refinery gas, Table C.3). The EEC produced 165×10^6 t of diesel fuel in 1988 (IEA, *Energy Statistics of OECD Countries 1987-1988*), which amounts to 7.17 quads. The additional $0.8\text{-}1.0 \times 10^6$ t of process fuel required to meet the 0.05% standard indicates that the ratio of Btu-process energy/Btu-diesel will increase absolutely by 0.51-0.66

(e.g., 0.59-0.65). This represents roughly a 10% relative increase in the Btu-process energy/Btu-diesel ratio.

The energy requirement may be greater in the United States than in Europe because U. S. refineries may have less hydrogen available for hydrotreating, and they will have to make hydrogen, at an energy cost. As discussed below, the Clean Air Act (CAA) mandates a low-RVP, high-oxygen, low-VOC-forming, low-toxics reformulated gasoline, and this will require less severe reforming, which in turn will result in less hydrogen production.

The estimate of a 10% relative increase can be checked by assuming that the percent increase in energy cost, and hence energy use because of the manufacture of low-sulfur diesel, will be equal to the percent increase in total refining cost. The total percent increase in cost is calculated as follows: a refinery model commissioned by the EPA (1989, *Draft Regulatory Impact Analysis...*) projects that the regulations will increase the cost of making diesel fuel by about $0.02/gal. The Dutch study estimates the increase to be $0.038-0.057/gal (van Paassen et al., 1988). The difference between the wholesale price of diesel and the refiners acquisition cost for crude, as reported by the EIA's *Petroleum Marketing Monthly June 1989*, is typically $0.10-0.20/gal (diesel #1 sells for more than diesel #2; both are used by vehicles). Thus, the $0.02/gal increment represents a 10-20% increase in the apparent cost of making diesel fuel. This is consistent with the 10% increase calculated above.

Both the United States and Europe are likely to lower the limit on the aromatics content of diesel fuel. This will further increase the energy requirements of refining diesel fuel. Also, as mentioned above, the need in the United States to make hydrogen will increase energy requirements. Therefore, I assume an 0.7-point absolute increase in Btu-process-energy/Btu-diesel requirements (the high end of the range estimated above for making low-sulfur diesel fuel), from about 0.058 Btu/Btu at present, to about 0.065 (Table H.6). (As discussed below, I have assumed that increased energy use due to processing increasingly lower-quality crudes will be balanced by technical improvements in process efficiency and the phasing-out of older, less efficient refineries.) I do not assume any change in the amount of crude oil required to make a barrel of diesel fuel, as a result of the new standards. My base-case assumption is shown in Table H.6.

H.4.5 The Effect on Refinery Energy Consumption of Making Lower-RVP, Less Reactive Gasoline (Reformulated Gasoline): Qualitative Background Discussion

The new CAA Amendments (EPA, *CAA*, 1990) require a reduction in the volatility of gasoline, a reduction in the benzene content, a minimum oxygen content of 2%, and a reduction in the VOC-forming potential of gasoline. To meet these requirements, refineries will have to change their operations and inputs. These changes will increase refinery energy consumption; hence, emissions of greenhouse gases will increase, in 2000, compared to today.

Beginning in 1992, gasoline sold in the summer months (May-September) in the United States cannot have an RVP greater than 7.8-9.0 psi, depending on the average monthly temperature and ozone-attainment status of the area (9.0 RVP in ozone-attainment areas; 7.8 RVP in warm, nonattainment areas) (Federal Register, June 11, 1990; EPA, *CAA*, 1990). To satisfy these regulations, refiners will not be able to add butane (which is extremely volatile), and in some cases may have to remove butane. Butane adds bulk to gasoline and raises its octane level, and so the lost butane-bulk and octane will have to be made up somehow. The bulk can be at least partially made up, and the octane enhanced, by converting the surplus butane to high-octane, low-RVP components, such as heavy ethers (MTBE) and alkylates (EPA, *Final Regulatory Impact Analysis...Phase II Gasoline Volatility Regulations*, 1990). Additional bulk can be provided by reducing the severity of reforming, and perhaps by simply increasing the input of crude oil per barrel of gasoline.

The CAA Amendments require reformulated gasoline in the nine worst ozone-nonattainment areas, beginning in 1995 (EPA, *CAA*, 1990). The CAA specifies that gasoline must be at least 2.0% oxygen by weight, and not more than 25% aromatics by weight (or, provide a 15% reduction in emissions of VOCs and toxic air pollutants). Gasoline in CO nonattainment areas must be 2.7% oxygen in winter months. It is widely expected that refiners will meet these requirements by replacing some of the relatively reactive aromatics and light olefins with high-octane, low-reactivity oxygenates, MTBE and ETBE (Piel 1989; USGAO 1990; Boekhaus et al. 1990; U. S. Congress, OTA, 1990; EIA, AOOG, 1990). For example, the addition of 15% MTBE by volume will reduce the concentration of aromatics to about 22%, and add 2.7% oxygen by weight (Boekhaus et al. 1990).

To reduce aromatics, the use of the reformer, which produces aromatics, will have to be reduced. The old reformer feed will be redirected to the catalytic cracker, and the severity of catalytic cracking will be increased to favor the formation of olefins, which then can be alkylated or polymerized into highly branched, less reactive paraffins, or combined with alcohols to make oxygenates (Piel, 1989; Boekhaus et al., 1990; U. S. Congress, OTA, 1990; EIA, AOOG, 1990).

In summary, to make low-RVP, low-aromatics gasoline, refineries will probably reduce the severity of reforming, increase the severity of catalytic cracking, increase alkylation, and make or add more oxygenates. On balance, these changes are likely to increase the energy requirements of refineries. Reducing the severity of the reformer to reduce aromatics production, will reduce energy consumption in the reformer (the reformer is a big energy consumer), but will also reduce hydrogen production. Unless the refinery vented hydrogen prior to the reformulation (which is very unlikely), this hydrogen deficit will have to made up, probably by steam reforming natural gas. This, of course, will increase refinery energy use in the form of extra natural gas consumption. And the increased severity of catalytic cracking, and the increased use of alkylation and polymerization to produce alkylates and oxygenates, will also increase energy requirements.

The manufacture of MTBE or ETBE will also increase energy requirements, both inside and outside refineries. One liter of MTBE is produced from a reaction of isobutylene and 0.338 L of methanol, and 1 L of ETBE is produced from isobutylene and 0.425 L of ethanol

(Piel, 1989). In the United States, the methanol will be made from NG, and the ethanol will be made from corn.

Currently, isobutylene is derived from steam cracking and fluidized-bed catalytic-cracker (FCC) units in refineries, but these supplies are limited. Additional supplies will be made by processing the excess butane available as a result of the volatility restrictions discussed above (EIA, AOOG, 1990).

H.4.6 Quantifying the Extra Energy Cost of Making Low-RVP, Low-Aromatic, High-Oxygen Gasoline

The energy effects discussed above can be classified as in-refinery (changes in reforming, cracking, alkylation, and production of isobutylene), and out-of-refinery (manufacture of methanol or ethanol used to make MTBE and ETBE). The greenhouse gas emissions impact of out-of-refinery changes can be quantified relatively easily because the emissions model developed here includes complete fuel-cycle greenhouse-gas emissions from methanol and ethanol production. Thus, to incorporate out-of-refinery greenhouse gas emissions, the model calculates the fuel-cycle greenhouse gas emissions from the production and delivery of a specified amount of alcohol and adds this to greenhouse gas emissions from gasoline production. The specified effective alcohol content of gasoline is a variable. (The alcohol content is "effective" because the alcohol is transformed to MTBE or ETBE before blending. Currently, alcohols are less than 0.5% of volumetric refinery inputs.)

It is more difficult to estimate the energy effects of in-refinery changes. A spokesman for ARCO has said that it takes 10% more energy to make EC-1, ARCO's "clean" replacement for regular leaded gasoline (U. S. Congress, OTA, 1990). However, ARCO was able to dump the removed aromatics into the unleaded gasoline pool, a move which saved the financial and energy cost of converting the aromatics to more environmentally benign compounds. In a large program, the overall aromatic content will have to be reduced, and this will increase energy consumption.

Recently, ARCO has modeled the effects of complete gasoline reformulation on the use of energy at its 236,000 bbl/d plant in Anaheim, California. The modeling exercise fully reconfigured and re-optimized the plant to reformulate gasoline, and calculated process-area-by-process-area energy requirements for several reformulations. The output of products, and the input of crude, was kept at the pre-reformulation (base-case) level in all cases.

According to Dave Paulsen (1991), Process Coordinator for ARCO's Clean Fuel Program, the manufacture of a CAA gasoline, with 25% aromatics and 10% MTBE, will increase refinery-wide energy consumption of steam, power, and NG for heat by 11%. (ARCO generates all its process energy on site, including steam and power, from NG). This does not account for energy required to make MTBE (I have accounted for at least part of this extra energy separately). The manufacture of more radically reformulated gasoline, with 10% aromatics, 5% olefins, and 15% MTBE, designed to meet likely California standards for reformulated gasoline, will increase

refinery-wide energy requirements by 30%. The increased energy is due to extra use of alkylation, catalytic cracking, isomerization, hydrocracking, hydrotreating (a low-sulfur feed is needed), and steam reforming of NG to make hydrogen (to make up for the loss of hydrogen from the reformer).

The percent increase in the energy required to refine gasoline, given a percent increase in total refinery energy use, all of which is assignable to gasoline, and constant refinery output, is simply:

$$P_g = P_r/E_g$$

where:

P_g = percent increase in energy required to make a barrel of gasoline,

P_r = percent increase in total refinery energy requirements, and

E_g = Fraction of original (pre-reformulation) total refinery energy use assignable to gasoline.

The P_r has been given by ARCO. As estimated here, E_g is 0.70 for a typical refinery (ARCO's product mix is similar to the U. S. average). Hence, reformulated gasoline will require from 15.7% (moderate reformulation) to 42.9% (severe reformulation, very low aromatics) more energy than current gasoline, per gallon of gasoline. Since the reformulated gasoline specified here will contains 2.35% less energy per gallon, the manufacture of reformulated gasoline will require 18.4%-46.3% more energy, per Btu.

These results are for one refinery, utilizing current technology. Industry-wide energy requirements may be different. However, the Anaheim refinery is large and relatively efficient, and ARCO feels that it is modeled performance will be typical for the industry. Here, I use the ARCO results to represent the whole industry.

The increased energy demand of reformulation may be mitigated slightly by the use of more efficient equipment and catalysts (Paulsen, 1991; EIA, *The U. S. Petroleum Refining Industry in the 1990s*, 1990).

This estimate of a large increase in the energy requirement of reformulated gasoline is consistent with recent estimates that reformulated gasoline will cost 30-80% more than current gasoline (e.g., Boekhuas et al.'s 1990 estimate of an $0.08-$0.18/gal increase in the cost, depending on the amount of aromatics removed, against the current cost of about $0.23/gal, according to data from EIA's *Annual Energy Review* [various years] on the difference between refiner crude acquisition cost and refiner wholesale gasoline price).

H.4.7 Other Aspects of Reformulation

Reformulation will have other effects on greenhouse gas emissions. It will reduce the energy density and carbon content of gasoline and will probably reduce the amount of crude oil required to produce a barrel of gasoline. The reduction in energy density and carbon content is discussed in Appendix C. The effect of reformulation on gasoline yield depends on changes in the severity of reforming and catalytic cracking, the use of rejected butane, and the amount of MTBE or ETBE added. The rejection of butane and the increase in the severity of catalytic cracking will tend to reduce the gasoline yield per unit of input (EIA, AOOG, 1990; USGOA, 1990). However, if the butane is made into isobutylene and combined with methanol or ethanol to make MTBE or ETBE, the loss due to butane rejection will be mitigated or perhaps eliminated. Also, reducing the severity of reforming will increase the yield per barrel. And finally, the embodied alcohol component of the added MTBE or ETBE will displace some petroleum.*

Assuming that reformulated gasoline contains 2,749 g/gal (Table C.1), and, for analytical purposes, that the MTBE and non-MTBE components are nonmiscible, and given 2,824 g/gal MTBE (Table C.1), it follows that the non-MTBE part of reformulated gasoline contains 2,736 g/gal. If this non-MTBE part is 94% crude (higher than the 93% assumed above for standard gasoline because no butane, which is derived from NG, will be added to reformulated gasoline), then a gallon of reformulated gasoline contains $2{,}736 \times 0.94 \times 0.85 = 2{,}208$ g of crude, from the non-MTBE part (assuming 15% MTBE by volume). If the isobutylene part of MTBE comes from crude, then MTBE contributes 272 g of crude-derived material (given 0.338 gal methanol/gal MTBE). Therefore, the total crude-derived material in reformulated gasoline amounts to 2,480 g. Dividing by the heating value of reformulated gasoline (which is lower than that of standard gasoline; Table C.1) yields 20,295 g crude/106 Btu reformulated gasoline. (If vehicle miles traveled (VMT) is independent of gasoline composition, and the mi/10^6 Btu efficiency of a vehicle is the same on reformulated as on standard gasoline, then consumers will demand the same Btu amount from reformulated gasoline as standard gasoline, not the same amount of gallons.). This is 2.2% less crude required, per Btu, than with standard gasoline. (This calculation ignores any effects that changing gasoline refining might have on the production of other products.)

However, there is one more piece of the puzzle: the use of crude-derived process fuel (mainly refinery gas) to make reformulated gasoline. The ratio of crude-mass as feedstock to crude-mass as process fuel is likely to be different with reformulated gasoline because the composition of the gasoline is different and, more importantly, because reformulated gasoline requires considerably more energy to manufacture than does standard gasoline. It seems most reasonable to assume that refineries will meet the extra energy requirement by purchasing more fuel, mainly NG and electricity, rather than sacrificing more crude as process fuel, since that would be an uneconomic use of crude oil. This suggests that the manufacture of reformulated gasoline will indeed reduce the volume of crude input to the refinery, but will also increase the proportion of

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* Here is a very simplified calculation. Given that standard gasoline contains 2,791 g and 125,070 Btu/gal (Table C.1) and is 93% crude (or crude-derived material) by weight (see above), it follows that 10^6 Btu of gasoline requires 20,753 g of crude as feedstock. Additional crude-derived material, mainly refinery gas, is consumed as a process fuel.

refinery energy that is purchased, rather than refinery gas. (This is what I have assumed here.) However, a complete refinery model is needed to properly account for all the mass and energy flows and costs.

I assume that the net effect of reformulation is that the added alcohol (as MTBE or ETBE) displaces gasoline one-for-one, volumetrically. This ultimately reduces emissions of greenhouse gases from crude recovery and feedstock transport, per unit of gasoline produced (I count separately emissions from the production of the alcohol in the MTBE or ETBE). Given a volume percentage of MTBE or ETBE, I calculate the mass amount of methanol or ethanol (effectively) in the gasoline, per liter, and subtract this from the total grams/liter of the reformulated gasoline. What is left is the grams of crude-derived components per total liter of reformulated gasoline. This density is used to calculate the energy required to recover and transport the crude input to reformulated gasoline. This method properly separates the crude component of reformulated gasoline from the non-crude components, and calculates separately the energy required to process each component stream.

H.5 Conclusions Regarding the Amount of Energy Required to Make Current and Reformulated Gasolines

The average of the estimates of Table H.6 (counting the high and the low end of a range as one estimate each) is slightly less than 0.15 Btu of refinery energy per Btu of energy in standard (non-reformulated) gasoline. Considering that the high end of estimate 1 is unreasonably high, the best-guess range, without adjusting for gasoline reformulation, is 0.14 to 0.15. Therefore, I start with a baseline of 0.145 Btu/Btu-current-gasoline.

As discussed above, data provided by ARCO (Paulsen, 1991) indicate that making reformulated gasoline will require 18-46% more energy, per Btu of gasoline, depending on the degree of reformulation. "Interim" reformulations available as of February 1991 contain 20-25% aromatics by volume, and 1.0-2.5% oxygen by weight (Peyla, 1991). Nationally, the final-average reformulation is likely to be more severe than the minimum required by the CAA, and somewhat more severe than the interim reformulations, but not nearly as severe as the severest considered by ARCO (10% aromatics). I assume a national average reformulation to 20% aromatics, 5%, and 15% MTBE, which is consistent with national specifications suggested by ARCO (Piel, 1989).

The extra energy requirements of reformulating gasoline are a function of the aromatics content. If one interpolates linearly between an 18% increase in energy requirements with 25%-aromatics gasoline and a 46% increase with 10%-aromatics gasoline, then making 1 Btu of gasoline with 20% aromatics will require 27% more energy than making 1 Btu of standard gasoline. However, the energy requirements probably increase exponentially as the 10%-aromatics level is approached. This suggests that making 1 Btu of a modestly reformulated (20%-aromatics) gasoline, such as is assumed here, should require roughly 25% more energy than

making 1 Btu of current gasoline. This is what I assume here (Table H.6). In a scenario analysis, I consider the effects of a higher energy requirement (Table 12).

As will be discussed later, I assume that future improvements in refinery energy efficiency and the phasing out of older refineries balance any extra energy needed to process lower quality crude.

H.5.1 The Mix of Process Fuels Used to Produce Gasoline, Diesel, and Residual Fuel

Mertes and Huscwiz's (1980) analysis shows that gasoline, diesel, and residual fuel use essentially the same mix of fuels, namely, the refinery-wide average mix. The analysis in Craig et al. (1991) shows that gasoline and LPG use roughly the same mix, which also is the refinery-wide average. Assuming, then, that all products use the refinery-wide average, emissions of greenhouse gases from the refining of each kind of product, in g/106 Btu, are given by:

$$E_p = \text{SUM}\,[T_p \times S_{rf} \times E_{rf}]$$

where:

E_p = grams of CO_2-equivalent emissions per 10^6 Btu of product from refineries;

T_p = total refinery energy required by product, p, in 10^6 Btu of energy/10^6 Btu of product, counting electricity as Btu-electric (estimated above);

S_{rf} = total energy use of refinery fuel, rf, divided by total refinery energy use of all fuels (see discussion below); and

E_{rf} = grams of CO_2-equivalent emissions per 10^6 Btu of rf consumed (see Table A.2).

The mix of fuels used by refineries (used to calculate S_{rf}) has shifted somewhat during the 1980s. From 1981 to 1989, refineries increased their use of refinery gas and petroleum coke and decreased their use of residual fuel oil, crude oil, diesel fuel, and purchased natural gas. Electricity use has fluctuated (EIA, *PSA*, 1982-1990; see Table H.4). In the absence of reformulation, this trend might have continued. However, as discussed above, reformulation will dramatically increase refinery energy requirements, and it is likely that the extra energy requirement will be met by purchasing more natural gas and power, rather than using a greater percentage of a barrel of crude oil as process fuel. This means that the share of fuels other than refinery gas and perhaps petroleum coke is likely to increase. In addition, refinery gas is likely to contain less hydrogen as a result of reformulation because of decreased use of the reformer and increased use of hydrogen in

hydrotreating and hydrocracking. With these considerations, I have assumed that most of the extra energy required to reformulate gasoline is provided by purchased NG (Table 5).

H.5.2 Electricity Use by Refineries

Because most refineries in the United States are concentrated in a few areas, it is not reasonable to assume, without researching the matter, that the mix of fuels used at the electricity plants supplying the refineries is the same as the national average mix (if refineries were spread fairly evenly across the country, it would be reasonable to assume the national average electricity mix). As shown in Table H.8, most petroleum refining is done in the Gulf Coast, California, the Northeast, and near Chicago. The Gulf Coast and California use much more natural gas-based power than the does the rest of the nation, and as a result, the fuel input to electricity used by refineries is quite different from the national average. Moreover, overseas refineries exporting products to the United States almost certainly will use an electricity mix different from the U. S. average.

I have estimated the mix of fuels input to electricity generation in every refining center in the United States and the world. For the United States, I use EIA data on fuels used by every utility in the United States (EIA, 1989, data transmittal), information on the market area of every utility in the United States (*Electrical World...*, 1988), and data on the location and output of every refinery in the United States (EIA, *Petroleum Supply Annual*). For the world, I use EIA data on the amount of products imported from each country (EIA, *Petroleum Supply Annual*, 1988) and the electricity mix of virtually every country in the world (IEA, *Energy Balances...* and *Energy Statistics*, and U. N., 1988, 1989). With these data, one can calculate the mix of fuels used to generate electricity in every country and region and the contribution of that country or region to total refining done for U. S. consumption. (I make the simplifying assumption that refineries in other countries use as much electricity per unit output as do refineries in the United States. Considering that many overseas refineries are owned or operated by United States oil companies or were built or designed by U. S. firms, this assumption may be reasonable.) The inputs used for this analysis are detailed in Tables D.1-D.3.

Note: After I calculate the amount of energy required to produce a unit of gasoline, diesel, residual fuel, and LPG energy, I multiply this ratio by the "own-use" factors for each of the fuels, to account for use of the fuels in the petroleum cycle itself. The own-use factor is discussed generally in Appendix A, and detailed later in this appendix.

TABLE H.8 Location and Capacity of Major Refining Centers in the U. S.

Location	% of Total U. S. Refining Capacity
Texas (primarily Gulf Coast)	26.1
Louisiana (primarily Gulf Coast)	16.8
Los Angeles area, California	9.31
Chicago area, Illinois	5.11
San Francisco area, California	4.97
Philadelphia area, Pennsylvania	4.69
Northwest quadrant of Ohio	3.10
Seattle-Tacoma, Washington	2.97
Other Illinois	2.77
New Jersey	2.55
Northeast quadrant of Oklahoma	2.43
Gulf Coast, Mississippi	2.35
Southeast quadrant of Kansas	2.23
St. Paul, Minnesota	1.58
Other U. S.	13.04
U. S. Virgin Islands	3.48[a]

Source: EIA, *Petroleum Supply Annual 1988* (1989). Based on barrels/calendar-day atmospheric crude oil distillation capacity, including idle capacity, as of January 1, 1989.

[a] Based on U. S. total, excluding Virgin Islands.

H.6 Refinery Energy Use in the Future

Primarily as a result of energy conservation measures adopted in the late 1970s, refineries were more energy-efficient in the 1980s than in the early 1970s. In 1985, refineries used 14% less energy per barrel refined than in 1975 (*Hydrocarbon Processing*, November 15, 1988). Moreover, in 1985, refineries produced a higher quality product (e.g., higher-octane gasoline, unleaded gasoline) from a lower quality input (heavier, more sulfurous crude), which means that energy savings at constant quality (the real measure of efficiency improvement) was even higher. In support of this, Sigmon (1984) estimates that refineries used 23% less energy per barrel in 1982 than in 1972, at constant input and output quality and constant product mix (the actual improvement in efficiency was only 10%, which shows that changes in input and output quality and in product mix strongly affect energy consumption). Similarly, Pelham and Moriarty (1985) found that from 1972 to 1983, refineries reduced energy consumption per barrel by 25.7%, at constant input and output quality.

Presently, the energy consumed by refineries amounts to about 9.5% of the energy value of the products (Table H.4). However, new refineries are more efficient than this current national average, and there is room for improvement in new refineries. Haynes (1976) estimated that refineries could reduce their energy consumption 20% by using more efficient catalytic cracking, better furnace control, more heat recovery, and other measures. In 1980, the U. S. General Accounting Office estimated that new refineries could be as much as 30% more efficient than existing refineries, and that existing refineries could be up to 20% more efficient by retrofitting (p. 21). Gaines and Wolsky (1981) note that nonfuel petroleum products, such as polymers, greases, and asphalts can be recycled, with potentially huge energy savings. Pelham and Moriarty (1985) estimated that refineries could technically (although not necessarily economically) reduce energy consumption by 14%, primarily by recovering waste heat and optimizing steam usage.

I assume that crude and energy prices will rise in the future and will induce new refineries to be more efficient in their use of crude and process energy, so that perhaps they will consume only 8% of the energy value of the products — holding constant (analytically, for the moment) the quality of the crude input and the quality and mix of the product output.

The quality of the crude slate is expected to decline, and refineries will have to expend additional energy to remove additional sulfur and metals from the crude and to convert heavier crudes into light products (Haynes, 1976; Sigmon, 1984). Lawrence et al. (1980) found that if lower-quality crude (Alaskan oil, in this case) were 25% of the crude refinery input, refinery energy requirements would be 0.2% higher (in absolute terms; about 2.5% in relative terms) than in the no-lower-quality-crude case. This suggests that processing all lower-quality crude could increase refinery energy requirements on the order of 1%, in absolute terms (10% in relative terms). The API estimated that changes in product quality and mix from 1972 to 1982 increased energy consumption by 17% per barrel in relative terms, at constant technical efficiency. Increasing the mean octane will also increase energy use, primarily in the alkylation and isomerization units (the reformer will not be used because of restrictions on the aromatics content). Any further reduction of the sulfur content of diesel fuel will also increase refinery energy requirements.

The result is that lower input quality and higher output quality (above and beyond the level of reformulation analyzed here) will increase the amount of energy required to produce all products, compared with current refineries, and will probably at least balance technical improvements in efficiency. Because of these competing forces, I assume no change in overall refinery energy efficiency in 2000, compared with 1987. This assumption is supported by a historical trend: throughout the 1980s, the amount of energy required to produce an energy unit of product has remained relatively constant (Table H.4a). (This result is not confounded by significant changes in the output mix; for example, according to data in the EIA's *Annual Energy Review*, 1990, the gasoline fraction of total output remained roughly the same from 1981 to 1989).

H.7 Energy Used to Transport Crude Oil and Petroleum Products

The amount of energy used to transport crude oil and petroleum products is the sum of the amount used by trains, trucks, tankers, and pipelines (Table E.1). Trucks and trains use diesel fuel, ships use residual fuel oil, and pipelines use electricity. For each of these modes, the total amount of energy consumed is equal to the Btu/ton-mile energy intensity of the mode multiplied by total ton-miles by mode. Btu/ton-mile data are compiled in Table E.2 and discussed in Appendix E. In this section, I review and calculate ton-mile data for transportation of crude oil and petroleum products.

For crude oil, the object is to calculate the amount and kind of energy required to transport the amount of all crude input to U. S. refineries because I have output data for U. S. refineries, which can be matched with the input data. Crude comes to U. S. refineries primarily by pipeline and tanker, but also by rail and truck. Presumably, very little U. S.-bound exported crude is moved by rail or truck in foreign countries. However, some crude comes to U. S. refineries via pipelines in Canada, and a good deal of crude is imported from overseas and comes in via international tanker. Some of the imported crude is first shipped by pipeline from the producing field to the tanker. All of these movements must be accounted for.

There are several independent sources of data on barrel and ton-mile domestic movement of crude oil and petroleum products by water, rail, pipeline, and highway. I will review these sources and state my assumptions for domestic ton-miles. Unfortunately, there are no such ready-made ton-mile data for movements of U. S.-bound crude oil and products outside U. S. land and territorial waters, so I calculate ton-miles from other data, as detailed below.

H.7.1 Ton-Miles of Crude and Products Shipped in Pipelines in the United States

The Association of Oil Pipelines (AOP) reports ton-miles of crude and petroleum products shipped by pipeline from the Annual Report (Form 6) of oil pipeline companies to the Federal Regulatory Commission. There are no other data on ton-miles per se, but there are separate estimates of tonnage and mileage, which can be used to check the plausibility of data from the Association of Oil Pipelines.

The EIA's *Petroleum Supply Annual* reports barrels of crude received at U. S. refineries by pipeline. Converting the barrel data to tons (6.65 bbl of crude/ton; EIA *Monthly Energy Review*), and dividing this into the AOP's independent ton-mile data, yields an average length of crude haul by pipeline of 824 miles in 1987 and 787.3 miles in 1986. DOT's *National Transportation Statistics* divides AOP ton-miles by tonnage estimates from Transportation Policy Associates and gets 772.4 mi in 1986. (I do not know the source of the data from Transportation Policy Associates; it may be the EIA data). Qualitatively, these estimates are consistent with each other and with pipeline mileage and flow tonnage shown on maps in the Congressional Research Service (1977).

Hooker et al. (1980) estimated a mean shipment distance of 1,390 mi for shipping petroleum products by pipeline from the Gulf Coast to the Northeast, and 2,115 mi by coastal tanker. However, the Northeast is the terminus of oil product pipelines originating in the Gulf Coast, and a considerable amount of oil is shipped shorter distances, from the Gulf Coast to Chicago or St. Louis and from west Texas to the Gulf Coast.

It thus appears that the AOP ton-mile data are consistent with other partial data. I use the AOP ton-mile estimates, rather than multiply the EIA quantity estimates by average length of haul, because the AOP data are original and are reported in the units needed here.

H.7.2 Mix of Fuels Used at Plants Supplying Power to Petroleum Pipelines

In my base case, I assume that pipelines draw from the U. S. average power mix. There is some evidence to support this: Hooker et al. (1980) calculated that the power companies supplying electricity to Colonial and Plantation oil pipelines used 26% (Colonial) and 15% (Plantation) oil, 41% and 66% coal, 13% and 8% nuclear, 4% and 6% hydro, and 16% and 5% other, in 1977. The average of these two is not too far off from the 1977 U. S. average power mix.

H.7.3 Accounting for Movement of U. S.-Bound Crude Oil in Canadian and Other Foreign Pipelines

Canada exports a large amount of crude oil to the United States via pipeline, and the AOP does not count ton-miles of movement in Canadian pipelines in Canada — it counts ton-miles only when the oil in the pipeline crosses the border into the United States (the pipeline changes names at that points, too) (AOP, personal communication, 1989). For a complete account of the petroleum system, I estimate the amount of crude shipped by pipeline from Canada to the United States, and the length of the haul in Canada.

The Trans Mountain Pipe Line and the Interprovincial Pipe Line are the two biggest Canadian pipeline companies exporting crude to the United States. In 1987, Interprovincial shipped 191 million barrels of Canadian oil roughly 800 mi to the U. S. border (Interhome Energy, 1989); Trans Mountain ships about 17,000 bbl/d from Edmonton 725 mi to the Seattle area (Trans Mountain, personal communication, 1989). (Interprovincial ships some U. S.-produced oil to the United States, but I assume this is oil produced in the lower 48 states and shipped in the U. S. portion of the pipeline; hence, the oil is already accounted for in U. S. Bureau of the Census production and AOP transport figures.) A few other pipelines ship much smaller amounts of crude to the United States; I assume an additional 2×10^9 ton-miles. There are no product pipelines from Canada to the United States (AOP, personal communication, 1989). The result, using 6.76 bbl/ton for Canadian crude (EIA, *International Energy Annual*, 1989), is about 25×10^9 ton-miles in Canadian pipelines.

A small amount of U. S.-bound crude is moved from the interior of foreign countries to the coast, where it is loaded onto tankers and sent to the United States. I did not find data on this sort of movement. Worldwide, it appears that most major oil fields (Indonesia, Venezuela, Mexico, the Middle East — with some exceptions — and Nigeria, are located on or near the coast. Major exceptions include fields in Algeria, and some fields in the Middle East. If 15% of all imported crude (excluding Canada) is moved an average of 800 mi by pipeline before being loaded onto a tanker, the result is another 25×10^9 ton-miles. I add this to the Canadian total and AOP's U. S. total, to get the grand total shown in Table E.1.

H.7.4 Ton-Miles of Crude and Petroleum Products Shipped by Railroad in the U. S.

The Federal Railroad Administration (FRA) reports tons and ton-miles of various commodities transported by rail. Railroads are required by the Interstate Commerce Commission to submit audited waybills — statements describing the destination, weight, and other attributes of cargo moved by rail — to the Federal Railroad Administration. The FRA calculates tons, ton-miles, car-miles, and other statistics for each commodity from a sample of the waybills, and publishes the results in *Carload Way Bill Statistics*, Statement TD-1 (USDOT, FRA, 1989) . The American Association of Railroads (AAR) also uses the waybill data to calculate railroad transportation statistics. The AAR data agree with the FRA data to within about 1% for the four years I checked (1979, 1982, 1986, and 1987).

I used FRA's *Waybill Statistics* (USDOT, FRA, 1989, 1982) for railroad ton-miles for crude oil and petroleum products in 1987. I use the ton-mile data for petroleum product classification 29, the largest category, which includes coke, tar, LPG, etc., for consistency with the EIA production and importing data, which also include these items. The data include ton-miles of petroleum products shipped from Canada to the United States. I assume that so little U. S.-bound petroleum is moved by railroads in other countries that it can be ignored (this certainly seems reasonable, given that total petroleum movement by rail in the United States already is quite small).

H.7.5 Ton-Miles of Crude and Products Shipped in U. S. Waters

The annual publication from the Army Corps of Engineers, *Waterborne Commerce of the United States* (U. S. Department of Army) reports tons and ton-miles of movement of crude oil and petroleum products in U. S. waters. The Corps gets data on movement of domestic cargo directly from vessel operators; data on movement of foreign cargo come from the U. S. Bureau of the Census. For petroleum products in 1987, I use their data for SIC 29, which includes asphalt, coke, and LPG, for consistency with the EIA production and import data, the FRA railroad data, and the truck data discussed in section H.7.7.

The Army Corps of Engineers data includes ton-miles of crude oil movement between Alaska and the Lower 48 States, and between points in the United States, Puerto Rico, and the

Virgin Islands. This is convenient because a large amount of crude is shipped from Alaska to the U. S. West Coast, and a very large amount of foreign crude is refined at Puerto Rico and the Virgin Islands and shipped to the U. S. mainland. However, the Army Corps does not report ton-miles of movement between foreign ports and ports in the United States, Puerto Rico, and the Virgin Islands. To estimate ton-miles of crude and product imports to the United States, one must know how much oil each region of the U. S. imports from each exporter, and how far the oil travels. This is estimated next.

H.7.6 Overseas Movement of U. S.-Bound Crude and Petroleum Products

The EIA's *Petroleum Supply Annual* reports the amount of oil each region of the United States receives from every exporting country in the world. The regions are the five "Petroleum Administration for Defense" districts (PADDs): the East Coast and Appalachia (PADD I), the Midwest (II), the Gulf Coast (III), the Rocky Mountains (IV), and the West Coast (V). The Rocky Mountain Region (PADD IV) imports crude oil and products only from Canada, primarily via pipeline, and so this region can be excluded from the calculation of ton-miles of imports by water (I have already estimated ton-mile of imports from Canada via pipeline). The Midwest (PADD II) imports products from Canada, either via pipeline or across the Great Lakes, and imports crude from many countries. I assume the crude imported by PADD II lands at the Gulf Coast (PADD III) and is shipped north via the large crude oil pipelines, or on barges up the Mississippi, so that PADD II does not import crude or products directly, and also can be excluded from the calculation (I separately estimated pipeline imports from Canada, pipeline movement in the United States, and river movement in the United States). This leaves PADDs I, III, and V as receiving regions for foreign crude oil and petroleum products.

To estimate ton-miles, the EIA's estimates of barrels imported by a region from a country must be translated into point-to-point estimates. Rather than attempt to estimate every actual port-to-port movement of crude oil and products, I have used large ports to represent movements to and from important regions. At the receiving end in the United States, I assume all imports to the East Coast (PADD I) land at New York; all imports to the Gulf Coast (PADD III) land at Houston; and all imports to the West Coast (PADD V) land at Los Angeles.

At the shipping end, began by grouping exporters into seven regions: (1) West Africa (Nigeria, Liberia, Angola, Ivory Coast, Cameroon, Gabon, Congo, Zaire, Togo, Ghana, South Africa, Benin, and Mauritania), (2) the Mediterranean (Algeria, Spain, Portugal, Italy, Yugoslavia, Greece, Turkey, Tunisia, Hungary, Rumania, Egypt, Israel, Bulgaria, and Syria), (3) Northern Europe (United Kingdom, Ireland, Norway, France, West Germany, East Germany, Belgium, Denmark, Sweden, Switzerland, Finland, and the Netherlands), the (4) Middle East (Saudi Arabia, Kuwait, United Arab Emirates, Iran, Iraq, Oman, Jordan, Pakistan, and the Soviet Union), (5) the South Pacific (Indonesia, Malaysia, Australia, India, Korea, Japan, Singapore, China, Taiwan, India, Brunei, and Thailand), (6) South America (Colombia, Venezuela, Ecuador, Brazil, Peru, Argentina, Trinidad and Tobago, Uruguay, and the Netherlands Antilles), and (7) Central America (Mexico, Panama, Jamaica, Bahamas, Bermuda, and Guatemala). I then picked the largest exporting port in the region to represent the region, if that port also was about as far from

the United States. as other major ports in the region, on average. For example, Ad Damman, next to the major Saudi Arabian exporting terminal at Ras Tanura, represents the Middle East. However, if the largest exporting port or country in a region clearly was closer to the United States than other exporting countries in the region, I added mileage to compensate. For example, the bulk of imports from South America comes from its north coast Colombia, Venezuela, Trinidad and Tobago, and the Netherlands Antilles — and are well represented by the exporting terminal at Puerto Miranda near Maracaibo, Venezuela, especially since Venezuela is the major exporter of South America. However, a small amount of oil comes from much farther away (Brazil and Argentina) and so I have added mileage to the distance to Maracaibo to account for this.

For distance between ports, I used the U. S. Defense Mapping Agency's *Distances Between Ports* (1985). The figures are shown in Table H.9.

To convert the EIA's estimate of barrels of crude oil imported to tons of crude oil imported, I used API's (1989) estimate of barrels of foreign crude per ton. To convert the EIA's estimate of barrels of imported petroleum products to tons of imported products, I multiplied the API's estimate of the barrels per ton for a particular product (e.g., gasoline, coke, fuel oil) by the ratio of imports of that product to imports of all petroleum products, for all products, and summed, to produce an weighted average density for imported products.

I did the calculation just described for 1987. The resulting ton-miles are shown in Table E.1.

H.7.7 Ton-Miles of Crude and Products Shipped by Truck in the United States

I will review five sources of data, all of which have shortcomings and require various kinds of adjustments to yield an estimate of truck ton-miles.

1. The U. S. Bureau of the Census' *Truck Inventory and Use Survey* (USDOC, 1985) is sent to all truck operators. This document reports truck characteristic and mileage data, but not tonnage, by type of commodity carried. Therefore, it samples the appropriate universe, but does not report a key item of data. According to the *Survey* (USDOC, 1985), 262,200 trucks carried petroleum 5.3881×10^9 truck-miles in 1982, an average of 20,500 mi/truck. (Petroleum presumably includes a small amount of crude oil, as well as petroleum products, but the amount of crude carried by trucks is negligible compared to the amount of products.). Most of these trucks (141,000) were tank trucks, and most of the shipments were local hauls. The mileages include empty backhauls (U. S. Bureau of the Census, personal communication, 1989). Deliveries of 6,500-9,000 gal are common, according to the U. S. CRS (1977). Assuming an average shipment size of 3,000-10,000 gal and 6.6 lb of product/gal on average, the result is $53\text{-}178 \times 10^9$ ton-miles, with a best guess, based on 7,000 gal, of 124×10^9 ton-miles.

TABLE H.9 Nautical Miles between Ports

Exporting Region:	Middle East	North Europe	West Africa	Mediterranean	South Pacific	Central America	South America
Representative Port:	Ad Damman	Bergen	Lagos	Algiers[a]	Jakarta	Tampico	Maracaibo[a]
Representative Country:	S. Arabia	Norway	Nigeria	Algeria	Indonesia	Mexico	Venezuela
U. S. Region and Port							
East Coast: New York	8,261	3,367	4,883	4,117	12,644	2,029	2,390
Gulf Coast: Houston	9,821	5,035	5,952	5,673	12,191	502	2,339
West Coast: Los Angeles	12,349	7,762	8,065	8,201	7,342	4,441	4,150

Source: *Distances between U. S. Ports*, Defense Mapping Agency (1985).

[a] I have added 500 nautical miles to the distances shown for Algiers and Maracaibo distances, to make the distances more representative of their regions.

2. The AOP estimates ton-miles of petroleum carried by trucks by using data from the *Petroleum Supply Annual* and from "Financial and Operating Statistics" reported by the American Trucking Association, but the data are doubtful. The AOP (1989) estimates that trucks carried 22.7×10^9 ton-miles of crude and petroleum products in 1982, but it does not know if the data from which it calculated this figure include empty backhauls. If they do not, then the 22.7 would have to be about doubled for a proper accounting of the total mileage by trucks carrying petroleum, and the result would be about 45×10^9 ton-miles in 1982.

3. According to the 1977 *Commodity Transportation Survey* (U. S. Bureau of the Census, 1981), manufacturers shipped petroleum products 14.7×10^9 ton-miles by truck in 1977, based on tonnage shipped and one-way shipping distances. Counting the empty backhauls, the figure would be about 29×10^9 ton-miles. However, the survey is sent only to "manufacturers" as defined by the Standard Industrial Classification; wholesale bulk terminals and bulk plants are classified under "wholesale," not "manufacturing," so they do not receive this survey. This means that the *Commodity* numbers underestimate, probably considerably, actual ton-mileage by truck.

The U. S. Bureau of the Census initiated another Commodity Transportation Survey in 1983 but will not officially release the data on account of their poor quality. However, it will release data to researchers for internal use only; I am happy to report that the 1983 tonnage data are not terribly far from the 1977 tonnage data.

4. In 1982, virtually all (98%) petroleum bulk plants in the United States reported to the U. S. Bureau of the Census (1985, *Census of Wholesale Trade*) that they received their products primarily by truck. However, these bulk plants reported total volume sales amounting to only 16% of total products supplied in the United States in 1982 (U. S. Bureau of the Census, *Census of Wholesale Trade*, 1985; EIA, *PSA*).

5. Most, if not virtually all, petroleum products are shipped to the final end user by truck. If 90% of all petroleum products move at some point by truck, an average of 75 mi one way, then trucks shipped 116×10^9 ton-miles in 1982 (Using EIA *PSA* data, and assuming 6.6 lb/gal).

I believe that the first and fifth and estimates are the most complete and reliable. With these considerations, my estimates for crude and product ton-miles are shown in Table E.1.

It is safe to assume that there is essentially no truck movement of U. S.-bound crude oil and products in foreign countries. Trucks are used to mainly to deliver products to multiple retail and scattered retail outlets, not, obviously, to export large quantities of petroleum to the United States. Scattered truck movement across the United States borders can be ignored.

H.7.8 Allocation of Crude and Product Transport Energy to Gasoline, Diesel, and Residual Fuel

For crude transport, total transport energy is allocated to each product based on its share of the weight of the crude oil and the amount of product from a unit of crude.* This is then multiplied by an own use factor, described generally in the Appendix A and discussed in detail below (see Table H.10).

For transportation of petroleum products, transport energy is allocated to product X as total energy multiplied by the ratio of the weight of all X to the weight of all products. I have tried to define "all products" consistently throughout, to include coke, tar, LPG, unfinished oils, and the like as well as gasoline, diesel, etc. Thus, "all products" is defined the same in the calculation of total transport energy and in the calculation of weight shares.

The results of the allocation are input to Table 3 as Btu-process energy/Btu-net product available to consumers.

H.7.9 Transportation of Crude Oil and Petroleum Products in the Future

The sources of petroleum will change in the future as domestic production declines and imports increase, and this will change overall petroleum transportation patterns. The EIA's *Annual Outlook for Oil and Gas 1990* (1990) projects the following changes from 1989 to 2000: a 56% increase in imports of crude oil, a 16% increase in imports of refined products, a 14% decline in total domestic production of petroleum (onshore, offshore, and Alaskan crude plus NGPLs plus other oils and synthetic crude plus processing gain), a 23% decline in domestic production of crude oil (as distinguished from petroleum, which, as noted above, includes more than crude oil), an 18% decline in lower-48 onshore crude production, a 1% decline in lower-48 offshore production, a 49% decline in Alaskan production, and a 300% increase in domestic production of "other" petroleum (unfinished and other oils, other hydrocarbons, alcohols, blending components, and synthetic crude). These increases and decreases will continue through the year 2010. Overall, the main effects are a decrease in production in Alaska and the Gulf Coast region and an increase in imports.

These changes have several implications for the transportation of crude oil and petroleum products. The drop in U. S. production in Alaska and the Gulf Coast will probably reduce crude shipments by pipeline and domestic waterway (as a percentage of total petroleum consumption), because pipelines and domestic waterways mainly move domestically produced crude oil. Imported crude generally is landed, refined, and consumed at big port cities, not landed and

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* See the discussions on how energy used to recover crude is allocated to products (section H.2.5); the allocation of transport energy is similar.

TABLE H.10 Petroleum Own-Use, in Quads of Own Use of Fuel per Quad of Fuel Produced, Each Stage, 1987

Stage	Gasoline	Diesel	Residual
Recovery[a]	0.00239	0.01334	0.01461
Crude transport[b]	0.00003	0.01085	0.07923
Refining[c]	0.00000	0.00002	0.00051
Product transport[b]	0.00164	0.03623	0.01952
Total[d]	0.0041	0.0605	0.1139
Own use factor[e]	1.004	1.064	1.128

Assumptions necessary to do the calculation:

0.092 × 10^3 barrels of residual fuel burned per 10^6 kWh of refinery power.

0.096 × 10^3 barrels of residual fuel burned per 10^6 kWh of generic power.

0.177 quad residual fuel oil burned per quad pipeline power.

0.900 diesel share of total energy used by trucks transporting fuels (rest is gasoline).

0.800 residual oil share of total energy used by oil tankers (rest is diesel fuel).

[a] Gasoline, diesel, or residual fuel used directly at oil recovery sites, as reported by the U. S. Census, plus residual fuel used to supply electricity to oil recovery.

[b] Diesel used by trains, trucks, and tankers; gasoline used by delivery trucks; residual fuel used by tankers and at power plants supplying electricity to pipelines.

[c] Gasoline, diesel, and residual fuel used directly at refineries, as reported by the EIA's *Petroleum Supply Annual*, plus residual fuel used at power plants supplying electricity to refineries.

[d] Total may not equal sum of components shown, because of independent rounding.

[e] Total production of each fuel (U. S. refinery production plus imports, as reported by EIA's *Petroleum Supply Annual*), in quads, divided by total production less own use of each fuel.

shipped far inland to midcontinent refineries (USDOT and USDOE, 1980; this is supported by EIA PSA data showing that, in 1989, the Midwest region, PAD District II, imported only 20% of its refinery input, excluding imports from Canada, while domestic pipeline shipments of crude into the region were 62% of refinery crude input). However, this could change in the future.

The increase in imports will, of course, increase tanker shipments of crude. If imports from Canada increase, international pipeline shipments will increase as well. However, Canada is not expected to significantly increase petroleum exports (EIA, AOOG, 1990).

There probably will be fewer changes in the transportation patterns of petroleum products than in the patterns for crude oil for two reasons. First, the percentage of total product supply that is imported will increase only slightly, from 12.6% to 13.4% (EIA, AOOG, 1990). Second, the drop in domestic production of crude and increase in imports of crude will not dramatically affect regional production of products because refiners are motivated to maximize product output regardless of the source of the crude. There may be a small drop in product distribution distances, as regional refining capacity is expanded and refineries on average move closer to end users.

All these effects can be summarized as follows: (1) there will be a large increase in the percent of total ton-miles by tankers, (2) there will be a small decrease in the percent of total ton-miles by pipeline, and (3) there will be little change in product patterns. In accordance with the EIA projections cited above, I assume a 50% increase in crude ton-miles by international tanker, a 10% decrease in pipeline ton-miles, and no change in product patterns, for 2000, relative to calculated values for 1987. For lack of data, I assume that the mix of countries remains the same.

H.8 Adjusted Final Consumption of Petroleum

As noted throughout, one needs to calculate own-use of gasoline, diesel, and residual fuel, in order to convert "process energy/106 Btu produced" to "process energy/106 Btu available to consumers". The calculation of own-use and net use of gasoline, diesel, and residual fuel is shown in Table H.10. Table H.3 shows some of the EIA petroleum supply data used in Table H.10 and in other calculations throughout the report (1987 data are used because the Census data and other data are for 1987).

To calculate net use of gasoline, diesel, and residual fuel, I subtracted from total product output of each fuel (total output is equal to refinery production plus imports plus field production) the amount of the fuel used by petroleum refineries (EIA, *Petroleum Supply Annual)*, oil production operations (U. S. Bureau of the Census, *Census of Mineral Industries, Fuels and Electric Energy Consumed*, 1990), and crude and product transport modes. See Table E.1. Trains use diesel fuel only (EIA, *Petroleum Marketing Monthly,* June 1988). Pipelines use electricity from the national average power mix. Trucks use 90% diesel fuel and 10% gasoline. (According to the 1982 *Truck Inventory and Use Survey*, diesel trucks accounted for 93% of all miles traveled by heavy-heavy trucks and 28% of all miles traveled by light-heavy trucks; virtually all petroleum transportation fuels are delivered by heavy trucks). Tankers use 90% residual fuel and 10% diesel fuel (based on data in Marks, 1982, and Davis et al., 1989).

Appendix I:

Nuclear Energy

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Nuclear Energy

I.1 Overview*

A nuclear reactor releases energy from the fission of uranium 235 (U-235). This energy, in the form of heat, boils water to produce steam, which then turns a turbine connected to an electric generator.

There are several stages in the production of the uranium fuel used by nuclear reactors: mining uranium-containing ore; extracting, concentrating, and converting the uranium; increasing the proportion of the fissionable isotope, U-235; and assembling the fuel. Uranium is extremely energy dense, and relatively little of it (compared with coal, for example) is needed to power a reactor. Because the nuclear energy cycle requires so little uranium, there is no need to economize on its transport by using an efficient bulk carrier system (like railroads) or by locating uranium producing and handling operations near to one another. Thus, civilian nuclear fuel is transported almost entirely by truck, and facilities for mining, conversion, enrichment, fuel fabrication, and disposal are scattered widely across the country (USDOT and USDOE, 1980).

In the United States, uranium is mined and milled primarily in Utah, Colorado, Texas, New Mexico, Arizona, and Wyoming. At the mills, which are usually located at or near the mines, ore containing about 0.1-0.3% uranium oxide (U_3O_8) by weight is refined or concentrated to at least 75% U_3O_8 (yellowcake). The mining and milling companies ship the yellowcake by truck to Allied Corporation in southern Illinois or Sequoyah Fuels Company (General Atomic) in Oklahoma (EIA, *World Nuclear Fuel Cycle Requirements,* 1989), where U_3O_8 is converted to uranium hexafluoride (UF_6), the form of uranium required by gaseous-diffusion/uranium-enrichment facilities. The converters then ship the UF_6 by truck to the U.S. Department of Energy (DOE) enrichment facilities. A small amount of U.S. uranium is enriched in Europe (EIA, *Uranium Industry Annual 1988*, 1989).

Up to and including the conversion process, isotopes of uranium in ore, yellowcake, or UF_6 occur in their natural proportions, about 99.3% nonfissionable uranium 238 (U-238) and 0.7% fissionable U-235. For a uranium fuel to sustain a fission reaction and thus provide continuous fission energy (in a light-water reactor), the proportion of the fissionable U-235 in the fuel must be increased (enriched) several fold above the natural level. Today, virtually all enriching in the United States and abroad is done by the gaseous diffusion process, in which UF_6 is gasified and pumped through the porous membrane filters that let through more of the UF_6 that contains U-235 than that containing U-238. The DOE owns two operating enrichment plants, both gaseous diffusion operations (one at Portsmouth, Ohio, operated by Goodyear Aerospace, and one at Paducah, Kentucky, operated by Union Carbide; a former facility at Oak Ridge, Tennessee, was closed on December 15, 1987). These two plants produce most of the enriched

* From USCRS, 1977; USDOT and USDOE, 1980; EIA, *Uranium Industry Annual 1988*, 1989.

uranium used by U.S. utilities; the rest is produced by the EURODIF gaseous diffusion plant in France.

There are other technologies for enriching uranium: centrifugal separation, which is used in Europe, and laser isotope separation, which is being developed. In a centrifuge, the heavier U-238 portion of UF_6 accelerates more slowly than the lighter U-235 and is thereby separated. Several years ago the United States started to develop centrifuge technology, but canceled the program in favor of laser isotope separation. Presently, the world has only one operating centrifuge plant, a small facility in the Netherlands.

Uranium-atomic vapor laser isotope separation (U-AVLIS) is under development in the United States at Lawrence Livermore Laboratory in California and Oak Ridge National Laboratory in Tennessee. The U-AVLIS technology is expected to produce enriched uranium at a lower cost than gaseous diffusion or gaseous centrifuge technology (Davis et al., 1982; USDOE, *Plan for the Demonstration, Transition, and Development of U-AVLIS Technology,* 1990). The current U-AVLIS demonstration and deployment plan slates construction for 1993 and operation for 1997 (USDOE, *Plan for the Demonstration, Transition, and Development of U-AVLIS Technology,* 1990). However, the current DOE uranium-enrichment operating plan assumes no U-AVLIS through 1998.

The enrichment process produces two streams of UF_6: one is enriched in U-235 (compared with the natural proportion of U-235), and the other is depleted. The depleted stream, which is about 4-5 times more massive than the enriched stream, is stored at the enrichment plant for possible use in breeder reactors (the U.S. breeder program has been mothballed). The enriched UF_6 is shipped by truck to fuel fabrication facilities located at Lynchburg, Virginia (Babcock & Wilcox); Windsor, Connecticut (Combustion Engineering); Richland, Washington (Advanced Nuclear Fuels); Wilmington, North Carolina (General Electric); and Columbia, South Carolina (Westinghouse) (status as of February 1989, according to EIA, *World Nuclear Fuel Cycle Requirements*, 1989). The fabricators convert UF_6 to uranium oxide (UO_2) and assemble the UO_2 into the devices that will be loaded into nuclear reactors. The fuel assemblies are then shipped by truck to the reactors. The companies that fabricate the fuel also build nuclear reactors and ship the fuel from the enrichment plant to the fabricator (EIA, *World Nuclear Fuel Cycle Requirements,* 1989; U.S. Congressional Research Service, 1977).

The nuclear fuel must be disposed of after it is consumed by the reactor. Waste materials with a low level of radioactive contamination are sent by truck to disposal facilities at Barnwell, South Carolina; Beatty, Nevada; or Hanford, Washington (USDOE, *Energy Technologies and the Environment, Environmental Information Handbook*, 1988). Low-level-waste shipments are expected to reach about 30,000 truckloads per year by 1990 (USDOT and USDOE, 1980). Currently, wastes with a high level of contamination are stored at the reactor site in ponds, awaiting the opening of a long-term high-level waste repository.

Greenhouse gases are emitted throughout the nuclear-fuel cycle, wherever process energy is consumed. Mining and milling operations consume diesel fuel, natural gas, electricity, and other fuels. The trucks that move uranium at various stages of the cycle consume diesel fuel, albeit a very small quantity in total. Conversion, enrichment, and fabrication facilities require electricity

and natural gas; gaseous-diffusion enrichment facilities actually consume a considerable amount of power. These energy requirements are discussed in more detail in the next section.

I.2 Energy Used by Uranium Mines and Mills

The data used in this analysis are from the U.S. Bureau of the Census, *Census of Mineral Industries*, for 1982 and 1987 data. There is a general description of the census data in Appendix F.

The census reports energy use by the aggregate group "uranium-radium-vanadium mining and milling" and the aggregate group "metal mining services," which serves the production of iron, lead, copper, bauxite and other ores, as well as the production of uranium. The census does not indicate the portion of energy that should be assigned to uranium mining and milling only; hence, this portion must be estimated.

According to the U.S. Bureau of the Census (Frati, 1989), there is no radium mining and little vanadium mining, so the uranium-radium-vanadium category is almost all uranium. In support of this, note that in 1987, the value of uranium concentrates was 93% of the combined value of uranium and vanadium concentrates. I therefore assign 93% of the energy used in the uranium-vanadium-radium industry to uranium mining.

I have assumed that the portion of energy used by the metal mining services group that should be assigned specifically to uranium production is equal to the ratio of energy use by uranium mining and milling to energy use by all metal mining concerns (excluding mining services), where energy use in uranium mining and milling is estimated as above. This ratio is about 0.10. The ratio that is based on value of production is about the same.

It appears that the census survey covers every industry involved in any kind of uranium mining, milling, and preparation. According to the Standard Industrial Classification (SIC) code that the survey uses, the uranium-radium-vanadium ore industry includes all establishments engaged in mining, milling, and otherwise preparing ores. The leaching of uranium is explicitly included in the list of covered activities, which suggests that all forms of uranium production (from in-situ leaching, heap leaching, tailings and mine water, low-grade ore and by-product processing, as well as from conventionally mined ore) are included in the survey. I assume this to be the case.

Tables I.1 and I.2 show the data and assumptions used to calculate energy consumption by the uranium mining and milling industry in 1982 and 1987. In the base case, I use the 1987 data. However, because there is a large difference between the calculated 1982 and 1987 energy requirements (in Table I.1), I do a scenario analysis using the 1982 data.

TABLE I.1 Energy Used to Explore, Mine, and Mill Uranium

	1982		1987	
	In Units	In Percent	In Units	In Percent
Crude oil (10^3 bbl)	0.0	0.00	0.0	0.00
Diesel (10^3 bbl)	252.9	15.55	91.2	16.73
Residual (10^3 bbl)	145.8	9.67	0.5	0.10
Natural gas (10^9 ft^3)	2.6	28.39	0.8[a]	25.94
Coal (10^3 tons)	27.3[b]	6.15	18.0[b]	12.12
Electricity (10^6 kWh)	1,024.8	36.89	359.9	38.70
Gasoline (10^6 gal)	2.2	2.95	1.1	4.49
Other (10^6 dollars)	0.3[b]	0.00	0.4[b]	0.00
Total (quads or 10^{15} Btu)	0.0095		0.0032	
USDOC production totals (10^3 tons)[c]	9.56		6.35	
EIA[d] production totals (10^3 tons)[c]	13.20		5.80	
Quads-recovery/10^3 tons-U_3O_8[e]	0.0010		0.00050	

[a] The census did not disclose the amount of natural gas used by metal mining services in 1987. However, the census did report that metal mining services used almost no natural gas in 1982. Therefore, I assume that metal mining services used no natural gas in 1987.

[b] The census did not disclose the cost or quantity of coal or the cost of "other" fuels used in uranium-radium-vanadium mining and milling in 1982 or 1987. However, the *sum* of the total cost of coal and the total cost of "other" fuels used can be calculated from the census data. I apportion this sum to coal and to "other" fuels according to the ratio of the total cost of coal used in all metal mining industries to the total cost of "other" fuels used in all metal mining industries. I then divide the total cost of coal by the price of coal, as reported by the census (in $/$10^6$ Btu), to get the total energy value of coal used, and divide the total cost of "other" fuels by the $/$10^6$-Btu-price of "other" fuels to get the total energy value of "other" fuels.

The census also did not disclose the value of "other" fuels used by metal mining services in 1982 or 1987. I back-calculated the 1987 value, using census data, and calculated the 1982 value by assuming that the 1982 ratio of the value of "other" fuels to the value of all fuels was the same as the 1987 ratio.

[c] Uranium concentrates.

[d] From EIA, *Uranium Industry Annual 1987* (1988).

[e] Based on U.S. Department of Commerce (USDOC) production estimates.

Sources: U.S. Department of Commerce, U.S. Bureau of the Census, *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); U.S. Department of Commerce, U.S. Bureau of the Census, *1987 Census of Mineral Industries, Ferroalloy Ores, Metal Mining Services, and Miscellaneous Metal Ores* (1990); U.S. Department of Commerce, U. S. Bureau of the Census, *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985).

TABLE I.2 Data Used to Adjust Census Data on Energy Used to Recover Feedstocks

Standard Industrial Classification Area	Purchased Fuels ($)[a]/ Distributed Fuels ($)[c] 1982	1987	All Products ($)[b]/ Distributed Products ($)[d]	
Uranium-vanadium-radium	1.079	1.264	1.138	1.134
Metal mining services	1.202[e]	1.174	Not used	

Other data:

0.100 = fraction of metal mining services assigned to uranium (my estimate; see text).
0.930 = fraction of uranium-vanadium-radium energy assigned to uranium (my estimate; see text).
0.137 = 10^6 Btu/dollar of "other" fuels, 1982 (value given by the census).
0.161 = 10^6 Btu/dollar of "other" fuels, 1987 (value given by the census).

[a] The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies that were not surveyed (the census estimated the value for these companies) and by companies that did not report the amount of each type of fuel they used.

[b] The total dollar value of all products (e.g., uranium ore) of all companies engaged in the activity, including products of companies that were not surveyed (the census estimated production for these companies) and products of companies that did not classify or detail their products (e.g., did not state the type of coal they produced).

[c] The dollar value of the fuels purchased by companies that reported the amount of each type of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only the total cost of purchased fuels with no breakdown or details.

[d] The dollar value of products of those companies that reported the amount and type of each product.

[e] The cost of undistributed fuels was not disclosed, but could be calculated by assuming a value for "other" fuels (see Table I.1, footnote b).

Note: See sources for Table I.1.

I.2.1 Comparing Some of the Census Data with Data from Other Sources

The DOE Energy Information Administration (EIA) (EIA, *Uranium Industry Annual 1987*, 1988) reports slightly lower uranium concentrate shipments for 1987 than does the census, but much higher shipments for 1982. The EIA also reports slightly more crude ore production in 1987 and significantly more in 1982. This comparison seems to validate the 1987 census data but casts doubt on the quality of the 1982 data. I therefore use the 1987 data in estimating the energy intensity of uranium mining and milling. I calculate energy used by mining and milling operations, per unit of concentrate shipped, using the 1987 census data. I then convert this to energy use per unit of net nuclear generation using the data series of Table I.3 for U_3O_8 requirements per unit of generation.

When the DOE estimates of energy used per mining and milling facility are scaled up to the amount of ore produced for all purposes in 1982, the energy consumption data for uranium mining and milling in 1982 are reasonably close to the estimates in USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors* (1983). In scaling the DOE factors, I assume that open-pit mining and underground mining produced ore in proportion to the final 1982 total production for each kind of mine, as reported by EIA.

I.2.2 Future Energy Use by Uranium Mining and Milling

As the concentration of uranium in the ore decreases, the energy required to mine and process the ore increases dramatically (Mortimer, no date). Mortimer shows that a nuclear fuel cycle based on very low-grade ore, less than 100 parts-per-million (ppm) uranium oxide, or 0.01% (0.1-0.3% are typical values for today), will produce as much CO_2 as a fossil-fuel cycle with the same electricity output. Consequently, if the United States uses lower-grade ores in the future, fuel-cycle energy requirements may rise substantially. However, ore quality has not declined over the last 10 years (EIA, *Uranium Industry Annual 1988*, 1989). It is not likely that ore quality will decline significantly in the forseeable future. Consequently, I do not consider the possibility of increased energy requirements for mining and milling.

I.3 Energy Used to Transport Uranium

The amount of energy used by trucks in transporting uranium is the product of the weight of the shipment, the distance, and the Btu/ton-mi energy consumption rate of the truck.

I.3.1 Tons Transported

Total tonnage at any stage of the fuel cycle is the sum of the weight of the uranium (as fuel, yellowcake, or UF_6) and the containers and packaging. The amount of packaging is related to the amount of uranium; the amount of uranium is related to the total power output from nuclear power plants. Therefore, to estimate the total amount of energy consumed by trucks in transporting

TABLE I.3 Nuclear Fuel Consumption and Generation Data

Year	10^6 SWUs[a]	Tons U_3O_8 Enriched[a]	Net TWh Generation[b]	Net TWh Consumable[c]
1977	4.950	8,500	250.883	249.852
1978	4.950	8,500	276.403	275.267
1979	5.600	9,000	255.155	254.106
1980	5.850	10,000	251.116	250.084
1981	5.800	10,000	272.674	271.553
1982	6.500	11,500	282.773	281.610
1983	8.200	15,000	298.677	297.449
1984	8.000	15,000	327.634	326.287
1985	7.900	16,250	383.691	382.114
1986	8.000	18,250	414.038	412.336
1987	6.950	17,500	455.270	453.398
1988	6.200	18,500	526.901	524.735
1989	8.511	19,100	529.400	527.223
1990	7.497	17,650	535.103	532.903
1991	9.112	19,200	553.117	550.843
1992	8.073	19,250	555.365	553.082
1993	8.772	18,950	559.373	557.073
1994	7.702	17,950	559.796	557.495
1995	9.828	19,450	562.141	559.830
1996	8.093	19,700	563.900	561.582
1997	9.800	17,300	565.658	563.332
1998	9.635	18,000	572.734	570.379
1999	9.015	18,000	575.156	572.791
2000	9.434	17,900	576.402	574.032
2001	9.712	18,600	580.411	578.025
2002	9.838	17,800	583.010	580.613
2003	9.993	17,250	585.969	583.560
2004	9.617	20,050	588.929	586.508
2005	9.971	15,250	591.888	589.455
2006	9.138	20,800	594.847	592.401
2007	10.946	18,400	592.284	589.849
2008	9.535	21,500	595.216	592.769
2009	11.390	19,250	591.886	589.453
2010	12.076	22,800	589.728	587.303
1977-1988	79	158,000	3,995	3,978
1977-2020	287	572,150	16,598	16,526
1990-2010	199	395,050	12,073	12,021

TABLE I.3 (Cont'd)

Year	SWMUs/ MWh Generated	Tons U_3O_8/ GWh Generated	MWh Enrichment/ MWh Generated[d]
1977-1988	0.0197	0.0395	0.0474
1977-2010	0.0173	0.0345	0.0414
1990-2010	0.0165[e]	0.0327	0.0396
1980-1990	(from Table I.6)		0.0392

[a] Data from 1989-2010 are year-by-year projections from the INM (EIA, data transmittal, March 5, 1990). The historical data for a separate work unit (SWU) are back-calculations based on 5-year historical average uranium mass flows and U-235 assays. The SWU forward projections are based on projections of assays and uranium requirements.

[b] Data through 1989 are from EIA's *Commercial Nuclear Power* (WINES model). The year-by-year post-1989 projections are from the INM (EIA, data transmittal, March 5, 1990).

[c] Net nuclear generation minus nuclear power used to mine, mill, convert, enrich, or fabricate uranium.

[d] The product of SWUs/MWh and 2.4 MWh enrichment/SWU.

[e] The Organization for Economic Cooperation and Development, Nuclear Energy Agency (1987) shows 0.0158 SWU/MWh-generated over the life of a pressurized-water reactor.

Notes: The WINES model projects nuclear generating capacity and nuclear electricity generation for the United States and the world (reported in *Commercial Nuclear Power*). The INM model takes the WINES results and projects uranium requirements, SWU requirements, fuel burn-up, and fuel discharge for the United States and the world (results reported in *World Nuclear Fuel Cycle Requirements*). The WINES lower reference-case (actually the base case) projections of nuclear electricity generation shown here are consistent with (almost identical to) the separate electricity generation projections of the EIA's Intermediate Future Forecasting System (IFFS) (published in the *Annual Outlook for U.S. Electric Power*), which are, in turn, consistent with the projections in EIA's *Annual Energy Outlook*. (*Commercial Nuclear Power, World Nuclear Fuel Cycle Requirements, Annual Outlook for U.S. Electric Power,* and *Annual Energy Outlook* are published annually by the EIA.)

There is little difference among EIA's lower reference case, upper reference case, and no-new-orders case through the year 2010. After 2010, EIA assumes major capacity additions in the upper reference case and no new capacity in the no-new-orders case. Nevertheless, one should keep in mind that EIA's projection of uranium and SWU requirements, per unit of generation, depend on the assumed amount of new capacity, because the initial core loading requires a large amount of uranium.

uranium (and waste), one must know the relationship between uranium requirements and electricity output, and the relationship between packaging weight and uranium weight, for each stage of the fuel cycle.

Rotty et al. (1975) provide most of this data: they show the total weight of a shipment (uranium or waste plus containers and packaging) relative to a unit amount of U_3O_8 at every stage of the cycle. Thus, if one knows how much U_3O_8 is associated with the amount of power output, one has all of the information necessary to do the calculation. The data of Rotty et al. (1975) are shown in Table I.4.

The U.S. Congressional Research Service (CRS) (1977) provides the same sort of ratio but excludes container weight. I have included the CRS figures in Table I.4 for a rough comparison; the ratios between stages for both sets of data should be similar except where the packaging requirements change dramatically. The Rotty et al. (1975) ratios of conversion to enrichment and enrichment to fabrication are similar to the CRS ratios, but the Rotty et al. (1975) ratios of fabrication to fuel and fuel to waste are higher than the CRS ratios. This indicates, as one would expect, that the amount of packaging and container weight increase considerably when a finished fuel rod or hazardous waste, as opposed to the raw fuel material, is being shipped.

The relationship between U_3O_8 weight and electricity output is analyzed later.

I.3.2 Average Miles

I estimated the mileage from mines to converters and converters to enrichers from maps 16 and 17 in the CRS, *National Energy Transportation Report* (1977). These maps show shipments (in tons and energy units) from uranium mines to the two conversion plants and from the conversion plants to the three DOE enrichment facilities in 1976 (little is different in 1989). Uranium is mined in essentially the same places today as it was in 1976, and all domestic enrichment is done at two of the three DOE plants. For the mileage from enrichers to fabricators, and from fabricators to reactors, I used the mileage estimates in the Oak Ridge National Laboratory (ORNL) safety study (O'Donnell and Choy, 1981). These estimates seem roughly consistent with the CRS maps. (I did not measure exact distances on the CRS maps because after enrichment there are many possible paths to fabricators and reactors.) I estimated mileage to low-level waste repositories assuming that all low-level waste is transported to the nearest of the three currently operating sites. I assume that all high-level waste would be transported to the planned Yucca Mountain geologic repository in Nevada.

The energy used to transport ore to the mill and energy used at the mill are apparently included in the census estimates of energy used in uranium mining.

The mileages estimated here are for domestic uranium activity. Since data for foreign uranium activity are not readily available, I assume that these estimates apply, on average, to all uranium activity theoretically associated with 1987 nuclear net generation.

Table I.4 Transporting Uranium, Finished Fuel, and Nuclear Waste

Material Produced	Weight Excluding Containers (total tons/ton U_3O_8)[a]	Weight Including Containers (total tons/ton U_3O_8)[b]
Ore (to mills)	300-900[c]	--
U_3O_8 (to converters)	1.0	1.50
UF_6 (to enrichers)	1.48	2.24
Enriched UF_6 (to fabricators)	0.286[d]	0.58
Fuel (to reactors)	0.275[e]	1.01
High-level waste (to repositories)	0.275[e]	1.45
Low-level waste (to burial sites)	1.26	1.45

[a] From U.S. Congressional Research Service (1977).

[b] From Rotty et al. (1975).

[c] The CRS estimates 500. The Nuclear Assurance Corporation Report, contained in the CRS report, estimates 606. Data in the EIA, *Uranium Industry Annual 1987* (1988) indicate that this ratio has varied from 300 (in 1986) to 900 (in 1984), depending on the concentration of uranium in the ore, with the average being about 800 from 1978 to 1987. (Note that the U.S. Bureau of the Census figures in Table I.1, which cover mining *and* milling, presumably include the use of energy to transport ore from the mine to the mill.)

[d] The ratio of the unenriched to the enriched UF_6 factors, 1.48:0.286 (about 5), is consistent with the fact that the percentage of U-235 content is increased by a factor of about 5 in the enriching process.

[e] Based on the total weight of the fuel, not just the uranium weight.

My estimates of the mileage from enrichers to fuel fabricators, fuel fabricators to reactors, and reactors to waste disposal sites are the same as the estimates in Rotty et al. (1975). They estimate 800 miles from mills to converters and 800 miles from converters to enrichers.

I.3.3 Btu/Ton-Mile

The estimate is based on the data of Table E.2 and is the same for all trucks.

My assumptions for transport are shown in Table I.5.

I.4 Energy Used to Enrich Uranium

To estimate greenhouse gas emissions due to uranium enrichment, per unit of electricity output from nuclear power plants, one must know the amount and kind of energy used to enrich uranium, per unit of output from nuclear plants. The amount of energy used to enrich uranium is a function of the enrichment technology and the degree of enrichment desired. In the following paragraphs, I analyze the amount of energy (electricity) required to enrich uranium, per unit of electricity output from power plants (using current technology), and the source of the electricity used for enrichment. I also discuss future enrichment technology.

There are at least two ways to estimate the amount of electricity required to enrich uranium (using current technology), per unit of electricity output from nuclear power plants. One way is to correlate total energy use by uranium-enrichment facilities over a period of years with total electricity output from nuclear power plants over the same period of years. The other way is to estimate electricity requirements per unit, called a separate work unit (SWU), and then estimate the relationship between SWUs and electricity output.

I.4.1 Method 1

Table I.6 shows the electricity consumed (in MWh) by the three DOE gaseous diffusion plants (GDPs) from October 1, 1979, to September 30, 1989 (data transmitted by Lee Ewing, EIA, Washington D.C., October 12, 1989). The consumption data are for fiscal years, October 1-September 30. However, these data do not represent total enrichment services required by U.S. nuclear power plants, because, on the one hand, it appears that about 8% of the enrichment service at the GDPs is for the military, not for power plants (USDOE, *Uranium Enrichment Enterprise, Operating Plan*, 1989), and that about 30% is for foreign customers (EIA, *World Nuclear Fuel Cycle Requirements 1990*, 1990). On the other hand, about 12% of the total U.S. enrichment requirements are handled by EURODIF in France. I adjust the total electricity consumption at the GDPs accordingly and divide by net nuclear electricity generation in the United States. The results are shown in Tables I.6 and I.3.

TABLE I.5 Nuclear Transportation by Truck

Mill to converter	
Tons of U_3O_8 moved	17,500
Total tons/tons U_3O_8	1.500
Average miles	1,000
Calculated ton-miles	26,250,000
Btu/ton-miles	2,500
Calculated quads	0.000066
Converter to enricher	
Total tons/tons U_3O_8	2.240
Average miles	500
Calculated ton-miles	19,600,000
Btu/ton-miles	2,500
Calculated quads	0.000049
Enricher to fabricator	
Total tons/tons U_3O_8	0.580
Average miles	800
Calculated ton-miles	8,120,000
Btu/ton-miles	2,500
Calculated quads	0.000020
Fabricator to reactor	
Total tons/tons U_3O_8	1.010
Average miles	500
Calculated ton-miles	8,837,500
Btu/ton-miles	2,500
Calculated quads	0.000022
Reactor to burial	
Total tons/tons U_3O_8	1.450
Average miles	1,000
Calculated ton-miles	25,375,000
Btu/ton-miles	2,500
Calculated quads	0.000063
Reactor to repository	
Total tons/tons U_3O_8	1.450
Average miles	1,200
Calculated ton-miles	30,450,000
Btu/ton-miles	2,500
Calculated quads	0.000076
Total quads used	0.000297
Total quads used/ quads power output	0.000192

Notes: The tons/ton U_3O_8 are from Table I.4. The mileage data are from maps and Rotty et al. (1975). The Btu/ton-miles are based on data in Rose (1979).

I.4.2 Method 2

The work required to separate or enrich uranium is expressed in SWUs. The SWU is defined mathematically in terms of the concentration of U-235 in the input uranium stream, the concentration in the output uranium fuel (enriched) stream, and the concentration in the output waste (depleted) stream. The greater the difference between the concentration of U-235 in the waste (tails) and product streams (that is, the more separation required), the more SWUs are required.

Rotty et al. (1975) reviewed estimates of the amount of electricity required to produce an SWU and came up with a range of 2.3-2.8 MWh, with 2.4 being the best estimate for future plants. Davis et al. (1982) also use 2.4 MWh/SWU. The DOE's operating plan for uranium enrichment (USDOE, *Uranium Enrichment Enterprise, Operating Plan*, 1989) assumes about 2.4 MWh/SWU.

TABLE I.6 Electricity Consumption at DOE Gaseous Diffusion Plants

Fiscal Year[a]	Oak Ridge (MWh)	Paducah (MWh)	Portsmouth (MWh)	Total (MWh)
	7,223,485	11,670,256	6,466,896	25,360,637
	6,156,606	9,361,670	6,872,044	22,390,320
	6,151,119	9,392,777	6,869,443	22,413,339
	6,154,676	9,417,035	6,875,144	22,446,855
	6,190,048	9,275,480	9,668,732	25,134,260
	3,149,289	7,537,087	13,270,483	23,956,859
	0	6,435,620	11,348,198	17,783,818
	0	5,168,770	12,350,134	17,518,904
	0	4,641,663	8,969,234	13,610,897
	0	6,390,212	13,394,543	19,783,755
	0	10,385,566	16,591,959	26,077,525
Total				2.375×10^8
Adjustment factor (accounting for military use and foreign enrichment)				0.0705[b]
Net MWh generation, 1980-1990				4.277×10^9[c]
MWh enrichment/MWh generation				0.0392[d]

[a] The fiscal year (FY) is October 1 to September 30. The data shown are from October 1, 1979, to September 30, 1990.

[b] Not all of the energy used at the GDPs went to enrich energy for U.S. power plants, and not all U.S. utility-uranium is enriched at the U.S. GDPs. This factor accounts for this. It appears that about 30% of the SWUs provided by the U.S. GDPs are for foreign utilities, primarily Japanese (based on data in EIA, *World Nuclear Fuel Cycle Requirements 1990*, 1990), and that about 8% of the SWUs are for the military (USDOE, *Uranium Enrichment Enterprise, Operating Plan*, 1989). On the other hand, U.S. utilities have about 12% of their uranium enriched overseas (EIA, *Uranium Industry Annual 1987*,1988). This indicates that 62% of the work of the U.S. GDPs (100% minus 30% for foreign utilities, minus 8% for military) went toprovide 88% of the U.S. total nuclear power generation (100% minusthe 12% derived from foreign enrichment). (0.62/0.88 = 0.705)

[c] From Table I.3. The data are from January 1, 1980, to December 31, 1990. This period is shifted four months ahead of the FY period data for enrichment, but this is acceptable because there is a lag between enrichment and generation.

[d] MWh enrichment multiplied by the adjustment factor, divided by MWh generation.

Notes: Electricity consumption data from Lee Ewing (1989, 1991).

It is more difficult to estimate the relationship between SWUs and net nuclear generation. The SWUs, of course, cost money, and there is a trade-off between SWU cost and natural uranium cost: one can produce a given amount of U-235 with a lot of SWUs and a little natural uranium, or with a lot of natural uranium and a few SWUs. If SWUs are cheap and natural uranium is expensive, it is worthwhile to use a lot of SWUs to get as much U-235 from the natural uranium as possible and thereby minimize the amount of natural uranium required. On the other hand, if natural uranium is cheap and SWUs are expensive, then it is better to conserve SWUs by feeding a lot of natural uranium to the process and separating it less. (This discussion is illustrative; in practice, there are upper and lower limits on the concentration of U-235 in the enriched uranium, and these bound the cost trade-off. The cost trade-off is very real, however, and genuinely complicates predictions of SWU requirements.)

Because of these trade-offs, any relationship between SWUs and electricity output must be built on economic models. One of the most detailed models available is the EIA's International Nuclear Model (INM), which projects the SWU and uranium requirements associated with the amount of net nuclear generation projected by the EIA's World Integrated Nuclear Evaluation System (WINES) model (see notes to Table I.3). Table I.3 shows the EIA's historical (back-projected) and projected relationships among U_3O_8, SWUs, and net nuclear generation. Note that the EIA projects that fewer and fewer SWUs will be needed to produce a MWh of nuclear power. This is partly because the EIA projects that utilities will use enriched fuel more efficiently by increasing their burn-up rate, and partly because the EIA assumes no new capacity additions through 2010.

Method 2, using MWh-enrichment/SWU and SWU/MWh-net-generation data, yields a slightly higher MWh-enrichment/MWh-net-generation value than does Method 1 (Table I.3). Because of the uncertainty of the adjustments of Method 1, I use the Method 2 results. Specifically, I use the EIA projections of SWUs required and MWh generated from 1990 to 2010 to calculate my year-2000 base-case values.

Part of the difference between the two methods is that the EIA model does not allow for uranium stocks, whereas the actual demand for SWUs incorporates changes in uranium stocks. Technically, one should count stocks, since stock requirements are "real" and a form of consumption. That is, one should assign to electricity generation not only the amount of uranium (and SWUs) actually consumed in reactors over a period of time but also the total average uranium stock maintained. For practical purposes, stocks can be ignored if (a) the average stock level is small compared with the aggregate consumption over many years or (b) if it can be assumed that eventually stocks will be consumed. I ignore stocks.

I.4.3 Future Enrichment

As noted above, enrichment technologies other than gaseous diffusion are available (gas centrifuge) or under development (laser isotope separation). Both of these processes use considerably less electricity to enrich uranium than does gaseous diffusion, which requires considerable electricity to drive the compressors to move the uranium gas through the filters.

According to Davis et al. (1982), centrifuge and U-AVLIS technologies use about 0.1 MWh/SWU, compared with 2.4 MWh/SWU for gaseous diffusion.

Because U-AVLIS probably will not come on line before the turn of the century, I assume that in the year 2000, all enrichment will be done at GDPs. However, new enrichment capacity would be required in a large nuclear-power program in the future, and this would likely be supplied partly by U-AVLIS technology or something similarly efficient. I consider the use of U-AVLIS in scenario analyses for hydrogen and electric vehicles using nuclear energy.

I.4.4 Improvements in the Efficiency of Generating Plants

There is ample room for nuclear utilities to increase the amount of electricity they generate from a unit of heavy metal input (EIA, *World Nuclear Fuel Cycle Requirements, 1990*, 1990). The two basic ways to improve this measure, called "the burn-up rate," are to increase the concentration of U-235 and to redesign the fuel rods. Increasing the concentration of U-235 requires work, in the form of extra SWUs, but the energy payoff in greater efficiency generally exceeds the energy cost of the extra SWUs. The EIA's projections for SWU use and electricity use assume a steady improvement in the burn-up rate. Hence, efficiency improvements are built into the year-2000 estimates used here.

I.4.5 Electricity Mix for Uranium Enrichment

The mix of fuel input to the electricity plants supplying the DOE enrichment facilities can be estimated quite accurately. According to DOE (USDOE, *Uranium Enrichment Enterprise, Operating Plan*, 1989), the Portsmouth facility contracts with the Ohio Valley Electric Corporation (the contract will be renewed in 1992), and the Paducah facility has a contract with Electric Energy Inc. through the year 2005. Each of these utilities owns one large coal-fired plant (EIA data transmittal, 1990). The DOE facilities have access through these utilities to regional power markets, but about 90% of the power in Ohio and Kentucky comes from coal (see Table D.1). Thus, it appears that the DOE gaseous diffusion facilities will be using nearly 100% coal-based power for the foreseeable future.

As noted above, the GDP of EURODIF satisfies about 12% of the U.S. enrichment needs. I assume that EURODIF draws power from the French national-average power mix, which is dominated by nuclear power (EIA, *Energy Balances of OECD Countries 1986-1987*, 1989). The model thus weights the Kentucky power mix by 88% and the French power mix by 12%. The final results are shown in Table I.7.

For simplicity, I assume that this mix will remain the same in the future, even if new enrichment technologies come on line. This amounts to assuming that U-AVLIS plants would be located where the electricity mix is the same as in the area of the GDPs.

TABLE I.7 Net Energy Analysis of Nuclear Power: Results of Rotty et al. (1975) and Mortimer (no date)

Stage in the Cycle	10^6 Btu of Total Energy[a] per 10^6 Btu of Electricity from a Nuclear Power Plant[b]		
	Rotty et al. (1975)	Mortimer (no date)[c]	This Report
Mining and milling	0.0101	0.078	0.0053
Conversion	0.0118		
Enrichment	0.0469		0.0396
Fabrication	0.0044		
Power plant (construction and auxiliary power)	0.0292		
Waste storage	0.0003		
All fuel and waste transportation	0.0005		0.00019
Conversion + enrichment + fabrication + storage	0.0634	0.048	0.0415

[a] Electricity counted at 3,412 Btu/kWh.

[b] For a 1,000-MW pressurized-water reactor (PWR) operating for 30 years at 75% of rated capacity (in the Rotty et al. report and this report) and a 1,000-MW PWR operating for 35 years at 62% (in the Mortimer report). The capacity and lifetime differences do not matter, because the energy input/ output ratio is of interest and if the output changes, the input should change proportionately.

[c] Mortimer (no date) estimates that fuel enrichment and fabrication produces 6.71×10^6 metric tons of CO_2, and uranium mining and processing produces 0.689×10^6 metric tons over the life of a 1,000-MW PWR. He uses 210 metric tons CO_2/TJ-electric for the electricity in the United Kingdom and 64 metric tons/TJ for thermal fuels, on average. Assuming a 45/55 power/thermal-fuel mix for the mining and milling stage (Table I.1) and a 95/5 mix for the enrichment and fabrication stage, I back-calculate 33,100 TJ/yr for fuel enrichment and fabrication and 5,312 TJ/yr for mining and milling. The total plant output is 683,618 TJ/yr. Mortimer assumes that 90% of the uranium is enriched by gaseous diffusion and 10% by gas centrifuge.

Notes: My estimates (this report) are from EIA publications, DOE (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*, 1983), and other sources (see text).

I.5 Fuel Used by Conversion and Fabrication Facilities, Auxiliary Boilers, and Standby Generators at Nuclear Power Plants

The DOE (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors,* 1983) gives data on fuel consumption by conversion and fuel fabrication plants. Rotty et al. (1975) estimated a considerably higher figure, but they included energy embodied in chemicals used at the facilities and in the materials of the facilities. I use the DOE values. My assumptions and the findings of Rotty et al. (1975) are compared in Table I.7.

Nuclear power plants use auxiliary steam generators, running on diesel fuel, to provide clean steam for start-up and in-plant heating. In addition, the Nuclear Regulatory Commission (NRC) requires periodic testing of on-site diesel generators to provide power for safety equipment in the event of a loss of power from the reactor (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*, 1983). The DOE (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*, 1983) cites an estimate of 109 tons of sulfur oxide (SO_x) per year from diesel-fuel generators and boilers. This means that, given its assumption of 0.5% sulfur and 100% sulfur dioxide (SO_2), 3.1×10^6 gal of diesel fuel were burned, producing about 1,500 g $CO_2/10^6$ Btu of power from the plant. Similarly, Meridian Corporation (1989), using a 1981 version of the DOE *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors* (1983), estimates 1,558 g $CO_2/10^6$ Btu of power produced by the reactor. However, Rotty et al. (1975) stated that a 1,000 MW pressurized-water reactor operating at 75% capacity would use only 90,900 gal of diesel fuel per year, which would result in only 40 g $CO_2/10^6$ Btu of net power from the reactor.

I follow the DOE *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors* (1983) and assume that 0.15 gal of diesel fuel are used per 10^6 Btu of power produced from the plant. I multiply this fuel use by the full fuel-cycle CO_2-equivalent emission factors for diesel-fuel industrial boilers (Table A.2). Note that the contribution of the diesel generator is much less than the contribution of enriching uranium.

I.6 The Relationship between Tons of U_3O_8 and Nuclear Power Plant Output

I.6.1 Overview

In the section about the amount of energy required to transport uranium, estimates of tonnage carried by trucks were expressed relative to a unit amount of U_3O_8. To complete that calculation and determine the total tonnage carried per unit of net nuclear power generated, one must know how many weight units of U_3O_8 are required to produce a unit of power. Knowing this, one can calculate the weight of UF_6, fabricated fuel, and spent fuel that is carried per unit of power, because the weights of UF_6, fabricated fuel, and spent fuel are known relative to the weight of U_3O_8. Knowing the total tonnage carried at each step of the cycle, per unit of power

output, allows one to calculate total energy consumption and thus total emissions of greenhouse gases, per unit of nuclear electricity delivered to the end-user.

There are two ways to calculate the relationship between U_3O_8 and electricity output: compare historical uranium consumption with historical nuclear electricity generation or use future-projected and back-projected uranium requirements and historical and projected nuclear power generation. The latter is done by the EIA with INM and WINES. The results of the EIA's modeling are shown in Table I.3. In terms of generating capacity, the result is 242 tons U_3O_8/GW of capacity (70% capacity factor) for 1977-1978, and 201 tons U_3O_8/GW of capacity for the 1990-2010 period. I use the 1990-2010 figures here because I use the same EIA modeling results to determine the relationship between SWUs and electricity output, and because the historical EIA modeling results are reasonably close to other results.

I.6.2 Comparison of the EIA Modeling Results with Other Estimates of U_3O_8 Requirements per Electricity Output

The EIA modeling estimates of yearly uranium requirements can be compared with a short data series of actual uranium requirements, and the EIA-data-based tons U_3O_8/GW-annual capacity can be compared with other estimates of the same value.

I.6.2.1 Actual Uranium Use

Actual usage of U_3O_8 can be calculated as the amount of uranium sent by utilities to domestic and foreign enrichers, plus any natural uranium exchanged for enriched uranium, plus imported enriched uranium or fabricated fuel, less exports of enriched uranium or fabricated fuel. The EIA (EIA, *Uranium Industry Annuals* for 1984 through 1988, 1985-1989) reports the uranium sent to domestic and foreign enrichment plants, including exchanges of natural for enriched uranium, for the years 1984 to 1988. They do not report imports or exports; however, I assume that these are near zero. Table I.8 shows the actual uranium requirements calculated from the EIA data.

The INM back-estimates of uranium requirements for the years 1984-1988 (the only years for which there are data on the total amount of uranium enriched for U.S. utilities) are close to the actual amount of uranium enriched for those years — as close as were the utility projections for each of those of years — projections that were made the year before the actual occurrence (Table I.8). For this reason, I use the INM forward- and back-projections for both SWUs and uranium requirements.

I.6.2.2 Other Estimates of Tons of U_3O_8/GW

Table I.9 compares the EIA-based estimate with other estimates of tons of U_3O_8/GW. The EIA value for 1977 to 1988 is consistent with other estimates. The projected improvement for 1990-2010 is due to the projected increase in the burn-up rate and the absence of new capacity.

TABLE I.8 Actual and Projected Uranium Enrichment Requirements, 1984-1988 (10^3 tons)

Year	Amount of Uranium Actually Enriched[a]	Back-Projection of INM[b]	Utility Projection Made the Prior Year[a]
1984	14.15	15.0	17.0
1985	17.00	16.3	19.1
1986	15.35	18.3	16.2
1987	14.50	17.5	18.0
1988	15.40	18.5	17.0

[a] EIA, *Uranium Industry Annual* (various years).

[b] EIA, *World Nuclear Fuel Cycle Requirements 1988* (1989).

Notes: The data for 1983 are incomplete (EIA, *Survey of United States Uranium Marketing Activity 1983*, 1984): imports and exports are not shown, and it is not clear if there were any deliveries to foreign enrichers and, if so, if they were included. For 1977-1982, the EIA, in *Survey of United States Uranium Marketing Activity 1983* (1984), reports only deliveries of uranium to DOE enrichment plants by domestic utilities and inventory levels. It is not clear if the data on delivery to DOE enrichment plants from 1977-1982 actually include deliveries to foreign enrichment plants, if there were any such deliveries (from 1984-1988, about 3×10^6 lb of U_3O_8-equivalent were sent to foreign enrichment plants), or if the data include exchanges of natural for enriched uranium (the 1984-1988 data do not include this information).

I.7 Adjusted Net Nuclear Electricity Consumption (or, Nuclear Power Available for the Transportation Sector)

Recall that the ultimate objective is an estimate of grams of greenhouse gases emitted per 10^6 Btu of nuclear power available to power automobiles. The amount of nuclear power available to transportation is slightly less than the amount of nuclear power generated because a portion of nuclear generation is used in the nuclear fuel cycle itself to mine, mill, convert, enrich, fabricate, and dispose of uranium. This internal or "own" use of nuclear power must be deducted from net generation to arrive at the amount of nuclear power that actually leaves the system and is available for cars.

TABLE I.9 Tons of U_3O_8/GW Capacity (70% capacity factor)

Reference	Estimate
USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control* (1983)	214
USDOE, *Status of the Uranium Industry* (1985)	215[a]
USDOE, *Energy Technologies and the Environment, Environmental Information Handbook* (1988)	215[b]
U.S. Congressional Research Service (1977)	225[c]
EIA, *World Nuclear Fuel Cycle Requirements* (1989), data for 1977-1988	242
EIA, *World Nuclear Fuel Cycle Requirements* (1989), data for 1990-2010	201
Nuclear Assurance Corporation (U.S. Congressional Research Service, 1977)	267
Rotty et al. (1975)	~280[d]
Nuclear Assurance Corporation (U.S. Congressional Research Service, 1977), pre-1976	348[e]

[a] It is not clear if initial core loading is included in this estimate.

[b] Drawing on information similar to that in USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control* (1983), this source states that 33-34 tons of enriched UO_2 (containing 3.3% U-235) are needed for one GW (70% capacity factor). Given that (a) the enrichment process increases the weight percentage of U-235 about 5 times above its natural value, (EIA, *Uranium Industry Annual*, 1989), (b) 10-15% of the tons are lost during enrichment (USDOE, *Status of the Uranium Industry*, 1985), and (c) uranium is 84.7% of U_3O_8 (but 88.1% of UO_2), about 200 tons of U_3O_8 would be required for the GW of power (apparently excluding the initial loading). Adding an initial loading of about 500 tons, spread over 30 years, brings the total to about 215 tons/GW.

[c] It states that 35 metric tons of enriched uranium are needed to supply one GW of power, but it apparently assumes an 80% capacity factor. Scaling this down linearly to 70%, converting to English tons, and converting from uranium to UO_2 gives 38 tons of UO_2 per GW, or about 225 tons U_3O_8. It is not clear if the initial loading is included.

[d] The value depends on the type of nuclear power plant, the tails assay, and more. This is a roughly representative number.

[e] This is not an estimate of the lifetime average ton/GW requirement; it is an estimate of the actual tons loaded/GW prior to 1976. An estimate like this, which covers the first few years of the life of power plants, will be higher than an average estimate covering the whole life, because more fuel is loaded initially, in the first year, than is consumed in subsequent years (about 25% of the initial loading is replaced every year). By 1976, most plants were relatively new, and none had reached the end of their lives. Thus, the high estimate here reflects the influence of the initial core loading.

Notes: Estimates include initial core loading and are estimates for the lifetime of a power plant, unless otherwise noted.

The EIA (EIA, *Commercial Nuclear Power 1989, Prospects for the United States and the World*, 1989) reports and projects net generation by nuclear power plants. Net generation is power that leaves the plant and is available for off-site users. It is equal to the gross production coming from the generators minus electricity use by the nuclear power station, which is about 5% of gross production. All of the EIA's electricity figures are based on net generation.

The amount of nuclear-based electricity used in the mining, processing, enrichment, and disposal of nuclear fuel is equal to the total amount of electricity used at each of these steps multiplied by the share of the total from nuclear power plants. The total amount of power used to mine and mill uranium is shown in Table I.1. Data on the share of enrichment power from nuclear power plants is shown in Table 7. (For uranium mining, I assume the national average power mix.)

I.8 Net Energy Analysis of Nuclear Power: Comparison with Rotty et al. (1975) And Mortimer (No Date)

In 1975, Rotty et al. published a comprehensive energy analysis of the nuclear power cycle. In this analysis, for every stage from mining through disposal of nuclear waste, they counted direct energy inputs; energy embodied in manufacturing, assembling, and transporting materials; energy used in construction; and energy embodied in the chemicals used in uranium mining (sulfuric acid) and treating wastewater. If their study were up to date, I would have used most of their results without doing any original calculations. Unfortunately, the study is rather old, but it is still useful to compare the results of their analysis with the numbers calculated here (see Table I.7).

The estimates of energy requirements calculated here are somewhat lower than the other estimates of Table I.7. There are several reasons for this. First, my estimates are based on the EIA projections of SWU and uranium requirements and electricity output for the year 2000, and the EIA projects that nuclear power plants will use nuclear fuel increasingly more efficiently. This reduces the amount of uranium required to produce a unit of power from the plant, and so reduces the amount of uranium that must be mined, transported, and processed, per unit output.

Second, the EIA projections of uranium and SWU requirements are for existing plants that are well beyond their initial core loading, whereas the other estimates are for the average uranium and SWU requirements over the life of a nuclear plant. The life-cycle estimate will be higher because it accounts for the initial core loading, and the initial loading requires more uranium than subsequent core replacements. Since the EIA assumes no new capacity through 2010, its estimates effectively exclude the effect of the initial core loading. This also reduces the amount of uranium required to produce a unit of power from the plant.

In addition, the difference between the estimates for transportation are due in part to the use of a higher Btu/ton-mi figure for trucks in Rotty et al. (1975). The difference between the combined figures for conversion, enrichment, and fabrication is due partly to the much higher value for conversion in Rotty et al. (1975), which results from their inclusion of the energy

required to make the conversion plant. Finally, the difference between the estimates for mining and milling are due partly to my use of the relatively low figure for 1987.

In a scenario analysis, I consider a lower average burn-up rate, the addition of new power plant capacity, and the 1982 mining and milling energy requirements.

Mortimer (no date) has published the results of a net energy and carbon dioxide (CO_2)-emission analysis of the nuclear fuel cycle. Although the paper does not contain details (details are included in his earlier papers), his results are close to mine (Table I.7).

The analysis of energy use and CO_2 emissions in Mortimer (no date) is especially interesting because it shows how quickly energy use and emissions increase as uranium ores of progressively lower quality are used. As the concentration of uranium in the ore decreases, the energy required to mine and process the ore increases dramatically. In fact, Mortimer (no date) shows that a nuclear fuel cycle based on very low-grade ore, less than 100-ppm uranium oxide, or 0.01% (0.1-0.3% typical values for today), will produce as much CO_2 as a fossil-fuel cycle with the same electricity output. This suggests that it may be energetically and environmentally unsound to use very-low-grade uranium ores.

Appendix J:

Methanol from Coal and Natural Gas

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J.1 Overview

Methanol is now the most widely promoted alternative transportation fuel in the United States, but this popularity is very recent. Throughout the 1970s and early 1980s, the preferred option for replacing petroleum was petroleumlike synthetic fuels made from coal and oil shale. Methanol was considered an inferior option partly because it was thought that, because natural gas was in short supply, methanol would have to be made from coal. The main argument against methanol, though, was that it was too different from petroleum. Methanol would require new or modified distribution systems and vehicles, whereas synthetic crude could simply be added to natural crudes at refineries, helping oil companies maintain the usefulness of present investments and insulating consumers from change.

In the early 1980s, perceptions began to shift, motivated by three new insights: first, the cost of manufacturing petroleumlike fuels was greater than had been anticipated; second, natural gas was more abundant than had been thought; and third, petroleumlike synthetic fuels did not help reduce persistent urban air pollution. Today, the air quality problem is perhaps most salient, and many cities and the Environmental Protection Agency (EPA) are turning to methanol in the hope that it can help reduce urban ozone levels.

J.1.1 Feedstocks

At present, economic and environmental considerations favor natural gas over coal and biomass as a methanol feedstock. The least expensive natural gas is remote natural gas (RNG), which is gas in foreign (usually third-world) countries remote from readily accessible markets that is priced at about $1.00 per 10^6 Btu or less. Initially, methanol would be made in these low-cost, gas-rich countries and imported to the United States. Eventually, the price would be high enough to make domestic gas, and then coal and biomass, competitive as feedstocks. The location of the natural gas feedstock is important in a greenhouse analysis because it determines how far methanol must be transported and how much energy is used.

J.1.2 Greenhouse Gas Emissions from Methanol Use

Greenhouse gases are emitted from the production and transmission of the feedstock coal or gas, the conversion of the coal or gas to methanol, and the distribution of the methanol to end-users, primarily by ship and truck. Each of these is discussed in the following sections.

J.2 Greenhouse Gas Emissions from the Recovery and Transport of Feedstock

Greenhouse gas emissions from the recovery and transport of feedstock are estimated as:

$$G_{m\text{-}s} = G_{c,n\text{-}s} \times E \times (1 + T) \times (1 + L)$$

where:

$G_{m\text{-}s}$ = grams of greenhouse gases at stage s (recovery or transport of the feedstock) per energy unit of methanol consumed by vehicles,

$G_{c,n\text{-}s}$ = grams of greenhouse gases emitted at stage s per energy unit of coal or natural gas delivered to conversion facilities,

E = coal or natural gas energy required per unit of methanol energy produced,

T = energy units of methanol consumed by delivery trucks per energy unit of methanol delivered to vehicles, and

L = amount of methanol lost to evaporation per energy unit of methanol delivered to vehicles.

These variables are treated as follows:

1. The calculation of $G_{c,n\text{-}s}$, greenhouse gas emissions from the recovery and transport of coal and natural gas per unit of energy made available to end-users, is detailed in the appendices on coal and natural gas. In this case, the methanol conversion facility is treated as an end-user of coal and natural gas. In the calculation of the amount of energy required to transport natural gas to a methanol plant, I assume a shorter transmission distance from a gas field to a methanol plant than from a typical gas field in the United States to a typical end user. ICF Resources, Inc. (ICF, *Estimates of the Cost of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990) estimates that there would be 400 to 1,000 miles of pipeline from a field flaring gas to a methanol-production plant, a distance that is considerably less than the distance from the major gas fields in the Gulf Coast of the United States to major end users in the northeastern United States. ICF also assumes that the amount of energy consumed by a pipeline compressor is proportional to the transmission distance. Accordingly, I assume that pipelines delivering gas to methanol plants would be 40% as long as pipelines currently delivering gas to end users in the United States, and that energy consumption by pipeline compressors is proportional to the total transmission distance.

I assume that methanol plants would not be connected to low-pressure distribution lines.

In the coal-to-methanol case, I assume that the methanol plant would be located at a major coal field in the United States.

2. The amount of coal or natural gas required per unit of methanol produced is estimated in the following sections in this appendix, which analyzes a large body of literature.

3. The variable T, which reflects the use of methanol to deliver methanol, is, of course, unknowable today. I leave it as a variable in the model. In the base case, I assume no methanol is used.

4. The variable L, the liquid loss factor, is calculated from an estimate of the amount of methanol spilled or evaporated from ships, marine terminals, bulk terminals, trucks, and service stations, per gallon of methanol delivered. This factor is estimated in Appendix B.

5. The g/10^6 Btu estimate, $G_{m\text{-}s}$, is converted to g/mi by multiplying by 10^6 Btu/mi. (10^6 Btu/mi is calculated as described in Appendix A.)

J.3 The Conversion of Natural Gas to Methanol

The conversion of natural gas to methanol produces carbon dioxide (CO_2) from the use of natural gas as a process fuel, methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO), and nonmethane hydrocarbons (NMHC). The use of purchased electricity also produces greenhouse gas emissions.

CO_2 emissions from the methanol-production facility are calculated as:

$$3.66666 \times (C_n - C_m - C_o)$$

where:

C_n = carbon in the input natural gas per unit of methanol output,

C_m = carbon in a unit of methanol output,

C_o = carbon emitted in CH_4, CO, and NMHC per unit of methanol output.

The difference between the carbon in the input natural gas and the carbon in the output methanol can be calculated from the ratio of the natural gas energy input to methanol energy output, which is discussed in considerable detail below.

Methane, CO, NMHC, nitrogen oxide (NO_x), and N_2O emissions per unit of fuel output are calculated as the product of emissions per energy unit of feedstock input and the ratio of input energy to output energy. Intech (1990) reports CO, NO_x, and hydrocarbon (HC) emissions from methanol plants. I use these values here. Data on methane, NO_x, CO, and NMHC emissions from plants producing methanol and other products (Texas Air Control Board, 1990), combined with data on the production capacity of methanol facilities (U. S. Department of Commerce, 1985), indicate that the Intech (1990) estimates may be low. Nevertheless, I use the Intech (1990) estimates.

There are no published data on emissions of N_2O and methane from methanol production plants. Steam-reforming and the burning of natural gas as a process fuel will produce some N_2O. Because large amounts of natural gas are handled, there will be some methane emissions. The numbers in Table A.2 are rough estimates. Note that I assume lower N_2O emissions from methanol production plants than from petroleum refineries.

My assumptions (in g/10^6 Btu-input; the values given above are in g/10^6 Btu-output) are shown in Table A.2. I subtract the carbon emitted as CO, NMHC, and methane from the input carbon before calculating CO_2 emissions.

Note that the efficiency of the conversion of natural gas to methanol is doubly important: it determines the amount of CO_2 emissions from the conversion process and the amount of natural gas that must be produced and transported, per unit of methanol output. Because of this importance, I discuss the conversion process and its efficiency in detail.

J.3.1 Description of the Conversion Process

In most modern methanol plants, methanol is produced in three major steps: gasification, methanol synthesis, and distillation. In the first step, natural gas is reformed with steam into CO and water:

$$CH_4 + H_2O \text{ ---> } CO + 3H_2$$

This production of synthesis gas via steam reforming requires relatively high-pressure steam and high reaction temperatures. These high pressures and temperatures are generated by burning supplemental natural gas, excess hydrogen, and purged synthesis gas and by recapturing waste heat from the reforming process.

The initial steam reforming produces a gas with a 3:1 hydrogen-to-carbon ratio. Since methanol synthesis requires a 2:1 ratio, the reformed gas is actually carbon deficient. In general, there are two ways to make up this deficiency: either add carbon, typically in the form of CO_2, which is attractive if a cheap source of CO_2 is available (methanol plants are sometimes integrated with ammonia plants, because the manufacture of ammonia is similar and produces excess CO_2), or burn the excess hydrogen to provide heat for the steam reforming reaction.

In any case, because of the scarcity of carbon, the methanol synthesis reaction (the second major stage of the process) is repeated several times until about 90% of the carbon in the CO in the synthesis gas is converted to carbon in the methanol product. The methanol synthesis reaction is:

$$CO + 2H_2 \text{ ---> } CH_3OH$$

In this reaction, the syngas is passed over a catalyst that accelerates the conversion of the reactants to methanol. First-generation methanol plants used relatively ineffective catalysts and had to operate at 250-350 bars and 320-400°C, in the synthesis stage, to convert syngas to methanol at an acceptable rate. Modern plants use catalysts active at lower temperatures and pressures: 50-100 bars and 230-280°C (Chem Systems, 1988).

The methanol synthesis reactor converts about half of the synthesis gas to methanol on the first pass, thus producing a mixture of gaseous methanol and unconverted syngas. The mixture of unconverted syngas and gaseous methanol is cooled, and the methanol condenses out and is removed. The unconverted syngas is then reheated and pressurized and passed back through the reactor. This recycling continues until most of the carbon is converted to methanol. In most systems, synthesis gas and waste heat provide the energy, including electrical energy, needed to reheat and repressurize the unconverted syngas.

In the third stage, minor unwanted components are removed from the raw liquid methanol (out of the synthesis reactor) to provide methanol of chemical-grade purity. The volatile components (CO, methane, aldehydes, ketones, etc.) are removed from the raw methanol in a "topping" column, and the water, ethanol, and higher alcohols are removed in a refining column. The refining column uses much more energy (primarily low-pressure steam) than the topping column (Thiagarajan and Ilgner, 1984).

The natural gas and power requirements of current-technology methanol production plans are shown in Table J.1.

J.3.2 Areas for Process Efficiency Improvement

There are several major ways to improve the efficiency and/or lower the cost of methanol production: develop catalysts that are more effective at lower temperatures and pressures; use waste heat and purge gases more efficiently and remove the heat of the methanol synthesis reaction more effectively; and increase the conversion of syngas to methanol.

J.3.2.1 Catalysts

The yield of methanol from the synthesis reaction increases as pressure increases and temperature decreases. At atmospheric pressure, the synthesis reaction is thermodynamically favored (has negative free energy and proceeds spontaneously) at temperatures below 140°C. However, current catalysts are not very active below 140°C (Sheldon, 1983). The upshot is that

TABLE J.1 Energy Use of Natural Gas-to-Methanol Plants

Process Description	Btu Energy In/ Btu Methanol Out: Feedstock	Power	O_2	Grade of Methanol[a]	Reference
Conventional steam reforming	1.65[b]	I	NU	F?	Korchnak (1988)
Conventional steam reforming	1.56	0.0029	NU	F?	Salmon (1986)
Conventional steam reforming	1.43-1.65[c]	I[d]	NU	C	Chem Systems (1988)
Conventional steam reforming plus low pressure synthesis	1.51[b]	?	NU	C	*Hydrocarbon Processing*, November (1989)
Steam reforming plus ICI synthesis	1.54[e]	?	NU	F?	Kuo (1987)
Steam reforming plus ICI synthesis, maximum CO_2 addition	1.47[e]	?	NU	F?	Kuo (1987)
Steam reforming plus Lurgi low-pressure synthesis	1.60[b]	?	NU	C	Marschner and Moertel (1986)
Combined steam and autothermal reforming	1.30-1.38[c]	?	?	C	Chem Systems (1988)
Combined steam and autothermal reforming	1.53[b]	I	I	F?	Korchnak (1988)
Lurgi combined steam and autothermal reforming (reforming at 780°C, 40 bar; synthesis at 240-270°C, 70-100 bar)	1.49[b]	I	I	C	*Hydrocarbon Processing*, November, p. 79 (1987)[f]
Catalytic partial oxidation plus tube-cooled methanol synthesis	1.50[b]	I	I	F?	Korchnak (1988)
Advanced partial oxidation scheme	1.33-1.43[c]	?	?	C	Chem Systems (1988)[g]
Partial oxidation with once-through liquid-phase synthesis	1.60	-0.024	I	C	Chem Systems (1990)
Direct partial oxidation	1.37-1.45[e,h]	?	I	F?	Kuo (1987)
Partial oxidation/low-temperature liquid catalyst (248°F and 194-psi in the synthesis section)	1.39[i]	-0.012[i]	NU	F?[j]	O'Hare et al. (1988)
Gas-Solid-Solid Trickle Flow Reactor (about 500 K in the synthesis section)	1.37[k]	I	NU	C	Westerterp et al. (1988)

See next pages for footnotes.

TABLE J.1 (Cont.)

[a] If the reference does not state the grade of methanol or imply a fuel grade, I assume chemical grade, since most, if not all, plants currently produce chemical-grade methanol.

[b] Based on an LHV of 56,700 Btu/gal.

[c] Based on the 10^6 Btu-natural gas/gal-methanol requirements reported in the reference (p. 12). However, the thermal efficiencies reported by Chem Systems and the 10^6 Btu-natural gas/gal-methanol requirements are not consistent on an HHV basis, which is the basis that Chem Systems claims to use. For example, Chem Systems associates 62% thermal efficiency with 0.092 10^6 Btu-natural gas/10^6 Btu-methanol on an HHV basis. However, on the basis of methanol's HHV of 64,500 Btu/gal, 0.092 implies an efficiency of 0.0645/0.092 = 70%. Conversely, 62% efficiency and 0.092 imply a heating value for methanol of about 57,000 Btu/gal, which is the LHV of methanol. Thus, Chem Systems either made a mistake in its thermal efficiency calculations, used LHVs, or did not calculate thermal efficiency and 10^6 Btu-natural gas/ gal-methanol requirements in the same way. The Chem Systems numbers (which, when interpreted as I have here, result in high efficiencies) should be considered with this in mind.

[d] A spreadsheet shows a "0" entered under "Utilities," which Chem Systems defines to be primarily purchased power.

[e] Based on LHV.

[f] The authors show a dash ("-") under "kWh of Electricity Consumed." This probably means that no (or a negligible amount of) power is purchased. The authors write that the natural gas process consumes 29.7 GJ of natural gas per metric ton of methanol; I have assumed they use LHVs. See also Marschner and Moertel (1986).

[g] Chem Systems expects that advanced plants designed to minimize capital costs will be slightly less efficient than combination reforming plants.

[h] Higher figure includes energy credit for surplus steam.

[i] The plant produces a small amount of electricity for export. The value is based on O'Hare et al.'s assumption of 64,500 Btu/gal. (The HHV of gas is not specified.)

[j] The process diagram shows a single distillation tower, which may mean a single column producing a fuel-grade product. Also, the article is about methanol as a fuel.

[k] Based on the author's claim that the process will reduce consumption of raw materials by 10-12% (I assume 11%) compared with the Lurgi low-pressure process, and assuming 1.54×10^6 Btu-natural gas/10^6 Btu-methanol for the Lurgi process.

TABLE J.1 (Cont.)

Notes: LHV = lower heating value; HHV = higher heating value.

An "I" in the "Power" column means that the electrical energy consumption is included in the feedstock energy consumption (part of the gas feed generates all of the power requirements on-site). A "?" in the "Power" column means that the amount is not specified, and that it is not clear if the power is purchased or provided by the feedstock. Power is calculated as 3,412 Btu/kWh. A negative sign in front of the figures in the "Power" column means that the process produces net power for export. In all cases, the feedstock fuel provides all of the energy needed to generate steam. An "I" in the "O_2" column means that the energy required to make oxygen is included under "Power" or "Feedstock." A "?" in the "O_2" column means that oxygen is used, but it is not clear if the energy required to make the electricity to make oxygen is included in the power consumption or feedstock consumption figures. An "NU" in the "O_2" column indicates that oxygen is not used in the process.

I assume 22.7 kJ/g or 64,500 Btu/gal HHV for methanol, and 19.95 kJ/g and 56,700 Btu/gal LHV.

the temperature must be high for the catalyst, and the pressure must be high to compensate for the thermodynamic unfavorability of the higher temperature. The successful development of a catalyst that is active at low temperatures would allow the use of lower pressures, which would save compression energy and extend the life of the plant.

J.3.2.2 Heat Management

Heat management is quite important. The synthesis reaction produces a great deal of heat which, if not removed, will degrade the catalyst. Recovering the heat effectively protects the catalyst and provides process heat for other sections of the plant.

J.3.2.3 Conversion to Methanol

Only about half of the carbon in the syngas is converted to carbon in methanol in the first pass through the reactor, so that the syngas must be recycled through the synthesis reactor. Increasing the conversion of syngas to methanol in each pass will reduce the energy used to recompress and reheat the unconverted syngas that is sent back to the synthesis reactor.

J.3.3 New Conversion Technologies

Several efficient new conversion technologies have been developed to address the issues presented in Section 3.2.

J.3.3.1 The Lurgi Low-Pressure Combined Reforming Process

The methanol synthesis reaction is highly exothermic, and if the heat it produces is not removed, the reaction slows, the catalysts deteriorate, and unwanted products form. The Lurgi process addresses this problem by wrapping the synthesis reactor in a cooling jacket filled with water; the reaction heat is transferred to the water, which boils and provides the steam to run the process. Because the temperature is reduced, the methanol content is increased and the syngas does not have to be pressurized as much to produce a given amount of methanol (compared with higher-temperature processes). Thus, the Lurgi process makes more effective use of the waste heat from the reactor and reduces compression energy requirements.

The Lurgi process also combines conventional steam reforming with a catalytic autothermal reaction: half of the natural gas feed is sent to the steam reformer, and the other half is combined with the syngas output of the reformer and reacted with oxygen over a nickel catalyst at very high temperatures (1700°C) (Chem Systems, 1988). The final syngas has a 2:1 hydrogen-to-carbon ratio, as required for methanol synthesis. It thus makes fuller use of the of methane feed and is attractive in cases where feedstock costs are high. Also, the oxidation reaction provides process heat for the reforming stage and eliminates the furnace needed to provide the heat for reforming in reforming-only processes (Energy and Environmental Analysis, *Methanol's Potential as a Fuel for*

Highway Vehicles, 1988). However, the autothermal reaction does require oxygen, and power is required to separate oxygen from the air. This must be accounted for in an energy balance.

J.3.3.2 Better Methanol Removal Systems

With conventional conversion technology, methanol removal requires water to cool the gas coming out of the reactor and energy to recompress and reheat the syngases for recycling. Dutch researchers have developed ways of removing methanol without cooling and reheating (Westerterp et al., 1988). In one system, called the Gas-Solid-Solid Trickle Flow Reactor (GSSTFR), the product formed at the catalyst surface is removed continually by a solid adsorbent, which trickles over the catalyst bed. With uniform distribution of the adsorbent and the proper flow rate, all of the methanol will be removed. This allows the reaction to progress toward completion (since the methanol is being removed as it is made) so that essentially all of the syngas can be converted in one pass. The developers estimate that the GSSTFR system reduces consumption of raw materials (presumably feed syngas gas) by 10-12% and water by 50% and produces excess steam for export.

In a similar concept, the Reactor System with Interstage Product Removal (RSIPR), methanol is removed from the product gas mixture after it passes over the catalyst (as opposed to *while* it is passing over the catalyst, as in the GSSTFR system), but at the inlet temperature of the reactor, so that the product stream does not have to be cooled. The methanol is adsorbed by a selective liquid, and the unconverted syngas passes on to a second smaller reactor (smaller because there is less gas) located just downstream of the first.

J.3.3.3 Partial Oxidation of Natural Gas*

The partial oxidation reaction:

$$CH_4 + 1/2\ O_2 \text{ ---> } CO + 2H_2$$

produces hydrogen and carbon in exactly the proportions needed to synthesize methanol, so that there is no need to add CO_2, delete hydrogen, or add an autothermal reaction (see the Lurgi low-pressure process, above) to produce the proper ratio, as there is with steam reforming. Moreover, the partial oxidation reaction is exothermic, so no fuel is required to run the reaction.

The partial oxidation reaction runs fine with air as the source of the oxygen. However, if air is used, nitrogen will be present in the syngas mixture (inert, but present), and this will make the second step, methanol synthesis, less efficient. (Recall that syngas must be recompressed after every pass through the reactor.) If the syngas contains a lot of inert gas (like nitrogen), then a lot of work is spent to heat and compress material that does not make methanol. To use partial oxidation, either the recycling must be eliminated from the methanol synthesis stage, or oxygen

*From O'Hare et al. (1988).

must be separated from air before the partial oxidation stage. Oxygen separation is expensive and wipes out the energy savings of the partial oxidation route.

Brookhaven National Laboratory has designed a low-temperature liquid catalyst system that converts 90% of the CO in the syngas to carbon in methanol in one pass through the reactor. This means that no recycling is necessary, which in turn means that the presence of nitrogen in the feed stream is of less consequence. The conversion rate is high because the catalyst is active at very low temperatures, and the lower the temperature, the higher the conversion. The unconverted gas is burned in a gas turbine that generates more power than the plant needs. All of the energy required to operate the plant is obtained from the natural gas.

J.3.3.4 Liquid Phase Methanol Synthesis

Compared with a conventional catalyst, a liquid catalyst removes the heat of the synthesis reaction better and allows a more complete conversion of syngas to methanol in one pass. This reduces the cost and complexity of conventional heat management systems and eliminates the economic and energy cost of recycling. Air Products and Chemicals (Brown et al., 1989) is testing a liquid-phase catalyst (solid catalyst powder, slurried in a hydrocarbon liquid) in a "once through" methanol synthesis plant in La Porte, Texas. The catalyst works particularly well with synthesis gas produced from coal gasification. No estimates of overall efficiency are available.

J.3.3.5 Direct Methane Conversion

As discussed above, the conventional natural-gas-to-methanol process has two steps, reforming and synthesis. However, it is possible to directly convert methane to methanol without the energy-intensive reforming step via direct partial oxidation, a process in which methane is reacted with an oxidant (typically oxygen or N_2O) either catalytically or noncatalytically. In one of the more promising processes, methane and oxygen react in a glass-lined, noncatalytic reactor at 65 bars and 458°C. If high yields of methanol can be sustained from this process, it may be more efficient and less costly than conventional reforming. The best results to date show that about 83% of the natural gas can be converted to methanol (Gray et al., 1988).

Methane also can be directly converted to methanol by biological processes. Certain organisms, called methanatrophs, derive energy by oxidizing methane to CO_2 and water. Under normal conditions, methanol is an intermediate, not a final, product in this process. However, the process can be manipulated so that methanol accumulates as the final product. This conversion process has several potential advantages: it takes place at ambient temperatures and pressures, is not capital-intensive, and can convert nearly all methane to methanol. Work in this area is underway (Corder et al., 1988).

Table J.1 summarizes the energy requirements of most of these new and developing technologies. Note that all of them use less energy than conventional steam-reforming and methanol synthesis. These technologies are featured in scenario analyses.

J.3.4 Issues in Calculating the Energy Consumption of Natural Gas-to-Methanol Plants

Before the energy efficiency estimates of Table J.1 can be applied to making methanol as a motor fuel, three issues must be addressed: power requirements, oxygen requirements, and the difference between chemical-grade and fuel-grade methanol.

J.3.4.1 Power Requirements

Methanol plants may purchase electricity or use waste heat to boil water to run a steam generator. Technically, one should estimate the power consumption of plants that purchase electricity and include it in the overall energy efficiency estimate, both for the sake of completeness and for fair comparison with the plants that generate their own power. However, power consumption at methanol plants is such a small portion of total energy use that this exercise probably would not be worthwhile. The U. S. Department of Commerce (USDOC) (1985) notes that "fed with natural gas, a methanol plant requires little additional external energy" (p. 7). Researchers at Davy McKee (Smith et al., 1984) show that the power used by a methanol plant producing 2,750 metric tons per day is only 0.58-0.744% of the energy content of the methanol product. Because power consumption is so small, I have ignored it where it is not included in the overall efficiency estimates.

J.3.4.2 Oxygen Requirements

Some conversion schemes, such as direct oxidation and autothermal reforming, require pure oxygen. A greenhouse or energy-use analysis should count the electricity consumed by the electric motors that separate oxygen from air (electricity requirements are shown in Table J.2). In all of the estimates of Table J.1, with the possible exception of the estimates based on the Chem Systems data, either oxygen is not used or the energy of separation is accounted for in the statistics on power use or natural gas consumption.

J.3.4.3 Fuel-Grade Versus Chemical-Grade Methanol

It takes slightly less energy to make fuel-grade methanol than to make chemical-grade methanol, because the higher alcohols and ethers can be left in the methanol if it is to be used as a fuel. This permits the use of a single distillation column rather than the two required to distill chemical-grade methanol (Chem Systems, 1988). Eliminating a distillation column frees up low-pressure steam. If this steam can be used in other parts of the plant or exported, and so displace other steam or energy use or provide an energy credit, total energy consumption should decrease, albeit only slightly. In theory, then, plant producing fuel-grade methanol should be slightly more efficient than plants producing chemical-grade methanol.

The energy analysis of Rosen et al. (1986) shows that the energy in the steam sent to the distillation columns constitutes 2% of the energy in the input natural gas. At most, then, making fuel-grade methanol rather than chemical-grade methanol could reduce energy consumption by about 2%. This difference should be kept in mind when considering the data of Table J.1, where I have used the results for fuel-grade methanol.

TABLE J.2 Electricity Required to Make Oxygen

kWh power/lb 100% O_2	Reference
0.211	Brown et al. (1982)
0.207	Paul et al. (1983)
0.204[a]	Lacey and Stroud (1983)
0.189	Deane et al. (1984)

[a] Given as 2,250 Btu of fuel per pound of oxygen. I assumed that 2,250 Btu of fuel produces 700 Btu of power (31% efficiency).

J.3.4.4 Conclusion: Estimating the Efficiency of Natural Gas-to-Methanol Plants

The amount of feedstock consumed by a natural gas-to-methanol plant is a critical factor in the calculation of greenhouse gases and must be estimated carefully. In estimating this efficiency, it is important to keep in mind two things. First, the efficiency of future methanol plants will depend in part on the expected cost of the feedstock. If the gas is cheap, and expected to stay cheap, it may not pay to invest extra money in energy-efficient technologies. Chem Systems (1988) notes that "it is not uncommon for recent natural gas reforming plants built in areas of the world where gas is inexpensive to be designed to consume up to 32 mmBtu/metric ton [of methanol]" (p.11), which is about 10% more than what Chem Systems reports for most modern methanol plants. Moreover, gas is usually cheapest in remote or relatively undeveloped countries, and the plants built in these places will probably rely on established, reliable technology instead of innovative and efficient unproven designs.

Second, even if future plants are considerably more efficient than the best current plants, the future average efficiency will be closer to the current efficiency until most of the plants are new. This probably will take quite some time unless there is a crash methanol development and technology-improvement program.

The upshot of this is that it is certainly *not* reasonable to assume, as an average future efficiency, the highest projected efficiencies of the best, most advanced technologies under development. In fact, for the foreseeable future, it is almost certain that new plants will use the best of proven, current technology, not the best of the unproven (technically and economically) new technologies.

The data of Table J.1 clearly indicate that the current state-of-the art efficiency is about 65% for fuel-grade methanol. An important issue to note is that the current *average* efficiency probably is noticeably less. I assume that by the year 2000 (my base-case analysis), the average efficiency will equal the current state of the art, so that methanol plants will consume 1.54×10^6 Btu of natural gas for every 10^6 Btu of methanol produced. However, I do test the effects of assuming very efficient, advanced technologies (1.4×10^6 Btu/10^6 Btu).

The reasonableness of the base-case assumptions used here is further demonstrated by comparing them with the efficiency assumptions used in several recent estimates of the future production cost of methanol. (Estimates of the cost of methanol must include an assumption regarding the efficiency of natural gas-to-methanol conversion, because the contribution of the feedstock to the production cost of methanol is the product of the $/10^6$ Btu cost of the feedstock and the ratio of 10^6 Btu-feedstock to 10^6 Btu-methanol.) Table J.3 shows several such estimates, including those done for California (Bechtel, 1989) and the U. S. Department of Energy (DOE) (Chem Systems, 1988). Their assumptions are consistent with mine.

For a long-run, best case for methanol, I assume a conversion efficiency of 71.4% (1.4 10^6 Btu of natural gas per 10^6 Btu of methanol produced).

J.4 Using Flared Gas to Make Methanol or Liquefied Natural Gas

A small amount of the gas produced in association with oil production has no use and is simply flared and, hence, wasted. If this gas were put to work instead, the work would be accomplished with virtually no emissions of greenhouse gases, assuming that the gas would have been flared were it not put to work (e.g., made into LNG or methanol). In fact, if one subtracts all of the CO_2 originally contained in flared natural gas from the life-cycle CO_2-equivalent grams-per-mile emissions from methanol vehicles, on the grounds that it would have been emitted anyway, the total fuel-cycle CO_2-equivalent emissions are greatly reduced (Table 12, Scenario 18-e).

This flared gas could be made into methanol or liquefied natural gas (LNG) for use by motor vehicles. Given the possibility of making very low greenhouse-gas-emitting methanol or LNG from flared gas, it is worth determining how much flared gas is available. If the gas is made into methanol, the amount available to the U. S. transportation sector, as a percentage of highway fuel use in the United States, can be calculated as:

$$P_y = 100 \times T_y \times P \times Ec \times US \times C \times Ef / H_y$$

where:

P_y = percentage of highway fuel demand satisfied in year Y by methanol from vented and flared gas,

T_y = total amount of vented and flared gas in year Y (in quads) in the absence of the policy to make methanol from remote gas,

P = fraction of T in countries that are willing to sell vented and flared gas to the United States and from which the United States is willing to buy (politically available variable),

Ec = fraction of politically available vented and flared gas that is worth recovering and converting to methanol (economics variable),

TABLE J.3 The Efficiency of Natural Gas-to-Methanol Conversion (as assumed in several recent cost studies)

Study	Process	10^6 Btu Natural Gas/ 10^6 Btu Methanol
California Fuel Methanol Cost Study (Bechtel, 1989)[a]	Conventional steam reforming	1.52
California Fuel Methanol Cost Study (Bechtel, 1989)[a]	Catalytic partial oxidation	1.50
California Fuel Methanol Cost Study (Bechtel, 1989)[a]	Combined reforming	1.43
California Fuel Methanol Cost Study (Bechtel, 1989)[a]	Fluidized-bed synthesis	1.40
SRI International (Schumacher, 1989)	Uses Bechtel study	1.52
EPA, *Analysis of the Economic and Environmental Effects of Methanol as an Automotive Fuel* (1989)	Uses Bechtel and other studies	1.52
USDOE (Chem Systems, 1988)	Conventional steam reforming	1.55[b]
USDOE (Chem Systems, 1988)	Advanced schemes	1.40[b]
Brandman Associates (1987)		1.55[c]
American Petroleum Institute (Lareau, 1989)		1.55
California Energy Commission (Koyama and Darling, 1988)	Catalytic partial oxidation	1.46-1.55[d]
Amoco (Wagner and Tatterson, 1987)	Conventional steam reforming	1.50

[a] Based on 1.2×10^9 gal/day capacity, as reported in the text, and a 95% capacity factor, as told to me by one of the study authors.

[b] They assume 100,000 Btu-natural gas/gal of methanol for conventional schemes and 90,000 for advanced schemes, such as combined reforming and partial oxidation, and appear to be using HHVs. I have assumed 64,500 Btu/gal HHV for methanol (Table J.1, footnote c).

[c] The authors assume 100,000 Btu natural gas/gal of methanol; I assume that they are using HHVs.

[d] The low end is for high-cost feedstock.

US = fraction of the economically and politically available gas that the United States will be able to capture (U. S. competition variable),

C = ratio of methanol energy delivered to the United States to methanol energy in the feedstock,

Ef = factor to account for the efficiency advantage of methanol, and

H_y = projected quads of petroleum highway fuel in year Y.

What is the highest percentage that variable P_y could be? Imagine an aggressive U. S. program to convert the highway fleet to methanol and develop remote methanol from natural gas. It would take 20 years to get a significant number of plants planned, built, and running worldwide and to get enough cars built and bought to use the methanol.

What is variable T likely to be in 20 years? In 1987 and 1988, world oil producers vented and flared about 3 quads of gas (EIA, *International Energy Annual*, 1989, 1991), much less than in the 1970s. This quantity will continue to decline as more and more flared gas is reinjected, exported via pipeline, exported as LNG, or used locally in developing countries. In a recent analysis of the availability of vented and flared gas, ICF (*Estimates of the Costs of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990) notes that Canada and the United Kingdom are likely to find uses for gas presently being flared; Malaysia recently has made use of most of the gas it had previously flared; Iran is planning to reinject or export more currently flared gas; Algeria is planning to increase its reinjection capability; and Nigeria is trying to discourage flaring.

The United Nations projects that in 2010, half as much gas will be flared as in 1986. This suggests that less than 2 quads will be available. I will assume 2 quads (variable T_y) to be somewhat favorable to policies emphasizing the use of vented and flared gas.

Large amounts of gas are located in countries that either will not do business with the United States or are so unstable that they make potential investors leery. The U.S.S.R., Iran, Iraq, Libya, and perhaps other countries in the Middle East might fall into this category. Thus, more than 20% of vented and flared gas may be unattractive or unavailable for political reasons. However, I assume that only 15% of the economically available gas is politically excluded, so P = 85%.

Not all of the gas will be economically attractive. After all, gas is vented and flared either because there is not enough of it (in the right place, at the right pressure) to justify recovery and use, or because there is not enough capital to develop the infrastructure needed to use the gas (see ICF, *Estimates of the Costs of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990, for examples). Presumably, much of the gas vented and flared in industrialized areas of Western countries is not worth recovering for any use. However, some natural gas-to-methanol technologies can be economical on a small scale. I will suppose that 85% (= variable Ec) of the flared gas can be economically converted to methanol.

The United States will not be the only country interested in methanol (or LNG) as a transportation fuel. Other countries will compete for the methanol, and this demand will be in addition to the factors that have reduced and will continue to reduce the quantity of wasted gas in the 1980s. Assume, though, that the United States receives 75% (variable US) of the wasted gas available for methanol (this is much larger than the U. S. share of transportation energy among the industrialized countries concerned about air quality and energy security).

Not all of the energy in the flared gas ends up in the product methanol. Some of the flared gas is used to lift, process, and transport the rest of the gas, and much energy is lost at the methanol plant. Depending on the situation and the efficiency of the methanol plant, 60-65% of the energy in flared gas will end up as energy in methanol delivered to the United States. I assume 62% (variable C).

A quad of methanol will replace more than a quad of petroleum, however, because methanol can be used more efficiently. I assume a 15% efficiency advantage (variable Ef; Appendix B).

As for variable H_y, let us assume that improvements in vehicular efficiency keep pace with increasing vehicle miles traveled (VMT) and the desire for larger, heavier, more powerful cars, so that overall highway fuel consumption remains at 16.6 quads of petroleum (Davis and Hu, 1991).

With these probably favorable assumptions, variable P, unfortunately, is fairly small -- about 5%. With pessimistic assumptions, variable P would be more on the order of 2 or 3%.

The point of this is not that we should not put otherwise wasted gas to work. We should. The point is that not much of this particular type of wasted gas is available to the United States when total U. S. demand for transportation fuels is considered.

Another promising option, from a greenhouse standpoint, is the use of landfill gas. I do not consider this here.

J.5 The Conversion of Coal to Methanol*

Emissions of CO_2 are calculated here following the method used to calculate CO_2 emissions described in Section J.3 (from the difference between input and output carbon, and accounting for emissions of non-CO_2 greenhouse gases).

Note that this method assumes that all coal carbon that does not end up in methanol, methane, CO, or NMHC emissions, ends up as CO_2. Actually, there are two nonoxidation fates for the remaining coal carbon: particulate matter or entombed tar. Particulate matter emissions are negligible. Some carbon may end up in tar, but if the tar is burned or otherwise exposed to air, the carbon will eventually end up as CO_2. The amount of carbon in tar (from coal to methanol plants)

* See Section J.3 for an explanation about the importance of the efficiency of the conversion of coal to methanol.

that is never burned or oxidized is probably negligible, too. I ignore these nonoxidation fates (although the model has the capacity to consider them).

The discussion of the use of electricity and oxygen applies here as well.

J.5.1 General Description of the Processes

Like the natural-gas-to-methanol process, the coal-to-methanol process proceeds in two stages: gasification and synthesis. The synthesis stage here is the same as the synthesis stage in the natural gas scheme. The main difference between the coal-to-methanol and natural gas-to-methanol processes is in the gasification process. The coal-to-methanol process uses much more energy than does the natural gas-to-methanol process, because the feed coal and the syngas it produces must be processed more intensively.

Several coal-conversion technologies have been commercialized or are under development. Because the widespread use of coal-to-methanol is probably a long way off, I will not discuss these technologies in detail. Instead, I will identify current commercial technology, advanced technology, and promising technologies under development and note their energy use (coal requirements per unit of methanol produced). For details on coal gasification, see Brown et al., *Eighth Annual EPRI Conference on Coal Gasification*, EPRI GS-6485, August 1989; Nowacki (ed.), *Coal Gasification Processes*, 1981; and Figueiredo and Moulijn (ed.), *Carbon and Coal Gasification*, 1986.

The so-called "first-generation" plants use the Lurgi, Winkler, or Koppers-Totzek processes. All three are commercially proven and used on a large scale. They use different grains of coal, different types of gasification beds, and operate at different temperatures and pressures. In most designs, the input coal supplies all of the energy needed for process fuel, electricity, and steam generation, as well as for gasification (see the many processes reviewed by Nowacki [ed.], *Coal Gasification Processes*, 1981). The received coal is divided into two streams. One stream is gasified, and the other stream is burned to generate process heat, steam, and electrical energy. Because all of the process energy is provided by the input coal, energy accounting is much easier. The coal requirements of first-generation gasification plants are shown in Table J.4.

The "second generation" of coal conversion technology uses a gasification scheme developed by Texaco and a synthesis scheme developed by Imperial Chemical Industries (ICI). Fluor Engineers and Constructors (Buckingham et al., 1981) provides a very detailed description of methanol production via Texaco gasification and ICI synthesis. Its analysis details the production and consumption of power, oxygen, steam, and fuel gas. All energy requirements, from steam to the electricity used to clean coal, are ultimately provided by the feed coal, whose energy and carbon contents are stated. The energy requirements of this process, along with the energy requirements for a generic second-generation coal-to-methanol plant and for a Texaco-gasification/Lurgi-synthesis plant, are shown in Table J.4.

TABLE J.4 Energy Use of Coal-to-Methanol Plants

Process Description	Btu Energy In/ Btu Methanol Out			Moisture-Free Coal		Grade of Methanol[a]	Reference
	Feedstock	Power	O_2	% C	Btu/lb		
Lurgi gasification and Lurgi synthesis	2.11	I	I	NS	NS[b]	F	Salmon (1986)
Lurgi low-pressure process	2.04	I	?	NS	NS	C	*Hydrocarbon Processing*, November (1987)
Lurgi gasification and ICI synthesis	1.77[c]	I	I[d]	53.6	11,818[e]	F	Salmon (1986)
First generation coal gasification (generic)	1.88	I?	I?	NS	11,240	F	Chem Systems (1988)[f]
Texaco gasification	1.88	I	I[d]	69.5	12,589[e]	F	Salmon (1986)
Texaco gasification and Lurgi synthesis	1.87	I	I	69.8	12,670	F	Paul et al. (1983)
Second generation coal gasification (generic)	1.81	?	?	NS	11,240	F	Chem Systems (1988)[f]
High-rate entrained-flow gasification	1.78	0.0014	I	70.7	12,425	C	Mountain Fuel Resources, Inc. (1985)
Texaco gasification and ICI synthesis	1.71	I	I	69.8	12,670	F	Buckingham (1981)
Once-through methanol with Texaco gasification and ICI methanol synthesis in an IGCC plant	1.75	I	I	70.5	12,774	F	Deane et al. (1984)[g]
Once-through methanol with Texaco gasification and liquid-phase methanol synthesis in an IGCC plant	1.48	I	I	69.5	12,771	F	Brown et al. (1982)
Once-through methanol with Texaco gasification and liquid-phase methanol synthesis in an IGCC plant	1.43[h]	I	I	NS	11,240	F	Chem Systems (1988)[f]
Once-through methanol with Texaco gasification and liquid-phase methanol synthesis in an IGCC plant	1.41[i]	I	I	NS	11,241	F	Chem Systems (1990)

[a] F = fuel grade; C = chemical grade. If the reference does not state the grade of methanol or imply a fuel-grade, I assume chemical grade.

[b] 6,576 Btu/lb as received.

TABLE J.4 (Cont.)

[c] Includes an HHV of the minor amount of nonmethanol fuel products, such as synthetic natural gas (SNG) and diesel oil.

[d] The report states that plants are "grass-roots plants, self-sufficient in steam and electricity" (p. 23). This indicates that everything, including oxygen production, is done on site.

[e] On an m.a.f. basis, the (Illinois #6) coal fed to the Texaco gasification was 77.6%°C and 14,050 Btu/lb (HHV), and the (Western) coal fed to the Lurgi process was 74.5%°C and 12,720 Btu/lb (HHV). As received, the Illinois #6 coal was 11,160 Btu/lb, and the Western coal was 8,509 Btu/lb.

[f] It seems, but is not clear, that in the Chem Systems designs, all oxygen and power is produced on site. There is no "Power" subcategory under "Utilities" in its cost spreadsheets, except for the once-through/IGCC process, where power is exported. I assume Chem Systems uses HHVs throughout. A remark on page 52 indicates that the coal is "moisture-free."

[g] Coal was 61.2%°C, 11,241 Btu/lb as received (including moisture and ash).

[h] Based on Chem System's allocation of coal to methanol in the coproducing plant. I checked this by scaling the electricity-only IGCC plant (described in the Chem Systems analysis) down to the power output of the coproducing plant and assigning the difference in coal use to methanol. The result was 1.40×10^6 Btu-coal/10^6 Btu-methanol.

[i] Chem Systems states that 19% of the 5,544 tons/day coal feed goes to produce 977.6 tons/day methanol, which, at 25.5 10^6 Btu/ton HHV for the Illinois #6 coal (dry), amounts to 1.41×10^6 Btu-coal/10^6 Btu-methanol.

Notes: LHV = lower heating value; HHV = higher heating value; "m.f." means moisture-free and refers to dry, but not ash-free, coal; NS = not specified; "m.a.f." means moisture- and ash-free.
An "I" in the "Power" column means that part of the coal feed generates all of the power requirements on-site. A "?" in the "Power" column means that it is not clear if the power is purchased or provided by the feedstock. An "I" in the O_2 column means that the energy required to make oxygen is included under either "Power" or under "Feedstock." A "?" in the "O_2" column means that oxygen is used, but it is not clear if the energy required to make the electricity to make oxygen is included in the power consumption or feedstock consumption figures.
Power is calculated as 3,412 Btu/kWh. In all cases, the feedstock fuel provides all of the energy needed to generate steam.
All figures are calculated on the basis of the assumption that 1 gal of methanol generates 64,500 Btu, except for the figure from *Hydrocarbon Processing*, p. 79 (1987), which assumes an LHV of 56,700 Btu/gal.

J.5.2 Once-Through Methanol (OTM) with Liquid-Phase Methanol (LPM) Synthesis in an IGCC Plant (coproduction of methanol and electricity)

This process, in which methanol and electricity are coproduced, results in the lowest emissions of greenhouse gases from any coal-to-methanol process (Wright, 1989). The basic idea is to gasify coal, convert some of the gas to methanol, burn the unconverted gas to produce electricity, and use the methanol as a peaking fuel or sell it as a transportation fuel. "Once through" means that the synthesis gas from coal gasification passes over the methanol synthesis catalyst only once (in conventional methanol synthesis the syngas is passed over the catalyst many times). It is possible to use only one pass because the liquid-phase catalyst converts more syngas to methanol in one pass than does an ordinary catalyst, and because the unconverted syngas is not wasted but is sent to the combined-cycle power plant to produce electricity. Moreover, the syngas coming from the gasification section does not have to be shifted to the 2:1 hydrogen:carbon monoxide ratio required for ordinary methanol synthesis. The process thus saves energy when compared with an ordinary coal-to-methanol process, because it eliminates the energy of recycling the syngas through the catalyst (while still making full use of the syngas), eliminates the energy of shifting the syngas composition, and uses the heat released by methanol synthesis to raise steam (Brown et al., 1982). (The energy benefit of not having to shift the hydrogen-to-carbon monoxide composition of the syngas can be seen by comparing the energy consumption of the once-through integrated gasification combined-cycle [IGCC] process with that of the liquid-phase catalyst [Brown et al., 1982], which works with unshifted syngas, with the efficiency of the once-through IGCC process with ordinary ICI synthesis [Deane et al., 1984], which requires shifted syngas; Table J.4.)

Utilities will be interested in this process because it reduces the cost and maximizes the use of the gasification unit. These savings result from the capability to downsize the gasifier capacity to 80% of what the power generation system can accept and to operate the gasifier at capacity most of the time. The gasifier can be smaller (in capacity) than the power train, because, when the power train is running at 100% of its capacity -- which is well above the capacity of the gasification unit -- the extra fuel requirement (20%) can be met by using the methanol that was made when the gasifier was coproducing electricity and methanol. Thus, the gasification unit can operate near capacity all the time, producing excess methanol when the demand from the power train is less than the maximum gasification capacity and sending the excess to the power train when the demand from the power train is more than the gasifier can meet. This efficient coproduction and use of methanol should reduce electricity costs (Weinhold, 1987; Brown et al., 1989).

Emissions of greenhouse gases from coproduced methanol depend on how one treats the fact that there are two major products. The correct accounting depends on which product, electricity or methanol, is deemed to be the primary one. As discussed below, electricity will generally be the major product, since utilities will produce the methanol to use as a peaking fuel or to sell on the side. If one assumes that electricity will be the major product, then one should compare the energy (coal) consumption of the coproducing IGCC plant with the energy (coal) consumption of the coal-based electricity-only IGCC plant that would have been built to produce the same amount of electricity as the coproducing plant (if the coproducing plant were not built). That is, in the "with methanol" scenario, a utility must meet an electricity demand of X units but also sell excess methanol as a transportation fuel; in the "without methanol" scenario, the utility must still meet the X units of electricity demand but is not interested in producing methanol. The

difference in energy consumption between the two facilities is attributable to methanol production. In the two coproduction cases shown in Table J.4, in which electricity is the major output (Brown et al., 1982; Deane et al., 1984), the authors assigned energy consumption to methanol in precisely this way: by subtracting the coal consumption of an electricity-only IGCC plant from the coal consumption of the IGCC plant coproducing the same amount of power. I believe this to be the correct method.

In this analysis, I assign to methanol production the difference between coal consumption at a coproducing plant and a noncoproducing plant, using the data of Table J.4.

It is possible that a coproducing plant would be built primarily to sell methanol and only secondarily to sell power. In this case, the "with methanol" scenario represents a plant selling methanol (as a transportation fuel) and a minor amount of electricity; the "without methanol" scenario represents no plant at all because, hypothetically, there is no market for methanol. In the "without methanol" scenario, someone other than the would-be methanol producer must generate the minor amount of electricity that would have been sold had the coproducing plant been built. In calculating the greenhouse gas emissions attributable to methanol production, the energy used to generate the electricity in the "without methanol" scenario must be subtracted from the total energy used by the coal-to-methanol plant in the "with methanol" scenario. Since the generator (in the "without methanol" scenario) is not necessarily the company that would have built the coal-to-methanol plant, one cannot assume that coal is used to generate the (minor amount of) exported electricity. Thus, in the "with methanol" case, one must make an assumption about what fuel would have been used to generate the exported electricity had the coproducing plant not been built. If one assumes the fuel is coal, the result would be the same as in the case where electricity, not methanol, is the major product (see above). Otherwise, the result would be different and dependent on the particular assumptions. I consider this situation to be unlikely.

How much OTM/LPM/IGCC methanol would be available? The potential supply depends on two factors: how much of the coal energy would go into methanol rather than electricity, and how much IGCC/methanol capacity would be installed.

It is expected that electricity would be the major output of a power/methanol coproduction plant because, as discussed above, coproduction of methanol reduces the cost of electricity. For example, in a recent proposal, the Cool Water IGCC plant would be modified to produce about 80% electricity and 20% methanol on an energy basis (Brown et al., 1989). In the two analyses by the Electric Power Research Institute (EPRI) shown in Table J.4, the split is about 60/40 in favor of electricity, counting power at 3,142 Btu/kWh (Brown et al., 1982; Deane et al., 1984). In the Chem Systems (1988) analysis, the split is 70/30 electricity, and in the most recent Chem Systems report (1990), 81% of the coal goes to make electricity. In Wright's (1989) analysis, the split is 75/25 electricity/methanol.

Furthermore, only a portion of this methanol produced would be available for transportation, because these plants are supposed to produce methanol during off-peak hours for use as a peaking fuel by the plant.

Only a portion of the projected requirement for new capacity in the United States will be satisfied by coal IGCC power plants; nuclear, gas turbine, conventional coal, solar technologies, and others will also contribute. It appears, then, that only a limited amount of OTM/LPM/IGCC is available.

J.5.3 Emissions of Methane, Nitrous Oxide, Carbon Monoxide, Nitrogen Oxide, and Nonmethane Hydrocarbons from Coal-Conversion Plants

The combustion of coal as a process fuel, the gasification of coal to produce methanol, and other processes within a coal-to-methanol plant would produce some non-CO_2 greenhouse gases. (See Table A.2 and notes for estimates.)

J.6 Methanol Transport*

J.6.1 General Method

The amount and kind of energy used to distribute a unit of methanol energy is a function of the amount of methanol moved by each mode of transport, the length of haul by each mode, and the Btu/ton-mi energy intensity of each mode. All of these factors must be known or estimated to calculate the distribution energy requirements for methanol.

The Btu/ton-mi energy consumption values of the various modes are known (see Table E.2). However, because essentially no methanol is used in transportation today, there are no historical data available to tell us how much methanol is likely to be shipped, how far it would be shipped, or the shipment mode in a large-scale methanol program. To calculate the energy requirements of methanol distribution, then, one must make some assumptions about where the methanol would come from, where it would be consumed, and how it would be shipped. Where the methanol comes from depends, of course, on whether the feedstock is coal, gas, or biomass, and separate sets of assumptions have to be made for each feedstock. I have done this here. In the following paragraphs, I explain the general method I use to construct a hypothetical distribution system for methanol and then follow with my specific numerical assumptions. The discussion of the general method also applies to the distribution of ethanol or methanol from wood. In the following paragraphs, I refer to "alcohols," meaning ethanol as well as methanol.

Recall that the object here is to estimate the amount and kind of energy required to distribute a unit of alcohol fuel. It is important that the distribution energy requirements are expressed relative to a unit of alcohol fuel delivered; it means that it does not matter, mathematically, how much alcohol one assumes is being distributed. In other words, we are not interested in projecting absolute, total distribution energy requirements; we are interested in calculating energy requirements per unit of fuel delivered. Thus, I start by assuming that X tons of methanol or ethanol are to be produced and distributed, where X is any value. I then assume that a certain

* See Table E.1.

fraction of X is distributed by tanker on international water, a certain fraction by truck, a certain fraction by pipeline, and so on. I estimate average haul lengths for each of these modes. Finally, I calculate net consumption of alcohol fuel as X less the fraction of X used by trucks to deliver alcohol fuel.

With these assumptions, the amount of energy used to deliver one energy unit of methanol or ethanol can be calculated as:

$$(\text{SUM [over all m]}\ X \times F_m \times D_m \times E_m)/(C \times (X - O \times X))$$

where:

X = amount of methanol or ethanol produced and distributed, in tons (an arbitrary number),

F_m = fraction of total production distributed by mode m (estimated),

D_m = average length of shipment by mode m, in miles (estimated),

E_m = average energy intensity of mode m, in Btu/ton-mi (Table E.2),

C = Btu/ton of alcohol fuel (from the data of Table C.1), and

O = fraction of alcohol used by trucks to deliver alcohol.

(Parameterized: the model allows the user to specify any combination of alcohol and diesel trucks distributing alcohol; anywhere from 0% to 100% of the total alcohol-fuel ton-miles by truck could be transported by alcohol-burning heavy-duty trucks. The Btu/ton-mi efficiency of alcohol-distributing, alcohol-burning trucks is calculated automatically on the basis of data in Table 2 relating the efficiency of alcohol-burning trucks to the efficiency of diesel trucks. This procedure is the same for methanol from biomass and ethanol).

The important thing to note here is that X, the total alcohol fuel produced and distributed, can be factored out of the numerator and denominator of the equation and canceled. This means that the calculation can be done either without X or with any value for X. Although it is mathematically purer to do the calculation without X, it is more understandable to include an arbitrary assumption about total methanol or ethanol production and distribution, so I have kept X and defined it as 100×10^6 tons (the result would be the same if X were 10^9 tons or 6 tons). I have then estimated the amount of tonnage shipped by each mode relative to this 100×10^6-ton starting point.

Note that no more than X can be distributed by any one mode, but that the sum of tonnages distributed by all modes generally will exceed X. This is because most fuel is shipped by more than one mode.

Finally, two more general notes on constructing hypothetical fuel and feedstock transport systems. First, it is important to try to project, as realistically as possible, the relative tonnage shares of pipelines and trucks, because pipelines consume the least Btu/ton-mi and trucks consume the most of all transport modes (tankers and trains rank between pipelines and trucks). Thus, assumptions about pipeline and truck traffic strongly determine the overall energy requirements of fuel distribution. Pipelines ship large batches of fuel relatively long distances from large producers to large markets; trucks ship very small batches to very dispersed, small end-users. This means that assumptions about the structure of a fuel distribution system depend in part on the size and location of producers and markets; the size and location of producers depend in part on the density, location, collection, and transport of the feedstock. I consider these issues qualitatively in my construction of fuel distribution systems for methanol from natural gas, coal, and wood and for ethanol from corn and wood.

Second, assumptions about feedstock transport must be consistent with assumptions about product transport. For example, if it is deemed most economical to site a plant near its feedstock but far from its markets, it will take relatively little energy to transport the feedstock and a lot of energy to transport the product.

J.6.2 Assumptions for Methanol from Natural Gas

It is widely believed that by the year 2000, most methanol will come from low-cost gas in South or Central America, the Middle East, or the South Pacific/Indonesia area. In the base case, I assume that 75% of all methanol is made from "remote" natural gas in foreign countries. In the scenario analyses (Table 12), I consider a case in which all methanol is made from foreign sources and a case in which all methanol is made from domestic gas.

I assume that the plants would be located on coasts, where the product methanol could be loaded directly onto tankers for export to the United States. The plants would be located over coastal gas fields or connected by pipelines to large inland fields. I assume that, on average, natural gas would be collected and shipped a relatively short distance via pipeline to the methanol plant (compare the energy required to ship foreign natural gas to methanol plants with the energy required to ship domestic natural gas to end-users, shown in Table 3). Then the methanol would be shipped to the United States, an average distance of about 5,500 miles (Table E.1), in a tanker fleet similar in size to the current petroleum-product tanker fleet (Table E.5).

In the United States, the distribution system for a large methanol program would eventually be similar to that for petroleum products. (It is probably optimistic to assume that this would occur by the year 2000.) Once foreign methanol is landed, some of it would be delivered inland by pipeline or domestic waterways, or both, (assuming a large market in places like Chicago, Denver, Phoenix, St. Louis, Ohio, and Atlanta) and some would be delivered by truck directly to end-users in port cities. In addition, any methanol produced in the United States and Canada would be distributed largely by pipeline and domestic waterways (again, assuming a substantial methanol program). Thus, a fair amount of methanol would move by pipeline or domestic waterway (but probably less than would move on international waters). I assume that about 40% of total methanol production would move by pipeline at some point (either as a second leg for foreign

methanol or a first leg for North American methanol) and that 40% would move by domestic waterways.

Very little methanol would move by rail for the same reasons that very little crude and petroleum products now move by rail: pipelines and tankers are more economical for large shipments, and trucks are more flexible for delivery to widely dispersed end-users (Sperling, 1988).

Finally, I assume that all of the methanol produced would be shipped in the final leg by truck to the end-user. Since very few, if any, end-users of transportation fuels are large enough to support direct delivery by pipeline, rail, or tanker, this assumption seems reasonable. My mileage and tonnage assumptions, given an arbitrary production of 100×10^6 tons of methanol, are shown in Table E.1.

J.6.3 Assumptions for Methanol from Coal

The distribution of methanol from coal would be quite different than the distribution of methanol from natural gas. The most important difference is that very little methanol from coal would be imported. The United States has a substantial amount of low-cost coal. Methanol made from this coal would likely always be cheaper than imported methanol from coal, at least in part because the imported methanol would incur an additional shipping cost relative to domestic methanol from coal. Therefore, I assume no importation of methanol from coal and, hence, no distribution of methanol by international water.

A second difference is that coal-to-methanol plants would be large enough to support a considerable pipeline distribution system, at least according to simple, rule-of-thumb economic criteria. However, Sperling (1988) points out that there are considerable risks to investing in a new pipeline network, and these risks may convince producers to use existing rail lines and waterways. Nevertheless, I assume that if any methanol was made in large coal plants by the year 2000, most of it would be shipped via pipeline, either directly from the coal-to-methanol plant or as the second leg of a journey begun on domestic water. Coal not initially shipped by pipeline presumably would be shipped by water or, in some cases where plants and markets are relatively small, by rail cars.

Coal-to-methanol plants would probably be located in coal-mining areas because it would be cheaper to transport the product methanol long distances by pipeline than to transport coal by rail from the mine to a methanol plant close to an urban area (Sperling, 1988). Some feasibility studies of coal-to-methanol processes have assumed plants are located at the minemouth. Thus, I assume that virtually no energy would be used to transport coal to the plant, but that product transport by pipeline, tanker, and rail would be a relatively lengthy proposition (see Table E.1).

Finally, as I assumed in the methanol-from-natural-gas case, I assume that all methanol would travel in the final leg to the end-user via truck. My assumptions are shown in Table E.1.

Note that the model allows one to specify that methanol (from natural gas or coal) should be delivered to end-users by methanol-burning trucks. The need to produce the extra methanol consumed by the delivery trucks is accounted for in the model by the own-use distribution factor. In the base case, I have assumed that all fuel distribution trucks use diesel (none use methanol). In sensitivity analyses not shown in this report, I have determined that this assumption is not important.

I have not allowed for the possibility of methanol-burning trucks delivering coal to methanol plants, because energy use by coal-delivery trucks is small compared with energy use by coal-delivering trains.

Appendix K:

Biofuels (Ethanol from Corn; Ethanol, Methanol, and Synthetic Natural Gas from Wood)

Appendix K:

Biofuels (Ethanol from Corn; Ethanol, Methanol, and Synthetic Natural Gas from Wood)*

K.1 Overview

(Parts of this overview are adapted from Sperling and DeLuchi, 1989).

Biological matter (biomass) can be a feedstock for the production of a range of liquid and gaseous fuels. Although biomass has been used to make transportation fuels since the 19th century, major biomass transportation fuel activities were not initiated until the late 1970s, when Brazil and the United States fermented sugar cane and corn, respectively, into ethanol. In the United States, the ethanol is mixed in a 10/90 blend with gasoline so that it can be burned in conventional, unmodified gasoline-powered vehicles.

Biomass fuels are attractive because the feedstocks are renewable and domestically available, and could therefore permanently displace imported petroleum. The use of biofuels in transportation can reduce CO_2 emissions from the transportation sector; the amount of the reduction depends on the amount and kinds of fuels used at the various stages of processing.

While virtually all current biomass transportation fuel activities involve the fermentation of crops and food wastes containing large amounts of starch and sugar, the more promising option is the use of lignocellulosic material, especially wood pulp. Lignocellulosic material is more abundant and generally less expensive than starch and sugar crops. The most promising processes for converting lignocellulose (hereafter referred to as wood) into high-quality transportation fuels are thermochemical conversion into methanol or hydrolytic conversion into ethanol; less promising are pyrolysis processes that convert biomass into low-grade petroleum-like liquids. Biomass may also be thermochemically gasified and then cleaned and upgraded into a clean medium or high-Btu gas.

K.1.1 Resource Availability

How much biomass energy is available? The answer depends on the biomass feedstock: there certainly is not enough corn to fuel the entire highway fleet, but there is, potentially, enough biomass of all kinds to replace virtually all gasoline use. Ferchak and Pye (1981, part I) argue that by 2000, current and modified agricultural practices could produce more than 30 10^9 gal/yr of ethanol from starch and sugar crops. Conversion of agricultural, forestry, and municipal solid wastes, and conversion of lignocellulose, could provide at least 100 10^9 gal/yr. This total (130 10^9 gal) would be sufficient to fuel most of the U. S. highway fleet. Similarly, Lynd

* For ease in use, all Appendix K tables appear at the end of the appendix.

(1989) reviews several estimates of the availability and composition of biomass (from waste, silviculture, and agriculture) and estimates that 140 10^9 gal/yr could be produced — about enough to replace all motor gasoline use in the United States. A recent interlaboratory "white paper" on renewable energy states that woody and herbaceous biomass could produce 8.5-27.5 quads of ethanol (the whole highway sector currently consumes about 15 quads/yr) (*The Potential of Renewable Energy*, 1990). The paper projects that an intensive R & D effort, focusing in large part on wood-to-fuel technology, could provide 8.0 quads of liquid fuels from energy crops, 0.40 quads of ethanol from corn, and 10.4 quads of bioenergy for other energy-using sectors by 2030. It appears, then, that biomass has a lot of potential (cost, environmental, and institutional and political considerations aside).

K.1.2 Cost

Perhaps the most crucial uncertainty about biofuels is how much they will cost. Although all biofuels are expensive now, compared with petroleum-based fuels (and corn-derived ethanol probably never will be as cheap as gasoline), wood-based biofuels may someday be economical. For example, Hinman et al. (1989) estimate that with current technology, ethanol can be produced from wood by converting the xylose for $1.23/gal (plant gate cost). Hinmen et al. also show that if the xylose is not converted to ethanol, but is burned in the boiler instead (about 0.66 kWh/gal), excess electricity is produced. SERI (Stevens, 1989) believes that today methanol can be produced from wood for $0.75/gal (at the plant gate). Considering the energy density and combustion efficiency of ethanol and methanol, this translates to about $1.60/gal of gasoline in the case of ethanol, and $1.30/gal of gasoline in the case of methanol. These gasoline-equivalent prices do not include distribution, retailing, and taxes; with these included, the final gasoline equivalent prices will be on the order of $2.00/gal. However, SERI (Stevens, 1989) believes that, in the future, ethanol can be produced from wood by enzymatic hydrolysis for $0.60/gal (plant gate production cost; about $0.77/gal gasoline equivalent), and that methanol can be produced for $0.55/gal (plant gate cost). At these production prices, ethanol and methanol from biofuels could compete with gasoline retailing for less than $1.00/gal.

For general discussions of the production, economics, environmental impacts, and the R&D status of biofuels, see Klass (1987), Anderson et al. (1988), Segal et al. (1987), Stevens (1987), Gaines et al. (1987), and *The Potential of Renewable Energy* (1990). For a review of progress in enzymatic hydrolysis, see Wright (1988).

K.2 Energy Used to Process Biomass and Biofuels: Ethanol from Corn

There has been considerable debate recently about whether the use of ethanol will reduce or increase emissions of greenhouse gases compared with gasoline (Segal, 1989; Ho, 1989; Marland and Turhollow, 1990; EPA *Analysis of the Economic and Environmental Effects of Ethanol as a Vehicle Fuel*, 1990).

These reports disagree on several issues: the amount of fertilizer required by corn crops, the energy invested in fertilizers, the amount of on-farm energy consumed, the correct way to handle the problem of multiple products, the energy requirements of corn-to-ethanol plants, and more. None of the current reports estimate the amount of energy invested in machinery and plant equipment, do detailed scenario analyses, or consider emissions of N_2O from fertilizers (an unpublished draft report circulated by Acurex considers N_2O and, in fact, was the first to do so).

This report addresses these and other issues. Specifically, it:

- Attempts to resolve the controversy regarding fertilizer use and the productivity of corn acreage by calculating fertilizer use per bushel directly;

- Properly accounts for the small amount of acreage that is not fertilized at all;

- Considers current and future energy requirements in the manufacture of nitrogenous fertilizers;

- Uses a mix of fuel for electricity generation that is characteristic of that in the corn belt states;

- Considers in detail N_2O emissions from denitrification of fertilizer (Appendix N);

- Details original calculations of the amount of energy used to farm corn-growing land, specifically (based on actual energy cost and price data for corn farming), and finds that the energy requirements of corn farming generally have been overestimated;

- Points out that new corn-conversion technologies will not be used merely because they are more energy efficient: cost, availability, reliability, environmental standards, and other factors also will be more important considerations;

- Considers natural gas (NG) as well as coal as the source of process heat;

- Considers the use of corn stover instead of coal to provide process heat (this greatly reduces CO_2 emissions because the stover is a biofuel);

- Emphasizes that because we are examining the consequences of an ethanol-promotion policy, the conceptually correct way to allocate emissions to the multiple products of the corn-to-ethanol process is to first assign all process

emissions to ethanol, and then deduct emissions from the production and use of the products displaced by the by-products of the corn-to-ethanol process;

- Calculates the co-product credit (deduction) in two ways, to establish high and low ranges;

- Examines emissions from the use of wood as a feedstock to make methanol, ethanol, synthetic natural gas (SNG), and gasoline;

- Offers a wide range of sensitivity analyses; and

- Reviews estimates of the energy embodied in farm equipment, and finds that the energy is a large source compared with the energy embodied in equipment used in petroleum, gas, coal, and uranium cycles (Appendix P).

K.2.1 Fertilizer Requirements

Corn farming uses large amounts of nitrogen, phosphorus, and potassium fertilizers. Nitrogen fertilizers embody a lot of energy as NG, and so total emissions of greenhouse gases from the corn-to-ethanol cycle are sensitive to assumptions about fertilizer use.

Recently, Ho (1989) and Marland and Turhollow (Segal, 1989) presented sharply different views on the total energy required to produce corn. One issue at the heart of their debate is a disagreement about how many bushels of corn will be harvested from an acre. Marland and Turhollow and Ho needed to know this because they calculated energy use per bushel of corn as the product of energy use per acre and acres per bushel. Energy use per acre in turn is the sum of energy embodied in fertilizer use per acre and farm-fuel energy used per acre. Now, this method is correct only if the acres-per-bushel estimate corresponds to the fertilizer-per-acre and fuel-per-acre estimate; that is, if the amount of fertilizer and fuel used per acre, as assumed in the analysis, is the amount used to produce the assumed amount of bushels of corn per acre. It is not right to use a generic bushel/acre figure with a generic fertilizer/acre figure; there is a real relationship between bushels of corn produced and amount of fuel and fertilizer used, and this relationship should be used in the analysis.

We can see, then, that the number we are after is pounds of fertilizer and amount of fuel per bushel of corn. This number can be calculated directly, year-by-year, from available data. It turns out that the amount of fertilizer used to produce a bushel of corn has been nearly constant over the last 20 years (the mix of fertilizers used also has remained relatively stable, especially over the last 10 years).

The relationship between fertilizer input and bushel output can be demonstrated two ways. First, the data in Table K.1 show that from 1969 to 1988, the 5-year bushel-corn/lb-fertilizer

averages do not vary much. Farmers get about as many bushels of corn out of 1 lb of fertilizer today as they did in 1970. There was an increase for 1985-1987, but this does not indicate a trend. In 1988, the ratio dropped again.

Second, multiple regressions run to explain bushel per acre yield show that pounds per acre fertilizer use is a significant explanatory variable (Table K.2), under a range of model specifications. (Note, though, that Teigens' (1989) more detailed analysis found no coherent overall fertilizer effect.)

Therefore, in this analysis I sidestep the debate over bushels per acre by using bushels per pound of fertilizer directly. I use the 20-year average, which is the same as each 5-year average through 1983, and would be the same as the 5-year 1984-1988 average if it were not for the anomalously high three years. I believe this satisfactorily resolves the fertilizer-use issue.

Note that the data in Table K.1 show yield per acre actually harvested for grain, and compute fertilizer use with proper accounting for nonfertilized acreage.

Lime, sulfur, micronutrients, and manure are applied to some corn-growing land. In 1988, lime was applied to 6% of corn land, sulfur to 10%, micronutrients to 11%, and manure to 18% (USDA, *Agricultural Resources...*, 1989). Sulfur was applied at the rate of 11 lb/acre, and lime at 1.9 ton/acre; no application rate was given for micronutrients and manure (USDA, *Agricultural Resources...*, 1989). With these data, and data on acreage harvested for grain, and bushels of corn harvested for grain in 1988 (Table K.1), one can calculate pounds of lime and sulfur applied per bushel of corn, on average, for 1988. With data on the energy content of lime (620 Btu/lb; Blankenhorn et al. 1985) and sulfur (443 Btu/lb; Hudson 1980), one can calculate the embodied energy in and hence greenhouse gas emissions from the lime and sulfur fertilizer. The value for sulfur turns out to be trivially small; the value for lime is small but not insignificant, because such huge amounts of lime are used (note the application rate of 1.9 tons/acre, on those acres receiving lime).

The energy embodied in and emissions from the use of lime and sulfur are included in the results of this analysis (Tables 6, 9, and K.7). I have ignored the use of micronutrients since there is a lack of data on the application rate, energy content, and use of manure, because manure presumably has no energy cost (aside from the energy required to apply the manure, which is included in the farming energy requirements of Table K.6).

K.2.2 N_2O and NO_x Emissions from Nitrogen in Fertilizer

This is a relatively large source. See Appendix N for estimates.

K.2.3 Energy Invested in Fertilizers

Although there has been little debate over the amount of energy embodied in fertilizer, there is legitimately more room for disagreement here than in the question of the amount of fertilizer used. I will discuss two relatively detailed estimates of the energy embodied in fertilizers, one by TRW (1980), and one by Turhollow (1989). Note that all the fuel used, including NG used as the chemical base, should be counted because it all ends up as CO_2 (and presumably would not have ended up as CO_2 had it not been used in fertilizer manufacture). First, I summarize the results of the detailed analysis by TRW (1980):

Energy required to mine 100 ton of potash or phosphate rock:

17,400 kWh
361 gal diesel fuel
40 gal lube oil
27 gal gasoline

Energy required to produce 1,000 lb of P_2O_5 (as 70% H_3PO_4), wet process phosphoric acid:

3,060 lb phosphate rock
840 lb molten sulfur
112.5 kWh

Energy required to make 1,000 lb of anhydrous ammonia (NH_3) al feedstock

5,740 SCF NG as fuel
6.54 kWh

Energy required to make 1,000 lb nitric acid (HNO_3):

292 lb NH_3
4.5 kWh
130 lb steam

Energy required to make 1,000 lb ammonium nitrate (NH_4NO_3):

281 lb NH_3
805 lb HNO_3
20 kWh
1,250 lb steam

Energy required to make 1,000 lb diammonium phosphate $(NH_4)_2HPO_4$:

230 lb NH_3
1,175 lb H_3PO_4 (40% P_2O_5)
1.5 gal fuel oil
10 kWh

These results can be compounded into values that are comparable to those compiled by Turhollow (1989). Table K.3 compares the two reports and also includes estimates by several others. The differences between the estimates may be due in part to the difference between older and newer technology (Turhollow's numbers come from relatively old sources). Turhollow (1989) cites a 1985 source that states that new ammonia plants can produce nitrogen twice as efficiently as old plants by using only 15,170 Btu/lb nitrogen (counting electricity at about 10,400 Btu/kWh.) King (1983) states that modern ammonia plants consume 30 megaJoules (MJ) of NG/kg of ammonia produced, or 15,600 Btu/lb, which is consistent with Turhollow's source. King also claims that by the time the ammonia is converted to a typical solid fertilizer like ammonium nitrate, and allowance is make for building the plants, packaging, transportation, and application of the fertilizer, the total energy consumed is about 60 MJ/kg of nitrogen, or 26,000 Btu/lb of nitrogen. Ferchak and Pye (1981) cite a 1976 estimate that the energy requirement for medium supplements is 20,000 Btu/lb.

Today, fertilizer is probably produced with a mix of new and old plants. In the future, most fertilizer will be produced by new plants. Therefore, in my base-case scenario, I pick values between those for new and old plants.

A very small amount of energy is required to transport fertilizers. Assuming a 500-mi haul by train, at 500 Btu/ton-mi, and a 50-mi haul by truck, at 2,000 Btu/ton-mi, 350,000 Btu will be required to move a ton of fertilizer, or 175 Btu to move 1 lb. This is less than 1% of the energy required to make the fertilizer, and so it can be assumed to be subsumed under fertilizer-manufacturing energy.

Multiplying Btu-input per pound of fertilizer by pound-fertilizer/bushel-corn, and dividing by gallon-ethanol/bushel and Btu/gallon, gives Btu-fertilizer/Btu-ethanol. The result is shown in Table K.7. My estimate is at the low end of the range of estimates in the literature. This is due to a lower fertilizer/bushel requirement, rather than a lower Btu/pound-fertilizer requirement.

K.2.4 Energy Use on the Farm

For two reasons, I have done an original calculation of energy used in corn farming rather than use existing estimates. First, Table K.7 shows that existing estimates of energy use in corn farming vary widely. Second, data are available to allow a direct calculation of diesel, gasoline, LPG, and NG used by farms to produce corn, specifically, without referring to bushel per acre corn yields. These data allow one to resolve the discrepancies in the literature with reasonable accuracy.

The calculation proceeds by several steps, using three data sets specific to farming or corn farming. I begin with USDA data on the amount of money that corn-producing farms spent on fuel and electricity, including fuel used for drying and electricity used for irrigation, per acre of corn planted (USDA, *Costs of Production*, "Cost of Production" and "Farm Costs and Returns" surveys). These dollars-per-acre figures are shown in Table K.4. Then, I disaggregate this total

dollars-per-acre figure into dollars per acre for each fuel type, by multiplying the total dollars-per-acre figure by the ratio of:

(expenditure on fuel X):(total expenditures for all energy)

for each fuel. The expenditure data come from the USDA *Farm Production Expenditures* reports (various years) that show the total amount of money that farms in the corn belt states spend on diesel fuel, gasoline, LPG, NG, electricity, motor oils, and other fuels (coal, kerosene, wood...I treat these as coal). The expenditure data are shown in Table K.5. Next, the dollar-each-fuel per acre-planted figures are divided by the dollar million Btu price of the fuels, to give million Btu-each-fuel/acre-planted. The price data are from the USDA's *Agricultural Prices* reports (various years), which report prices paid by farmers for specific fuels (data shown in Table K.4), and from fuel expenditure and quantity data in USDA's *Farm Production Expenditures* (various years). Finally, the million Btu/acre figure for each year is matched with year-by-year corn production (Table K.1), to give million Btu/bushel for each year. The results of this analysis are shown in Table K.6.

Neither the on-farm energy-consumption figures in Table K.6, nor the fertilizer-energy estimates include the energy embodied in seeds, pesticides, and herbicides. Marland and Turhollow (1990), Giampietro and Pimentel (1990), and another unpublished source indicate that the energy embodied in insecticides is less than 5% of the energy embodied in fertilizer; however, Giampietro and Pimentel (1990) show that the energy embodied in seeds and herbicides is 18% of the energy embodied in the fertilizer. This relatively high value is supported by expenditure data, which show that corn farmers spend nearly as much on chemicals and seeds as they do on fertilizers (USDA, *Costs of Production*, various years). (Pimentel [1990] estimates that energy embodied in seeds, herbicides, and insecticides is 25% of the energy embodied in fertilizer.) I believe that these higher values are more accurate, and so I multiply fertilizer energy requirements by 1.2 to account for all other seeds and chemicals. (This assumes that the energy embodied in chemicals and seeds is mostly NG, as is the energy embodied in fertilizers.)

The resultant fertilizer and farm-energy totals are shown in Table K.7, along with several other estimates. My estimate of farm energy is lower than most of the others, which I attribute to my use of detailed, recent, corn-specific data. For example, Pimentel's (1990), relatively high estimates assume very high energy requirements per pound of fertilizer, assumptions which are probably based on relatively old technology.

K.2.5 Energy Use on the Farm in a Large Ethanol Program

If, as Ho (1989) argues, a large ethanol program will require the use of less productive farmlands, then the incremental corn production will require more energy for irrigation, cultivation, and fertilization than the current average production that is estimated here. The Renewable Fuels Association (1989) counters that 8.6×10^6 set-aside acres of land of "not poor quality" (and not

in the conservation reserve) can be brought in production to yield 5.7×10^9 gal of ethanol, without reducing domestic use or exports of corn.

However, 5.7×10^9 gal of ethanol will replace less than 5% of U. S. gasoline consumption. A much larger ethanol program will not only bring marginal corn lands into production, it will probably subtract from domestic uses and exports of corn. It is difficult to predict the extent to which this will occur because at some point it will become more economical to switch feedstocks than to eke out further production from corn lands. So, while it is clear that a very large ethanol program will be more energy intensive, on average, than the current small program, it is not at all clear how much more intensive. Moreover, Marland and Turhollow (1990) cite a USDA report that concludes that a large ethanol program will reduce by-product credits, which would result in an increase in greenhouse gas emissions.

To address these possibilities, I construct a scenario analysis in which marginal farming energy requirements are higher than the average calculated here and fewer by-products can be sold.

K.2.6 Energy Used to Transport Corn to the Conversion Plant

More than two-thirds of the of total U. S. ethanol (from corn) production capacity is located in major corn-growing states, Illinois and Iowa (Klass, 1990). Ethanol plants are located near feedstocks, rather than near major markets for the fuel because feedstock transport costs are greater than fuel transport costs, and by-product markets are located in corn-growing areas (Anderson et al., 1988). Katzen (1979) sited the plant in their analysis in Illinois near both coal and corn. These facts suggest that corn is transported from the field to the plant primarily by truck, with perhaps some shipment by rail.

To estimate the energy requirements of transporting corn to the biofuel plant, I typically assume that a truck, consuming 2,144 Btu/ton-mi of truck travel (see Table E.2), travels 40 miles one way (80 mi round trip) from the field to the conversion facility or to a train depot, resulting in 171,520 Btu/ton. Occasional train transport, I assume, brings the total to 200,000 Btu/ton (Btu/ton-mile data are shown in Tables E.1 and E.2), or 100 Btu/lb of corn. At 56 lb/bu of corn (U. S. *Statistical Abstract*), the result is 5,600 Btu/bu. This relatively large value (a sizable percentage of the farming energy per bushel) is due to the low effective-energy density of a bushel of corn: at 56 lb/bu, 2.6 gal ethanol/bu (my assumption throughout; typical yields are between 2.5 and 2.7 gal/bu), and 84,600 Btu/gal-ethanol, corn has an effective energy density of 3,928 Btu/lb, about one-fifth that of crude oil (even if the energy in the corn-fermentation by-products are counted, the density is still only about 40% that of crude oil).

The few other estimates of transport energy for corn are considerably higher than mine (see Table K.7). However, those estimates are not detailed and it is impossible to evaluate their quality. Given that corn-to-ethanol plants will be located near corn fields, it does not seem reasonable to assume much longer truck or train hauls than I have assumed here, and so it does not seem reasonable to use higher transport energy requirements.

K.2.7 Energy Consumed by the Corn-to-Ethanol Conversion Process

Although there has been considerable debate over the corrective assumption regarding the amount of energy required to turn corn into ethanol, the disagreements center not so much around the energy requirements of a particular technology, but rather around which technologies should be chosen as representative of a future industry average. Table K.7 shows several estimates of the amount and kind of energy used by conversion plants to produce one unit of ethanol energy (and, in most cases, to dry the by-products). The range in Table K.7 primarily reflects differences among technologies, not differences in the estimates for a particular technology. Wayman and Parekh (1990) show that the energy requirements of corn-to-ethanol plants can vary by nearly a factor of 3, the main determinants being the configuration of the distillation system, the concentration of alcohol in the beer, and the technology.

The data in Table K.7 suggest that the current industry average energy consumption is least 0.55 Btu of energy per Btu of ethanol out of the plant (e.g., data from Jones, 1989; Keim, 1989). However, the data also show that the conversion process can be considerably more efficient than this (e.g., Marland and Turhollow, 1990; Wayman and Parekh, 1990; Energy Fuels Development Corp., 1989). (I note, however, that Jones, 1989 states that the processes he describes make extensive use of energy-saving technologies.) The question, then, is what industry energy consumption would look like in the future in a larger corn-to-ethanol program.

The use of more efficient technologies and techniques will depend on many factors including: the capital cost of energy-efficient equipment; the rate of payback in lower energy and operating expenses; the effect of more efficient technologies and techniques on the types, quantity, and quality of output, and on other plant operations; the reliability of the energy-efficient equipment and practices; the extent to which producers know about ways to improve efficiency; and more.

It is not possible to quantify the development and adoption of energy-efficient conversion technologies and processes. It would seem, though, that there is considerable room for improvements in energy efficiency, both because the current industry performance is well below the state of the art and because the state of the art itself probably can be improved significantly by further R & D. In my base case, I assume an energy consumption toward, but not at, the low end of the range of current practice. I consider higher and lower energy consumption values in scenario analyses.

K.2.8 Energy Used to Dry Residues

The energy consumption estimates in Table K.7 include energy used to dry the residue from the distillation process. The residue is dried so that it will not spoil when it is shipped to feedlots. However, if the residue is fed to livestock at the ethanol plant, it need not be dried (Henneke, 1991; Chambers et al., 1979). This can save 16,000-28,000 Btu drying energy per gallon of ethanol (Henneke, 1991; EPA, *Analysis of the Economic and Environmental Effects of Ethanol as an Automotive Fuel*, 1990; Keim, 1989; Chambers et al., 1979). In this analysis, I

consider a no-drying scenario, in which total process energy is reduced by 0.30 Btu-process energy/Btu-ethanol, but the by-product credits remain the same.

K.2.9 Use of Natural Gas as a Process Fuel

It is possible, though not likely, that NG, not coal, will provide the process heat for some ethanol plants. The use of NG would reduce considerably emissions of greenhouse gases from ethanol production because of the much lower carbon/Btu content of NG. However, NG is much more expensive than coal and is available only via a gas pipeline. Most likely, NG would be used only if it were too costly to meet very strict effluent standards (for SO_x, particulates, and metals) with coal.

K.2.10 Use of Corn-Field Residue as a Process Fuel

Corn stalks and cobs can be collected and burned for fuel. The use of corn residue produces much less greenhouse gas than does the use of coal because CO_2 emitted from the combustion of corn does not count as a net emissions. There is more than enough energy in the residues to run the corn-to-ethanol conversion process.

Chambers et al. (1979) and White (1980) estimate energy credits for the use of corn-crop residue (also called stover). However, current calculations (Ho, 1989; Marland and Turhollow, 1990; draft unpublished report by Acurex) do not include the energy value of the stover, probably because most plants would have to modify their burners to use crop residue. Also, some crop residues have alternative uses. Nevertheless, this report considers the use of corn residues as a fuel because they can so strongly affect the greenhouse impact of corn-to-ethanol. According to Starr et al. 1978), residues are being used as a fuel in some situations.

There are several issues concerning the use of corn-crop residues as a fuel: the amount of residue that can be removed without causing erosion or depleting nutrients; the energy required to collect, transport, and prepare the residue; and the energy required to replace any nutrients or soil lost due to removal of the stover.

Some crop residue must be left on the soil to maintain fertility, reduce evaporation, recycle minerals, increase the content of organic matter, promote biological activity, and aerate soil (Flaim, 1979; Pimentel et al., 1981). Removing corn mulch can increase soil loss and water runoff by a factor of 10 (Flaim, 1979), which in turn can cause sedimentation and pollution (Pimentel et al., 1981). Table K.13 shows the amount of residue produced from corn farming and the amount of residue that can be removed without causing unacceptable soil erosion.

Pimentel et al. argue that "even with proper management practices, severe soil degradation problems can result from residue removal." (1981, p. 1114). Their analysis accounts for nutrients

lost from residue and excess soil loss and decreased productivity due to soil loss. The losses depend on the slope of the land and the farming practices; the losses are greater on steeper slopes. Table K.13 shows the results of Pimental et al.'s (1981) calculations.

There are other considerations. SERI (Flaim, 1979) notes that residues left on the soil can also depress germination rates, increase pesticide requirements, and increase the potential for disease. I do not account for this.

Maurya et al. (1980) point out that residue harvest could interfere with other farm operations. They found that at worst, residue harvest could delay replanting and reduce crop yields by 2.1%, but noted that simple changes could reduce these losses to negligible levels.

Green (1975) noted that the use of corn stalks as a supplemental boiler fuel increased particulate emissions and calculated that, with 60% corn stalks by volume, particulate emission standards would be exceeded. It is likely, though, that modern control technology can reduce PM emissions to acceptable levels.

My assumptions are as follows. First, note that the data in Table K.13 indicate that even under unfavorable assumptions, corn residue can provide more than enough energy, including energy for electricity generation, for converting corn to ethanol (at least 22.5×10^6 Btu-residue/acre are available, and not more than 20×10^6 Btu/acre are required to convert corn to ethanol). Therefore, availability is not a constraint, and I assume that as much residue as is needed is used, with any residue available in excess of energy requirements remaining on the land. I assume that collection consumes 3 gal of diesel fuel/ton residue (Starr et al., 1978; Table K.13 here), and I calculate transport requirements by assuming that the residue is transported by the same mode and for the same distance as the corn grain. The fertilizer needed to replace nutrients lost in removed residue and eroded soil (Table K.13) is added to total fertilizer requirements. Finally, the reduction in corn yield due to soil loss is handled by increasing the Btu-process energy per Btu-output factor accordingly (Table K.13).

The burning of the corn residue will produce some non-CO_2 greenhouse gases. Because there are no emissions data for the combustion of corn residue exclusively, data for combustion of wood and waste are used here (Table A.2). (Burning the corn stover in the field also will produce non-CO_2 emissions. I do not estimate these here.)

K.2.11 Emissions of Non-Carbon Dioxide Greenhouse Gases

Emissions of CO, CH_4, N_2O, NO_x, and NMHCs from corn-to-ethanol plants are calculated as the sum of emissions from fuel use, and emissions from all other process areas. Emissions from fuel use are calculated from data on the amount of each kind of fuel used, and the emission factors for industrial boilers using the particular fuels (Table A.2). Emissions of CO and NMHCs from other process areas are estimated by subtracting fuel-use emissions from total,

plant-wide emissions of CO and NMHCs (Table A.2). Emissions of CH_4 from nonfuel-use process areas are estimated as a fraction of NMHC emissions. I assume no NO_x and N_2O emissions from the nonfuel-burning parts of the plant.

K.2.12 Mix of Fuels Used to Generate Electricity at Corn-to-Ethanol Plants

Ethanol production plants can use a lot of electricity, and so one's assumptions about the mix of fuels used to generate that electricity can significantly affect the overall results. The mix of fuels, of course, depends on where the plants are located. As noted above, ethanol plants will generally be located near large supplies of corn and coal because it is cheaper to transport the product long distances to markets than the feedstocks long distances to conversion plants. The major corn-growing states are Iowa, Illinois, Nebraska, Minnesota, Indiana, Ohio, Wisconsin, South Dakota, and Missouri (USDA, *Crop Production*, 1990); of these, Illinois, Indiana, and Ohio are major coal-producing states (EIA, *Coal Production*, 1990). Presently, most corn-to-ethanol production capacity is located in Illinois and Iowa (Klass, 1990; Anderson, 1988).

I assume that the Midwest will continue to produce large amounts of both corn and coal, and so it will be home to future corn-to-ethanol plants. My specific assumptions, which roughly follow the current distribution of ethanol production capacity (Klass, 1990), are shown in Table D.1. Note that coal dominates the electricity mix in the current ethanol-producing regions. Moreover, both NERC (1990) and the EIA (*Annual Outlook for U. S. Electric Power,* 1990) project that coal will continue to dominate the mix for the next 10-20 yr. I have used the average of the EIA and NERC projections for the likely ethanol-producing states. This projected regional mix has much more coal than has the national average mix, which means that calculations based on the national average mix likely will understate total CO_2 emissions from corn-to-ethanol plants.

K.2.13 Distribution of Ethanol from the Plant to the End-User

To calculate greenhouse gas emissions from the distribution of ethanol, the greenhouse gas emissions model requires input assumptions about the amount and distance of ethanol movement by pipeline, truck, train, international tanker, and domestic tanker. These input assumptions (see Table E.1) are scaled to an arbitrarily chosen 100×10^6-ton/yr level of ethanol production. The calculation is explained in detail in the section "Methanol Transport" at the end of Appendix J (as explained there, the level of production does not matter because everything in effect is scaled by the level of production). The absolute tonnages are not by themselves meaningful; they are meaningful only relative to the arbitrarily chosen level of total production (again, see the discussion in Appendix J). Here, I explain my specific assumptions regarding the length of shipments, and the amount of total production shipped by each mode.

Presently, most ethanol is transported from the fermentation plant to the blending terminal by truck or train (Anderson et al., 1988). The Kentucky Agricultural Energy Corporation ethanol plant distributes its ethanol by rail, and the South Point Ethanol Plant ships ethanol by truck, rail,

and river barge (Jones, 1989). This situation is not likely to change, even in a large ethanol program, because ethanol plants will probably not be large enough to support a pipeline distribution system, or even shipment by tanker. Both of these modes typically require throughput of at least 300 million gallons per year (Sperling, 1988), which is more than the largest ethanol plant in the U. S. can produce, and 5 times more than what most plants produce (Anderson et al., 1988). Sperling (1988) concludes that "tanker trucks and railcar-size shipments provide the best match with biomass plants..." (p. 232). Thus, as shown in Table E.1, I assume that most of the ethanol produced will move several hundred miles by rail. I assume that no ethanol will be imported, and so no ethanol will be transported by international tanker, but a small amount will move via domestic waterways.

Presumably, all ethanol will be transported to the end user by truck; therefore, as in the methanol distribution analyses, the amount of ethanol moved by truck equals the amount produced. However, in the case of ethanol, I assume that a considerable amount of fuel will be transported directly from the plant to end users, who likely will be more than 100 mi distant (one-way), on average. Hence, I assume a relatively long average ethanol haul by truck.

All mileage, tonnage, and Btu per ton-mile assumptions (given an arbitrary ethanol production of 100×10^6 tons) are shown in Table E.1.

K.2.14 Handling of Multiple Products: The By-Product-Credit Problem

More than just ethanol comes out of the ethanol production process, and so one must ask how total greenhouse gas emissions from the process should be allocated among the different products. The answer to this is straightforward, at least conceptually, once one recognizes that the whole point of calculating greenhouse gas emissions from the manufacture and use of ethanol is to help answer the question, "Should we make ethanol from corn?" That is, we are interested in seeing what happens if we make ethanol from corn — compared, by default, to not making it, and using gasoline, or some other fuel, instead.

We may, therefore, begin by saying, "If the United States endorses ethanol from corn, it will build and operate a large number of additional ethanol plants; if it does not endorse ethanol, it will not, and will make something else (probably gasoline) instead." We wish to compare these with and without scenarios: we wish to estimate whether the ethanol world produces more or less greenhouse-gas emissions than the gasoline world. In the "with" scenario, we have emissions from most or all of the ethanol production-and use-cycle. In the "without" scenario, we have all the emissions from the production and use of the work-equivalent amount of gasoline, plus the emissions from the production and use of the products (call these the "by-product substitutes") that would have been displaced by the by-products of the ethanol production process. The difference between the with and without scenarios is the result of the ethanol policy.

Now, if we wish to compare emissions from the ethanol case with emissions from a baseline gasoline case, we must move the emissions associated with the by-product substitutes

from the gasoline side of the ledger to the ethanol side of the ledger, by subtracting these emissions from the fuel-cycle totals for ethanol. To do this, one must know what the ethanol by-products would displace, and how much of what kind of energy would have been used to make the by-products.

Unfortunately, the problem of the by-product credit is difficult to resolve, for three reasons. First, the amount and kind of by-products available depend on the conversion technology ("wet milling" produces different by-products than "dry milling") and the operating conditions of the particular technology, and these are difficult to specify "on average." Certainly, there can be many by-products, including animal protein feed, corn oil, CO_2, fusel oil, and fertilizer. Second, it is very hard to predict how much of which kinds of by-products actually will be sold; not all will be sold all the time, because of lack of buyers, lack of infrastructure to connect buyers and sellers, saturation of by-product markets, inertia on the part of producers, inhibiting regulations, or ignorance about the utility of the by-products. Third, even if an average set of salable by-products can be identified, it is not easy to figure out exactly what the by-products displace, and how much of what kind of energy would have been used to make whatever is displaced.

What is required, then, is a very detailed engineering and economic and political analysis; the economic part is probably more important because it does little good to identify by-products without determining if they can or will be sold. However, this is beyond the scope of my effort here. Instead, to encompass the likely range of values of the by-product credit, I estimate it in two entirely different ways and run the model using both kinds of estimates.

In the first method, I count the by-product credit as the energy value of products displaced by three major by-products: distillers dried grains and solubles (DDGS; displaces soybean meal as animal protein), fusel oil (displaces coal process fuel), and ammonium sulfate (displaces fertilizer). I use this method in the base-case analysis. In the second method, I will follow Marland and Turhollow in their draft report (Segal, 1989), the Renewable Fuels Association (1989), and Environmental Resources Limited (1990) and estimate the by-product credit based on the energy or market value of all the residue of the fermentation process.

Note that method 1 is a more direct approach to the conceptually correct method. However, one can argue quite easily that each of the by-products identified would not in fact displace what they have been assumed to displace here (e.g., that something other than soybean meal would be used were DDGs not available) or that different by-products would be produced. I do not address these questions. Method 2 (based on energy value or market value) should not be viewed as a directly, conceptually valid alternative, but rather as an indirect way of getting at the right answer (to be used if one feels that the assumptions of method 1 are too unpalatable). The upshot is that as yet, there there is entirely satisfactory way of estimating by-product credits.

I. Method 1: specific credits for DDGS, ammonium sulfate, and fusel oil (and N_2O emissions from fertilizer, as discussed in Appendix N on N_2O).

The dried, nonfermented residue of the alcohol-making process can displace soy meal as a protein. Table K.8 shows several estimates of the energy credit from displacing soy meal (the amount of energy which would have gone to produce the food-equivalent amount of soy protein.) The data are in reasonable agreement, and indicate that the by-product credit for DDGS should be between 7,000 and $10{,}000 \times 10^6$Btu/ 10^6 gal of ethanol (HHVs); I assume 8,000 Btu/gal. I also assume that the greenhouse gas emissions from transporting the DDGS cancel the emissions that would have resulted from transporting the soymeal. Incidentally, DDGS is the only major by-product reported by the Kentucky Agricultural Energy Corporation, and the South Point Ethanol Plant (Jones, 1989).

TRW (1980) stated that then-current ethanol productions could be increased nine-fold before the market for DDGS was saturated. The OTA (U. S. Congress, 1990) states that the U. S. market for by-products would become saturated at a few billion gallons of ethanol per year but that perhaps by-products could be sold overseas.

Ammonium sulfate scrubbed from the flue gases of the ethanol facility can be used as a fertilizer and can thereby reduce the amount of NG-based fertilizer used by farms growing corn for ethanol plants. The Katzen process (1979) produces 60.75 tons of ammonia per million gallons of ethanol, of which, according to TRW (1980), 87% is available for use as a fertilizer. This results in 0.106 lb of NH_3/gal of ethanol. (TRW calculates that this amount of ammonia used as a fertilize will save $1{,}685 \times 10^6$ Btu of NG, 4×10^6 Btu of coal, 1×10^6 Btu of residual fuel, and 21×10^6 Btu of diesel fuel. However, to avoid calculating the energy value of the credit fertilizer differently than that of the input fertilizer, I deduct the ammonia directly from the fertilizer requirements, and then figure the energy required to make the remaining required fertilizer). Assuming that sulfur will have to be scrubbed from all future coal-burning ethanol facilities, and that there always will be a market for the by-product fertilizer (which seems reasonable, since the fertilizer market is huge compared to the amount of by-product), it is reasonable to assume that this by-product will always be produced and salable.

The amount of ammonia produced is proportional to the sulfur content of the coal. The Katzen design analyzed by TRW assumes high-sulfur coal (greater than 3% sulfur by weight, according to the EIA's *Quarterly Coal Report*).

In Illinois, where most ethanol facilities will be located, the average sulfur content of coal delivered to power plants in 1987 was 1.93%; in Iowa, it was 0.86%; and in other ethanol-producing states, it was about 2.4% (EIA, *Cost and Quality of Fuels for Electric Utility Plants 1987*, 1988). The weighted average would be about 1.75% sulfur by weight. Restrictions on sulfur emissions may force the use of lower-sulfur coal, or require sulfur removal before combustion. I assume that the average sulfur content of coal delivered to ethanol plants will be half that of the Katzen analysis, and hence that ammonia production will be half that calculated by TRW

(this factor-of-two change in ammonia production results in a 1% change in grams-per-mile greenhouse gas emissions for the ethanol cycle).

Note that if NG or crop residue is used as a fuel instead of coal, this credit will not be available because these fuels have much less sulfur than coal. I account for this in the scenario analyses using these fuels.

Finally, higher alcohols and esters (called "fusel oil") and aldehydes are produced as a by-product, and these can added to the ethanol product or burned as process fuels along with the coal (other uses of fusel oil may be more valuable). The Katzen design produces 0.0304 lb of fusel oil (0.00448 gal) per gallon of ethanol. Wayman and Parekh (1990) report 0.134 lb of fusel oil per gallon of ethanol. At about 33 Btu/g of C_3 to C_5 alcohols (*CRC Handbook*, 1975), the result is about 500-2,000 Btu of fusel oil/gal of ethanol. Ho (1989) assumes that fusel oil and aldehydes from an unspecified process displace 3,000 Btu of coal/gal of ethanol. The data used here result in about 2,000 Btu/gal.

At the Kentucky Agricultural Energy Corporation Plant and the South Point Ethanol Plant, CO_2 from fermentation is sold to adjacent or on-site users (Jones, 1989). Whether or not this sale and use of by-product CO_2 constitutes a CO_2 credit for ethanol production depends on where the CO_2 would have come from had it not been provided by the ethanol facilities. If the CO_2 would have come from the atmosphere, either directly or via plants, then the use of CO_2 from ethanol facilities provides no benefit, because the atmospheric concentration of CO_2 is the same in either case (because the source of the CO_2 is the same). However, if the biomass-derived CO_2 displaces fossil-derived CO_2, there is a CO_2 benefit to using the ethanol, unless the fossil-derived CO_2 is a by-product that simply will be vented if it is not used.

These complications make it difficult to estimate a CO_2 credit for ethanol production. Moreover, it seems that any sizable ethanol fuel program would quickly saturate any local demands for CO_2. I assume that, in a national ethanol program, nearly all CO_2 from the fermentation area would be vented. In any case, CO_2 from fermentation appears to be only a small portion of total CO_2 from ethanol production, with most CO_2 coming from coal combustion.

II. Method 2. This method estimates an energy credit based on the total energy value of the part of the corn that is not turned into alcohol. Marland and Turhollow (Segal, 1989) cite a recent USDA analysis that shows that 48.9% of the cost of corn was born by the by-products, and the remainder by the ethanol. Then they allocate energy inputs (farm production energy and ethanol-plant conversion energy) to by-products and ethanol using the same proportions. This results in a rather sizable credit of around 32,000 Btu/gal of ethanol (counting electricity at 10,400 Btu/kWh, and using their lower bound estimate of the amount of energy required to convert corn to ethanol). Similarly, the Renewable Fuels Association (1989) notes that 55% of the corn kernel is turned into ethanol, and the remainder into (potentially) usable by-products. They conclude from this that 55% of the total energy input to corn production and processing be assigned to ethanol production and 45% to by-products.

As suggested above, the total-value or total-energy-content approach assumes that the uses and things that the by-products replace would have consumed as much energy — and the same kind of energy — as did the production of the by-products.* Neither assumption is likely to be exact. Certainly, there is no reason to believe that the amount and kind of energy used to make the things displaced by ethanol by-products are at all similar to the amount and kind of energy used to make the by-products. This method probably describes an upper limit to the energy and emissions credit that can be assigned to ethanol production.

Finally, note that the counterfactual-type analysis (comparison of the with-ethanol world and the without-ethanol world) can produce interesting results. For example, increased demand for corn ethanol may not translate into increased planting and farming of corn: the ethanol may be made by diverting to a distillery corn starch that already is being used as an animal feed, and the lost animal feed then made up by increased use of forage or some grain other than corn. Thus, in this case, the net effect of an ethanol policy is an increase in the production of something other than corn as an animal feed. I have not considered such scenarios here.

K.3 Energy Used to Make Methanol, Ethanol, Synthetic Natural Gas, and Gasoline from Wood

Wood is potentially a much more abundant bio-energy feedstock than crops. In 1985, the USDOE projected that energy from conversion of trees to ethanol, methanol, or gas could supply about 5.7 quads of energy 2010, considerably more than any other biomass source (excluding direct combustion of wood) (Klass, 1987). These trees would be grown in a system known as short-rotation intensive-cultivation (SRIC), designed to maximize wood production and minimize cost. The trees would be fast growing, closely spaced, and harvested frequently (hence the name SRIC), to ensure a large and continuous supply of feedstock (see Ranney et al. 1987, for a review). Several researchers have investigated the energy and material input to SRIC (these are reviewed below).

Wood can be gasified and cleaned up to produce a substitute, medium-Btu NG; gasified and then converted to methanol, via normal methanol synthesis; or hydrolyzed by enzymes and converted to methanol. Energy-use data are available for all three routes, and all are analyzed in this report.

Energy and greenhouse gas accounting for wood-based biofuels is relatively straightforward, compared to corn to ethanol. Essentially all of the wood is consumed at plant,

* Note that it is the amount and kind of energy that would have been consumed by the things replaced by the by-products, and not the energy used by the by-products themselves, that is of interest. This is because if we make the ethanol, we end up with emissions from the ethanol process, but have eliminated the emissions from the processes associated with the things displaced by the ethanol by-products. Thus, the net increase in emissions in the with-ethanol world compared to the without-ethanol world is emissions from ethanol production less emissions from processes displaced by ethanol by-products. (Gasoline is treated separately).

either as process fuel or feedstock for methanol or SNG, and are no major by-products. Two minor difficulties are fertilizer use for SRIC, and oxygen use at conversion plants.

K.3.1 Energy Used in Silvicultural Operations

Energy is used to plant, irrigate, fertilize, harvest, dry, transport trees, and to make the equipment used in these operations. Generally, less energy is used in silviculture than in corn farming, per unit of fuel ultimately provided, because trees require less fertilization and irrigation than does corn, and require little much management while they are growing.

Table K.9 shows estimates of the energy inputs to silviculture, per unit of wood energy available. These estimates are in reasonable agreement, and they show that silviculture is much less energy intensive than agriculture. I have broken the total energy estimates of Table K.9 into five items: fertilizers, irrigation, physical equipment, drying, wood transport, and other (planting and harvesting, primarily). Energy embodied in equipment is small and is ignored. Energy for transport and drying are separated from energy for harvest.

Fertilizers (especially nitrogen fertilizers) are relatively energy intensive, and so one's assumption about fertilizer use in SRIC will noticeably affect calculated total emissions of greenhouse gases from the production of wood-fuels. Unfortunately, there is enormous variability in the amount of fertilizer required in SRIC: some sites will not need any, and some sites will need a lot. Table K.10 summarizes a few estimates or records of fertilizer use in SRIC. Blankenhorn et al. (1985) applied large amounts of fertilizer to their test plots, but also found that unfertilized sites produced nearly as much wood as fertilized sites, if weeds were controlled (Ranney et al. 1987, confirm this). In a personal communication to me, Turhollow (1989) claims that much less fertilizer will be in SRIC than was used by Blankenhorn et al. Klass (1987) lists 6 SRIC experiments which did not use fertilizer.

An additional complication is whether or not lime will be used. Blankenhorn et al. (1985) applied lime, but I have not seen mention of it elsewhere. Although little energy is required to make a pound of lime, Blankenhorn et al. applied a huge amount and, moreover, the manufacture of lime from calcium carbonate drives off CO_2:

$$CaCO_3 \xrightarrow{\text{heat}} CaO + CO_2$$

The model calculates these CO_2 emissions; they turn out to be as large as the CO_2 emissions from the use of fuel to make the lime.

The greenhouse model calculates fertilizer energy use from input data on of the pounds of N, P_2O_5, K_2O, and lime fertilizer applied per fertilized, percent of acreage fertilized, wood yield per acre, and energy required to make fertilizer. In the base case, I assume that 50% of SRIC land

is fertilized, at the rate close to that suggested by Turhollow, without lime, and produces 6 dry tons/acre (after harvesting loss). In scenario analyses, I consider more fertilizer (including lime and incidental CO_2 emissions from lime) combined with lower yields, and less fertilizer combined with higher yields. The energy requirements for manufacture of N, K_2O, or P_2O_5 fertilizer are calculated as in the ethanol-from-corn analysis (see Table K.3). N_2O emissions from denitrification of fertilizer are included (see Appendix N on N_2O).

Wood that will be gasified to produce methanol or SNG must at some point be dried, and drying consumes a fair of energy (wood that will be converted to ethanol will not be dried) (Blankenhorn et al., 1985). Wood can be dried at the plantation and shipped dry or it can be shipped green and then dried at the fuel conversion facility. An advantage to drying at the fuel-conversion facility is that there will probably be enough waste heat to dry the wood (see notes to Table K.11). Therefor, I assume that wood that needs to be dried will be dried at the wood-conversion plant at no extra energy cost.

Irrigation increases energy requirements (and cost) considerably, but according to the Oak Ridge studies (Blankenhorn et al., 1985), it increases yield only slightly or not at all. It appears that SRIC will be done without irrigation in many, if not most, cases. I assume no irrigation in all scenarios.

As the data in Table K.9 show, relatively little energy — about 1% of the energy in the harvested wood — is embodied in the equipment used in silviculture. Because I do not count the energy embodied in the equipment used in the other alternative-fuel cycles (except in corn to ethanol), and because this embodied energy is so small, I ignore it here.

In summary, I assume that half the SRIC acreage is fertilized and half is not, that none of the acreage irrigated, and that drying is done at the conversion site at no extra energy cost. I assume that all the "other" fuel (about 0.035 Btu/Btu-wood, for planting, harvesting, chipping) is diesel fuel used by trucks, harvesters, chippers, tractors, and so on. Below, I account the energy required to transport wood to the conversion site.

K.3.2 Energy Required to Transport the Feedstock from the Plantation to the Wood-to-Ethanol or Methanol Conversion Facility

Because it is considerably more costly to transport wood than to transport methanol or ethanol (the wood is much bulkier, much less energy dense than alcohol) wood-to-fuel plants will be located in the middle of large wood plantations, to minimize the average haul of wood to the plant. The wood will obviously be hauled to the plant by truck; no other mode is flexible enough to cover all the ground in a wood plantation. Consequently, the total energy required to move one ton of wood feedstock to the wood conversion facility will simply be the average length of haul multiplied by 2,216 Btu/ton-mi, which is the energy intensity of transporting wood by truck (Table E.2). Diesel fuel will supply the energy.

The average truck haul will depend on the effective radius of the wooded area. This, in turn, depends on trade-offs among wood shipping costs, plant-amortization costs, and product shipping costs: as the wooded area serving a plant increases, feedstock shipping costs increase; however, as the plant gets bigger and reaps economies of scale, lower-cost product transport modes, such as railroads and even pipelines, become available. According to Sperling (1988), the lowest-cost outcome, considering plant amortization and wood shipping cost, is a plant with a capacity of less than 200×10^6 gal/yr. Assuming 150×10^6 gal/yr actual production, 56% wood-to-methanol conversion efficiency, 8,350 Btu/lb wood, 6 net tons wood/acre/yr (after harvesting loss), and 50% of the total land area around a plant is actually growing wood (the rest being given over to roads, facilities, and otherwise unusable or unused land), an area of 344,000 acres, or 538 mi^2 (radius of 13 mi), would be required to support the plant. The average haul would be around 9 mi, one way. At 2,216 Btu/ton-mi, 8,350 Btu/lb, and an 18-mi round trip, the final result is 0.002 Btu-diesel/Btu-wood.

However, some analysts feel that plants larger than 150×10^6 gal/yr would be more economical. Some researchers at SERI believe that wood-to-ethanol plants would draw from an area with a 50-mi radius, which would support an alcohol plant on the order of 2×10^9 gal/yr. Similarly, Smith and Corcoran (1981) in their analysis of wood-to-fuel energetics, assumed that wood would be transported 50 mi one way from the field to the plant (see result in Table K.9). Blankenhorn et al. (1985) calculated roughly the same energy requirements for wood transport as Smith and Corcoran did, implying similar assumptions.

If one assumes an average round trip of 70 mi (corresponding to a feeding area of radius 50 mi), the result is 0.009 Btu-diesel fuel/Btu-wood, consistent with the results of Table K.9. I round this up to 0.01 to account for circuities and the occasional use of other modes.

K.3.3 Energy Used in Conversion Processes

Net greenhouse gas emissions from conversion of wood to fuels are equal to emissions from electricity generation plus emissions of non-CO_2 greenhouse gases from wood gasification and combustion (less a CO_2 credit). Thus, it is important to estimate the electricity requirement in a fairly precise way, because electricity use can be responsible for a large fraction of total greenhouse-gas emissions from biofuels cycles. The amount of wood required per unit of fuel produced is important as well, not because of emissions from wood combustion or gasification (which are for the most part not counted), but because the more wood required, the greater the emissions from silviculture. Some processes, especially methanol-production processes, may require a considerable amount of wood for process heat and feedstock.

Table K.11 shows several estimates of the amount of wood and power required to produce one energy unit of methanol, SNG, ethanol, or gasoline. The estimates of the efficiency of wood gasification are in close agreement, probably because wood-to-SNG is the most developed of the wood-to-fuel routes considered here. I use the more recent estimates of Table K.11.

Estimates of the efficiency of conversion to methanol don't agree as well, probably because the processes are less well-developed. Methanol production from wood will require more energy than gasification, because of the energy losses and power requirements of the synthesis stage. I use values towards the lower end of the range of Table K.11.

Estimates of the efficiency of producing ethanol are quite scattered because the process is not well-developed, and several approaches are being considered. Wood and electricity consumption depend greatly on whether or not the xylose is fermented, and what is done with the lignin. The most recent research indicates that xylose can be fermented economically, but that lignin should be used to provide fuel and electricity for the plant and electricity for export. Wyman and Hinman (1990) assume that 90% of the carbohydrates are converted to ethanol, and that the lignin is burned to provide heat to run the rest of the process. Researchers now expect that steam produced from the combustion of the lignin can generate more than enough electricity to run the plant and provide all process heat (Table K.11). Assuming that the electricity can be sold, the wood-to-ethanol process should be assigned a negative electricity consumption. In this analysis, I assume a wood-to-ethanol process that converts cellulose and xylose, burns the lignin, and exports electricity.

Some processes use oxygen, and this can complicate the greenhouse analysis. If the gasifier is oxygen-blown rather than air-blown, the energy used to separate the oxygen from the air must be counted since it is not entirely trivial. If all the electrical and process heat energy is provided on site by wood feed, then the oxygen is accounted for. If the oxygen is made using purchased electricity, and the electricity consumption of the facility is known, the problem is again taken care of. However, if the oxygen is imported or made on-site by using purchased power with no accounting of power consumption, the energy used to generate oxygen must be estimated. I have assumed that oxygen use, if any (and if not explicitly quantified), is accounted for in the energy-use values in Table K.11.

K.3.4 Emissions of CH_4, CO, NMHCs, and N_2O

Wood gasification and combustion produce CH_4, CO, NMHCs, NO_x, and probably N_2O. EPA's AP-42 provides emission factors for wood-waste boilers, but these probably apply only to lignin combustion in an ethanol plant. Dahlberg et al. (1988) indicate that methane emissions from the combustion of wood chips are almost 100 times higher than methane emissions from combustion of fossil fuels, and CO emissions are about 10 times higher.

Obviously, one has to make do with poor data. For wood to ethanol, I assume that all emissions come from the burning of lignin to provide process heat, and I apply AP-42 factors for CO, NMHC, NO_x, and CH_4 emissions from the combustion of wood in boilers. (Data on the HHV of lignin and the amount of lignin in process fuel are reported in the notes to Table K.11.) For wood gasification (to produce SNG or methanol), I begin with an estimate of NO_x emissions from wood gasification (Table A.2). Then I estimate CH_4, NMHC, and CO emissions by multiplying this NO_x emission factor for gasification by the ratio of CH_4, NMHC, or CO to NO_x

emissions from wood boilers. This assumes that the ratios of emissions from wood gasification are the same as for wood boilers.

To calculate the net effect of CH_4, I deduct the amount of CO_2 that provides the carbon released in the CH_4 (the carbon in the CH_4 emissions was originally in the atmosphere as CO_2).

K.3.5 By-Products

None of the studies reviewed here report any substantial energy by-products from wood cultivation and conversion. In gasification, and gasification and synthesis, most of the energy in the biomass ends up in the fuel product or in the gas or char that is burned to provide process heat. In wood-to-ethanol processes, the cellulose (50% of the wood) is converted to ethanol, the xylose (25% of the wood) probably will be, and the lignin (25% of the wood) can be burned as a fuel to generate more than enough power to run the process or can perhaps be converted to fuel. Wyman and Hinman (1990) imply that in a large ethanol-from-wood program, the wood will be converted to fuel or used as fuel. Therefore, I assume no major nonfuel by-products from any wood-to-fuel process. (Ferchak and Pye, 1981, note that process residues can be returned to the soil as fertilizer; I assume that this has a negligible effect, if any, on fertilizer requirements.)

K.3.6 Energy in Labor

In principle, one should consider the incremental energy requirements of people involved in the biofuel cycle, where "incremental" is relative to the amount of energy the laborers would require were there no biofuels program. It is possible, of course, that the incremental energy requirement so defined would be negative. In any event, incremental labor energy is utterly trivial, whatever its sign. Blankenhorn et al. (1985) estimate that the energy required by moderately active people in SRIC operations, less the energy required by slightly active people, would be 0.002% of the energy in the fuel product (but again, there is no reason to believe that the laborers would be less active if they were not employed in SRIC operations). Even the total energy requirements of laborers, not just incremental energy, would be small, on the order of 0.02% of the energy in the product (Ferchak and Pye, 1981). Giampietro and Pimentel (1990) show 0.03% for corn to ethanol. Labor can be completely ignored.

K.3.7 Distribution of Wood-Derived Fuels from the Plant to End User

To calculate greenhouse gas emissions from the distribution of ethanol or methanol from wood, the greenhouse gas emissions model requires input assumptions about the amount and distance of fuel movement by pipeline, truck, train, international tanker, and domestic tanker. These input assumptions, shown in Table E.1, are scaled to an arbitrarily chosen 100×10^6-ton/yr level of ethanol or methanol production. The calculation is explained in detail in

the section "Methanol Transport," at the end of Appendix J (as explained there, the level of production does not matter, as everything in effect is scaled by the level of production). The absolute tonnages are not by themselves meaningful; they are meaningful only relative to the arbitrarily chosen level of total production (again, see the discussion in Appendix J). Here, I briefly explain my assumptions regarding the total production shipped by each mode.

The structure of a wood-fuel distribution system will depend on the optimum size and best location of wood-to-fuel plants, in a large-scale wood-to-fuels program. As discussed above, Sperling (1988) argues that alcohol plants will be relatively small, and will ship their product primarily by truck and rail. However, the 2×10^9 gal/yr plants envisioned by others would be large enough to use pipelines economically, if a large market were available, and especially if several plants shared a pipeline. Even so, pipelines would not be built until a large alcohol-fuel market were well-developed, because pipelines are a large and risky investment. I assume that in 2000 most wood fuels will be shipped by rail to bulk terminals, and from there transported by truck to end users.

My assumptions are the same for ethanol and methanol. Of course, ethanol distribution turns out to require less energy because ethanol contains more energy per gram than does methanol.

I assume that SNG will be delivered from production plants to end users via pipeline. I assume that SNG pipelines will be smaller than NG pipelines because SNG facilities will be smaller and more decentralized than NG production areas. More energy is required to move a gas through a smaller-diameter pipeline, all else equal, and so I assume a higher transmission energy requirement for SNG (Table 3). The new SNG pipelines probably will rely more on combined-cycle turbines than do NG pipelines at present, because combined-cycle turbines are more efficient and have lower fuel costs, and SNG will be expensive (Table 5).

Note on SNG energy density: The SNG estimates in Table K.11 are for medium-Btu syngas, which consists of large amounts of CO, H_2, and CO_2, and typically has a higher heating value in the range of 300-600 Btu/SCF — much less than that of NG. If medium-Btu syngas is used as such in vehicles, then the density of the SNG will be much less than that of natural gas, and the range of the SNG vehicle will be much less than that of the NGV. The SNG can be cleaned up to have a higher energy density, but clean up requires additional energy, which I have not accounted for here. These points should be kept in mind when considering the results of the SNG analysis.

Biomass also can be converted into petroleum-like liquids. Presently, the production of gasoline from wood is less efficient than the production of methanol, but researchers expect to improve this considerably (Gaines et al., 1987; Stevens, 1987, 1989). Estimates are shown in Table K.11.

K.4 Note on Use of Biofuels as Process Fuels

In a large biofuel program, it is possible that biofuels themselves will be used to harvest, deliver, and distribute feedstocks and fuels. For example, methanol-burning trucks may deliver wood-methanol to end users, and ethanol-burning harvesters may harvest wood to be converted to ethanol. This "own-use" of fuel changes total greenhouse gas emissions both directly, as a consequence of burning the biofuel rather than (typically) diesel fuel, and indirectly, because of the need to make the additional fuel used by the trucks and harvesters themselves.

The greenhouse model allows the user to specify that some or all of the energy used to harvest and transport biofuel feedstocks (corn or wood) and to distribute biofuels by truck be the biofuel itself rather than diesel. Both the direct emissions effect and the indirect "own-use" effect are accounted for. In the base case, I have assumed that no biofuels are used at any stage of the process. I have checked the importance of this assumption in sensitivity analyses and reported the cases in which changing this assumption noticeably affects the results (see scenario analyses in Table 12).

K.5 Land Use and the Estimation of the Greenhouse Effect of Biofuels

It is usually assumed that because the CO_2 released from the burning of a biofuel is equal to the CO_2 removed from the atmosphere by the biofuel-feedstock, a biofuel program will be in carbon balance, with no net emissions of greenhouse gases (emissions from the use of process energy and fertilizers aside). In this section, I will show that generally this will not be true.

There are two ways in which a biofuel program can, on balance, emit or uptake greenhouse gases (emissions due to energy use and process fuels aside). One has to do with the transformation of CO_2 to a more potent greenhouse gas, the other with land use:

1. If carbon is removed from the atmosphere as CO_2 but returned as CH_4, CO, or NMHCs (out of the tailpipe), there will be an increase in radiative forcing because CH_4, CO, and NMHCs are more potent than CO_2; this has the same effect as a net increase in emissions of CO_2.

2. The adoption of a biofuel program represents a change in land use, compared to no biofuel program. This change (e.g., the removal of the original vegetation) can result in net emissions of greenhouse gases. More precisely, the time-integrated carbon content of the biofuel ecosystem will probably be different than the time-integrated carbon content that would have resulted had the original ecosystem been left alone, and this will difference constitute a net change in carbon emissions to the atmosphere. This carbon content can be broken down into a soil component and a biomass component.

The first consideration, the transformation of CO_2 to more potent organic species, can be modeled relatively easily, and is done so here. The second consideration has many facets, and is more difficult to quantify. In this section, I will discuss the major aspects of point 2 and estimate the general magnitude of the effects. We will see that emissions from changes in land use can be surprisingly large and can either add considerably to greenhouse gas emissions from a fuel production-and-use cycle, or offset many years of fuel-cycle emissions.

K.5.1 Change in the Carbon Content of Soils and Biomass Over Time

Consider Figure K.1, which illustrates a result of clearing a forest to plant crops. Assume that had the forest remained, it would have been in carbon equilibrium; that is, that it was neither net growing nor decaying, on balance (ignoring seasonal variations in carbon density), before it was cleared. This counterfactual, shown by the solid horizontal line, is the baseline against which changes in carbon density are measured. Note that this baseline need not be equilibrium; if the cleared forest were young and still growing, it would have been a net sequesterer of carbon over time, and the baseline would have a positive slope.

If we cut down the forest and plant crops, two things happen. First, much of the carbon in the original forest ecosystem will be released, over time. This drop, shown by the short-dash line, can be broken down into a biomass-loss component (vertically hatched area) and a soil-loss component (horizontally hatched areas). Second, the carbon content of the new crop system will increase relatively rapidly from zero (it did not exist before) to its equilibrium value as the crops grow. The carbon-content history of the crop system is shown by the long-dash line.

Most of the carbon in the forest biomass and much of the carbon in the forest soil will oxidize. The rate of oxidation will depend on the amount of forest biomass that is burned (oxidation is immediate), the amount that is left to rot (oxidation within 10-100 yr, depending on climate, soil, wood type, and other factors), the amount converted to paper (oxidation within 10 yr) and the amount converted to wood products (oxidation within 100 years) (Detwiler and Hall, 1988; Houghton et al., 1983). A small amount of carbon may be removed permanently from the global carbon cycle as charcoal (Detwiler and Hall, 1988; Bolin, 1986; Campbell, 1986; Woodwell et al., 1983). The soil will lose carbon quite rapidly, within five years.

When the farming stops, and the forest either is replanted or left to recover on its own, the carbon content of the biomass and soil will start to increase and, over many decades, will approach its original equilibrium value. Thus, the total carbon-history of the forest will be a bowl, usually steeper on the "oxidation" side than on the "regrowth" side. (Note that for purposes of illustration, I consider that a certain amount of carbon in the soil belongs to the forest system, even after the forest biomass has been removed, and that the crop system is overlayed on the forest system.)

The carbon history of the crop system will be the inverse of the history of the displaced forest system. After the initial rapid growth of the first planting, the carbon content will reach and

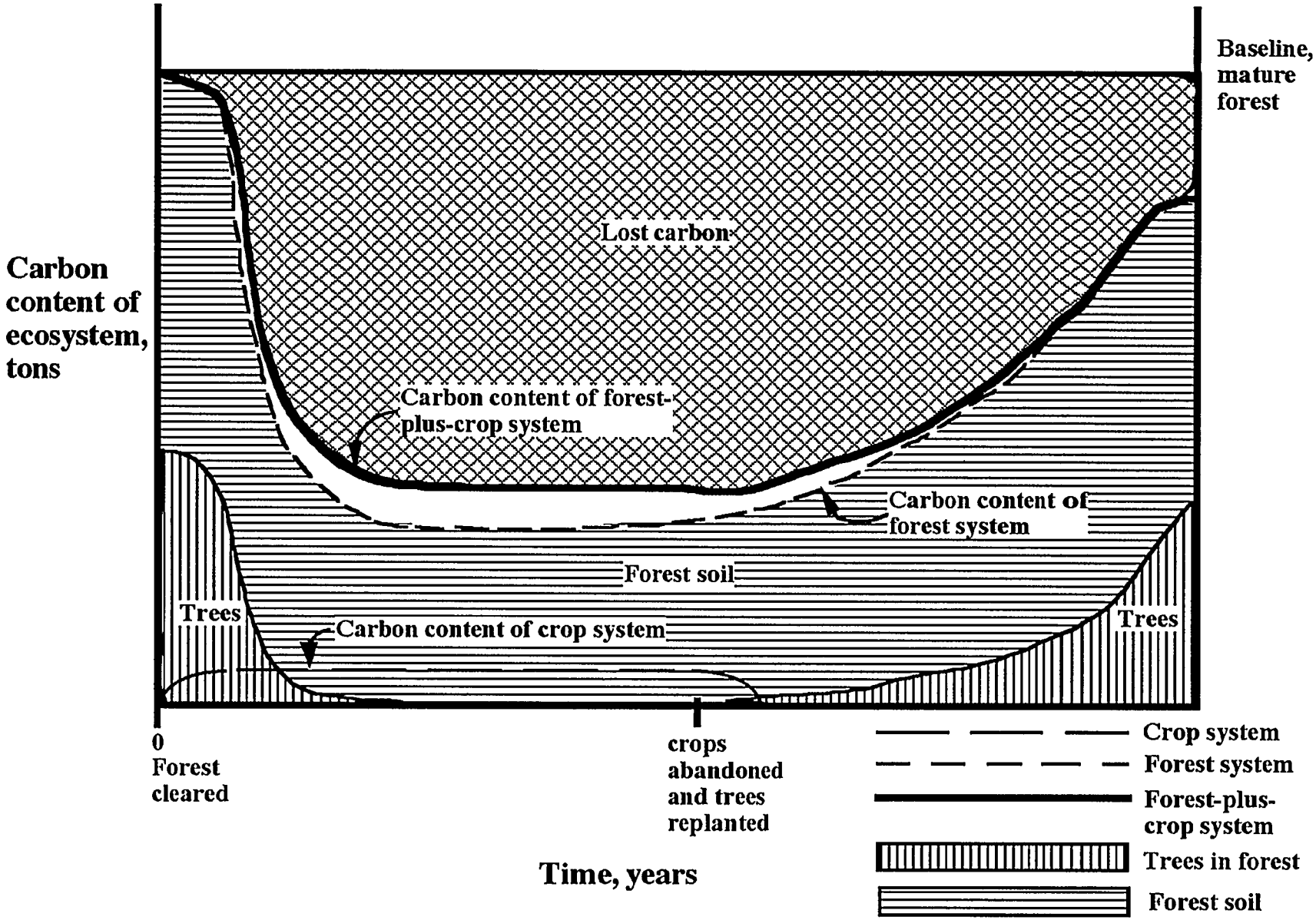

FIGURE K.1 Carbon History of Replacing Forest with Crops

remain at its equilibrium value. This is because after the first planting, the rate of oxidation of the carbon (i.e., the rate of burning the fuel made from the plant) will about equal the rate of carbon uptake by new plantings (ignoring the probably minor effect of changes in stocks of biofuels). This equilibrium will continue until the last batch of fuel is burned; for this batch, there will be no counterbalancing uptake by plants, because the program will be over; thus, the total carbon content will go to zero. One might take the perspective that the CO_2 in the first crop is in effect not released until the last crop is burned.

The grand-total carbon history of the forest-to-crop system is simply the sum of the separate crop and forest histories. This is shown by the thick line in Figure K.1. The difference between this history and the baseline, "would-have-been" history of the original forest is the effect on carbon content of switching to biofuel crops (cross-hatched area). On the basis of the assumption that all carbon lost from biomass and soils enters the atmosphere, the loss of carbon is equal to the emission to the atmosphere. Hence, the cross-hatched area shows CO_2 emissions to the atmosphere over time as a result of switching from forest to crop.

The case illustrated in Figure K.1 is only an example; the results will be quite different if, instead, range land is cleared for SRIC plantations. In general, the net CO_2 change (the double line of Figure K.1) can be either positive or negative; the outcome will depend on the difference between the carbon content of the soil and biomass of the original ecosystem and the carbon content of the soil and biomass of the biofuel system, and on the rate of CO_2 uptake and release. Also, Figure K.1 shows the results only for a particular site. In a biofuel program, many sites will be developed over time, so that the total CO_2 curve will rise and fall much more gradually.

With respect to global warming, the important features of the net change in carbon are the total amount and rate of carbon uptake or release. More CO_2 emission is worse than less, because the equilibrium means global temperature increases with CO_2 concentration, and a faster rate is worse than a slower rate because ecosystems have difficulty adapting to rapid change. In the following sections, I will review the biomass and soil carbon content of various ecosystems, and consider the issue of rate of CO_2 release.

K.5.2 Changes in the Carbon Content of Biomass

Table K.12 shows estimates of the carbon content of biomass in crops, grasslands, crops, open woodlands, SRIC plantations, and dense forests. Biomass is about half carbon, so the more biomass per acre, the more carbon per acre in the biomass. Note that forests contain at least an order of magnitude more carbon than do grasses and crops.

The longer the time between the initial clearing and the eventual recovery (if any) of the original ecosystem, and the longer recovery takes, the more the emissions from the initial clearing will affect climate. In some situations, the initial carbon release will be considerably more important than the eventual carbon uptake during recovery. For example, burning a forest will release a large amount of carbon very quickly; much of this carbon in effect will remain in the

atmosphere for decades, until the delayed and slow process of regrowth removes it. (Obviously, regrowth will not fix the physically same carbon that was oxidized as a result of clearing. From the standpoint of carbon accounting, though, all CO_2 is the same.)

Similarly, if there is a considerable time between the beginning and end of a biofuels program, then the build-up of carbon in the first planting of the biofuel feedstock (crop or tree) will not be negated by the final release, in the last burning, for many decades. Thus, replacing crops with SRIC trees will result in a large initial sequestering of carbon.

K.5.3 Changes in the Carbon Content of Soil

The carbon content of the soil is a function of local precipitation, temperature, ground cover, plant fall, biological activity, soil type, and other factors. Generally, soils in natural forests contain more carbon per acre than do shrubland and grassland soils, which in turn contain more carbon than crop soils (Burke et al., 1989; Schlesinger, 1977; Table K.12). The conversion of forest soils to permanent agriculture increases the oxidation of the organic matter in the soil, and over the course of few years decreases its carbon content by about 40-50% (Detwiler and Hall, 1988; Woodwell, et al. 1983; Houghton et al., 1983). Even the conversion of range land to crop land can reduce the carbon content of the soil by 20-40% (Burke et al., 1989) in a relatively brief period. If farming stops and the forest recovers, soil carbon will return to near its original level, but as long as the land is cultivated, the soil will contain 40-50% less carbon per acre than before.

Although crop soils generally have less organic matter than do other soils, careful soil management, intended to improve crop yield and reduce erosion will build organic matter in the soil and thereby increase its carbon content (Wallace et al., 1990; Homberg, 1988). Homberg (1988) claims that with proper corn farming, the total carbon in an acre of soil can be built up about 1% per year, enough to remove 0.73 t of CO_2 from the air, per year. Wallace et al., (1990) imply that 0.26 t of CO_2 could be removed, per acre, per year. Havlin et al., (1990) have shown that by adding crop residues to the surface and tilling less often the organic matter in the soil can be built up at about 1-2% per year.

However, such a high net build-up can not be sustained forever. At some point the rate of oxidation of organic matter will equal the rate of addition, and the system will be in dynamic equilibrium. Assuming that the soil reaches steady state (in which carbon added equals carbon oxidized and released) after 10 yr of build-up, a total of 7.3 metric tons of CO_2 will be sequestered in each acre of crop soil. As shown in Table K.12, this amount, while not trivial, is an order of magnitude smaller than the CO_2 lost from the soil as a result of clearing a forest. It will offset a couple years of greenhouse gas emissions from the corn-to-ethanol production and use cycle.

Changes in soil use can cause interesting second-order emissions of greenhouse gases. For example, phosphorus fertilizer that runs off crop land and reaches aquatic systems can cause eutrophication and create anoxic regions where organic matter is not oxidized (Bolin, 1986).

Thus, fertilizer use indirectly can increase carbon sequestering in some water bodies — a point which favors conversion to crop land. On the other hand, Bowden and Bormann (1986) report that N_2O emissions from cleared tropical soils are two orders of magnitude higher than from undisturbed soils. However, as shown in Table K.12, the N_2O release from the soil is insignificant compared to the CO_2 release. The fertilizer effect probably is small as well.

K.5.4 Summary

A biofuel program likely will change the carbon-storage history of the land. On one side of the ledger, most or all of the preexisting biomass cleared to make way for the first planting of the biofuel crop will oxidize to CO_2 at a rate dependent on the type and fate of the biomass. On the other, the new biofuel feedstock crop will sequester CO_2. The soil can either gain or lose carbon, depending on the carbon content of the soil of the new and old ecosystems.

The emissions or uptakes resulting from land-use changes can greatly exceed emissions from the entire fuel production and use cycle. For example, in round numbers, the clearing of a dense forest to plant crops will release about 200 metric tons (t) of CO_2 per acre (soil release plus biomass release; Table K.12). By comparison, the entire corn-to-ethanol production-and-use cycle, including vehicle manufacture, emits about 3.5 t of CO_2-equivalent gases/acre/yr (assuming, in round numbers, 100 bu/acre/yr, 2.6 gal/bu, 23 mi/gal of ethanol, and 590 g/mi CO_2-equivalent emissions from the entire cycle, including vehicle manufacture). Thus, this land use change will emit, in a relatively short period of time, as much as will more than 50 years of ethanol production and use. Even clearing an open woodland with half the carbon density of a dense forest will release as much CO_2 as will more than 25 yr of ethanol production and use. This release will be only partially mitigated if and when the forest recovers after cultivation stops.

Of course, farmers in the United States will not clear forests to plant corn for ethanol. Moreover, there probably is not a large overlap between land suitable for energy forests, and land suitable for energy crops (Energy Resources Limited, 1990). The point here is that even seemingly minor changes in land use — like converting range land to agriculture, which is not so unlikely in the United States — may result in nontrivial emissions of greenhouse gases, compared to emissions from the [rest of the] fuel production-and-use cycle. This conclusion is supported by an analysis by Environmental Resources Limited (1990), which shows that clearing set-aside (grass) land to grow energy crops releases to 19-38% as much CO_2 (per liter of ethanol) as the production of the ethanol (including by-product credits for ethanol production).

Conversely, a considerable amount of CO_2 can be sequestered in SRIC plantations — enough to balance many years of emissions from the production and use of the wood fuel. Converting crop land to SRIC plantations will sequester (net) about 50 t of CO_2 per acre in the biomass (Table K.12). (I assume, perhaps conservatively, that the carbon content of the soils in SRIC systems will be about the same as the carbon content of soils in crop systems; see note i, Table K.12.) By comparison, the entire alcohol production and use cycle will emit about 1.6 t of CO_2-equivalent emissions/acre/yr (assuming 6 dry tons/acre/yr, 8,500 Btu/lb-wood, 43%

conversion efficiency to ethanol, 84,600 Btu/gal of ethanol, 23 mi/gal of ethanol, and 140 g/mi CO_2-equivalent emissions from the entire cycle, including vehicle manufacture). Thus, the uptake of carbon as a result of the land use change will offset about 30 years of emissions of greenhouse gases, including emissions from vehicle manufacture. And in the case of SRIC, the land may well be managed as a forest when the program is over, rather than converted back to cropland, so that there will be no later emissions of CO_2 (from the clearing of the forest) to consider. And since SRIC likely will be directed to abandoned or marginal range and crop land, it is reasonable to conclude that an SRIC program in the United States will provide a one-time CO_2 uptake, and that the whole planting and fuel use program will generate no net greenhouse gases for many decades. Note, too, that the CO_2 uptake offsets all greenhouse gas emissions from the alternative-fuel production-and-use cycle: NO_x, N_2O, CH_4, CO, and NMHCs from all processes.

K.6 Biofuels from Waste

SNG, methanol and ethanol can be made from urban and agricultural wastes, as well as from trees. In many instances, waste will be an attractive feedstock, because it is essentially free.

From a greenhouse perspective, there are at least two opposing considerations in the analysis of making fuels from urban or agricultural wastes. The first, which favors turning wastes into fuels, is that some (of the carbon in) biowaste will decompose to methane if it is not converted to a fuel, whereas, if it is converted to a fuel, it will be oxidized to CO_2, which is less potent. The second, which favors leaving the waste alone, is that some waste oxidizes so slowly as to have only a minor effect on climate, whereas biofuels made from waste will be burned rapidly and so contribute to more rapid climate change.

This implies that, to calculate net greenhouse gas emissions from the use of biomass waste as fuel, relative to the base case of leaving the biomass as waste, one should:

- Ignore the fraction of total carbon that would have oxidized quickly anyway, had the waste been left as waste, because the result — a high rate of CO_2 emissions — is the same in either case (use as a fuel, or leave as waste).

- Ignore the fraction of total carbon that ends up as methane in either case (the burning of a biofuel will produce a small amount of methane).

- Assign, to each mole of biofuel carbon that would have taken longer to oxidize had the biomass not been converted to fuel, a weight ranging from 0 to 1.0, where 0.0 indicates that the slower rate of oxidation (from waste) is treated the same as the faster rate (from fuel combustion), and 1.0 that the slower-oxidizing carbon in waste is treated as though it never oxidizes. The sum of these weighted moles is the total (time-weighted) CO_2 emission due to rapidly burning waste as fuel rather than leaving it as waste to oxidize more slowly.

- Deduct at least 4 moles of CO_2 for each mole of fuel carbon that would have been released in CH_4 had the biomass waste been left to decay. This follows from the fact that 1 mole of CH_4 has a warming effect equivalent to at least 5 moles of CO_2 (see Appendix O), which means that emitting 1 mole of CO_2 instead of 1 mole of CH_4 — equivalent to 5 moles of CO_2 — results in a net removal (relative to the waste/CH_4 base case) of at least 4 moles of CO_2.

Unfortunately, the data do not permit a definitive estimate of these processes. I note, however, that humans generate a huge volume of waste, most of it buried in landfills or disposed at sea, where oxidation may be relatively slow. Olson (1982) notes that poorly aerated landfills remove carbon from the global cycle, and others have calculated that every year at least 0.38 Gt of carbon in human waste alone are "subtracted from any substantial oxidation" (*Nature,* 1986). Also, as noted above, pollution, such as from the disposal of nutrients containing waste, creates conditions that increase permanent carbon deposition. It is quite possible, then, that converting a biowaste to a biofuel will result in the rapid release of a substantial amount of carbon that would have been released slowly, or never, and that this effect will outweigh the benefit of reducing methane emissions. This should be analyzed before major greenhouse benefits are claimed for biofuels from waste.

TABLE K.1 Corn Production Data

Year	1,000 Bushels Corn	1,000 acres Harvested for Grain	Bushels/ Harvested Acre	July Rain (in.)	August Temp. (°F)	Fertilizer Used (lb/acre)[a]				Bushels per lb Fertilizer
						Total	Nitrogen	P_2O_5	K_2O	
1969	4,687,057	54,574	85.88	2.30	73.30	213	102	56	55	0.40
1970	4,152,243	57,358	72.39	3.32	73.60	230	105	64	61	55 6
1971	5,646,260	64,123	88.05	4.43	71.60	208	101	55	52	0.42
1972	5,579,832	57,513	97.02	4.38	72.90	229	110	59	59	0.42
1973	5,670,712	62,143	91.25	4.85	74.30	218	106	55	57	0.42
1974	4,701,402	65,405	71.88	1.78	71.30	211	97	54	61	0.34
1975	5,840,757	67,625	86.37	2.24	75.00	204	99	50	55	0.42
1976	6,289,169	71,506	87.95	3.01	71.20	249	123	60	66	0.35
1977	6,505,041	71,614	90.83	3.68	71.60	250	123	60	67	0.36
1978	7,267,927	71,930	101.04	4.86	72.90	244	120	59	65	0.41
1979	7,928,139	72,400	109.50	5.42	72.30	260	130	61	69	0.42
1980	6,639,396	72,961	91.00	3.14	76.40	252	125	57	70	0.36
1981	8,118,650	74,524	108.94	5.65	71.60	265	133	60	72	0.41
1982	8,235,101	72,719	113.25	4.81	71.00	260	131	57	72	0.43
1983	4,174,251	51,479	81.09	2.35	78.70	258	132	56	71	0.31
1984	7,672,130	71,915	106.68	3.38	74.50	257	134	52	71	0.41
1985	8,875,453	75,209	118.01	3.14	70.30	254	136	52	66	0.47
1986	8,225,764	68,907	119.37	5.18	69.30	237	125	51	61	0.50
1987	7,131,300	59,505	119.84	4.82	73.20	241	127	51	64	0.50
1988	4,928,681	58,250	84.61	3.07	77.10	254	133	55	66	0.33
1989	7,527,152	64,781	116.19							
Summaries										
1969-73			87.03	3.86	73.14	220	105	58	57	0.40
1974-78			87.92	3.11	72.40	232	112	57	63	0.38
1979-83			102.00	4.27	74.00	259	130	59	71	0.39
1984-88			110.35	3.92	72.88	249	131	52	66	0.44
1969-88			97.05	3.79	73.11	240	120	56	64	0.40

[a] Total pounds of fertilizer used divided by all planted acreage, not just fertilized acreage. This method thus properly accounts for nonfertilized acreage.

Sources: Three USDA publications: *Weather in U. S. Agriculture, Fertilizer Use and Price Statistics,* and *Feed Situation and Outlook.*

TABLE K.2 Results of Multiple Regression to Explain Bushels/Acre Corn Production

		Fertilizer		Rain		Temperature	
Independent variables[a]	R_2	Coeff.	t[b]	Coeff.	t	Coeff.	t
Rain, Temp., Fert.[c]	0.643	0.294	3.67	5.43	2.54	-1.92	-1.78
Rain, Temp., Fert.[d]	0.382	0.288	2.79	1.60	1.31	-1.11	-0.45
Rain, Fert.[e]	0.576	0.267	3.20	7.10	3.48		
Fertilizer	0.291	0.292	2.79				

[a] In general, squaring the rain, temperature, and fertilizer dependent variables, singly or in combination, did not change any of the results.

I also ran the regression with a "technology improvement" variable, meant to capture the effect on yield of improvements in the technology of planting, growing, and harvesting corn. The variable was set to 1 in the base year (1969 or 1978), and then increased at 1.5% per year. The technology variable was statistically very significant, and it improved the R_2 of the regression. Interestingly, it did not dramatically change the t statistic for the rain and temperature variables, but it did make the fertilizer variable insignificant. However, I have not shown the results with the technology variable because it is rather arbitrary.

[b] Here, a t-statistic above 2.60 is significant at the 0.99 level, and a statistic above 1.75 is significant at the 0.95 level.

[c] Independent variables are July rainfall in inches, August temperature in °F, and total fertilizer application in lb/acre. Dependent variable is bushels of corn per acre. I used August temperature and July rain data because Teigen (1989) found that these were the most important components of weather. I verified this here (see note d).

[d] As in note a, except using rain and temperature data for the months of May through August. This specification is significantly worse, which is consistent with Teigen's (1989) finding.

[e] July rainfall, lb/acre fertilizer.

TABLE K.3 Energy Used to Make Fertilizers, Btu/lb of N, P_2O_5, or K_2O

Energy Source	Nitrogen, N, in NH_3	Nitrogen, N, in NH_4NO_3	Phosphorus, P_2O_5	Potash, K_2O
From Turhollow (1989)				
Natural gas	30,602		1,986	1,677
Electricity	266		1,181	860
1) Total	30,868		3,167	2,537
From TRW (1980)[a]				
Natural gas	19,603	23,803		
Gasoline			52	17
Diesel fuel			766	250
Fuel oil			92	30
Steam		4,646		
Electricity	27	263	1,292	297
2) Total	19,630	28,712	2,202[b]	594
3) Total from ORNL[c]		28,860	4,515	4,515
4) Total from G & P[d]	37,818		4,959	3,735
5) Total from Pimentel[e]	37,551		11,298	4,465
Used here, base case	25,000		3,000	3,000

Notes: I converted from physical units to energy units by using values of Table C.1 and assuming 3,412 Btu/kWh of electricity.

[a] Converted to per lb-nitrogen from per lb-NH_3 or lb-NH_4NO_3. Calculated from data in the text.

[b] Does not include the energy needed to make molten sulfur. That energy may be the difference between Turhollow's and TRW's estimate.

[c] Blankenhorn et al. (1985). Includes energy for mining, production, transportation, storage, and transfer of fertilizer. I assume that their estimate for ammonium nitrate is in units of Btu/lb-N, not Btu/lb-NH_4NO_3, because even they appear to mean "N" when they say "ammonium nitrate." They also show 620 Btu/lb for lime.

[d] Giampietro and Pimentel (1990). I calculated the K_2O figure by multiplying their figure for K alone by 0.8298, the mass percentage of K in K_2O, and the P_2O_5 figure by 0.4366, the mass percentage of P in P_2O_5. They show 566 Btu/lb limestone (presumably lime, which is made from naturally occurring limestone).

[e] Pimentel (1990).

TABLE K.4 Energy Expenditures[a] per Acre of Corn Planted and Prices Paid[b] by Farmers for Fuels

Year	Energy $/ Planted Acre of Corn[a]	Regular Gasoline ($/gal[b])	Unleaded Gasoline ($/gal[b])	Diesel Fuel ($/gal[b])	LPG ($/gal[c])	Power ($/kWh[c])	My Assumptions[d] NG ($/10^3 ft^3)	My Assumptions[d] Coal ($/ton)
1980	23.74	1.104	1.139	0.969	0.62	0.047	3.39	28.76
1981	28.82	1.248	1.257	1.143	0.70	0.053	4.00	32.31
1982	24.99	1.214	1.201	1.130	0.66	0.062	4.82	34.90
1983	20.95	1.000	0.997	1.000	0.77	0.065	5.59	35.50
1984	19.45	1.129	1.115	1.058	0.75	0.068	5.55	35.12
1985	22.87	1.140	1.135	1.043	0.72	0.070	5.50	34.53
1986	18.22	0.848	0.837	0.748	0.64	0.069	5.08	33.30
1987	18.80	0.883	0.851	0.769	0.56	0.068	4.78	31.83
1988	16.47	0.858	0.823	0.744	0.58	0.067	4.63	30.60

[a] From USDA, Economic Research Service, *Costs of Production* (various years). My "energy $/planted acre of corn" figure is the sum of the USDA's fuel, lube, and electricity cost per acre and drying cost per acre. The electricity cost in the former includes the cost of electricity used for irrigation. The drying cost per acre, according to the USDA, is all fuel costs (mostly LPG). For every year, I have used the latest, revised figures.

Note that technically, we want to know energy-dollars per acre of corn harvested for grain rather than energy-dollars per planted acre of corn. However, the two are likely to be extremely close, because virtually all planted acreage is harvested for grain.

[b] Calculated by dividing total expenditure on fuel used for farming (Table K.5) by total quantity of fuel purchased for farming, in the corn belt (excludes household use of fuels) (USDA, *Farm Production Expenditures*, various years).

[c] From USDA, *Agricultural Prices*. LPG prices are for July of the year. Price of power from 1985-1988 is my estimate, based on EIA data.

[d] Based on data in EIA *Annual Energy Review 1989* (1990).

TABLE K.5 Thousands of Dollars of Expenditures on Fuels and Electricity by U. S. Farms in the Corn Belt (except as noted)

Year	Regular Gasoline	Unleaded Gasoline	Diesel Fuel[a]	LPG	Power[b]	NG	Other[a] (coal)	Total[c]
1980[d]	2,678,195	791,094	3,328,379	678,782	1,779,492	270,438	13,324	9,919,885
1981[d]	2,795,068	915,530	3,591,805	717,544	2,137,253	291,905	9,829	10,891,753
1982	507,517	115,353	656,114	205,713	334,074	34,666	1,308	1,922,852
1983	443,053	125,089	682,337	140,625	341,221	27,687	4,151	1,846,969
1984	389,882	108,716	614,754	204,856	381,791	14,196	24,772	1,808,524
1985	347,443	91,703	625,617	228,975	373,203	28,908	11,019	1,775,772
1986	252,500	64,302	448,651	159,069	381,341	19,298	4,400	1,394,626
1987	244,673	56,399	478,792	101,317	412,499	21,807	29,512	1,394,965
1988	203,360	58,416	422,925	81,747	415,412	21,045	4,037	1,260,834

Note that these data are expenditures by all farms in the corn belt, whereas what we want is expenditures for corn farming in particular. However, the difference is almost certainly unimportant, first, because corn farming is a major part of all farming in the corn belt, and second, because we are interested in the percent of the total energy expense spent on each fuel, not the absolute expenditures themselves, and there is likely to be much less variation among farms in this number (the ratio) then in the absolute numbers.

[a] For 1980-1983, figures under "diesel fuel" include kerosene and fuel oil, and figures under "other" are the difference between the total shown by the USDA and the sum of all the expenditure categories shown. For 1984-1988, the figures under diesel fuel include only diesel fuel, and the "other" category, which is explicitly shown by the USDA for these years, includes coal, kerosene, wood, and other fuels.

[b] Includes electricity for irrigation.

[c] Includes a small amount of expenditure for "motor oils, grease, and special fluids." This expenditure for oil and fluids must be included in the total expenditure here because it is included in the dollar/acre figures of Table K.4; that is, the "expenditure total" here, which is used to determine each fuel's share of total energy expenditures, must be defined the same way as the "total" in "total energy $/acre." Note, though, that I do not actually count any emissions from oxidation of grease. This is because I cannot determine how much of the expenditure is for grease, which eventually oxidizes to CO_2, and how much is for non-CO_2-producing "special fluids."

[d] National expenditure data, as opposed to expenditures in the corn belt.

Source: USDA, *Farm Production Expenditures* (various years).

TABLE K.6 Million Btu Per Planted Acre of Corn (except last column)

Year	Regular Gasoline	Unleaded Gasoline	Diesel Fuel	LPG	Power	NG	Other (coal)	Total	10^6 Btu/ Bushel
1980	0.726	0.208	1.140	0.229	0.308	0.197	0.024	2.832	0.0311
1981	0.741	0.241	1.153	0.236	0.361	0.199	0.018	2.949	0.0271
1982	0.679	0.156	1.046	0.354	0.239	0.096	0.011	2.582	0.0228
1983	0.628	0.178	1.073	0.180	0.204	0.058	0.029	2.350	0.0290
1984	0.464	0.131	0.867	0.256	0.205	0.028	0.166	2.117	0.0198
1985	0.491	0.130	1.071	0.357	0.236	0.070	0.090	2.444	0.0207
1986	0.486	0.125	1.087	0.283	0.246	0.051	0.038	2.317	0.0194
1987	0.467	0.112	1.164	0.212	0.281	0.063	0.273	2.572	0.0215
1988	0.387	0.116	1.029	0.160	0.278	0.061	0.038	2.070	0.0245

Data on 10^6 Btu/acre are calculated from data of Tables K.4 and K.5. Data on 10^6 Btu/bushel are calculated by dividing total 10^6 Btu/planted-acre by bushels/acre-harvested for grain (Table K.1).

TABLE K.7 Estimates of Energy Used to Grow Corn and Produce Ethanol, Btu-Process Energy/Btu-Ethanol

Reference	Fertilizer[a]	Farming	Farm Equipment	Corn Transport	Conversion to Ethanol: Coal	Conversion to Ethanol: Electricity[b]	Conversion to Ethanol: Facility	Notes
Giampietro and Pimentel (1990)	0.33	0.16	0.13	0.06	0.90	I?	0.06	c
Jones (1989)	NE	NE	NE	NE	0.79	0.057	NE	d
Jones (1989)	NE	NE	NE	NE	0.60	0.071	NE	e
Anderson (1988)	-------0.41-0.62-----		NE	?	0.57-0.85	?	NE	f
Ferchak and Pye (1981)	-------0.46-0.53-----		I?	NE	---see Katzen (1979)---			g
Katzen Associates (1979)	---------0.44--------		NE	I	0.49	0.050	<0.01	h
Chambers et al. (1979)	0.41	0.34	0.09	0.11	0.59	I?	0.04	i
Ho (1989)	0.21	0.22	NE	NE	0.59	0.052	NE	j
Parisi (1983)	0.28	0.23	0.10	0.05	0.42	I	0.09	k
Marland and Turhollow (1990)	0.17	0.10	NE	NE	0.33-0.53	0.048	NE	l
Pimentel (1990)	0.27 (0.33)	0.27	0.07	0.006	NE	NE	NE	m
Wayman and Parekh (1990)	NE	NE	NE	NE	0.28-0.77	0.036-0.049	NE	n
Energy Fuels Development (1990)	---------0.29--------		NE	NE	0.38	0.11	NE	o
Keim, IRI (1989)	NE	NE	NE	NE	0.63	0.052	NE	p
This report	0.19	0.10	NE	0.03	0.35-0.60	0.050	NE	q

An "I" under "conversion to ethanol/electricity" means electricity use is included in the estimate of coal-energy requirement; "?" means it is not clear if the electricity-energy is included in the coal-energy or if it has simply not been counted. "?" under "corn transport" means that it is not clear if corn transport energy has been included under farming energy or not. "I" under "corn transport" or "farm equipment" means that the energy is included under "farming" and "fertilizer." "NE" means that the particular kind of energy use is not estimated. Estimates are based on higher heating values, unless stated otherwise.

For methanol, I assume 22.7 kJ/g or 64,500 Btu/gal HHV and 19.95 kJ/g or 56,700 Btu/gal LHV; for ethanol, I assume 84,600 Btu/gal HHV and 75,670 Btu/gal LHV.

[a] Does not include N_2O emissions from denitrification of fertilizer (see Appendix N).

[b] Electricity counted at 3,412 Btu/kWh, unless otherwise noted.

TABLE K.7 (Cont.)

[c] "Farming" energy includes labor (negligible), fuel, electricity, and energy embodied in herbicides, insecticides, and seeds. "Fertilizer" energy includes energy embodied in lime fertilizer. "Farm equipment" energy includes energy embodied in transport vehicles. Energy required to ship water to the conversion plant is not included.

[d] Based on actual energy and material balance for the South Point Ethanol plant in October 1984. The plant yielded 2.69 gal/bu of corn and 3,212 tons of DDGS/10^6 gal of ethanol. Energy for drying DDGS is included. I count electricity at 3,412 Btu/kWh and coal at 21×10^6 Btu/ton. I ignore energy in limestone, chemicals, and water.

[e] Based on the actual energy and material balance for the Kentucky Agricultural Energy Corporation plant in July, 1987. The plant yielded 2.58 gal of ethanol/bu of corn and produced 2,985.6 tons of DDGS/10^6 gal of ethanol. I count electricity at 3,412 Btu/kWh and coal at 21×10^6 Btu/ton.

[f] Anderson takes his numbers from other sources, including the Katzen report (1979) and an earlier report by Amoco.

[g] Ferchak and Pye (1981) cite a 1976 estimate that "total cultural energy" requirements for corn are $10.2\text{-}11.621 \times 10^6$ Btu/acre-year (I assume HHV); at 100 bu/acre and 2.6 gal of ethanol/bu (my assumption), the result is 0.46-0.53 Btu/Btu ethanol. Their use of "total" implies that the energy embodied in farm machinery is included.

[h] The farming and fertilizer energy requirement is from a 1974 report and includes energy used for field preparation, harvesting, fertilizer, transport, and miscellaneous activities. The Katzen design produces 2.57 gal of ethanol/bu and consumes 9.2 tons/d of ammonia, 1.2 tons/d of yeast, 3.7 tons/d of chemicals for treating wastewater, and 1,500 gal/d of denaturant. It produces 536.7 tons/d of DDGS and 31.6 tons/d of ammonium sulfate. The by-product DDGS is dried with waste heat from the boilers.

I calculated the electricity consumption assuming a 32% generation efficiency.

The ammonia consumption amounts to 0.121 lb/gal of ethanol produced, or 0.02-0.04 Btu-ammonia/Btu-ethanol, depending on one's assumption about the amount of energy required to make ammonia. This is a nontrivial amount of energy. Nevertheless, I do not count it, because I have not evaluated all chemical inputs for all fuels and processes.

The Katzen design is cited by Chambers et al. (1979), White (1980), TRW (1980), Ferchak and Pye (1981), the *DOE Handbook* (1983), and Anderson (1988). The 0.01 figure for facility energy (under "conversion to ethanol") is from the TRW report (1980).

TABLE K.7 (Cont.)

[i] Data are for a project described by ACR Process Corporation, of which Chambers is (was) president. The ACR process was designed specifically to produce gasohol (that is, gasoline and ethanol together, not just ethanol which later would be blended with gasoline) and have low energy consumption. It produces 2.5 gal/bu. Conversion figures include energy for drying by-products. All figures are supposed to include all nonrenewable energy inputs, which implies that electricity is included.

Two other studies cited by Chambers et al. estimate about 1.9 Btu of process energy and 0.60 Btu of agricultural energy per Btu of ethanol. Chambers et al. claim that the ACR estimate for agricultural energy is more realistic than these other two.

In converting Chamber et al.'s estimates of process energy requirements to percentages of energy in the ethanol product, I have used their estimate of 77,200 Btu/gal of ethanol, on the assumption that they were consistent and always used lower heating values.

Chambers et al. calculate energy embodied in capital equipment by multiplying the capital cost by 100,000 Btu/dollar. Lave (1977) cites an estimate of 77,600 Btu/dollar.

[j] The main difference between Ho and Marland and Turhollow (1990) is that Ho assumes that corn fields yield 90 bu/acre (the 10-year average in the U. S.) and M & T assume a 1987 value of 119. Another difference is that Ho uses all lower heating values, whereas M & T use all higher values. This means that if both Ho and M & T says a process takes 10,000 Btu/gal of ethanol, the energy consumption is 13.2% for Ho, but only 11.% for M & T.

Ho says that conversion plants use 12,000 Btu/gal of ethanol for electricity and direct heat. I assume that all of this is electricity, and that he means Btu-thermal, and convert back to Btu-electric at 10,400 Btu/kWh. Ho's energy consumption data may come from earlier work by Keim (see note p).

[k] The value for "farm equipment" includes energy embodied in transport trucks (the value for corn transport does not) and is based on the estimate of Chambers et al. (1979) and one other reference.

The value for "farming" includes energy used by machinery, irrigation, and "other." Fuel type is not specified. The value for "conversion to ethanol/coal" is equal to the sum of energy for wort preparation, fermentation, alcohol recovery, and "other" (lighting, administration...). It apparently does not include energy for drying by-products, as that is counted in the by-product analysis.

It is not clear how the author derived the value for "conversion to ethanol/facility." In the text, he mentions only the estimate by Chambers et al. (1979), which is quite a bit lower.

[l] Fertilizer energy requirements are about 96% NG and 4% electricity (Btu-electric). Farming energy is 86% liquid fuel for direct use, 11% energy for irrigation and embodied in pesticides, and the rest electricity. I have converted from their 10,400 Btu/kWh to 3,412 Btu/kWh. See also Marland and Turhollow in Segal (1989) for an earlier version of their work. Based on a fairly thorough literature review.

TABLE K.7 (Cont.)

[m] Pimentel assumes a corn yield of 110 bu/acre. I assume 2.6 gal/bu. Energy ratio under "Fertilizer" includes energy in lime. If the energy values of seeds, insecticides, and herbicides are included here, the ratio increases to 0.33. The energy ratio under "Farming" includes irrigation, drying, electricity, gasoline, and diesel fuel.

[n] The lower coal consumption figure is based on Wayman and Parekh's report of a plant that consumes 21,000 Btu/gal (I assume they are using lower heating values), a value they say "is considered low by industry standards" (p. 199). They correlate this figure with a steam consumption rate of 2.04 kg steam/liter of ethanol (indicating about 1,200 Btu/lb steam). Then, they show that whole grain milling consumes up to 5.64 kg steam/liter of ethanol.

The lower electricity consumption figure is calculated from Wayman and Parekh's figure of 0.24 kWh/liter for whole grain milling; the higher, from their figure of 0.32 kWh for wet milling (I use HHVs).

[o] The values shown for conversion are design values. Actual energy consumption is lower: 0.34 Btu-coal/Btu-ethanol and 0.085 Btu-electricity/Btu-ethanol.

[p] Keim shows 1.3 kWh of purchased power per gallon and 40 lb of steam from coal per gallon. I assume 1,195 Btu/lb steam and 90% generation efficiency, following a personal communication from Ho to Keim.

[q] See text for details. Fertilizer energy estimate from data of Table K.1 and K.3, with additional accounting for energy embodied in herbicides, insecticides, and seeds (factor of 1.2; see text), and energy in lime and sulfur fertilizer. Farming energy estimate from data of Table K.6. Conversion energy estimates are from consideration of data of this table. Although in the base case, I do not account for energy embodied in farming equipment and conversion facilities, in the scenario analyses of the main chapter, I do consider the effect of assuming that 0.15 Btu of energy is embodied in equipment and facilities per Btu of ethanol produced.

TABLE K.8 Estimates of By-Product Credit for DDGS

Reference	DDGS Replace	Total Btu/gal	% Breakdown in Btu/gal G / D / R / C / NG / E
TRW (1980)	Soy protein	8,526[a]	32/28/1/31/7/[a]
Ho (1989)	Soy protein	7,000-7,600[b]	
Marland & Turhollow (1990)	Soy protein	7,390[c]	--/45/--/30/6/20
Chambers et al. (1979)	Corn feed	7,000-20,000[d]	
EPA (1990)[e]	Soybeans	8,777-9,418[f]	
Giampietro and Pimental (1990)	Feed	10,500[g]	

G = gasoline; D = diesel fuel; R = residual fuel; C = coal; NG = natural gas; E = electricity.

[a] 2,695 Btu gasoline, 2,415.5 Btu diesel fuel, 110.6 Btu residual fuel, 577.8 Btu NG, 2,635.7 Btu coal, and 91.5 Btu other energy. I have not assigned the 91.5 Btu to a fuel category. Electricity does not show up here because TRW has already broken down electricity into specific input fuels; in other words, the breakdown shown in this note includes fuel inputs to electricity. TRW assumes 3,544 tons of DDGS/10^6 gal of ethanol, based on the design described by Katzen Associates (1979), which is a bit higher than the actual production of DDGS reported recently by two ethanol plants (Jones 1989); see notes to Table K.7. Wyman and Hinman (1989) report 3,269 tons of DDGS/10^6 gal of ethanol for whole corn milling. This is close to the Katzen number (3,544).

[b] Ho (1989) reports 7,000 Btu/gal using LHV; if he had used HHV, the result would have been about 7,600 Btu/gal. TRW and Turhollow use HHV; Chambers et al. apparently use LHV.

[c] They estimate 0.721 lb of soybean meal per lb of DDGS and count electricity at 10,400 Btu/kWh.

[d] Chambers et al. assign DDGS used as animal feed (not protein feed) a credit of about 27% of the energy required to produce corn, which results in 7,000 to 20,000 × 10^6 Btu/10^6 gal of ethanol, depending on one's assumption regarding the amount of energy required to produce corn (the upper end probably is too high).

[e] *Analysis of the Economic and Environmental Effects of Ethanol as an Automotive Fuel.*

[f] The reference actually shows the soybean farming credit as 1.37-1.47 lb of CO_2/gal of ethanol produced. If the CO_2 credit comes from the use of diesel tractors, at 70,800 g of CO_2/ 10^6 Btu of diesel (Table A.2), the result is 8,777-9,418 Btu of diesel/gal of ethanol. I assume HHV.

[g] The authors may be using LHV. If so, the use of HHV would raise the total to about 11,600 Btu/gal.

TABLE K.9 Energy Required to Grow and Harvest Wood in SRIC Systems, Btu-Process Energy/Btu-Wood

Reference	Tree Type	Btu/lb	Fertilizer	Irrig.	Equipment	Drying	Transport	Other[a]	Total[b]
Blankenhorn et al. (1985)	Poplar	8,319	0.069	0.029	I[c]	NI	I	0.067	0.165[d]
Blankenhorn et al. (1985)	Poplar	8,319	0.070	NI	0.020	NI	0.009	0.037	0.136[e]
Ledig (1981)	Poplar	NS	0.032	0.058	NI	NI	NI	0.005	0.094
Ledig (1981)	Poplar	NS	0.038	0.017	0.007[f]	NI	NI	0.027	0.089
Ranney et al. (1987)	Generic	8,100	?	?	?	I	I	- -	0.083[g]
Ledig (1981)	Jack pine	NS	0.021	0.022	0.009[f]	NI	NI	0.027	0.079
Ledig (1981)	Poplar	NS	0.047	NI?	NI?	NI	NI	0.028	0.074
Smith & Corcoran (1981)[h]	Generic	8,350	0.040	NI	0.003	NI	0.011	0.014	0.068
Blankenhorn et al. (1985)	Poplar	8,319	NI	NI	0.016	NI	0.008	0.035	0.059[e]
Ferchak & Pye (1981)	Generic	8,350	NI[i]	NI	0.006[j]	NI	NI	0.040	0.046[k]
Parisi (1983)	Generic	NS	I	I	I	NI	I	- -	0.019
This report	Generic	8,350	0.039[m]	NI	NI	I[n]	0.008	0.035	0.087

SRIC = short-rotation intensive cultivation; ODT = oven-dried ton of wood. "I" means that the energy for the category is included in the total shown but is not broken out separately; "NI" means the energy item is not counted at all; "?" means not clear if included in the total or not; "NS" means not specified.

[a] Energy used for planting, harvesting, chipping, etc.

[b] Excludes energy used for transport and energy embodied in equipment.

[c] Includes energy embodied in agricultural equipment but not in the wood-to-fuel conversion plant. Blankenhorn et al. (1985) do a detailed calculation of the energy embodied in machinery; it includes energy required to make the materials (mostly steel), energy required to fabricate the machinery, and energy required to maintain and repair the machinery. Their figures for energy in materials agree with mine (Appendix P), but their figures for fabrication energy seem high.

[d] This scenario is not given explicitly in the reference. I have added irrigation energy cost to a fertilizer-only case.

TABLE K.9 (Cont.)

[e] Table 3-8 of Blankenhorn et al. (1985) shows establishment, maintenance, fertilizer (if any), and harvest and transport energy requirements for an SRIC-to-ethanol scenario. I have broken their estimate for "establishment" into energy embodied in equipment and other energy, and their estimate for "harvest and transport" into energy embodied in equipment, including transport trucks, energy used by transport trucks, and harvest energy. I then add all the energy embodied in equipment and assign it to my "equipment" category. I assign the energy used by transport trucks to my "transport" category; all the remaining energy (nonequipment, nontransport energy used for establishment, harvest, and maintenance) I assign to "other."

I apportion their single number in their Table 3-8 for "harvest and transport" energy into energy embodied in equipment, transport energy, and harvest energy, by using their data from their Table C-8, strategy B: I assign fuel use by tractor truck and trailer van to my "transport" category, all fixed energy to my "equipment" category, and harvest energy to my "other" category. I apportion establishment energy into equipment and other energy by using the data of their Tables A-15 and A-16.

[f] Irrigation equipment.

[g] Presumes drying to 20% moisture (authors may mean "passive" drying; it is not quite clear). The authors note that fertilizing improves growth on some sites, but, in general, less fertilizer is used than in agriculture, and in some cases, no fertilizer is needed. Not clear if energy embodied in capital is included. The authors give a single total energy requirement, not broken down into subareas.

[h] Data in reference are in 10^6 Btu/ODT. I assume 8,350 Btu-lb. Their fertilizer use and energy content assumptions were 1,000 lb of nitrogen/acre/yr and 33,000 Btu-lb for manufacturing and applying fertilizer. They assume energy required to build roads would be small. Data in reference indicate that energy cost would be the same if no fertilizer were used (energy input would be reduced by about half, but yield would be reduced by about half, too).

[i] Manure, but no chemical fertilizer.

[j] Based on a yearly, amortized, embodied energy requirement of 3,979 Btu/lb, a number Ferchak and Pye get from a 1973 report. Since energy consumption has declined considerably since pre-1973, the 3,979 figure is probably too high. To see this, consider the data of Table P.4. Assume that the material in the farm equipment averages 25,000 Btu/lb, and that repair brings the total to 30,000 Btu/lb before amortization. If the equipment lasts 15 years, the result is 2,000 Btu/lb per year, half the figure used by Ferchak and Pye.

[k] Data in original in Btu/ODT. They assume a rather high yield of 10 oven-dried tons/acre/yr, and 1/2 ton residue-fertilizer (such as manure, not chemical fertilizer) per oven-dried ton of wood. I assume 8,350 Btu/lb-wood.

TABLE K.9 (Cont.)

[l] Given as 0.038 Btu-input/Btu-ethanol. I assume 50% conversion efficiency to ethanol. Parisi does not break his estimated total energy requirement into subareas.

[m] This is the figure for fertilized acreage only. Some acreage is not fertilized. Calculated from data of Table K.10.

[n] Included in the energy used by the conversion facility.

TABLE K.10 Fertilizer Use for and Productivity of SRIC

Reference	Fertilizer (lb/acre/yr) N	P_2O_5	K_2O	Lime	Yield (dry tons/acre/yr)
Turhollow (1989)	44.6	13.4	13.4	0	5.00[a]
Blankenhorn et al. (1985)[d]	151.3	83.4	99.5	2079.6	4.30
Smith & Corcoran (1981)	1,000.0	NS	NS	NS	5.00[c]
Ranney et al. (1987)	------- Zero in some cases ---------				5.85[d]
Ranney et al. (1987)	------- Zero in some cases ---------				7.65-9.00[e]
Klass (1987)	-------- No fertilizer used ---------				4.2-27.3[f]
Base-case assumptions here[g]	150.0	25.0	25.0	0.0	6.0

[a] Yield after harvesting loss of about 20%, indicating about 6.0 tons/acre/yr before losses.

[b] Fertilizer and yield figures are four-year totals for the Basher site, with fertilization and no irrigation, divided by four. Yield is after harvesting loss of 10% has been deducted.

[c] "Growth rate."

[d] 1987 value. Not clear if this accounts for harvesting losses.

[e] Projection for the year 1996, assuming ambitious research. Not clear if this includes harvesting losses.

[f] Not clear if this is after or before harvesting. Range shown is overall range for six different SRIC systems not using fertilizer. High end of range applies to cottonwoods. Excluding cottonwoods, typical yield was 6-7 tons/yr.

[g] Fertilizer applied to acres receiving fertilizer. I assume in the base case that about 50% of the acres receive fertilizer.

TABLE K.11 Energy Required to Convert Wood to Fuel, Btu-in/Btu-Fuel

Process and Reference	Wood	Electricity	Other	Notes
Methanol/wood/gasification				
Chrysostome et al. (1986)	2.05-2.36	NS		a
Mehrling and Reimert (1986)	2.22	NS		b
Klass (1987)	1.75-2.04	NS		
Stone and Webster (1987)	1.74	0.083		c
DOE (1983)	1.75	0.0164		d
White (1980)	1.35	0.019		e
SERI (1989)	NS	0.038		f
Hall et al. (1990)	1.73	0.019	?	g
SNG/wood/gasification				
Feldmann et al. (1988)	1.46	0.024		h
DOE (1983)	1.37	0.000005		i
Flanigan et al. (1988)	1.36	NS	1.44	j
SERI (1989)	NS	0.02		f
Evans et al. (1988)	1.33	0.033		k
Gaines et al. (1987)	~1.33	NS		l
Cogliati (1986)	1.35	I		m
Bridgwater (1990)		0.011		mm
Ethanol/wood/enzymatic hydrolysis				
Stone and Webster (1985)	3.16	0.31		n
Ferchak and Pye (1981)	2.83	0.05-0.24	(-0.90)	o
Blankenhorn et al. (1985)	2.17	NS		p
Wright (1988)	2.00	0.08		q
Lynd (1990)	1.7-2.0	I?		r
Hinman et al. (1989)	?	-0.02		s
Private communications from SERI	2.35	-0.08		t
Wood-to-gasoline				
Stevens (1989)	1.4-2.7	0.01-0.03		u
Gaines et al. (1987)	1.6-3.1	NS		v

NS = not specified; "I" means included in wood requirement.

For methanol, I assume 22.7 kJ/g or 64,500 Btu/gal HHV and 19.95 kJ/g or 56,700 Btu/gal LHV; for ethanol, I assume 84,600 Btu/gal HHV and 75,670 Btu/gal LHV. Electricity is counted at 3,412 Btu/kWh, unless otherwise noted.

[a] This estimate includes neither electric power nor energy required to convert oxygen.

[b] Some of the steam raised from the wood fuel is used to separate air and provide oxygen. However, some electricity is still imported. Wood drying is included in the system.

TABLE K.11 (Cont.)

[c] The electricity figure is equal to the amount reported as being purchased, 0.30 Btu-electric/Btu-methanol, plus my calculation of the amount of electricity required to produce the required oxygen. I calculated this to be 0.053 Btu-electric/Btu-methanol, based on the reported oxygen consumption of 0.6 kg-O_2/liter methanol and an oxygen-manufacturing power demand of 0.2 kWh/lb-O_2 (Table J.2). It is not clear if wood drying is included, as I have not consulted the original reference.

[d] The *DOE Handbook* (1983) expresses electricity consumption as Btu of electricity/Btu of product. I assume that Btu of electricity refers to end-use power consumption (3,412/Btu/kWh). The DOE estimates do not include energy used to make the equipment used to convert the biomass. They assume 9,650 Btu/lb for the wood feed to the methanol process.

[e] White estimates that the use of purchased electricity produces 13 lb of $CO_2/10^6$ Btu of methanol. He assumes that the electricity plants use coal and have a heat rate of 10,340 Btu/kWh and that coal produces 225 lb of $CO_2/10^6$ Btu. These numbers result in 0.019×10^6 Btu of power (end-use electricity)/10^6 Btu of methanol. He also states that wood combustion or gasification produces 292 lb of CO_2 per 10^6 Btu of methanol. Assuming 50% carbon in the wood, and 8,500 Btu/lb (Klass 1987), the result is 1.35×10^6 Btu of wood/10^6 Btu of methanol.

[f] Stevens (personal communication, 1989) of the Solar Energy Research Institute (SERI) says that the latest information at SERI indicates 0.7-0.75 kWh/gal of methanol, from wood gasification. He estimated that production of medium-Btu SNG from wood would require 25-50% less power, because the methanol synthesis loop, in which the gas is compressed, would be eliminated.

[g] The authors report that electricity for the process costs $0.0290/gal. Assuming $0.08/kWh, the result is 0.3625 kWh/gal, or 0.019 Btu/Btu. The process produces excess steam but also requires some additional fuel (probably on the order of 0.04 Btu-fuel/Btu-methanol). I assume that the energy value of the excess steam is equal to the energy value of the extra fuel required.

The Hall et al. data are from a December 1989 report by Chem Systems, *Assessment of Cost of Production of Methanol from Biomass*, for SERI.

[h] These figures include wood drying: wood is dried in this system by waste heat from the gasifier. The process apparently does not require pure oxygen.

[i] See note d regarding electricity consumption and equipment. The medium-Btu syngas process uses a small amount of natural gas to burn the wood. They assume 8,538 Btu/lb for wood chip feed for SNG.

[j] Typical test results were: 1,557,317 Btu/h feed, 1,140,813 Btu/h gas (apparently HHV), and 78 lb/h propane (21,110 Btu/lb). Process does not require pure oxygen. Authors remark that excess heat probably would be sufficient for drying the wood. The "other" fuel is the propane; a surprisingly large amount is required.

TABLE K.11 (Cont.)

[k] The data given in the reference are 0.22 lb-O_2/lb feed, 8,306 Btu/lb-feed, and 75% thermal efficiency. I assume 0.2 kWh/lb-O_2, from Table J.2.

[l] The authors state that the long-term goal is to achieve an overall thermal efficiency of 95%, which implies that only 5% of the feed wood energy is required for process energy (unless process energy is provided by other sources). It is not clear if their energy estimates include power or drying.

[m] The author states that the heat in flue gas would be used to dry the wood and generate electricity for the plant. No oxygen (air separation) is required if it is acceptable for the medium-Btu syngas to have some methane; if the methane is to be removed, oxygen must be added, at an additional energy cost. A small amount of auxiliary fuel (propane) is used at startup.

[mm] Bridgwater (1990) cites a 1986 review of gasifiers that states that power costs 0.114 English pounds per gJ produced. In 1986, the industrial sector in the United Kingdom paid 5.3 cents/kWh, and the pound and the dollar traded at the rate of 0.68:1 (EIA, *International Energy Annual 1986*, 1987). This results in 3.163 kWh/gJ.

[n] I calculated the electricity consumption from their electricity cost data, assuming 4 cents/kWh. It is not clear if drying is included or if xylose is assumed to be converted.

[o] Values shown do not include energy embodied in labor, chemicals, or plant and equipment, which add up to an additional 0.032 Btu/Btu-ethanol (assuming the low end of the range of chemical requirements), of which 3/4 is energy embodied in the ethanol plant. They appear to assume 43,000 Btu/lb of material in the ethanol plant. This probably is high by a factor of two: concrete, probably the main material in an ethanol plant, contains much less than 10,000 Btu/lb, and steel, the second-most common material, contains around 20,000-30,000 Btu/lb. Material transport and assembly (plant fabrication) typically require much less energy than material manufacture. Thus, it seems likely that the whole process of making and assembling the materials for a plant averages no more than 20,000 Btu/lb.

The wood requirement is calculated from their assumption of 71 gal of ethanol per oven-dried ton and my assumption of 8,500 Btu/lb of wood. I presume that the energy required to dry the wood is included in the wood or electricity requirements, since Ferchak and Pye state that drying and electricity are taken to be "subsidiary to an on-site processing plant" (p. 19).

One process cited by Ferchak and Pye required 3 lb of chemicals/gal, which, at 20,000 Btu/lb, would require 71% of the energy in the output ethanol. This seems quite high, but could indicate that chemical usage can be quite important in some designs and processes.

Ferchak and Pye assume that none of the lignin and a small portion of the other carbohydrate (about 14% of the weight of the dry wood) is not converted to fuel. The energy value of the lignin and the unconverted carbohydrate mash is about 90% of the energy value of the produced ethanol. This energy could be used to generate more than enough electricity to run the process. For example, some processes can export . electricity at the rate of about 0.03 Btu-electric/Btu-ethanol (Hinman et al., 1989).

TABLE K.11 (Cont.)

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[p] They appear to assume that a small amount of the xylose, and none of the lignin, is converted to ethanol.

[q] Wright (1988) states that agitation costs $0.13/gal of ethanol; Wyman (1989) says $0.15/gal. This indicates roughly 2 kWh/gal, or an energy requirement of about 8%.

SERI has confirmed that 2 kWh/gal is reasonable, for current technology (Stevens, 1989). However, the technology is very young, and power consumption almost certainly will be reduced significantly with technical progress. Wyman (1989) suggests that the power cost could drop to only a "few" cents per gallon of ethanol, which implies about 1/2 kWh/gal. The wood feedstock is about 50% cellulose and 25% xylose at 7,400 Btu/lb, and 25% lignin at 11,300 Btu/lb. Wright states that in the current separate hydrolysis and fermentation (SHF) process, 73% of the cellulose in the feed wood is converted to ethanol, and the xylose and lignin are burned for process heat. This indicates that the energy in the parts of the wood feed used for process heat exceeds the energy in the feed converted to ethanol by a factor of about two. The relatively low conversion of wood to fuel also makes the ethanol product relatively expensive. To reduce the cost of ethanol, the xylose and perhaps lignin fractions must also be converted to fuel. The difficulty with xylose is that standard industrial yeast will not ferment it; the difficulty with lignin is that chemical rather than biological conversion is required. The state of the art in xylose and lignin conversion is reviewed in SERI's *FY Ethanol from Biomass Annual Report*, SERI/SP-231-3521, June (1989). Note that the most recent plans convert the xylose but burn the lignin to provide process heat.

Wright's estimate for enzymatic hydrolysis uses no xylose or lignin conversion. It is not clear if wood drying is included or if it is necessary.

[r] Lynd states that overall thermal efficiency for high-yield processes is 45%-60% and implies that electricity is produced on-site by burning the unconverted lignin. It is not clear if feed drying is included.

[s] The authors estimate that a process using both the xylose and the lignin as boiler fuels would generate surplus electricity worth 4.62 cents/gal. Assuming 8 cents/kWh, the result is 0.023 Btu-electric surplus per Btu of ethanol.

[t] These are unpublished estimates from researchers in the field. The process converts cellulose and xylose to ethanol, and uses all the lignin as a boiler fuel. The process produces substantial excess electricity.

[u] High end of range is "present case"; low end is "future case." Apparently assumes pre-dried wood chips and apparently does not require oxygen. In both cases, the char contains most of the input energy not lost or converted to gasoline; a portion of the char is burned to provide process heat, and a portion is packaged as char product.

[v] High end of range is 1987 value; low end is most optimistic goal.

TABLE K.12 Release or Uptake of Greenhouse Gases in a Biofuel Program, in Metric Tons of CO_2 or CO_2-Equivalent Emissions per Acre, as a Result of Changes in Land Use

Possible Releases of CO_2, per Acre						Possible CO_2 Uptake, per Acre			
			CO_2 from Soil			By Soil		By First Planting	
CO_2 from Oxidation of Previous Biomass[a]									
Grassland	Open Woodland	Dense Forest	Range to Crop	Forest to Crop	N_2O from Soil	Crop to Corn	SRIC	SRIC	SRIC
~10[b]	40-60[c]	100-300[d]	23[e]	90[f]	0.2[g]	7[h]	0-?[i]	7-11[j]	40-60[k]

SRIC = Short-rotation intensive cultivation.

[a] "Biomass" includes all above-ground plant material, dead or alive, and the belowground root system. "Soil" refers to all other belowground carbon (generally to the first meter of depth). The numbers shown assume that all of the biomass carbon eventually oxidizes to CO_2 but say nothing about the rate of oxidation. Generally, a portion of the biomass will be burned immediately, a portion will rot in a few years, a portion will rot over many years, part will be used as wood and last for a century, and some, perhaps, will be permanently remain as as charcoal (Houghton et al., 1983).

[b] Whittaker and Likens (1973; 3 metric tons of carbon per acre); Hall (1990; 6-11 tons of carbon/hectare in the U. S.).

[c] Whittaker and Likens (1973; 11 metric tons of carbon per acre of woodland and shrubland); Detwiler and Hall (1988; 11-15 metric tons of carbon per acre of primary, open tropical forest); Hall (1990; 27 tons of carbon per hectare in the U. S., and 21-120 in Africa and Asia).

[d] Whittaker and Likens (1973; 36 metric tons of carbon per acre for boreal forests, 81 for tropical rain forests); Detwiler and Hall (1988; 33-60 metric tons of carbon per acre for primary, closed tropical rain forests); Birdsley (1990; 38 metric tons of carbon per acre of spruce/fir forest in northeastern U. S., and 76 metric tons of carbon per acre of loblolly pine forest in the southeastern U. S.); Hall (1990; 80-200 tons of carbon/hectare closed forests).

[e] Burke et al. (1989).

TABLE K.12 (Cont.)

f Forest soils contain 88-206 metric tons carbon per hectare, depending on type and age of the forest (Schlesinger 1977; Birdsley 1990, shows a similar range), and the conversion of forests to agriculture releases 40-50% of the carbon in the soil (Detwiler and Hall, 1988; Woodwell et al., 1983; Houghton et al., 1983). A typical release is about 60 metric tons of carbon/hectare, or 24 metric tons per acre, or about 90 metric tons of CO_2 per acre. Hall (1990) shows a lower estimate.

g Emissions from cleared forests. Bowden and Bormann (1986) found that 0.33 kg of nitrogen degassed as N_2O from water in forest soil, per hectare of cleared land, and said that a "similar" amount degassed from the soil itself. Taking "similar" to mean "same," and using an N_2O-to-CO_2 conversion factor of 290 (Table 8), the result is 244 kg CO_2-equivalent emissions per acre of cleared forest, or 0.244 metric tons per acre (which I round to 0.2). They did not report N_2O emissions from soils of cleared grasslands or other ecosystems.

h This is the CO_2 uptake from an intensive program to build organic matter in the soil, relative to no such program. Assumes a build-up of 0.73 metric tons of CO_2 per year (Homberg 1988), for what I assume is a maximum of 10 years, before oxidation of soil carbon equals uptake. Wallace et al. (1990) imply that 0.26 metric ton of CO_2 could be sequestered per acre per year for 100 years, but they appear to have overlooked oxidation of the organic matter.

i Cropland to SRIC. Reliable data are not available. However, it probably is reasonable to assume that the carbon content of the soil of SRIC systems will be similar to the soil carbon content of crop systems and much less than the content of undisturbed, natural forests. The ground in an SRIC system will be kept free of detritus, to supress weeds and facilitate movement between rows, and will be disturbed frequently by planting and harvesting, whereas in a natural forest, the soil is covered with litter and low-growing plants and remains relatively undisturbed.

j Whittaker and Likens (1973) report 2 metric tons of carbon per acre of "cultivated land," generally. Blankenhorn et al. (1985) measured 16 dry metric tons of corn specifically, per hectare. Assuming 48% carbon by weight, the result is 3.1 metric tons of carbon per acre. The difference between Birdsley's (1990) estimate of total carbon for cultivated systems and Burke et al.'s (1989) measurement of carbon in the soil of cultivated land is about 2 metric tons per acre. Hall (1990) cites an estimate of 5 tons of carbon per hectare, or 6.7 metric tons of carbon per acre.

k Assuming a growth rate of about 5-8 English tons per acre per year (see Table K.10; Wyman and Hinman, 1990, assume 7 English tons), a five-year growth period before the first harvest, and 48% carbon by weight.

TABLE K.13 Data Used to Calculate Energy Balance of Using Corn-Crop Residue as a Fuel

Residue			Collection	Nutrient Loss (tons/ton-residue)			% Corn
Available Ton/Acre	Removable Ton/Acre	HHV Btu/Ton	Energy (10^6 Btu/ton)	N	P	K	Loss per Ton/Acre
2.45-2.6[a]	1.5-2.0[b]	15-16[c]	0.14-0.84[d]	0.0075	0.001	0.0045	0.3-3.2[f]

[a] Starr et al. (1978), SERI (Flaim, 1979; Duave and Flaim, 1979), and Pimentel et al. (1981). Chambers et al. (1979) report an estimate of 3.6 tons/acre, but the estimates by the others, particularly SERI, are of higher quality.

[b] SERI (Flaim, 1979; Duave and Flaim, 1979) and Pimentel et al. (1981). SERI estimates the amount of residue that can be removed without exceeding soil-loss limits set by the U. S. Soil Conservation Service.

[c] For dry residue with 15% moisture (Green, 1975; Starr, 1978). With higher moisture content, the value is about 12×10^6 Btu ton (Pimentel et al., 1981; Chambers et al., 1979).

[d] Starr et al. (1978) estimated that collection, preparation, and delivery of residue would require from 2.17 to 4.16 gal of diesel fuel per ton of residue, with most of the energy being used to collect, bale, and grind the residue. The total excluding transportation was 2.05 to 4.04 gal/ton, which is 284,000-560,000 Btu/ton, or 2-4% the energy value of the residue.

Starr et al. (1978) do not include energy for drying, since 15%-moisture crops will not spoil and can be shredded and fired in coal-fired boilers. Maurya et al. (1980) calculated that to collect (but not transport) residue required about 6% of the energy content of the residue.

Pimentel et al. (1981) estimate that 1.3% of the energy value of the residue is required to collect (not transport) the residue.

The estimate by Starr et al. (1978) is most detailed and seems most reliable.

[e] Pimentel et al. (1981) calculate that a ton of residue contains 0.01 ton of nitrogen, 0.001 ton of phosphorus, and 0.009 ton of potassium. If the ton of residue is removed, these nutrients are no longer available.

There is an additional loss of nutrients from soil eroded as a result of removing the residue. On flat land, and with conservation tillage, each ton of residue removed causes additional erosion of 0.53 ton; on steeper land, with conventional tilage, the loss is 2.57 tons/ton-residue removed; and with no tillage and a cover crop, there is no extra loss loss (Pimentel et al., 1981). 0.005 ton of nitrogen and 0.001 ton of phosphorus are lost per ton of erosion. Assuming 1 ton of erosion per ton of residue removed, on average, the result is 0.005 ton of nitrogen and 0.001 ton of phosphorus per ton of residue removed. This is added to the loss from the removed residue itself. The total is 0.015 ton of nitrogen, 0.002 ton of phosphorus, and 0.009 ton of potassium lost per ton of residue removed.

TABLE K.13 (Cont.)

Pimentel et al. apparently assume that if the residue were not removed, it would be left on the ground to prevent erosion and provide nutrients. However, analysts familiar with corn-farming practices indicate that about half the corn stover is not used to control erosion and provide nutrients but simply is burned in the field. (In support of this, I note that only about 20% of corn-farming land is covered with residue after planting, according to the USDA's *Agricultural Resources*, 1989.) When the stover is burned, it loses most of its nutrients, and it no longer protects against erosion. Hence, if this stover that normally would be burned in the field were instead burned at the corn-to-ethanol facility, there would be little change in soil erosion or nutrient content. To account for this, I reduce the results calculated above, from the Pimentel et al. data, by a factor of 2.0. (Note that the failure to use nutrients in the stover that is burned in the field is implicitly accounted for in the fertilizer-use data calculated in Tables K.1 to K.3, because those are real data from current practice.)

[f] Percent reduction in corn yield, per ton of residue removed, per acre. Pimentel et al. (1981) estimate that the removal of 3.85 tons of residue from a hectare (not an acre) of conventionally tilled land with a slope of 6-12% reduces corn yields by an average of 10% over 30 years. On flat land with conservation tillage, the removal of 4.19 tons of residue from a hectare reduces corn yield by 1%. This indicates 0.24-2.6% reduction per ton/hectare removal rate, or 0.6-6.4% ton/acre removed.

However, as discussed in note e above, not all the stover would remain on the ground in any case — some would be burned and effectively wasted. As per note e, I assume that half the stover would have been burned anyway, which means that only half of the stover removed for fuel actually would contribute to further erosion.

Appendix L:

Hydrogen

Appendix L:

Hydrogen

L.1 Overview*

Hydrogen is a very attractive transportation fuel in two important ways: it is the least polluting fuel that can be used in an internal combustion engine, and it is potentially available anywhere there is water and a clean source of power. The prospect of a clean, widely available transportation fuel has motivated much of the research on hydrogen fuels.

Serious work on hydrogen vehicles began in the 1930s, when Rudolph Erren converted over 1,000 vehicles to hydrogen and hydrogen/gasoline operation in England and Germany. However, interest in the fuel waned after World War II. The resurgence of research and experimental activity came in the late 1960s and early 1970s as programs began in Europe, Canada, the Soviet Union, Japan, and the United States.

L.1.1 Hydrogen Production

Elemental hydrogen occurs freely on earth in only negligible quantities. It is chemically very active, readily forming compounds with many other elements. Hydrogen is most abundant and accessible in water and the fossil fuels: coal, oil, and natural gas. Of the fossil fuels, coal is by far the most plentiful.

Of course, hydrogen derived from fossil fuels is not a clean, renewable resource. Most of the hydrogen research community agrees that eventually hydrogen should be produced from water. There are several methods for splitting water to produce hydrogen: thermal and thermochemical conversion, photolysis, and electrolysis. Of these, electrolysis, or splitting of water with electricity, is the most attractive at present.

When hydrogen is produced from water electrolytically, the ultimate energy source is the feedstock used to generate the electricity. Fossil fuels would not be used, because it would be cheaper and more efficient and would generate less carbon dioxide (CO_2) to gasify the coal, oxidize the oil, or reform the natural gas directly to produce hydrogen. Nonfossil feedstocks, such as solar, geothermal, wind, hydro, and nuclear energy, would be used. Of these, solar energy and nuclear energy (from breeder reactors or, possibly, fusion plants) are available for the long term. This report considers both solar and nuclear energy as hydrogen feedstocks.

*From DeLuchi, "Hydrogen Vehicles," in Sperling, ed., 1989.

L.1.2 Hydrogen Distribution

Hydrogen probably will be transported via pipeline from the site of production to end users as a gas. Ideally, the current natural gas pipeline distribution system will be used for at least the initial stages of a transition to hydrogen. (It appears that if certain compounds are added to the hydrogen the natural gas system can be used.) Hydrogen also can be shipped in liquid form, in 13,000-gal tank trucks, 35,000-gal rail cars, or, for short distances, in vacuum-jacketed pipelines.

L.1.3 Use of Hydrogen in Vehicles

Hydrogen may be stored on board a vehicle as a gas bound with certain metals (hydrides), as a liquid (LH_2) in cryogenic containers, or as highly compressed gas (690 atm) in ultra-high-pressure vessels. All of these systems are bulky and costly. In this paper, the two most common forms of hydrogen storage, as LH_2 or as a hydride, are analyzed.

Vehicular hydride storage systems usually consist of long, thin hollow cylinders filled with granular metal alloy, a heat exchange system, and a casing. They are pressurized with hydrogen to about 500 psi. Exhaust heat from the engine, carried by cooling water, is used to release the hydrogen from the metal lattice during vehicle operation.

Liquid hydrogen is stored in double-walled, super-insulated vessels designed to minimize heat transfer and the boil-off of LH_2. It takes a good deal of energy to liquefy hydrogen and, as shown in this report, the use of this energy can result in surprisingly high levels of greenhouse gases.

For a recent analysis of a solar-hydrogen energy system for the United States, see Ogden and Williams (1989). For a recent review of hydrogen as a transportation fuel, see DeLuchi, *International Journal of Hydrogen Energy* (1989).

L.2 Emissions of Greenhouse Gases from the Production and Use of Hydrogen

Greenhouse gases can be emitted at several points in the hydrogen production and use cycle: from the manufacture and assembly of materials used to make nuclear or solar power plants, hydrogen pipelines, and hydrogen vehicles; from the nuclear fuel production and use cycle; from the combustion of hydrogen used in pipeline compressors (presumably, a small amount of nitrous oxide [N_2O] and nitrogen oxide [NO_x] will be produced); from the use of electricity to compress or liquefy hydrogen; and from the tailpipe of internal combustion engine vehicles (ICEVs).

As shown in Appendix P, emissions from the manufacture and assembly of materials used to make pipelines and power plants probably are very small. Emissions from materials manufacture and assembly for vehicles are not so small; they are quantified in that appendix and

included in the results here. This appendix discusses the calculation of emissions from hydrogen production, distribution, and compression or liquefaction. Emissions from vehicles are discussed in Appendix B.

L.2.1 Emissions from Nuclear-Electrolytic Hydrogen Production

If hydrogen is produced from solar-photovoltaic power, there are no emissions of any kind, except from materials manufacture. If hydrogen is produced from nuclear power, there are emissions from the mining, transport, conversion, and enrichment of nuclear power, as discussed in Appendix I. Emissions per unit of end-use hydrogen energy are equal to:

$$G_h = G_n \times El \times (1 + T) \times (1 + O) \times (1 + L) \times (1 + B)$$

where:

G_h = grams of greenhouse gases per energy unit of hydrogen consumed by vehicles,

G_n = grams of greenhouse gases per energy unit of nuclear power from the reactor,

El = nuclear energy from the reactor per unit of hydrogen energy produced by electrolysis (the reciprocal of efficiency of electrolysis),

T = energy units of hydrogen consumed by pipeline compressors per energy unit delivered to hydrogen stations,

O = own use or the amount of hydrogen consumed by power plants supplying electricity to hydrogen compression or liquefaction stations per unit of hydrogen delivered to vehicles,

L = hydrogen leaks from pipelines per unit of hydrogen delivered to vehicles, and

B = amount of LH_2 that boils off and is lost to the atmosphere per energy unit of LH_2 consumed by the vehicle.

These variables are treated as follows:

1. G_n — The calculation of greenhouse gas emissions per unit of nuclear power is detailed in Appendix I. In the case of hydrogen, I examine the effect of changing the energy requirement of uranium enrichment from that of gaseous diffusion to that of laser isotope separation, because a large, future nuclear-electrolytic hydrogen program would greatly increase demand for nuclear power and require new enrichment capacity.

2. El — The efficiency of electrolysis (1/El) depends on the kind of electrolyzer; 83% probably is representative of future technology (DeLuchi, *International Journal of Hydrogen Energy*, 1989; Ogden and Williams, 1989).

3. T — I estimate T to be about 0.1 (DeLuchi, 1989; Ogden and Williams, 1989).

4. O — Use of hydrogen at stations supplying electricity to compression or liquefaction facilities is calculated from data on the amount electricity consumed per unit of hydrogen produced (discussed below) and the percentage of that electricity generated from hydrogen. Presently, I assume this percentage to be zero.

5. L — Estimated to be half the volumetric leakage rate with natural gas. Swain and Swain (1990) found that the energy leakage rate from a hydrogen pipeline was 46% of the leakage rate from a natural gas pipeline when both systems delivered energy to end users at the same rate. This means that the volumetric leakage rate with hydrogen was 46% of the volumetric leakage rate with natural gas. (To see this formally: the kJ/mole value for hydrogen is 32% of the value for natural gas [Table C.3], which means that the hydrogen pipeline, compared to the natural gas pipeline, was delivering 3.12 times as many moles/s, and leaking 1.43 times [0.46 × 3.12] as many moles/s. This means that the hydrogen volumetric leak rate, compared to the natural gas volumetric leakage rate, was 1.43/3.12 = 0.46.)

6. B — Estimated to be about 0.01 (DeLuchi, *International Journal of Hydrogen Energy*, 1989); it could vary from 0 to 0.1. See Appendix B for details.

L.2.2 Emissions from Hydrogen Transport by Pipeline

Presumably, the combustion of hydrogen in a pipeline compressor will produce some N_2O from the atmospheric nitrogen. For want of data, I assume that hydrogen combustion in pipeline compressors produces N_2O at the same rate (in grams per million Btu of fuel burned) as does natural gas combustion for electricity generation.

L.2.3 Emissions from Compression or Liquefaction of Hydrogen for End Use

The results of this report show that compression or liquefaction of hydrogen — especially liquefaction — produces nontrivial amounts of greenhouse gases. These emissions are attributable to the burning of fossil fuels to produce electricity.

The amount of energy required to compress hydrogen is strongly dependent on the ratio of the final pressure to the initial pressure. Ogden and Williams (1989) calculate that compressing hydrogen from 300 psi (the pressure of transmission lines) to 750 psi (for delivery

to hydrides), requires about 0.01 Btu-electric/Btu-hydrogen. If the hydrogen is delivered to the station through a low-pressure (14.7-psi) distribution line, the compression electricity requirement increases to about 0.06 Btu-electric/Btu-hydrogen (my calculation, using Ogden and Williams' formula relating compressor capacity to input and output pressure).

Currently, state-of-the art hydrogen liquefaction requires about 0.30 Btu-electricity/Btu-LH_2 produced (DeLuchi, *International Journal of Hydrogen Energy*, 1989; private communications from Allied Signal). With advanced technology expected by the year 2000, the electricity requirement could drop to 0.26 Btu-electric/Btu-LH_2 (Blazek et al., 1986). However, this must be adjusted for vaporization losses during transfers between the liquefaction plant and the vehicle. The LH_2 probably will be made at large centralized facilities and, in many cases, will be transferred three times (i.e., production plant to truck, truck to station, and station to vehicle) before it reaches the vehicle. At least 10% of the LH_2 will vaporize at each transfer if the lines and tanks are warm; if they are cold, about 5-7% will vaporize (DeLuchi, *International Journal of Hydrogen Energy*, 1989; private communications from LH_2 suppliers). On average, around 16% of the LH_2 will boil off, all told. Thus, overall, about 84% of the originally liquefied LH_2 will reach the vehicle as LH_2, which means that the liquefaction energy requirement per unit of LH_2 *delivered* to the motorist will be higher than the energy requirement per unit of LH_2 *produced* — 0.26/0.84 = 0.31 Btu-electric/Btu-LH_2-delivered.

The vaporization loss and, hence, the energy requirement per unit of LH_2 delivered to motorists, could be greatly reduced if LH_2 could be liquefied at the point where it would be dispensed to vehicles because this would eliminate two of the three transfers. However, small-scale liquefaction does not appear to be economical.

Because the amount and kind of electricity used to compress or liquefy hydrogen is an important determinant of emissions of greenhouse gases from the use of hydrogen, the electricity mix for hydrogen compression or liquefaction can be specified separately from the other mixes. In sensitivity analyses, I investigate the effect of changing the mix.

L.2.4 Calculation of Net Hydrogen Available to the Transportation Sector

The amount of energy needed to provide a unit of hydrogen to the transportation sector depends, in part, on how much hydrogen is lost to leakage or boil-off, and how much is consumed along the way as a process fuel. The model accounts for all of these losses or uses, albeit in a somewhat simplified fashion.

In calculating the amount of hydrogen that must be produced to support net consumption, I ignore hydrogen used to generate electricity used to mine, convert, enrich, or otherwise process uranium used to make nuclear power used to electrolyze water to produce hydrogen. Since relatively little electricity (compared to the output of the nuclear plant) is used for these processes, and little of that will come from hydrogen for many years to come, this simplification does not seriously affect the results. I do, however, account for hydrogen used to generate the electricity used to compress hydrogen. I account for the hydrogen consumed by pipelines in the

transmission of hydrogen to service stations, but do not account for hydrogen used by pipelines to transmit the hydrogen used to generate the electricity used to compress or liquefy hydrogen.

Finally, emissions per unit of hydrogen energy consumed are converted to emissions per mile by multiplying by million Btu per mile, which is calculated relative to the miles-per-gallon efficiency of the comparable gasoline or diesel vehicle, as explained in Appendix B.

In summary, I estimate:

1. 0.03 Btu of electricity is used per each Btu of hydrogen that is compressed for hydrides.

2. 0.26 Btu of electricity is used for liquefaction per each Btu of liquid hydrogen that is produced.

3. 0.31 Btu of electricity is used for liquefaction per each Btu of liquid hydrogen that is delivered to motorists.

4. 0.10 Btu of hydrogen is consumed by pipeline for each Btu of hydrogen that is delivered.

Appendix M:

Emissions of Methane from Vehicles, Natural Gas Operations, Oil Production, Coal Mines, and Other Sources

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Emissions of Methane from Vehicles, Natural Gas Operations, Oil Production, Coal Mines, and Other Sources

M.1 Methane as a Greenhouse Gas

According to the Intergovernmental Panel on Climate Change (IPCC) (*Climate Change*, 1990), methane (CH_4) will contribute more to global warming than any other non-CO_2 greenhouse gas — about 15% of the total warming over the next century. Molecule per molecule, methane has about 20 times the radiative forcing of carbon dioxide (CO_2), although it also has a much shorter lifetime (Appendix O). When methane is destroyed by the hydroxyl radical (OH), it forms CO_2 and water vapor (H_2O), both greenhouse gases.

The concentration of methane was relatively constant for 2,000 years prior to 1600 A.D., started increasing rapidly about 150 years ago, and is now increasing at roughly 1.0% per year (Ramsussen and Khalil, 1984; Stauffer et al., 1985; Ramanathan et al., 1985; Bolle et al., 1986; Pearman et al., 1986; Watson et al., 1990). The increase between 1600 A.D. and today, from about 0.8 parts per million volume (ppmv) to 1.72 ppmv, may have caused an 0.23°C warming worldwide (Chameides, 1983). And the current percent rate of increase in the concentration of methane will increase, if the rising global mean temperature excites the release of methane from hydrates in permafrost and ocean sediments and establishes a positive feedback cycle. An increase in the concentration of methane may also result in increases in ozone (O_3), which also is a greenhouse gas (Ramanathan, 1988).

Most methane comes from the anaerobic fermentation of organic matter in rice paddies and swamps and from the fermentation of mammalian organic excrement (Ramanathan et al., 1985; Bolle, et al., 1986; Mooney et al., 1987; Whalen et al., 1989; Watson et al., 1990). The decline in the concentration of OH, the principal scavenger of methane (via the reaction, $CH_4 + OH \longrightarrow CH_3 + H_2O$), due to an increase in carbon monoxide (CO) ($2CO + HO \longrightarrow 2CO_2 + H_2$), may also be a factor (Stauffer et al., 1985), as might be an increase in decaying plant matter. The use of fossil fuels accounts for 10-20% of yearly global methane emissions (Ehhalt and Schmidt, 1978; Bingemer and Crutzen, 1987; Whalen et al., 1989; Watson et al. ,1990).

M.2 Methane from Vehicles

Methane is a combustion product of gasoline, diesel, methanol, ethanol, liquified petroleum gas (LPG), and natural gas internal-combustion-engine (ICE) vehicles. Table M.1 is a compilation of reported measurements of emissions from petroleum- and alternative-fuel-powered vehicles.

TABLE M.1 Methane Emissions from Highway Vehicles

Type of Vehicle	Emission Control Equipment	Test[a]	Odometer	Methane (g/mi)	Reference
Gasoline LDV					
1978 Ford Fairmont	NS	NS	NS	0.05-0.08[b]	Aerospace (1982)
(12) 1977-1981 passenger cars	NS	NS	NS	0.02-0.18 [0.06][b]	Aerospace (1982)
1978 Oldsmobile Cutlass[c]	Oxygen catalytic converter and EGR	FTP-75	NS	0.06-0.08	Urban and Garbe (1979)
1979 Chevrolet Impala	Oxygen catalytic converter and EGR	FTP-75	New	0.06	Peninga (1981)
1980 Dodge Diplomat	Oxygen catalytic converter and EGR	FTP-75	New	0.11	Peninga (1981)
(4) 1978-1980 passenger cars[d]	3-way catalytic converter and EGR; 2 cars with oxygen catalytic converter	FTP-75	New	0.09-0.39	Braddock (1981)
(4) 1978-1979 passenger cars[e]	3-way catalytic converter; 2 cars with oxygen catalytic converter	FTP-75	New	0.03-0.11 [0.07]	Smith and Black (1980)
(16) 1975-1978 passenger cars	Various	FTP-75	Various	0.19-0.32	Sigsby et al. (1987)
(30) 1979-1982 passenger cars	Various	FTP-75	Various	0.14-0.18	Sigsby et al. (1987)
1985? Chevrolet S-10 truck	Oxygen catalytic converter and EGR	FTP-75	~4,000	0.02	BC Research (1986)
1985? Dodge 600es truck	3-way catalytic converter	FTP-75	~4,000	0.02	BC Research (1986)
1985? Ford F250 truck	No catalytic converter	FTP-75	~4,000	0.20	BC Research (1986)
1981 Volkswagon Rabbit (MeOH control)*	3-way catalytic converter	FTP-75	25,000	0.03	CARB (1985)
1981 Ford Escort (MeOH control)*	3-way catalytic converter	FTP-75	38,000	0.23	CARB (1985)
1984 Ford Mustang (MeOH control)*	3-way catalytic converter	FTP-75	1,000	0.14[f]	Gabele et al. (1985)
1984 Chevrolet Cavalier (MeOH control)*	3-way catalytic converter	FTP-75	4,500	0.04[f]	Gabele et al. (1985)
1984 GM Delta 88 (CNG control)*	3-way catalytic converter and EGR	FTP-75	High	0.10	Bruetsch (1988)
1987 Ford Crown Victoria (CNG control)*	3-way catalytic converter and EGR	FTP-75	Low	0.11	Bruetsch (1988)
1987 GM Celebrity (CNG control)*	3-way catalytic converter and EGR	FTP-75	Low	0.02	Bruetsch (1988)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test[a]	Odometer	Methane (g/mi)	Reference
(5) 1987 Ford Crown Victorias (MeOH control)*	3-way catalytic converter	FTP-75	0-16,000	0.08-0.15 [0.10]	CARB (June, 1988)
(2) 1987 Ford Crown Victorias (MeOH control)*	3-way catalytic converter	FTP-75	11,000-22,000	0.078	CARB (1989)
(9) 1984-1987 4-cylinder passenger cars	Various	FTP-75	3,000-62,000	0.08-0.15	Stump et al. (1989)
(11) 1985-1987 4-8 cylinder cars	Various	FTP-75	7,000-64,000	0.13-0.20	Stump et al. (1989)
Carb lifetime average factor	3-way catalytic converter	FTP-75	50,000	0.056[g]	CARB (1986)
EPA lifetime average factor (1981+)	3-way catalytic converter	FTP-75	Over life	0.10	EPA (1985)
MOBILE4 emission factor (1990-2020)			Fleet average	0.04-0.12	My runs of MOBILE4
Gasoline HDV					
Ford truck	NS	Chassis HDTC	11,000	2.13	Dietzmann et al. (1981)
International Harvester truck	NS	Chassis HDTC	15,000	0.28	Dietzmann et al. (1981)
5 trucks, 1973-1980	NS	Chassis HDTC	35,000-105,000	0.4-1.0	Black et al. (1984)
EPA lifetime average factor (1987+)	None	HDTC	Over life	0.18	EPA (1985)
MOBILE4 emission factor (1990-2020)			Fleet average	0.18-0.28	My runs of MOBILE4
Diesel HDV					
1979 Caterpillar 4-stroke	NS	Chassis HDTC	7,000	0.05	Dietzmann et al. (1981)
1979 Mack 4-stroke	NS	Chassis HDTC	69,000	~0	Dietzmann et al. (1980)
1979 Cummins 4-stroke	NS	Chassis HDTC	26,000	~0	Dietzmann et al. (1980)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test[a]	Odometer	Methane (g/mi)	Reference
1977 DDC 2-stroke	NS	Chassis HDTC	60,000	~0	Dietzmann et al. (1980)
- - - - - - - - - - - - - - - - - - -					
CARB lifetime average factor	None	HDTC	150,000	0.16[h]	CARB (November, 1986)
EPA lifetime average factor (1987+)	None	HDTC	Over life	0.10	EPA (1985)
MOBILE4 emission factor (1990-2020)			Fleet average	0.10-0.12	My runs of MOBILE4
Natural Gas Dual-Fuel LDV					
1980 Dodge Diplomat	Oxygen catalytic converter and EGR	FTP-75	New	1.09	Peninga (1981)
1979 Chevrolet Impala	Oxygen catalytic converter and EGR	FTF-75	New	0.66	Peninga (1981)
1985? Chevrolet S-10 truck	Oxygen catalytic converter and EGR	FTP-75	~4,000	0.7-2.5[i]	BC Research (1986)
1985? Dodge 600es truck	3-way catalytic converter	FTP-75	~4,000	0.6-1.4[i]	BC Research (1986)
1985? Ford F250 truck	No catalytic converter	FTP-75	~4,000	1.83-5.64[i]	BC Research (1986)
1978 Ford Fairmont[b]	NS	NS	NS	1.47-1.81	Aerospace (1982)
(12) 1977-1981 passenger cars[b]	NS	NS		0.60-3.13 [1.40]	Aerospace (1982)
1985 Ford Ranger	3-way catalytic converter	FTP-75	NS	2.19-4.38	Overby and Regdon (1987)
1984 GM Delta 88	3-way catalytic converter and EGR	FTP-75	High	2.37-2.46[i]	Bruetsch (1988)
1987 Ford Crown Victoria	3-way catalytic converter and EGR	FTP-75	Low	3.03-3.55[i]	Bruetsch (1988)
1987 GM Celebrity	3-way catalytic converter and EGR	FTP-75	Low	1.41-1.50[i]	Bruetsch (1988)
1986 Mercury Marquis	3-way catalytic converter ?	FTP-75	NS	2.63-3.59	Natural Gas Vehicle Coalition (1989)
1986 Buick	3-way catalytic converter	FTP-75	25,000	1.803	CARB (1989)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test[a]	Odometer	Methane (g/mi)	Reference
Natural Gas Dedicated LDV					
1983 Ford 3.81 V-6	None	EPA-CVS	New	0.9-2.5[k]	Swain et al. (1983)
1984 Ford Ranger Pickup	Oxygen catalytic converter and EGR	FTP-75	Low	1.06	Adams (1985)
1984 Ford Ranger Pickup	Oxygen catalytic converter and EGR	FTP-75	NS	1.17-1.31[j]	Bruetsch (1988)
1989 Dodge Van	3-way catalytic converter	FTP-75	4,000	1.44	Gabele (1990)
Natural Gas HDV					
Diesel dual-fuel pilot	NS	SAE 13-mode	NS	27.2[l]	BC Research (1987)
GMC 454 CID V-8 bus engine	3-way catalytic converter	Modified HDTC	Low	0.6[m]	Goetz (1988)
GMC 454 CID V-8 bus engine	3-way catalytic converter	Modified HDTC	Low	2.4[m]	Goetz (1988)
GMC 454 CID V-8 bus engine	3-way catalytic converter	HDTC	Low	1.92[n]	Alson et al. (1989)
Cummins L-10 lean-burn engine	No catalytic converter	13-mode test	NS	4.0[m]	Lawson (1988)
Methanol Dual-Fuel LDVs					
(7) 1987 Ford Crown Victorias (M85)	3-way catalytic converter	FTP-75	0-16,000	0.02-0.06 [0.04]	CARB (June, 1988)
(7) 1987 Ford Crown Victorias (M50)	3-way catalytic converter	FTP-75	0-16,000	0.05-0.10 [0.07]	CARB (June, 1988)
1988 Chevrolet Corsica (M100)	3-way catalytic converter	FTP-75	4,000	0.003	CARB (June, 1988)
1988 Chevrolet Corsica (M50)	3-way catalytic converter	FPT-75	4,000	0.01	CARB (June, 1988)
(2) 1987 Ford Crown Victorias (M85)	3-way catalytic converter	FTP-75	11,000-22,000	0.044	CARB (1989)
(2) 1987 Ford Crown Victorias (M100)	3-way catalytic converter	FTP-75	11,000-22,000	0.021	CARB (1989)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test[a]	Odometer	Methane (g/mi)	Reference
Methanol Dedicated LDVs					
(2) 1981 Volkswagon Rabbit (M85)	3-way catalytic converter	FTP-75	4,500	0.01-0.02	CARB (1985)
Same cars as above (M90)	3-way catalytic converter	FTP-75	22,000	0.02-0.03	CARB (1985)
Same cars as above (M85)	3-way catalytic covnerter	FTP-75	56,000-66,000	0.03-0.13	CARB (June, 1988)
(2) 1981 Ford Escort Wagons (M90-95)	3-way catalytic converter	FTP-75	5,000-50,000	0.07	CARB (1985)
1981 Ford Escort Wagon (M90)	3-way catalytic converter	FTP-75	85,000-115,000	0.09	CARB (1985)
(8) 1983 Ford Escort Wagons (M90)	3-way catalytic converter	FTP-75	0-20,000	0.01-0.14 [0.06][o]	CARB (1985)
1982 Chevrolet Citation (M85-90)	3-way catalytic converter	FTP-75	30,000-40,000	0.03	CARB (1985)
1983 Pontiac Phoenix (M85)	3-way catalytic converter	FTP-75	2,400	0.02	CARB (1983)
1983 Ford Escort (M90)	3-way catalytic converter	FTP-75	1,500	0.06	Gabele et al. (1985)
1981 Volkswagon Rabbit (M100)	Heated catalytic converter[p]	FTP-75	NS	0.01	Blair and Piotrowski (1988)
1985 Toyota Camry (M85)	3-way catalytic converter	FTP-75	0-26,000	0.02	CARB (June, 1988)
1985 Toyota Camry (M85)	No catalytic converter	FTP-75	0-26,000	0.02	CARB (June, 1988)
1986 Toyota Carina (M85)	3-way catalytic converter	FTP-75	0-9,000	0.02	CARB (June, 1988)
1987 Ford Crown Victoria (M85)	3-way catalytic converter	FTP-75	2,500	0.04	CARB (June, 1988)
Methanol HDVs					
MAN spark-ignited 6-cylinder engine	Oxygen catalytic converter	HDTC	NS	0.002[q]	Ullman and Hare (1982)
MAN spark-ignited 6-cylinder engine	Oxygen catalytic converter	r	28,300	0.04; 0.12[r]	Ullman and Hare (1986)
DDC 6V-92TA spark-assisted 2-stroke	NS	r	8,900	1.17; 0.72[r]	Ullman and Hare (1986)
Other Kinds of Vehicles					
1979 Hydrogen pick-up truck	NS	FTP-75	23,000	0	CARB (1989)
1988 dual-fuel LPG Chevrolet	NS	FTP-75	14,000	0.046	CARB (1989)
1987 Ford Crown Victoria FFV (ethanol)	NS	FTP-75	22,000	0.196	CARB (1989)

See next pages for footnotes.

TABLE M.1 (Cont.)

[a] FTP = Federal Test Procedure. HDTC = Heavy Duty Transient Cycle, engine test; the chassis version of the HDTC tests the whole chassis, not just the engine. CVS = constant volume sample.

[b] The researchers actually *measured* methane emissions for the Fairmont. They *assumed* that methane was 80% of total HCs from 1977 NGVs, 87% from later year NGVs, and 12% from gasoline vehicles.

[c] Methane emissions increased slightly after several engine malfunctions. However, with rich idle, emissions were 0.52 g/mi.

[d] Emissions were around 0.10 g/mi for three of the four vehicles, with summer fuel at 78°F ambient temperature, but over 0.20 g/mi with winter fuel at 55°F ambient temperature.

[e] Methane emissions varied moderately with the type of gasoline, and generally increased slightly from 0-15,000 miles. Methane emissions in the NYCC cycle were higher, and in HFET lower, than in FTP.

[f] Methane was measured for the Mustang only; I assume that methane was the same percent of HC exhaust from the Cavalier as from the Mustang. The Cavalier is more similar in weight and power to the Escort than is the Mustang.

[g] Range reflects primarily different ambient temperatures. Methane emissions were lowest at 21°C,which is typical of FTP test conditions, and highest at the lowest temperature (-6.7°C).

[h] CARB estimates that 7.5% of the total organic gases (TOG) from gasoline LDVs are nonreactive. I assume that all of these nonreactive gases are methane, and that no methane is counted as reactive. I then multiplied the lifetime average TOG emission factor for LDVs by 0.076. For HDDVs, CARB assumes that 4.4% of TOG are nonreactive.

[i] Emissions varied with the conversion kit.

[j] The authors reported total HCs and four different ways of measurig NMHCs. My range is their HC minus their high NMHC to their HC minus their low NMHC.

[k] Emissions varied with spark advance and air-fuel ratio. The test cycle was an approximation of the EPA-CVS.

[l] Reported in the reference as 13 g/bhp-hr and 85-90% methane. I converted g/bhp-hr to g/mi using EPA's (1985) 2.31 factor.

[m] I assume 85% methane in total reported HCs, and use EPA's 2.31 conversion factor. The first Goetz (1988) test was by the manufacturer. The second test was by EPA. In tests reported by Goetz (1988) , HDTC was modified to reflect transit bus applications. (Also see Alson et al. (1988) for the results of other EPA tests on the GMC engine.)

[n] Conversion factor = 2.31.

TABLE M.1 (Cont.)

[o] New vehicles tended to emit in the range of 0.03 g/mi. Older vehicles emitted around 0.06 g/mi. The average was around 0.06 g/mi. Three vehicles had electronic fuel injection.

[p] A resistively-heated-monolithic catalyst designed to reduce cold-start HC and HCHO emissions.

[q] They report 70 mg of methane in the cold-start transient test, 0 in the hot-start test, and about 0.3 kW-hr work in both tests. I used their formula (p.16) to convert these to mg/hp-hr, and then used a 2.31 conversion factor.

[r] First value emitted over bus transient cycle; second value emitted over central business district transient cycle.

* See the same type of vehicle tested on alternative fuel in this table. The 1981 Rabbit and the 1981 Escort (tested by CARB, 1985) are production-line gasoline vehicles and should be compared to the 1981 dedicated methanol Rabbits and Escorts tested by CARB (1985). The 1984 Mustang and the 1984 Cavalier (tested by Gabele et al., 1985) are also production-line gasoline vehicles and should be compared to the dedicated methanol Escort tested by Gabele et al. (1985) (see footnote f to this table). The Delta 88, the Crown Victoria, and the Celebrity (tested by Bruetsch, 1988) are dual-fuel CNG/gasoline vehicles. The 1987 Crown Victorias (tested by CARB, June 1988; 1989) are flexible fuel methanol/gasoline vehicles. The asterisked vehicles in the first part of this table and the flexible-fuel Crown Victorias shown under "Methanol Dual-Fuel LDVs" are the same.

Note: EPA testing protocol requires that all emissions be corrected for background concentration (i.e., that the ambient concentration be subtracted from gross measured emissions). I therefore have assumed that all reported emissions are net of background. (In any case, methane in exhaust is about two orders of magnitude more concentrated than is methane in ambient air.)

NS = not specified. Numbers in brackets are my approximate averages of ranges. EGR = exhaust gas recirculation. ? = model year of vehicle is not certain. NYCC = New York City Cycle. HCHO = formaldehyde. HFET = Highway Fuel Economy Test. DDC = Detroit Diesel Corporation (prior to January 1, 1988, this was Detroit Diesel Allison Division). CID = Cubic Inch Displacement. MAN = Maschinen Fabrik Augsburg-Nurnberg. MeOH = methanol.

M.2.1 Gasoline Vehicles

The data of Table M.1 show that gasoline-powered light-duty vehicles (LDVs) with 3-way catalysts emit between 0.02 and 0.2 g/mi of methane, with values for recent model-year cars centering around 0.08-0.10 g/mi. MOBILE3, the EPA's (1985) emission model, indicates 0.1 g/mi from gasoline LDVs at low altitude (details are given in Chun, 1988). MOBILE4, the recent update of MOBILE3, indicates 0.04-0.12 g/mi of methane, depending on the fleet year analyzed (Table M.1; the 0.12 figure is the difference between exhaust total hydrocarbons (THC) and exhaust nonmethane hydrocarbons [NMHCs] from light-duty gas vehicles [LDGVs] in the year 1990; the 0.04 figure is the same difference in the year 2020). For the year 2000, MOBILE4 assumes 0.05 g/mi.

Methane emissions will be reduced by the new Clean Air Act Amendments. However, it will not be reduced nearly as much (in percentage terms) as will NMHCs because the new standards exclude methane and methane is hard to oxidize catalytically. Consider, for example, the data of Table M.1, which show that emissions from catalyst-equipped vehicles are not dramatically lower than emissions from uncontrolled vehicles (compare tests on uncontrolled gasoline and natural gas vehicles versus controlled vehicles). The EPA's study for MOBILE3 found that catalyst-equipped vehicles emit only 0.2 g/mi less methane than noncatalyst vehicles — a much smaller reduction than with NMHCs.

The data of Table M.1 suggest that, for all fuels, methane emissions are not a strong function of the age of the vehicle. The EPA's (1985) analysis for MOBILE3 corroborates this, showing that methane emissions from gasoline vehicles do not deteriorate with age. It also appears that methane emissions are not a function of vehicle efficiency, based on data (not shown here) on the efficiency of vehicles in Table M.1. However, methane emissions, like THC emissions, appear to increase with decreasing temperature (Stump et al., 1989, 1990).

With these considerations, a value of 0.05 g/mi of methane appears reasonable as a lifetime average for the year 2000. This also is the MOBILE4 value for the year 2000.

M.2.2 Natural Gas Vehicles

As expected, natural gas LDVs emit at least an order of magnitude more than gasoline LDVs because methane is the primary component of natural gas. The range of reported emissions from natural gas vehicles (NGVs) is quite wide, ranging from 0.6 to 4 g/mi for dual-fuel vehicles and about 1-2 g/mi for dedicated vehicles, and shows no strong patterns with respect to age, model year, or fuel economy. Ambient temperature also is not important (Gabele, 1990). It is possible that methane emissions from NGVs will be reduced as the vehicle technology improves and the high-end emissions are eliminated. The need to meet relatively tight NMHC standards may also reduce methane emissions somewhat. An estimate between 1.0 and 2.0 g/mi, but closer to 1.0 g/mi, is most reasonable for dedicated, advanced-technology vehicles meeting a tight NMHC standard in the year 2000. Because of the importance of this value to total CO_2-equivalent emissions from NGVs, I consider lower and higher values in scenario analyses.

M.2.3 Methanol Vehicles

Methanol LDVs definitely emit less methane than do gasoline vehicles. This is indicated by comparisons of dedicated gasoline vehicles with same- or similar-model dedicated methanol vehicles (Table M.1) and by tests showing that methane emissions increase with the gasoline content of the fuel used by a flexible-fuel vehicle (FFV) (Tables M.2, M.3, and M.4). Also, the upper end of reported methane emissions from methanol LDVs is not as high as the upper end for gasoline LDVs. Table M.2 compares methane emissions from FFVs and from similar gasoline and methanol vehicles. The data indicate that dedicated 100%-methanol (M100) vehicles emit 50% as much methane as dedicated gasoline vehicles, and M85 vehicles emit about 66% as much. The model used here follows the data of Tables M.1 and M.2 and assumes that emissions from gasoline/methanol mixtures are equal to the M100 emission rate multiplied by the methanol fraction, plus the gasoline emission rate multiplied by the gasoline fraction of the mixture.

Note that it is very important to compare *same or similar* methanol and gasoline vehicles. As shown in Table M.1, methane emissions for both gasoline and methanol vehicles can range from nearly zero to over 0.1 g/mi, and if one randomly picks a few test results for gasoline vehicles and a few for methanol, one may find that methanol vehicles emit a lot more methane than do gasoline vehicles, or vice-versa. The correct method is to compare methane emissions from vehicles with the same basic engine, fuel injection, mileage, emission control equipment, vehicle weight, etc. This is correct because manufacturers will build either a gasoline vehicle or a methanol version of the *same* vehicle, depending on economics, environmental regulations, and so on.

M.2.4 Ethanol, Liquefied Petroleum Gas, and Hydrogen Vehicles

I assume that ethanol vehicles emit as much methane as do methanol vehicles. The one ethanol datum of Table M.1 shows a high methane emission level, but the vehicle (an FFV) was not designed to burn ethanol, and the California Air Resources Board (CARB) is not confident of the result. Because methanol and ethanol are both alcohols and are similar fuels, it is reasonable to expect that they will emit roughly similar amounts of methane.

The CARB tested one dual-fuel LPG vehicle, which emitted about as much methane as the gasoline vehicle (Table M.1). Since LPG contains no methane and, in general, the species profile of hydrocarbon (HC) emissions reflects the HC composition of the fuel, there is no reason to expect LPG vehicles to emit large amounts of methane. On the other hand, because LPG is not similar to methanol, there is no reason to expect that the properties that make alcohol-fuel vehicles emit less methane than gasoline-fuel vehicles would apply to LPGs. Consequently, I assume that LPG vehicles emit as much methane as do gasoline vehicles.

Theoretically, hydrogen vehicles might emit trace amounts of methane from the combustion of lubricating oil. However, the CARB (1989) speciated HC emissions from the lubricating oil of a hydrogen vehicle and did not find any methane. I assume no methane emissions.

TABLE M.2 Methane Emissions from Methanol Vehicles Divided by Methane Emissions from the Same or Similar Gasoline Vehicles

Vehicle Comparison	Fuel Comparison	Reference	Ratio (g/mi)
FFV			
Chevrolet Corsica FFV	M100/M0	Gabele (1989)	0.19-0.26
Ford Escort FFV	M100/M0	Ford (1988)	0.50
Ford Crown Victoria FFV	M100[a]/M0	Ford (1988)	0.88
Ford Crown Victoria FFV	M100/M0	CARB (1989)	0.27
2.5-L GM VFV	M100/M0	Williams et al. (1989)	0.05
Chevrolet Corsica FFV	M85/M0	Gabele (1989)	0.33-0.59
Ford Escort FFV	M85/M0	Ford (1988)	0.70
Ford Crown Victoria FFV	M85[b]/M0	Ford (1988)	1.69
Ford Crown Victoria FFV	M85/M0	CARB (1989)	0.56
Ford Crown Victoria FFV	M85/M0	CARB (June, 1988)	0.40
2.5-L GM VFV	M85/M0	Williams et al. (1989)	0.39
Dedicated vehicles			
1981 Volkswagon Rabbit	M95/gasoline	CARB (1985)	0.33-0.67
1981 Ford Escort	M90-95/gasoline	CARB (1985)	~0.30
1984 Ford Mustang/1983 Ford Escort	M90/gasoline	Gabele et al. (1985)	0.43
1981 Volkswagon Rabbit	M85/gasoline	CARB (1985)	1.00-4.33

[a] At 3,000 mi, from Table M.3.

[b] At 16,000 mi, from Table M.3.

Note: Calculated from the data shown in Tables M.1, M.3, and M.4.

M.2.5 Heavy-Duty Vehicles

The data for heavy-duty vehicles (HDVs) are more scattered. The MOBILE3 and MOBILE4 assumption for heavy-duty diesel vehicles (HDDVs) does not quite agree with the data from the tests reported in Table M.1. Nevertheless, I have used MOBILE4 values.

There also are wide ranges reported for natural gas and methanol HDVs. The range with methanol is so wide, and there are so few data, that it is probably best to assume that methanol HDVs would emit less than HDDVs (just as methanol LDVs will emit less than gasoline LDVs), rather than try to make an estimate based on a few scattered data.

TABLE M.3 Methane and Nitrous Oxide Emissions from Flexible-Fuel Vehicles Tested by Ford

Vehicle	Fuel	Miles on Catalyst	Number of Tests	Emissions (mg/mi) CH_4	N_2O	HCOH	NO_x	NO_x/N_2O
FFV Ford Escort	Indolene	4,000	6	44	116	0	565	4.9
	M50	4,000	2	28	129	24	410	3.2
		50,000	2	23	127	31	890	7.9
	M85	No catalyst	4	34	-2[a]	181	2,735	-1,823.3
		4,000	2	31	105	46	430	4.1
		50,000	4	30	112	53	593	5.3
	M100	No catalyst	2	31	-3[a]	244	2,570	-1,028.0
		4,000	4	22	54	47	353	6.5
		50,000	5	20	123	70	556	4.5
FFV Ford Crown Victoria	Gasoline	12.500	1	42	13	25	753	57.9
	M85	No catalyst	7	68	2	533	1,408	758.4
		0	3	37	7	4	570	77.7
		3,000	3	31	12	19	703	58.6
		16,000	1	71	16	27	840	52.5
		30,000	3	45	18	46	788	43.8
		4,000[b]	3	48	18	92	676	38.3
	M100	No catalyst	5	39	-0.4[a]	676	1,089	-2,723.0
		3,000	7	37	14	33	524	36.7

[a] Vehicle actually consumes net N_2O.

[b] Catalyst was contaminated with oil.

Source: Ford Motor Company, speciated emissions data transmittal (1988).

M.2.6 Aggregate Methane Emissions from a Large Natural-Gas-Fueled Fleet

Although methane emissions from vehicles are a nonnegligible fraction of total CO_2-equivalent emissions from highway vehicles, petroleum-fueled highway vehicles account for a negligible percentage of total methane emissions worldwide. However, NGVs emit considerably more methane than petroleum-fueled vehicles, and one might want to know if an all-NGV fleet would contribute significantly to global methane emissions. I have calculated that even if all vehicles worldwide were fueled by natural gas and emitted relatively large amounts of methane per mile, the global concentration of methane would increase by only a tiny amount (DeLuchi et al., *A Comparative Analysis of Future Transportation Fuels*, 1987). Considering further that it is very difficult to catalyze methane emissions to CO_2 and water (a unit of carbon is less greenhouse

TABLE M.4 Federal Test Procedure (FTP) Methane Emissions from Two Variable-Fuel Vehicles (mg/mi)

Temperature (°F)	Chevrolet Corsica[a] Percent Methanol/Percent Gasoline 100/0	85/15	50/50	25/75	0/100	Ratio (M100/M0)
40	NA	41	48	68	82	NA
75	9	20	26	25	34	0.26
90	8	14	26	36	42	0.19
	2.5 L GM VFV[b] Percent Methanol/Percent Gasoline 100/0	85/15	50/50	15/85	0/100	Ratio (M100/M0)
	2	14	20	16	36	0.05

[a] From data in Gabele (1989).

[b] From data in Williams et al. (1989).

Note: NA = not available (the car would not start below 60°F on 100% methanol).

effective as CO_2 than as methane, and so from a greenhouse standpoint the transformation of methane to CO_2 is desirable), it probably would not be cost-effective to concentrate on reducing methane emissions from the vehicles.

M.3 Leaks of Methane from Natural Gas Production, Transmission, and Distribution

In a previous, preliminary estimate of greenhouse gases from the use of alternative transportation fuels (DeLuchi et al., *Transportation Fuels and the Greenhouse Effect*, 1987), I assumed that the amount of gas actually leaking from natural gas systems is equal to the amount of gas (between 1 and 3%) that, according to the Energy Information Administration (EIA), is unaccounted for (EIA, *Natural Gas Annual*, annual publication). Other researchers cited numbers of similar magnitude, ranging from 3 to 4% (see Bolle et al., 1986). It now appears that the estimates of 3-4% for the U. S. system are as much as an order of magnitude too high.

It is important to understand that unaccounted-for is not a measure of leakage; it is simply the difference between the sum of the components of natural gas supply and the sum of the components of natural gas disposition. With millions of consumers and a quarter of a million producing wells (and different data-gathering and reporting protocols), it is not particularly surprising that supply does not exactly equal disposition. Thus, unaccounted-for gas has no physical meaning. This is illustrated by the value for 1988: *negative* 0.4% (EIA, *Monthly Energy Review,* April 1989). If a positive value of unaccounted-for gas represents leakage to the atmosphere, then a negative value would have to mean removal from the atmosphere.

However, gas does leak from production, storage, transmission, and distribution systems. In the course of normal operations, gas leaks (or is vented) from instruments that operate on gas, from valves opened to drain liquids from pipelines and, on occasion, from overpressure valves. Gas may be vented from buildings during construction or emitted during the purging of pipelines (AGA, "Natural Gas Transmission and Distribution Methane Emissions," 1989, SS-88-4-1). Intentional venting probably accounts for a minority of losses.

Studies of leakage per se (as opposed to unaccounted-for gas), consistently indicate a loss rate of less than 1% (Table M.5). Recently, the American Gas Association (AGA, "Natural Gas Transmission and Distribution Methane Emissions," 1989) reported the results of a national survey asking natural gas transmission and distribution companies to estimate gas losses in their systems. The respondents indicated a total loss of about 0.34%. The transmission companies claimed to be confident about 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 estimated total leakage to be in the range of 0.2-0.3% (AGA, "Natural Gas and Climate Change: The Greenhouse Effect," 1989). Similarly, the Alphatania Group surveyed 41 natural gas companies operating worldwide and found that leakage from transmission and distribution was 43% of throughput (Canadian Gas Association, 1990; Table M.5). They also estimate that leakage from gas production was about 0.20% of throughput.

According to Okken and Kram (1989), gas companies estimate that less than 1% of the gas carried in modern natural gas distribution grids leaks, and that methane emissions from the maintenance and repair of pipelines and compressors in the Netherlands are about 0.005% of the amount of methane transported.

In 1989, the Pacific Gas and Electric Company (PG&E) (Cottengim et al., 1989) completed what it called 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

TABLE M.5 Recent Surveys, Studies, or Estimates of the Rate of Leakage of Natural Gas Transmission and Distribution Systems

Organization (Reference)	Natural Gas Lost, Percent of Delivered Natural Gas: Production	Trans-mission	Distri-bution	Comments
Canadian Gas Association (1990)	0.25	0.018-0.082	0.03	Estimate for Canadian companies
Alphatania Group (CGA, 1990)[a]	0.20	0.13	0.30	Survey of 41 companies worldwide
AGA (SS-88-4-1, 1989)		0.06	0.28	Survey of U. S. natural gas companies
European gas companies[b]		0.005	<1.00	Higher loss in old distribution lines
Germany (Okken, *Energy Policy,* 1990)		—	0.50	
PG&E (Cottengim et al., 1989)		0.14		Mostly distribution losses[c]

[a] As reported by the Canadian Gas Association (1990); also mentioned in Wilson (1990).

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

[c] 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%.

rupture by the number of ruptures in 1987. All told, intentional and unintentional losses amounted to only 0.14% of total deliveries. In fact, losses were only 9% of all unaccounted-for gas; the biggest source of unaccounted-for gas was inaccuracies in orifice meters.

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

Some researchers speculate that leaks from older distribution systems may exceed 1% of transported gas. However, there are no reliable data, not only on leaks from older systems but also on the amount of gas carried in older systems. I suspect that the vast majority of gas is carried in modern systems because most gas is consumed in developed countries. In 1987, the United States, Canada, France, Japan, Italy, West Germany, Britain, the Netherlands, and Japan accounted for nearly half of total global gas consumption, and all of these countries undoubtedly have mostly modern distribution systems. These countries plus the rest of Europe and the

U.S.S.R. accounted for 80% of global consumption. (However, the systems in Eastern Europe and the U.S.S.R. may be leakier than those in the West.) More importantly, *future* systems everywhere in the world will be more like the tightest current systems than the leakiest ones, and we are, in energy policy, interested in the greenhouse consequences of future energy choices. Over the next several decades most (if not nearly all) gas likely to be used by the United States will be transported in systems that, according to preliminary studies, lose much less than 1% of throughput.

Finally, I note that staff at the EIA believe that gas leaks total less than 0.5% of total deliveries (McCarrick, 1990), and that the *International Workshop on Methane Emissions from Natural Gas Systems, Coal Mining, and Waste Management Systems* (1990) has come to essentially the same conclusions as I have stated here.

M.3.1 Venting and Flaring of Natural Gas at Gas-Producing Wells

Data from the U. S. Minerals Management Service (Nixdorff, 1991) indicate that 0.04% of the gas produced from federal offshore gas wells in the Gulf of Mexico is vented or flared. Virtually all of this vented or flared gas is likely to have been flared rather than vented. Similarly, gas companies have estimated that no more than 0.005% of total production is vented (*Options for Reducing Greenhouse Gas Emissions*, 1990). Presumably, vented gas is included in the above estimates of total gas lost from production. Even if vented gas is not included, and so should be added to the above estimates, it would have no effect on the overall results: intentional venting, at 0.001-0.005% of production, is 40-200 times smaller than total gas leakage. It therefore can be ignored.

Data from Nixdorff (1991), and information in *Options for Reducing Greenhouse Gas Emissions* (1990), indicate that 0.01-0.04% of total production is flared. This is about 100 times smaller than the amount of gas used as a process fuel in gas fields. Hence, intentional flaring, which has the same greenhouse effect as burning gas as a process fuel, is completely trivial and well within the uncertainty of the estimate of the amount of gas used as a process fuel. It, too, can be ignored.

M.3.2 Assumptions Used in this Section

The greenhouse model used here disaggregates natural gas losses into losses from production (including gas lifting, gathering, and processing), transmission, and distribution. All three kinds of losses apply to compressed natural gas (CNG) and natural gas users. However, only production and transmission losses apply to methanol from natural gas (and to natural gas power plants), since methanol plants will be located near production fields or large-volume transmission lines. (This gives an advantage to methanol use, since distribution losses, which will not occur with methanol use, are larger than transmission losses.) Also, in the methanol-from-natural-gas case, the leakage rate from gas transmission is less than in the CNG case, because pipelines from remote gas fields to the methanol plants will be shorter than pipelines from U. S. gas fields to U. S. gas end users (see Appendix J).

Production, transmission, and distribution losses can be estimated using the data of Table M.5. However, one could argue that a portion of the gas lost during gas production operations would have leaked anyway, from natural formations, had all the gas been left in the ground (Gold, 1988). Gold says that in some cases production of gas "demonstrably" reduces methane leakage, but he does not estimate the overall effect of producing gas. In my base case, I assume a *net* leakage rate (total leakage from natural gas facilities less the amount that would have leaked had the gas field not been developed) equal to the lower of the estimates of Table M.5.

M.3.3 Natural Gas Leaks from Natural Gas Compressors and Liquefiers

There are no data on the rate of gas leakage (if any) from natural gas compressors. It is likely that the leakage rate is low because high leakage rates would be hazardous and uneconomical. I expect that little or no gas leaks from the CNG-nozzle/vehicle-port interface because the connection is tightly interlocking, and gas does not flow until the nozzle locks into place. I assume that any leakage from CNG stations is small compared with leakage from distribution stations, and can be considered to be subsumed by the estimate for distribution leaks.

Leakage from a properly functioning liquefied natural gas (LNG) station also should be minimal. The LNG dispensers are fully automatic and self-sealing and have a vapor return line that sends vaporized fuel back to the liquefier or gas pipeline. I assume essentially no regular gas leakage from LNG stations.

If an LNG vehicle is idle for one to three weeks, vaporized LNG will begin to be vented from vehicular storage tanks. (The amount of time before venting begins depends on the storage technology; see DeLuchi et al., 1987, *Comparative Analysis of Future Transportation Fuels*, for a brief discussion.) Tanks vent at about 14 g/hour. However, if the vehicle is driven at least once a week (and most vehicles are), the tank will draw off the vaporized LNG and will not vent. Consequently, in the base case for LNG, I assume that very little LNG is lost to boil-off. (See Appendix B for more discussion.)

M.3.4 Composition of Gas Leaks and Its Relevance to Global Warming

Pipeline-quality gas contains CO_2, NMHCs and, of course, methane. These greenhouse gases have different warming potentials per gram, and, consequently, the precise overall warming effect of natural gas leaks depends on the proportions of these individual compounds.

The composition of pipeline gas is discussed in Appendix C and shown in Table C.3. In the calculation of CO_2-equivalent greenhouse gas emissions from natural gas leaks, separate warming factors are assigned to each species (warming factors are derived in Appendix O).

M.3.5 Synthetic Natural Gas Systems

I assume that pipelines delivering medium-Btu synthetic natural gas (SNG) will leak at the same rate as pipelines delivering regular natural gas (Table 5). SNG is composed of hydrogen (H_2), CO_2, CO, methane, and small amounts of NMHCs (Feldmann et al., 1988; Flanigan et al., 1988). The greenhouse effect of leaks of SNG is equal to the CO_2 equivalent of each of the components of SNG, less a CO_2 credit for each mole of carbon emitted, since all of the carbon in SNG originally comes from atmospheric CO_2 via photosynthesis. I assume 20% H_2, 20% CO_2, 40% CO, 13% CH_4, and 7% NMHCs (following Flanigan et al., 1988).

M.4 Vented and Flared Associated Gas from Oil Production

Many fields contain both natural gas and crude oil. Some of these fields contain mostly crude oil and are developed primarily for the sale of the crude. However, the extracting of the crude also produces small amounts of natural gas, and if there is so little of this coproduced (or associated) gas that it cannot be collected and sold economically, it must be disposed of somehow. There are three ways to dispose of unmarketed associated gas: reinject it into the producing field, burn it (called flaring), or simply vent it to the atmosphere. If the gas is reinjected, it never enters the atmosphere and obviously is of no concern in an analysis of emissions of greenhouse gases. However, venting releases the gas in its original state (as mostly methane), and flaring releases it as CO_2. Emissions of methane and CO_2 from venting and flaring of associated gas should be assigned to the use of petroleum fuels, since the emissions result from the extraction of the crude oil.

Several sources, including the United Nations, the Organization of Petroleum Exporting Countries (OPEC), government energy agencies, and major international gas companies, estimate the amount of gas vented and flared locally, regionally, and worldwide. The EIA analyzes the quality of these data and publishes "best estimates" (*International Energy Annual*, 1991, 1982-1989; J. Johnson, 1990). Table M.6 shows the EIA's world total vented and flared gas (a combined figure; venting and flaring are not distinguished) from 1981 to 1988, the latest year for which data are available.

As shown in Table M.6, the quantity of vented and flared gas, and the ratio of vented and flared gas to total oil production generally have been declining. Worldwide, venting and flaring will continue to decline as natural gas increases in value and is reinjected, used domestically, or exported. The United Nations (U.N.) projects that in 2010, the amount of venting and flaring will be half of what it was in 1987 (United Nations, Energy data base, no date). Major gas-producing developing countries are expected to use associated gas to help fuel industrial development (International Energy Agency [IEA], *Energy Policies and Programmes of IEA Countries, 1988 Review*, 1989).

I have assigned venting and flaring to U. S. petroleum use by dividing the amount of gas vented or flared in eight regions of the world by the total crude production in these regions, then multiplying each regional ratio by the amount of that region's crude that the United States

TABLE M.6 Vented or Flared Natural Gas (world totals)

	Year							
	1981	1982	1983	1984	1985	1986	1987	1988
Vented/flared (TCF)	3.87[a]	NA	3.85	3.53	3.08	2.98	2.89	3.20
Reinjected (TCF)	4.08[b]		5.41	5.77	6.33	6.15	7.35	7.46
Dry gas produced (TCF)	54.53		54.45	59.27	62.17	63.25	66.17	69.75
Crude oil produced (mbd)[c]	55.78		52.97	54.20	53.65	55.87	56.31	58.46
Ratio (vented/flared to crude production)	6.94%		7.27%	6.51%	5.74%	5.34%	5.13%	5.47%

[a] The EIA (1983) shows the total as 3.269, with data for the U.S.S.R and other Middle East countries unavailable. In later years, the total for these was around 0.6 TCF. I have added this to the given 3.269 total. All subsequent figures for vented/flared natural gas include the U.S.S.R and other Middle East countries.

[b] This total probably does not include data for the U.S.S.R and other Middle East countries, as above. I did not check.

[c] From EIA, *Annual Energy Review* (1990).

Note: mdb = thousand barrels per day. NA = not available.

Source: From EIA, *International Energy Annual*, issues published from 1983-1991, except as noted.

consumes (directly as crude or indirectly as products). This gives a disaggregated, regionally weighted venting and flaring number for U. S. oil consumption. Table M.7 shows the actual results for 1987 and the projected results for the year 2000. The projected year-2000 results are calculated by applying a reduction factor to the 1987 results; the reduction factor accounts for the expected reduction in venting and flaring in regions that now vent and flare a lot of gas (U.N., no date; ICF, 1990). It is based in part on U.N. projections of venting and flaring in the year 2000 in eight regions of the world and is discussed briefly in the notes to Table M.7.

I assign venting and flaring to the production of crude oil only (and not to crude, gas, and natural gas liquids (NGLs) production jointly) because if a well is venting and flaring a significant amount of gas, it obviously is not marketing gas. If there is enough gas associated with a well to justify gas recovery, the gas and the NGLs will be recovered and little, if any, gas will be flared because the gas is valuable. If there is not enough gas to make recovery worthwhile, then it will be flared and only crude will be produced. (I have assumed that field production of NGLs is associated with the production of natural gas.) In support of this, EIA survey data show that *no* gas was vented and flared from wells that produce only natural gas (EIA, *Natural Gas Annual 1989*, 1990).

Hence, it seems logical to assign venting and flaring to crude production only.

TABLE M.7 Calculation of Weighted Venting and Flaring Emissions from the Average Barrel of Crude Used by the United States

Region[a]	Middle East	North Europe	West Africa	Mediter-ranean	South Pacific	Central America	South America	North America	Total
Vented/flared in region, BCF, 1987[b]	920	94	559	301	337	75	439	235[c]	2,942
Crude production in region, mbd, 1987[d]	23,305	3,626	1,982	3,635	5,445	2,590	3,485	10,630	54,698
SCF-natural gas/bbl-oil, in region, 1987[e]	108.2	71.0	772.7	226.9	169.6	79.3	345.1	60.6	N/A
Year-2000 venting/flaring divided by year-1987 venting/flaring[f]	0.90	1.00	0.50	0.67	0.67	1.00	0.67	1.00	N/A
SCF-NG/bbl-oil, year 2000[g]	97.3	71.0	386.3	158.8	127.2	79.3	231.2	60.6	N/A
To United States									
Crude from region, mb, 1987[h]	359,060	136,455	302,013	62,594	146,499	220,632	256,688	3,269,359	4,753,300
Products from region, mb, 1987[i]	51,969	66,238	12,780	134,557	40,908	140,955	195,692	87,570	730,669
Crude share from region, 1987	0.075	0.029	0.063	0.015	0.031	0.048	0.056	0.682	1

Weighted SCF-natural gas/bbl-oil for crude used by the United States, year 2000: 102.4[j]

[a] See Appendix H for a listing of countries in the regions.

[b] From EIA, *International Energy Annual* (1989). Data for countries not in the EIA are from the U.N. natural gas data base.

[c] Includes gas vented and flared from U.S. federal offshore oil platforms (see text for discussion.)

TABLE M.7 (Cont.)

[d] Crude oil only. Calculated as production of oil, which is crude + NGLs + other oils + refinery gain (as reported in the EIA, *International Energy Annual,* 1989), less EIA's reported refinery gain, other oils, and NGLs.

[e] Calculated from the previous two lines.

[f] Projected venting and flaring per barrel in the year 2000 divided by actual venting and flaring in the year 1987. This represents the expected continuing decline in venting and flaring in some regions of the world. Venting and flaring in North America, Central America, and Western Europe is already very low and probably cannot decline further. On the other hand, many of the countries that now vent and flare a lot of gas are trying to reduce the rate. For example, Nigeria, the largest flarer of gas in the world, "has stated policies encouraging alternatives to flaring," including domestic use of the gas and export, and Algeria is planning to increase its reinjection of gas to enhance oil recovery (ICF, *Estimates of the Costs of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990).

The United Nations has projected venting and flaring emissions in seven regions of the world through the year 2020 (United Nations, no date). The year-2000/year-1987 values used here are based in part on the U.N. projections.

[g] The product of the two previous lines.

[h] From data in the EIA, *Petroleum Supply Annual* (1988).

[i] Calculated as crude from the region plus the crude equivalent of products from the region, divided by the total crude and the total crude equivalents of products. The crude equivalent of products is equal to: volume of products multiplied by the U.S. ratio of refinery crude input to refinery product output. I assume that products from Country X are made from crude oil from Country X, except in the case of products from the Bahamas, U.S. Virgin Islands, Puerto Rico, and Netherlands Antilles. These countries produce no crude, so I assume that the crude comes from Central America.

[j] The crude share multiplied by SCF-natural gas/bbl-oil for each region, summed for all regions.

Notes: mbd = thousand barrels per day. mb = thousand barrels. N/A = not applicable.

M.4.1 Completeness of the EIA Data

The EIA collects venting and flaring data from state agencies in the United States and from foreign governments. The state offices report venting and flaring from *all* onshore oil wells but only *state*, not *federal*, offshore oil wells. To estimate venting and flaring in the United States, the EIA uses only the state data; therefore, the EIA data for the United States do not include venting and flaring from federal offshore oil wells (EIA, Office of Oil and Gas, 1991).

The U. S. Mineral Management Service (MMS) does collect data on venting and flaring from federal offshore oil wells. In 1990, in the Gulf of Mexico, 48 standard cubic feet (SCF)* of gas was vented or flared from oil wells per each barrel of crude oil produced (calculated from total venting and flaring and total production for the Gulf of Mexico, January 1990 to November 1990; transmitted by Nixdorff, 1991). Since production from federal offshore oil wells in the Gulf of Mexico is typically about 90% of total federal offshore oil production (U. S. MMS, 1989), one can assume that this 48-SCF-per-barrel (bbl) rate applied to all federal offshore oil wells in 1990. With this venting and flaring rate and data on total federal offshore production (U. S. MMS, 1989), one can estimate total vented and flared gas for federal offshore oil wells. It amounts to about 15% of the vented and flared gas reported by the EIA.

In Table M.7 I have added the federal offshore venting and flaring, calculated as above, to the total reported by the EIA for 1987.

It is possible (but not likely) that a large amount of associated 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. (1974) 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 incomplete compared with the data sources used in *Sea Technology* (1974) and Brooks et al. (1977)? The answer appears to be the former, because *Sea Technology* (1974) cites the U. S. Department of the Interior (probably the U. S. Geological Survey), and because Brooks et al. (1977) cite personal communications from the U. S. Geological Survey, and the MMS has taken over the venting/flaring-data-collection function from the U. S. Geological Survey (Nixdorff, 1991). The data thus come from the same source and show that venting and flaring have declined. (Note, too, that the MMS data come from oil companies, which are supposed to report *all* venting and flaring.)

In the base case, I assume that the EIA plus the MMS data cover all sources of vented and flared gas.

* A standard cubic foot of gas is measured at 60°F, 14.73 psia, dry.

The EIA does not know if the sources they use for other countries are incomplete. Since I have no reason to assume that they are seriously incomplete, I make no further adjustments to the EIA data. However, in a scenario analysis, I consider the possibility that data from other countries are incomplete.

M.4.2 Vented versus Flared Gas

To calculate the greenhouse effect of vented and flared gas, the aggregate measure (vented and flared) must be disaggregated to the amount vented (venting releases methane, NMHCs, and CO_2) and the amount flared (flaring produces CO_2). Although none of the reference documents for vented and flared gas (aggregated) estimate the proportion that is vented and the proportion that is flared, it is widely believed that most, if not all vented and flared gas is actually flared. Staff members at the Office of Oil and Gas at the EIA expect that at least 95% of all vented and flared gas is actually flared; the term "vented and 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, unreinjected associated gas must be flared to destroy toxic compounds in the raw gas and prevent the accumulation of an explosive concentration of natural gas. 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 EIA staff (McCarrick, 1990) believe that well over 95% of vented and flared gas is flared. However, 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 the U. S. Geological Survey estimated that 70% of offshore vented and flared gas actually was vented in 1974. In support of this, Brooks et al. (1977) also found a high concentration of methane and other hydrocarbons in the waters of the Gulf.

There are two possibilities here: either the fraction of vented gas has declined considerably (to 5% or less), as implied by the EIA, or else there is still a large amount of perhaps clandestine venting (more than 50%). I take a middle ground and assume that venting has declined somewhat. In 1987, 21 BCF of gas was vented or flared from offshore oil leases (based on 48-SCF/offshore-bbl, from above, and 437×10^6 bbl produced from state and federal offshore leases, according to the MMS, 1989), and 121 BCF was vented or flared from onshore fields (124-BCF from onshore and state offshore production, as reported by the EIA, minus my estimate of 3-BCF from the offshore state leases). If 2.5% of onshore gas and 25% of offshore gas was vented, then overall about 6% of vented and flared gas was actually vented in the United States in 1987.

To get from the venting fraction applicable to U. S. crude oil production in 1987 to the fraction applicable to production of all crude oil ultimately consumed by the United States in the year 2000, one must know the venting fractions of countries that export crude and products to the United States and the path of the venting fraction over time. I assume that, on the one hand, some oil exporters now vent more than 6% of total vented and flared gas, but that on the other hand, the

venting fraction will decline somewhat worldwide, so that by the year 2000, the venting fraction applicable to U. S. consumption will be 6%. I consider a higher percentage in a scenario analysis.

M.4.3 Composition of Vented and Flared Gas and Its Relevance to Global Warming

Raw natural gas contains methane, CO_2, and NMHCs. These greenhouse gases have different warming potentials per gram, and consequently the precise overall warming effect of vented raw natural gas depends on the proportions of these individual compounds in the raw gas.

I have back-calculated the composition of raw natural gas using data on the composition of pipeline gas (reported in Weaver, 1989), the amount of nonhydrocarbon gases removed from raw gas (data given by the EIA, *Natural Gas Annual 1989*, 1989), the composition of nonhydrocarbon gases removed (my assumption), and the amount and composition of natural gas liquids removed from raw gas (data from EIA, *Natural Gas Annual*, 1989). The results are shown in Table C.3. This method produces detailed and mutually consistent estimates of the composition of raw and pipeline gas and allows as precise an estimate as possible of the greenhouse impacts of leaks of pipeline gas and raw gas.

In the calculation of CO_2-equivalent greenhouse gas emissions from vented gas, separate warming factors are assigned to each species (warming factors are derived in Appendix O). I assume that all carbon in flared gas oxidizes to CO_2.

M.4.4 Assignment of Venting and Flaring Emissions to Products

The result of the calculation of Table M.7 is a weighted value (in SCF of natural gas per barrel) of oil used by the United States. This number has to be converted to SCF of gas per 10^6 Btu of each product made available to end users. I do this with the following formula:

$$VF_p = O_p \times D_p/Dc \times VFc \times H_p$$

where:

VF_p = SCF of gas vented or flared per 10^6 Btu of product (p) available to end users;

O_p = own-use factor for product (p) (see appendix on general methods);

D_p = density of product (p) (Table C.1);

Dc = density of crude oil (Table C.1);

VFc = SCF of gas vented or flared per bbl of crude used by the United States (weighted average) (Table M.7); and

H_p = volumetric heating value of product(p) (EIA data; Table C.1).

M.5 Methane Emissions from Coal Mining

M.5.1 Overview

The processes that produce coal, called coalification, also produce methane. Some of the methane produced is stored in the coal bed. However, coalification produces much more methane than the coal can store. This excess methane 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 ft^3 of methane (Ayers and Kelso, 1989).

When coal is mined, methane seeps out of the coal and into the mine. To prevent the accumulation of a hazardous concentration of methane, the gas is mixed with air and vented to the atmosphere or, in a few instances, collected at the face, drained, and used as a fuel.

The rate of methane emission from coal mines depends on the age, depth, and structure of the coal bed; the mining technique; the rank and quality of the coal; and other factors. Emissions increase with the depth of the mine and the rank of the coal; the higher the fixed carbon content of the coal, the higher the methane content (Deul and Kim, 1988; Kuuskraa and Brandenburg, 1989). In room-and-pillar mining, methane comes from the recovered coal, the support structures, surrounding coal beds, and unmineable coal seams. In longwall mining, methane is emitted from mined coal, unmineable seams, and from the strata that collapse when the supports are removed. In surface mining, methane is emitted from mined and exposed coal and from adjacent seams.

Most of the methane in mined coal is released by the pressure drop as a result of the coal being exposed to atmospheric pressure. Most of the remaining methane is released when the coal is cleaned, crushed, and prepared for final use. A small amount of methane remains in the prepared coal and is burned with the coal.

Some coal-bed methane can be recovered and used as a fuel before the bed is mined for coal. U. S. coal beds contain about 400 trillion cubic feet (TCF) of methane, of which 90 TCF are recoverable (Ayers and Kelso, 1989; H.T. Black, 1990). Coal-bed methane research and development has grown considerably in recent years, and several large methane recovery projects are operating, almost ready to operate, or planned (Ayers and Kelso, 1989; Kuuskraa and Brandenburg, 1989; Schraufnagel et al., 1990). In 1988, 28 billion cubic feet (BCF) of methane were recovered from coal beds, mostly in Alabama, Colorado, and New Mexico (EIA, *Natural Gas Annual 1989*, 1989). Kuuskraa and Brandenburg (1989) project that by the early 1990s, this amount will increase to 365 BCF/yr.

Still, several obstacles to the large-scale development of coal-bed methane remain, including the difficulty of finding highly permeable, productive spots in coal fields; the high costs of gas recovery; the environmental impacts of disposing of coproduced water; and the reluctance of coal companies to get involved (Schraufnagel et al., 1990).

M.5.2 Estimating Methane Emissions from Coal Mining

Until quite recently, there has been no detailed estimate of methane emissions from coal mining. In a much-cited chapter of a book on climate change, Bolle et al. (1986) make a table of several estimates of methane emissions from coal mining, including estimates by Crutzen and Gidel (1983) and Rasmussen and Khalil (1984). These and other sources cited in Bolle et al. (1986) take their numbers from articles by Ehhalt and Schmidt (1978) and Ehhalt (1974). These two authors, in turn, refer to a National Aeronautics and Space Administration (NASA) study by Hitchcock and Weschler (1972). This NASA report uses an estimate from Koyama (1963). Koyama's estimate appears to be original. However, Koyama was concerned mainly with methane from paddy fields; he estimates methane emissions from coal mining in a one-sentence calculation in which he assumes coal fields produce methane at a rate of 21 cm^3/g of coal produced (p. 3973). This unreferenced, unelaborated, 1963 assumption has been propagated through the literature for many years.

A more accurate estimate is needed. I have compiled estimates of methane emissions from all coal mining and methane emissions from underground mining, and I have compiled estimates of and calculated the methane content of coal. The results and details of my calculations are shown in Table M.8. Although the value of ultimate interest is that for methane emissions from all mining, it is useful to examine, in addition, methane emissions from underground mining alone and the methane content of coal, because the three values are related.

The order of the magnitudes of the three values of emissions from all mining, emissions from underground mining, and the methane content of coal are as one would expect (Table M.8). The emission rate from underground mines should be, and is, greater than the all-mines average, since surface mines emit less methane per ton produced than do underground mines. (Generally, methane content increases with depth.) The emission rate from a mine per ton of coal mined should be greater than the methane content of a ton of mined coal because the face and cracks of the mined surface, as well as the mined material, emit methane. The emission rate from a mine declines over time as faces that have already emitted some of their methane are mined, but the lifetime-average emission rate from a mine (total methane emitted/total coal produced) will still exceed the methane content of the coal because, when the mine is abandoned, the remaining coal will be depleted in methane. (It will have less methane, on average, than it did before mining.) When a mine is abandoned, a considerable amount of coal remains — coal that was either part of the superstructure of the mine or unmineable. However, most of the methane in that remaining coal has been desorbed because of the lower pressures (due to the removal of coal, overburden, and methane). Thus, nearly all of the methane is released from a coal field, but only a portion of the coal is recovered. The result is that the amount of methane released per unit of mined coal should be considerably higher than the amount of methane contained per unit of coal in place. (One factor works against this: a portion of the adsorbed methane never desorbs from the coal, even when the coal is mined and crushed, and so ends up being burned to CO_2 rather than being released as methane; however, the amount is small.)

TABLE M.8 Emissions of Methane from Coal Mining

Reference	Methane (ft^3) per Ton of Coal	Type of Estimate
Emissions from all mining[a]		
Ehhalt and Schmidt (1978)	87- 306[b]	Global average
Okken and Kram (1989)	247-309[c]	Global average
Okken and Kram (1989)	211	U. S. average
ICF Incorporated (1990)	400	U. S. average[d]
ICF Incorporated (1990)	492	World average[d]
Emissions from underground mines[e]		
Deul and Kim (USBOM) (1988)	25-3,100	Range from over 100 U. S. mines
Deul and Kim (USBOM) (1988)	833	1975 Average; 60 U. S. mines
Curl (IEA) (1978)	160-1,300	From a German study
Methane content of coal[f]		
Deul and Kim (USBOM) (1988)	416-705	Anthracite
Deul and Kim (USBOM) (1988)	192-544	Low and medium-volatile bituminous
Deul and Kim (USBOM) (1988)	64-288	High-volatile bituminous
Deul and Kim (USBOM) (1988)	64-224	Shallow, high-volatile bituminous
Deul and Kim (USBOM) (1988)	200	Estimate of average U. S. gas content
This report	180[g]	Estimate of average U. S. gas content

[a] Total methane emitted as result of coal mining in the world or in the United States divided by total coal production in the world or in the United States.

[b] I divided their estimate of global methane emissions from coal by 1975 worldwide coal production, including lignite and brown coal, assuming a methane density of 20 g/SCF. Ehhalt and Schmidt (1978) cite a 1972 report, which in turn cites a 1963 paper (see text).

[c] Based on 1979 coal production.

[d] Based on ICF's estimate of 368 BCF of methane emitted in the United States and 2,494 BCF of methane emitted globally, and EIA data on United States and world coal production.

[e] Cubic feet of methane emitted from an underground mine per ton of coal produced from that underground mine. The U. S. Bureau of Mines (USBOM) emission rates (Deul and Kim, 1988) are measured at the exhaust fan of the mine. Note that this is not the same sort of ratio as in footnote a. Here the ratio applies only to a specific mine or set of mines, whereas in footnote a, global or regional averages are used. The estimates of emissions to the atmosphere include (or ought to include) emissions from surface as well as underground mines. A global average could be calculated from per-mine values if values were obtained for every kind of mine, and the values were then weighted by global production from that kind of mine.

TABLE M.8 (Cont.)

[f] Cubic feet (ft^3) of methane contained in a sample ton of coal. This is further removed from a global emission estimate. Total methane emissions are greater than the amount of methane contained in a piece of mined coal; emissions also come from the face of the wall and the cracks in the wall from which the coal was recovered.

[g] I have multiplied the typical methane content of each class of coal by the share of that class of 1987 total coal production in the United States and summed over all classes. The data I used are as follows:

Class of Coal	% Fixed Carbon, Moisture and Ash-Free	Methane (ft^3) per ton	Share of 1987 U. S. Production (%)
Anthracite	94.1	560	0.3
Low-volatile bituminous	80.7	450	2.7
Medium-volatile bituminous	73.5	450	5.8
High-volatile A bituminous	60.5	190	35.7
High-volatile B & C bituminous and subbituminous	~55	130	46.8
Lignite	51.6	120	8.6

The fixed carbon percentages are from EIA, *Coal Data: A Reference* (1989), and are representative of each coal class. The production shares are from EIA, *Coal Production - 1987* (1988). The ft^3-methane/ton methane contents are from Deul and Kim (1988). I have picked typical values (not averages) from Deul and Kim from their ranges (for the direct determination method) for anthracite, low-volatile bituminous, medium-volatile bituminous, and high-volatile bituminous coals. I have assumed that the methane content of subbituminous coal is equal to that of high-volatile bituminous coal because the composition of the two kinds of coal are very similar. I have assumed that lignite contains less methane than does high-volatile bituminous coal because lignite has somewhat less fixed carbon (and methane content is related to fixed carbon).

Note: USBOM = U. S. Bureau of Mines

Thus, one would expect the national-average emission into the air, per ton of coal mined, to be considerably greater than the national-average methane content of coal because of the abandonment of mines with depleted coal. The data of Table M.8 confirm this. Compare, for example, my estimate of the average methane content of coal, 180 ft^3/ton, with a recent, comprehensive estimate of methane emissions from coal mines, 380 ft^3/ton (ICF, 1990).

The draft ICF (1990) report estimates emissions from coal mining and use for every state in the United States as a function of the amount of coal mined, the mining technique, and the methane content of the coal. The approach to estimating the methane content of the coal is similar to the one used here but more disaggregated, and the study takes the additional step of relating methane content to emissions.

M.5.3 Fate of Methane Emissions from Coal Mines

Most, but not quite all, of the methane released from coal enters the atmosphere as methane. Methane may be mixed with air and vented; collected, drained, and flared; or collected, drained, and used as a fuel. Most methane simply is mixed with air and ventilated to the surface. The vented methane is too dilute to be used as a fuel: by law, the vented gas must contain less than 1% methane (Kim, 1990), which is too little to burn. Okken and Kram (1989) state that about 10% of the emitted methane is captured and used as fuel, but this seems high: underground bituminous mines reported consuming 500 million ft^3 of natural, manufactured, and mixed gas in 1987 (U. S. Department of Commerce, U. S. Bureau of the Census, *1987 Census of Mineral Industries, Coal Mining,* 1989), which is much less than 1% of the roughly 300 BCF that, according to Table M.8, would have been emitted by underground bituminous mines. (Of course, it is possible that mines do not report use of coal-bed gas.) Deul and Kim's (1988) discussion of methane recovery indicates that presently only a miniscule fraction of coal-bed gas is put to work. The ICF (1990) report states that only in Alabama do some mining operations use captured methane. Thus, it is safe to assume that virtually all methane is vented to the atmosphere.

The recovery of methane from coal beds in advance of mining, for use as a fuel, will probably reduce methane emissions from mining, but not by as much as might be imagined. This is because the beds from which gas will be recovered are either unmineable (because the coal is too deep, as in the San Juan Basin of Colorado) or so gassy that they would not have been mined had the gas not been removed. In the latter case, the recovery of methane in advance of mining may reduce the methane content to a typical level and, hence, will not really lower the overall emission rate.

Based on this, I assume that U. S. average emissions from mines are 380 ft^3/ton of coal mined. I then assume that in the year 2000, 5% of the coal-bed emissions will be sold as fuel and 5% will be flared. The estimate of methane emissions per ton of coal produced is converted to emissions per ton of coal available to end users by multiplying by the ratio of production to available consumption (Appendix F).

M.5.4 Composition of Coal-Bed Methane and Its Relevance to Global Warming

Coal-bed gas contains small amounts of ethane and CO_2, in addition to methane. These greenhouse gases have different warming potentials per gram; consequently, the precise overall warming effect of vented coal-bed gas depends on the proportions of these individual compounds.

Deul and Kim (1988) show the composition of coal gas from seven coal beds. Coal-bed gas generally contains a bit more methane and much less of the higher hydrocarbons than does natural gas. It contains nitrogen and CO_2, but no sulfur compounds. My assumptions are shown in Table C.3.

In the calculation of CO_2-equivalent greenhouse gas emissions from vented coal-bed gas, separate warming factors are assigned to each species (warming factors are derived in

Appendix O). I assume that all carbon in the small amount of flared coal-bed gas oxidizes completely to CO_2.

M.6 Methane Emissions from Other Combustion Sources (Trains, Ships, Pipeline Compressors, Electricity Plants, Etc.)

For trains, ships, pipeline compressors, tractors, engines, electricity-generating plants, wood boilers, and several other sources, I have used AP-42 (Volumes I and II) methane emission factors (Table A.2; methane emissions from power plants are shown in Table D.4). For cases in which AP-42 provided estimates of THC emissions but not methane emissions, I multiplied the THC emission factor by an estimate of the methane proportion of THC emissions, based on known proportions for the same fuel in similar applications.

The South Coast Air Quality Management District (1990) and the Texas Air Control Board (1990) report total annual methane emissions from specific petroleum refineries in California and Texas. These emission values, divided by the total output of the refineries (in 10^6 Btu) (EIA, *Petroleum Supply Annual*, various years), results in 0.24-2.4 g-methane/10^6 Btu-output, with most values falling toward the lower end of the range. This total emission factor is consistent with the methane contribution from fuel combustion alone, which is about 0.1 g/10^6 Btu output. (One would expect that fuel combustion would produce only a small part of the total refinery methane emissions.) Thus, methane emissions from refinery process areas, excluding boilers, typically are around 0.4 g/10^6 Btu.

There are few data on methane emissions from facilities producing only methanol. Data on methane emissions from plants producing methanol and other products (Texas Air Control Board, 1990), combined with data on the production capacity of methanol facilities (U. S. Department of Commerce, Office of Chemicals and Allied Products, *A Competitive Assessment of the U. S. Methanol Industry*, 1985), indicate that methane emissions may be on the order of 1-10 g/10^6 Btu of methanol. However, it is not clear how methane emissions should be allocated among the multiple products. Note, though, that this range for methanol (1-10) is consistent with the range estimated for petroleum refineries (0.24-2.4) because methanol plants process natural gas, whereas petroleum refineries process crude oil.

For wood boilers, I use AP-42's methane emission factor. The wood-boiler emission factors apply to the burning of lignin to provide steam in a wood-to-ethanol plant. (However, data in Dahlberg et al. [1988] indicate that methane emissions from the combustion of wood chips are almost 100 times higher than those from the combustion of fossil fuels — 300 ppmv in effluent gas versus 5 ppmv.)

For methane emissions from corn-to-ethanol plants, coal-to-methanol plants, and wood gasification, see the notes to Table A.2.

M.7 Other Sources of Methane

M.7.1 Methane from Road Asphalt

Sackett and Barber (1988) estimate that about 15% of the carbon in newly produced asphalt is converted to methane by photochemical and thermal processes. It is not clear if they mean that every year 15% of the carbon is converted, or if total conversion over the lifetime of asphalt can be represented as 15% in one year (the year the asphalt was produced). It seems as though they mean the latter. Assuming this, this methane source can be allocated to highway vehicles, in grams per mile, via the following procedure. According to the 1987 *Census of Manufactures* (U. S. Department of Commerce; industries 2911, 2951, an 2952), 85% of the asphalt produced by refineries in 1987 was paving grade, and the rest was roofing grade or unclassified. In 1987, U. S. refineries produced 158 million barrels of asphalt and road oil (EIA, *Petroleum Supply Annual,* Volume 1, 1988; this is essentially all asphalt). On the basis of these two facts, I estimate that road-grade asphalt produced in 1987 contained 18.7 Tg of carbon. Applying Sackett and Barbers' (1988) 15% factor gives 2.8 Tg of methane in 1987 from the action of sunlight on the new road asphalt. Multiplying this by a 20:1 methane-to-CO_2 mass conversion factor results in 55 Tg of CO_2-equivalent gases, which, when allocated to the 1.92 trillion miles traveled by all vehicles in 1987 (Federal Highway Administration, *Highway Statistics 1987*, 1988), results in 28 g/mi CO_2-equivalents — about 9% of the tailpipe emissions from a 30-mpg car.

This is not an insignificant source, compared with the other transportation-related greenhouse-gas sources. However, road use, or vehicle-miles-traveled (VMT), is not a function of the type of fuel being used. In other words, there is no plausible relationship between production of road grade asphalt and the choice of transportation energy. Therefore, consideration of this source of greenhouse gases would merely add a single, but not small, g/mi increment to *all* the alternatives. Moreover, I am not aware of low-greenhouse-gas-emitting alternatives to asphalt that could be used on a wide scale. For these reasons, I do not consider this source further. (Note again, though, that this source is relatively large and should be included when comparing automobile transportation with mass transit.)

M.7.2 Methane from Nuclear Reactors

Pressurized-water nuclear reactors produce about 900 Ci/yr of a reduced form of methane, $^{14}CH_4$ (Whalen et al., 1989). However, at 4.6 Ci/g of carbon-14, the total methane production is infinitesimal.

M.7.3 Methane from Liquefied Natural Gas

The use of LNG probably results in additional emissions of methane, but these are tiny and can be ignored. About 2.5% of the loaded LNG boils off during a 15-day trip, but this is used by the tanker as fuel (Chem Systems, 1988). More LNG boils off during off-loading at the terminal, but this is presumably reliquefied or used as fuel. It does not seem likely that more than about

0.2% of the cargo is vented. The EIA (EIA, *Annual Outlook for Oil and Gas 1990*, 1990) projects that the United States will import less than 1 TCF of LNG in the year 2010. The 2 BCF of boiloff from this LNG would be about 1% of total venting and flaring in the United States, and less than 5% of the *lower* estimates of leakage from natural gas systems. Obviously, this small number is lost in the uncertainty surrounding venting and flaring and natural gas leaks.

M.8 Greenhouse Credit for Gas Sources Used as Fuel

Methane leaks naturally from natural gas formations, coal mines, and landfills. Leakage from landfills alone may account for 10-20% of global methane emissions (Bingemer and Crutzen, 1987). If one does nothing about these sources, they will continue to contribute to global warming. On the other hand, if one taps these gas sources and puts them to work as fuel, one would be getting "free" energy from the standpoint of global warming: since the gas would have been vented anyway, burning it as a fuel and deriving work would be useful and would not contribute additional CO_2, relative to the counterfactual. In fact, by putting the gas to work, one would not only get useful work but would actually reduce emissions of greenhouse gases, since burning the gas produces CO_2 and work, whereas venting it releases methane, with no work provided. Hence, one can argue that any gas energy, now and in the future, mined from gas that would have been vented should be assigned a net greenhouse credit. Thomas Gold (1988) has advanced this sort of argument.

Currently, very little of the methane emitted from these sources is collected and used as a fuel. However, these sources are likely to be used more in the future, although their total contribution will still be small compared with that from the use of fossil natural gas (*The Potential of Renewable Energy*, 1990).

Appendix N:

Emissions of Nitrous Oxide from Vehicles, Power Plants, and Other Sources

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N.1 Nitrous Oxide as a Greenhouse Gas

Nitrous oxide (N_2O) is a potent greenhouse gas with a radiative forcing of over 100 times that of carbon dioxide (CO_2) per molecule, and a lifetime of more than 100 years (see Appendix O). N_2O also is involved in stratospheric ozone chemistry (Kramlich et al., 1988; Ryan and Strivastava, 1989). However, global emissions of N_2O emissions are small compared with global emissions of methane (CH_4) and CO_2 and, hence, the contribution of N_2O to future warming is expected to be relatively small (*Climate Change*, 1990).

The concentration of tropospheric N_2O has been increasing at about 0.2%-0.3%/yr over the last 40 years or so, from a preindustrial concentration of about 0.285 parts per million volume (ppmv) (Weiss, 1981; Bolle et al., 1986; Khalil and Rasmussen (in Dickinson and Cicerone, 1986); Pearman et al., 1986; Watson et al., 1990). The primary anthropogenic sources of N_2O are oceans and soils (Bowden and Bormann, 1986; Watson et al., 1990). The combustion of fossil fuels appears to contribute only a minor amount (and less than previously thought, as explained below), although uncertainties remain. The main sink for N_2O is photolysis in the stratosphere (Watson et al., 1990).

N.2 Nitrous Oxide Emissions from Vehicles

N_2O is emitted directly from vehicles (Table N.1). The N_2O emissions from catalyst-equipped gasoline-powered light-duty vehicles (LDVs) depend significantly on the type and temperature of the catalyst rather than total nitrogen oxide (NO_x) levels or fuel nitrogen content. Gasoline contains relatively little nitrogen, and so fuel NO_x and fuel N_2O emissions from autos are low. The high temperatures and pressures of the internal combustion engine (ICE) are sufficient to form NO_x thermally, but are evidently inefficient for production of N_2O (Hao et al., 1987). Thus, cars without catalytic converters produce essentially no net N_2O (Table N.1). On the other hand, Weiss and Craig (1976) predict N_2O exhaust concentrations of up to 400 ppmv from autos with platinum reduction catalysts only, according to the reactions:

$$6NO + 4NH_3 \rightarrow 5N_2O + 6H_2O$$

and

$$2NO + H_2 \rightarrow N_2O + H_2O$$

TABLE N.1 Nitrous Oxide Emissions from Gasoline, Diesel, and Methanol Vehicles

Type of Vehicle	Emission Control Equipment	Test	Odometer (mi)	Emissions		NO_x/N_2O[a]	Reference
				ppmv	mg/mi		
Gasoline LDV							
NS	No catalytic	NS	NS	0.1-0.2[b]	0	NS	Pierotti and Rasmussen (1976)
1977 AMC Pacer	No catalytic converter; air pump	FTP-75	NS		5[c]	400	Urban and Garbe (1979)
1977 Volvo	Lean operation; no O_2 sensor	FTP-75	200		0	--	Bradow and Stump (1977)
1978 Oldsmobile Cutlass	Oxygen catalytic converter and EGR	FIP-75	NS		18[c]	45	Urban and Garbe (1979)
1978 Chevrolet Malibu	Oxygen catalytic coverter and air pump	FTP-75	NS		8[c]	86	Urban and Garbe (1979)
1978 Chevrolet Malibu	Oxygen catalytic converter and no air pump	FTP-75	NS		66[c]	18	Urban and Garbe (1979)
1978 Ford Granada	Oxygen catalytic converter and air pump	FTP-75	NS		34[c]	58	Urban and Garbe (1979)
1978 Ford Mustang	Oxygen catalytic converter and no air pump	FTP-75	NS		43[c]	38	Urban and Garbe (1979)
NS	Unspecified catalytic converter	NS	NS	up to 1.0	up to 21[d]	NS	Pierotti and Rasmussen (1976)
NS	Oxygen and reduction catalytic converter	NS	NS	up to 10	up to 300[d]	NS	Weiss and Craig (1976)
1978 Oldsmobile Cutlass V-8	Oxygen catalytic converter	FTP-75	NS	0.27-0.77[e]	23[e]	NS	None; EPA unpublished data used

TABLE N.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test	Odometer (mi)	Emissions ppmv	Emissions mg/mi	NO_x/N_2O[a]	Reference
1977 Oldsmobile Cutlass V-8	Oxygen catalytic converter	FTP-75	NS	0.42-1.68[e]	47[e]	NS	EPA unpublished
1978 Ford Pinto	3-way catalytic converter and EGR	FTP-75	New		34-35[g]	19-26	Smith and Black (1980)
1978 Pontiac Sunbird	3-way catalytic converter and EGR	FTP-75	New		32-48[g]	20-40	Smith and Black (1980)
1978 Saab	3-way catalytic converter and no EGR	FTP-75	New		16-35[g]	10-34	Smith and Black (1980)
4 1978-1980 passenger cars	3-way catalytic converter and 2-way oxygen catalytic converter	FTP-75	New		63-101[h]	8-24	Braddock (1981)
2.2 L Renault	3-way catalytic converter; EFI	FTP-75	NS		50-55	NS	Prigent and DeSoete (1989)[i]
Diesel LDV							
1.9 L Citroen	NS	FTP-75	NS		50-58	NS	Prigent and DeSoete (1989)[i]
Flexible-Fuel Vehicle							
With gasoline or indolene							
Ford Crown Victoria	3-way catalytic converter	FTP-75	12,500		13	58	Ford (1988)[j]

TABLE N.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test	Odometer (mi)	Emissions		NO_x/N_2O[a]	Reference
				ppmv	mg/mi		
Ford Escort	3-way catalytic converter	FTP-75	4,000		116	5	Ford (1988)[j]
With 85% methanol/ 15% gasoline							
Ford Crown Victoria	No catalytic converter	FTP-75	3,000-24,000		2	758	Ford (1988)[j]
Ford Crown Victoria	3-way catalytic converter	FTP-75	16,000		16	52	Ford (1988)[j]
Ford Escort	No catalytic converter	FTP-75	NS		-7	-370	Ford (1988)[j]
Ford Escort	3-way catalytic converter	FTP-75	4,000		105	4	Ford (1988)[j]
Gasoline HDV							
1979 Ford	NS	Chassis HDTC	11,000		96	133	Dietzmann et al. (1981)
1979 International Harvester	NS	Chassis HDTC	15,000		48	272	Dietzmann et al. (1981)
Diesel HDV							
1977 DDC-stroke	NS	Chassis HDTC	60,000		68-85[k]	494-571	Dietzmann et al. (1980)
1979 Caterpillar 4-stroke	NS	Chassis HDTC	7,000		22-35[k]	545-785	Dietzmann et al. (1980)
1979 Mack 4-stroke	NS	Chassis HDTC	69,000		50-58[k]	500-565	Dietzmann et al. (1980)
1979 Cummins 4-stroke	NS	Chassis HDTC	26,000		35-47[k]	517-773	Dietzmann et al. (1980)

[a] This is the ratio of g/mi emissions (not the ratio of ppm), except as noted.

TABLE N.1 (Cont.)

[b] This is gross concentration; the background concentration of 0.3 ppm has not been deducted. Hence, in this case, uncontrolled vehicles actually consume net N_2O.

[c] Figures shown are reported averages of several tests with emission control systems functioning properly. Some test results were higher or lower than averages. Disabling EGR increased N_2O emissions by a factor of 1.5-3.0. (Prigent and De Soete [1989] also found that N_2O emissions increase when EGR is disconnected.) Other malfunctions are relatively unimportant.

[d] I subtract the background concentration of 0.3 ppmv. The authors report only ppmv. For an order of magnitude estimate of mg/mi, I use the ppmv - to - mg/mi conversion factor implied by the EPA (unpublished) data. This conversion factor is only approximate because it depends on the mass flow rate of exhaust gases, which depends on efficiency and engine size.

[e] ppmv is the range reported for three bags in the FTP cold start test (mg/mi as reported in the reference). Similar emission rates are reported for other test cycles.

[f] With the oxygen sensor disconnected, the N_2O emissions disappeared.

[g] Low end is at 0 mi; high end is 15,000 mi. The N_2O did not vary appreciably with the type of gasoline. Emissions were consistently higher in NYCC and lower in HFET than in FTP.

[h] Results at normal FTP ambient temperature (~78°F). At 55-60°F, one vehicle showed a substantial increase in N_2O emissions; another showed a substantial decrease; and two were unaffected.

[i] SO_2 content of the gas is reported to be 12 ppm for undiluted samples and 10 times less for diluted samples. This is well below what appears to be the concentration that actuates artifactual N_2O formation.

[j] Ford reported detailed speciated FTIR data for two flexible-fuel Escorts and two flexible-fuel Crown Victorias, at different methanol/gasoline mixtures, and with different catalysts and catalyst ages. The Escort was tested on indolene; the Crown Victoria was tested on gasoline. A more detailed summary of the Ford test results is given in Table M.3.

[k] Emissions vary with the quality of diesel fuel used.

Note: EPA testing protocol requires that all emissions be corrected for background concentration (i.e., the ambient concentration must be subtracted from the total measured emissions). I therefore have assumed that all reported emissions are net of background, unless it is clear that they are not (as in Weiss and Craig, 1976; Pierotti & Rasmussen, 1976).
NS = not specified. EGR = exhaust gas recirculation. EFI = electronic fuel injection. FTP = Federal Test Procedure. chassis HDTC = 1983 Heavy Duty Transient Cycle, chassis version. DDC = Detroit Diesel Corporation. NYCC = New York City Cycle. HFET = Highway Fuel Economy Test. FTIR = Fourier Transform Infrared (spectroscopy).

Seinfeld (in Pierotti and Rasmussen, 1976) suggests that N_2O production in 3-way catalysts (those that oxidize hydrocarbon [HC] and carbon monoxide [CO] and reduce nitric oxide [NO]) may occur by a different route:

$$NH_3 + 2O_2 \rightarrow N_2O + 3H_2O$$

Alternatively, as suggested by Soete (Ryan and Srivastava, 1989; see also Prigent and De Soete, 1989), the NO can be reduced by CO rather than hydrogen (H_2):

$$2NO + CO \rightarrow N_2O + CO_2$$

Prigent and De Soete (1989) conclude that the N_2O is formed at relatively low catalyst temperatures; at higher temperatures, the N_2O itself is destroyed. They show a graph in which N_2O formation, via reduction by CO over a metal catalyst, peaks at 120 ppmv at 500 K and drops to zero at 400 and 650 K. Prigent (in Ryan and Srivastava, 1989) shows N_2O formation across a 3-way platinum-rhodium catalyst peaking at 180 ppmv at about a 635 K catalyst inlet temperature (which implies a slightly cooler temperature across the catalyst). The dependence of N_2O formation on temperature results in higher emissions from a cold-start test than a hot-start test, and relatively high emissions during catalyst light-off (Prigent and De Soete, 1989). This situation has important implications, one of which is that electrically heated catalysts, which will probably be used in the future to reduce cold-start HC emissions, will probably reduce N_2O emissions, too.

The data of Table N.1 agree with the theory discussed above. As shown in Table N.1, N_2O emissions from cars with 3-way catalysts are uniformly higher than from cars without catalysts, although still comparatively low. In further support of this, Lindskog (in Ryan and Srivastava, 1989) has found that after a cold start the concentration of N_2O in the exhaust pipe, measured after the catalytic converter, is two times higher than the concentration measured before the catalytic converter. The N_2O emissions increase slightly with the age of the catalyst (although the trend certainly is not strong; [Table M.3]), and substantially if EGR is disconnected (Table N.1, note c). Colder ambient temperatures may increase or decrease N_2O emissions (Table N.1, note h). However, lower *catalyst* temperatures almost certainly increase N_2O emissions (Ryan and Srivastava, 1989). This discrepancy is possible because, once a vehicle is warmed up, the temperature of the catalyst is not directly related to the air temperature; it is determined by the temperature of the exhaust gases, which are determined by engine load and combustion conditions. The type of drive cycle appears to influence N_2O as well (Table N.1, g).

Table N.1 shows that emissions from heavy-duty diesel vehicles (HDDVs) are similar to emissions from passenger cars equipped with catalytic converters, but that emissions from gasoline-powered heavy trucks may be higher.

N.2.1 Nitrous Oxide Emissions from Vehicles Powered by Alternative Fuels

The preceding analysis indicates that N_2O emissions from vehicles powered by alternative fuels will depend primarily on the operating temperature and composition of catalysts optimized for the particular fuel. Such catalysts are being developed for methanol but not for natural gas,

ethanol, liquefied petroleum gas (LPG), or hydrogen. Until such optimized vehicles are developed and tested for N_2O, the existing alternative-fuel data base will have to suffice.

Tests by Ford (1988) on "flexible-fuel" Escorts and Crown Victorias showed that N_2O emissions were roughly the same for cars running on gasoline, 50% methanol, 85% methanol, and 100% methanol, and that these emissions did not change appreciably with the age of the catalyst (Tables M.3 and N.1); the one exception was the Escort with a new catalyst and 100% methanol, which had significantly lower emissions. The Escort emitted about 120 mg/mi, and the Crown Victoria about 15 mg/mi. Based on these results, which show no difference in N_2O emissions between methanol-powered and gasoline-powered vehicles, and the lack of any reason to believe that N_2O emissions from optimized methanol vehicles should be much higher or lower than N_2O from gasoline, I assume the level of emissions is the same for methanol LDVs and gasoline LDVs and the same for methanol heavy-duty vehicles (HDVs) and diesel HDVs.

I also assume parity between natural gas, ethanol, LPG, and petroleum vehicles, although there are no supporting data. I assume that all HDVs emit at the same level, too. However, I assume that hydrogen LDVs emit no N_2O because hydrogen vehicles probably will not have catalytic converters.

As discussed above, N_2O formation is related to the temperature across the catalyst. Different fuel and engine combinations will produce different exhaust gas temperatures and, hence, different N_2O emission rates. One way to project N_2O emissions, then; is to estimate the temperature of exhaust gas as a function of fuel type, engine design, engine operation, and catalyst location, and then estimate N_2O emissions as a function of temperature. (This method still does not account for the effect of different catalyst materials.)

My base-case N_2O grams-per-mile assumptions, based on the data and analysis of Table N.1, and assuming the use of electrically heated catalysts to reduce cold-start emissions, are shown in Table B.2. The data of Table N.1 indicate that most vehicles emit 30-100 mg/mi of N_2O. The average for very low-mileage vehicles with a 3-way catalyst is about 60 mg/mi. The lifetime average for these vehicles may be slightly higher, as indicated weakly by the data of Table M.3, and the notes to Table N.1. The failure of emission controls can increase or decrease N_2O emissions: disabling EGR increases N_2O, but disabling the oxygen sensor eliminates N_2O (Table N.1). However, the use of an electrically heated catalyst, or a close-coupled catalyst to reduce cold-start emissions of HC and CO will probably reduce N_2O emissions from the levels of Table N.1.

It appears, then, that the lifetime, in-use N_2O emission rate for vehicles meeting the new Clean Air Act standards for HC and CO will be about the same as the N_2O emission rate of Table N.1. I assume 60 mg/mi.

N.2.2 Nitrogen Oxide and Nitrous Oxide

One way to get around a lack of N_2O emissions data for alternative fuels is to assume a generic relationship between NO_x and N_2O. (The NO_x emissions are almost always known.)

However, there is no theoretical or empirical basis for assuming that N_2O emissions are directly proportional to NO_x emissions. The data of Table N.1 show clearly that the amount of N_2O emissions and the proportion of NO_x to N_2O can encompass a range that extends over an order of magnitude. For any particular vehicle, a change in operating conditions that increases NO_x emissions may decrease N_2O emissions. Indeed, the high temperatures that favor NO_x formation may destroy N_2O emissions. In regard to N_2O emissions from power plants, Sloan and Laird (1990) write that "the observed correlation between N_2O and NO_x was . . . caused wholly by artifact production" (p. 1205). For these reasons, I do not use an NO_x:N_2O ratio, and instead assume that N_2O emissions per mile are the same for LDVs with the same pollution control equipment, regardless of the fuel used. This assumption undoubtedly will be shown to be incorrect as more data become available, but for now, it appears to be the only supportable assumption.

N.2.3 Artifactual Nitrous Oxide Formation

As discussed below, researchers recently have discovered that N_2O may form in the containers of the gas samples waiting to be analyzed. However, this artifactual formation probably does not occur with the analysis of automobile exhaust gases for four reasons. First, a high concentration of sulfur is necessary to promote the formation of N_2O, and gasoline does not contain enough sulfur to generate the threshold sulfur concentration required. The threshold appears to be about 600-1,000 ppm; in the gasoline-vehicle tests by Prigent and De Soete (1989), the sulfur dioxide (SO_2) concentration was two or three orders of magnitude lower. Second, if the N_2O observed in vehicle tests was primarily a result of artifactual formation, and not of gas reactions across a catalytic converter, there probably would not be a significant difference between N_2O production with and without catalytic converters. Third, the production of N_2O across 3-way catalysts can be explained (see above). Fourth, Prigent and De Soete (1989) also measured N_2O on-line (i.e., without storing the samples), and the results were consistent with the results of the vehicle/chassis dynometer tests.

N.3 Nitrous Oxide Emissions from Stationary Sources

Power plants also emit N_2O. Table N.2 shows emissions of nitric oxide (NO) and N_2O as a function of type of fuel, type of combustion, combustion temperature, sulfur content, and sampling protocol.

Early tests, especially those by Hao et al. (1987), indicated that coal-fired power plants emitted relatively large amounts of N_2O. Oil-fired plants were found to emit less than coal-fired plants, but still a lot, and gas-fired plants were found to emit much less than coal-fired plants. Hao et al. (1987) found that 14% of the fuel nitrogen was converted to N_2O and that the concentration of N_2O in the sample (measured in parts per million volume) was about 29% the of NO_x concentration. With coal-fired plants, the parts-per-million-volume concentration ranged into the hundreds (Table N.2).

TABLE N.2 Measurements of Nitrous Oxide Emissions (ppm)

Combustor Type	Fuel	Sample Collection Method[a]	Temperature (K)	Sulfur Content of Fuel (%) or Flue Gas (ppm)	NO (ppm)	N_2 (ppm)	Reference
On-line sampling							
Six utility boilers	Coal	On-line gas chromatograph	NA	NS	~400	0-4	Clayton et al. (1989)
Tunnel furnace	Coal	On-line gas chromatograph	NA	380-1,450 ppm	~600	2.2-4.2	Linak et al. (1989)
Small boiler	Gas	On-line gas chromatograph	NA	0 ppm	62	0	Linak et al. (1989)
Tunnel furnace	#2 fuel oil	On-line gas chromatograph	NA	236 ppm	189	1.3	Linak et al. (1989)
Once-through	#6 fuel oil	On-line gas chromatograph	NA	3% in oil	220	0	Ryan et al. (1989)
Drum boiler	Bituminous coal	On-line gas chromatograph	NA	6% in coal	386	3.3	Ryan et al. (1989)
Conventional boiler	Coal?	On-line non-dispersive i.r.	NA	1,200 ppm	NA	6-16[b]	Sloan and Laird (1990)
Low-NO_x boiler	Coal?	On-line non-dispersive i.r.	NA	1,200 ppm	NA	12-20[b]	Sloan and Laird (1990)
Opposed-fired boiler	Coal	On-line non-dispersive i.r.	NA	NS	662-982	2-11	Kokkinos (1990)
Tangentially fired boiler	Coal	On-line non-dispersive i.r.	NA	NS	325-498	1	Kokkinos (1990)
Integrated-gasification combined cycle (IGCC)	Coal	On-line non-dispersive i.r.	NA	NS	19	1	Kokkinos (1990)
Front-fired boiler	Oil	On-line non-dispersive i.r.	NA	NS	268	1	Kokkinos (1990)
Front-fired boiler	Gas	On-line non-dispersive i.r.	NA	NS	120	2	Kokkinos (1990)
Combustion turbine	Gas	On-line non-dispersive i.r.	NA	NS	19	4	Kokkinos (1990)

TABLE N.2 (Cont.)

Combustor Type	Fuel	Sample Collection Method[a]	Temperature (K)	Sulfur Content of Fuel (%) or Flue Gas (ppm)	NO (ppm)	N_2 (ppm)	Reference
Effect of sulfur and/or temperature							
Fixed-bed (laboratory)	Graphite	On-line gas chromatograph	1,000	0	1, 000	4	Soete (1989)
Fixed-bed (laboratory)	Graphite	On-line gas chromatograph	1,275	0	1,000	0	Soete (1989)
Fixed-bed (laboratory)	Graphite	On-line gas chromatograph	1,275	NS	700	4	Soete (1989)
Entrained flow reactor	Peat	On-line infrared spectrometer	1,000	0.14% S peat	710	~380[c]	Aho and Rantanen (1989)
Entrained flow reactor	Peat	On-line infrared spectrometer	1,123	0.14% S peat	870	~125[c]	Aho and Rantanen (1989)
Fluid-bed versus high-temperature combustion							
CFBC	Coal	Aluminum bags, stored	NA	NS	130	96	Ryan et al. (1989)
Grate combustion	Coal	Aluminum bags, stored	NA	NS	150	20	Ryan et al. (1989)
CFBC	Coal	Aluminum bags, stored	NA	NS	NA	79-165	Ryan et al. (1989)
Tangentially fired	Coal	Aluminum bags, stored	NA	NS	NA	3- 38	Ryan et al. (1989)
FBC	Coal	On-line infrared spectrometer	NA	NS	NA	100	Ryan et al. (1989)
Coal combustor (CFBC)	Coal	On-line infrared spectrometer	NA	NS	2,000	30	Ryan et al. (1989)
CFBC	Coke	Aluminum bags, stored dry	1,180	NS	32	124[d]	Aamand and Andersson (1989)

TABLE N.2 (Cont.)

Combustor Type	Fuel	Sample Collection Method[a]	Temperature (K)	Sulfur Content of Fuel (%) or Flue Gas (ppm)	NO (ppm)	N_2 (ppm)	Reference
CFBC	Coke	Aluminum bags, stored dry	1,073	NS	32	170[d]	Aamand and Andersson (1989)
CFBC	NS	On-line non-dispersive i.r.	NA	NS		20-100	Kokkinos (1990)
CFBC	Coal	NS	NA	NS	80-315	NA	Makansi (1991)
Emission controls							
With SCR	Coal	Stainless steel, stored	NA	NS	NA	3-6[d]	Ryan et al. (1989)
Low-NO_x boiler	Coal?	On-line non-dispersive i.r.	NA	1,200 ppm	NA	12-20[e]	Sloan and Laird (1990)
Front-fired boiler with urea	Oil	On-line non-dispersive i.r.	NA	NS	117	23	Kokkinos (1990)
On-line versus stored sampling:							
Tangentially fired	Pulverized coal	On-line gas chromatograph	NA	~1,200 ppm	385	4.5	Ryan et al. (1989)
Wall-fired	Pulverized coal	PVC bag, stored	NA	~1,200 ppm	700	32	Ryan et al. (1989)
Down-fired	Pulverized coal	On-line gas chromatograph	NA	NS	600	<10	Ryan et al. (1989)
Down-fired	Pulverized coal	Stainless steel, stored	NA	NS	150-900	10-220	Ryan et al. (1989)
Conventional wall-fired	Coal?	On-line non-dispersive i.r.	NA	1,200 ppm	~700	11-17[b]	Sloan and Laird (1990)
Conventional wall-fired	Coal?	Plastic bag, 2-3 days, wet	NA	1,200 ppm	~700	53-121[b]	Sloan and Laird (1990)

TABLE N.2 (Cont.)

Combustor Type	Fuel	Sample Collection Method[a]	Temperature (K)	Sulfur Content of Fuel (%) or Flue Gas (ppm)	NO (ppm)	N_2 (ppm)	Reference
Conventional wall-fired	Coal?	Plastic bag 8-17 days, wet	NA	1,200 ppm	~700	114-211[b]	Sloan and Laird (1990)
Conventional wall-fired	Coal?	Plastic bag, 3-15 days, dry	NA	1,200 ppm	-700	12-18[b]	Sloan and Laird (1990)
Early tests (May have artifactual N_2O formation):							
Utility boiler	Coal	Glass syringe, stored	NA	NS	~450	156-204	Hao et al. (1987)
Utility boiler	Oil	Glass syringe, stored	NA	NS	~170	13- 81	Hao et al. (1987)
Utility boiler	Gas	Glass syringe, stored	NA	NS	~ 60	2- 10	Hao et al. (1987)
Utility boiler	Oil	Pyrex flask, stored	~1,700	NS		25	Weiss and Craig (1976)
Utility boiler	Coal	Pyrex flask, stored	~1,770	NS		25.8	Weiss and Craig (1976)
Utility boiler	Coal	Stainless steel, stored	NA	NS	NA	33-38	Pierotti and Rasmussen (1976)
Utility boiler	Gas	Stainless steel, stored	NA	NS	NA	3-11	Pierotti and Rasmussen (1976)

[a] I assume that gas samples that were not analyzed on-line (i.e., immediately, as they were being produced) were stored.

[b] Measured at 3% oxygen, dry.

[c] ppm was reported at 1,073 K per 10% CO_2. They also reported the percent of fuel nitrogen converted to N_2O at 1,000, 1,073, and 1,123 K. I estimate ppm at 1,000 and 1,123 K by assuming that the ratio of ppmv concentrations at two temperatures is equal to the ratio of fuel conversion percentages at the same two temperatures.

[d] Results reported as 73 mg-N_2O/MJ-coke and 100 mg/MJ, with a conversion factor to ppm of 1.7.

[e] The concentration was 10-25 ppmv before the SCR device.

Notes: CFBC = circulating fluidized-bed combustor. NA = not available. NS = not specified. i.r. = infrared analyzer.
See Ryan and Srivastava (1989) for a similar table.

Coal(?) = Sloan and Laird (1990) do not specifically state which fuel was used, but test conditions and results indicate that the fuel was coal.

N.3.1 Artifactual Formation of Nitrous Oxide

However, more recent research shows that these earlier, high N_2O values obtained for power plants are the result of artifactual N_2O formation. In 1988, Muzio and Kramlich (1988) reported that "the storage of moist combustion products containing SO_2 and NO for periods as short as 2 hours can lead to the formation of several hundreds of parts per million [ppm] of N_2O in the sample containers where none originally existed" (p. 1369). Drying the stored flue gas reduced, but did not eliminate, this artifactual in-sample N_2O formation; removing the sulfur eliminated it. The presence of sulfur in the sample flue gas increased the concentration of N_2O by two orders of magnitude, from less than 5 ppm to several hundred ppm. The effects of moisture and sulfur are illustrated in Table N.2.

Importantly, there appears to be an "activation" level of SO_2. Below 600 ppm of SO_2 in the furnace, the concentration of N_2O in the sample remained quite low, about 15 ppm or less; at 1,000 ppm of SO_2, the concentration of N_2O jumped to about 260 ppm. This suggests that a low-sulfur fuel will not produce enough SO_2 to cause the artifactual, in-sample formation of N_2O. Gasoline is only 0.03% sulfur by weight, compared to about 1% for coal; hence, as argued above, it probably does not contain enough sulfur to cause artifactual formation of N_2O.

The discovery of the artifactual formation of N_2O and of the implication that direct N_2O emissions may not be as high as previously thought is actually consistent with expectations, based on combustion kinetics and experiments, about how much N_2O should be formed. In fact, explaining the earlier, higher levels was proving to be something of a problem, since N_2O formed early in the flame zone should be destroyed rapidly before it reaches the exhaust (Lyon et al., 1989). According to Kramlich et al. (1988), the first major EPA-sponsored workshop on N_2O concluded "with an unsolved mystery: it was possible to explain the fact that . . . combustion systems could produce N_2O . . . [but not] that N_2O could survive the combustion environment which produced it and be present in the discharged flue gases" (p. 4-4). The second workshop did not clear up the mystery; the participants concluded that the then-current data base on N_2O emissions was not good enough to support estimates of global sources and sinks of N_2O, and that it was not reasonable to estimate N_2O as a function of NO_x emissions.

It thus appears that previous estimates of N_2O emissions may be high by at least an order of magnitude. (Compare the results of on-line sampling, with which there is no artifactual N_2O formation, to the results of the earlier sampling, and note the direct comparisons of on-line versus stored sampling [Table N.2].) In further support of this conclusion, I note that Aho and Rantanen (1989) reported that under normal conditions in large combustors, N_2O is less than 2% of the sum of NO and NO_2 concentration — an order of magnitude less than the Hao et al. (1987) finding of 29%. (On the other hand, they found that, with the low-temperature combustion of peat, the conversion of fuel nitrogen (N) to N_2O could exceed the conversion to NO. The issue of low-temperature combustion is addressed below.)

N.3.2 Unresolved Issues in Nitrous Oxide Emission Estimation

There are a few qualifications to the recent finding that stationary-source combustion may produce little N_2O. First, direct N_2O emissions from low-temperature combustion, such as in fluidized-bed combustors and catalytic crackers, may still be substantial. Second, N_2O may be formed in the atmosphere indirectly from direct NO emissions, possibly by the same mechanism as in artifactual in-sample formation.

Another, less important, unresolved issue is the role of emission control systems in N_2O formations. These three issues are taken up next.

1. Modeling and experimental results indicate that fluidized-bed combustors, which operate at lower temperatures than do utility boilers and so produce less NO_x, may produce considerably more N_2O than boilers (Ryan and Srivastava, 1989; Aamand and Andersson, 1989; Kokkinos, 1990; Makansi, 1991). Fluidized-bed combustion (FBC) is used at one stage in the production of gasoline: when the fluidized-bed catalytic cracking unit (FCCU), which breaks the large hydrocarbon molecules of crude into the smaller molecules of gasoline, becomes coated with coke residue from the crude, the coke is burned off the catalysts by fluidized-bed combustion (called, in this case, regeneration). Hence, this step in the refining process may produce nontrivial amounts of N_2O (Lyon et al., 1989). Indeed, the few tests on fluidized-bed combustion using on-line sampling, or other processes that are free of artifactual N_2O formation, indicate substantially higher N_2O emissions than higher-temperature combustion processes (Table N.2).

2. It is conceivable that the reaction responsible for artifactual N_2O formation,

$$2NO + SO_2 \xrightarrow{H_2O} N_2O + SO_3$$

could occur in the plumes of power plants and produce N_2O. However, Sloan and Laird (1990) point out that the concentration of the reactants in plumes is much less than in the flue gas samples that generate artifactual formation (and the reaction in the samples is already quite slow) so that in plumes in the atmosphere, the reaction likely will be much to slow too generate much N_2O. Kokkinos (1990) agrees.

Other artifactual formation routes may exist. Recently, Soete (1989) demonstrated that with combustion in the presence of sulfur (in the form of $CaSO_4$, as might result from emission control devices), the concentration of N_2O dropped with increasing temperature up to about 1,200 K, then increased to a maximum of about 4 ppm at 1,275 K, and then declined again. This demonstration of N_2O formation at high temperatures may reestablish the possibility of significant N_2O formation from the combustion of fossil fuels.

Soete (1989) also suggests that in fluidized-bed combustors, N_2O may be formed from the reduction of NO and the oxidation of reduced sulfur compounds, via a path similar to that suspected of generating artifactual N_2O at room temperature in samples with sulfur and NO:

$$2NO + CaSO_r \rightarrow N_2O + CaSO_4$$

The particular sulfur compound Soete investigated, $CaSO_4$, is reduced (and thus "prepared," in a sense, for oxidation by NO) by CO and carbon (C), above 1,200 K. Above about 1,400 K, N_2O is destroyed. With other sulfur compounds or different concentrations of oxygen, N_2O formation as a function of temperature may be different.

Nevertheless, in the absence of specific evidence to the contrary, I assume that real stack gas becomes too dilute too quickly to permit significant formation of N_2O via reactions involving sulfur species.

3. The effect of NO_x control on N_2O emissions from stationary sources is unclear. NO_x control technologies may increase N_2O emissions (Lyon et al., 1989), but perhaps not by much. Linak et al. (1989) reported that combustion modifications to control NO_x emissions from coal-fired units caused only a slight (less than 5 ppm) increase in N_2O concentration. Sloan and Laird (1990) found no significant difference in N_2O emissions between low-NO_x and conventional burners (Table N.2), and Aamand and Andersson (1989) found that injecting ammonia into the combustion zone of circulating fluidized-bed combustors did not affect N_2O emissions. In fact, in one experiment, the use of selective catalytic reduction (SCR) actually reduced the N_2O concentration (compared with the level before the SCR; Table N.2). However, urea injection into an oil-fired boiler may have increased N_2O emissions (Kokkinos, 1990; Table N.2).

Given these preliminary findings, I assume that future emission controls on stationary sources will not dramatically affect N_2O emissions.

N.3.3 My Assumptions

Direct N_2O emissions from high-temperature combustors appear to be low. I assume that N_2O emissions from fossil-fuel boilers are in the upper-middle end of the range of recent estimates from on-line sampling. (I use the upper-middle end to give at least a small weight to the possibility of secondary N_2O formation in post-stack gases and the possibility of increased elevated emissions from plants with emission controls.) My assumptions, in grams per million Btu, are shown in Table D.4.

I assume that petroleum refineries have higher emissions (per unit output), primarily due to the use of fluidized-bed combustion (Table A.2).

To convert the emission values measured in parts per million volume, of Table N.2 to grams per 10^6 Btu of fuel, I calculated grams of N_2O per 10^6 Btu of fuel from data in several references that gave values in parts per million volume, then compared the two. The results are shown in Table N.3. The conversion between parts per million volume and grams per 10^6 Btu depends on the CO_2 concentration of the flue gas, which in turn depends on the fuel used. However, for simplicity, I assume that parts per million volume converts to grams per 10^6 Btu numerically at a 1:1 ratio for all fuels, as is roughly indicated by the results of the Table N.3.

N.4 Nitrous Oxide Emissions from Other Combustion Sources

There are no data on N_2O from trains, ships, natural gas pipeline compressors, farm equipment, loaders, petroleum refineries, well equipment, methanol plants, etc. (The AP-42 report on emissions does not give N_2O values.) Consequently, for most sources, I assume that N_2O emissions depend only on the kind of fuel burned, so that, for example, the N_2O emission rate, in grams per 10^6 Btu, from a ship burning residual fuel oil is the same as the known rate from a power plant burning residual fuel oil. (I use the residual fuel factors for diesel as well as residual fuel.)

As discussed above, I assume a relatively high N_2O emission rate for petroleum refineries due to the low-temperature FCCUs. I assume there will be N_2O emissions from methanol plants because the catalysts used to promote methanol synthesis operate at temperatures lower than those found in utility boilers (Appendix J), and, as discussed above, low temperatures -- at least in FBC units and across automobile catalysts -- seem to produce more N_2O emissions. However, low temperature is not a sufficient condition for high N_2O emissions, and, moreover, there are no data on emissions from methanol facilities. Therefore, to check the importance of these assumptions, I also have zeroed out N_2O emissions from all sources for which there are no real data. The overall results are not appreciably different.

For N_2O emissions from coal-to-methanol plants, corn-to-ethanol plants, wood boilers, and wood gasification, see the notes to Table A.2. (These are basically "guesstimates.")

N.5 Nitrous Oxide from the Corona Discharge from High-Voltage Electricity Transmission Lines

A corona discharge can occur as a result of electric fields set up by high-voltage transmission lines. The strength of these electric fields is proportional to the charge density, which tends to be high on isolated conducting surfaces with small radii of curvature, such as power lines. The electric fields will attract ions in the air with charges opposite those of the conductor. The attracted ions may be accelerated enough to produce more ions upon collision with air molecules, which makes the air still more conducting and increases the corona discharge. This process can form atmospheric trace species, such as N_2O.

TABLE N.3 Converting N_2O from Parts per Million Volume to Grams per Million

Reference	Fuel	ppmv	g/10^6 Btu
Aho and Rantanen (1989)[a]	Peat	70-250	75-263
Weiss and Craig (1976)[b]	Coal	25.8	27.2
Pierroti and Rasmussen (1976)[c]	Coal	33	46
Hao et al. (1987)[d]	Coal	156-204	88
Hao et al. (1987)[d]	Oil	13-81	27
Dahlberg et al. (1988)[e]	Coal	100	74
Dahlberg et al. (1988)[e]	Oil	30	16
Aamand and Andersson (1989)[f]	Coke	1.7	1.05

[a] Calculated from their data on heating values, nitrogen content, and conversion of nitrogen to N_2O for 10% CO_2 and 1,100 K.

[b] Using their data, I first calculated 0.03 MT-N_2O/quad.

[c] My calculation is based on their data.

[d] Based on NO_x/N_2O ratio and NO_x emission factors.

[e] As shown in the reference. They also found that CO emissions were less than 200 ppmv, and that CH_4 emissions were 5 ppmv for all fuels except wood chips and firewood; for wood chips and firewood CO emissions were 2,000 ppmv or greater, and CH_4 emissions were 3,000 ppmv.

[f] As stated in the reference, at 6% oxygen.

Note: I use 20×10^6 Btu/ton of coal, 6.2×10^6 Btu/barrel of fuel oil, and 1,020 Btu/SCF of gas for all calculations as rough estimates of worldwide averages.

Hill et al. (1984) calculated that in 1980, the corona energy loss from power transmission lines in the United States probably created 2.3×10^{10} g of N_2O and at most created 4.4×10^{11} g of N_2O. In 1980, U.S. electric utilities delivered $2{,}094 \times 10^9$ kWh of electricity (EIA, *Annual Energy Review 1989*, 1990). Using an N_2O-to-CO_2 conversion factor of 290 (Table 8), the N_2O formed from the corona discharge most likely amounted to 3.2 g of CO_2 equivalents per kWh of delivered fuel, and at most amounted to 61 g of CO_2 equivalents per kWh-delivered fuel. The most likely estimate of 3.2 g/kWh is less than 1% of the emissions from the fossil-fuel power-plant cycle (Table D.4) and only about 5% of emissions from the nuclear-fuel cycle.

The calculations of Hill et al. (1984) are a first-cut, and they point out that this source needs to be better quantified. Fortunately, their most-likely estimate is so small that it does not matter if it is included in the total of greenhouse-gas emissions from electricity generation and use. (I have included it here.) However, the maximum estimate of 61 g/kWh is of the same order of magnitude as emissions from the nuclear-fuel cycle and, hence, cannot be ignored. Therefore, I have included an electric-vehicle scenario analysis using the high-end estimate for N_2O from a corona discharge.

N.6 Nitrous Oxide and Nitrogen Oxide Emissions from Fertilizer

As estimated in Appendix K, a considerable amount of fertilizer is used to grow corn. A small amount of the nitrogen in the fertilizer is released to the atmosphere as N_2O and NO_x (the rest ends up in the crop, in the soil, in water, in microorganisms, or in the air as gaseous nitrogen [N_2]). The net amount of N_2O and NO_x released from corn fields depends on the amount and type of fertilizer, soil and weather conditions, agricultural practices, and more (Eichner, 1990; Anderson and Levine, 1987; Conrad et al., 1983). (The contribution of N_2O from fertilizer to greenhouse gas emissions from the corn-to-ethanol process was first estimated in an unpublished work by Stefan Unasch of Acurex Corporation, Mountain View, California.)

N.6.1 Nitrous Oxide Emissions

Recently, Eichner (1990) reviewed and summarized most of the available data on N_2O emissions from soils, including studies of N_2O emissions specifically from corn fields. The corn studies found that about 0-1.8% (average of about 1.3%) of the nitrogen in the fertilizer had evolved to the atmosphere as nitrogen in N_2O during the study period. Mosier et al. (1986) found that 1.5% of the nitrogen in fertilizer applied to corn was lost as nitrogen in N_2O (compared to 0.4% for barley) and cited an earlier study that estimated a 1.3% loss rate (0.6% for barley). (These two studies were covered in Eichner [1990], but she did not report the amount of fertilizer nitrogen evolved to N_2O.) Anderson and Levine (1987) calculated that 1.2% of the fertilizer applied to a corn plot in April and May was lost as nitrogen in N_2O in June, July, and August (the corn was harvested in September).

Researchers expect that fertilizers continue to produce N_2O after the study period and, further, that some of the applied fertilizer is carried away by drainage and groundwater and evolves to N_2O off the site, beyond the measuring equipment. Eichner (1990) and the Intergovernmental Panel on Climate Change (IPCC) (Watson et al., 1990) double the measured, on-site N_2O emissions to account for these other avenues of N_2O production. Eichner's doubling is a rough estimate; the IPCC's doubling is based on two studies (Ronen et al., 1988; Conrad et al., 1983). Data in Ronen et al. (1988) indicate that *upper limit* emissions of N_2O from the drainage of fertilized land could be twice as high as the average emission rate measured for corn (1.3%, as above). They do not say what the typical situation would be. Conrad et al. (1983) cite one study of the leaching of nitrogen fertilizer into groundwater and another showing that groundwater may be supersaturated with N_2O, and then they assume that the N_2O emissions from groundwater containing leached nitrogen fertilizer may be equal to the measured field losses.

If these doubling estimates are correct, then about 2.6% of the nitrogen in fertilizer ends up as nitrogen in N_2O in the air. However, it must be emphasized that the accounting for off-site evolution of N_2O from groundwater and drainage water is based on virtually no data and is extremely uncertain.

With these data (and caveats), grams of N_2O from fertilizer per 10^6 Btu of ethanol made available to end users can be calculated as:

$$N2O_f = N2O_e \times F \times N \times 453.65 \times 1.57 \times BG \times LL \times O \times V \times S$$

where:

$N2O_f$ = grams of N_2O from fertilizer per gallon of ethanol produced;

$N2O_e$ = grams of nitrogen evolved as N_2O per gram of nitrogen of fertilizer, on-site and during the sampling period (1.3%, as above);

F = factor to account for N_2O evolved after the sampling periods and off the site (assumed here to be 2);

N = nitrogen application rate, in lb-nitrogen/bushel of corn (about 1.23, according to the data of Table K.1);

453.6 = grams per pound;

1.57 = molecular weight of N_2O/molecular weight of N_2;

BG = bushels of corn/gal of ethanol;

LL = liquid loss factor (Appendix B);

O = own use factor (Appendix A);

V = gal ethanol/10^6 Btu (Appendix C); and

S = the share of N_2O emissions that should be assigned to ethanol (assumed here to be at least 0.8, as explained below).

Taking the calculation two steps further (by dividing $N2O_f$ by miles per gallon of an ethanol vehicle and multiplying by the N_2O-CO_2 conversion factor) reveals that N_2O from fertilizer can be a surprisingly large source of greenhouse gases per mile. This prompts one to examine the uncertainty of the values for the variables in the equation for $N2O_f$.

It is clear that BG and N are known well and are not likely to be in error by more than 10 or 20% (the case of low-input agriculture being treated separately). The biggest uncertainties, of course, lie in the measured N_2O formation rate and especially the enhancement factor (F). $N2O_e$

for corn was quite a bit higher than $N2O_e$ for grains, plants, and grasses; however, it was consistently higher and most of the studies did produce similar results (Eichner, 1990; Mosier et al., 1986; Anderson and Levine, 1987). It is not clear if the higher rate for corn can be explained plausibly, or if it is reasonable to expect that further research will bring the rate for corn closer to the rate for, say, grains. It also is possible that the high evolution rate for corn is due to the type of fertilizer. Nevertheless, current research clearly indicates that about 1.3% of fertilizer nitrogen is converted to N_2O during study periods.

The enhancement factor (F) of 2 is a bit better than a guess, but not much. In a scenario analysis, I consider an enhancement factor (F) of 1.25 instead.

The share factor (S), which accounts for the possibility that the use of the by-products of the corn-to-ethanol process will eliminate some N_2O emissions, is virtually impossible to estimate accurately. However, the factor is likely to be high; that is, it is likely that the by-products will not displace nearly as much fertilizer-derived N_2O emissions as will be produced by the corn farming. To understand this, one must recognize two things: first, that the correct way, in principle, to calculate the share factor (S) is to attribute *all* N_2O emissions from the corn farming to ethanol production and then to deduct N_2O emissions from any crop-growing foregone because of the availability of the ethanol by-products; second, not much N_2O would be so foregone. The first point follows because we are, hypothetically, interested in the effects of an ethanol policy, without which there would be no incremental ethanol production and, in most cases, no incremental N_2O emissions from the soil. In other words, if we choose to make ethanol from corn, there will be N_2O emissions from the fertilizer; if we choose not to, there will be no emissions (except for the case in which ethanol is produced by diverting corn feed to ethanol production and the feed is made up of grass).

The second point follows because only some of the by-products will substitute for other crops (distiller's dried grains and solubles [DDGS] may displace some soybean production, but fusel oil and ammonium sulfate will not displace crops) and because the growing of these displaced crops (such as soybeans) probably does not release as much N_2O as does the growing of corn. For example, total N_2O emissions per acre from corn fields , on average, almost four times higher than total emissions from soybean fields (Eichner, 1990). (These are total emissions during the sample period, not just emissions attributo fertilizer; corn and soybean sites were not necessarily treated similarly, and emissions were not adjusted to reflect crop output.) Further, data in Marland and Turhollow (1990) indicate that the ethanol protein by-product associated with 1 acre of corn will displace only 0.7 acre of soybeans so that, all told, the N_2O-from-soybean credit, relative to a unit emission of N_2O from corn growing, is equal to $1.0 \times 0.7 \times 0.25 = 0.175$. This means that net (after credit) emissions of N_2O from the fertilization of corn fields is about 80% of the gross N_2O emission.

In the base-case analysis, I assign 80% of the N_2O emissions to ethanol production (because the by-products effectively displace 20% of the emissions). In the case in which by-product credits are assigned based on the energy value of all by-products, I implicitly assign only 55% of N_2O emissions to alcohol production.

The upshot of this uncertainty analysis is that N_2O emissions from fertilizer use are likely to be high unless the current data are substantially wrong and stacked against ethanol. In scenario analyses, I consider different values for the share factor (S), the enhancement factor (F), and $N2O_e$.

N.6.2 Nitrogen Oxide

There are few data on NO_x emissions from fertilizer use. Anderson and Levine (1987) found that 0.79% of the fertilizer applied to a corn site was lost as nitrogen in NO. Other researchers also appear to be finding that NO emissions are of the same order of magnitude as N_2O (Guenzi, 1991). However, there is considerable uncertainty at this point and the findings are tentative, to say the least.

Anderson and Levine (1987) did not measure NO_2 but reported on a study in which as much NO_2 as NO was emitted. However, because this is insufficient evidence, I ignore NO_2. Anderson and Levine (1988) also did not measure the NO evolved off the site; however, they did find that NO was not emitted from soil saturated with water, which implies that little would be emitted from groundwater or drainage water containing fertilizer. (I assume no off-site production of NO.)

The calculation of NO emissions per gallon is analogous to the calculation for N_2O.

N.6.3 Wood-to-Fuel Sytems

As discussed in the appendix on biomass, some short-rotation intensive cultivations (SRIC) systems may use fertilizer. This fertilizer will result in the evolution of some N_2O and NO_x, with the magnitude depending on the factors mentioned above. The calculation of this emission is similar to that for corn (above), although some of the terms are defined differently. The biggest difficulty in this calculation is that no one has studied N_2O emissions specifically from SRIC systems. It is likely, though, that emissions are less than from corn fields. Data in Eichner (1990) show that grass and plant fields evolve only about 0.25% of fertilizer nitrogen as N_2O, compared with 1.3% for corn. In the absence of specific data, I assume 0.3% (with an enhancement factor of 2.0). I consider higher values in a scenario analysis. For NO, I use the same factor as for corn.

The share factor (S) for N_2O from SRIC systems should be one, because wood-to-fuel systems do not produce by-products.

Appendix O:

Converting Emissions of Methane, Nitrous Oxide, Carbon Monoxide, Nonmethane Hydrocarbons, and Nitrogen Oxides to the Temperature-Equivalent Amount of Carbon Dioxide

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Converting Emissions of Methane, Nitrous Oxide, Carbon Monoxide, Nonmethane Hydrocarbons, and Nitrogen Oxides to the Temperature-Equivalent Amount of Carbon Dioxide

O.1 Background

One can best understand the combined effect on climate of all greenhouse gases emitted as a result of using alternative fuels if all of the emissions are represented by one measure. I do this here by expressing all greenhouse gas emissions in terms of one of the gases. Specifically, I convert methane (CH_4), carbon monoxide (CO), nitrous oxide (N_2O), nonmethane hydrocarbons (NMHCs), and nitrogen oxide (NO_x) mass emissions into the mass amount of carbon dioxide (CO_2) emissions with the same temperature effect. The "same temperature effect" is defined here in terms of degree-years over a period of time, where one degree-year is an increased surface temperature of 1°C for one year. Thus, CH_4 emissions, for example, are converted to the temperature-equivalent amount of CO_2 emissions by calculating the annual mass emissions of CO_2 that would result in the number of degree-years of warming produced by a given annual CH_4 mass emission rate. The number by which CH_4 (or N_2O, CO, NMHC, or NO_x) is multiplied to give the temperature-equivalent mass of CO_2 emissions is called the equivalency factor (EF), and the result of the conversion is a "CO_2-equivalent" amount of CH_4. Thus, 4 g/yr of CH_4 multiplied by, for example, 20 (the equivalency factor) gives 80 g/yr of CO_2-equivalents. This 80 g/yr can be added directly to actual CO_2 emissions to produce a total, single estimate of CO_2-equivalent greenhouse gas emissions.

In order to convert non-CO_2 greenhouse gas emissions into CO_2 emissions having the equivalent temperature effect, one needs to know, for both gases, the relationship between the equilibrium surface temperature and the equilibrium atmospheric concentration, and the relationship between the increase in the yearly emissions and the increase in the equilibrium atmospheric concentration. One also must consider interactions between gases (for example, CO and CH_4) and the ultimate fate of the gases. (CH_4 ends up being oxidized to CO_2 and water vapor [H_2O] by the hydroxyl radical [$OH^{\cdot}$].) Finally, one must pick a period of time to do the analysis; since one is equating degree-years of warming over a period of time, the equation will depend on the length of time chosen. This choice is important.

O.2 The Calculation of Equivalency Factors

A simple calculation of equivalency factors is presented in DeLuchi et al., *Transportation Fuels and the Greenhouse Effect*, 1987. Okken and Kram (1989) (see also Okken, *Energy Policy*, 1990) and Grubb (1989) also derive equivalency factors. However, the most sophisticated and accurate estimates are in recent papers by Lashof and Ahuja (1990), Rodhe (1990), Wilson (1990), and the Intergovernmental Panel on Climate Change (IPCC) (Shine et al., 1990). All four papers use the same basic method, paralleling that used to develop the ozone (O_3) depletion potential for

chloroflourocarbons (CFCs). The basic formula (following Lashof and Ahuja, 1990, and Shine et al., 1990) is:

$$EF_i = \frac{\int_{0-t} a_i(t)\, C_i(t)}{\int_{0-t} a_{co_2}(t)\, C_{co_2}(t)}$$

where:

EF_i = equivalency factor for gas (i), relative to CO_2,

$a_i(t)$ = relative radiative forcing of gas (i) as a function of time, in units of: °C-increase per ppm (parts per million)-increase for gas (i)/°C-increase per ppm-increase for CO_2,

$c(t)$ = function expressing the amount of gas (i) that remains in the atmosphere over time, and

t = length of time (years into the future) considered.

All papers express c(t) as an exponential decay function. In Lashof and Ahuja (1990), this function is:

$$e^{-t/r_i}$$

where:

t = defined as above and

r_i = *average* residence time of gas (i), in years (note that this is the average residence time, not the actual residence time of every unit of emission).

The values used in the papers for these parameters are summarized in Table O.1. For many parameters, the authors use essentially the same values; however, this does not mean that, in general, the method and the data are flawless. In fact, there are several key uncertainties, including the effective lifetime of CO_2 and other greenhouse gases; the relative radiative forcing of CH_4 and other gases; the effect of changing concentrations of all gases on their residence times and radiative forcing; the indirect effect of chemical reactions among gases; and the selection of the appropriate timeperiod for the analysis. These problems are discussed briefly in this section (see Shine et al., 1990, for a further discussion of some of these issues).

TABLE O.1 Comparison of Four Calculations of Greenhouse Gas Equivalency Factors

Reference: Parameter	Wilson (1990)	Lashof & Ahuja (1990)	Rodhe (1990)	*Climate Change* (1990)
r_{co2}	100	230[a]	(120[b])	(120[b])
r_{ch4}	9	14.4[c]	10	10
r_{n2o}	150	160	150	150
r_{o3}	0.2	NS	0.1	~0.1[d]
r_{co}	NS	2.1	NA	~0.2[e]
r_{cfc-12}	NS	120	120	130
a_{ch4}	25	44[f]	25	21
a_{n2o}	250	256	200	206
a_{o3}	2,000	NS	2,000	NS
a_{co}	NS	44	NS	NS
a_{cfc-12}	NS	19,500	15,000	15,800
Results[g]				
EF_{ch4}	10 (18)[h]	10	i	9
EF_{n2o}	375	180		190
EF_{co}		2.2		2
EF_{nmhc}				6
EF_{nox}				14
EF_{cfc12}		3,700		4,500

[a] An "effective" lifetime, calculated by the authors from the behavior of CO_2 in ocean-atmosphere-biosphere-CO_2 models. See text for further discussion.

[b] This is the time required for the concentration of CO_2 to decline to $1/e$ (37%) of its original value. It is not the effective, weighted-average residence time actually used by the authors in their calculation of equivalency factors.

[c] The value is 9.6 x 1.5; the 1.5 accounts for the increase in the lifetime of CH_4 caused by increasing CH_4 emissions (a sort of congestion effect).

[d] According to the IPCC (Watson et al., 1990), ozone has a lifetime of "at most several weeks" (p. 29).

[e] According to the IPCC (Watson et al., 1990), CO has a lifetime of "2-3 months" (p. 30).

TABLE O.1 (Cont.)

[f] The value is 25 x 1.7; the 1.7 accounts for the effect of CH_4 on the concentration of ozone and H_2O.

[g] The equivalency factors on a mass basis, integrated to infinity (500 years, in the IPCC *Climate Change* analysis).

[h] Wilson shows a factor of 10 in her Table 4. However, 10, on a mass basis, is not consistent with the factor of 5 she shows for a mole basis (5 x 2.75 [the relative molar masses of CO_2 and CH_4] = 13.75). Further, I recalculated the mass equivalency factors, using her formula, values, and assumptions, and came up with 6.65 (mole basis) and 18.3 (mass basis).

[i] Rodhe gives value for t = 100 yr only. I have not calculated values for t = infinity, using her formula and input values, because her input data, method, and results are, in most cases, close to those of the IPCC (Shine et al., 1990).

Notes: r_i and a_i are as defined in text. The a_i are on a mole basis.
EF_i = equivalency factor (conversion factor) between gas (i) and CO_2 on a mass basis, with zero discount rate and no time cutoff, except as noted.
NS = not specified.

O.2.1 The Effective Lifetime of Carbon Dioxide

The equivalency factors for all greenhouse gases depend quite strongly on the estimated or assumed effective lifetime of CO_2. The longer the effective lifetime of CO_2, the greater its warming effect, and the less the relative warming effect of other gases. (Recall that in calculating the equivalency factor, the cumulative warming effect of CO_2 is in the denominator.) The problem here is that it is more difficult to estimate a lifetime for CO_2 than for the other greenhouse gases because CO_2 behaves differently.

After a *non*-CO_2 greenhouse gas is emitted, it is removed from the atmosphere by chemical and physical processes and never returns. The average lifetime of a non-CO_2 gas can be defined as the ratio of the atmospheric content (in grams) to the removal rate (in g/yr) (Watson et al., 1990). The CO_2, however, is not destroyed in the atmosphere by chemical processes; rather, it cycles between major reservoirs, such as the ocean and the atmosphere. Thus, a CO_2 lifetime defined only by the absolute CO_2 removal rate will considerably understate the actual concentration of CO_2 because removed CO_2 can return to the atmosphere. The effective lifetime of CO_2 depends on how one models this cycling.

After a pulse injection of CO_2 and the corresponding instantaneous increase in the atmospheric concentration of CO_2, the concentration will decline rapidly in the first decades, (then much more slowly over a period of centuries), and eventually reach a new equilibrium

concentration greater than the preinjection concentration (Watson et al., 1990). This process can be modeled with ocean-atmosphere models. Given the results of a model, one can calculate a weighted-average residence time.

Lashof and Ahuja (1990) take this approach. Using the results of an ocean-general circulation model, they assume that 9.8% of a pulse CO_2 emission is, in effect, permanently removed from the atmosphere in 1.9 years; 24.9% in 17.3 years; 32.1% in 73.6 years; 21.0% in 362.9 years; and 13.1% in 1,000 years. The result (the sum of the product of the percentages and the lifetimes) is 253 years. The original model used an infinite lifetime instead of 1,000 years because a portion of the CO_2 is never removed, but since this results in an infinite weighted-average residence time for CO_2, Lashof and Ahuja arbitrarily reduced the infinite-lifetime category to 1,000 years. As they note, the calculation of the weighted-overall-average residence time is extremely sensitive to this choice because 13.1% of CO_2 emissions will have this long life, whatever it is assumed to be. If one chooses 5,000 years, the weighted-average residence time is 750 years instead of 230 years; if one chooses 500 years, it is 160 years.

Shine et al. (1990) also represent the behavior of CO_2 using an ocean-atmosphere model, but they use a different model (although, at one point, the IPCC report refers to the model used by Lashof and Ahuja). Shine et al. (1990) state that 50% of a pulse-injection of CO_2 is effectively removed in 50 years, and that 50% of the remainder is removed in 250 years, so that after 250 years, only 25% is left. A portion is never removed. They do not give the weighted-average effective lifetime, and one cannot calculate it from their data because they do not state how they handle the portion of the CO_2 pulse that has an infinite lifetime. Thus, it is not clear if Shine et al. (1990) use a different effective weighted-average lifetime than do Lashof and Ahuja. They do report a lifetime for CO_2 of 120 years, but this is based on a different definition of the lifetime (the amount of time required for the concentration to decline to 1/*e* [37%] of its original value) and is not the effective weighted-average residence time according to the circulation model (and apparently is not the implicit residence time they use to calculate equivalency factors).

Rodhe's (1990) treatment is similar to that of the IPCC, although she uses yet another circulation model. She also reports a 1/e lifetime of 120 years. The upshot of this is that the all-important question of the correct effective weighted-average lifetime of CO_2 is still open to debate and could range from 100 to 500 years or more.

There is some uncertainty regarding the current lifetime of other greenhouse gases, due in part to uncertainty about the sources and sinks of the gases. I have not explored the effect of this uncertainty on the calculation of equivalency factors.

O.2.2 The Relative Radiate Forcing of Methane

All of the papers reviewed here assume that a molecule of CH_4 absorbs 20 to 25 times more energy than a molecule of CO_2 (see a_{ch4} in Table O.1). This value is consistent with what generally has been reported in the literature. However, a recent analysis of spectroscopic and satellite data found CH_4 to be only 13.2 times more effective than CO_2 (Gamache and Golomb, 1990). The use of this lower value would reduce EF_{ch4} by a factor of almost 2.

According to Shine et al. (1990), there is uncertainty in the basic spectroscopic data for other greenhouse gases, particularly CFCs.

O.2.3 Future Lifetimes and Radiative Adsorptive Strength

To date, all calculations of equivalency factors use a single average residence time (r_i) for all of the gases. In reality, though, the residence time of a greenhouse gas will change as its own concentration and the concentration of other gases change. For example, as the concentration of CH_4 and CO increase, the lifetime of CH_4 will increase if the production of OH, the primary chemical sink for both species, remains roughly constant. Ideally, one would express the lifetime of CH_4 as a function of the concentration of CH_4 and CO over time. This has not yet been done. Lashof and Ahuja (1990) do make a simple adjustment to account for this effect in the case of CH_4 (see notes to Table O.1).

Similarly, studies to date have assumed constant values for the relative radiative forcings (a[t]), even though the radiative forcing of a gas depends on both its own concentration and the concentration of other gases, which change over time. For example, there is significant overlap between some of the infrared adsorption bands of CH_4 and N_2O (Shine et al., 1990), which means that the relative radiative forcing of these gases in the future may be less than it is at present, as they both fill the same thermal emission window.

O.2.4 The Effect of Indirect Greenhouse Gases and Chemical Interactions

The production, alteration, and destruction of greenhouse gases and greenhouse-gas precursors can produce other greenhouse gases or greenhouse-gas precursors and affect the concentration, distribution, and lifetime of (other) greenhouse gases. The incompletely understood and difficult-to-model interactions between NO_x, CO, NMHCs, OH, O_3, and H_2O typify this sort of problem (see Appendix Q and Shine et al., 1990, for further discussion).

Current calculations of equivalency factors consider only a few such interactions and, generally, only simply. Lashof and Ahuja (1990) explicitly consider the effect of CO emissions on the lifetime of CH_4 (CO and CH_4 "compete" for the same chemical sink); Wilson (1990) and Rodhe (1990) do not. Wilson considers the effect of CH_4 on tropospheric ozone in some detail. The IPCC chapter (Shine et al., 1990) considers the effect of CH_4 on tropospheric ozone and stratospheric H_2O, and the effect of CO, NMHC, and NO_x on tropospheric ozone. All papers account for the fact that the carbon in all organic species ends as CO_2.

O.2.5 The Length of Time to be Considered in the Analysis

Equivalency factors depend greatly on the length of time considered. For virtually all gases, the equivalency factor is much smaller if one considers a 500-year period rather than a 10-year period, because virtually all greenhouse gases have a greater radiative forcing per mole but a shorter residence time than does CO_2. If, in the calculation of the equivalency factor for a

particular greenhouse gas, one considers a period of time less than or equal to the life of the greenhouse gas, the equivalency factor will be relatively high because, over the whole period of analysis, the greenhouse gas will be in the atmosphere and causing a greater forcing than CO_2. However, over a much longer period, the greenhouse gas will have been gone from the atmosphere for most of the time (or will have oxidized to CO_2 and water), so its average warming effect will be less over the longer period than over the shorter period. The importance of the time period can be seen in Table O.2, which shows the IPCC's equivalency factors for 20-, 100-, and 500-year periods.

There are two ways to approach the question of the right time period for the analysis: use a time cutoff, with no "discounting" of warming in future years, or use a nonzero discount rate with no time cutoff. Here I argue that it is inappropriate to use a discount rate for this problem, because the resulting equivalency factor is too sensitive to small changes in the rate. I argue that we should express the extent of our concern about future warming through our choice of a time cutoff. (We should not use a cutoff on top of a discount rate because it is an unnecessary and unfamiliar combination.) I will support this argument by calculating equivalency factors using both the discount-rate method and the time-cutoff method and then examining the difference.

Consider Table O.2 and Table O.3, which show equivalency factors as a function of t, the time horizon or point beyond which all greenhouse warming is ignored. These tables show that moving from a long-term horizon of 100-200 years to a short-term horizon of 20-50 years roughly doubles or triples the equivalency factor for CH_4, CO, and NMHC. This relationship is simple and concrete: shorten the time horizon from a century or two to a few decades, and most non-CO_2 greenhouse gases become two or three times as important. This timescale is a human one, and the effect (a doubling or tripling) is easy to understand.

Alternatively, one can apply a discount rate to future warming, disvaluing all future warming relative to current warming. To illustrate, I will use simple linear models of the

TABLE O.2 IPCC Mass Equivalency Factors[a]

Time (yr)	Greenhouse Gas					
	CH_4	N_2O	CO	NMHC	NO_x	CFC-12
20	63	270	7	31	150	7,100
100	21	290	3	11	40	7,300
500	9	190	2	6	14	4,500

[a] Includes indirect effects (e.g., effect of CO, NMHC, and CH_4 on ozone).

Source: Shine et al. (1990).

TABLE O.3 EF_{ch4} as a Function of Time Cutoff

Time (t)	EF_{ch4}, Using Formula and Data from: Wilson[a] (1990)	Lashof and Ahuja (1990)	Rodhe (1990)	Shine et al. (1990)
20 yr				63
50 yr	60	40		
100 yr	41	24	(15) 30[b]	21
200 yr	28	16		
Infinity	18	10		9[c]

[a] I follow Wilson (1990) in assuming that 1 mole of CH_4 produces 0.85 mole of ozone and 0.85 mole of CO_2. However, I also account for the fact that, since the ozone and CO_2 are produced from the decay of CH_4, and CH_4 lasts an average of nine years (according to her) before it decays, the ozone and the CO_2 will be around for nine fewer years to cause warming. This means that if the warming effect of a mole of CH_4 is calculated from $t = 0$ to $t = 100$ years, the warming effect of the 0.85 mole of ozone and CO_2 produced by the CH_4 should be calculated from $t = 9$ to $t = 100$ years.

[b] Rodhe calculates the direct heating effect of CH_4, and then appears to estimate that the indirect effects of CH_4 (formation of ozone and H_2O, and eventual oxidation to CO_2) are equal to the direct effect, so that the total heating effect is about twice the direct effect. In this table, the lower number shown is the calculated direct effect; the upper number is the (assumed) total effect.

[c] Integration to t = 500 yr.

Note: All equivalency factors are on a mass basis.

atmospheric fate of CH_4 and CO_2 emissions. Assume that a mole of CO_2 in effect stays in the atmosphere 200 years and causes a unit increase in temperature every year for the 200 years. Assume that an emission of a mole of CH_4 lasts only 10 years as CH_4, but causes a 25-unit increase per year for those 10 years, after which it is converted to CO_2 and causes a unit increase per year for the next 200 years. (I ignore the effect of CH_4 emissions on ozone and H_2O.) With a zero discount rate, the equivalency factor, on a mass basis, is:

$$2.75 \times (25 \times 10 + 200)/200 = 6.19$$

Now apply a discount rate of i. The three separate streams -- CH_4 for 10 years, CO_2 for 200 years, and CO_2-from-CH_4 for 200 years (this last stream starting in year 10) can be viewed as annuities and discounted by the formula:

$$([1 + i]^n - 1)/(i[1 + i]^n)$$

where:

n = number of years and

i = discount rate.

In addition, the 200-year stream of CO_2-from-CH_4, starting in year 10, must be discounted back to year zero by $1/(1 + i)^{10}$. The resulting mass equivalency factors (EF_{ch4}), as a function of interest rate i, are shown in Table O.4.

Note that the equivalency factor changes sharply with small (perhaps meaningless) changes in the interest rate. For example, from a discount rate of 1% to a rate of 3%, the equivalency factor doubles. It is difficult to imagine that many people can meaningfully distinguish between an interest rate of 1% and an interest rate of 3%, yet the difference between these is a factor of 2 in EF_{ch4}.

It is likely that people can more naturally represent their balancing of present and future concerns by referring to blocks of time within the realm of human experience than by trying to understand quantitatively how a 1% interest rate treats the future differently than a 3% rate. All of us understand human timescales, but few can attach much meaning to small differences indiscount rates. Because of the difficulty in choosing between small interest rates and the sensitivity of the result to small changes in the rate, I feel it is better to pick a time cutoff (or time horizon) with no interest rate.

TABLE O.4 Methane Equivalency Factor as a Function of the Discount Rate

i (%)	EF_{ch4}
0.0	6.2
0.5	7.9
1	10.0
3	19.7
5	28.2
7	35.2

Notes: i = discount rate (see text for explanation).

O.3 Review of Estimates of Equivalency Factors and Assumptions Used in This Analysis

O.3.1 Methane

Wilson's estimate of the equivalency factor for CH_4 appears to be relatively high (Table O.1, note g). Part of the explanation is that Wilson uses a much shorter average residence time for CO_2. Recall from above that a shorter residence time reduces the cumulative warming effect of CO_2 and thereby increases the warming effect of the other gases relative to CO_2. The main reason for Wilson's higher equivalency factor, though, is her assumption of a relatively long lifetime for ozone -- twice as long as that assumed by the IPCC (Shine et al., 1990) and Rodhe (1990). Wilson adds the warming effect of 1 mole of ozone to the direct warming effect of each mole of CH_4 that oxidizes in the troposphere, because the oxidation of 1 mole of CH_4 on balance leads to the formation of 1 mole of ozone. Also, because of the very high relative radiative forcing of ozone (Table O.1), a difference of a factor of 2 in the lifetime makes a big difference in the final result.

The lifetime of tropospheric ozone is probably on the order of a few weeks rather than a few months (Bolle et al., 1986; Wuebbles and Edmonds, 1988; Watson et al., 1990). With this correction to Wilson's calculation, there is reasonable agreement concerning the equivalency factor for CH_4.

In this report, I use values very slightly less than those of the IPCC, in token deference to the recent evidence that the radiative forcing of CH_4 may be less than heretofore thought (see discussion above).

O.3.2 Nitrous Oxide

Three (Rodhe, 1990; Lashof and Ahuja, 1990; and Shine et al., 1990) of the four papers calculate virtually the same equivalency factor for N_2O. (Rodhe's equivalency factor for a 100-year period is 300, very close to the IPCC's equivalency factor of 290, as shown in Table O.2.) This agreement is due in part to N_2O having few indirect effects on climate and, hence, being relatively easy to model.

Wilson's equivalency factor for N_2O is higher because she uses both a relatively short effective lifetime for CO_2 (which reduces the cumulative warming impact of N_2O) and a relatively high molar radiative forcing for N_2O. I note that if Wilson's calculation is redone with the 230-year CO_2 residence time used by Lashof and Ahuja (1990), the result, for an infinite time horizon, is an EF_{n2o} of 160, which is close to the results of the others.

O.3.3 Carbon Monoxide, Nonmethane Hydrocarbon, and Nitrogen Oxide

The IPCC (Shine et al., 1990) and Lashof and Ahuja (1990) calculate the same equivalency factor for CO for the long-term horizon (Table O.1).

Only the IPCC has estimated equivalency factors for the ozone precursors, NMHC and NOx. As discussed in Appendix Q, it is difficult to calculate the warming effect of NMHC and NOx; hence the equivalency factors used here must be viewed as *very* preliminary.

The IPCC gives a generic equivalency factor for NMHCs; it does not give specific factors for individual hydrocarbons and probably does not intend that the NMHC factor apply as such to emissions of alcohols. To adapt the equivalency factor of NMHCs to include alcohols and to enable it to distinguish, crudely, between individual hydrocarbons, I will convert the equivalency factor to a carbon-weight basis. The rationale for this is twofold. First, part of the warming effect of NMHCs and alcohols (indeed, of any organic compound) is due to the eventual oxidation of the carbon to CO2; hence, part of the mass-based warming effect of any organic compound will be a function solely of the carbon content. Second, it appears that, at least for some NMHCs, the higher the carbon number, the higher the ultimate ozone-forming potential. Seinfeld (1989) notes that higher-carbon alkanes consume more nitric oxide (NO), which shifts the NO, atomic oxygen (O), molecular oxygen (O_2), ozone (O_3), and NO_2 equilibrium in favor of O_3. Also, reactivity increases with carbon number within any family of compounds, and reactivity Pmay be related to ozone-forming potential globally (it certainly is related to ozone formation in urban areas).

Accordingly, I convert the IPCC's factor for NMHCs to a carbon (C) basis. I assume that the IPCC based its equivalency factor for NMHCs on the current NMHC mix, which the IPCC says is mostly terpenes, isoprenes, and alkenes (Shine et al., 1990). For this mix, the average carbon-weight content is about 85%. Thus, the values of Table 8 are equal to the IPCC values of Table O.2 divided by 0.85. This gives an equivalency factor based on the carbon content of NMHCs and alcohols.

The most important effect of expressing the equivalency factor of NMHCs on a carbon basis is to exclude the weight of oxygen in methanol and ethanol emissions.

O.3.4 The Base-Case Time Horizon and Equivalency Factors of This Analysis

As we saw above, the equivalency factors are a function of the time horizon. This analysis follows the IPCC (*Climate Change*, 1990), and considers time periods of 20, 100, and 500 years. I use the 100-year time period as the base case. However, I use these horizons only to give a range of results; I do not endorse the use of a short (less than 50- or 100-year) horizon. In fact, there is scant justification for the use of a 20-year time horizon.

The case for a long time horizon is obvious: global warming is a very long-term problem and will affect many generations to come. Several greenhouse gases persist for centuries. Even if net anthropogenic emissions of greenhouse gases are eliminated, the global climate still will be in flux for decades, primarily because of the large thermal inertia of the ocean. And the deep ocean,

which stores CO_2, turns over on a time scale of centuries. Therefore, to account for most of the climatic effects of current emissions of greenhouse gases, one must extend the analysis for decades at least; otherwise, the warming effects of some emissions will be ignored.

Of course, one reasonably might attach less importance to the very long-term than to the middle-term. This might be a reason for choosing a 100-year time period over a 500-year period, but it would not seem to justify choosing a 20-year time period, since such a short view would discard a large portion of the period of climate change.

An argument recently advanced in support of using a very-short-term horizon is that we should be concerned with the *rate* of warming as well as with the ultimate increase in equilibrium surface temperature, and that the short-term horizon represents the effect of different gases on the rate of global warming (Wilson, 1990; Shine et al., 1990). The implicit claim is that the greater the 20-year warming factor for a particular greenhouse gas, the greater the rate of warming due to that gas. But I would argue that, while the rate of warming certainly is important (because the ability of biological systems to adapt to change depends on the rate of change), equivalency factors based on a short-term horizon do not tell us anything about the relative contribution of different gases to the rate of global warming.

A 20-year equivalency factor, as defined now, tells us how much radiative forcing a unit emission of a gas causes over 20 years relative to a unit emission of CO_2. It does not tell us how the forcing occurs over the 20 years, or what happens after the 20 years, as a result of the one-time emission of one unit of the gas. (One can calculate these trajectories, but the point is that the equivalency factor itself tells us nothing about them.) More importantly, the overall *global* rate of warming depends on the total quantity and rate of emissions of *all* gases, and the equivalency factors as calculated now consider neither total emissions nor the rate of emissions -- they tell us the relative radiative forcing of a one-time emisssion of a unit of a gas. Thus, not only does the equivalency factor not characterize the warming trajectory due to a unit emission of gas, it does not tell us anything at all about the *global* warming trajectory of a *global* emissions scenario involving particular overall amounts of the gas. So, not only is a short-term equivalency factor not a cardinal measure of the relative contribution of a gas to the global rate of warming (an equivalency factor of 18.6 is not twice as "fast" or "bad" as an equivalency factor of 9.3), it is not even an *ordinal* measure (an equivalency factor of 18.6 does not even indicate a faster or worse overall rate of warming than an equivalency factor of 9.3). The current equivalency factors, then, do not help us evaluate the effect of any particular policy on the rate of global warming.

To best see that equivalency factors cannot be used to evaluate the effects of gases on the rate of warming, one can compare the equivalency factors as calculated now with a conceptually sound measure of the relative contribution of different gases to the rate of global warming. To make a conceptually sound measure, one might calculate the global warming trajectory caused by a specific global emissions scenario, then change hypothetical emissions of one gas only and recalculate the warming trajectory. One would repeat this, changing emissions of different gases one at a time. One then would try to relate the change in emissions of each gas to some aspect of the corresponding change in the warming trajectory, such that the relation represented the relative contribution of the particular gas to the rate of warming. If one is able to represent or define the rate of warming in a way that captures the importance, or "bad" effects, of a "fast" rate of

warming, then one has a measure of the relative contribution of emissions of a particular gas to the undesirability of a "fast" rate of warming for the specific emissions scenarios considered. (Note, though, that it will not be easy to define an appropriate rate of warming because we do not understand the specific relationship between warming trajectories and damage to the planet. How will we compare a very fast warming over 10 years to a slower, but still rapid, warming over 20 years? Definitions and weights will likely seem quite arbitrary.)

There are two things to note about this conceptually sound measure of the relative contribution of different gases to the rate of warming. First, it looks nothing like the equivalency factors as calculated now. The correct measure relates changes in global emissions to some aspect of a global warming trajectory and defines and ranks rates of warming; the equivalency factors calculated now involve neither total emissions, nor warming trajectories, nor definitions of warming rates. Second, any particular measure of the relative contribution of a gas to the overall rate of climate change (however defined) probably would hold only for the specific emissions scenario considered. Different baseline emissions scenarios (and there are innumerable emissions scenarios) probably would give quite different results. Thus, one probably could not claim that a rate-of-warming factor calculated for a particular scenario had *general* implication. (Note that the equivalency factors, which represent a gas's relative contribution to equilibrium warming, are also a function of emissions, implicitly, because the relative radiative forcing and the lifetime of the gases are a function of their concentration, which in turn is a function of emissions. However, it is likely that the current equivalency factors are less sensitive to changes in the implicit underlying emissions scenarios than the rate-of-warming factor outlined here would be to changes in the explicit emissions scenario.)

I conclude, therefore, that there is, at present, little justification for the use of a 20-year time horizon in the calculation of equivalency factors.

Appendix P:

Greenhouse Gas Emissions from Making Materials for Vehicles, Power Plants, Pipelines, Ships, Trains, etc., and from Assembling Vehicles

Appendix P:

Greenhouse Gas Emissions from Making Materials for Vehicles, Power Plants, Pipelines, Ships, Trains, etc., and from Assembling Vehicles

P.1 Greenhouse Gas Emissions from Assembling Vehicles

It takes energy to assemble vehicles, and the use of most forms of energy produces greenhouse gases. The amount of energy used to assemble vehicles is related to the weight of the vehicle being assembled, and because alternative-fuel vehicles (AFVs) generally will not weigh the same as the gasoline- and diesel-fuel vehicles they replace, the assembly of AFVs will require a different amount of energy than the assembly of similar gasoline and diesel-fuel vehicles and will produce a different amount of greenhouse gases. Therefore, emissions from vehicle assembly should be included in the estimation of the greenhouse effect of alternative transportation fuels.

To calculate emissions of greenhouse gases from vehicle manufacture, it is most convenient to start with the amount of energy required to assemble 1 pound (lb) of vehicle. If one knows the total empty weight of one class of vehicle (e.g., passenger vehicles), one can calculate the total energy required to assemble that particular class of vehicle. With data on the kind of energy, one can calculate emissions of greenhouse gases per vehicle assembled, and with data on the lifetime mileage of that class of vehicle, one can calculate emissions of greenhouse gases per mile for that particular class of vehicle. Emissions per mile for any other class of vehicle of X (e.g., heavy trucks) can be calculated by multiplying emissions per mile for the known class (Y) by the ratio of weights, X:Y, on the assumption that assembly energy is proportional to vehicle weight.

In this section, I calculate assembly energy per lb-vehicle by using current data on total energy consumption by vehicle manufacturers, total amount of each class of vehicle produced, and weight of each class of vehicle. I compare the result with two older estimates of Btu/lb. I then break down the assembly energy into electricity and types of fuel. Finally, with data on lifetime mileage by class of vehicle, I calculate greenhouse gas emissions per mile due to vehicle assembly.

I assume that energy required for assembly is directly proportional to vehicle weight for all vehicles — alternative-fuel vehicles, petroleum-fuel vehicles, electric vehicles (EVs), and internal-combustion-engine vehicles (ICEVs) — regardless of the materials they are composed of. I allow for the possibility that AFVs may have a different number of lifetime vehicle miles traveled (VMT) than the petroleum-fuel vehicles they replace, and so they have a different grams-per-mile (g/mi) emission rate due to vehicle assembly. (A longer lifetime spreads the assembly energy and emissions out over more miles and lowers the g/mi per mile emission rate due to assembly).

I include the weight of alternative-fuel storage systems (e.g., batteries, high-pressure tanks) in the total vehicle weight for the purpose of estimating emissions from vehicle assembly. This implicitly assumes that it takes a battery manufacturer as much energy to assemble a pound of

vehicle as it does a vehicle manufacturer to assemble a pound of vehicle (excluding the storage system). This is probably not exactly right, but it is probably a good approximation.

P.1.1 Energy Used by Vehicle Manufacturers

In 1985, the manufacture of transportation equipment (e.g., aircraft, railroad equipment, watercraft, and motor vehicles*) consumed 0.321 quad of primary energy (EIA, *Manufacturing Energy Consumption Survey*, 1988). (This does not include energy used to make the materials used in motor vehicles, which I consider separately, below). Primary energy is the energy value of all fuels and electricity used by the manufacturer. The EIA *Manufacturing Energy Consumption Survey* (MECS) does not report energy consumption by subsector of the transportation equipment manufacturing industry. The U.S. Bureau of the Census's *Annual Survey of Manufactures* (ASM) reports that the manufacture of motor vehicles and motor vehicle equipment consumed 0.068 quad of electricity (Btu-electric) in 1985, but it does not give further data on energy consumption by the motor vehicle manufacturing sector. (The MECS and the ASM estimates of net electricity consumption by manufacturers of transportation equipment are within 5% of each another.)

There are at least two ways to infer energy consumption by motor vehicle manufacturing by using the MECS and ASM data. First, one can assume that the motor vehicle sector's share of total energy consumption in the transportation equipment industry is equal to the dollar value of shipments of motor vehicles, divided by the dollar value of shipments of all transportation equipment. This ratio was 0.61 in 1985 (ASM, 1988).

Second, I note that motor vehicle manufacturers accounted for 58.6% of the total spending for energy by transportation equipment manufacturers, 57.9% of total electricity use by all transportation equipment manufacturers, and 67% of total spending for fuels other than electricity. These statistics are close to the 61% ratio based on total value, and they suggest that motor vehicle manufacture consumed about 60% of the 0.321 quad consumed by all transportation equipment manufacturers. This results in 0.1926 quad.

P.1.2 Curb Weight of Vehicles, by Class

Heavenrich (1988) provides data on the average gross vehicle weight (GVW) and assumed payload of 1985 model year cars and light trucks weighing less than 8,500 lb. With these data,

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* The standard industrial classification (SIC) category "Motor Vehicles and Motor Vehicle Equipment" (SIC 371) includes establishments that manufacture and assemble complete passenger cars, trucks, and buses; establishments that manufacture car and truck chassises and bodies; establishments that manufacture motor vehicle parts and accessories; and establishments that manufacture motor homes and truck trailers. It does not include manufacturers of motorcycles, automotive glass, automotive batteries, tires and tubes, stamped body parts, carburetors, and other minor auto parts. Therefore, my estimate of energy used in vehicle manufacturing excludes energy used to make some parts.

one can calculate the average curb or "empty" weight of passenger vehicles and light trucks: it is simply the GVW less the standard assumed payload (300 lb).

Unfortunately, the same cannot be done for medium and heavy (which together I call "other") trucks, because even if the average GVW could be calculated, there is no standard assumed payload that can be deducted from the GVW to yield the curb weight. Instead, I calculate the average curb weight for other trucks (cab and trailer) from data on the average curb weight and number of trucks, by three weight classes:

$$ACW_o = F_{8500} \times CW_{8500} + F_m \times CW_m + F_h \times CW_h$$

where:

ACW_o = average curb weight of other trucks (medium and heavy trucks),

F_{8500} = the number of trucks between 8,500 and 10,000 lb GVW divided by the number of all trucks weighing more than 8,500 lb (0.14, according to data from the Motor Vehicle Manufacturer's Association [MVMA]),

CW_{8500} = curb weight of trucks between 8,501 and 10,000 lb GVW (I assume 8,950 lb, which is the midpoint GVW of 9,250 minus a 300-lb payload),

F_m = number of medium trucks (GVW 10,001-19,500 lb) divided by the number of all trucks weighing more than 8,500 lb (0.05, according to the MVMA),

CW_m = curb weight of medium trucks (14,000 lb; my assumption),

F_h = number of heavy trucks (GVW of more than 19,500 lb) divided by the number of all trucks weighing more than 8,500 lb GVW (0.81, according to the MVMA), and

CW_h = curb weight of heavy trucks, cab plus trailer (20,000-25,000 lb, according to the manufacturers, dealers, and drivers I spoke with).

The resulting average weights for passenger cars, light trucks, and heavy trucks are shown in Table P.1. These weights are multiplied by the number of vehicles manufactured in each class (discussed next) to produce total weight of manufactured vehicles, which can then be divided into total manufacturing energy to yield Btu/lb.

P.1.3 Number of Vehicles Manufactured (needed to calculate Btu/lb-vehicle)

The MVMA (1987) reports production of passenger cars and production of motor trucks and buses, but does not disaggregate production of motor trucks and buses by gross vehicle weight. However, they disaggregate factory sales of motor trucks and buses by vehicle weight (I need production data because manufacturing energy consumption is related to units produced, not units sold). I have assumed that the (unknown) ratio, number of trucks produced in a given weight class X divided by total production of trucks and buses, is equal to the (reported) number of trucks of weight class X sold by the factory divided by total factory sales of trucks and buses. This seems reasonable, since production very nearly equals factory sales.

One further assumption is needed here. The MVMA factory sales data define light trucks as those that weigh 6,001-10,000 lb GVW, but the U. S. Environmental Protection Agency (EPA) weight data used above define light trucks as those that weigh less than 8,500 lb GVW. Therefore, I need an estimate of the proportion of trucks in the 6,001-lb to 10,000-lb GVW category that weigh more than 8,500 lb. According to *Ward's Automotive Yearbook*, which reports the weight of every light truck made in the United States, few trucks weigh 8,500-10,000 lb GVW compared with the number that weigh less than 8,500 lb. On the basis of *Ward's Yearbook*, I assumed that 10% of the 6,001-lb to 10,000-lb trucks were between 8,500 and 10,000 lb.

P.1.4 Comparison With Other Estimates

The Btu/lb result of the preceding analysis is shown in Table P.1, along with two older estimates. In a thorough analysis, Berry and Fels (1972, 1973) used data from the 1967 *Census of Manufactures* to calculate the energy required to assemble autos and produce the materials used in autos. They calculated a higher energy requirement/pound auto assembly in 1967 than I do for 1987 assembly, which probably results, in large part, from improvements in energy-use efficiency over the 20-year period. Part of the difference, though, results from the fact that Berry and Fels (1972) counted energy for assembly of certain parts that I omitted, such as carburetors and other minor vehicle subsystems.

Hudson's (1982) estimate is between mine and that of Berry and Fels, which is consistent with an assumption of increasing efficiency of manufacture. The rest of the difference between my estimate and Hudson's estimate might result from different definitions of vehicle fabrication and vehicle manufacture. Hudson does not define vehicle fabrication in terms of SIC categories; it may be the same as the large group, SIC 371, "Motor Vehicles and Motor Vehicle Equipment," or it may include just the largest subcomponent, SIC 3711, "Motor Vehicles and Passenger Car Bodies." Given these considerations, I assume a Btu/lb value as shown in Table P.1 .

TABLE P.1 Data Used to Estimate Energy (Btu) Consumed to Assemble a Pound of Vehicle

Vehicle	Curb Weight (lb)[a]	Vehicles Made (10^6)[a]
Passenger car	3,121	8.185
Light truck[b]	3,663	3.035
Other truck[b]	20,625[c]	0.430

0.1926	Calculated quads used to assemble motor vehicles[d]
4,239	Calculated Btu/lb-vehicle[e]
Compare with:	
5,657	Hudson (1982)
6,208	Berry and Fels (1972)
5,000	Used here[f]

[a] See text for discussion and sources.

[b] "Light trucks" weigh less than 8,500 lb gross. "Other trucks" weigh more.

[c] I calculated an average 31,500 GVW for trucks weighing more than 8,500 lb GVW.

[d] From MECS and ASM data. See text for discussion and methods.

[e] 0.1926 quad divided by weight of all vehicles made.

[f] I have used a value higher than calculated from MECS and ASM data because, as discussed in the text, those data do not include all relevant assembly operations.

P.1.5 Breakdown of Total Energy

According to MECS, in 1989, about 31% of the total energy used to make transportation equipment in the Midwest was electricity (as Btu per electric); 8% was oil, 43% was natural gas (NG), and 18% was coal. (I use the distribution for the Midwest region because about two-thirds of all autos are manufactured in the Midwest.) Here, I will assume 35% for electricity rather than the 31% of MECS, because 0.35 × 0.1926 quad of total energy consumed by vehicle manufacturers (see above) equals 0.068 quad electric, which is the figure given in the ASM for the manufacture of motor vehicles. I then adjust the other energy shares proportionately (7% oil, 41% NG, and 17% coal).

P.1.6 Electricity Mix Used by Auto Manufacturing Plants

Emissions of greenhouse gases from the use of electricity to assemble autos depend on the mix of fuels used to generate electricity. This mix is determined by the location of assembly plants and the generating mix of the utilities that serve them. *Ward's Automotive Yearbook* (as reported in *Motor Vehicle Facts and Figures, 1987*) shows auto and truck assembly by city and state. This data, combined with data from the Energy Information Administration (EIA) on the mix of fuels used to generate electricity in every U. S. utility, and data on the service area of every U. S. utility (Electrical World, 1988), gives the breakdown of electricity use by fuel type for auto and truck and assembly in the United States. (I have assumed that auto- or truck-manufacturing energy divided by total manufacturing energy is equal to the weight of all autos produced, or all trucks produced, divided by the weight of all vehicles produced.) Electricity mixes by city and city shares of total motor vehicle manufacturing energy are shown in Table D.1.

P.1.7 Lifetime Mileage of Vehicles

I estimate the average lifetime mileage of petroleum-fuel passenger cars, light trucks, and other trucks as the cumulative mileage at the median age of scrappage for each vehicle. The *Transportation Energy Data Book 9* reported the medium age of scrappage for cars, light trucks (up to 10,000 lb GVW), and heavy trucks (more than 26,000 lb GVW). The California Air Resources Board (1986) shows cumulative mileage as a function of age for cars, light-duty trucks, and heavy gasoline and diesel trucks. (I assumed half of the heavy-duty trucks were diesel and half were gasoline). For this calculation, I ignore the discrepancy between the 8,500-lb and the 10,000-lb definition of a light truck. I also ignore the fact that cumulative mileage at median lifetime is not the same as average lifetime mileage (the number I want), the latter being total miles traveled by all vehicles in a class before scrappage, divided by the number of vehicles. The results for petroleum-fuel heavy-duty vehicles (HDVs) and light-duty vehicles (LDVs) are shown in Table P.2.

In the base case, I assume that petroleum, methanol, ethanol, NG, hydrogen, and liquefied petroleum gas (LPG) light-duty vehicles all have the same lifetime (Table P.2). However, electric

TABLE P.2 Lifetime of Vehicles and Fuel-Storage Systems in Miles

Vehicle	Petroleum	Alcohol	NGVs	EVs	Hydrogen	LPG
Passenger car	108,000	108,000	108,000	153,000[a]	108,000	108,000
Light duty truck	163,000	163,000	163,000	163,000	163,000	163,000
Heavy-duty truck	335,000	335,000	335,000	NA[b]	335,000	335,000
LDV fuel storage	108,000[c]	108,000[c]	150000[d]	104,000[e]	300,000[f]	108,000[g]
HDV fuel storage	335,000[c]	335,000[c]	335,000[d]	NA[b]	600,000[f]	3,350,00[g]

Lifetime for petroleum-fuel vehicles from data in CARB (1986) and *The Transportation Energy Data Book*, edition 9. See text for more details.

[a] Electric vehicles will last longer than ICEVs (DeLuchi, 1989). I assume a 42% increase in life.

[b] EVs will not be used in HD applications.

[c] Tanks for liquid fuels are cheap and durable. They generally last the lifetime of the vehicle but are not valuable enough to salvage at the end of the life of the vehicle. Hence, I assume that liquid-fuel tanks have the same life as the vehicle.

[d] The situation with CNG tanks is complicated. U. S. DOT currently demands that composite tanks be destroyed after only 15 years, but manufacturers guarantee them for much longer than this, and Italy allows steel tanks to last 30 years (see DeLuchi, Sperling, and Johnston, 1987). If the 15-year limit remains, CNG tanks could last for a little longer than one HDV lifetime, and almost 1.5 LDV lifetimes. If the limit is raised, which certainly seems reasonable in light of the manufacturer warranty and the performance of the tanks to date, tanks could last for much longer. However, for tanks to last beyond one vehicle lifetime, they will have to removed from the scrapped first vehicle and reinstalled in another. It is not clear how such large-scale recycling might be restricted or what it might cost.

In the base case, I have assumed conservatively that CNG tanks last 15 years — about one HDV lifetime and almost 1.5 LDV lifetimes. In a scenario analysis, I consider a 30-year life for CNG tanks in both LDVs and HDVs.

For LNG, see the discussion pertaining to LH_2.

[e] An advanced Na/S battery should last for about 1,000 deep cycles, to 80% DOD (DeLuchi, 1989; Hamilton, 1988). Assuming 104 miles per deep cycle (80% of a maximum range of 130 miles, as in Table 2), the battery lifetime is 104,000 miles.

[f] There are several reasons to assume that hydrides will last for several LDV lifetimes. With very pure hydrogen, hydrides can last for hundreds of thousands of miles (DeLuchi, 1989). Hydrides are very expensive — much more expensive than CNG, LPG, or LNG containers — and hence definitely will be worth recycling. Finally, hydrides do not have to be safety-tested as CNG containers do; hence, their reuse probably will not be as subject to potentially restrictive regulation.

In the base case, I assume that hydrides last for 2,500 cycles to 80% of capacity, resulting in 300,000 miles for LDVs and 600,000 miles for HDVs (based on 80% of the ranges of Table 2). I consider a 5,000-cycle life in a scenario analysis.

TABLE P.2 (Cont.)

	Little is known about the lifetime of LH_2 dewars or about the feasibility and cost of transferring a container from one vehicle to another. In the base case, I simply assume that the container dies with the vehicle.
g	I assume that an LPG tank will last as long as the vehicle, but that typically it is not worthwhile to salvage an LPG tank, which means that the tank lasts only as long as the vehicle.

vehicles will definitely have a longer life than comparable ICEVs because electric motors last much longer than internal combustion engines (DeLuchi et al., 1989). EVs can be in service at least twice as long as comparable ICEVs, but I have assumed conservatively only a 42% longer life in the base case. In a scenario analysis (Table 12), I consider a longer life (this reduces g/mi emissions from vehicle assembly). It is also possible that dedicated natural gas vehicles (NGVs) will have a somewhat longer life than gasoline vehicles; I also consider this in a scenario analysis (Table 12).

In the base case, I assume that all HDVs have the same life. However, the lifetime of dedicated, advanced alternative-fuel heavy-duty vehicles is not known, and alternative fuel, spark-ignited or spark-assisted HDVs may not last as long as diesel fuel HDVs. I examine the effect of a shorter (250,000-mi) life in a scenario analysis.

P.1.8 Summary

Using the preceding data, the model calculates grams of greenhouse gases emitted from vehicle assembly per mile of travel by the vehicle. The results are shown in Table 9.

In the model, the mix of fuels input to electricity plants supplying auto manufacturing facilities is a variable. Changing the mix from the baseline to more or less coal and nuclear (within plausible bounds) changed the g/mi emissions from vehicle manufacture by no more than 7% and did not at all affect the overall standing of the alternatives relative to one another.

Note that I assume that assembly energy is solely a function of the weight of the vehicle, not of the kinds of materials being assembled. Thus, I assume that it takes as much energy to assemble a 2,500-lb EV as a 2,500-lb LPG vehicle also implicitly assume that it takes as much energy to assemble 1 lb of material for an alternative-energy storage medium (e.g., battery, hydride, or compressed natural gas tank) as it does to assemble 1 lb of vehicle. These simplifications are undoubtedly quantitatively, but hopefully not qualitatively, incorrect.

P.2 Greenhouse Gas Emissions from the Manufacture of Materials

Energy is used to make and assemble the materials used in vehicles, trains, ships, pipelines, power plants, vehicles, etc. The manufacture of some kinds of materials, such as aluminum, is quite energy intensive and produces a lot of greenhouse gases. Since many materials are used at every stage of every fuel cycle, and different fuel cycles use different materials, a full accounting of the greenhouse effect of alternative fuels must consider the emissions from making materials. Below, I first calculate the energy intensiveness of materials generally, then greenhouse gas emissions from the manufacture of materials for vehicles specifically. I then consider the use of materials at other points in the fuel cycle.

P.2.1 Amount and Kind of Energy Used to Make Materials

Greenhouse gas emissions from the mining, processing, and fabricating of materials (e.g., steel, iron, aluminum, concrete, etc.) are equal to the amount and kind of energy used to mine, process, and fabricate materials, multiplied by a greenhouse gas emission factor for each kind of energy used. The greenhouse gas emission factors are described and estimated in previous appendixes. This section describes the data and equations used to estimate the amount and kind of energy required to make materials, drawing on a report by Hudson (1982). The results are compared to estimates by Berry and Fels (1972) and Argonne National Laboratory (Aarons and Wolsky, 1978; Darby and Aarons, 1979; Sapp, 1981) in Table P.3.

Hudson (1982) analyzed in detail the energy used to make several materials. He compiled and reviewed estimates of the energy required to mine, refine, and fabricate ores and materials, accounting for recycling, and from these data, he calculated the energy (Btu) required to produce 1 lb of finished materials. He also disaggregated this final energy requirement by type of fuel. His estimates of each type of energy (Btu) per pound of material can be multiplied by the weight of material in a vehicle to provide estimates of the amount of each kind of fuel embodied in the materials of a vehicle, and these estimates, in turn, can be multiplied by the greenhouse-gas emission factors for each kind of fuel.

Hudson was interested in the energy use in the United States, and so did not count energy consumed in foreign countries to make products imported by the United States. From the perspective of the global greenhouse, however, it makes little difference if the carbon dioxide (CO_2) from the energy used to make a product is emitted in Europe or North America; what matters is how much greenhouse gas is emitted from a process, anywhere. Hence, I have adjusted his estimates by setting his "made in the U. S." coefficients to 1.0 in every case. Hudson's formula is:

$$E_T = (A_1 \times a_1 + A_2 \times a_2 + B \times b)V \times Z + D \times W \times Z \times O + C \times V \times Z \times o + C \times W \times Z \times o$$

TABLE P.3 Btu per Pound Intensiveness of Auto Assembly and Materials Manufacture

Process or Material	Reister (1977)	Berry & Fels (1972)	Hudson (1982)[a]	ANL (1978-1983)
Cold-rolled steel		26,366	20,264	15,000-21,000[b]
Cold-rolled alloy steel		27,680		
Cold-rolled stainless steel		39,408	30,816	
Cast iron		12,500	9,774	
Cast steel		23,300		
Automotive sheet		25,368		
Rolled/drawn aluminum	174,050	125,289	103,800	92,000-130,000[c]
Cast aluminum	173,050	107,086	9,500[d]	
Forged aluminum		125,127		
Nickel			64,101	
Titanium			185,677	
Plastics/composites	12,2450		64,598	
Rubber			55,612	
Glass			9,800	
Rolled copper	110,900	63,975	64,022	
Cast copper		62,243		
Rolled zinc		39,622	47,860[e]	
Cast zinc		43,853	47,860[e]	
Sound deadener			7,000	
Battery lead			11,678	
Sodium			46,000	
Sulfur			443	
Concrete[f]	1,165-2,205			543-1,936
Auto assembly		8,994	6,660	
Auto shipping		217		
Materials transport		630		

Btu/lb for materials manufacture are based on Btu-thermal, except as noted; that is, energy used to generate electricity has been taken into account (although this is not entirely clear in the case of Hudson's data; see footnote a). Berry and Fels assume that electricity generation is 32.8% efficient; Hudson appears to assume 30% for electricity generation and distribution.

[a] Projections for the year 1980, "Scenario I." I show the 1980 scenario here (rather than the year 2000 scenario results I use in the actual base-case analysis) to allow more direct comparison with the other estimates, which are not projections.

As far as I can tell, Hudson counts electricity as Btu-thermal. In a footnote to one of his tables (one which reviews estimates for steel), Hudson says "as far as can be determined, all data [are] either stated in or converted to a fossil fuel Btu basis" (p. 9). Although Hudson does not repeat this note for any of the other materials, I assume it applies to all materials.

[b] From Darby and Arons (1979), counting direct energy consumption from ore mines to steel mills and fabrication of semifinished products, for several kinds of products. They appear to count electricity at 3,412 Btu/kWh (energy from electricity is referred to as "electrical energy," which implies Btu-electric).

TABLE P.3 (Cont.)

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[c] From Arons and Wolsky (1978). The 130,000 figure is Btu of fuel/lb of fabricated aluminum product, from a 1976 report. The 92,000 figure is total energy use (counting all electricity, even hydro, as Btu-thermal) in the entire industry — mining to fabrication — in 1977, divided by the weight of aluminum shipments (imports excluded) in 1977. The difference may result from aluminum recycling, which is very energy efficient and is included in the lower figure (the one based on national energy and product totals) but not in the higher one. Note that Hudson's estimate accounts for recycling.

According to Arons and Wolsky (1978) and Shen (1981), the production of primary aluminum (the steps after mining and before fabrication) requires about 85,000 Btu/lb of aluminum.

[d] Assumes 100% made from scrap.

[e] Type of zinc manufacture not specified.

[f] In the manufacture of concrete, there are four sources of CO_2: (1) the use of energy to make cement, (2) the use of energy to transport cement and make bags for cement, (3) the use of energy to process and transport gravel, and (4) the conversion of $CaCO_3$ to CaO in the manufacture of cement. In this table, Reister (1977) and ANL (Sapp, 1981) estimate the total amount of energy (sources 1-3) required to produce a pound of ready-mix concrete (low end of the range) or finished concrete product (high end of the range). Most concrete for building is used as ready mix. In the following paragraphs, I examine sources 1-4 in some detail, relying partly on Sapp's estimates.

1. *Energy required to make cement.* Sapp's (1981) detailed analysis shows that the manufacture of Portland cement required about 3,700 Btu/lb in 1976 (based on Btu-thermal for electricity use). The Portland Cement Association (1986, 1989) reports about 3,650 Btu/lb for cement manufacture in 1976, 3,030 Btu/lb in 1985, and 2,950 Btu/lb in 1988. (I have converted their electricity-consumption figures to thermal Btu.)
2. *Energy required to make bags and transport cement.* According to Sapp (1981), this requires about 100 Btu/lb-cement. Thus, a reasonable value for cement manufacture and transport is about 3,000 Btu/lb (Btu-thermal). To convert this estimate of Btu/lb-cement to Btu-due-to-cement/lb-concrete, one must know how much cement is in concrete. Data in Sapp (1 metric ton of cement makes 4 cubic yards of concrete), Meridian (1989; density of concrete is 127 lb/ft^3), and EPA (AP-42; density of concrete is 148 lb/ft^3) indicate that Portland cement is about 15% the weight of concrete. Therefore, concrete contributes about 450 Btu of embodied energy/lb-concrete.
3. *Energy required to make, process, and transport noncement ingredients in concrete.* Sapp's (1981) analysis indicates that cement accounts for most of the energy embodied in ready-mix concrete. This seems reasonable, since gathering and transporting the gravel should not require much energy. I assume 50 Btu/lb-concrete for noncement components.

The total of items 1-3 is 500 Btu/lb for ready-mix concrete.

TABLE P.3 (Cont.)

4. *CO_2 emissions from $CaCO_3$ to CaO.* Cement manufacture also produces CO_2 via the transformation of limestone ($CaCO_3$) to lime (CaCO):

$$CaCO_3 \text{ --> } CaO + CO_2.$$

Given that cement is about 63.5% CaO by weight, one weight unit of cement produces 0.5 weight unit of CO_2 (after Marland et al., 1989). If concrete is 15% cement (see above) by weight, then making 1 lb-concrete results in 0.075 lb-CO_2 from this source, which is in addition to the emissions above from the use of energy.

One can express the CO_2 release from $CaCO_3$ conversion in terms of the amount of energy use that would produce the same CO_2 emission. The use of an additional 400 Btu/lb in cement manufacture would result in 0.075 lb-CO_2/lb-concrete. Hence, total "effective" energy use in the production of ready-mix concrete could be expressed as 500 Btu/lb (direct use) plus 400 Btu/lb (energy-use equivalent of emissions from $CaCO_3$ to CaO). The grand total for ready-mix concrete is thus 900 Btu/lb. To account for manufacture and use of concrete products, I use 1,000 Btu/lb for concrete in general.

where:

E_T = total energy in Btu/lb, in 2000;

A_1 = mining or feedstock energy in Btu/lb, in 1975;

a_1 = fraction of ore or material that is mined or extracted in the United States;

A_2 = processing energy for other ores in Btu/lb, in 1975;

a_2 = fraction of other ore that is processed in the United States;

B = refining energy in Btu/lb, in 1975;

b = refining efficiency factor (year 2000 Btu/lb divided by year 1975 Btu/lb);

V = fraction of semifabricated material that originates from virgin material, in 2000;

Z = fraction of semifabricated material that is produced in the United States;

D = scrap processing energy in Btu/lb, in 1975;

O = scrap processing efficiency factor (year 2000 Btu/lb divided by year 1975 Btu/lb);

W = fraction of semifabricated material that originates from recycled material (1 – V);

C = semifabrication energy in Btu/lb, in 1975; and

o = semifabrication efficiency factor (year 2000 Btu/lb divided by year 1975 Btu/lb).

I have recalculated E_T for all materials for which Hudson had data by using Hudson's equation and his values for all the variables except a_1, a_2, and Z, which I have set equal to 1.0. I use the average of his "scenario-I" and "scenario-II" year 2000 values. In most cases, this results in a 15% reduction in Btu/lb energy use in 2000 compared with 1975. For the materials for which Hudson did not have enough information to specify all of the variables for his equation (glass, plastics, and sound deadeners), I use the final, undisaggregated estimates for 2000 (the average of scenarios I and II). I have adjusted Hudson's estimate for plastic to remove his assumption that 22% of the feedstock petroleum would have been imported in 1980 and, hence, for his purposes, need not have been included.

Table P.3 shows the results of the calculation. Hudson's results are reasonably consistent with those of two other studies, as shown in Table P.3.

The estimates in Table P.3 count electricity as Btu-thermal; that is, they count fossil-fuel input energy to electricity, not electrical output energy. I have left the estimates in this form because it is not possible to convert all of them to a Btu-electric basis. In Table P.4, I have converted Hudson's estimates to a Btu-electric basis.

I broke down Hudson's Btu/lb totals into types of fuel (coal, oil, NG, and electricity) by using data in Hudson (the results are shown in Table P.4). Hudson provided estimates of how much of the total energy used to make materials comes from coal, NG, petroleum, electricity, and "other," counting electricity as Btu-thermal. I converted his Btu-thermal to Btu-electric by multiplying by 30% (the value he apparently used for the efficiency of electricity generation), and I counted "other" energy as electricity. In most cases the "other" category was zero or very small; in the one case where it was large (aluminum manufacture), Hudson noted specifically that "other" referred to hydroelectric power.

TABLE P.4 Amount and Kind of Energy Required to Make a Pound of Material, and Fractions of Materials in LDGVs

Material[c]	Energy in 2000 (Btu/lb)[a]	Energy Share[a]				Fraction Material in LDGV[b]
		Coal	Oil	NG	Power	
Plain carbon steel	13,315	0.59	0.06	0.23	0.13	0.451
High strength steel	20,876	0.59	0.06	0.23	0.13	0.075
Stainless steel	22,220	0.63	0.06	0.20	0.11	0.010
Other steels	13,315	0.59	0.06	0.23	0.13	0.015
Iron	8,445	0.65	0.06	0.25	0.04	0.146
Plastics/composites	61,433	0.00	0.28	0.70	0.02	0.071
Fluids and lubricants	0					0.057
Rubber	38,307	0.20	0.30	0.41	0.10	0.043
Aluminum	44,352	0.04	0.05	0.60	0.31	0.050
Titanium	60,498	0.03	0.18	0.10	0.69	0.000
Glass	8,408	0.02	0.18	0.75	0.05	0.027
Copper	46,303	0.56	0.19	0.13	0.11	0.016
Zinc die castings	32,743	0.35	.00	0.54	0.10	0.006
Powdered metal components	3,926	0.03	0.38	0.29	0.29	0.007
Other materials (lead)	6,273	0.37	0.03	0.30	0.30	0.026
Sodium	15,658	0.26	0.01	0.00	0.73	0.000
Sulfur[d]	443	0.60	0.00	0.30	0.10	0.000

[a] From Hudson (1982) year 2000 projections, as detailed in the text. Shares here are based on Btu-electric. See also Reister (1977).

[b] From *Ward's 1989 Automotive Yearbook.*

[c] The materials categories in *Ward's Yearbook* and in Hudson did not match exactly. I used Hudson's cold-rolled steel factors for Ward's "plain carbon steel," "high-strength steel," and "other steels"; his cast-iron factor for Ward's "iron"; his tire factors for Ward's "rubber"; his zinc factor for Ward's "zinc die castings"; his sound deadener factors for Ward's "powdered metal components"; and his lead factor for Ward's "other materials." I ignored "fluids and lubricants" in Ward's breakdown. (Hudson did not have data). Most of these substitutions and assumptions probably are reasonable. I chose sound deadeners and lead for the last two Ward's categories because data in Millar et al. (1982) indicate that of the materials not mentioned explicitly in *Ward's Yearbook*, these are the heaviest.

[d] Breakdown for sulfur is my assumption.

P.2.2 Greenhouse Gas Emissions from the Manufacture of Materials Used in Motor Vehicles

Grams of CO_2-equivalent emissions of greenhouse gases from the manufacture of the materials used in a vehicle are calculated as the sum of emissions from the manufacture of the materials in the vehicle, excluding the fuel-storage equipment, plus emissions from the manufacture of materials in the fuel-storage equipment. I distinguish between the vehicle and its storage equipment because all ICEVs, storage equipment aside, are comprised of essentially the same materials, regardless of the fuel; whereas the weight and composition of fuel-storage systems is variable (a battery is very different from a hydride or a gasoline tank). Ideally, one would distinguish between EVs and ICEVs, but the data to do this are not available.

Formally, the calculation is:

$$T_g = \text{SUM [for all f, m]} \; E_{f,m} \times W_m \times G_f/VMT$$

where:

T_g = total greenhouse gas emissions from the manufacture of materials for one vehicle per mile of travel or for one piece of storage equipment per mile of its life;

$E_{f,m}$ = total Btu of fuel, f, required from mining to fabrication to produce 1 lb of material, m;

W_m = weight of material, m, in the vehicle or the fuel storage equipment;

G_f = grams of CO_2-equivalent emissions of greenhouse gases from the recovery, refining, transport, and combustion of 1 Btu of fuel, f; and

VMT = lifetime mileage of the vehicle or its storage equipment (Table 2).

The amount and kind of energy required to make materials, $E_{f,m}$, was discussed in the preceding section, and the greenhouse emission factor for each fuel, G_f, is described generally in the main text of this report and in detail in the various appendixes. All that is needed, then, is a calculation of W_m, the weight of each material in each kind of vehicle and fuel storage system.

For all vehicles or storage tanks, the weight of each material, m, is calculated as the product of the total curb weight of the vehicle (less the weight of the fuel tank) or the total fuel storage system weight, and the fraction of the total weight that is m. Therefore, we need to know four things: the weight of the vehicle, the weight of the fuel storage system, the composition of the vehicle, and the composition of the fuel storage system.

Table 2 shows the weight of the vehicles and fuel storage systems considered in this analysis. For the composition of vehicles, I use data in *Ward's 1989 Automotive Yearbook*, which gives a detailed breakdown of the weight of materials in a typical light-duty car. I assume that this distribution of materials in LDVs is the same for all vehicles: LDVs and HDVs; all alternative-fuel vehicles, including EVs; and petroleum-fueled vehicles. (Obviously, this assumption is not accurate in the case of EVs; moreover, it may be important because it takes much more energy to make a pound of copper, aluminum, or plastic than a pound of steel. Nevertheless, I calculate emissions from manufacture of materials, assuming the same composition as ICEVs.) This breakdown is shown in Table P.4. The article in *Ward's* notes that, since 1977, the amount of plain carbon steel in the typical U. S. car has decreased; the amount of high-strength steel, plastics, and aluminum has increased, and that this trend is expected to continue. However, I have used the Ward's data without adjustment.

The composition of fuel storage systems and batteries can be estimated from data in the literature. Table P.5 documents my estimates.

I also assume, implicitly, that the energy required to assemble a pound of battery is the same as the energy required to assemble a pound of vehicle. This, too, may not be accurate.

P.2.3 Greenhouse Gas Emissions from the Manufacture of Materials Used to Make Power Plants, Uranium Mines, Pipelines, Trains, Ships, etc.

Greenhouse gases are emitted from the consumption of fossil-fuels used to make and assemble materials for the equipment and facilities associated with alternative fuels: power plants, refineries, methanol production plants, pipelines, oil wells, coal mines, tankers, transmission towers, automobile assembly plants, etc. If the use of alternative fuels will require the construction of new facilities and equipment, emissions from the materials and assembly of these facilities and equipment should be calculated and divided by the amount of vehicle mileage associated with the output or throughput of the facility or equipment. However, my calculations and literature review indicate that, with a few exceptions, the amount of energy used to make and assemble the materials of equipment and facilities is very small compared to energy output or throughput.

Table P.6 shows the amount of energy embodied in the major materials used in several kinds of energy facilities, and compares this with the output or throughput by those facilities. In almost every case, the energy embodied in the materials is less than 1% (sometimes much less) of the energy produced or carried by the system.

Table P.6 does not account for energy used at the construction site. However, available evidence indicates that this is small compared to the energy embodied in the materials (e.g., compare the energy required to assemble vehicles with the energy embodied in the materials in vehicles). Mortimer (1989) has estimated that the use of fuels during the construction of a coal-fired power plant accounts for only 0.1% of total life-cycle CO_2 emissions from the power plant

TABLE P.5 Breakdown of Weight in Fuel Storage Tanks

Material	CNG[a]	LNG[b]	EVs[c]	Hydride[d]	LH_2[e]	LPG[f]
Carbon steel	0.000	0.400	0.000	0.000	0.000	0.900
Stainless steel	0.000	0.550	0.600	0.066	0.300	0.047
Other steels	0.050	0.050	0.050	0.034	0.050	0.000
Iron	0.000	0.000	0.020	0.450	0.000	0.010
Plastic/composites	0.500	0.000	0.020	0.000	0.250	0.000
Aluminum	0.450	0.000	0.050	0.450	0.350	0.033
Titanium	0.000	0.000	0.000	0.450	0.000	0.000
Glass	0.000	0.000	0.047	0.000	0.000	0.000
Copper	0.000	0.000	0.033	0.000	0.050	0.010
Sodium	0.000	0.000	0.060	0.000	0.000	0.000
Sulfur	0.000	0.000	0.120	0.000	0.000	0.000

[a] The composition of a CNG container depends on cost, pressure, weight, and bulk considerations. Carbon-wrapped, aluminum-lined containers are among the strongest per unit weight but also are very expensive, kevlar wrapping is less expensive and less strong, and fiberglass wrapping is least expensive and least strong. Most CNGVs to date have used either all steel or fiberglass-wrapped aluminum cylinders. I assume that future CNGVs will use fiberglass-wrapped, aluminum-lined cylinders.

Morris, Segimoto, and Lynn (1986) report that a carbon-wrapped, aluminum-lined pressure vessel, 50 inches long by 10 inches in diameter, is 52% aluminum, 42% carbon/epoxy composite, and 6% insulation. They also show that a kevlar-wrapped aluminum container that is not as strong is 63% aluminum and 37% kevlar. According to Morris et al., a fiberglass/resin matrix weighs 2 to 3 times more than a carbon/resin matrix and weighs 1.5 to 2 times more than a kevlar/resin matrix, at constant volume and pressure. This indicates that a fiberglass-wrapped, aluminum-lined vessel for automobiles would be at least 50% composite material and less than 50% aluminum. There also would be some additional in weight in mounting brackets and other hardware, which I assume would be made of steel. With these considerations, I assume that about half of the total vessel-plus-hardware weight is composite material, 5% is miscellaneous steel, and the rest aluminum.

[b] Constable et al. (1989) state that LNG containers consist of an inner vessel of stainless steel or aluminum alloys, an outer casing of low-carbon steel, and stainless-steel piping and valving. Adkins (1989) gives a similar description. From this description, I assume a vessel consisting primarily of stainless steel and low-carbon steel, with a small amount of other steel for tank support and mounting.

TABLE P.5 (Cont.)

[c] This is the estimated weight breakdown for the Na/S battery only; it does not account for the differences between the materials in an ICEV powertrain and an EV powertrain.

Auxer (1991) estimates, roughly, that a Na/S battery is about 12% sulfur, 6% sodium, 20% ceramics, and the rest steels, wiring, insulation, and other materials. The steel battery housing accounts for a large portion of the total weight. He notes that Na/S batteries contain many kinds of materials.

I use Auxer's estimates for sodium and sulfur and assume that most of the rest of the weight is stainless steel in the housing and other components. I have arbitrarily distributed a small amount of weight among several other materials.

See also Haase (1987), Nelson (1989), and Quinn et al. (1989).

[d] The weight breakdown composition depends on the composition of the hydride. See Stewart (1986) and DeLuchi (1989) for discussions and examples of hydrides for automobiles. Some hydrides may be fairly energy intensive. For example, iron-titanium hydrides, which are quite common, may be about half iron and half titanium by weight (as was the hydride for a Post Office Jeep converted to hydrogen, according to Stewart [1986]), and titanium is very energy intensive. I assume an iron-titanium hydride here.

[e] LH_2 dewars have been made of stainless steel, aluminum, aluminum alloys, and combinations of these (Peschka, 1987; Stewart, 1986). Peschka (1987) expects that future LH_2 tanks will be made of advanced, lightweight, composite materials. The inner vessel and the outer vessel may not be the same material. Dewars also may have copper radiation shields, and insulation.

Given the wide range of possible materials for future LH_2 vessels, the possibility of having different materials for the inner and outer vessels, and the use of yet different materials for things like radiation shields, I specify a generic dewar that contains stainless steel, aluminum, and composites. The weight share of composites is slightly less, because composites are lighter per unit of strength.

[f] Webb (1990) reports that LPG tanks generally are made of steel, but that fiber-reinforced plastics are being used experimentally in Europe. Bechtold and Timbario (1983) state that LPG tanks are manufactured from low-carbon steel. The Western Liquid Gas Association (1988) cites a company that makes aluminum LPG tanks. A 70-lb steel tank holds about 12.5 gallons of propane; a fiber-reinforced plastic tank weighs half as much (Webb, 1990). I assume low-carbon-steel tanks.

TABLE P.6 Energy Embodied in the Major Materials of Large Energy Facilities and Other Equipment

Facility and Major Materials[a]	Energy in Materials Divided by Energy Produced or Carried over Life[b]
Open-pit uranium mine: concrete, steel, iron	0.00009
Underground uranium mine: concrete, steel, iron	0.0003
Nuclear-fuel conversion plant: concrete, steel	0.00008[c]
Gaseous diffusion plant: concrete, steel, iron	0.0009[c]
Boiling water nuclear power plant:	0.002[d]
Western unit coal train: steel, aluminum, copper	0.0005
Coal truck: steel	0.0002
Coal power plant, western coal: concrete, steel, copper	0.005[e]
High-voltage power transmission: concrete, steel, al., copper	0.008
Onshore oil well: concrete, steel	0.0007
Enhanced oil recovery: concrete, steel	0.003
161,000 dwt oil tanker: steel[f]	0.0014
Onshore gas extraction: concrete, steel	0.008
Natural gas pipeline: steel	0.004
Medium-Btu biogas facility: concrete, steel	0.008
Large hydroelectric plant: concrete, steel, iron, al., copper	0.005
Solar-photovoltaic plant: concrete, steel, glass[g], silicon	0.015
Biofuels:	
Corn-to-ethanol plant: presumably concrete, steel	0.01-0.06[h]
Farm equipment, corn-to-ethanol: steel	~0.10[i]
SRIC equipment, wood-to-fuel: steel	0.01-0.04[j]

[a] Data on materials from the *DOE Handbook* (1983), except as noted. The handbook has quantitative estimates. In virtually every case, steel accounts for most of the embodied energy.

[b] Except as noted, energy in materials calculated as the amount of materials, as given in the *Handbook*, multiplied by the thermal energy embodied per unit of material (25,000 Btu/lb for all kinds of steel, 1,000 Btu/lb of concrete [which accounts for CO_2 released from the transformation of $CaCO_3$ to CaO; see note f, Table P.3], 125,000 Btu/lb of aluminum, 10,000 Btu/lb of iron, 50,000 Btu/lb of copper and silicon; these count electricity as Btu-thermal at roughly 10,500 Btu/kWh, for simplicity). Lifetime energy output or throughput is equal to yearly output or throughput of facility, as given in the *Handbook*, multiplied by the plant lifetime in years, as given in the *Handbook* (generally 20 to 30 years, except for the hydro plant, which is 60 years). I assume 30 years for the high-voltage power line.

TABLE P.6 (Cont.)

[c] The sum of these two, 0.001, compares well with the result of a calculation based on British data. From 1971 to 1978, the construction of the uranium-processing buildings of British Nuclear Fuels Limited (BNFL) required 2.2 million tons of concrete (Ferguson, 1981; I have recalculated the weight given in the original). The manufacture of this concrete required about 4.4 trillion Btu (direct energy and "effective" energy; see Table P.3, note f). It appears that a similar amount of energy was embodied in the steel. Over the same 8-year period, BNFL processed about 14,000 metric tons of natural uranium, which should have produced about 1.3 quads of electrical energy (assuming 0.0395 ton uranium/gWh generated, from Table I.3). Assuming that the BNFL plants will produce for a total of 30 years, total effective output will be around 4.9 quads-electric, and the material-energy/output-energy ratio will be about 0.002.

[d] The estimate of Rotty et al. (1975), which includes energy used by diesel generators, is an order of magnitude higher. See Table I.7. The output here is electricity, in Btu-electric.

[e] This result compares well with the result of a calculation based on British data. The Central Electricity Generating Board in England estimates that a 1,000-MW coal-fired power plant requires 500,000 tons of concrete and 18,750 tons of steel (Ferguson, 1981). With the Btu/lb figures of note b above, a 30-year life, and 70% capacity figure, the energy embodied in the materials is 0.003 of power output.

The output here is taken to be Btu-electric. For a coal-fired plant, it may be more accurate to divide the Btu embodied in the materials by the Btu of fuel input to the power plant rather than by the Btu-electric output; doing this would reduce the ratio by a factor of three and reinforce the conclusion that emissions from materials manufacture are small.

[f] Data on steel content from Marks (1982). He shows a calculation in which a 161,000-dwt tanker weighs 28,171 tons (virtually all steel) and completes 8.49 round trips per year. Elsewhere, he assumes that ships lasts 20 years. With these data, and assuming that 96% of the dwt is oil, one can calculate that the ship carries 26.2 million tons of crude — about 1 quad — over its life.

[g] The DOE *Handbook* does not give the amount of glass, so I have not included glass in this calculation.

[h] From Table K.7. I have dropped the estimate by Parisi (1983) because, as explained in the notes to K.7, it appears to be unreliable.

[i] From Table K.7. Relative to ethanol produced by the whole system.

[j] From Table K.9, converted to per-Btu-fuel-produced basis.

(this value apparently refers to direct use of fuels during construction; not to fuels used to make materials). He also estimated that emissions during the construction of a nuclear power plant are three times larger, but the result (0.3%) is still insignificant.

Several other estimates confirm that the manufacture of major materials used in major facilities, such as power plants, adds very little to the life-cycle CO_2-equivalent emissions from highway vehicles. Meridian Corporation (1989) estimates that the final manufacture of concrete and steel used to build coal or nuclear power plants produces about 300 g of $CO_2/10^6$ Btu of power output; to build photovoltaic power plants, about 1,600. These are about 0.1% and 0.6% of the g of $CO_2/10^6$ Btu-power emissions from the operation of coal-fired plants, percentages that are of the same order of magnitude as the estimates in Table P.6. Meridian apparently does not count CO_2 emissions from mining and refining the material and definitely does not count CO_2 from the actual construction of the plants.

Rotty et al. (1975) estimate that $2{,}311 \times 10^9$ Btu of coal and 447×10^9 Btu of electricity (at 3,412 Btu/kWh) are consumed to make a 1,000-MW nuclear reactor. Assuming the national average power mix, this construction energy use would produce about 370×10^9 g of CO_2-equivalent emissions (including emissions from mining and transporting the coal and the electricity fuels and emissions from non-CO_2 greenhouse gases) or about 540 g of CO_2-equivalent emissions per 10^6 Btu of power output. This figure is quite consistent with Meridian's estimate when one remembers that Meridian considers only CO_2 and only the final manufacture of materials.

White (1980, p. 3) remarks that, in most cases, emissions from the manufacture of materials used for construction are "quite small compared with the major conversion and product combustion emissions of CO_2."

Biofuel cycles may be an exception to this rule. The data in Table P.6 (based on the data of Tables K.7 and K.9) show the energy embodied in the equipment and facilities used in the biomass cycle exceeds the energy embodied in the coal, oil, gas, and uranium cycles by one order of magnitude. This is not implausible because biomass resources are considerably less energy dense and less concentrated than fossil fuels, and they require much more intensive use of collection, transport, and processing equipment and facilities. If accurate, this result is important. For example, if the energy invested in all equipment in the corn-to-ethanol cycle is assumed to be 10% of the energy in the output ethanol, then grams per mile emissions for the ethanol cycle increase by 5-9%, depending on the source of the energy used to make the materials in the equipment. This is a nontrivial amount, and should be included in a fair comparison. I have included it in a scenario analysis here (Table 12).

I conclude from this that, with the possible exception of biofuel-production facilities, large energy-producing facilities embody relatively little energy, compared to what they produce. In this report, I have ignored emissions associated with the building of major facilities, such as power plants, petroleum refineries, and nuclear-fuel fabrication plants. It seems likely that consideration of such items will not change the rankings among the alternatives (with the possible exception of

biofuels). I have included indirect energy consumption by trains, pipeline, trucks, and ships, where indirect includes energy used for maintenance, construction, manufacturing, and other activities (see Appendix E).

Note, however, that the use of alternative fuels will not automatically require immediate construction of new facilities. The timing and scale of the construction of new facilities will depend on the demand for a new fuel relative to existing capacity to make and transport the fuel. In some cases, existing capacity will be used up relatively quickly; in other cases not nearly so quickly. For example, in the case of methanol, all existing plants will be operating at capacity at relatively low levels of demand for methanol. Therefore, to support a large-scale methanol program, new plants will have to built, and the very minor greenhouse emissions attributable to building these facilities will be assigned to methanol. On the other hand, the use of EVs is not likely to require new generating and transmission capacity for many years because until the EV program becomes very widespread, most EVs will be recharged at night by using otherwise idle capacity. Consequently, if a more detailed analysis shows, for certain fuel cycles, a significant amount of energy use and emissions generation in the manufacture and assembly of the materials of energy facilities, one must then determine the rate at which new facilities will be required.

P.3 Greenhouse Gases from Making Chemicals and Other Materials

For two reasons, this report does not estimate greenhouse gas emissions from the manufacture of chemicals used in the various fuel cycles. First, it is difficult to get data on all the chemicals used in all the fuel cycles analyzed here and difficult to get information on the amount and kind of energy required to make all the chemicals. Second, estimates in the literature indicate that the total energy required to make chemicals and other non-structural materials is, in most cases, negligible. Rotty et al. (1975) found that, generally, direct energy use at the several stages of the nuclear fuel cycle dominates indirect use (chemicals, materials, and construction).

Similarly, Sapp (1981) found that direct energy use in the cement manufacturing industry is 94% of total energy use. Since the total energy used to make the cement that is used to build the facilities that generate power or fuel is small compared to the output of those energy facilities, the energy used to make chemicals is tiny compared to energy output from energy facilities. And finally, Lynd et al. (1991) estimate that the energy required to make the chemicals used in the wood-to-ethanol process is 1% of the energy in the ethanol produced.

As an illustration, suppose that the energy used to make chemicals bought by petroleum refineries is as much as 10% of the total process energy used by petroleum refineries (a figure which seems high by severalfold). Even so, this energy for the chemicals would be no more than 1% of the energy output of petroleum refineries (because total process energy consumed is about 10% of output). Therefore, I tentatively conclude that consideration of emissions of greenhouse gases from the manufacture of chemicals used in the fuel cycles would change the absolute results by less than 1%, and not change the relative results at all.

Again, the biofuel cycles may be exceptions. As noted in Table K.7, the energy required to make the ammonia used by the Katzen (1979) corn-to-ethanol design amounts to 0.02-0.04 Btu/Btu-ethanol, and the process uses other chemicals as well.

Appendix Q:

Chlorofluorocarbons, Ozone, and Water Vapor

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Chlorofluorocarbons, Ozone, and Water Vapor

Q.1 Chlorofluorocarbons

Q.1.1 Background

The various chlorofluorocarbon (CFC) compounds are among the most potent of the greenhouse gases. A CFC molecule has several thousand times the radiative forcing of a carbon dioxide (CO_2) molecule and can persist in the atmosphere for centuries before being photodissociated in the stratosphere (Watson et al., 1990). The Intergovernmental Panel on Climate Change (IPCC) (Watson et al., 1990) expects CFC emissions to account for 11% of the total global warming over the next century, in spite of multinational agreements limiting production of CFCs. (Absent the agreements limiting production, CFCs would be responsible for more future warming than methane.) Moreover, the chlorine released by the decomposition of CFCs destroys odd-numbered oxygen molecules (O or ozone [O_3]), thus depleting the protective blanket of stratospheric ozone that absorbs ultraviolet radiation (Brasseur, 1987). CFC emissions are therefore harmful both as greenhouse gases, directly and indirectly, and as an ultimate cause of increased exposure to high-energy solar radiation.

All CFCs come from industrial processes; there are no natural sources. Over the past few decades, the concentration of CFCs has grown rapidly and now is increasing at least 4% per year (Watson et al., 1990). The Montreal Protocol will reduce the rate of increase, but CFCs will remain in the atmosphere for many years because of their long lifetimes.

Q.1.2 CFCs from Vehicles

The only significant source of CFCs from highway vehicles is the air-conditioning system. The CFCs leak from this system during regular operation and are released entirely when the coolant is changed or the auto is scrapped. This contribution to the greenhouse effect of CFCs from automobiles is independent of the type of fuel used. Strategies for reducing CFC releases, such as recovering cooling equipment from scrap yards, are also independent of type of the fuel used.

The refrigerant used in automobile air-conditioning systems is Freon (CF_2Cl_2), or CFC-12. The concentration of CFC-12 has increased from a preindustrial level of zero to about 340 parts per trillion volume (pptv) in the early 1980s and has been increasing at about 6%/yr (WMO, 1985). The greenhouse model here calculates grams per mile of CFC-12 given the amount of refrigerant consumed per light-duty vehicle (LDV) or heavy-duty vehicle (HDV) over its life and the lifetime mileage of the vehicle. I assume 3,400 g released (based on information from Shiller (1989); see Table Q.1, footnote e) and 108,000 miles, resulting in 31.5 mg/mi. This

TABLE Q.1 Estimated Emissions of CFCs from Mobile Air Conditioners

Total Emissions			VMT by Cars with Air-Conditioning[a]	Estimated Emissions[b]
10^9 g	Region/Year	Reference	(10^9 mi)	(g/mi)
46.0	USA/1986	Ford[c]	1,200	0.038
31.5	USA/1985	EIA[d]	1,200	0.026
4.278	California/1990	CARB[e]	170	0.025
-- Calculation based on emissions from a single car --				0.031[f]

[a] Rough estimates are based on total vehicle-miles-traveled (VMT) data from *Highway Statistics* and vehicle air conditioner use data in Hammerle et al. (1988). I assume greater use of air-conditioning in California than nationally.

[b] Total grams from the first column, divided by total miles from the fourth column.

[c] Hammerle et al. (1988).

[d] EIA, *Potential Costs of Restricting Chlorofluorocarbon Use,* 1989 (includes manufacturing losses).

[e] CARB, *Review and Evaluation of Programs for the Reduction of Chlorofluorocarbon Emissions from Motor Vehicle Air Conditioning Systems, Volume 1, Executive Summary,* 1990 (includes manufacturing losses).

[f] According to Ford (Shiller, 1989), the amount of CFCs in a vehicle's air-conditioning system has declined from about 4 lb (prior to concern over CFCs and ozone) to a little under 3 lb in response to planned phase-outs of CFCs. I have assumed 2.6 lb. The CFC charge is changed out about twice over the life of an LDV, so that a total of three full charges are released (the last charge is released when the vehicle is scrapped). This amounts to 3,400 g over the average 108,000-mi life of an LDV, or 31.5 mg/mi. (Emissions from vehicle manufacturing and in-field system charging are small and can be ignored.)

estimate is consistent with estimates of aggregate CFC releases from the U.S. and California fleets (Table Q.1).

Vehicles without air-conditioning, of course, should be counted at 0 mg/mi. I assume that HDVs use the same amount of CFC-12 per mile as do LDVs.

Using a CFC-to-CO_2 conversion factor of 7,300 on a mass basis (Table 8), 31.5 mg/mi of CFC-12 results in 230 g/mi CO_2 equivalent. This is about 33% of the CO_2 equivalent of all other greenhouse gas emissions from the tailpipe of gasoline vehicles and more than 75% of the tailpipe CO_2-equivalent emissions from methanol and natural gas vehicles. Thus, replacing CFC-12 with a nongreenhouse gas would reduce the tailpipe and CFC greenhouse contribution of light-duty highway vehicles by a very large amount.

According to Ford (Hammerle et al., 1988), the automotive industry plans to eliminate CFC-12 as soon as possible. Ford states that existing CFC-12 facilities are being modified to produce a CFC-12 substitute, the fluorocarbon FC-134a ($C_2H_2F_4$). DuPont has a pilot plant producing developmental volumes of FC-134a for toxicity testing and market development (*Oil and Gas Journal*, September 5, 1989). This fluorocarbon has two environmental advantages over CFC-12: it does not contain chlorine and, hence, should not deplete stratospheric ozone; and, even though it has an infrared absorption band similar to that of CFC-12, it has a lifetime of only a few years (compared to over 100 years for CFC-12) and should not be as potent a greenhouse gas. Toxicology assessments of FC-134a should be completed by 1990, at which time replacement of CFC-12 could begin. Vehicle air-conditioning systems may have to be redesigned to accommodate FC-134a because it is somewhat less efficient at cooling than is CFC-12 (Hammerle et al., 1988). Ford also mentions the development of processes using water vapor rather than CFCs to produce foam for automotive applications.

Q.2 Ozone

Q.2.1 Background

Tropospheric ozone is a greenhouse gas, as well as a regulated oxidant pollutant. An important source of tropospheric ozone in the lower atmosphere in urban areas is the complex series of photochemical reactions involving reactive hydrocarbons (RHCs or NMHCs), nitrogen oxide (NO_x), and carbon monoxide (CO) emissions from highway vehicles and other fossil fuel combustion (Bolle et al., 1986).

The concentration of ozone near the earth's surface appears to be increasing, but there is no clear trend in the upper troposphere, where ozone is most effective as a greenhouse gas (Watson et al., 1990). In the mid- to high-latitudes of the Northern Hemisphere, an increase has been observed in the last two decades, particularly in the summer (Bolle et al., 1986), due at least in part to emissions of ozone precursors from airplanes, industry, and vehicles. Wang et al. (1985) and Campbell (1986) estimate that a doubling of the present tropospheric distribution of ozone would

raise the surface temperature by 0.9°C. Ramanathan et al. (1985) predict an 0.1°C increase as a result of a uniform 15% increase in tropospheric ozone from 0 to 9 km.

An absolute increase in ozone in the upper troposphere causes a much greater increase in the surface temperature than do ozone increases in other regions of the troposphere (Wang et al., 1985; Shine et al., 1990). Wang et al. (1985) imply that aircraft NO_x emissions are instrumental in elevating ozone levels. Similarly, Liu et al. (in Ramanathan et al., 1985) argue that most photochemical production of ozone occurs above the boundary layer, in the free troposphere, and that ground-level sources of NO_x are not important in ozone formation in the troposphere at an altitude of 2-8 km. If these claims are true, emissions of ozone precursors from vehicles would contribute little to greenhouse warming. On the other hand, Crutzen and Gidel (1983) claim that the upward transfer of photochemically active species from the polluted boundary layer to the free troposphere (via fast exchange episodes such as cyclones, thunderstorms, fronts, and intertropical convergence) was underestimated by the models and could contribute significantly to ozone formation and, ultimately, climate change.

The atmospheric chemistry and activity of ozone is complex (Crutzen and Gidel, 1983; Ramanathan et al., 1985; Wang et al., 1985; Bolle et al., 1986; Dickinson and Cicerone, 1986; Penner, 1990; Watson et al., 1990). Much remains to be learned about the production and destruction of ozone (all of the trace gases considered here, and others, are involved); the movement of ozone vertically and latitudinally within the troposphere, and between the stratosphere and the troposphere; the relationship between changes in the vertical and latitudinal distribution of ozone and the surface temperature (ozone, unlike the other trace gases, is not uniformly mixed in the troposphere); and the feedback effect on temperature of increasing temperature, changes in precipitation, and concentrations of other trace gases.

Q.2.2 Ozone from Vehicles

Ozone formation in the boundary layer due to vehicular emissions depends in part on the quantity and composition of hydrocarbon (HC) emissions (see Seinfeld, 1986 and 1989, for a discussion of the atmospheric chemistry). Enough is known about emissions of ozone precursors from petroleum-fueled vehicles and their atmospheric chemistry to support an estimate of the contribution of gasoline and diesel vehicles to ozone formation in urban areas in the lower troposphere. Less is known about the effect of methanol and electric vehicles (EVs), and next to nothing is known about the effect of natural gas, hydrogen, ethanol, and liquefied petroleum gas (LPG) vehicles.

Models of single- and multi-day ozone (smog) episodes have shown that methanol substitution for gasoline would reduce peak *urban* ozone levels (see Sperling and DeLuchi, 1991, for a review). The effect of methanol substitution on global climate would depend on the extent to which any reduction in ground-level urban ozone corresponded to a reduction in total global average ozone concentration in the middle and upper troposphere, and on the temperature effect of changes in the vertical distribution of ozone.

Emissions from optimized natural gas vehicles (NGVs) have not been completely characterized, and there is no model of ozone formation from NGV emissions. Qualitative analysis of what little is known suggests that NGVs might contribute slightly less to ozone formation in urban areas than methanol. Methane, the primary constituent of HC exhaust from NGVs, is essentially nonreactive and does not contribute to ozone formation in urban areas. The reactive HC emissions from NGVs appear to be, on the whole, less reactive than those from gasoline and methanol vehicles, although there are few data. This suggests that the use of natural gas would result in a moderate reduction in ozone formation in the boundary layer in urban areas, compared to gasoline, and a small reduction compared to methanol (see Sperling and DeLuchi, 1991, for a summary). But, as mentioned with regard to methanol, one must then determine the change in total (urban + rural + ocean) ozone, along with the change in the vertical distribution and global concentration of ozone resulting from changes in ozone in the boundary layer, and then estimate the associated temperature effects.

For at least two reasons, the use of EVs also could reduce ozone formation in the boundary layer in urban areas. First, power plants produce fewer nonmethane hydrocarbons (NMHCs) per mile of vehicle travel than gasoline and diesel vehicles, regardless of the fuel used at the power plant or the type of plant (Wang et al., 1990). Second, most of the emissions attributable to the use of EVs would occur at night, assuming that batteries were recharged overnight, and could be dispersed by nighttime air movement aloft before the irradiation necessary for ozone formation was most intense. Consistent with these expectations, models of ozone formation due to substitution of EVs for gasoline vehicles have shown very large decreases in ozone formation per EV or mile of travel (Hempel et al., 1989; Dowlatabadi et al., 1990).

However, while nighttime emissions may reduce smog formation in urban areas, they may not reduce ozone formation in the free troposphere because the boundary layer descends at night, and emissions from high stacks may be more likely to be carried to the free troposphere than are ground-level daytime emissions. And, since ozone is more effective as a greenhouse gas in the free troposphere than in the boundary layer, the use of EVs may not reduce the greenhouse effect of ozone as much as it reduces the concentration of ozone in urban areas.

A difficulty in applying the results of ozone-formation models to global warming is that the models calculate ozone concentration in urban areas, whereas in global warming we are interested in the global *average* ozone. Emissions of ozone precursors may leave an urban area and enhance ozone formation outside the area. A fuel that produces slowly reacting NMHC may reduce urban ozone, but may increase exurban ozone, because most of the photooxidation and ozone formation will occur after the NMHCs have left the urban area.

Q.2.3 Estimation of Ozone-Caused Warming from Vehicles

A formal modeling of the relationship between emissions of NMHC, NO_x, and CO and the concentration of ozone, and between ground-level ozone and global warming, is beyond the scope of this report and, in fact, would be quite complex. The IPCC (Shine et al., 1990) has provided very preliminary estimates of the global warming potential of ozone precursors, NMHC, NO_x, and CO, using relatively simple models of tropospheric chemistry. I use their values here. (I have

adjusted the NMHC factor to an NMHC-C factor; see Appendix O for further details.) Data on emission rates of NMHC, CO, and NO_x are from the U.S. Environmental Protection Agency's (EPA's) MOBILE4, EPA's AP-42, and studies of emissions from alternative-fuel vehicles relative to gasoline- and diesel-fuel vehicles (see Appendix B for more details).

Q.3 Water Vapor

The combustion of hydrogen-containing fuels -- gasoline, diesel fuel, methanol, and natural gas -- forms water vapor (H_2O). Water is much more abundant in the atmosphere than CO_2 and controls about 10 times more infrared radiation flux (Campbell, 1986; Dickinson and Cicerone, 1986; Mooney et al., 1987). However, the climatic effect of increased water vapor emissions is not easily determined because water vapor emissions can contribute to both global heating and cooling (Ramanathan, 1988), depending on the effect of the added vapor on global cloud cover, humidity, and precipitation. On one hand, water as vapor and clouds absorbs solar radiation and absorbs and emits thermal radiation (Dickinson and Cicerone, 1986). On the other hand, clouds reflect about 60% of the shortwave radiation they receive from the sun, causing net cooling at the surface. Very recent satellite research into the earth's radiation budget indicates that, on balance, reflection of shortwave radiation wins out, and clouds at present cause a net cooling of the earth (Ramanathan et al., 1989). However, realistic cloud effects have not yet been incorporated into greenhouse models (Kerr, 1989). Modeling the feedback effects of the warming on cloud formation will be especially difficult (Ramanathan et al., 1989).

In any event, my calculations indicate that water vapor emissions from current fossil fuel use (the direct contribution, not accounting for any feedback effects on evaporation) are negligible -- about 0.05% of the average amount of water in the atmosphere and 0.0013% of current global evaporation (DeLuchi, Sperling, and Johnston [1987]). I therefore ignore water vapor emissions from highway vehicles.

With solar-electrolytic hydrogen, there is no net emission of water because the hydrogen is made from water and then emitted as water. There will be changes in the distribution and form of water -- the hydrogen will be made from liquid water in one location and then emitted as water vapor in a different location -- but the total amount of water vapor emitted will be quite small compared to global evaporation (DeLuchi, et al., *A Comparative Analysis of Future Transportation Fuels,* 1987).

Appendix R:

Scenarios for Europe and Japan

Appendix R:

Scenarios for Europe and Japan

R.1 Introduction

The base-case input parameters are meant to represent the United States in 2000. To obtain emission results for countries other than the United States, important input variables in the model must be changed to represent the pertinent country or region. To model Japan and Europe, I changed the major input variables pertaining to (1) emissions from electricity generation, (2) emissions from petroleum refining, (3) tailpipe and evaporative emissions from gasoline and diesel-fuel vehicles, (4) tailpipe and evaporative emissions from alternative-fuel vehicles, (5) methane emissions from coal mining, and (6) fuel and feedstock transportation. These changes are discussed next. To model Canada, I assumed that all the base-case United States data apply, except the national average electricity mix.

R.2 Greenhouse Gas Emissions from Electricity Generation in Europe and Japan

To calculate greenhouse gas emissions from the generation of electricity used for a particular process (e.g., petroleum refining), one must know in what countries the process is done, the mix of fuels used to generate the electricity and the efficiency of electricity generation in those countries, and the emission factors for power plants in those countries. (This method follows the method used for the U. S. base case; see Appendix D.) In this section, these data are developed for the European and Japanese emission scenarios.

R.2.1 Geographic Distribution of Electricity-Consuming Processes Related to Fuel Use and Vehicle Use in Europe and Japan

Table R.1 shows the distribution of petroleum refining, uranium enrichment, and automobile manufacturing done for the countries of the European Economic Community (EEC) in 1988 and 1989. I assume that the distribution will be the same in 2000. To simplify the analysis, I assume that all the uranium nuclear fuel used in Japan is enriched in the United States, but that all the automobiles used in Japan are made in Japan and all the gasoline and diesel fuel used in Japan are produced in Japan.

TABLE R.1 Geographic Distribution of Electricity-Using Processes Pertaining to Use of Vehicles and Fuels in Europe, 1988-1989

Process	Fraction of Each Process that Is Done in the Following Countries						
	U.K.	Japan	Germany	France	Italy	U. S.	Nether-lands
Auto manufacture[a]	0.10	0.05	0.30	0.25	0.15	0.15	0.00
Petroleum refining[b]	0.20	0.00	0.20	0.20	0.20	0.20	0.20
Uranium enrichment[c]	0.00	0.00	0.00	0.85	0.00	0.15	0.00

[a] The auto-manufacturing shares are calculated from data on world motor-vehicle production (Motor Vehicle Manufacturer's Association, 1990).

[b] The petroleum-refining shares are based on the total petroleum-refining capacity of European countries (IEA, *Energy Statistics of OECD Countries, 1987-1988*, 1990).

[c] The uranium-enrichment shares are calculated from data in EIA, *World Nuclear Fuel Cycle Requirements* (1990). (EURODIF, the main enrichment facility in Europe, is in France.)

R.2.2 Electricity Generation Shares by Fuel Type, Electricity Generation, and Distribution Efficiency

Table R.2 shows projections of generation shares by fuel type and of generation and distribution efficiencies for Japan and countries in Europe in 2000. Note that the estimates in Table R.2 are the power mix used for all purposes in each country (the national "average" mix), not the power mix likely to be used for any specific purpose within those countries. Therefore, they are comparable to the United States average or generic power mix in Table 6.

R.2.3 Emission Factors for Electricity Generation

Emission factors for electricity generation (g/10^6 Btu-fuel input, as per Table D.4) vary from country to country. (See IEA, *Electricity Controls in Electricity Generation and Industry*, 1988, for a summary of emission standards in Europe.) The IEA (1991) projected carbon monoxide (CO) and nitrogen oxides (NO_X) emission factors for electricity generation in Europe and the Pacific in 2005. I have used these projections (to represent 2000), along with the

TABLE R.2 Projected Electricity-Generation Shares by Fuel Type and Projected Electricity-Generation Efficiency in Europe and Japan for the Year 2000

	Generation by Type of Fuel[a]				Efficiency of Electricity Generation and Distribution[b]		
Country	Coal	NG	Oil	Nuclear	Coal	NG	Oil
Canada	0.18	0.03	0.04	0.16	0.34	0.42	0.39
France	0.08	0.01	0.02	0.70	0.33	0.53	0.30
Germany	0.50	0.06	0.04	0.33	0.33	0.33	0.41
Japan	0.19	0.17	0.14	0.38	0.41	0.41	0.42
Sweden	0.03	0.01	0.02	0.43	0.19	0.20	0.24
United Kingdom	0.70	0.01	0.09	0.18	0.32	0.26	0.32
EEC-wide[c]	0.41	0.15	0.07	0.16	0.33	0.36	0.34

[a] The generation shares were calculated from each country's projection of its mix of fuels input to electricity generation in the year 2000 (International Energy Agency, *Energy Policies and Programmes of IEA Countries*, 1989), except in the case of France. The value for France is its actual 1987 mix as shown in IEA, *Energy Balances of OECD Countries, 1986-1987* (1989).

[b] I calculated the efficiency of electricity generation for each fuel in each country in 1987 on the basis of data in the IEA report, *Energy Balances of OECD Countries, 1986-1987* (1989) (converted from lower to higher heating values), then assumed that electricity generation and distribution will be 5% more efficient (in relative terms) in the year 2000 than it was in 1987.

[c] The estimate of EEC-wide generation and distribution efficiency is my own. EEC = European Economic Community.

base-case U. S. emission factors for methane (CH_4), nitrous oxide (N_2O), and nonmethane organic compounds (NMOC) (Table R.3). Note that the IEA's NO_x emission factors are lower than my projections for the United States (Table D.4).

R.3 Emissions from Petroleum Refineries in Europe and Japan

Emissions from refineries in Europe and Japan are a function of the mix of fuels used to generate process heat, the amount of fuel used to produce a particular product, and the emission factors for refinery boilers.

TABLE R.3 Projected Emission Factors for Electricity Generation in Europe and the Pacific, by Fuel Type, in Grams of Pollutant per 10^6 Btu of Fuel Input[a]

	Europe				Pacific (Japan)			
Pollutant	NG	NG	Oil	Coal	NG	NG	Oil	Coal
CO	24	24	6	50	24	24	6	50
NO_X	97	97	96	174	24	24	56	190
CH_4, N_2O, NMOCs	-- Same as Table D.4 --				-- Same as Table D.4 --			

[a] Emission factors are given on a higher-heating-value basis. The CO and NO_X emission factors are IEA (1991) projections for the year 2005. The CH_4, N_2O, and NMOC emission factors are assumed to be the same as projected here for the United States in the year 2000 (Table D.4).

[b] I assume that 75% of the natural gas used as a power plant fuel is burned in boilers in the year 2000.

I assume that in 2000, refineries in Europe and Japan will produce low-sulfur diesel fuel, and standard, unleaded, nonreformulated gasoline. I assume standard gasoline but low-sulfur diesel fuel because, according to a comprehensive review of fuel quality and emissions regulations in Europe (McAarragher et al., 1990), there are, at the moment, no hard plans to introduce reformulated gasoline in Europe. However, it appears that low-sulfur diesel fuel will be required by the mid to late 1990s.

R.3.1 Fuel Use by Refineries

I project the mix of fuels used by refineries in Europe and the Pacific (the Pacific is used here to represent Japan) by using 1988 data from the International Energy Agency (IEA, *Energy Statistics of OECD Countries, 1987-1988,* 1990). The 1988 data are shown in Table R.4. In Table R.4, I have included the IEA's estimates of fuel used by refineries in the United States for comparison with the EIA data used in this report (Table H.4). The IEA data for the United States (Table R.4) are reasonably consistent with the EIA data used here.

I use the "Energy %" results in Table R.4 for 1988 to represent the mix of fuels used by refineries in Europe and the Pacific in 2000. To calculate the energy intensity of refineries in Europe, in Btu of process fuel per Btu of product, additional analysis is required. European refineries probably consume less energy per Btu of gasoline produced than do refineries in the United States because they produce less gasoline per barrel of crude (and the average process

TABLE R.4 Fuel Use by Refineries in Europe and the Pacific, 1988[a]

Process Fuel Used at Refinery[b]	EEC[c] Energy Use[d]	EEC[c] % of Energy[e]	United States Energy Use[d]	United States % of Energy[e]	Pacific Region Energy Use[d]	Pacific Region % of Energy[e]
NG + coke gas (10^9 cal)	11,424	3.41	157,365	21.09	2,445	1.83
Refinery gas (10^3 t)	12,385	47.18	32,951	56.32	7,575	72.29
LPG (10^3 t)	193	0.68	962	1.51	8	0.07
Coke (10^3 t)	3,330	8.32	14,478	16.23	419	2.62
Oil (10^3 t)	11,143	35.11	583	0.82	2,384	18.82
Electricity (gWh)	20,676	5.31	34,966	4.03	6,788	4.37
Total quads used	1.33	100.00	2.96	100.00	0.53	100.00
Total crude + NGL refinery input (quads)[f]	22.94		31.12		7.98	
Ratio of fuel use to total input (%)[g]		5.79		9.52		6.64

[a] The data on the amount of each process fuel consumed are from the IEA report, *Energy Statistics of OECD Countries, 1987-1988* (1990). I converted these data from the units shown to quads by using the heating values of Tables C.1 and C.3.

[b] t = metric ton (1,000 kilograms) and cal = calorie.

[c] EEC = European Economic Community.

[d] The amount of fuel used in 1988, in the units indicated.

[e] For each fuel, the energy % is equal to the amount of Btu of that fuel used by refineries divided by the total amount of Btu of fuel used by refineries, multiplied by 100.

[f] Calculated from the following data on refinery input:

	EEC	United States	Pacific
Crude input (10^3t)	524,563	701,269	183,833
NGL input (10^3 t)	5,075	16,230	564

From IEA, *Energy Statistics of OECD Countries, 1987-1988* (1990).

[g] Total quads of fuel used by refineries for process energy, divided by total quads of crude oil and natural gas liquids input to refineries, multiplied by 100.

energy per Btu of gasoline increases as the gasoline yield increases) and, in particular, less unleaded gasoline.

Note that the data of Table R.4, which show that European refineries consume much less energy per barrel of crude input than U. S. refineries, do not by themselves show that European refineries consume less energy per barrel of any individual product because, in Europe, a much larger fraction of the crude input is converted into products, such as diesel and residual fuel, that require relatively little energy to make (EIA, *Energy Statistics of OECD Countries, 1987-1988,* 1990). The low overall energy consumption of European refineries is thus explained, at least in part, by the output mix. However, my own calculations indicate that European refineries also consume less energy per barrel of product, at least for now.

Forthcoming tailpipe-emissions regulations in Europe will require the use of a catalytic converter, which in turn will require the use of unleaded gasoline. This will increase energy requirements. On the other hand, Europeans will likely continue to use much more diesel fuel than do Americans, and this situation will tend to keep energy requirements per Btu of gasoline lower in Europe. I assume 0.12 Btu of process fuel per Btu of gasoline in Europe in 2000. For low-sulfur diesel fuel, I assume the same value as in the United States.

R.3.2 Emission Factors for Refinery Boilers

To calculate emissions from refinery boilers in Japan and Europe, I use the base-case emission factors for refinery boilers in the United States for all pollutants except NO_x (Table A.2). For NO_x, I use projections made by the IEA (1991) for 2005 to represent the year 2000 (Table R.5).

R.4 Emissions from Gasoline Light-Duty Vehicles and Diesel-Fuel Heavy-Duty Vehicles in Europe and Japan

Presently, exhaust emission standards are much more lax in Europe than in North America. However, the European community is finalizing relatively stringent new motor vehicle emissions standards (McAllagher et al., 1990). Considering these standards, the IEA (1991) has used the U. S. Environmental Protection Agency (EPA) MOBILE4 emissions model to project CO, CH_4, and NO_x emission factors for motor vehicles in Europe in 2005. These projections are shown in Table R.6. Since the IEA (1991) did not project NMOC emissions, I estimated tailpipe and evaporative NMOC emissions in Europe using the EPA's MOBILE4 emission model. I specified the input parameters to MOBILE4 so that it approximately reproduced the IEA's projected emission factors for CO, NO_x, and CH_4 (Table R.6), then used the corresponding MOBILE4 NMOC emission factor. I assume that vehicles in Europe will use three-way catalytic converters, so they will emit about the same amount of N_2O as that projected here for vehicles in the United States in 2000.

TABLE R.5 Projected NO_x Emission Factors for Refinery Boilers in Europe and the Pacific for the Year 2005, in Grams per 10^6 Btu of Fuel Input[a]

Boiler	Europe	Pacific
NG boiler	37.8	13.0
Oil boiler	96.0	0.0

[a] Calculated by multiplying the base-case NO_x emission factor for industrial boilers (Table A.2) by the ratio of the IEA (1991) projection of the NO_x emission factor for European and Japanese refinery boilers in 2005 to its projection of the factor for U. S. refinery boilers in 2005. I use the IEA's "Pacific" factors to represent Japan.

TABLE R.6 Projected Emission Factors for Light-Duty Gasoline Vehicles and Heavy-Duty Diesel Vehicles in Europe, in Grams per Mile[a]

Pollutant	LDGV	HDDV
CH_4	0.14	0.16
CO	14.5	8.05
NO_x	1.29	27.40
Tailpipe NMOC	1.00	2.50
Evaporative NMOC	1.65	0.00
N_2O	0.06	0.06

[a] CH_4, CO, and NO_x emission factors are the IEA (1991) projections for Europe in 2005. Tailpipe and evaporative NMOC emission factors are from my run of MOBILE4, set to reproduce the IEA's projected European emission factors. The N_2O emission factors are from Table B.2.

I assume that Japan will adopt the new emissions standards mandated by the U.S. Clean Air Act (CAA), and that as a consequence, vehicles in Japan will have the same emission factors as projected here for vehicles in the United States in 2000 (Table B.2).

The IEA's (1991) projections for the United States do not account for the new CAA legislation affecting motor vehicles. Thus, if any country in Europe adopts the new U. S. standards, vehicles in those countries will have emission factors lower than those shown here. I did not account for this possibility.

Evaporative emissions from gasoline vehicles are a function of the volatility of gasoline and the extent and effectiveness of emission controls. There are no strict limits on gasoline volatility in Europe or Japan. However, the European community is planning to control evaporative emissions from both vehicles and Stage I fuel restocking at service stations. Some European countries are considering controlling emissions from refueling vehicles. Therefore, to estimate evaporative emissions in Europe in 2000, I reran the EPA's MOBILE4 model and my own model of upstream evaporative emissions, assuming that gasoline has an RVP of 11.5, that emissions from refueling

vehicles are controlled beginning in 1998, and that Stage I refueling is controlled. Because vehicular and upstream evaporative emissions of gasoline are a relatively minor source of greenhouse gases, I have not shown the new European results here.

R.5 Emissions from Alternative-Fuel Vehicles in Europe and Japan

I establish two cases for alternative-fuel LDVs: a stoichiometric case and a lean-burn case. In the stoichiometric case, I use the base-case relative thermal efficiency values in Table 2. I assume that all alternative-fuel LDVs in Europe and Japan emit the same amount of NO_X as gasoline LDVs in Europe and Japan, and that alcohol-fuel LDVs emit the same amount of CO as the gasoline LDVs, but that gaseous-fuel LDVs emit less CO than gasoline LDVs. I scale NMOC and CH_4 emissions so that the ratio of emissions from alternative-fuel LDVs to emissions from gasoline LDVs is the same as it is in the U.S. base case.

Because the new EEC standards will not be nearly as strict as the new U.S. CAA standards, lean-burn alternative-fuel LDVs might be able to meet the new EEC NO_X standard. In the lean-burn case for alternative-fuel vehicles in the EEC, I assume that their relative thermal efficiency improves by 10 absolute percentage points over the values in Table 2 (e.g., methanol goes from +15% to +25%), and that CO emissions are less than in the stoichiometric case — significantly less in the liquefied petroleum gas and compressed natural gas cases. I assume that NMOC and CH_4 emissions are 25% lower than in the EEC stoichiometric case for alternative-fuel vehicles.

I assume that alternative-fuel HDVs will have lower NO_X emissions than EEC diesel HDVs because the IEA emission projections for diesel HDVs are quite high, and alternative-fuel HDVs can produce lower NO_X emissions when the NO_X standard is not constraining all vehicles to the same emission level. I assume that alternative-fuel HDVs will emit more CO and NMOCs than will diesel HDVs. I calculated evaporative emissions on the basis of the relative volatility and the molecular vapor weight of the alternative fuel (Appendix B), and I estimated tailpipe NMOC emissions relative to NMOC from gasoline vehicles.

For all cases and all countries, I use the N_2O emission factors in Table B.2 because N_2O is formed on a three-way catalyst.

For all countries, I assume the base-case U. S. electric vehicle characteristics.

R.6 Methane Emissions from Coal Mining in Europe and Japan

Most of the coal used in Japan is imported from Australia (EIA, *International Energy Annual*, 1991). The methane emission factor for coal produced in Australia is about 300 ft^3/ton (ICF, *Methane Emissions*, 1990). The average for coal produced in and imported to Europe is about 450 ft^3/ton-produced (ICF, *Methane Emissions*, 1990). I use these values here for the year 2000 analysis.

R.7 Feedstock Production and Feedstock and Fuel Transport Patterns in Europe and Japan

To model feedstock and fuel transportation patterns in Europe and Japan, I used data on international production and movement of coal, oil, and gas as reported by the EIA (*International Energy Annual*, 1991).

R.7.1 Coal

I assume that Europe produces most of the coal it consumes but that it imports some coal from the United States by dry bulk carriers. I assume that rail transport distances for coal are shorter in Europe than in the United States. For coal use in Japan, I assume that most coal is imported from Australia and that rail transport distances within Japan are very short.

R.7.2 Crude Oil and Petroleum Products

I assume that Europe imports a greater fraction of the total crude oil it uses than does the United States. I assume that pipeline transport distances for both crude oil and petroleum products are shorter in Europe than they are in the United States. I also assume that truck transport is not as long in Europe as in the United States, because Europe is more densely settled than the United States. In Japan, I assume that most oil is imported from the Middle East and that pipeline transport distances within Japan are very short.

R.7.3 Natural Gas

For natural gas (NG) use in Europe, I use the base-case U. S. values for production and transport. Natural gas fields in Western Europe are closer to major consumers than are NG fields in the United States, but Europe also imports a lot of NG from the U.S.S.R., and this NG must be piped a long distance to end users in Europe. In Japan, I assume that all gas is imported as liquefied natural gas from the South Pacific.

Appendix S:

References for Volumes 1 and 2

Appendix S:

References for Volumes 1 and 2*

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