TABLE C.1 (Cont.)

[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: ARCO EC-1[d]	ARCO No-Lead[d]	Summer Grade[e]	Winter Grade[e]	Yearly Average[f]	Reform-ulated[g]	Diesel: 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.)

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[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.)

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[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.)

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[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.)

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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.)

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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

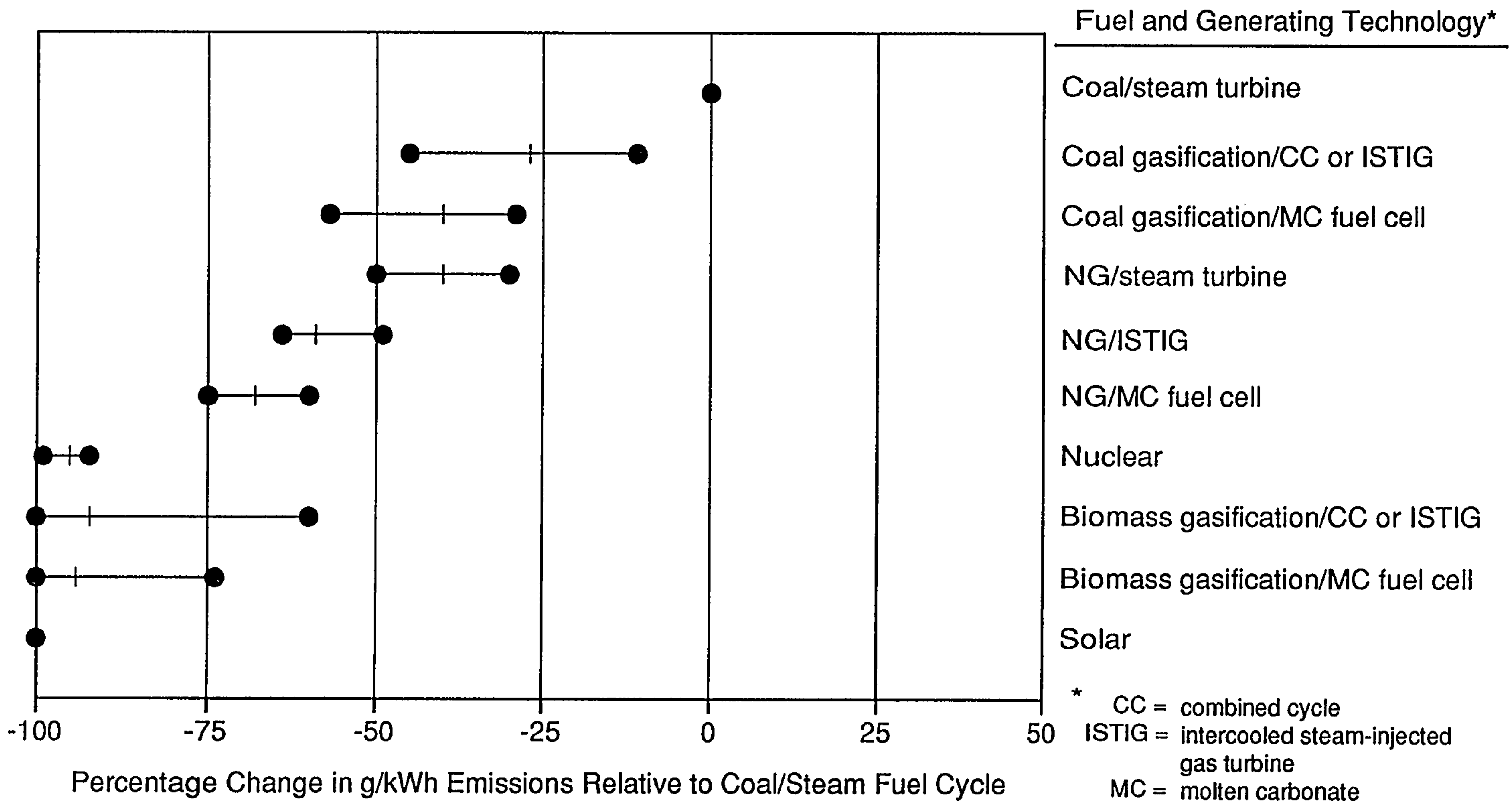
Units are grams of CO_2-equivalent emissions per kWh delivered to end users. Assumes 92% distribution efficiency. Includes N_2O emissions from corona discharge from high-voltage transmissions lines (Table D.4). Based on 100-year time horizon (Table 8).

[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.



* CC = combined cycle
ISTIG = intercooled steam-injected gas turbine
MC = molten carbonate

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.)

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[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.)

[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

	Calculated	Input	Input	Input Fraction of Ships in Each dwt Class[d]					
dwt Class	Relative Payload	Btu/ ton-mile[a]	Relative Distance[b]	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

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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).