Several problems arise in calculating energy use from the survey data. First, the Census Bureau withholds fuel consumption data for some sub-activities in the industries. In a few instances this is done because the data are poor, but most often the data are withheld because only one company was involved in the activity and the Census Bureau cannot disclose data about an individual firm. These data have to be estimated. I discuss particular difficulties as they arise for particular fuels (see notes to the tables in pertinent appendixes).

Second, some companies do not report detailed data on fuel use, and some small companies are not surveyed. The Census Bureau estimates the value, but not the quantity or types, of the fuel used by these companies (this is called undistributed fuel; electricity apparently is not included). If one assumes that the energy used by the companies that did not report detailed data or were not surveyed, comprised fuels in the same proportions as did the energy used by companies that reported detailed data, then one can scale up the amount of reported fuel use by the ratio of the total value of all fuels (the estimated value of undistributed fuels plus the reported value of detailed fuels) to the value reported for detailed fuels. An indication that this is assumption is reasonable is that the 10^6 Btu/$ value the Census Bureau uses for undistributed fuels is very close to the value implicit in my assumption.

Similarly, the census estimates the value, but not the quantity, of a small proportion of total production (e.g., tons of coal) by mineral industries. The total quantity of production (reported plus unreported production) can be estimated by scaling reported production by the ratio of total value to reported value.

Third, the Census Bureau lumps Liquefied Petroleum Gas (LPG), coke, wood, and other minor fuels together into an "other" category, and reports the cost of these other fuels, but not their energy content. To calculate greenhouse gas emissions, one must convert this expenditure on other fuels to a physical or energy amount of a specific kind of fuel. I do this in several steps. First, I convert the dollars spent on other fuels into energy units by using the Census Bureau's 10^6 Btu/$ factor for other fuels (Table F.1). Then, I scale this estimate of other fuels by the factor, discussed above, that accounts for undistributed fuels. Finally, on the assumption that most of the other fuels are LPG or coke and so would have an average carbon content similar to that of diesel fuel, I assign the energy embodied in other fuels to diesel fuel. (I note, too, that the Census Bureau 10^6 Btu/$ factor for other fuels is close to the Census Bureau's 10^6 Btu/$ factor for diesel fuel.) Since, in most cases, industries consume only small amounts of other fuels, minor errors in estimating greenhouse gas emissions from other fuels are tolerable.

Fourth, the Census does not always cover every activity related to the industry. For example, the coal mining survey covers mining, preparation, coal cleaning, and coal mining services (which perform such things as overburden removal), but does not appear to include reclamation services. I have ignored such errors of omission on the assumption that they are unimportant.

TABLE F.1 Data Used to Adjust Census Data on Energy Used to Recover Coal

SIC area	\$ Purchased Fuels[a] per \$ Distributed Fuels[c] 1982	\$ Purchased Fuels[a] per \$ Distributed Fuels[c] 1987	\$ All Products[b] per \$ Distributed Products[d] 1982	\$ All Products[b] per \$ Distributed Products[d] 1987
Bituminous coal mining	1.049	1.332	1.087	1.086
Anthracite coal mining	(use rates for bituminous)	- -	1.063	1.060

Also: 0.137 × 10^6/\$ of other fuels 1982 (value used by the Census) and 0.161 × 10^6 Btu/\$ of other fuels 1987 (value used by the Census).

Sources: Publications from the U. S. Department of the Commerce, Bureau of the Census: *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985); *1987 Census of Mineral Industries, Coal Mining* (1990).

[a] The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies not surveyed (the Census estimated the value for these companies) and by companies that did not report how much of each kind of fuel they used.

[b] The total dollar value of all products (crude oil, dry gas, NGLs, uranium ore, etc.) of all companies engaged in the activity, including products from companies not surveyed (the Census estimated production for these companies), and products from companies that did not classify or detail their products (e.g., did not state what kind of coal they produced).

[c] The dollar value of the fuels purchased by companies that reported the amount of each kind of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only total cost of purchased fuels, with no breakdown or details.

[d] The dollar value of products of those companies that reported the amount and kind of each product.

Fifth, some estimates are not disaggregated sufficiently for my purposes. For example, the survey reports energy used by metal mining services, but does not disaggregate the services or the energy by the type of metal mining (e.g., uranium, iron, bauxite, etc.). More seriously, energy use in oil and gas extraction is reported together. Fortunately, there are plausible ways to disaggregate these values, as I discuss in appendixes pertaining to particular fuels, such as Appendix H (petroleum), Appendix G (natural gas), and Appendix I (nuclear energy).

F.3 Energy Used to Mine and Prepare Coal

Table F.2 shows the results of my analysis of the U.S. Bureau of the Census survey of energy use in coal mining. The analysis indicates that very little energy is used to mine and prepare coal — less than 1% of the energy available in the coal (Table F.3).

F.3.1 Comparison with Other Data

The Census Bureau data can be compared with engineering estimates of energy use in the U.S. Department of Energy's (DOE's) *Energy Technology Characterizations Handbook* (1983). The DOE *Handbook* gives diesel and electricity requirements for reference eastern underground mines and eastern and western surface mines. These per-mine values can be scaled up to total underground, western surface, and eastern surface coal production in the United States in 1982, and checked against the Census Bureau figures (I assume that western underground mines, which the DOE did not characterize, have the same energy requirements as eastern underground mines). As shown below, these scaled-up values are very close to the Census Bureau data used here.

According to the Energy Information Administration's (EIA's) *Coal Production — 1992* (EIA, 1983), 337.010 × 10^6 ton of coal was produced at underground mines in the U. S. (mostly in Appalachia), 248.068 × 10^6 ton at surface mines west of the Mississippi, and 247.446 × 10^6 ton at surface mines in the East. Scaling up the DOE *Handbook* (1983) figures to these national production levels yields:

	Underground	East Surf.	West Surf.	Total
Electricity, 10^6 kWh	13,233	1567	23	14,823
Diesel, 10^3 barrels	307	17,800	2,506	20,613
Total quads				0.171
Total quads from 1982 Census, used here				0.150

The total energy figures are reasonably close. The DOE *Handbook* 1983 figures include coal preparation but not beneficiation, which is treated separately. Since it is not clear if beneficiation is included in the Census Bureau data (the Standard Industrial Classification of coal mining does not mention it specifically) and to what extent the process is used, I have ignored it.

TABLE F.2 Energy Used to Mine and Clean Coal

	1982		1987	
Fuel Used	Units	Energy (%)	Units	Energy (%)
Crude oil (10^3 bbl)	0.0	0.00	0.0	0.00
Diesel (10^3 bbl)[a]	11,955.9	46.50	13,272.0	47.58
Residual (10^3 bbl)	1,606.0[b]	.74	1,246.6	4.82
Natural gas (10^9 ft^3)	0.8	0.58	1.5	0.93
Coal (10^3 tons)	378.3	5.39	446.0	5.86
Electricity (10^6 kWh)	5,300.6[c]	34.86	7,458.2[c]	36.66
Gasoline (10^6 gal)	66.4	5.55	43.7	3.36
Other (10^6 \$)	4.2	0.38	7.9	0.78
Total energy (quads)	0.150	100.00	0.162	100.00
USDOC production totals (10^6 tons)	853.8		931.9	
EIA production[c] totals (10^6 tons)	838.1		918.8	

Sources: See those listed for Table F.1.

[a] I assigned half of the diesel fuel used in coal mining to scraping equipment and half to loading equipment by using EPA AP-42 emission factors for each (Table A.1).

[b] The use of residual fuel in anthracite mining in 1982 was not disclosed. I estimated this by multiplying diesel fuel use in anthracite mining by the ratio of residual fuel use to diesel fuel use in bituminous and lignite mining.

[c] Coal mines generated and sold an undisclosed amount of electricity in 1982 and 1987. These electricity sales should be subtracted from the amount purchased. I estimated electricity sales in coal mining by using data on electricity purchased and sold in all mineral industries.

[d] From EIA, *Coal Production* (1983, 1988). The correct Census figure to compare with the EIA data is the sum of reported net tonnage shipments of all coal (lignite, bituminous, and anthracite) and coal not specified by kind (n.s.k.). Coal n.s.k. is coal whose value but not weight was reported to the Census. According to the Minerals Branch of the Census, the amount of coal n.s.k., as a percentage of reported net shipments, is roughly equal to the value of n.s.k coal as a percentage of the value of all reported net tonnage — about 10% (Roy Frank, October 12, 1989).

TABLE F.3 Coal Production and Consumption Sheet

Item	1982	1987
Production (10^3 tons)[a]	853,766	930,996
Own use (10^3 tons)[b]	4,606	5,261
Net consumption (10^3 tons)[c]	849,160	925,735
Net consumption (quads)	18.12	19.76
Production/consumption[d]	1.0054	1.0057
Production efficiency[e]	0.0083	0.0082

[a] From Table F.2.

[b] The amount of coal used at coal mines, as shown in Table F.2, plus the amount of coal used at electricity plants supplying power to coal mines, assuming coal mines draw from the national average power mix. Does not include coal used to make electricity used by refineries making diesel fuel used by trains to deliver coal, and similar third-order own use, because the amount is negligible.

[c] Production minus own use.

[d] The ratio of coal produced to coal available to end users. This ratio is used to convert methane emissions per ton of coal produced to methane emissions per ton of coal to end users. See Appendix M.

[e] Total energy used at coal mines, as shown in Table F.2, divided by quads of net consumption.

Note, too, that the amount of coal production reported to the Census Bureau is about the same as the amount reported to the EIA (Table F.2). This agreement indicates that the Census Bureau data are fairly reliable.

F.4 Energy Used to Transport Coal

The amount of energy used to transport coal is the sum of the amount used by trains, trucks, ships, and coal slurry pipelines (see Table E.1). Trucks and trains use diesel fuel, ships use residual fuel oil, and slurry pipelines use electricity. For each of these modes, the total amount of energy consumed is equal to the Btu/ton-mile energy intensity of the mode multiplied by total coal tonnage carried by the mode and the average length of haul. Btu/ton-mile data are compiled in Table E.2 and discussed in Appendix E. In this section, I calculate the amount of coal hauled by each mode and the average length of shipment.

F.4.1 Tons of Coal Shipped, by Mode

I use data from the EIA's *Coal Distribution* (1988), which reports coal tonnage shipped by rail, water and truck, as stated by coal distributors themselves. I have counted all coal distributed domestically, coal distributed to the Canadian border, and all secondary forms of transportation (the mode of shipment to lakes, rivers, or coastal ports). For coal exported overseas, I count shipment to the U. S. coast, but not beyond.

Pipeline tonnage data are from the *Transportation Energy Data Book* (Davis and Hu, 1991) for the Black Mesa pipeline, which is the only coal slurry pipeline operating. (*Coal Distribution* [1988] lumps pipeline tonnage with tramway and conveyor belt tonnage.)

The EIA's *Coal Distribution* estimates of tons of coal exported and tons of coal produced in the United States are consistent with the figures reported in the EIA's *Annual Review of Energy*. The 1987 *Coal Distribution* estimate of tons of coal shipped by rail (counting rail as both a primary and a secondary means of transportation) agrees to within better than 5% with the estimate in the Federal Railroad Administration's (USDOT, 1987) *1987 Carload Waybill Statistics*. (The *Waybill Statistics* are independent samples of railroad commodity movements.) The railroad data in the *Coal Distribution* report thus appear to be quite reliable.

Waterborne Commerce of the United States, Calendar Year 1986 (U. S. Department of Army, 1987) reports a significantly larger tonnage of coal moved on lakes and rivers than does the EIA. This discrepancy is probably due to different definitions and categories. The two sources agree on tons of coal exported overseas.

F.4.2 Average Length of Haul

The EIA does not report mileage data for coal movement by rail. However, the *1987 Carload Waybill Statistics* (U. S. DOT, 1989) reports both tons and ton-miles of coal movement by rail. As noted above, the USDOT tonnage estimates agree with the EIA's tonnage estimates, which suggests that it is consistent to calculate the average length of haul from the *Waybill Statistics* and apply it to the EIA data. The result is 490 mi in 1987 (478 mi in 1982).

The Clean Air Act's (CAA)'s) limits on sulfur emissions from coal-fired plants will likely induce the greater use of low-sulfur western coal (EIA, *Improving Technology*, 1991; they estimate that the share of Western coal will increase from about 40% to about 50%, due to the CAA). On average, western coal fields are located further from power plants than are eastern coal fields, and hence the greater use of western coal will increase the average length of haul by rail. Therefore, I assume that the average haul in 2000 is somewhat longer than at present.

Waterborne Commerce of the United States (U. S. Department of Army, 1988, 1989) reports that coal was shipped an average of 446 mi by water in 1987 and 456 in 1986. The DOE

Handbook (1983) assumes 190 mi one-way for eastern barges and 400 mi one-way for western barges. I use 450 mi (it is probably the best raw data available).

The DOE *Handbook* (1983) assumes 60 mi round-trip per coal-delivery truck. I will use this value.

The Black Mesa coal slurry pipeline is 273 mi long, according to the *Transportation Energy Data Book*, and USDOT's *National Energy Transportation Study* (1980). I have assumed a length of 300 mi to account for the coal shipped by tramway and conveyor belt.

For comparison, The *National Energy Transportation Report* (U. S. CRS, 1977) reports average miles of coal haul for railroads, water, and road as 300, 480, and 50-75 (p. 62).

My assumptions for Btu/ton-mile, tonnage, and average length of haul are shown in Table E.1.

F.4.3 Energy Used to Dispose of Coal Ash

In the United States, coal contains about 10% ash by weight, on average (EIA, *Coal Data, 1989*). The ash does not burn and must be gathered up and disposed of. In addition, the sludge from flue-gas desulfurization units must be disposed of. In 1984, U. S. electric utilities generated about 69 10^6 ton of coal ash and 16 10^6 ton of FGD sludge, for a total of 85 10^6 ton (EPA, *Wastes from the Combustion of Coal...* 1987). In the greenhouse gas emissions model, this quantity is approximated as the product of the weight of coal and the ash weight fraction.

However, relatively little waste is trucked off site for disposal; most generating stations dispose of or recycle their waste on site (EPA, *Wastes from the Combustion of Coal...*, 1987). I assume that this disposal occurs at essentially no additional energy cost, and so multiply the quantity of waste generated by a small factor representing the quantity disposed off site. Moreover, the small amount of waste shipped off-site probably goes to the nearest landfill, mine, or surface impoundment. I assume 50 mi round trip by the disposal trucks.

F.5 Coal Available for Consumption, and Production and Transportation Efficiency

The calculation of the amount of coal made available to end users is straightforward: it is equal to the amount of coal produced, less the amount used at coal mines and at coal-fired power plants supplying electricity to the coal-production and transportation cycle. This is shown in Table F.3. In the case of coal, there are no losses or product transformations to account for.

Total energy used in coal mining divided by total coal energy available to end users for 1982 and 1987, is shown in Table F.3. Note that the ratios for 1982 and 1987 are virtually identical. Total energy used in coal transportation divided by total coal energy available to end users for 1987 is shown in Table E.1.

Table F.3 also shows the ratio of coal produced to coal available to end users. This ratio is used to convert methane emissions per ton of coal produced to methane emissions per ton of coal to end users (see Appendix M).

Appendix G:

Natural Gas and Natural Gas Liquids

Appendix G:

Natural Gas and Natural Gas Liquids

G.1 Overview

Raw natural gas (NG) is a mixture of hydrocarbons, water, nitrogen (N_2), carbon dioxide (CO_2), and often sulfurous compounds. The proportions of these compounds vary considerably from place to place, from nearly pure methane to mostly inert compounds (CO_2, nitrogen, and water) and contaminants. NG is found onshore and offshore by itself in gas-only fields and in association with petroleum. The Gulf Coast states produce most of the NG in the United States.

To be shipped in a pipeline and used as a fuel, NG must be separated from any co-produced liquids and purged of undesirable components. This processing involves several steps. First, the NG is separated from any liquids such as water, crude oil, and hydrocarbon condensate. The higher-weight alkanes (ethane, propane, and butane) are condensed, collected, and sold separately as fuels, because they typically have more value when they are separated than when they are components of an NG mixture. The NG is dried of water vapor, which can promote corrosion or lead to the formation of ice-like compounds called hydrates, which can plug gas lines. Finally, toxic and corrosive compounds, such as hydrogen sulfide (H_2S), and those without energy value, such as N_2 and CO_2, are removed (Kumar, 1987).

Natural gas recovery, cleanup, and transmission require energy (typically the NG itself), and the use of this energy produces greenhouse gases. Natural gas clean-up can release CO_2 and methane (CH_4); in addition, small amounts of CH_4 leak from fields and pipelines.

G.2 Energy Used to Lift and Process Natural Gas

There are two annual sources of information on the amount and kind of energy used to recover and process NG: the Energy Information Administration (EIA's) *Natural Gas Annual* and the U. S. Bureau of the Census's *Census of Mineral Industries, Fuels and Electric Energy Consumed.* The EIA form, EIA-176, which is sent to all companies involved in any phase of the NG business, records the amount of NG used in lease operations (field operations, such as drilling, heating, dehydrating, and compressing gas) and plant operations (removing nonhydrocarbon gases and natural gas liquids from the raw NG. See any *Natural Gas Annual.* The amount used for plant operations includes NG used as a fuel, NG lost, and NG vented or flared. I assume that very little NG is lost or vented and subsume this amount under my estimate of leakage from gas production.) From the responses given on survey form EIA-176, the EIA estimates the national total consumption of NG as lease and plant fuel. The EIA's results for 1982 and 1987 are shown in Table G.1. The EIA does not report the use of fuels other than NG. It also is not clear if some of the lease NG consumed was for oil production instead of NG production.

The U. S. Bureau of the Census reports the amount and kind of energy used to recover both NG and crude petroleum and the amount and kind of energy used to clean NG and produce natural gas liquids (NGLs) (Table G.2). The census does not report energy used by NG production separately from the energy used to produce both oil and NG. For a general description of the U. S. Census data, see Appendix F. Thus, associated with the EIA data is the problem of excluded energy sources and perhaps the problem of separating the oil and NG. Associated with the census data is the problem of separating the oil and the NG.

I use the U. S. Census data and then apportion process energy among petroleum, NG, and NGLs on the basis of the following observations:

First, it is likely that virtually all of the NG reported to the U. S. Bureau of the Census as being used to lift NG or oil was in fact used to lift or reinject NG. I infer this because the Bureau's estimate of the amount of NG used in oil and gas field operations is close to the EIA's estimate of the amount of NG used in field operations, and the EIA data probably refer to NG-lifting and NG-reinjecting operations only. The EIA survey (form EIA-176) is sent to NG producers and the survey is about gas, not oil, so the EIA feels that most, if not all, of the lease gas was used to produce or reinject gas, not oil (McCarrick, February 13, 1990). (There are no data on gas use by companies that produce only gas.) In any case, only a quarter of U. S. gas comes from wells that also produce oil (EIA, *Natural Gas Annual*, 1990), so most of the responding firms probably produce mostly or only gas.

The second observation is that energy used to reinject NG should in most cases be assigned to oil production because gas is reinjected mainly to pressurize oil wells and enhance oil recovery. If a producer intends to market gas from a field, it will not reinject any of the gas being produced, except in exceptional circumstances.

The EIA data clearly indicate that reinjected gas should be assigned to oil production. In states that do not produce any gas from oil wells (i.e., in states that produce gas only from gas-only wells), no gas is used for repressuring (EIA, *Natural Gas Annual 1989*, 1990). This situation is true for every state producing little or no gas from oil wells, including states that produce a lot of gas from gas-only wells. Gas is used for repressuring only in states that produce gas from oil wells.

In the United States most of the gas repressuring occurs in Alaska. In fact, in Alaska, virtually all associated gas is reinjected (EIA, *Natural Gas Annual 1989*, 1990) because there is no market for the gas. The data from Alaska suggest that producing and reinjecting associated natural gas require more energy (lease gas) than is required for producing gas for marketing: field operators in Alaska consumed 9.654 standard cubic feet (SCF) of lease gas per 100 SCF of all

TABLE G.1 Natural Gas and Natural Gas Liquid Production and Use Data

Item	USC 82[a]	EIA 82[b]	USC 87[a]	EIA 87[b]
Natural gas (NG) data				
Dry NG produced (10^9 ft^3)	17,908.9	17,758.0	16,844.7	16,536.0
Residue gas from NGL plants (10^9 ft^3)	11,198.4	13,193.2	10,219.3	11,685.9
Lease fuel (10^9 ft^3)[c]	324.4	386.1	458.5	481.8
NGL plant fuel (10^9 ft^3)[d]	471.4	515.4	390.3	408.1
Pipeline fuel (10^9 ft^3)	597.0[*]	597.0	519.0[*]	519.0
Unaccounted for loss (10^9 ft^3)[e]	474.7[*]	474.7	358.9[*]	358.9
Pipeline power (10^6 kWh)	2,377.2[*]	2,377.2	2,066.6[*]	2,066.6
NG for own-use power (10^9 ft^3)[f]	15.5[*]	15.5	12.7[*]	12.7
Net NG for end use (10^9 ft^3)[g]	16,104.2	15,847.6	15,165.3	14,815.5
Net NG for end use (quads)	16.6	16.3	15.6	15.3
Natural gas liquid (NGL) data				
Total NGL (10^6 bbl)	725.4	561.9	709.0	580.7
HHV[h] of NGL (quads)	2.77	2.14	2.70	2.21
Summary statistics				
10^9 ft^3 delivered gas[j]/10^9 ft^3 gas for end use	1.087	1.096	1.091	1.096
10^9 ft^3 dry gas produced/10^9 ft^3 gas for end use	1.112	1.121	1.111	1.116
Btu NG produced/Btu NGL + NG produced	0.870	0.895	0.865	0.885
Btu recovery energy/Btu NG + NGL	0.019	0.023	0.025	0.028
Btu production energy/Btu NG produced	0.022	0.026	0.019	0.021
Btu production energy/Btu NGL produced	0.035	0.035	0.031	0.030
Transmission energy[k]/Btu gas for end use	0.038	0.038	0.035	0.035
Btu compression or liquefaction energy per Btu CNG or LNG produced:				0.050[l]
Factor to account for NG used in liquefaction or compression:				1.027[m]

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[*] The Census does not report this, so I have used data from the DOE Energy Information Administration (EIA).

[a] From the following publications from the U. S. Department of the Commerce, Bureau of the Census: USC 82 = *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985); USC 87 = *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); *1987 Census of Mineral Industries, Crude Petroleum and Natural Gas* (1990); *1987 Census of Mineral Industries, Natural Gas Liquids* (1990); and *1987 Census of Mineral Industries, Oil and Gas Field Services* (1990).

[b] EIA 82 = *Petroleum Supply Annual 1982* (1983), and EIA 87 = *Petroleum Supply Annual 1987* (1988).

[c] Fuel used at NG field operations.

TABLE G.1 (Cont.)

[d] Fuel used at NGL removal plants.

[e] Includes transmission and distribution leaks and losses. The reader will note that these are not the figures reported by the EIA. The EIA UAF figure is the difference between total supply and total consumption; I am interested in the difference between supply and consumption, excluding imports, exports, and storage additions and withdrawals. I have adjusted the UAF accordingly.

[f] Amount of natural-gas used at NG-fired generating plants supplying electricity to NG producers and pipelines. Calculated by multiplying total electricity consumption at NG field operations, NGL plants, and NG pipelines by the fraction supplied by NG-fired power plants.

[g] Equal to dry production minus NG used for lease fuel, plant fuel, and pipeline fuel; minus NG used by power plants supplying the NG system; and minus UAF gas. Does not account for NG used to compress or liquefy NG; that is accounted for separately. Excludes imports, because energy used to produce and transmit imports has not been counted. Excludes storage changes, on the assumption that in the long run, there should be no net change in storage.

[h] A weighted average calculated by the EIA, based on the amount and heating value of the constituents (butane, propane, ethane, pentanes plus plant condensate).

[i] These summary values are slightly different in the case of NG to methanol, because pipelines serving methanol plants will consume less fuel because of the shorter shipping distance. This reduction in pipeline energy affects all statistics, because it increases the amount of gas available for end use.

[j] Delivered gas is equal to net for end use plus lease, plant, pipeline, and own-use gas.

[k] The energy value of pipeline gas plus the energy value of electricity used by electric pipeline compressor stations. In the case of NG to methanol, this value is adjusted to account for the shorter shipping distance.

[l] Based on the data of Table G.6.

[m] Accounts for NG used to liquefy or compress NG.

gross withdrawals, whereas operators in the rest of the country used 2.372 SCF of lease gas per 100 SCF withdrawn (EIA, *Natural Gas Annual 1989*, 1990). In Alaska, 79.5% of gross gas withdrawal was reinjected and 20.0% was marketed; in the rest of the United States, 4.7% was reinjected and 92.7% was marketed. On the basis of these data, and assuming that the energy requirement of reinjection in Alaska is representative of the national average requirement, one can calculate the amount of lease gas used for reinjection and the amount of lease gas used to lift gas that is marketed:

$$2.372 = 0.047X + 0.927Y$$

$$9.654 = 0.795X + 0.200Y$$

TABLE G.2 Energy Used to Recover Raw Natural Gas and at Natural Gas Liquid Plants

Fuel Used	Natural Gas Recovery[a]				Natural Gas Liquid Plants[b]			
	1982		1987		1982		1987	
	Units	Energy (%)	Units	Energy (%)	Units	Energy (%)	Units	Energy (%)
Crude oil (10^3 bbl)	1742.8	2.52	602.4	0.68	0.0	0.00	0.0	0.00
Diesel (10^3 bbl)	4584.3	6.66	3169.0	3.61	29.2	0.03	5.3	0.01
Residual (10^3 bbl)	731.9	1.15	251.4	0.31	0.0	0.00	0.0	0.00
Natural gas (10^9 ft^3)	324.4	83.47	458.5	92.45	471.4	97.04	390.3	97.58
Coal (10^3 tons)	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
Electricity (10^6 kWh)	2391.4[c]	2.04	1884.0[c]	1.26	3327.5[d]	2.27	2690.4[d]	2.22
Gasoline (10^6 gal)	113.2	3.53	52.5	1.28	6.3	0.16	1.6	0.05
Other (10^6 \$)	18.4	0.63	13.2	0.41	18.6	0.51	3.5	0.14
Total quads used	0.401		0.512		0.501		0.413	

Sources: See Table G.1.

[a] Energy used to recover raw natural gas. Energy apportioned between oil and gas using assumptions of Table G.4 (discussed in text above).

[b] Energy used at NGL facilities.

[c] Oil and gas producers generated and sold a small amount of electricity in 1982. I have subtracted this amount from the total amount of electricity purchased. The Census did not disclose the amount sold in 1987; I have estimated sales in 1987 by using data on electricity purchased and sold in all mineral industries.

[d] NGL plants sold a small amount of electricity in 1982 and 1987. I have deducted this from the amount purchased.

where:

X = SCF of lease gas used/SCF of gas reinjected and

Y = SCF of lease gas used/SCF of gas marketed.

On the basis of these U. S. data, X = 11.65 SCF/100-SCF-reinjected and Y = 1.97 SCF/100-SCF-marketed. This result indicates that 286 billion cubic feet (BCF) of gas, or 44.5% of total lease gas, was used for reinjection in the United States, given 641 BCF of total lease gas used in 1989 (EIA, *Natural Gas Annual 1989*, 1990). Thus, if the use of lease gas is a function of the amount reinjected and the amount marketed, and if the rate of using lease gas is the same in Alaska as it is in the rest of the country, one should assign 44.5% of total lease-gas use to oil production.

Of course, one could argue that conditions in Alaska are unusual and that elsewhere, much less lease fuel is required to reinject an SCF of gas. In this case, one might assume that only Alaskan lease-gas consumption should be assigned to oil recovery. (Alaskan gas operations consumed 29% of all lease gas used in the United States in 1989. One could argue that an even lower percentage should be assigned to oil production. Thus, it appears that 25-45% of lease-gas use in the United States should be assigned to oil production. In the base case, I assign 35% of total gas consumption to oil and 65% to production.

Since the assignment of the use of lease fuel to oil production is a function of the amount of gas reinjected and since the United States imports much of its oil, it is important to determine if the rate of reinjection in the countries that export oil to the United States is significantly different than the U. S. rate of reinjection. Using EIA (*International Energy Annual*, 1989) and United Nations (U.N., no date) data on reinjection, I have calculated the weighted average SCF of reinjected oil/bbl if oil exported to the U. S. rate for all U. S. imports. (The calculation is analogous to the calculation of weighted average venting and flaring per barrel, which is shown in Table M.7.) Countries that export oil to the United States reinject at a rate of about 600 SCF/bbl oil exported to the U. S.; the U. S. rate is about 630. Hence, there is no significant difference.

The third and final observation is that, according to the EIA (McCarrick, February 13, 1990) and Lieberman (1987), NG field equipment and processing plants use only a very small amount of electricity relative to the amount of gas they use. In support of this on, I have found that electricity use is only 2% of the total energy used at processing plants owned by interstate pipeline companies. Webb and PPS Ltd. (1983) show that power use is about 5% of total gas and power use by an NGL plant. My assumptions and results are shown in Tables G.2 and G.4.

Table G.1 compares EIA and U. S. Bureau of the Census survey estimates of the production and NG consumption of NG at NGL plants and NG facilities in 1982 and 1987. (The NGL data in the *Natural Gas Annual* and the *Petroleum Supply Annual* come from the same

TABLE G.3 An Estimate of the Amount of Electricity and Gas Used as Process Fuel by Interstate Pipeline Companies

Item[a]	Cost (10^6 \$)[a]	My Assumption (\$/unit of energy)[b]	Energy (quads)	Percent of Total Energy
For products extraction				
Fuel[d]	31.02	2.04/10^3 ft^3	0.0157	98.0
Power	4.48	0.048/kWh	0.000318	2.0
For transmission				
Gas fuel	375.89	2.04/10^3 ft^3	0.190	97.6
Other fuel & power[e]	65.48	0.048/kWh	0.00465	2.4

[a] From *EIA's Statistics of Interstate Natural Gas Pipeline Companies* (1988).

[b] Gas price is average price paid by interstate pipeline companies for gas from producers, gatherers, and/or processing plant operators, in 1988 (EIA's *Natural Gas Annual*). Electricity price is 1988 average retail price to industrial customers (EIA's *Monthly Energy Review*).

[c] Calculated here from energy expenditures and energy price. I assume 1,032 Btu/SCF for natural gas. The calculation of energy is just an intermediate step in the calculation of energy shares; the energy figures do not represent total process energy use by the natural gas industry or by natural gas pipelines.

[d] I assume all natural gas.

[e] I assume all electric power.

survey.) Table G.2 shows the Bureau's data on specific fuels used by NGL plants. The two sources agree quite closely on total dry gas production, energy used by NGL plants, and energy used in field operations in 1987. They do not agree as well on total production by NGL plants and energy used in field operations in 1982. I have used values in the middle of the ranges of the two sets of data.

Webb and PPS Ltd. (1983) show that an NGL plant in Canada uses about 0.021 Btu of gas and electricity per Btu of dry gas and NGLs produced, with about 95% of the input energy being gas. The data in Table G.1 show that about 0.034 Btu of NG is used to produce 1 Btu of NG and NGL, which is reasonably close to the Canadian data.

TABLE G.4 Data Used to Adjust Census Data on Energy Used to Recover Feedstocks

SIC area	\$ Purchased Fuels[a] per \$ Distributed Fuels[c]		\$ All Products[b] per \$ Distributed Products[d]	
	1982	1987	1982	1987
Oil and gas extraction	1.136	1.111	1.123	1.125
Oil and gas field services	1.138	1.422	Not used	Not used
Natural gas liquids	1.009	1.039	1.003	1.004

Other assumptions:

0.650 fraction of NG used by oil and gas production assigned to NG (my estimate; see discussion in text).
0.050 fraction of all other oil and gas production energy assigned to NG (my estimate; see discussion in text).
0.400 fraction of energy used by drilling services assigned to NG (my estimate; see discussion in text).
0.161×10^6 Btu/dollar of "other" fuels, 1987 (value used by the Census)
0.137×10^6 Btu/dollar of "other" fuels, 1982 (value used by the Census)

Sources: See Table G.1.

[a] The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies not surveyed (the Census estimated the value for these companies) and fuels used by companies that did not report how much of each kind of fuel they used.

[b] The total dollar value of all products (crude oil, dry gas, NGLs, uranium ore, etc.) of all companies engaged in the activity, including products from companies not surveyed (the Census estimated production for these companies) and products from companies that did not classify or detail their products (e.g., did not state what kind of coal they produced).

[c] The dollar value of the fuels purchased by companies that reported the amount of each kind of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only total cost of purchased fuels, with no breakdown or details.

[d] The dollar value of products of those companies that reported the amount and kind of each product.

G.2.1 Emissions from the Manufacture of Concrete Used in Gas Recovery

Mueller (1990), by using data in the DOE *Handbook* (1983), calculates nontrivial emissions from the manufacture of concrete used to plug gas wells. However, the DOE *Handbook* made a mistake in its calculation of the value used by Mueller; it divided total concrete consumption by oil output in one year instead of over the 20-year life of the field. The correct concrete application factor is 20 times smaller than the one used by Mueller, which results in negligibly small emissions.

As in the case of oil, emissions from the manufacture of the steel used at gas fields are quite a bit greater than emissions from the manufacture of concrete, although they are still small. Table P.6 shows total emissions from the manufacture of steel and concrete as a function of total gas produced over the life of the field.

G.2.2 Assigning Recovery and Processing Energy to NG and NGL

The energy required to lift raw NG and separate the NGLs from the dry NG must be assigned to both products. The correct way to do this depends, in the first place, on the policy being evaluated. Suppose we are evaluating the greenhouse effects of choosing whether or not to make compressed natural gas (CNG) or liquefied natural gas (LNG) fuels. If we choose to make the NG-based fuels, we will incur all the emissions from the energy used to lift and process the gas, but (relative to not making the NG-based fuels), we will avoid the emissions associated with the manufacture and use of whatever energy products would have replaced the NGLs coproduced with the NG. Thus, we should assign to NG production and processing all the emissions from raw gas production and processing, minus the emissions that would have occurred had the NGLs not been available as a result of the decision to make NG-based transportation fuels.

To correctly calculate this NGL credit, we would have to model the supply and demand of NGLs and NGL substitutes and determine what energy would be used if the NGLs (from the use of CNG and LNG) were not available. There are many counterfactuals: refineries could produce more LPG; NGL plants could further fractionate gas to produce more NGL (which would require the increased production of an NG-substitute to make up for the decline in pipeline gas); other fuels, not derived from NG, could be used instead of NGLs; the smaller supply of NGL could raise its price and reduce demand and use, compared with the CNG/LNG case; and so on. (The situation would be reversed if an LPG policy were being evaluated.)

Such modeling is beyond scope of this project. I use a simpler, though less conceptually correct, method of assigning raw gas production and processing energy to both NG and NGL. I treat NGL as a generic energy product that is completely substitutable for NG, and evenly assign the energy required to produce a unit of NG or NGL to both products on the basis of energy content. This production energy intensity is then adjusted separately for each product (NG, NGL) to account for "own use" ("own use" is explained in Appendix A):

$$PE_{ng} = Le/(P_{ng} + P_{ngl}) \times (P_{ng}/C_{ng})$$

where:

PE_{ng} = Btu of production energy per Btu of net NG energy consumed,

Le = total Btu used to produce raw gas (Table G.2),

P_{ng} = Btu of dry gas produced (Table G.1),

P_{ngl} = Btu of NGL produced (Table G.1), and

C_{ng} = Btu of NG consumed by end users (Table G.1).

For NGL, the calculation is the same, except that P_{ng}/C_{ng} is replaced by P_{ngl}/C_{ngl}, where C_{ngl} is Btu of NGL consumed by end users.

The calculation of the energy required to process NG in order to produce dry gas and NGL is not quite as straightforward because not all raw gas needs to be processed. In this analysis, the energy used at NGL plants is assigned to both NG and NGL. The resultant figure is the processing energy intensity for all NGLs. This figure is then weighted by the fraction of dry NG that has been processed (60-70% in the United States, a value that is dropping as more dry gas fields are discovered) to arrive at the processing energy for NG. Finally, these figures are adjusted to account for own use.

$$PR_{ng} = Pe/(Pr_{ng} + Pr_{ngl}) \times (Pr_{ng}/P_{ng}) \times (P_{ng}/C_{ng})$$

where:

PR_{ng} = Btu of processing energy per Btu of net NG energy consumed,

Pe = total Btu used at NGL plants (Table G.2),

Pr_{ng} = Btu of dry gas produced by NGL plants (Table G.1),

Pr_{ngl} = Btu produced by NGL plants (Table G.1),

P_{ng} = Btu of dry gas produced (Table G.1) (this cancels out), and

C_{ng} = Btu consumed by end users (Table G.1).

In general, the method of assigning production and processing energy to both NG and NGLs will be exactly, rather than approximately, correct, to the extent that the amount and kind of energy used to lift and process NG and NGLs, as calculated here, are the same as the amount and kind of energy that would have been used to make substitutes for the NGLs coproduced with the NG, had these NGLs not been available. Since NGLs and NG can substitute for each other in many applications (U. N. 1987), this assumption may be reasonably accurate.

G.2.3 Mix of Electricity and Fuels Used at NGL Plants

Table G.2 shows the amount of electricity consumed by NGL plants. I have assumed that NGL plants are located near petroleum refineries, so the plants use electricity generated from the same mix of fuels as the electricity used by refineries.

G.2.4 CO_2 Vented from Gas Processing Plants

Natural gas in the ground contains CO_2, hydrogen sulfide (H_2S), and other nonhydrocarbon gases. These gases are toxic or noncombustible; hence, they must be reduced to an acceptable level before the gas may be shipped to end users. The CO_2 separated at gas processing plants is either vented to the atmosphere or injected into an oil field to repressurize the field and enhance oil recovery. If it is vented, it is a greenhouse gas emission attributable to NG production (assuming that it would not otherwise leak naturally). CO_2 is reinjected if oil fields are nearby, if there is enough CO_2 to enhance oil recovery, and if oil prices are high enough to support enhanced oil recovery. It is vented if the amount of CO_2 is very small, if no oil fields are nearby, or if enhanced oil recovery is uneconomical.

These emissions of CO_2 from NG processing plants (aside from the CO_2 emissions from process energy used by those plants) are not great. There are only a few fields with very high levels of CO_2 or H_2S (Okken and Kram 1989; McCarrick 1990), and, as noted above, some of the CO_2 produced by these fields is reinjected. In the United States in 1988, the total amount of all nonhydrocarbon gases removed from raw gas was about 4.4% of marketed gas production (EIA, *NGA*; based on production and nonhydrocarbon release data for the states that reported both). The largest releases are in Wyoming, and are mainly attributable to a large gas field owned by Exxon, that is two-thirds CO_2. This 4.4% figure includes other gases besides CO_2 and does not account for reinjected CO_2. I assume that half of the nonhydrocarbon gases are CO_2 (on the basis of an Okken and Kram, 1989, estimate that the worldwide mean CO_2 content is 2%) and that 85% of the CO_2 is vented. I then assign this CO_2 emission to both dry NG production and NGL production.

As noted above, my input assumptions for 2000 follow the 1987 U. S. Bureau of the Census data (see also the section here on future energy use).

G.2.5 Emissions from Sulfur Removal

Recall that the use of carbonate to scrub sulfur oxides (SO_x) from the flue gas of a coal-fired power plant produces CO_2 (Appendix D). One might ask, then, if the removal of sulfur from NG produces CO_2. Sulfur is found in NG in the form of H_2S. If the concentration of H_2S exceeds certain limits, the H_2S must be separated from the rest of the NG and removed by absorbing the H_2S in an amine solution (EPA, AP-42, 1985 and 1988; amine absorption accounts for more than 95% of H_2S removal. Amine absorption does not itself produce any greenhouse gases. However, the eventual disposition of the sulfur in the separated H_2S may produce a minor amount of CO_2. The acidic waste gas from the amine process can be vented, burned, or, most commonly, sent to a sulfur recovery or sulfuric acid plant (EPA, AP-42, 1985 and 1988). Burning produces sulfur dioxide (SO_2); venting SO_2 releases H_2S (EPA, AP-42, 1985 and 1988).

Thus far, the sulfur-removal process produces no greenhouse gas emissions (aside from the use of process energy, which is considered separately here). If the H_2S is sent to a sulfuric acid plant, most of the sulfur will be converted to sulfuric acid (H_2SO_4), but a small amount will remain in the tail gas. New Source Performance Standards (NSPS) limit the amount of SO_2 in the tail gas of H_2SO_4 plants (EPA, AP-42, 1985 and 1988). The SO_2 emissions are reduced either by increasing the efficiency of conversion of SO_2 to H_2SO_4 or by scrubbing SO_2 in sodium sulfite/bisulfite. Neither process produces CO_2 directly.

However, if the H_2S is sent to a sulfur recovery plant (called a Claus plant), there is a small probability that minor amounts of CO_2 will be produced. There are three options for controlling SO_2 emissions from Claus plants to meet NSPS for SO_2: (1) scrub the SO_2; (2) increase the conversion of H_2S to elemental sulfur; or (3) convert the sulfur gas to H_2S and recover the sulfur (EPA, AP-42, 1985 and 1988). Some forms of the third option use carbonate (e.g., the Stretford process), but it appears that the carbonate solution is regenerated without net emissions of CO_2 (USDOE, *Energy Technologies and the Environment*, 1988). Option 2 does not produce CO_2. However, some forms of scrubbing (option 1) appear to use a carbonate process that produces CO_2.

The result of this is that total CO_2 emissions due to sulfur removal, per unit of NG delivered, will be very small. To illustrate this point, note that, typically raw NG contains about 1% sulfur by volume, and about 99% of this sulfur ends up as elemental sulfur or H_2SO_4 (EPA, AP-42, 1985 and 1988). Of the remaining sulfur, only a portion will pass through scrubbers that generate CO_2. CO_2 emissions from sulfur control probably amount to less than 0.00005 moles per mole of methane, which translates to roughly 3 g/10^6 Btu less than 0.005% of fuel-cycle emissions.

G.2.6 Liquefied Petroleum Gas from Refineries

Refineries produce some LPG (mostly propane), although considerably less than NGL plants produce. The calculation of greenhouse gas emissions from refinery-produced LPG follows the calculation for other petroleum products (up through the fuel production stage) and is explained in Appendix H.

The final g/10^6 Btu and g/mi emission factors for LPG are equal to emissions from NGL-derived LPG, weighted by the fraction of propane and butane from NGL plants and the fraction of propane and butane in the fuel, plus the same weighting from refinery-derived propane and butane. In 1987, NGL plants produced 60.8% of total (refinery + NGL plant) U. S. propane and 72.3% of total U. S. normal and isobutane (EIA, *PSA*, 1988). The base-case LPG composition is shown in Table C.3. On the basis of these figures and the base-case composition shown in Table C.3, NGL plants produced 61.4% of the base-case LPG components and refineries produced 38.6%. I use these values in the base case, and I test different values in sensitivity analyses.

It is appropriate to provide a note on LNG, synthetic natural gas (SNG), and pipeline imports here. In 1989, imports of LNG were only 0.2% of the total NG supply; SNG provided 0.85% of total supply (EIA, *The Outlook for Natural Gas Imports*, 1991; EIA, AOOG, 1990). The EIA projects that LNG imports will increase to 3-4% of the total NG supply in 2000, while SNG will account for only 0.6% of the total supply. LNG imports will ultimately be limited by the political difficulty of expanding LNG terminal capacity, which at present is only about 1 trillion cubic feet (TCF) (EIA, *The Outlook for Natural Gas Imports*, 1991; EIA, *Annual Outlook for Oil and Gas*, 1990).

This information suggests that if the natural gas vehicle (NGV) spawned increment in demand for NG is supplied by the current distribution of sources (domestic, SNG, pipeline imports, and LNG), less than 5% of NG for motor vehicles will come from LNG or SNG. Of course, it is possible that the incremental NG demand due to NGVs will be supplied primarily by LNG, but this prospect does not seem too likely, given that the demand for LNG may be constrained by terminal capacity and is likely to reach this limit without NGVs (EIA, *Outlook for Natural Gas Imports*, 1991). It is more likely that the NG used by NGVs will come from increased domestic production and increased pipeline imports.

Nevertheless, I include an NG-from-LNG scenario here, primarily because it is relatively easy to model. Liquefaction requires 0.10 10^6 Btu/10^6 Btu NG (Chem Systems, 1988; EIA, *The Outlook for Natural Gas Imports,* 1991). Transport requires 0.059 Btu/Btu LNG delivered (64% of this fuel use is NG; 36% is fuel oil) for a 12.81-day, 5,500-mi one-way trip (Chem Systems, 1988). See Table E.3 here; 5,500 mi is the transport distance used in the methanol-from-NG analysis.) Regasification requires 0.025 Btu/Btu of gas (EIA, 1991). On the basis of these data and proper accounting for the extra "own use" (see Appendix A) of NG for liquefaction, one can calculate the energy requirements and emissions of cycle for NGV that use foreign LNG.

G.3 Energy Used to Transport Natural Gas

Natural gas is transported across the United States in high-pressure transmission lines. The compressors located along these lines are primarily powered by gas-fueled reciprocating engines and gas turbines; a few are driven by electric motors. The engines, turbines, and power plants supplying electricity to the electric motors all have different emission factors. For example, gas engines emit considerably more CH_4, carbon monoxide (CO), and nonmethane hydrocarbons (NMHC) than gas turbines (EPA, AP-42, 1985 and 1998). Consequently, aggregate greenhouse gas emissions from NG transmission depend on the total amount of gas consumed by turbines, total amount consumed by engines, and the amount of electricity consumed by electric motors. In this section, I calculate the total amount of gas consumed by turbines and engines together, the breakdown between turbines and engines, and the total amount of electricity consumed.

G.3.1 Total Amount of Gas Consumed by Pipeline Compressors

Each year's EIA's *Natural Gas Annual* reports the quantity of gas consumed as a pipeline fuel, as determined by the EIA from responses on its survey form, EIA-176. These data are shown in Table G.1 for 1982 and 1987. (The EIA data on energy use by pipelines agree with data in the 1983 DOE *Handbook*). Unfortunately, the EIA does not estimate the breakdown between gas engines and turbines or the amount of electricity consumed by the very few electric compressors. In fact, there are no aggregate national data on the split among gas turbines, gas engines, and electric motors. To obtain this information, I surveyed NG transmission companies.

G.3.2 Breakdown between Engines and Turbines

Most pipeline compressor units are reciprocating engines, because engines are more efficient than turbines over a wider load range, and most pipelines must operate over a wide load range. Lieberman (1987, p. 112) states that turbines are a "sizable minority" of field and transmission compressor stations, but does not give a number. Kind (1989) has reported that the main transmission line of El Paso Natural Gas, a major interstate carrier, has 46 gas-turbine-driven centrifugal compressors and 223 reciprocating-engine-driven compressors, but he did not report the share of horsepower (relative energy use by turbines and engines depends on the relative horsepower and on the horsepower-hours).

To get a quantitative estimate of the national situation, I contacted five major interstate pipeline companies that serve different regions of the United States and asked them to tell me the percentage of total installed compressor horsepower in their system provided by turbines, reciprocating engines, and electric motors. The results are shown in Table G.5. On the basis of these data, I estimated the national breakdown between engines and turbines, by horsepower.

TABLE G.5 Energy Use by Gas Turbines, Gas Reciprocating Engines, and Electric Motors, on Transmission Pipelines

	1989 % Horsepower from:			1988 % of U. S. Total of:[a]	
Pipeline Company or Source	Turbines	Engines	Electric	TCF Moved[b]	Compressors
Natural Gas Pipeline of America (pers. comm., 1990)	~15	~85	<1	6	3
Tennessee Gas Pipeline & others[c] (pers. comm., 1990)	~25	~75	0	7	4
El Paso Natural Gas (Quinn, 1990)[d]	50	41	9	7	4
Enron (pers. comm., 1990)[e]	17	83	<1	9	13
Transcontinental Gas Pipe Line (pers. comm., 1990)[f]	14	83	4	9	3
National estimate by ORNL (Davis et al., 1989)	---------- 94 ---------		6[g]	100	100
My national estimate, from Table G.3	---------- 92 ---------		8[h]	100	100
National estimate, by Banks (1977)	---------- 96 ---------		4[i]	100	100

"pers. comm." = personal communication.

[a] From OGJ, November 27 (1989), for 1988. Some of these statistics are also in the EIA's *Statistics of Interstate Natural Gas Pipeline Companies.*

[b] Based on the statistic, "gas transported for others" (OGJ, November 27, 1989). TCF = trillion cubic feet.

[c] Also Midwestern Gas Transmission, East Tennessee Natural Gas, and Channel Industries.

[d] As of May 31, 1989: turbines = 324,188 hp; engines = 268,091; electric = 61,300.

[e] Horsepower shares include Northern Natural Gas, Florida Gas Transmission, Houston Pipeline, and Transwestern Pipeline. Compressor and gas delivered shares do not include Houston Pipeline.

[f] 1989 system totals = 979,519 horsepower, 4.279 billion hp-h. Electric-motor driven compressors = 37,500 hp, 131 million hp-h. Gas turbines = 133,000 hp, 458 million hp-h. Rest is reciprocating engine. Also, 39.768 × 10^9 ft^3 were used by compressors at 8.279 SCF/hp-h. The breakdown by horsepower-hour, as opposed to horsepower, was 10/88/3, which indicates that the reciprocating engines were actually used more. However, this probably cannot be generalized to all companies, since turbines can be used for baseload (e.g., El Paso Natural Gas) as well as for peaking.

TABLE G.5 (Cont.)

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[g] Based on this, they estimate that electricity use by electric-motor-driven compressors is about 1.5% (Btu-electric basis) of the Btu of gas consumed by gas-powered compressors.

[h] Based on the assumption that electric-motor-driven compressors are four times more efficient than gas-powered compressors on an end-use energy basis. This appears to be what ORNL (above) assumes.

[i] Banks estimates that 4-5% of compressors are electrically driven.

The statistics in the table refer to installed horsepower. To convert installed horsepower by type of compressor to gas consumed by type of compressor (which is the unit of I want), one must know horsepower-hours by type of compressor and fuel consumption per horsepower-hour by type of compressor. For simplicity, I have assumed that the national ratio of installed turbine horsepower to installed engine horsepower is a reasonable approximation of the ratio of horsepower-hours.

Turbines can be used to meet both baseload (e.g., in the El Paso Natural Gas System) and peaking (e.g., Transcontinental Gas Pipe Line) requirements, so there is no reason to assume that turbine horsepower is used more or less than reciprocating-engine horsepower. To convert the engine/turbine ratio of horsepower-hours of compressor output to a ratio based on gas consumption, I use the EPA's conversion factors of 7.14 SCF of gas/hp-h for engines and 9.52 SCF of gas/hp-h for turbines. Transcontinental (personal communication, 1990), which has mostly engines, used 8.279 SCF/hp-h for its system in 1989, which is consistent with the EPA assumptions. The results of this analysis are shown in Table G.5, in which I estimate the breakdown between turbines and engines in NG transmission.

G.3.3 Electricity Used by Electric-Motor-Driven Compressors

In Table G.3, I estimate the proportion of gas to electricity as pipeline energy on the basis of financial reports of NG pipeline companies. That estimate, converted from an energy basis to a horsepower basis, is then compared with two other estimates of the proportion of total horsepower supplied by gas and electricity (Table G.5).

The data of Table G.5 indicate that electric motors account for about 5% of the installed horsepower of compressors. Assuming that electric motors are four times more efficient than gas-powered compressors on an end-use basis, about 1.3% of the total energy consumed by pipelines (counting electricity at 3,412 Btu/kWh) would be electricity. This result is entered in Table G.5 as a proxy for the year 2000 (as explained below, energy intensity by 2000 is likely to be close to that in 1987).

G.3.4 Modes Used to Transport Liquefied Petroleum Gas

In the United States, most of the LPG is produced in Texas, Oklahoma, Louisiana, and New Mexico (EIA, *PSA*, 1990). Very little LPG is moved by rail or ship; virtually all of it is moved at some point by pipeline and truck (USDOT and USDOE, 1980). Pipeline networks fan out from the Gulf Coast and Southwest to the Midwest and East. In 1976, 90.6% of the LPG used in the United States was shipped by pipeline-truck combination, 3.4% by truck alone, 4.6% by combination pipeline-rail, 0.9% by rail alone, and 0.5% by tanker or barge (USDOT and USDOE, 1980). However, it is likely that more LPG is moved by ship or barge today than it was in 1976. In 1987, about 4% of the total LPG supply was imported from countries other than Canada (about 10% of total supply was imported, but 58% of the imports came from Canada, presumably by pipeline and truck) (EIA, *PSA*). On the basis of these considerations, I assume that 5% of the total LPG production moves by ocean-going tanker (I assume that this LPG comes from Algeria, which is the main source, aside from Canada, of imported LPG), 95% moves by pipeline at some point, 4% moves by rail at some point, and 100% moves by truck at some point (because the final distribution leg to the end user always is by truck). My assumptions are shown in Table E.1.

G.4 Energy Requirements of CNG Compression and LNG Liquefaction

To be stored on board a vehicle, NG must be either compressed to high pressure or liquefied. Both of these operations require energy in the form of electricity for compressors and NG for small liquefiers.

The electricity requirements of compressors depend on the amount of work the compressor must do on the gas; the amount of work depends on the difference between the pipeline inlet pressure at the station and the delivery pressure to the vehicles. Table G.6 shows the estimated actual energy requirements of CNG compressors; these estimates are consistent with the theoretical data estimated (1989) by Ho. Generally, less energy is required at a higher inlet pressure, which means that the difference between the station being located on a high-pressure trunk line or a low-pressure distribution line is somewhat important. In the base case, I assume compression from low-pressure distribution lines to high-pressure (3,600 psi) cascade storage bottles for fast-fill stations because if a CNG station is to be successful, it will have to be "fast-fill" and be located in an urban area.

Greenhouse gas emissions from electricity use by CNG compressors depend on the efficiency of electricity generation and the fuels used by electricity plants supplying the compressors. In the model, the electricity mix used by compressors is a separate variable, so it can be specified independently of the generic and other electricity mixes. I test different fuel mixes in sensitivity analyses.

In the LNG case, I assume that the gas is liquefied at the station (at the point of dispensing to consumers) by skid-mounted, self-powered liquefiers, rather than at large, central liquefaction facilities that transport LNG to service stations. The manufacturers of the small, on-site NG liquefiers report that the liquefiers consume about 0.2×10^6 Btu of NG from the pipeline for every 10^6 Btu of LNG produced (calculated from data in Cryogas Engineering, 1986, and Kennedy, 1987). If a small amount of the LNG vaporizes and must be reliquefied before it is delivered to the motorist, the energy requirement per unit delivered to the motorist will be slightly higher. If the liquefier is set up on a high-pressure gas line, the gas consumption can be reduced to 0.15×10^6 Btu/10^6 Btu (Constable et al., 1989). The effect of LNG boiloff and vaporization is discussed in Appendix B.

TABLE G.6 Compression Requirements of CNG Stations

Station Location	Inlet Pressure (psi)	Car Tank Pressure (psi)	Capacity (SCFM)	10^6 Btu-Power/ 10^6 Btu-CNG	Reference
Canada	175	3,000	65	0.015	Topaloglu (1984)
Pacific Rim	20-70	2,400	70[a]	0.055[b]	UN (1984)
New Zealand	5	3,000	60	0.073[c]	Abram et al. (1980)
U. S.		2,400	100	0.033	Bechtold et al. (1983)
New Zealand	50	3,000	176	0.027[c]	Abram et al. (1980)
New Zealand	300	3,000	265	0.021[c]	Abram et al. (1980)
U. S./Canada	- -	2,200-3,200	- -	0.03-0.05[d]	LaFrenz et al. (1981)
Sacramento, CA		3,000		0.026[e]	Elston (1990)

"--" = not specified. SCFM = standard cubic feet per minute. In the U. S., most inlet pressures are 5 psig or less.

[a] The reference stated that the station actually delivers 2,000 GJ per month. I back-calculated the capacity based on the assumption that the station operates at 60% capacity.

[b] I calculated this based on the assumption that in New Zealand (where the station was located) electricity is \$17.50/10^6 Btu (1983 U. S. \$).

[c] I calculated this from cost data in the reference. I assumed that the cost units in the reference were given in 1979 New Zealand dollars, and I calculated power consumption by using the 1979 conversion rate of \$1.1 NZ = \$1 U.S. and based on the 1979 cost of power in the U. S. being \$12.10/10^6 Btu.

[d] Data in reference given in \$-electricity/10^6 Btu-CNG. I assumed \$16/10^6 Btu-power (1980 U. S. \$), which was the average 1980 commercial sector price.

[e] Reported data were compression electricity cost of \$0.05/therm, electricity price of about \$0.065/kWh, and 100,000 Btu/therm of gas.

G.5 Calculation of NG Available to the Transportation Sector

As discussed in Appendix A, to calculate greenhouse gas emissions from the use of a fuel, one must know the amount and kind of process energy consumed per unit of the fuel made available for a particular use. For any particular fuel, this ratio depends on how that fuel is ultimately used. For example, in the case of NG, it takes a certain amount of energy to deliver a unit of NG to a power plant or to an LNG service station. However, the power plant can use all of the gas delivered to it to provide electricity; the LNG service station must use a portion of the delivered gas to liquefy the remainder, so less gas is available to cars than is available to power plants for a given amount of production. Because of this difference, one must calculate two separate energy/end-use ratios: one for transportation sector uses of gas and one for electricity-generating and industrial uses.

Table G.1 shows the NG supply and disposition sheet used to calculate the amount of NG available for end use per unit of energy used to produce and transmit NG. As just noted, two ratios must be calculated: one for transportation and one for all other end uses. In Table G.1, the efficiency figures "production energy/NG+NGL for end use" and "transmission energy/net for end use" are for the electricity and industrial sectors; they do not account for gas used to make CNG or LNG. These intensities are used to figure g/10^6 Btu emissions from the use of NG by power plants or industry. The g/10^6 Btu factor in Table G.6 is calculated on the basis of these factors.

To account for the use of gas to make CNG or LNG, one first calculates the ratio of the gas used to make CNG or LNG plus the CNG or LNG produced to the CNG or LNG produced, by using the data on the amount and kind of energy used to compress or liquefy gas. Then one multiplies the figures "production energy/NG+NGL for end use" and "transmission energy/net for end use" by this ratio to arrive at "production energy/NG+NGL for transportation end use" and "transmission energy/net for transportation end use". This energy intensity is then used to calculate greenhouse gas emissions per mile. A similar accounting is made for the loss, if any, of LNG due to boil-off.

G.5.1 LPG

For LPG, there are only two ways in which net consumption can differ from production: some produced LPG will leak and evaporate and some may be used by LPG-burning trucks to distribute LPG. In the base case, I assume a very low LPG leakage and evaporation rate; I also assume that no LPG delivery trucks use LPG themselves.

G.6 Future Energy Use in the Natural Gas Industry

G.6.1 Development of Unconventional Reserves

Presently, almost all of the NG used in the United States comes from conventional on-shore and off-shore deposits. However, a good deal of NG is located in so-called unconventional sources, such as tight sands and coal seams. As the wellhead price of NG rises, it will become increasingly economical to develop unconventional reserves (see AGA 1985). The EIA (AOOG, 1990) projects that the production of unconventional gas will increase to 2.70 TCF in 2000, or 12% of the total supply. It typically requires more energy to bring up unconventional reserves because the NG is located deeper, flows slower, is trapped or chemically bound, and so on. Therefore, if the price of NG rises and unconventional reserves are tapped, the amount of energy required to produce gas in the United States will rise. On the other hand, higher prices (and tighter environmental standards) may encourage the use of more efficient technologies, some of which are discussed next.

G.6.2 Past and Future Improvements in Technology and Efficiency

Since 1973, the ratio of NG used by pipeline compressors to NG produced has remained essentially constant at about 3%. The ratio of NG used as lease and plant fuel to NG produced has fluctuated between 5% and 7% (EIA, *Natural Gas Supply Annual*, various years). If the fraction of NG compressors powered by purchased electricity has remained near zero, and if the average length of shipment of NG has not changed appreciably, these EIA data imply that the efficiency of recovery and transmission has not improved. This lack of improvement may be, in part, be a result of operators replacing reciprocating engines with less efficient gas turbines, a trend the EPA observed in the mid-1970s (in EPA, AP-42, sheets dated April 1976).

However, tight nitrogen oxides (NO_x) emission standards and rising fuel prices will likely induce the use of more efficient production and transmission technologies in the future. For example, simple-cycle turbines, combined-cycle turbines, and lean-burn engines emit much less NO_x than do the common reciprocating engines (they also emit less CO, CH_4, and NMHC), and they can meet strict new NO_x emission standards that regular engines cannot. Of these, combined-cycle gas turbines and lean-burn engines also happen to be more efficient than the common, older engines. Rising wellhead prices, which the EIA projects through 2000 (EIA, *Annual Energy Outlook 1990*, 1990) will provide further incentive to use fuel-efficient technologies.

A combined cycle improves efficiency by using the thermal energy in the exhaust gases from the gas turbine, energy which is wasted in a simple-cycle turbine to raise steam in a boiler that then drives a steam turbine. In 1978, a report done for DOE said that the use of combined-cycle turbines would be the best way to improve the efficiency of the gas transport system (Banks and Horton, 1978). This technology is now starting to be used: a combined-cycle turbine at the Messina compression station on the Trans-Mediterranean pipeline has increased both efficiency and power output by 30% (Cocchi et al., 1989). Combined-cycle systems may be attractive wherever gas is expensive enough or wherever the need for power is great enough to justify the capital cost of adding the steam recovery system and if the steam system can be designed to follow variations in the turbine load.

Lean-burn engines operate at a higher air/fuel ratio and use less fuel per horsepower-hour than engines operating nearer to stoichiometry. As noted above, tight NO_x standards as well as higher fuel prices may force the use of lean-burn engines.

In the past few years an increasing number of pipeline companies have automated portions of their operations (see issues of the *Oil and Gas Journal.*) The development of sophisticated but relatively inexpensive software for monitoring and controlling pipeline performance in the face of rising power, labor, and fuel costs has made automation economically attractive. In 1986, Panhandle Eastern Pipe Line Co. expected to reduce its compressor fuel bill 15-20% as a result of automating key mainline compressor stations (Smith, 1986). Another compressor-engine control system reduced fuel consumption by 5% per year (*Oil and Gas Journal*, October 26, 1987).

G.6.3 Conclusion

The development of unconventional reserves will increase energy use in the NG industry, but this increase will be at least partially offset by the use of more efficient recovery and transmission technology. In the base case, I use 1987 energy use statistics to represent the year 2000 because energy-intensive production from unconventional reserves still will be a small percentage of total supply and because of the potential for counterbalancing efficiency improvements in production and transmission. Nevertheless, in a scenario analysis, I examine the effect of a 25% relative increase in the energy intensity of producing domestic gas.

Appendix H:

Petroleum

Appendix H:

Petroleum

H.1 Overview

Petroleum is the largest single energy source in the United States, accounting for over 40% of U. S. energy consumption (EIA, *Annual Energy Review 1989*, 1990). The highway transportation sector is almost 100% dependent on petroleum fuels, gasoline, and diesel fuel.

In the United States, most crude oil is produced in Alaska and on the Gulf Coast. Crude oil flows by water from Alaska to the West Coast and the Gulf, and from the Gulf to the East Coast or up the Mississippi. Gulf Coast refineries send petroleum products by water to the East Coast, and up the Mississippi and Ohio rivers. Products also flow by pipeline from the Gulf Coast to the East Coast. For larger volumes of crude oil, pipeline transport is cheaper and more efficient than water transport (USDOT and USDOE, 1980; USCRS, 1977).

The United States imports about half the oil (crude + products) it uses (EIA, *Annual Energy Review 1989*, 1990). Crude and products are imported from countries around the globe, including Canada, Mexico, Venezuela, Saudi Arabia, and Nigeria. In a greenhouse gas analysis, it is important to know where imported oil comes from because this determines how far, on average, the oil must be shipped, and this in turn determines energy use, and hence greenhouse gas emissions.

H.2 Energy Used in Oil Recovery

In this section, I analyze the amount and kind of energy used to produce crude oil, and I discuss the method used to allocate this energy to gasoline, diesel, residual fuel, and liquefied petroleum gases (LPG).

H.2.1 Overview of the Census Data

This subsection discusses the energy-use data reported by the U. S. Bureau of the Census of Mineral Industries. Appendix F on coal has a general description of the U. S. Bureau of the Census data.

The censuses of oil and gas production and oil and gas field services report energy used in oil and gas exploration, drilling, production, well closure, and related activities (see the Standard

Industrial Classification and Table H.1). Fuel use is reported for oil and gas producers and oil and gas field services, together, not separately, for the oil and gas industries. This joint consumption must be assigned to oil and gas production separately. I apportion these totals to oil and gas using the factors shown in Table H.2. As indicated in the table, I assign to natural gas production most of the gas used by oil and gas producers combined because natural gas producers use gas as their process fuel almost exclusively. The gas use that is assigned to oil production is primarily lease gas burned to provide energy to reinject associated gas used for repressurization of oil wells (see Appendix G).

I assign nearly all petroleum and electricity use to oil production, based on the analysis and data in Appendix G indicating that natural gas (NG) production uses very little electricity. I assign to oil somewhat more than half of the energy used by oil and gas field services since there are more oil than gas wells (EIA, *Annual Review of Energy 1989*, 1990) and oil is sought more actively than gas. Balancing this somewhat is that gas wells are more expensive than oil wells, according to the Energy Information Administration (EIA).

H.2.2 Comparison of the Census Energy-Use Estimates with Data from Other Sources

The DOE *Handbook* (1983) estimates that the energy used to produce oil in the lower 48 states onshore is 1.5% of the energy in the crude produced, with about half the energy requirement being diesel fuel used for development drilling and half electricity used by pumps. For offshore production, the figure is 9%, with fuel for drilling making up the bulk of the consumption. These two figures can be combined for comparison with the U. S. Bureau of the Census estimate: in 1987, all wells onshore and offshore in the lower 48 states produced 2.33 10^9 bbl of oil (*Petroleum Supply Annual 1987*); in the entire United States, offshore wells produced 366 10^6 bbl of oil, including lease condensate (Department of Interior, 1989). This indicates an average energy requirement of 2-3% of the energy value of crude, according to the DOE *Handbook*, which is consistent with the figure estimated from U. S. Bureau of the Census data.

Actual operating data for the S.H. Loe Oil Corporation are also consistent with these estimates. Before 1987, the company, which operates 148 stripper wells, used 450,000 kWh of purchased power to produce 8,100 bbl of oil, an efficiency (based on Btu-electric) of 3.3% (Spears, 1988). To reduce power costs, the company switched to NG to generate its own power on site; it used about 2,500 10^6 Btu of NG and reduced electricity consumption to 52,500 kWh. The resulting end-use consumption is higher than before (5.7% versus 3.3%), but the overall process efficiency, counting energy used to generate electricity, is considerably lower. Generating power on-site can thus be considered as an efficiency-improving technology in the future.

Note that I use the calculated U. S. energy intensity of petroleum recovery as representative of the energy intensity of recovering all crude, including foreign crude imported by the United States.

TABLE H.1 Energy Used to Explore and Drill for Oil

Fuel	1982		1987	
	Units	Energy (%)	Units	Energy (%)
Crude oil (10^3 bbl)	32,905.3	28.71	11,445.2	12.97
Diesel (10^3 bbl)	13,954.4	12.23	8,785.7	10.00
Residual (10^3 bbl)	5,861.3	5.54	605.5	0.74
Natural gas (10^9 ft^3)	181.7	28.19	249.4	50.28
Coal (10^3 tons)	0.0	0.00	0.0	0.00
Electricity (10^6 kWh)	33,385.4[a]	17.13	26,180.7[a]	17.46
Gasoline (10^6 gal)	270.4	5.09	166.0	4.06
Other (10^6 \$)	151.3	3.12	142.8	4.49
Total energy (quads)	0.665	100.00	0.512	100.00
Total production (USDOC[b]) (10^6 bbl)	3,187.3		3,216.3	
Total production (EIA[c]) (10^6 bbl)	3,156.7		3,047.4	

Sources: The following publications from the U. S. Department of the Commerce, Bureau of the Census: *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985); *1987 Census of Mineral Industries, Crude Petroleum and Natural Gas* (1990); and *1987 Census of Mineral Industries, Oil and Gas Field Services* (1990).

Energy apportioned to oil and gas as per Table H.2 and the discussion in Appendix G.

Note that the oil production reported by the USDOC agrees with the production reported by the EIA to within 1% for 1982 and 6% for 1987, which gives confidence in the energy use figures of the Census.

[a] Oil and gas producers generated and sold a small amount of electricity in 1982. I have subtracted this amount from the total amount of electricity purchased. The Census did not disclose the amount sold in 1987; I have estimated sales in 1987 using data on electricity purchased and sold in all mineral industries.

[b] The correct USDOC total is reported production plus oil's share of oil and gas not specified by kind (n.s.k.). In calculating oil production from the Census data, I have assumed that oil's share of the reported value of oil and gas n.s.k. is equal to oil's share of the total value of oil and gas that is specified by kind (63.5% in 1987; according to the Bureau of the Census, this is a reasonable assumption [Roehl 1989]) and that a barrel of oil specified by kind has the same average value as a barrel of oil n.s.k.

[c] EIA, *Petroleum Supply Annual* (1983, 1988).

TABLE H.2 Data Used to Adjust Census Data on Energy Used to Recover Feedstocks

	\$ Purchased Fuels[a]/ \$ Distributed Fuels[c]		\$ All Products[b]/ \$ Distributed Products[d]	
SIC Area	1982	1987	1982	1987
Oil and gas extraction	1.136	1.111	1.123	1.125
Oil and gas field services	1.138	1.422	Not used	Not used

0.350 fraction of NG used by oil and gas production assigned to oil (my estimate; see text for discussion).

0.950 fraction of all other oil and gas production energy assigned to oil (my estimate; see text for discussion).

0.600 fraction of energy used by drilling services assigned to oil (my estimate; see text for discussion).

0.137×10^6 Btu/\$ of other fuels, 1982 (value used by the Census).

0.161×10^6 Btu/\$ of other fuels, 1987 (value used by the Census).

Sources: See Table H.1.

[a] The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies not surveyed (the Census estimated the value for these companies) and fuels used by companies that did not report how much of each kind of fuel they used.

[b] The total dollar value of all products (crude oil, dry gas, NGLs, uranium ore, etc.) of all companies engaged in the activity, including products from companies not surveyed (the Census estimated production for these companies), and products of companies that did not classify or detail their products (e.g., did not state what kind of coal they produced).

[c] The dollar value of the fuels purchased by companies that reported the amount of each kind of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only total cost of purchased fuels, with no breakdown or details.

[d] The dollar value of products of those companies that reported the amount and kind of each product.

H.2.3 Efficiency of Oil Recovery in the Future

The overall average energy intensity of oil recovery is a function of the quality of crude oil, the location of the crude, and the recovery technology. Heavier crude requires more recovery energy than lighter crude; offshore oil requires more recovery energy than onshore oil, and enhanced oil recovery requires more energy than conventional recovery. The balance among these factors will be determined by oil price, quality, and availability; environmental regulations; energy policy; and the state of recovery technology.

The EIA's *Annual Outlook for Oil and Gas 1990* (AOOG, 1990) projects that offshore oil production will remain relatively constant through 2010. This assumes that the moratoria on drilling off the Pacific Coast will be lifted eventually; if they are not, total offshore production will probably decline.

The EIA also projects that production by enhanced oil recovery will remain fairly constant at about 0.5×10^6 Bd, or about 3% of total petroleum supply, through 2010, due to their forecast of fairly low prices. If the price of crude rises higher than expected, production from enhanced oil recovery could be higher.

Both foreign and domestic crudes are expected to continue to get heavier. This will slightly increase energy requirements.

Overall, it seems that the energy intensity of oil recovery will not increase appreciably by year 2000 and even beyond. Any small increases because of lifting of heavier crudes can probably be countered by efficiency improvements. Therefore, in the base case, I assume that the energy intensity of recovery in 2000 is the same as the calculated value for 1987.

H.2.4 Emissions from the Manufacture of Concrete Used to Plug Oil Well Holes

According to the DOE *Handbook* (1983), 1.1 lb of concrete is used to plug dry oil well holes per barrel of oil produced from onshore primary oil fields (the drilling success rate assumed in the DOE report is about right, according to EIA data). Applying an emission factor for concrete production (Table P.3, note f; the factor includes emissions from $CaCO_3 \longrightarrow CaO$), and accounting for differences between the density of crude and the density of products and for own use of petroleum, one can calculate g/mi emissions attributable to this use of concrete for gasoline, diesel fuel, and residual fuel oil. The result turns out to be trivial: about 0.1 g/mi CO_2-equivalents. I have not included this amount in the final results because it is so small. There are greater, but still quite minor, greenhouse-gas emissions from the manufacture of the steel used to build oil wells. The energy used to make both the concrete and the steel, as a fraction of total oil produced over the lifetime of the field, is shown in Table P.6.

H.2.5 Allocation of Oil Recovery Energy to Products

To understand how one should allocate to products the energy used to recover (and transport) crude oil, one must understand very generally how crude is transformed into products. I will describe the transformation of crude to products, first in terms of mass and then in terms of volume, and from this I will show how the energy used to recover and transport crude should be allocated to products.

Let us start with the ton (2000 lb) as the basic unit of crude oil. Suppose that anywhere from 30 to 60% of each unit of crude is suitable for making gasoline, and the rest (40-70%) is suitable for distillates, kerosene, residual fuel, and other products. Suppose, also, that no mass inputs other than crude go into any product. All of these assumptions, with the exception of the last, which will be lifted shortly, are roughly realistic.

Suppose that in the base case, we have 10 units (tons) of crude, each producing 50% (one-half ton) of gasoline and 50% (one-half ton) of other fuels, for a total of 5 tons of gasoline and 5 tons of other fuels. Now, suppose that the use of an alternative fuel reduces demand for gasoline by 1 ton and demand for distillates by 1 ton. What happens to crude input? Obviously, crude input is reduced by 2 tons (each of the 2 tons would have produced one-half unit, or 1 ton, of gasoline and one-half unit, or 1 ton, of distillate).

But what if demand only for gasoline is reduced by 1 ton? The refinery now has to make 4 tons of gasoline and 5 tons of other products. It could continue to make 50% of each ton of crude into gasoline and 50% into other products, use 10 units (tons) of crude, and simply throw out the unneeded 2 half-units of crude that would have gone to make the one unit (ton) of gasoline no longer needed. But that would be unnecessarily wasteful. Instead, the refinery will change the ratio of gasoline to other fuels drawn from each unit to reflect the new overall demand ratio. It will input 9 units of crude and extract from each unit, four-ninths (44.4%) gasoline, and five-ninths (55.5%) other products (recall that this yield ratio can vary, within limits defined by crude quality, refinery operating conditions, and other costs). Thus, the displaced unit of gasoline will displace exactly one unit of crude.

The result is that, in any case (within the limits of the capability of the refinery to adjust crude yields to reflect product demand ratios), the loss of 1 ton of product implies the loss of 1 ton of crude, given conservation of mass and assuming no inputs other than crude (I ignore mass lost as pollution because it is a very small fraction of the input mass). This means that one assigns recovery energy to products on a mass basis, not a volume basis.

The one-to-one equivalency is in mass terms, not volume terms, because mass, not volume, is conserved. Thus, if the gasoline-producing half-ton of crude has a volume of X barrels, the gasoline produced from it may be more or less than X barrels, depending on the density of gasoline relative to crude. As it turns out, gasoline is less dense than crude (the ratio of the density of gasoline to the density of crude is 0.874) because the molecules of crude input to gasoline are disintegrated and rearranged and recombined to take up more space as gasoline than as crude. This means that it takes less than one barrel of crude to produce one barrel of gasoline. This is a somewhat important fact because gasoline and crude production and consumption are almost always discussed in volume terms, not mass terms, and the volume change in going from crude to gasoline is over 10%. So, if one is working with gasoline gallons, one must at some point convert to grams in order to allocate to gasoline the energy used to recover and transport crude oil.

Now, to make this picture more realistic, one needs to account for refinery inputs other than crude. There are two additional kinds of inputs to account for: 1) unfinished oils, which end up in a range of products, and 2) inputs to gasoline: butanes, pentanes and higher, alcohols, motor gasoline blending components, and other hydrocarbons (I ignore other inputs to aviation gasoline). Because the unfinished oils presumably come from crude oil, have a density similar to that of crude, are used to make a range of products (as is crude), and, in any case, are a small input compared to crude (less than 5%, in volume terms), it is reasonable to treat them as if they were crude oil.

The point thus far is that to calculate the energy used to recover the crude that is used to make a barrel of any product except gasoline, one can multiply the energy required to recover a barrel of crude by the ratio of the density of the product to the density of the crude. (Of course, one can work in mass units from the start, using grams of crude, kg/g, etc.)

The situation is somewhat different with gasoline. The non-crude inputs to gasoline are less like crude than is unfinished oil, and are a slightly larger input, accounting for about 7% of the weight of finished gasoline (taking 2,000 g/gal for butanes and pentanes, 2,897 g/gal for gasoline blending components as naphtha, 3,000 g/gal for other hydrocarbons and alcohol, 2,791 g/gal for finished gasoline, and using input and production data from the EIA's *Petroleum Supply Annual*). This means that crude accounts for 93% of the weight of gasoline and, given that 1 ton of crude takes up 87.4% of the space of 1 ton of gasoline, and that 0.82 bbl of (the gasoline-making part of) crude goes toward a barrel of gasoline. The rest of the gasoline barrel comes from non-crude inputs and from the increase in volume resulting from rearranging the crude inputs.

Ideally, one would assume first that 0.82 bbl of crude makes a barrel of gasoline, calculate the energy required to recover the crude-based portion of gasoline, and then separately calculate the energy required to produce the non-crude components. I do this in a simplified way: I assume that the alcohol portion of the gasoline additives methyl tertiary butyl ether (MTBE) and ethyl tertiary butyl ether (ETBE) come from sources other than crude, but that the rest of the MTBE and ETBE and all other gasoline additives come from crude. I have separated the alcohol component of MTBE and ETBE because these are quite different from gasoline, and because the model can calculate emissions from the production of the alcohols (this is discussed further below, in connection with reformulated gasoline). I assume that, in effect, the rest of the gasoline blending components come from crude (or, what amounts to the same assumption, that the true feedstock for gasoline blending components, if it is not crude, has the same density and takes as much energy per barrel to recover as does crude oil).

There are further complications. As a result of a change in product demand, refineries may use a different slate of crudes that will require more or less energy to recover and transport than the original slate. Moreover, the marginal energy required to make a unit of product depends on the product demand ratio. I ignore these complications.

Thus, I allocate recovery energy by using density ratios for each product; formally:

$$Er_{p,i} = O_p \times (D_p/Dc) \times (Te_i/(Cr) \times H_p$$

where:

$Er_{p,i}$ = the amount of energy, i, required to recover the crude needed to make an energy unit of product, p, available to consumers;

O_p = the own-use factor for product, p (see Appendix A, and below);

D_p = the density of product, p (EIA data; Table C.1);

D_c = the density of crude oil (EIA data; Table C.1);

Te_i = total energy type, i, required to recover crude in the United States (Table H.1);

Cr = the volume of crude recovered (associated with the use of energy, Te_i (Table H.1); and

H_p = the volumetric heating value of product, p (EIA data; Table C.1).

In the case of reformulated gasoline, D_p is equal to grams of crude-derived gasoline per liter of reformulated gasoline. It is calculated as:

$$D_{p,g\text{-}c} = D_{p,rg} - MTBE \times 0.3386 \times D_m - ETBE \times 0.425 \times D_e$$

where:

$D_{p,g\text{-}c}$ = grams of crude-derived gasoline per total liter of reformulated gasoline,

$D_{p,rg}$ = total g/L density of reformulated gasoline (Table C.1), MTBE = MTBE volumetric fraction of reformulated gasoline,

0.3386 = effective methanol volumetric fraction of MTBE,

D_m = g/L density of methanol (Table C.1),

ETBE = ETBE volumetric fraction of reformulated gasoline,

0.425 = effective ethanol volumetric fraction of ETBE, and

D_e = g/L density of ethanol (Table C.1).

With the assumption that the energy intensity of oil recovery outside the United States is the same as the U. S. intensity, and the assumption that any non-crude components of products effectively come from crude, the single value calculated here can be used for all products, imported and domestic, consumed in the United States.

This calculation is done for each kind of energy, i, used to recover crude. The $Er_{p,i}$ for each kind of energy is multiplied by the g/10^6 Btu emission factors for that kind of energy to yield emissions of greenhouse gases per unit of product energy available to consumers. This is summed over all the kinds of energy to produce total emissions of greenhouse gases from crude recovery, per energy unit of product, p, available to consumers.

H.3 Greenhouse Gas Emissions from Refineries

The U. S. Environmental Protection Agency (EPA) reports total national emissions of carbon monoxide (CO), nitrogen oxides(NO_x) and volatile organic compounds (VOCs) (NMHCs) from petroleum refineries (*National Air Pollutant Emission Estimates*, 1990). The total is equal to emissions from the use of refinery fuels (LPG, NG, refinery gas, etc.) plus emissions from refinery process areas and equipment (catalytic crackers, valves and pumps, etc.). The EPA's calculation of emissions from process units accounts for the national average use of emission controls, which is determined from emissions data reported by refineries to states and then to the EPA. I have reproduced the EPA's method here.

Total emissions from refineries are calculated as:

$$E_r = GG_f + GG_{pa} + CO2_{co}$$

where:

E_r = emissions from refineries;

$GG2_f$ = CO_2-equivalent emissions from fuels consumed for process energy (e.g., refinery gas);

GG_{pa} = CO_2-equivalent of CO, NMHC, methane (CH_4), NO_x, and nitrous oxide (N_2O) emissions from all refinery process areas other than fuel combustion (e.g., fluid catalytic crackers and blowdown systems); and

$CO2_{co}$ = CO_2 emissions from refinery process units as a result of burning CO to CO_2.

By far, the largest component of E_r is GG_f.

H.3.1 Emissions of Greenhouse Gases from Boiler Fuels

The CO_2-equivalent emissions from fuel use are calculated from data on the amount and carbon content of fuels consumed by refineries (EIA, *Petroleum Supply Annual*; Tables H.4 and C.1 in this report) and emissions of non-CO_2 gases from industrial boilers (Table A.2). The CO, NMHC, and CH_4 emission factors in Table A.2 are uncontrolled emission factors for industrial boilers (EIA, AP-42). The NO_x emission factor is calculated by assuming that by 2000, 47% of boilers will meet recent New Source Performance Standards (NSPS) for NO_x from industrial steam-generating units, and 53% of boilers will be uncontrolled at the AP-42 rate (see DeLuchi, 1991, for details). The N_2O emission factor is the same as for utility boilers.

I have not developed emission factors for all 13 refinery fuels shown in Table H.4. To simplify, I have lumped them into six groups, as can be seen in Table 5, and have applied the most representative emission factor to each group. Thus, refinery use of NG, LPG, and steam is added together and multiplied by the total CO_2-equivalent emission factor for NG-fired industrial boilers (Table A.2; I use NG because NG is by far the dominant fuel of the three); use of still gas and hydrogen is added together and multiplied by the refinery gas emission factor (Table A.2); coal and coke are added and multiplied by the petroleum coke factor (Table A.2; coke consumption is much greater than coal consumption); and residual fuel and crude oil are added and multiplied by the emission factor for fuel oil-fired industrial boilers. Use of diesel fuel is multiplied by the diesel engine factor, and use of electricity is multiplied by the electricity-use factor specifically for refineries. With refinery gas, I have assumed that emissions of CH_4, NMHCs, and CO are the same as from NG-fired industrial boilers (refinery gas is mostly methane).

These CO_2-equivalent emissions from fuel use are allocated to products according to the amount of fuel required to make each product. The allocation of refinery energy to particular products is discussed later.

TABLE H.3 Petroleum Supply, 1987[a]

Item	10^3 bbl	10^6 kg
Refinery production		
Gasoline	2,497,019	292,706
Diesel	996,119	133,544
Residual fuel	323,201	48,529
NGLs and LRGs	163,703	
All products[b]	5,338,657	725,115
Imports		
Gasoline	140,204	
Diesel	93,176	
Residual fuel	206,138	
NGLs and LRGs	73,290	
All products[b]	731,437	
Field production		
Gasoline	123	
Diesel	516	
Residual fuel	0	
NGLs and LRGs	580,714	
All products[b]	605,612	
Total production		
Gasoline	2,637,346	309,155
Diesel	1,089,811	146,104
Residual fuel	529,339	79,480
NGLs and LRGs	817,707	
All products[b]	6,675,706	906,718
Refinery crude input	4,691,783	628,802
Other input	400,000	
Crude input/refinery production		
Gasoline	1.879	
Diesel	4.710	
Residual fuel	14.517	
NGLs and LRGs	28.660	
All products[b]	0.879	
All input/refinery production	0.954	

Source: EIA *Petroleum Supply Annual* (1988).

[a] This table is not mentioned in the text until Section H.8 on page H-44.

[b] All products includes asphalt, tar, petroleum coke, unfinished oils, LPG, and more.

TABLE H.4 Refinery Energy Use

Fuel	1981 Units	1981 Energy (%)	1989 Units	1989 Energy (%)
Crude oil (10^3 bbl)	399	0.09	24	0.00
Diesel fuel (10^3 bbl)	1,960	0.46	429	0.09
Residual oil (10^3 bbl)	26,656	6.77	11,733	2.61
LPG (10^3 bbl)	6,617	0.98	11,962	1.55
Natural gas (10^3 ft^3)	650,875	27.12	612,948	22.38
Refinery gas (10^3 bbl)	178,970	43.38	241,935	51.38
Marketable coke (10^3 bbl)	1,398	0.34	1,234	0.26
Petroleum coke (10^3 bbl)	55,346	13.47	77,444	16.51
Coal (10^3 tons)	1,059	0.93	172	0.13
Electricity (10^6 kWh)	33,044	4.55	31,621	3.82
Steam (10^6 lb)	24,575	1.19	29,210	1.24
H_2 (10^3 SCF)	0	0.00	0	0.00
Oils and other (10^3 bbl)	3,054	0.72	124	0.03
Total energy use (quads)				
Energy used	2.48	100.00	2.83	100.00
Process energy/product energy	8.92		9.46	

Source: EIA, *Petroleum Supply Annual* (1982, 1990).

TABLE H.4a Refinery Energy Intensity, 1981-1989, Btu-Used/Btu-Produced[a]

1981	1982	1983	1984	1985	1986	1987	1988	1989
0.0892	0.0916	0.0935	0.0914	0.0921	0.0957	0.0943	0.0949	0.0946

[a] This table is not mentioned in the text until Section H.6 on page H-34.

Refinery energy intensity calculated as:

$$Re = Er / (Ro \times Hr)$$

where:

Re = Btu-refinery energy/Btu-refinery output
Er = energy used by refineries, 10^6 Btu (EIA, *PSA*, 1982-1990)
Ro = refinery output, bbl (EIA, *PSA*, 1982-1990)
Hr = weighted average HHV (10^6 Btu/bbl) of refinery output, calculated as:
Hr = $(Hp \times P - Hi \times I + He \times E)/(P - I + E)$
Hp = weighted average HHV of total petroleum products supplied in the U. S. (EIA, AER, 1990)
P = total supply of petroleum products (EIA, AER, 1990)
Hi = weighted average HHV of imports (EIA, AER, 1990)
I = total imports (EIA, AER, 1990)
He = weighted HHV of exports (EIA, AER, 1990)
E = total exports (EIA, AER, 1990)

H.3.2 Emissions of Non-CO_2 Greenhouse Gases from Other Process Areas

DeLuchi (1991) calculates emissions of NMHCs, CO, and NO_x from all refinery operations excluding fuel combustion by using the method the EPA uses in calculating emissions for its National Emissions Data System (NEDS). The calculation assumes year-2000 controls of NO_x and fugitive HC emissions. These emissions factors are used here.

Emissions of CH_4 from non-fuel-use process areas are calculated by subtracting fuel-use CH_4 emissions from total, refinery-wide emissions. The calculation of emissions from fuel use is explained above. Total, refinery-wide emissions data are from the Texas Air Control Board (1990) and the South Coast Air Quality Management District (1990). The result is grams of methane emissions from particular refineries; this is converted to g/106 Btu by using data on the capacity of the refineries whose methane emissions were reported (EIA, PSA). See Appendix M for a more complete explanation.

I estimate N_2O emissions relative to N_2O emissions from utility boilers, considering the possibility that fluidized-bed combustors may emit relatively high amounts of N_2O (see Appendix N).

These process-area emissions of non-CO_2 greenhouse gases are then allocated separately to gasoline, diesel, and residual fuel, by using data in DeLuchi (1991). The allocation of process-area emissions is very similar to the allocation of fuel use, which is discussed below.

H.3.3 Emissions from Control of CO from Catalytic Crackers

I calculate CO_2 emissions from control of CO from catalytic crackers by estimating uncontrolled CO emissions by using AP-42 emission factors for catalytic crackers, and data in Thrash (1990) on national capacity of different kinds of catalytic crackers), subtracting from this actual CO emissions (as reported by the EPA), and converting the difference (controlled CO) to CO_2. The same could be done for controlled HC emissions, but the calculation is complicated by the fact that only one form of hydrocarbon (HC) control (flaring) converts HCs to CO_2. HC recovery, which reduces fugitive HC emissions and emissions from oil/water separation, does not produce CO_2. For simplicity, I assume that HC control does not produce CO_2.

H.3.4 Emissions from Sulfur Control

Recall that the use of carbonate to scrub oxides of sulfur (SO_x) from the flue gas of a coal-fired power plant produces CO_2 (Appendix D). One might ask, then, if the removal and control of sulfur at petroleum refineries produces significant amounts of CO_2.

Petroleum refineries have sulfur recovery plants that convert the H_2S in refinery gas streams to elemental sulfur. As discussed in Appendix G, H_2S sulfur plants probably produce only trivial amounts of CO_2. I ignore this source.

However, recent NSPS limit sulfur emissions from fluid catalytic cracking units (FCCUs) (Federal Register, August 17, 1989). The EPA expects that refiners will be able to meet the standards by using scrubbers, catalytic reduction, or low-sulfur feed. Presently, sodium scrubbers are used to control SO_x emissions from FCCUs.

The NSPS for FCCUs require that add-on control devices, such as scrubbers, reduce SO_x by 90%. Using a simple refinery emission model described in DeLuchi (1991), I have calculated that by the year 2000, control of SO_2 emissions from FCCUs will reduce SO_2 emissions by 0.756 g/gal of gasoline produced and 0.691 g/gal of diesel fuel produced, if all FCCUs that control SO_x achieve a 90% reduction over AP-42 uncontrolled emission levels. If half of the SO_2 is controlled by scrubbers that generate one mole of CO_2 per mole of SO_2 removed, then 0.52 g of CO_2 will be emitted per gallon of gasoline and 0.48 g of CO_2 per gallon of diesel fuel. At 30 mpg, this amounts to less than 0.005% of fuel-cycle CO_2-equivalent emissions. I ignore it here.

Recently, a dry carbonate-based scrubber has been installed on a petroleum coke calciner in a refinery in Colorado (Brown et al., 1990). This scrubber produces 2 mol of CO_2 for every 1 mol of SO_2 removed. The authors note that the scrubber could be used to remove SO_2 from the flue gas of FCCUs or fluid cokers, as well. Since SO_2 emissions from petroleum coke processes are less than from FCCUs, CO_2 emissions from the control of these SO_2 emissions will be negligible.

H.3.5 Emissions from Electricity Use

Emissions from electricity use from refineries are calculated by multiplying emissions from each type of power plant by refinery use of electricity from each type of plant. This is discussed in more detail later.

H.3.6 Emissions of CO_2 from Non-Fuel Sources

It is possible that some of the carbon in the input crude ends up neither as carbon in a product nor carbon in a refinery fuel, but is simply lost as CO_2. Presumably, though, the amount is very small: the purpose of refining is to separate and rearrange components of the crude, and the products contain about as much carbon as does the input crude. A rough carbon balance check, based on national crude input, product output, and carbon composition, shows that carbon input and output are very nearly equal. I assume that there is no significant loss of carbon as CO_2.

H.4 Calculation of Energy Used in Petroleum Refining, and Allocation to Products

H.4.1 Overall Energy Consumption

Petroleum refineries report energy consumption by type of fuel in the EIA's "Annual Refinery Report," and the EIA publishes the results in the *Petroleum Supply Annual* (Table H.4). These are the most detailed data available. The electricity consumption data reported by the EIA agree with the electricity consumption data reported in the Manufacturing Energy Consumption Survey (MECS) and the Annual Survey of Manufactures (ASM), and the overall-energy-consumption data in the Petroleum Supply Annual agree with the data in the MECS (after the energy used as a feedstock for nonfuel products is deducted from the MECS total). I use the EIA *Petroleum Supply Annual* data. The data for 1981 and 1989 are shown in Table H.4. Note that I assume that the U. S. refinery energy consumption data are representative of all refineries, including those overseas, that supply the United States with products.

H.4.2 Allocation to Particular Products

Refineries produce a wide range of products, from jet fuel to tar, and the energy consumption of refineries must be allocated to these products. The simplest course would be to assume that the energy consumed by a refinery per barrel of product is the same for all products. An argument in favor of this approach (besides its appealing simplicity) is that the major energy users in a refinery (crude distillation and cracking) produce multiple products. Getting to the bottom of the barrel (residual fuel oil and tar) requires removing the top of the barrel (butanes and light naphthas), and so the energy of separation or cracking should be assigned to all products in proportion to output. However, several energy consuming processes, such as reforming, alkylation, and isomerization, produce only one product (gasoline, in this case) and it would not be reasonable to allocate this energy to all refinery output. A product-by-product accounting is required. Here, I consider two approaches, one based on models of refinery of operation, the other based on energy consumption of major refining processes. After estimating the amount of energy required to make current gasoline and diesel fuel, I discuss how the reformulation of these fuels is likely to affect refinery energy consumption by 2000.

H.4.2.1 The Modeling Approach to Allocating Refinery Energy Use

As discussed in the Appendix A, to correctly estimate the energy required to refine gasoline, one would have to estimate energy use by refineries in "with gasoline" and "without gasoline" scenarios. The "with gasoline" scenario would project energy use by refineries producing a mix of products similar to the current mix. The "without gasoline" scenario would project energy consumption by refineries producing considerably less gasoline, under the presumption that an alternative fuel is displacing some gasoline demand. The difference in energy use by refineries in these two scenarios would be the correct energy consumption to assign to gasoline. Unfortunately, it is difficult to estimate how refineries will respond to a change in demand because refineries have several options: they can change the yield from a particular kind of crude; change refining processes, pathways, additives, etc.; change the mix of crudes they use; and in the long-run, invest in new technology.

Consequently, this approach to estimating refinery energy consumption requires a detailed model of refinery operations. Lawrence et al. (1980) modeled energy consumption of a modern, self-sufficient refinery (one that generates its own electricity) as a function of the ratio of gasoline production to distillate (diesel fuel, jet fuel, kerosene, and residual fuel) production (G/D), and the mean octane number of the gasoline. The refinery produces 76 mbd (thousand barrels per day) of gasoline and diesel fuel and about 75 mbd of other products. They found that if the change in the G/D ratio was high and the octane was low, less energy was required to produce gasoline.

By using data in Lawrence et al. (1980), energy requirements at 86 octane for the difference between G/D = 1.6 and 0.7 can be calculated by:

$$71Ga_{1.6} + 5De_{1.6} + 75R_{1.6} = 66; \quad O_{1.6} = 0.44$$

$$48Ga_{0.7} + 28De_{0.7} + 75R_{0.7} = 58; \quad O_{0.7} = 0.39$$

where:

Ga = energy required to make gasoline (10^9 Btu/10^3 bbl);

De = energy required to make diesel (10^9 Btu/10^3 bbl);

R = energy required to make the rest of the products (10^9 Btu/10^3 bbl);

O = energy required to make all products (10^9 Btu/10^3 bbl); and

numerical subscript (such as 0.7) = the G/D ratio.

If one assumes that $R_{1.6} = R_{0.7}$, and the same for Ga and De, then:

$$Ga = 0.35 + De$$

$$De = 0.54 - R$$

If R and De are roughly equal, then $De = R = 0.27$, and $Ga = 0.62$. This implies that the amount of energy required to refine a barrel of gasoline is about 12.8% of the energy in the barrel, and for diesel, about 5.0% (it appears that they use lower heating values for the energy value of refinery fuels, so I have used lower heating values for products in calculating these percentages).

At 90 octane, and G/De of 1.6 and 1.3, the results are:

$$Ga = 0.80 + De$$

$$De = 0.29 - R$$

which results in an energy requirement of 19.5% for gasoline and 2.7% for diesel fuel. (This difference between gasoline and diesel may be too large. Note that if all the energy used by refineries in 1988 was assigned only to gasoline — and gasoline output was only 45% of total refinery energy output in 1988 — the intensity would be 21%; see data in Table H.4. It seems unlikely that virtually all of the energy of the refinery is going to produce less than half of the product slate.) Thus, according to their model, refining a barrel of gasoline requires between 12.8% and 19.5% of the energy in the barrel, depending on octane and G/D ratio, for a refinery consuming about 9% of the energy value of all products, on average.

Ideally, one would specify the marginal energy requirements of gasoline and diesel manufacture at specific octanes and G/D ratios. However, this is beyond the scope of this project. I assume one overall average energy intensity.

H.4.2.2 The Allocation by Process Area Approach to Allocating Refinery Energy Requirements

A second way to assign refinery energy to particular products is to allocate the energy consumed by major refining processes to the output of those processes. Again, Lawrence et al. (1980) provide enough data to do this calculation. They show energy consumption by 10 major refining areas, as a function of the mean octane rating of the gasoline and the ratio of gasoline production to distillate production. Haynes (1976) also analyzes energy consumption by type of refining process and type of energy used fuel; his breakdown of refining areas is not quite the same as that of Lawrence et al.

In Table H.5 I show how Haynes and Lawrence et al. assign energy to various refining units. I then allocate energy use in each refining area to gasoline, diesel, and residual oil, according to the extent to which each area is used to produce each kind of product. (The allocation and explanations are shown in Table H.5.) With these data, along with the figure for the total energy used by refineries per unit of product energy output (Table H.4) and data on products and product output distributions (EIA *Petroleum Supply Annual*), it is easy to calculate the refinery energy required produce gasoline, diesel, and residual fuel. The results are shown in Table H.6.

TABLE H.5 Allocation of Products and Refinery Energy Use to Process Areas in a Refinery

	Allocation of Refinery Energy[a]		Product Allocation to Area[b]		
Product Allocation to Area[b]	Lawrence et al.	Haynes	Gasoline	Dist.	Residual
Crude distillation	0.276	0.364	0.454	0.302	0.070
Catalytic cracking	0.314	0.065	0.550	0.365	0.085
Thermal cracking		0.033	0.454	0.302	0.070
Hydrocracking		0.044	0.541	0.359	0.000
Desulfurization	0.020	0.454	0.302	0.070	
Hydrotreating		0.085	0.541	0.359	0.000
Alkylation	0.065	0.069	1.000	0.000	0.000
Reforming	0.191	0.225	1.000	0.000	0.000
Coking	0.038	0.032	0.541	0.359	0.000
Visbreaking		0.007	0.000	1.000	0.000
Propylene concentration	0.050		0.000	0.000	0.000
Gas oil refractionation	0.000		0.000	1.000	0.000
Isomerization	0.042	0.002	1.000	0.000	0.000
Hydrogen		0.025	0.541	0.359	0.000
Finishing and other	0.003	0.055	0.454	0.302	0.070
Total (as a check)	0.999	1.006			

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[a] Energy used in a particular process area divided by total refinery energy use.

[b] The fraction of total energy use in each process area assigned to gasoline, diesel, and residual fuel. I assigned the energy used by crude separation (atmospheric or vacuum distillation) to all refinery products, fuels and nonfuels, in proportion to refinery energy output, because all products go through crude separation first. Catalytic and thermal cracking likewise produce multiple products; thermal cracking, which in some cases produces nonfuel products, is assigned to all products (fuel and nonfuel) in proportion to outputs, whereas catalytic cracking is assigned to all fuel products in proportion to output. Alkylation, reforming, and isomerization, which produce high-octane gasoline components, are assigned entirely to gasoline (See Haynes, 1976; Lawrence et al., 1980; Wolsky and Gaines, 1981; EIA, *Petroleum Supply Annual,* and *The U. S. Petroleum Refining Industry in the 1980s*). Hydrocracking produces gasoline, distillates, butane, and LPG, and hydrotreating usually is done to middle distillates (Haynes, 1976; Wolsky and Gaines, 1981; EIA *Petroleum Supply Annual*), so I assign 90% of the energy consumed by hydrogen production and hydrogen-consuming processes to gasoline and distillate production. Cokers (a type of thermal cracker) produce gasoline, distillates, and coke, and gas oil refractionation is used to separate distillates (Lawrence et al., 1980). Visbreaking (a form of thermal cracking) is assigned to distillates (Haynes, 1976; Wolsky and Gaines, 1981; EIA, *Petroleum Supply Annual*).

TABLE H.6 Estimates of Refinery Energy Use, Btu-Process-Energy/Btu-Product

	Estimates for Standard Gasoline						Used Here	
Product	1	2	3	4	5	6	Standard	Reformulated
Gasoline	0.128-0.195	0.130	0.132	0.150	0.128-0.161	0.136	0.145	0.182
Diesel	0.027-0.050	0.068	0.073	0.041	0.064	0.022	0.058	0.065
Residual	0.025-0.046	0.064	0.050	0.033	- -			0.045
LPG		0.062	0.048		0.172	0.027		0.054[a]

All results adjusted to be consistent with total energy use by current refineries. All results on HHV basis, counting electricity as Btu-electric. The results based on references 1-5 have not been adjusted to account for the CAA Amendments in the U. S. that reduce the sulfur content of diesel and the RVP of and reactivity of gasoline. The values used here do no include the energy required to make the methanol component of added MTBE. That energy is accounted for separately. However, the values used here are meant to include any energy required to synthesize MTBE from methanol and isobutylene.

1 = My calculation using modeling results of Lawrence et al. (1980).

2 = My calculation using energy allocation to refining area by Lawrence et al. (1980).

3 = My calculation using energy allocation to refining area by Haynes (1976).

4 = Mertes and Huscwiz (1980), using data in Haynes (1976).

5 = White et al. (1982). I have reduced the numbers shown in their paper by 6%, to scale overall refinery energy requirements (per barrel of crude) down to 1987/88 levels. The low end refers to regular, the high end to premium gasoline.

6 = Craig et al. (1991).

[a] Includes energy for liquefaction. Based on rough allocation of process energy use (details not shown).

White et al. (1982) combine both approaches: they use a linear programming model to calculate energy consumption at each process area, and then they allocate process-area energy requirements to specific products by determining mass flow and separation across the particular unit and the ultimate fate of the mass. They modeled a modern refinery producing the gasoline and diesel fuel using crude oil that was expected to be marketed in the late 1980s. The results were similar to those in Lawrence et al. (1980): regular gasoline = 13.6%, premium gasoline = 17.1%, diesel fuel = 6.8%, and LPG = 18.3%. Note: the value for LPG is probably too high.

H.4.3 Other Sources of Information

Gaines and Wolsky (1981) compare seven estimates (including that of Haynes) of Btu of energy used by a refinery process per barrel of feed to the process. For most processes in refineries, the average of the seven estimates is within 20% of the Haynes value, which lends credibility to the Haynes allocation.

Mertes and Huscwiz (1980) do a calculation similar to mine, using the data in Haynes. They calculate the amount of diesel, residual fuel, LPG, NG, refinery gas, coke, and electricity used to make diesel fuel, residual fuel, and gasoline. The results are shown in Table H.7.

Recently, Craig et al. (1991) have allocated refinery energy to gasoline, diesel, and LPG based on process-area energy requirements reported in Sittig (1978). Their results are shown in Table H.6. Their value for gasoline is consistent with the results of the other studies discussed here; the value for diesel fuel is somewhat low. The Craig et al. value for LPG is almost one order of magnitude smaller than that of White et al. (1982). My own calculation results in a value closer to that of Craig et al. (My assumption for LPG is shown in Table H.6.)

Mertes and Huscwiz scaled values (see note d to Table H.7) are consistent with the output of Lawrence et al.'s refinery model and with the allocation of energy use by area to the three products, using Lawrence et al.'s data and Haynes' data. The results of the various ways of estimating energy requirements by product are shown in Table H.6.

H.4.4 Effect on Refinery Energy Consumption of Making Low-Sulfur Diesel Fuel

The final calculation of the energy required to make diesel fuel 2000 must reflect recent EPA regulations that will reduce the sulfur content of diesel fuel from 0.25% to 0.05% and cap the aromatic content at 35% (Federal Register, August 21, 1990). The reduction of sulfur content, by hydrodesulfurization (or hydrotreating), will require higher operating temperatures, more hydrogen, more waste gas treatment, and more sulfur recovery, and these will increase refinery energy requirements.

TABLE H.7 An Estimate of Amount and Type of Energy Used by Refineries to Produce Diesel Fuel, Residual Fuel, and Gasoline, 10^6 Btu Energy/10^6 Btu Product

Process Energy Source	Diesel Fuel		Residual Fuel		Gasoline	
	Btu/Btu[a]	%[b]	Btu/Btu[a]	%[b]	Btu/Btu[a]	%[b]
Diesel	0.000539	1.1	0.0005643	1.5	0.001830	1.1
Residual oil	0.00365	7.7	0.003595	9.5	0.01302	7.5
LPG	0.0005392	1.1	0.0005643	1.5	0.001830	1.1
Natural gas	0.01977	41.8	0.01390	36.7	0.06884	39.8
Coke	0.004974	10.5	0.003369	8.9	0.02378	13.8
Refinery gas	0.01381	29.2	0.01361	35.9	0.04924	28.5
Electricity	0.00399	8.4	0.002281	6.0	0.01432	8.3
Totals	0.04727	100.00	0.037884	100.00	0.17286	100.00
Total scaled to current refinery use[d]	0.041		0.033		0.150	

Source: Mertes and Huscwiz (1980).

[a] Btu of process energy used per 10^6 Btu of product.

[b] % of total process energy requirements.

[c] Btu-electric.

[d] Mertes and Huscwiz modeled refineries as consuming more energy than current refineries actually do. I have scaled down their total 10^6 Btu-process-energy/10^6 Btu-product estimates by the ratio of current refinery energy use to their assumed refinery energy use. Specifically, Mertes and Huscwiz assumed that the refinery produced in the ratio of 426 x 10^6 Btu of gasoline, 331 x 10^6 Btu of distillates, and 108 x 10^6 Btu of residual oil. This indicates a weighted average energy consumption of 10.8% of the energy value of the products, a factor about 1.15 higher than the current national average. Dividing their original results by 1.15 (to scale the results to current national average) yields energy intensities (10^6 Btu-fuel/10^6 Btu-product) of 4.1% for diesel, 3.3% for residual fuel, and 15% for gasoline.

Dutch researchers have estimated that an 0.05% sulfur cap will increase total refinery energy consumption by 0.8 to 1.0 × 10^6 t/yr at the 95 refineries in the 12 EEC countries (van Paassen et al., 1988). In the EEC, petroleum refineries mainly use refinery gas and residual oil as process fuels (IEA, *Energy Statistics of OECD Countries*, 1990), so the extra 0.8-1.0 × 10^6 t of process fuel amounts to 0.037-0.047 quad (using the g/10^6 Btu values for residual fuel, Table C.1, and refinery gas, Table C.3). The EEC produced 165 × 10^6 t of diesel fuel in 1988 (IEA, *Energy Statistics of OECD Countries 1987-1988*), which amounts to 7.17 quads. The additional 0.8-1.0 × 10^6 t of process fuel required to meet the 0.05% standard indicates that the ratio of Btu-process energy/Btu-diesel will increase absolutely by 0.51-0.66

(e.g., 0.59-0.65). This represents roughly a 10% relative increase in the Btu-process energy/Btu-diesel ratio.

The energy requirement may be greater in the United States than in Europe because U. S. refineries may have less hydrogen available for hydrotreating, and they will have to make hydrogen, at an energy cost. As discussed below, the Clean Air Act (CAA) mandates a low-RVP, high-oxygen, low-VOC-forming, low-toxics reformulated gasoline, and this will require less severe reforming, which in turn will result in less hydrogen production.

The estimate of a 10% relative increase can be checked by assuming that the percent increase in energy cost, and hence energy use because of the manufacture of low-sulfur diesel, will be equal to the percent increase in total refining cost. The total percent increase in cost is calculated as follows: a refinery model commissioned by the EPA (1989, *Draft Regulatory Impact Analysis...*) projects that the regulations will increase the cost of making diesel fuel by about $0.02/gal. The Dutch study estimates the increase to be $0.038-0.057/gal (van Paassen et al., 1988). The difference between the wholesale price of diesel and the refiners acquisition cost for crude, as reported by the EIA's *Petroleum Marketing Monthly June 1989*, is typically $0.10-0.20/gal (diesel #1 sells for more than diesel #2; both are used by vehicles). Thus, the $0.02/gal increment represents a 10-20% increase in the apparent cost of making diesel fuel. This is consistent with the 10% increase calculated above.

Both the United States and Europe are likely to lower the limit on the aromatics content of diesel fuel. This will further increase the energy requirements of refining diesel fuel. Also, as mentioned above, the need in the United States to make hydrogen will increase energy requirements. Therefore, I assume an 0.7-point absolute increase in Btu-process-energy/Btu-diesel requirements (the high end of the range estimated above for making low-sulfur diesel fuel), from about 0.058 Btu/Btu at present, to about 0.065 (Table H.6). (As discussed below, I have assumed that increased energy use due to processing increasingly lower-quality crudes will be balanced by technical improvements in process efficiency and the phasing-out of older, less efficient refineries.) I do not assume any change in the amount of crude oil required to make a barrel of diesel fuel, as a result of the new standards. My base-case assumption is shown in Table H.6.

H.4.5 The Effect on Refinery Energy Consumption of Making Lower-RVP, Less Reactive Gasoline (Reformulated Gasoline): Qualitative Background Discussion

The new CAA Amendments (EPA, *CAA*, 1990) require a reduction in the volatility of gasoline, a reduction in the benzene content, a minimum oxygen content of 2%, and a reduction in the VOC-forming potential of gasoline. To meet these requirements, refineries will have to change their operations and inputs. These changes will increase refinery energy consumption; hence, emissions of greenhouse gases will increase, in 2000, compared to today.

Beginning in 1992, gasoline sold in the summer months (May-September) in the United States cannot have an RVP greater than 7.8-9.0 psi, depending on the average monthly temperature and ozone-attainment status of the area (9.0 RVP in ozone-attainment areas; 7.8 RVP in warm, nonattainment areas) (Federal Register, June 11, 1990; EPA, *CAA*, 1990). To satisfy these regulations, refiners will not be able to add butane (which is extremely volatile), and in some cases may have to remove butane. Butane adds bulk to gasoline and raises its octane level, and so the lost butane-bulk and octane will have to be made up somehow. The bulk can be at least partially made up, and the octane enhanced, by converting the surplus butane to high-octane, low-RVP components, such as heavy ethers (MTBE) and alkylates (EPA, *Final Regulatory Impact Analysis...Phase II Gasoline Volatility Regulations*, 1990). Additional bulk can be provided by reducing the severity of reforming, and perhaps by simply increasing the input of crude oil per barrel of gasoline.

The CAA Amendments require reformulated gasoline in the nine worst ozone-nonattainment areas, beginning in 1995 (EPA, *CAA*, 1990). The CAA specifies that gasoline must be at least 2.0% oxygen by weight, and not more than 25% aromatics by weight (or, provide a 15% reduction in emissions of VOCs and toxic air pollutants). Gasoline in CO nonattainment areas must be 2.7% oxygen in winter months. It is widely expected that refiners will meet these requirements by replacing some of the relatively reactive aromatics and light olefins with high-octane, low-reactivity oxygenates, MTBE and ETBE (Piel 1989; USGAO 1990; Boekhaus et al. 1990; U. S. Congress, OTA, 1990; EIA, AOOG, 1990). For example, the addition of 15% MTBE by volume will reduce the concentration of aromatics to about 22%, and add 2.7% oxygen by weight (Boekhaus et al. 1990).

To reduce aromatics, the use of the reformer, which produces aromatics, will have to be reduced. The old reformer feed will be redirected to the catalytic cracker, and the severity of catalytic cracking will be increased to favor the formation of olefins, which then can be alkylated or polymerized into highly branched, less reactive paraffins, or combined with alcohols to make oxygenates (Piel, 1989; Boekhaus et al., 1990; U. S. Congress, OTA, 1990; EIA, AOOG, 1990).

In summary, to make low-RVP, low-aromatics gasoline, refineries will probably reduce the severity of reforming, increase the severity of catalytic cracking, increase alkylation, and make or add more oxygenates. On balance, these changes are likely to increase the energy requirements of refineries. Reducing the severity of the reformer to reduce aromatics production, will reduce energy consumption in the reformer (the reformer is a big energy consumer), but will also reduce hydrogen production. Unless the refinery vented hydrogen prior to the reformulation (which is very unlikely), this hydrogen deficit will have to made up, probably by steam reforming natural gas. This, of course, will increase refinery energy use in the form of extra natural gas consumption. And the increased severity of catalytic cracking, and the increased use of alkylation and polymerization to produce alkylates and oxygenates, will also increase energy requirements.

The manufacture of MTBE or ETBE will also increase energy requirements, both inside and outside refineries. One liter of MTBE is produced from a reaction of isobutylene and 0.338 L of methanol, and 1 L of ETBE is produced from isobutylene and 0.425 L of ethanol

(Piel, 1989). In the United States, the methanol will be made from NG, and the ethanol will be made from corn.

Currently, isobutylene is derived from steam cracking and fluidized-bed catalytic-cracker (FCC) units in refineries, but these supplies are limited. Additional supplies will be made by processing the excess butane available as a result of the volatility restrictions discussed above (EIA, AOOG, 1990).

H.4.6 Quantifying the Extra Energy Cost of Making Low-RVP, Low-Aromatic, High-Oxygen Gasoline

The energy effects discussed above can be classified as in-refinery (changes in reforming, cracking, alkylation, and production of isobutylene), and out-of-refinery (manufacture of methanol or ethanol used to make MTBE and ETBE). The greenhouse gas emissions impact of out-of-refinery changes can be quantified relatively easily because the emissions model developed here includes complete fuel-cycle greenhouse-gas emissions from methanol and ethanol production. Thus, to incorporate out-of-refinery greenhouse gas emissions, the model calculates the fuel-cycle greenhouse gas emissions from the production and delivery of a specified amount of alcohol and adds this to greenhouse gas emissions from gasoline production. The specified effective alcohol content of gasoline is a variable. (The alcohol content is "effective" because the alcohol is transformed to MTBE or ETBE before blending. Currently, alcohols are less than 0.5% of volumetric refinery inputs.)

It is more difficult to estimate the energy effects of in-refinery changes. A spokesman for ARCO has said that it takes 10% more energy to make EC-1, ARCO's "clean" replacement for regular leaded gasoline (U. S. Congress, OTA, 1990). However, ARCO was able to dump the removed aromatics into the unleaded gasoline pool, a move which saved the financial and energy cost of converting the aromatics to more environmentally benign compounds. In a large program, the overall aromatic content will have to be reduced, and this will increase energy consumption.

Recently, ARCO has modeled the effects of complete gasoline reformulation on the use of energy at its 236,000 bbl/d plant in Anaheim, California. The modeling exercise fully reconfigured and re-optimized the plant to reformulate gasoline, and calculated process-area-by-process-area energy requirements for several reformulations. The output of products, and the input of crude, was kept at the pre-reformulation (base-case) level in all cases.

According to Dave Paulsen (1991), Process Coordinator for ARCO's Clean Fuel Program, the manufacture of a CAA gasoline, with 25% aromatics and 10% MTBE, will increase refinery-wide energy consumption of steam, power, and NG for heat by 11%. (ARCO generates all its process energy on site, including steam and power, from NG). This does not account for energy required to make MTBE (I have accounted for at least part of this extra energy separately). The manufacture of more radically reformulated gasoline, with 10% aromatics, 5% olefins, and 15% MTBE, designed to meet likely California standards for reformulated gasoline, will increase refinery-wide energy requirements by 30%. The increased energy is due to extra use of alkylation, catalytic cracking, isomerization, hydrocracking, hydrotreating (a low-sulfur feed is needed), and steam reforming of NG to make hydrogen (to make up for the loss of hydrogen from the reformer).

The percent increase in the energy required to refine gasoline, given a percent increase in total refinery energy use, all of which is assignable to gasoline, and constant refinery output, is simply:

$$P_g = P_r/E_g$$

where:

P_g = percent increase in energy required to make a barrel of gasoline,

P_r = percent increase in total refinery energy requirements, and

E_g = Fraction of original (pre-reformulation) total refinery energy use assignable to gasoline.

The P_r has been given by ARCO. As estimated here, E_g is 0.70 for a typical refinery (ARCO's product mix is similar to the U. S. average). Hence, reformulated gasoline will require from 15.7% (moderate reformulation) to 42.9% (severe reformulation, very low aromatics) more energy than current gasoline, per gallon of gasoline. Since the reformulated gasoline specified here will contains 2.35% less energy per gallon, the manufacture of reformulated gasoline will require 18.4%-46.3% more energy, per Btu.

These results are for one refinery, utilizing current technology. Industry-wide energy requirements may be different. However, the Anaheim refinery is large and relatively efficient, and ARCO feels that it is modeled performance will be typical for the industry. Here, I use the ARCO results to represent the whole industry.

The increased energy demand of reformulation may be mitigated slightly by the use of more efficient equipment and catalysts (Paulsen, 1991; EIA, *The U. S. Petroleum Refining Industry in the 1990s*, 1990).

This estimate of a large increase in the energy requirement of reformulated gasoline is consistent with recent estimates that reformulated gasoline will cost 30-80% more than current gasoline (e.g., Boekhuas et al.'s 1990 estimate of an \$0.08-\$0.18/gal increase in the cost, depending on the amount of aromatics removed, against the current cost of about \$0.23/gal, according to data from EIA's *Annual Energy Review* [various years] on the difference between refiner crude acquisition cost and refiner wholesale gasoline price).

H.4.7 Other Aspects of Reformulation

Reformulation will have other effects on greenhouse gas emissions. It will reduce the energy density and carbon content of gasoline and will probably reduce the amount of crude oil required to produce a barrel of gasoline. The reduction in energy density and carbon content is discussed in Appendix C. The effect of reformulation on gasoline yield depends on changes in the severity of reforming and catalytic cracking, the use of rejected butane, and the amount of MTBE or ETBE added. The rejection of butane and the increase in the severity of catalytic cracking will tend to reduce the gasoline yield per unit of input (EIA, AOOG, 1990; USGOA, 1990). However, if the butane is made into isobutylene and combined with methanol or ethanol to make MTBE or ETBE, the loss due to butane rejection will be mitigated or perhaps eliminated. Also, reducing the severity of reforming will increase the yield per barrel. And finally, the embodied alcohol component of the added MTBE or ETBE will displace some petroleum.*

Assuming that reformulated gasoline contains 2,749 g/gal (Table C.1), and, for analytical purposes, that the MTBE and non-MTBE components are nonmiscible, and given 2,824 g/gal MTBE (Table C.1), it follows that the non-MTBE part of reformulated gasoline contains 2,736 g/gal. If this non-MTBE part is 94% crude (higher than the 93% assumed above for standard gasoline because no butane, which is derived from NG, will be added to reformulated gasoline), then a gallon of reformulated gasoline contains 2,736 × 0.94 × 0.85 = 2,208 g of crude, from the non-MTBE part (assuming 15% MTBE by volume). If the isobutylene part of MTBE comes from crude, then MTBE contributes 272 g of crude-derived material (given 0.338 gal methanol/gal MTBE). Therefore, the total crude-derived material in reformulated gasoline amounts to 2,480 g. Dividing by the heating value of reformulated gasoline (which is lower than that of standard gasoline; Table C.1) yields 20,295 g crude/106 Btu reformulated gasoline. (If vehicle miles traveled (VMT) is independent of gasoline composition, and the mi/10^6 Btu efficiency of a vehicle is the same on reformulated as on standard gasoline, then consumers will demand the same Btu amount from reformulated gasoline as standard gasoline, not the same amount of gallons.). This is 2.2% less crude required, per Btu, than with standard gasoline. (This calculation ignores any effects that changing gasoline refining might have on the production of other products.)

However, there is one more piece of the puzzle: the use of crude-derived process fuel (mainly refinery gas) to make reformulated gasoline. The ratio of crude-mass as feedstock to crude-mass as process fuel is likely to be different with reformulated gasoline because the composition of the gasoline is different and, more importantly, because reformulated gasoline requires considerably more energy to manufacture than does standard gasoline. It seems most reasonable to assume that refineries will meet the extra energy requirement by purchasing more fuel, mainly NG and electricity, rather than sacrificing more crude as process fuel, since that would be an uneconomic use of crude oil. This suggests that the manufacture of reformulated gasoline will indeed reduce the volume of crude input to the refinery, but will also increase the proportion of

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* Here is a very simplified calculation. Given that standard gasoline contains 2,791 g and 125,070 Btu/gal (Table C.1) and is 93% crude (or crude-derived material) by weight (see above), it follows that 10^6 Btu of gasoline requires 20,753 g of crude as feedstock. Additional crude-derived material, mainly refinery gas, is consumed as a process fuel.

refinery energy that is purchased, rather than refinery gas. (This is what I have assumed here.) However, a complete refinery model is needed to properly account for all the mass and energy flows and costs.

I assume that the net effect of reformulation is that the added alcohol (as MTBE or ETBE) displaces gasoline one-for-one, volumetrically. This ultimately reduces emissions of greenhouse gases from crude recovery and feedstock transport, per unit of gasoline produced (I count separately emissions from the production of the alcohol in the MTBE or ETBE). Given a volume percentage of MTBE or ETBE, I calculate the mass amount of methanol or ethanol (effectively) in the gasoline, per liter, and subtract this from the total grams/liter of the reformulated gasoline. What is left is the grams of crude-derived components per total liter of reformulated gasoline. This density is used to calculate the energy required to recover and transport the crude input to reformulated gasoline. This method properly separates the crude component of reformulated gasoline from the non-crude components, and calculates separately the energy required to process each component stream.

H.5 Conclusions Regarding the Amount of Energy Required to Make Current and Reformulated Gasolines

The average of the estimates of Table H.6 (counting the high and the low end of a range as one estimate each) is slightly less than 0.15 Btu of refinery energy per Btu of energy in standard (non-reformulated) gasoline. Considering that the high end of estimate 1 is unreasonably high, the best-guess range, without adjusting for gasoline reformulation, is 0.14 to 0.15. Therefore, I start with a baseline of 0.145 Btu/Btu-current-gasoline.

As discussed above, data provided by ARCO (Paulsen, 1991) indicate that making reformulated gasoline will require 18-46% more energy, per Btu of gasoline, depending on the degree of reformulation. "Interim" reformulations available as of February 1991 contain 20-25% aromatics by volume, and 1.0-2.5% oxygen by weight (Peyla, 1991). Nationally, the final-average reformulation is likely to be more severe than the minimum required by the CAA, and somewhat more severe than the interim reformulations, but not nearly as severe as the severest considered by ARCO (10% aromatics). I assume a national average reformulation to 20% aromatics, 5%, and 15% MTBE, which is consistent with national specifications suggested by ARCO (Piel, 1989).

The extra energy requirements of reformulating gasoline are a function of the aromatics content. If one interpolates linearly between an 18% increase in energy requirements with 25%-aromatics gasoline and a 46% increase with 10%-aromatics gasoline, then making 1 Btu of gasoline with 20% aromatics will require 27% more energy than making 1 Btu of standard gasoline. However, the energy requirements probably increase exponentially as the 10%-aromatics level is approached. This suggests that making 1 Btu of a modestly reformulated (20%-aromatics) gasoline, such as is assumed here, should require roughly 25% more energy than making 1 Btu of current gasoline. This is what I assume here (Table H.6). In a scenario analysis, I consider the effects of a higher energy requirement (Table 12).

As will be discussed later, I assume that future improvements in refinery energy efficiency and the phasing out of older refineries balance any extra energy needed to process lower quality crude.

H.5.1 The Mix of Process Fuels Used to Produce Gasoline, Diesel, and Residual Fuel

Mertes and Huscwiz's (1980) analysis shows that gasoline, diesel, and residual fuel use essentially the same mix of fuels, namely, the refinery-wide average mix. The analysis in Craig et al. (1991) shows that gasoline and LPG use roughly the same mix, which also is the refinery-wide average. Assuming, then, that all products use the refinery-wide average, emissions of greenhouse gases from the refining of each kind of product, in g/106 Btu, are given by:

$$E_p = \text{SUM}\,[T_p \times S_{rf} \times E_{rf}]$$

where:

E_p = grams of CO_2-equivalent emissions per 10^6 Btu of product from refineries;

T_p = total refinery energy required by product, p, in 10^6 Btu of energy/10^6 Btu of product, counting electricity as Btu-electric (estimated above);

S_{rf} = total energy use of refinery fuel, rf, divided by total refinery energy use of all fuels (see discussion below); and

E_{rf} = grams of CO_2-equivalent emissions per 10^6 Btu of rf consumed (see Table A.2).

The mix of fuels used by refineries (used to calculate S_{rf}) has shifted somewhat during the 1980s. From 1981 to 1989, refineries increased their use of refinery gas and petroleum coke and decreased their use of residual fuel oil, crude oil, diesel fuel, and purchased natural gas. Electricity use has fluctuated (EIA, *PSA*, 1982-1990; see Table H.4). In the absence of reformulation, this trend might have continued. However, as discussed above, reformulation will dramatically increase refinery energy requirements, and it is likely that the extra energy requirement will be met by purchasing more natural gas and power, rather than using a greater percentage of a barrel of crude oil as process fuel. This means that the share of fuels other than refinery gas and perhaps petroleum coke is likely to increase. In addition, refinery gas is likely to contain less hydrogen as a result of reformulation because of decreased use of the reformer and increased use of hydrogen in hydrotreating and hydrocracking. With these considerations, I have assumed that most of the extra energy required to reformulate gasoline is provided by purchased NG (Table 5).

H.5.2 Electricity Use by Refineries

Because most refineries in the United States are concentrated in a few areas, it is not reasonable to assume, without researching the matter, that the mix of fuels used at the electricity plants supplying the refineries is the same as the national average mix (if refineries were spread fairly evenly across the country, it would be reasonable to assume the national average electricity mix). As shown in Table H.8, most petroleum refining is done in the Gulf Coast, California, the Northeast, and near Chicago. The Gulf Coast and California use much more natural gas-based power than the does the rest of the nation, and as a result, the fuel input to electricity used by refineries is quite different from the national average. Moreover, overseas refineries exporting products to the United States almost certainly will use an electricity mix different from the U. S. average.

I have estimated the mix of fuels input to electricity generation in every refining center in the United States and the world. For the United States, I use EIA data on fuels used by every utility in the United States (EIA, 1989, data transmittal), information on the market area of every utility in the United States (*Electrical World...*, 1988), and data on the location and output of every refinery in the United States (EIA, *Petroleum Supply Annual*). For the world, I use EIA data on the amount of products imported from each country (EIA, *Petroleum Supply Annual*, 1988) and the electricity mix of virtually every country in the world (IEA, *Energy Balances...* and *Energy Statistics*, and U. N., 1988, 1989). With these data, one can calculate the mix of fuels used to generate electricity in every country and region and the contribution of that country or region to total refining done for U. S. consumption. (I make the simplifying assumption that refineries in other countries use as much electricity per unit output as do refineries in the United States. Considering that many overseas refineries are owned or operated by United States oil companies or were built or designed by U. S. firms, this assumption may be reasonable.) The inputs used for this analysis are detailed in Tables D.1-D.3.

Note: After I calculate the amount of energy required to produce a unit of gasoline, diesel, residual fuel, and LPG energy, I multiply this ratio by the "own-use" factors for each of the fuels, to account for use of the fuels in the petroleum cycle itself. The own-use factor is discussed generally in Appendix A, and detailed later in this appendix.

TABLE H.8 Location and Capacity of Major Refining Centers in the U. S.

Location	% of Total U. S. Refining Capacity
Texas (primarily Gulf Coast)	26.1
Louisiana (primarily Gulf Coast)	16.8
Los Angeles area, California	9.31
Chicago area, Illinois	5.11
San Francisco area, California	4.97
Philadelphia area, Pennsylvania	4.69
Northwest quadrant of Ohio	3.10
Seattle-Tacoma, Washington	2.97
Other Illinois	2.77
New Jersey	2.55
Northeast quadrant of Oklahoma	2.43
Gulf Coast, Mississippi	2.35
Southeast quadrant of Kansas	2.23
St. Paul, Minnesota	1.58
Other U. S.	13.04
U. S. Virgin Islands	3.48[a]

Source: EIA, *Petroleum Supply Annual 1988* (1989). Based on barrels/calendar-day atmospheric crude oil distillation capacity, including idle capacity, as of January 1, 1989.

[a] Based on U. S. total, excluding Virgin Islands.

H.6 Refinery Energy Use in the Future

Primarily as a result of energy conservation measures adopted in the late 1970s, refineries were more energy-efficient in the 1980s than in the early 1970s. In 1985, refineries used 14% less energy per barrel refined than in 1975 (*Hydrocarbon Processing*, November 15, 1988). Moreover, in 1985, refineries produced a higher quality product (e.g., higher-octane gasoline, unleaded gasoline) from a lower quality input (heavier, more sulfurous crude), which means that energy savings at constant quality (the real measure of efficiency improvement) was even higher. In support of this, Sigmon (1984) estimates that refineries used 23% less energy per barrel in 1982 than in 1972, at constant input and output quality and constant product mix (the actual improvement in efficiency was only 10%, which shows that changes in input and output quality and in product mix strongly affect energy consumption). Similarly, Pelham and Moriarty (1985) found that from 1972 to 1983, refineries reduced energy consumption per barrel by 25.7%, at constant input and output quality.

Presently, the energy consumed by refineries amounts to about 9.5% of the energy value of the products (Table H.4). However, new refineries are more efficient than this current national average, and there is room for improvement in new refineries. Haynes (1976) estimated that refineries could reduce their energy consumption 20% by using more efficient catalytic cracking, better furnace control, more heat recovery, and other measures. In 1980, the U. S. General Accounting Office estimated that new refineries could be as much as 30% more efficient than existing refineries, and that existing refineries could be up to 20% more efficient by retrofitting (p. 21). Gaines and Wolsky (1981) note that nonfuel petroleum products, such as polymers, greases, and asphalts can be recycled, with potentially huge energy savings. Pelham and Moriarty (1985) estimated that refineries could technically (although not necessarily economically) reduce energy consumption by 14%, primarily by recovering waste heat and optimizing steam usage.

I assume that crude and energy prices will rise in the future and will induce new refineries to be more efficient in their use of crude and process energy, so that perhaps they will consume only 8% of the energy value of the products — holding constant (analytically, for the moment) the quality of the crude input and the quality and mix of the product output.

The quality of the crude slate is expected to decline, and refineries will have to expend additional energy to remove additional sulfur and metals from the crude and to convert heavier crudes into light products (Haynes, 1976; Sigmon, 1984). Lawrence et al. (1980) found that if lower-quality crude (Alaskan oil, in this case) were 25% of the crude refinery input, refinery energy requirements would be 0.2% higher (in absolute terms; about 2.5% in relative terms) than in the no-lower-quality-crude case. This suggests that processing all lower-quality crude could increase refinery energy requirements on the order of 1%, in absolute terms (10% in relative terms). The API estimated that changes in product quality and mix from 1972 to 1982 increased energy consumption by 17% per barrel in relative terms, at constant technical efficiency. Increasing the mean octane will also increase energy use, primarily in the alkylation and isomerization units (the reformer will not be used because of restrictions on the aromatics content). Any further reduction of the sulfur content of diesel fuel will also increase refinery energy requirements.

The result is that lower input quality and higher output quality (above and beyond the level of reformulation analyzed here) will increase the amount of energy required to produce all products, compared with current refineries, and will probably at least balance technical improvements in efficiency. Because of these competing forces, I assume no change in overall refinery energy efficiency in 2000, compared with 1987. This assumption is supported by a historical trend: throughout the 1980s, the amount of energy required to produce an energy unit of product has remained relatively constant (Table H.4a). (This result is not confounded by significant changes in the output mix; for example, according to data in the EIA's *Annual Energy Review*, 1990, the gasoline fraction of total output remained roughly the same from 1981 to 1989).

H.7 Energy Used to Transport Crude Oil and Petroleum Products

The amount of energy used to transport crude oil and petroleum products is the sum of the amount used by trains, trucks, tankers, and pipelines (Table E.1). Trucks and trains use diesel fuel, ships use residual fuel oil, and pipelines use electricity. For each of these modes, the total amount of energy consumed is equal to the Btu/ton-mile energy intensity of the mode multiplied by total ton-miles by mode. Btu/ton-mile data are compiled in Table E.2 and discussed in Appendix E. In this section, I review and calculate ton-mile data for transportation of crude oil and petroleum products.

For crude oil, the object is to calculate the amount and kind of energy required to transport the amount of all crude input to U. S. refineries because I have output data for U. S. refineries, which can be matched with the input data. Crude comes to U. S. refineries primarily by pipeline and tanker, but also by rail and truck. Presumably, very little U. S.-bound exported crude is moved by rail or truck in foreign countries. However, some crude comes to U. S. refineries via pipelines in Canada, and a good deal of crude is imported from overseas and comes in via international tanker. Some of the imported crude is first shipped by pipeline from the producing field to the tanker. All of these movements must be accounted for.

There are several independent sources of data on barrel and ton-mile domestic movement of crude oil and petroleum products by water, rail, pipeline, and highway. I will review these sources and state my assumptions for domestic ton-miles. Unfortunately, there are no such ready-made ton-mile data for movements of U. S.-bound crude oil and products outside U. S. land and territorial waters, so I calculate ton-miles from other data, as detailed below.

H.7.1 Ton-Miles of Crude and Products Shipped in Pipelines in the United States

The Association of Oil Pipelines (AOP) reports ton-miles of crude and petroleum products shipped by pipeline from the Annual Report (Form 6) of oil pipeline companies to the Federal Regulatory Commission. There are no other data on ton-miles per se, but there are separate estimates of tonnage and mileage, which can be used to check the plausibility of data from the Association of Oil Pipelines.

The EIA's *Petroleum Supply Annual* reports barrels of crude received at U. S. refineries by pipeline. Converting the barrel data to tons (6.65 bbl of crude/ton; EIA *Monthly Energy Review*), and dividing this into the AOP's independent ton-mile data, yields an average length of crude haul by pipeline of 824 miles in 1987 and 787.3 miles in 1986. DOT's *National Transportation Statistics* divides AOP ton-miles by tonnage estimates from Transportation Policy Associates and gets 772.4 mi in 1986. (I do not know the source of the data from Transportation Policy Associates; it may be the EIA data). Qualitatively, these estimates are consistent with each other and with pipeline mileage and flow tonnage shown on maps in the Congressional Research Service (1977).

Hooker et al. (1980) estimated a mean shipment distance of 1,390 mi for shipping petroleum products by pipeline from the Gulf Coast to the Northeast, and 2,115 mi by coastal tanker. However, the Northeast is the terminus of oil product pipelines originating in the Gulf Coast, and a considerable amount of oil is shipped shorter distances, from the Gulf Coast to Chicago or St. Louis and from west Texas to the Gulf Coast.

It thus appears that the AOP ton-mile data are consistent with other partial data. I use the AOP ton-mile estimates, rather than multiply the EIA quantity estimates by average length of haul, because the AOP data are original and are reported in the units needed here.

H.7.2 Mix of Fuels Used at Plants Supplying Power to Petroleum Pipelines

In my base case, I assume that pipelines draw from the U. S. average power mix. There is some evidence to support this: Hooker et al. (1980) calculated that the power companies supplying electricity to Colonial and Plantation oil pipelines used 26% (Colonial) and 15% (Plantation) oil, 41% and 66% coal, 13% and 8% nuclear, 4% and 6% hydro, and 16% and 5% other, in 1977. The average of these two is not too far off from the 1977 U. S. average power mix.

H.7.3 Accounting for Movement of U. S.-Bound Crude Oil in Canadian and Other Foreign Pipelines

Canada exports a large amount of crude oil to the United States via pipeline, and the AOP does not count ton-miles of movement in Canadian pipelines in Canada — it counts ton-miles only when the oil in the pipeline crosses the border into the United States (the pipeline changes names at that points, too) (AOP, personal communication, 1989). For a complete account of the petroleum system, I estimate the amount of crude shipped by pipeline from Canada to the United States, and the length of the haul in Canada.

The Trans Mountain Pipe Line and the Interprovincial Pipe Line are the two biggest Canadian pipeline companies exporting crude to the United States. In 1987, Interprovincial shipped 191 million barrels of Canadian oil roughly 800 mi to the U. S. border (Interhome Energy, 1989); Trans Mountain ships about 17,000 bbl/d from Edmonton 725 mi to the Seattle area (Trans Mountain, personal communication, 1989). (Interprovincial ships some U. S.-produced oil to the United States, but I assume this is oil produced in the lower 48 states and shipped in the U. S. portion of the pipeline; hence, the oil is already accounted for in U. S. Bureau of the Census production and AOP transport figures.) A few other pipelines ship much smaller amounts of crude to the United States; I assume an additional 2×10^9 ton-miles. There are no product pipelines from Canada to the United States (AOP, personal communication, 1989). The result, using 6.76 bbl/ton for Canadian crude (EIA, *International Energy Annual*, 1989), is about 25×10^9 ton-miles in Canadian pipelines.

A small amount of U. S.-bound crude is moved from the interior of foreign countries to the coast, where it is loaded onto tankers and sent to the United States. I did not find data on this sort of movement. Worldwide, it appears that most major oil fields (Indonesia, Venezuela, Mexico, the Middle East — with some exceptions — and Nigeria, are located on or near the coast. Major exceptions include fields in Algeria, and some fields in the Middle East. If 15% of all imported crude (excluding Canada) is moved an average of 800 mi by pipeline before being loaded onto a tanker, the result is another 25×10^9 ton-miles. I add this to the Canadian total and AOP's U. S. total, to get the grand total shown in Table E.1.

H.7.4 Ton-Miles of Crude and Petroleum Products Shipped by Railroad in the U. S.

The Federal Railroad Administration (FRA) reports tons and ton-miles of various commodities transported by rail. Railroads are required by the Interstate Commerce Commission to submit audited waybills — statements describing the destination, weight, and other attributes of cargo moved by rail — to the Federal Railroad Administration. The FRA calculates tons, ton-miles, car-miles, and other statistics for each commodity from a sample of the waybills, and publishes the results in *Carload Way Bill Statistics*, Statement TD-1 (USDOT, FRA, 1989) . The American Association of Railroads (AAR) also uses the waybill data to calculate railroad transportation statistics. The AAR data agree with the FRA data to within about 1% for the four years I checked (1979, 1982, 1986, and 1987).

I used FRA's *Waybill Statistics* (USDOT, FRA, 1989, 1982) for railroad ton-miles for crude oil and petroleum products in 1987. I use the ton-mile data for petroleum product classification 29, the largest category, which includes coke, tar, LPG, etc., for consistency with the EIA production and importing data, which also include these items. The data include ton-miles of petroleum products shipped from Canada to the United States. I assume that so little U. S.-bound petroleum is moved by railroads in other countries that it can be ignored (this certainly seems reasonable, given that total petroleum movement by rail in the United States already is quite small).

H.7.5 Ton-Miles of Crude and Products Shipped in U. S. Waters

The annual publication from the Army Corps of Engineers, *Waterborne Commerce of the United States* (U. S. Department of Army) reports tons and ton-miles of movement of crude oil and petroleum products in U. S. waters. The Corps gets data on movement of domestic cargo directly from vessel operators; data on movement of foreign cargo come from the U. S. Bureau of the Census. For petroleum products in 1987, I use their data for SIC 29, which includes asphalt, coke, and LPG, for consistency with the EIA production and import data, the FRA railroad data, and the truck data discussed in section H.7.7.

The Army Corps of Engineers data includes ton-miles of crude oil movement between Alaska and the Lower 48 States, and between points in the United States, Puerto Rico, and the

Virgin Islands. This is convenient because a large amount of crude is shipped from Alaska to the U. S. West Coast, and a very large amount of foreign crude is refined at Puerto Rico and the Virgin Islands and shipped to the U. S. mainland. However, the Army Corps does not report ton-miles of movement between foreign ports and ports in the United States, Puerto Rico, and the Virgin Islands. To estimate ton-miles of crude and product imports to the United States, one must know how much oil each region of the U. S. imports from each exporter, and how far the oil travels. This is estimated next.

H.7.6 Overseas Movement of U. S.-Bound Crude and Petroleum Products

The EIA's *Petroleum Supply Annual* reports the amount of oil each region of the United States receives from every exporting country in the world. The regions are the five "Petroleum Administration for Defense" districts (PADDs): the East Coast and Appalachia (PADD I), the Midwest (II), the Gulf Coast (III), the Rocky Mountains (IV), and the West Coast (V). The Rocky Mountain Region (PADD IV) imports crude oil and products only from Canada, primarily via pipeline, and so this region can be excluded from the calculation of ton-miles of imports by water (I have already estimated ton-mile of imports from Canada via pipeline). The Midwest (PADD II) imports products from Canada, either via pipeline or across the Great Lakes, and imports crude from many countries. I assume the crude imported by PADD II lands at the Gulf Coast (PADD III) and is shipped north via the large crude oil pipelines, or on barges up the Mississippi, so that PADD II does not import crude or products directly, and also can be excluded from the calculation (I separately estimated pipeline imports from Canada, pipeline movement in the United States, and river movement in the United States). This leaves PADDs I, III, and V as receiving regions for foreign crude oil and petroleum products.

To estimate ton-miles, the EIA's estimates of barrels imported by a region from a country must be translated into point-to-point estimates. Rather than attempt to estimate every actual port-to-port movement of crude oil and products, I have used large ports to represent movements to and from important regions. At the receiving end in the United States, I assume all imports to the East Coast (PADD I) land at New York; all imports to the Gulf Coast (PADD III) land at Houston; and all imports to the West Coast (PADD V) land at Los Angeles.

At the shipping end, began by grouping exporters into seven regions: (1) West Africa (Nigeria, Liberia, Angola, Ivory Coast, Cameroon, Gabon, Congo, Zaire, Togo, Ghana, South Africa, Benin, and Mauritania), (2) the Mediterranean (Algeria, Spain, Portugal, Italy, Yugoslavia, Greece, Turkey, Tunisia, Hungary, Rumania, Egypt, Israel, Bulgaria, and Syria), (3) Northern Europe (United Kingdom, Ireland, Norway, France, West Germany, East Germany, Belgium, Denmark, Sweden, Switzerland, Finland, and the Netherlands), the (4) Middle East (Saudi Arabia, Kuwait, United Arab Emirates, Iran, Iraq, Oman, Jordan, Pakistan, and the Soviet Union), (5) the South Pacific (Indonesia, Malaysia, Australia, India, Korea, Japan, Singapore, China, Taiwan, India, Brunei, and Thailand), (6) South America (Colombia, Venezuela, Ecuador, Brazil, Peru, Argentina, Trinidad and Tobago, Uruguay, and the Netherlands Antilles), and (7) Central America (Mexico, Panama, Jamaica, Bahamas, Bermuda, and Guatemala). I then picked the largest exporting port in the region to represent the region, if that port also was about as far from the United States. as other major ports in the region, on average. For example, Ad Damman, next to the major Saudi Arabian exporting terminal at Ras Tanura, represents the Middle East. However, if the largest exporting port or country in a region clearly was closer to the United States than other exporting countries in the region, I added mileage to compensate. For example, the bulk of imports from South America comes from its north coast Colombia, Venezuela, Trinidad and Tobago, and the Netherlands Antilles — and are well represented by the exporting terminal at Puerto Miranda near Maracaibo, Venezuela, especially since Venezuela is the major exporter of South America. However, a small amount of oil comes from much farther away (Brazil and Argentina) and so I have added mileage to the distance to Maracaibo to account for this.

For distance between ports, I used the U. S. Defense Mapping Agency's *Distances Between Ports* (1985). The figures are shown in Table H.9.

To convert the EIA's estimate of barrels of crude oil imported to tons of crude oil imported, I used API's (1989) estimate of barrels of foreign crude per ton. To convert the EIA's estimate of barrels of imported petroleum products to tons of imported products, I multiplied the API's estimate of the barrels per ton for a particular product (e.g., gasoline, coke, fuel oil) by the ratio of imports of that product to imports of all petroleum products, for all products, and summed, to produce an weighted average density for imported products.

I did the calculation just described for 1987. The resulting ton-miles are shown in Table E.1.

H.7.7 Ton-Miles of Crude and Products Shipped by Truck in the United States

I will review five sources of data, all of which have shortcomings and require various kinds of adjustments to yield an estimate of truck ton-miles.

1. The U. S. Bureau of the Census' *Truck Inventory and Use Survey* (USDOC, 1985) is sent to all truck operators. This document reports truck characteristic and mileage data, but not tonnage, by type of commodity carried. Therefore, it samples the appropriate universe, but does not report a key item of data. According to the *Survey* (USDOC, 1985), 262,200 trucks carried petroleum 5.3881×10^9 truck-miles in 1982, an average of 20,500 mi/truck. (Petroleum presumably includes a small amount of crude oil, as well as petroleum products, but the amount of crude carried by trucks is negligible compared to the amount of products.). Most of these trucks (141,000) were tank trucks, and most of the shipments were local hauls. The mileages include empty backhauls (U. S. Bureau of the Census, personal communication, 1989). Deliveries of 6,500-9,000 gal are common, according to the U. S. CRS (1977). Assuming an average shipment size of 3,000-10,000 gal and 6.6 lb of product/gal on average, the result is $53\text{-}178 \times 10^9$ ton-miles, with a best guess, based on 7,000 gal, of 124×10^9 ton-miles.

TABLE H.9 Nautical Miles between Ports

Exporting Region:	Middle East	North Europe	West Africa	Mediterranean	South Pacific	Central America	South America
Representative Port:	Ad Damman	Bergen	Lagos	Algiers[a]	Jakarta	Tampico	Maracaibo[a]
Representative Country:	S. Arabia	Norway	Nigeria	Algeria	Indonesia	Mexico	Venezuela
U. S. Region and Port							
East Coast: New York	8,261	3,367	4,883	4,117	12,644	2,029	2,390
Gulf Coast: Houston	9,821	5,035	5,952	5,673	12,191	502	2,339
West Coast: Los Angeles	12,349	7,762	8,065	8,201	7,342	4,441	4,150

Source: *Distances between U. S. Ports*, Defense Mapping Agency (1985).

[a] I have added 500 nautical miles to the distances shown for Algiers and Maracaibo distances, to make the distances more representative of their regions.

2. The AOP estimates ton-miles of petroleum carried by trucks by using data from the *Petroleum Supply Annual* and from "Financial and Operating Statistics" reported by the American Trucking Association, but the data are doubtful. The AOP (1989) estimates that trucks carried 22.7×10^9 ton-miles of crude and petroleum products in 1982, but it does not know if the data from which it calculated this figure include empty backhauls. If they do not, then the 22.7 would have to be about doubled for a proper accounting of the total mileage by trucks carrying petroleum, and the result would be about 45×10^9 ton-miles in 1982.

3. According to the 1977 *Commodity Transportation Survey* (U. S. Bureau of the Census, 1981), manufacturers shipped petroleum products 14.7×10^9 ton-miles by truck in 1977, based on tonnage shipped and one-way shipping distances. Counting the empty backhauls, the figure would be about 29×10^9 ton-miles. However, the survey is sent only to "manufacturers" as defined by the Standard Industrial Classification; wholesale bulk terminals and bulk plants are classified under "wholesale," not "manufacturing," so they do not receive this survey. This means that the *Commodity* numbers underestimate, probably considerably, actual ton-mileage by truck.

The U. S. Bureau of the Census initiated another Commodity Transportation Survey in 1983 but will not officially release the data on account of their poor quality. However, it will release data to researchers for internal use only; I am happy to report that the 1983 tonnage data are not terribly far from the 1977 tonnage data.

4. In 1982, virtually all (98%) petroleum bulk plants in the United States reported to the U. S. Bureau of the Census (1985, *Census of Wholesale Trade*) that they received their products primarily by truck. However, these bulk plants reported total volume sales amounting to only 16% of total products supplied in the United States in 1982 (U. S. Bureau of the Census, *Census of Wholesale Trade*, 1985; EIA, *PSA*).

5. Most, if not virtually all, petroleum products are shipped to the final end user by truck. If 90% of all petroleum products move at some point by truck, an average of 75 mi one way, then trucks shipped 116×10^9 ton-miles in 1982 (Using EIA *PSA* data, and assuming 6.6 lb/gal).

I believe that the first and fifth and estimates are the most complete and reliable. With these considerations, my estimates for crude and product ton-miles are shown in Table E.1.

It is safe to assume that there is essentially no truck movement of U. S.-bound crude oil and products in foreign countries. Trucks are used to mainly to deliver products to multiple retail and scattered retail outlets, not, obviously, to export large quantities of petroleum to the United States. Scattered truck movement across the United States borders can be ignored.

H.7.8 Allocation of Crude and Product Transport Energy to Gasoline, Diesel, and Residual Fuel

For crude transport, total transport energy is allocated to each product based on its share of the weight of the crude oil and the amount of product from a unit of crude.* This is then multiplied by an own use factor, described generally in the Appendix A and discussed in detail below (see Table H.10).

For transportation of petroleum products, transport energy is allocated to product X as total energy multiplied by the ratio of the weight of all X to the weight of all products. I have tried to define "all products" consistently throughout, to include coke, tar, LPG, unfinished oils, and the like as well as gasoline, diesel, etc. Thus, "all products" is defined the same in the calculation of total transport energy and in the calculation of weight shares.

The results of the allocation are input to Table 3 as Btu-process energy/Btu-net product available to consumers.

H.7.9 Transportation of Crude Oil and Petroleum Products in the Future

The sources of petroleum will change in the future as domestic production declines and imports increase, and this will change overall petroleum transportation patterns. The EIA's *Annual Outlook for Oil and Gas 1990* (1990) projects the following changes from 1989 to 2000: a 56% increase in imports of crude oil, a 16% increase in imports of refined products, a 14% decline in total domestic production of petroleum (onshore, offshore, and Alaskan crude plus NGPLs plus other oils and synthetic crude plus processing gain), a 23% decline in domestic production of crude oil (as distinguished from petroleum, which, as noted above, includes more than crude oil), an 18% decline in lower-48 onshore crude production, a 1% decline in lower-48 offshore production, a 49% decline in Alaskan production, and a 300% increase in domestic production of "other" petroleum (unfinished and other oils, other hydrocarbons, alcohols, blending components, and synthetic crude). These increases and decreases will continue through the year 2010. Overall, the main effects are a decrease in production in Alaska and the Gulf Coast region and an increase in imports.

These changes have several implications for the transportation of crude oil and petroleum products. The drop in U. S. production in Alaska and the Gulf Coast will probably reduce crude shipments by pipeline and domestic waterway (as a percentage of total petroleum consumption), because pipelines and domestic waterways mainly move domestically produced crude oil. Imported crude generally is landed, refined, and consumed at big port cities, not landed and

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* See the discussions on how energy used to recover crude is allocated to products (section H.2.5); the allocation of transport energy is similar.

TABLE H.10 Petroleum Own-Use, in Quads of Own Use of Fuel per Quad of Fuel Produced, Each Stage, 1987

Stage	Gasoline	Diesel	Residual
Recovery[a]	0.00239	0.01334	0.01461
Crude transport[b]	0.00003	0.01085	0.07923
Refining[c]	0.00000	0.00002	0.00051
Product transport[b]	0.00164	0.03623	0.01952
Total[d]	0.0041	0.0605	0.1139
Own use factor[e]	1.004	1.064	1.128

Assumptions necessary to do the calculation:

0.092 × 10^3 barrels of residual fuel burned per 10^6 kWh of refinery power.

0.096 × 10^3 barrels of residual fuel burned per 10^6 kWh of generic power.

0.177 quad residual fuel oil burned per quad pipeline power.

0.900 diesel share of total energy used by trucks transporting fuels (rest is gasoline).

0.800 residual oil share of total energy used by oil tankers (rest is diesel fuel).

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[a] Gasoline, diesel, or residual fuel used directly at oil recovery sites, as reported by the U. S. Census, plus residual fuel used to supply electricity to oil recovery.

[b] Diesel used by trains, trucks, and tankers; gasoline used by delivery trucks; residual fuel used by tankers and at power plants supplying electricity to pipelines.

[c] Gasoline, diesel, and residual fuel used directly at refineries, as reported by the EIA's *Petroleum Supply Annual*, plus residual fuel used at power plants supplying electricity to refineries.

[d] Total may not equal sum of components shown, because of independent rounding.

[e] Total production of each fuel (U. S. refinery production plus imports, as reported by EIA's *Petroleum Supply Annual*), in quads, divided by total production less own use of each fuel.