

shipped far inland to midcontinent refineries (USDOT and USDOE, 1980; this is supported by EIA PSA data showing that, in 1989, the Midwest region, PAD District II, imported only 20% of its refinery input, excluding imports from Canada, while domestic pipeline shipments of crude into the region were 62% of refinery crude input). However, this could change in the future.

The increase in imports will, of course, increase tanker shipments of crude. If imports from Canada increase, international pipeline shipments will increase as well. However, Canada is not expected to significantly increase petroleum exports (EIA, AOOG, 1990).

There probably will be fewer changes in the transportation patterns of petroleum products than in the patterns for crude oil for two reasons. First, the percentage of total product supply that is imported will increase only slightly, from 12.6% to 13.4% (EIA, AOOG, 1990). Second, the drop in domestic production of crude and increase in imports of crude will not dramatically affect regional production of products because refiners are motivated to maximize product output regardless of the source of the crude. There may be a small drop in product distribution distances, as regional refining capacity is expanded and refineries on average move closer to end users.

All these effects can be summarized as follows: (1) there will be a large increase in the percent of total ton-miles by tankers, (2) there will be a small decrease in the percent of total ton-miles by pipeline, and (3) there will be little change in product patterns. In accordance with the EIA projections cited above, I assume a 50% increase in crude ton-miles by international tanker, a 10% decrease in pipeline ton-miles, and no change in product patterns, for 2000, relative to calculated values for 1987. For lack of data, I assume that the mix of countries remains the same.

## H.8 Adjusted Final Consumption of Petroleum

As noted throughout, one needs to calculate own-use of gasoline, diesel, and residual fuel, in order to convert "process energy/106 Btu produced" to "process energy/106 Btu available to consumers". The calculation of own-use and net use of gasoline, diesel, and residual fuel is shown in Table H.10. Table H.3 shows some of the EIA petroleum supply data used in Table H.10 and in other calculations throughout the report (1987 data are used because the Census data and other data are for 1987).

To calculate net use of gasoline, diesel, and residual fuel, I subtracted from total product output of each fuel (total output is equal to refinery production plus imports plus field production) the amount of the fuel used by petroleum refineries (EIA, *Petroleum Supply Annual*), oil production operations (U. S. Bureau of the Census, *Census of Mineral Industries, Fuels and Electric Energy Consumed*, 1990), and crude and product transport modes. See Table E.1. Trains use diesel fuel only (EIA, *Petroleum Marketing Monthly*, June 1988). Pipelines use electricity from the national average power mix. Trucks use 90% diesel fuel and 10% gasoline. (According to the 1982 *Truck Inventory and Use Survey*, diesel trucks accounted for 93% of all miles traveled by heavy-heavy trucks and 28% of all miles traveled by light-heavy trucks; virtually all petroleum transportation fuels are delivered by heavy trucks). Tankers use 90% residual fuel and 10% diesel fuel (based on data in Marks, 1982, and Davis et al., 1989).



**Appendix I:**  
**Nuclear Energy**



## Appendix I:

### Nuclear Energy

#### I.1 Overview\*

A nuclear reactor releases energy from the fission of uranium 235 (U-235). This energy, in the form of heat, boils water to produce steam, which then turns a turbine connected to an electric generator.

There are several stages in the production of the uranium fuel used by nuclear reactors: mining uranium-containing ore; extracting, concentrating, and converting the uranium; increasing the proportion of the fissionable isotope, U-235; and assembling the fuel. Uranium is extremely energy dense, and relatively little of it (compared with coal, for example) is needed to power a reactor. Because the nuclear energy cycle requires so little uranium, there is no need to economize on its transport by using an efficient bulk carrier system (like railroads) or by locating uranium producing and handling operations near to one another. Thus, civilian nuclear fuel is transported almost entirely by truck, and facilities for mining, conversion, enrichment, fuel fabrication, and disposal are scattered widely across the country (USDOT and USDOE, 1980).

In the United States, uranium is mined and milled primarily in Utah, Colorado, Texas, New Mexico, Arizona, and Wyoming. At the mills, which are usually located at or near the mines, ore containing about 0.1-0.3% uranium oxide ( $U_3O_8$ ) by weight is refined or concentrated to at least 75%  $U_3O_8$  (yellowcake). The mining and milling companies ship the yellowcake by truck to Allied Corporation in southern Illinois or Sequoyah Fuels Company (General Atomic) in Oklahoma (EIA, *World Nuclear Fuel Cycle Requirements*, 1989), where  $U_3O_8$  is converted to uranium hexafluoride ( $UF_6$ ), the form of uranium required by gaseous-diffusion/uranium-enrichment facilities. The converters then ship the  $UF_6$  by truck to the U.S. Department of Energy (DOE) enrichment facilities. A small amount of U.S. uranium is enriched in Europe (EIA, *Uranium Industry Annual 1988*, 1989).

Up to and including the conversion process, isotopes of uranium in ore, yellowcake, or  $UF_6$  occur in their natural proportions, about 99.3% nonfissionable uranium 238 (U-238) and 0.7% fissionable U-235. For a uranium fuel to sustain a fission reaction and thus provide continuous fission energy (in a light-water reactor), the proportion of the fissionable U-235 in the fuel must be increased (enriched) several fold above the natural level. Today, virtually all enriching in the United States and abroad is done by the gaseous diffusion process, in which  $UF_6$  is gasified and pumped through the porous membrane filters that let through more of the  $UF_6$  that contains U-235 than that containing U-238. The DOE owns two operating enrichment plants, both gaseous diffusion operations (one at Portsmouth, Ohio, operated by Goodyear Aerospace, and one at Paducah, Kentucky, operated by Union Carbide; a former facility at Oak Ridge, Tennessee, was closed on December 15, 1987). These two plants produce most of the enriched

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\* From USCRS, 1977; USDOT and USDOE, 1980; EIA, *Uranium Industry Annual 1988*, 1989.

uranium used by U.S. utilities; the rest is produced by the EURODIF gaseous diffusion plant in France.

There are other technologies for enriching uranium: centrifugal separation, which is used in Europe, and laser isotope separation, which is being developed. In a centrifuge, the heavier U-238 portion of  $UF_6$  accelerates more slowly than the lighter U-235 and is thereby separated. Several years ago the United States started to develop centrifuge technology, but canceled the program in favor of laser isotope separation. Presently, the world has only one operating centrifuge plant, a small facility in the Netherlands.

Uranium-atomic vapor laser isotope separation (U-AVLIS) is under development in the United States at Lawrence Livermore Laboratory in California and Oak Ridge National Laboratory in Tennessee. The U-AVLIS technology is expected to produce enriched uranium at a lower cost than gaseous diffusion or gaseous centrifuge technology (Davis et al., 1982; USDOE, *Plan for the Demonstration, Transition, and Development of U-AVLIS Technology*, 1990). The current U-AVLIS demonstration and deployment plan slates construction for 1993 and operation for 1997 (USDOE, *Plan for the Demonstration, Transition, and Development of U-AVLIS Technology*, 1990). However, the current DOE uranium-enrichment operating plan assumes no U-AVLIS through 1998.

The enrichment process produces two streams of  $UF_6$ : one is enriched in U-235 (compared with the natural proportion of U-235), and the other is depleted. The depleted stream, which is about 4-5 times more massive than the enriched stream, is stored at the enrichment plant for possible use in breeder reactors (the U.S. breeder program has been mothballed). The enriched  $UF_6$  is shipped by truck to fuel fabrication facilities located at Lynchburg, Virginia (Babcock & Wilcox); Windsor, Connecticut (Combustion Engineering); Richland, Washington (Advanced Nuclear Fuels); Wilmington, North Carolina (General Electric); and Columbia, South Carolina (Westinghouse) (status as of February 1989, according to EIA, *World Nuclear Fuel Cycle Requirements*, 1989). The fabricators convert  $UF_6$  to uranium oxide ( $UO_2$ ) and assemble the  $UO_2$  into the devices that will be loaded into nuclear reactors. The fuel assemblies are then shipped by truck to the reactors. The companies that fabricate the fuel also build nuclear reactors and ship the fuel from the enrichment plant to the fabricator (EIA, *World Nuclear Fuel Cycle Requirements*, 1989; U.S. Congressional Research Service, 1977).

The nuclear fuel must be disposed of after it is consumed by the reactor. Waste materials with a low level of radioactive contamination are sent by truck to disposal facilities at Barnwell, South Carolina; Beatty, Nevada; or Hanford, Washington (USDOE, *Energy Technologies and the Environment, Environmental Information Handbook*, 1988). Low-level-waste shipments are expected to reach about 30,000 truckloads per year by 1990 (USDOT and USDOE, 1980). Currently, wastes with a high level of contamination are stored at the reactor site in ponds, awaiting the opening of a long-term high-level waste repository.

Greenhouse gases are emitted throughout the nuclear-fuel cycle, wherever process energy is consumed. Mining and milling operations consume diesel fuel, natural gas, electricity, and other fuels. The trucks that move uranium at various stages of the cycle consume diesel fuel, albeit a very small quantity in total. Conversion, enrichment, and fabrication facilities require electricity

and natural gas; gaseous-diffusion enrichment facilities actually consume a considerable amount of power. These energy requirements are discussed in more detail in the next section.

## I.2 Energy Used by Uranium Mines and Mills

The data used in this analysis are from the U.S. Bureau of the Census, *Census of Mineral Industries*, for 1982 and 1987 data. There is a general description of the census data in Appendix F.

The census reports energy use by the aggregate group "uranium-radium-vanadium mining and milling" and the aggregate group "metal mining services," which serves the production of iron, lead, copper, bauxite and other ores, as well as the production of uranium. The census does not indicate the portion of energy that should be assigned to uranium mining and milling only; hence, this portion must be estimated.

According to the U.S. Bureau of the Census (Fрати, 1989), there is no radium mining and little vanadium mining, so the uranium-radium-vanadium category is almost all uranium. In support of this, note that in 1987, the value of uranium concentrates was 93% of the combined value of uranium and vanadium concentrates. I therefore assign 93% of the energy used in the uranium-vanadium-radium industry to uranium mining.

I have assumed that the portion of energy used by the metal mining services group that should be assigned specifically to uranium production is equal to the ratio of energy use by uranium mining and milling to energy use by all metal mining concerns (excluding mining services), where energy use in uranium mining and milling is estimated as above. This ratio is about 0.10. The ratio that is based on value of production is about the same.

It appears that the census survey covers every industry involved in any kind of uranium mining, milling, and preparation. According to the Standard Industrial Classification (SIC) code that the survey uses, the uranium-radium-vanadium ore industry includes all establishments engaged in mining, milling, and otherwise preparing ores. The leaching of uranium is explicitly included in the list of covered activities, which suggests that all forms of uranium production (from in-situ leaching, heap leaching, tailings and mine water, low-grade ore and by-product processing, as well as from conventionally mined ore) are included in the survey. I assume this to be the case.

Tables I.1 and I.2 show the data and assumptions used to calculate energy consumption by the uranium mining and milling industry in 1982 and 1987. In the base case, I use the 1987 data. However, because there is a large difference between the calculated 1982 and 1987 energy requirements (in Table I.1), I do a scenario analysis using the 1982 data.

TABLE I.1 Energy Used to Explore, Mine, and Mill Uranium

|  | 1982              |            | 1987              |            |
|--|-------------------|------------|-------------------|------------|
|  | In Units          | In Percent | In Units          | In Percent |
| Crude oil (10 <sup>3</sup> bbl)  | 0.0               | 0.00       | 0.0               | 0.00       |
| Diesel (10 <sup>3</sup> bbl)   | 252.9             | 15.55      | 91.2              | 16.73      |
| Residual (10 <sup>3</sup> bbl)   | 145.8             | 9.67       | 0.5               | 0.10       |
| Natural gas (10 <sup>9</sup> ft <sup>3</sup> )                                 | 2.6               | 28.39      | 0.8 <sup>a</sup>  | 25.94      |
| Coal (10 <sup>3</sup> tons)  | 27.3 <sup>b</sup> | 6.15       | 18.0 <sup>b</sup> | 12.12      |
| Electricity ( 10 <sup>6</sup> kWh)   | 1,024.8           | 36.89      | 359.9             | 38.70      |
| Gasoline (10 <sup>6</sup> gal)   | 2.2               | 2.95       | 1.1               | 4.49       |
| Other (10 <sup>6</sup> dollars)  | 0.3 <sup>b</sup>  | 0.00       | 0.4 <sup>b</sup>  | 0.00       |
| -----  |                   |            |                   |            |
| Total (quads or 10 <sup>15</sup> Btu)  | 0.0095            |            | 0.0032            |            |
| -----  |                   |            |                   |            |
| USDOC production totals (10 <sup>3</sup> tons) <sup>c</sup>                    | 9.56              |            | 6.35              |            |
| EIA <sup>d</sup> production totals (10 <sup>3</sup> tons) <sup>c</sup>         | 13.20             |            | 5.80              |            |
| Quads-recovery/10 <sup>3</sup> tons-U <sub>3</sub> O <sub>8</sub> <sup>e</sup> | 0.0010            |            | 0.00050           |            |

<sup>a</sup> The census did not disclose the amount of natural gas used by metal mining services in 1987. However, the census did report that metal mining services used almost no natural gas in 1982. Therefore, I assume that metal mining services used no natural gas in 1987.

<sup>b</sup> The census did not disclose the cost or quantity of coal or the cost of "other" fuels used in uranium-radium-vanadium mining and milling in 1982 or 1987. However, the *sum* of the total cost of coal and the total cost of "other" fuels used can be calculated from the census data. I apportion this sum to coal and to "other" fuels according to the ratio of the total cost of coal used in all metal mining industries to the total cost of "other" fuels used in all metal mining industries. I then divide the total cost of coal by the price of coal, as reported by the census (in \$/10<sup>6</sup> Btu), to get the total energy value of coal used, and divide the total cost of "other" fuels by the \$/10<sup>6</sup>-Btu-price of "other" fuels to get the total energy value of "other" fuels.

The census also did not disclose the value of "other" fuels used by metal mining services in 1982 or 1987. I back-calculated the 1987 value, using census data, and calculated the 1982 value by assuming that the 1982 ratio of the value of "other" fuels to the value of all fuels was the same as the 1987 ratio.

<sup>c</sup> Uranium concentrates.

<sup>d</sup> From EIA, *Uranium Industry Annual 1987* (1988).

<sup>e</sup> Based on U.S. Department of Commerce (USDOC) production estimates.

Sources: U.S. Department of Commerce, U.S. Bureau of the Census, *1987 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1990); U.S. Department of Commerce, U.S. Bureau of the Census, *1987 Census of Mineral Industries, Ferroalloy Ores, Metal Mining Services, and Miscellaneous Metal Ores* (1990); U.S. Department of Commerce, U. S. Bureau of the Census, *1982 Census of Mineral Industries, Fuels and Electric Energy Consumed* (1985).



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

| Standard Industrial Classification Area | Purchased Fuels (\$) <sup>a</sup> /<br>Distributed Fuels (\$) <sup>c</sup> |       | All Products (\$) <sup>b</sup> /<br>Distributed Products (\$) <sup>d</sup> |       |
|---|--|-------|--|-------|
|   | 1982   | 1987  |  |       |
| Uranium-vanadium-radium                 | 1.079  | 1.264 | 1.138  | 1.134 |
| Metal mining services                   | 1.202 <sup>e</sup>   | 1.174 | Not used   |       |

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Other data:

- 0.100 = fraction of metal mining services assigned to uranium (my estimate; see text).
- 0.930 = fraction of uranium-vanadium-radium energy assigned to uranium (my estimate; see text).
- 0.137 = 10<sup>6</sup> Btu/dollar of "other" fuels, 1982 (value given by the census).
- 0.161 = 10<sup>6</sup> Btu/dollar of "other" fuels, 1987 (value given by the census).

- <sup>a</sup> The total dollar value of all fuels (oil, gas, coal, power, etc.) purchased by all companies engaged in the activity, including fuels used by companies that were not surveyed (the census estimated the value for these companies) and by companies that did not report the amount of each type of fuel they used.
- <sup>b</sup> The total dollar value of all products (e.g., uranium ore) of all companies engaged in the activity, including products of companies that were not surveyed (the census estimated production for these companies) and products of companies that did not classify or detail their products (e.g., did not state the type of coal they produced).
- <sup>c</sup> The dollar value of the fuels purchased by companies that reported the amount of each type of fuel purchased. Not all companies were surveyed, and some of the companies surveyed reported only the total cost of purchased fuels with no breakdown or details.
- <sup>d</sup> The dollar value of products of those companies that reported the amount and type of each product.
- <sup>e</sup> The cost of undistributed fuels was not disclosed, but could be calculated by assuming a value for "other" fuels (see Table I.1, footnote b).

Note: See sources for Table I.1.

### **1.2.1 Comparing Some of the Census Data with Data from Other Sources**

The DOE Energy Information Administration (EIA) (EIA, *Uranium Industry Annual 1987, 1988*) reports slightly lower uranium concentrate shipments for 1987 than does the census, but much higher shipments for 1982. The EIA also reports slightly more crude ore production in 1987 and significantly more in 1982. This comparison seems to validate the 1987 census data but casts doubt on the quality of the 1982 data. I therefore use the 1987 data in estimating the energy intensity of uranium mining and milling. I calculate energy used by mining and milling operations, per unit of concentrate shipped, using the 1987 census data. I then convert this to energy use per unit of net nuclear generation using the data series of Table I.3 for  $U_3O_8$  requirements per unit of generation.

When the DOE estimates of energy used per mining and milling facility are scaled up to the amount of ore produced for all purposes in 1982, the energy consumption data for uranium mining and milling in 1982 are reasonably close to the estimates in USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors* (1983). In scaling the DOE factors, I assume that open-pit mining and underground mining produced ore in proportion to the final 1982 total production for each kind of mine, as reported by EIA.

### **1.2.2 Future Energy Use by Uranium Mining and Milling**

As the concentration of uranium in the ore decreases, the energy required to mine and process the ore increases dramatically (Mortimer, no date). Mortimer shows that a nuclear fuel cycle based on very low-grade ore, less than 100 parts-per-million (ppm) uranium oxide, or 0.01% (0.1-0.3% are typical values for today), will produce as much  $CO_2$  as a fossil-fuel cycle with the same electricity output. Consequently, if the United States uses lower-grade ores in the future, fuel-cycle energy requirements may rise substantially. However, ore quality has not declined over the last 10 years (EIA, *Uranium Industry Annual 1988, 1989*). It is not likely that ore quality will decline significantly in the foreseeable future. Consequently, I do not consider the possibility of increased energy requirements for mining and milling.

## **1.3 Energy Used to Transport Uranium**

The amount of energy used by trucks in transporting uranium is the product of the weight of the shipment, the distance, and the Btu/ton-mi energy consumption rate of the truck.

### **1.3.1 Tons Transported**

Total tonnage at any stage of the fuel cycle is the sum of the weight of the uranium (as fuel, yellowcake, or  $UF_6$ ) and the containers and packaging. The amount of packaging is related to the amount of uranium; the amount of uranium is related to the total power output from nuclear power plants. Therefore, to estimate the total amount of energy consumed by trucks in transporting

TABLE I.3 Nuclear Fuel Consumption and Generation Data

| Year      | 10 <sup>6</sup> SWUs <sup>a</sup> | Tons<br>U <sub>3</sub> O <sub>8</sub><br>Enriched <sup>a</sup> | Net TWh<br>Generation <sup>b</sup> | Net TWh<br>Consumable <sup>c</sup> |
|-----------|-----------------------------------|--|------------------------------------|------------------------------------|
| 1977      | 4.950                             | 8,500  | 250.883                            | 249.852                            |
| 1978      | 4.950                             | 8,500  | 276.403                            | 275.267                            |
| 1979      | 5.600                             | 9,000  | 255.155                            | 254.106                            |
| 1980      | 5.850                             | 10,000   | 251.116                            | 250.084                            |
| 1981      | 5.800                             | 10,000   | 272.674                            | 271.553                            |
| 1982      | 6.500                             | 11,500   | 282.773                            | 281.610                            |
| 1983      | 8.200                             | 15,000   | 298.677                            | 297.449                            |
| 1984      | 8.000                             | 15,000   | 327.634                            | 326.287                            |
| 1985      | 7.900                             | 16,250   | 383.691                            | 382.114                            |
| 1986      | 8.000                             | 18,250   | 414.038                            | 412.336                            |
| 1987      | 6.950                             | 17,500   | 455.270                            | 453.398                            |
| 1988      | 6.200                             | 18,500   | 526.901                            | 524.735                            |
| 1989      | 8.511                             | 19,100   | 529.400                            | 527.223                            |
| 1990      | 7.497                             | 17,650   | 535.103                            | 532.903                            |
| 1991      | 9.112                             | 19,200   | 553.117                            | 550.843                            |
| 1992      | 8.073                             | 19,250   | 555.365                            | 553.082                            |
| 1993      | 8.772                             | 18,950   | 559.373                            | 557.073                            |
| 1994      | 7.702                             | 17,950   | 559.796                            | 557.495                            |
| 1995      | 9.828                             | 19,450   | 562.141                            | 559.830                            |
| 1996      | 8.093                             | 19,700   | 563.900                            | 561.582                            |
| 1997      | 9.800                             | 17,300   | 565.658                            | 563.332                            |
| 1998      | 9.635                             | 18,000   | 572.734                            | 570.379                            |
| 1999      | 9.015                             | 18,000   | 575.156                            | 572.791                            |
| 2000      | 9.434                             | 17,900   | 576.402                            | 574.032                            |
| 2001      | 9.712                             | 18,600   | 580.411                            | 578.025                            |
| 2002      | 9.838                             | 17,800   | 583.010                            | 580.613                            |
| 2003      | 9.993                             | 17,250   | 585.969                            | 583.560                            |
| 2004      | 9.617                             | 20,050   | 588.929                            | 586.508                            |
| 2005      | 9.971                             | 15,250   | 591.888                            | 589.455                            |
| 2006      | 9.138                             | 20,800   | 594.847                            | 592.401                            |
| 2007      | 10.946                            | 18,400   | 592.284                            | 589.849                            |
| 2008      | 9.535                             | 21,500   | 595.216                            | 592.769                            |
| 2009      | 11.390                            | 19,250   | 591.886                            | 589.453                            |
| 2010      | 12.076                            | 22,800   | 589.728                            | 587.303                            |
| -----     |                                   |  |                                    |                                    |
| 1977-1988 | 79                                | 158,000  | 3,995                              | 3,978                              |
| 1977-2020 | 287                               | 572,150  | 16,598                             | 16,526                             |
| 1990-2010 | 199                               | 395,050  | 12,073                             | 12,021                             |
| -----     |                                   |  |                                    |                                    |

TABLE I.3 (Cont'd)

| Year      | SWMUs/<br>MWh Generated | Tons U <sub>3</sub> O <sub>8</sub> /<br>GWh Generated | MWh Enrichment/<br>MWh Generated <sup>d</sup> |
|-----------|-------------------------|---|---|
| 1977-1988 | 0.0197                  | 0.0395  | 0.0474  |
| 1977-2010 | 0.0173                  | 0.0345  | 0.0414  |
| 1990-2010 | 0.0165 <sup>e</sup>     | 0.0327  | 0.0396  |
| 1980-1990 | (from Table I.6)        |   | 0.0392  |

<sup>a</sup> Data from 1989-2010 are year-by-year projections from the INM (EIA, data transmittal, March 5, 1990). The historical data for a separate work unit (SWU) are back-calculations based on 5-year historical average uranium mass flows and U-235 assays. The SWU forward projections are based on projections of assays and uranium requirements.

<sup>b</sup> Data through 1989 are from EIA's *Commercial Nuclear Power* (WINES model). The year-by-year post-1989 projections are from the INM (EIA, data transmittal, March 5, 1990).

<sup>c</sup> Net nuclear generation minus nuclear power used to mine, mill, convert, enrich, or fabricate uranium.

<sup>d</sup> The product of SWUs/MWh and 2.4 MWh enrichment/SWU.

<sup>e</sup> The Organization for Economic Cooperation and Development, Nuclear Energy Agency (1987) shows 0.0158 SWU/MWh-generated over the life of a pressurized-water reactor.

Notes: The WINES model projects nuclear generating capacity and nuclear electricity generation for the United States and the world (reported in *Commercial Nuclear Power*). The INM model takes the WINES results and projects uranium requirements, SWU requirements, fuel burn-up, and fuel discharge for the United States and the world (results reported in *World Nuclear Fuel Cycle Requirements*). The WINES lower reference-case (actually the base case) projections of nuclear electricity generation shown here are consistent with (almost identical to) the separate electricity generation projections of the EIA's Intermediate Future Forecasting System (IFFS) (published in the *Annual Outlook for U.S. Electric Power*), which are, in turn, consistent with the projections in EIA's *Annual Energy Outlook*. (*Commercial Nuclear Power*, *World Nuclear Fuel Cycle Requirements*, *Annual Outlook for U.S. Electric Power*, and *Annual Energy Outlook* are published annually by the EIA.)

There is little difference among EIA's lower reference case, upper reference case, and no-new-orders case through the year 2010. After 2010, EIA assumes major capacity additions in the upper reference case and no new capacity in the no-new-orders case. Nevertheless, one should keep in mind that EIA's projection of uranium and SWU requirements, per unit of generation, depend on the assumed amount of new capacity, because the initial core loading requires a large amount of uranium.

uranium (and waste), one must know the relationship between uranium requirements and electricity output, and the relationship between packaging weight and uranium weight, for each stage of the fuel cycle.

Rotty et al. (1975) provide most of this data: they show the total weight of a shipment (uranium or waste plus containers and packaging) relative to a unit amount of  $U_3O_8$  at every stage of the cycle. Thus, if one knows how much  $U_3O_8$  is associated with the amount of power output, one has all of the information necessary to do the calculation. The data of Rotty et al. (1975) are shown in Table I.4.

The U.S. Congressional Research Service (CRS) (1977) provides the same sort of ratio but excludes container weight. I have included the CRS figures in Table I.4 for a rough comparison; the ratios between stages for both sets of data should be similar except where the packaging requirements change dramatically. The Rotty et al. (1975) ratios of conversion to enrichment and enrichment to fabrication are similar to the CRS ratios, but the Rotty et al. (1975) ratios of fabrication to fuel and fuel to waste are higher than the CRS ratios. This indicates, as one would expect, that the amount of packaging and container weight increase considerably when a finished fuel rod or hazardous waste, as opposed to the raw fuel material, is being shipped.

The relationship between  $U_3O_8$  weight and electricity output is analyzed later.

### I.3.2 Average Miles

I estimated the mileage from mines to converters and converters to enrichers from maps 16 and 17 in the CRS, *National Energy Transportation Report* (1977). These maps show shipments (in tons and energy units) from uranium mines to the two conversion plants and from the conversion plants to the three DOE enrichment facilities in 1976 (little is different in 1989). Uranium is mined in essentially the same places today as it was in 1976, and all domestic enrichment is done at two of the three DOE plants. For the mileage from enrichers to fabricators, and from fabricators to reactors, I used the mileage estimates in the Oak Ridge National Laboratory (ORNL) safety study (O'Donnell and Choy, 1981). These estimates seem roughly consistent with the CRS maps. (I did not measure exact distances on the CRS maps because after enrichment there are many possible paths to fabricators and reactors.) I estimated mileage to low-level waste repositories assuming that all low-level waste is transported to the nearest of the three currently operating sites. I assume that all high-level waste would be transported to the planned Yucca Mountain geologic repository in Nevada.

The energy used to transport ore to the mill and energy used at the mill are apparently included in the census estimates of energy used in uranium mining.

The mileages estimated here are for domestic uranium activity. Since data for foreign uranium activity are not readily available, I assume that these estimates apply, on average, to all uranium activity theoretically associated with 1987 nuclear net generation.

Table I.4 Transporting Uranium, Finished Fuel, and Nuclear Waste

| Material Produced                             | Weight Excluding Containers<br>(total tons/ton U <sub>3</sub> O <sub>8</sub> ) <sup>a</sup> | Weight Including Containers<br>(total tons/ton U <sub>3</sub> O <sub>8</sub> ) <sup>b</sup> |
|---|---|---|
| Ore (to mills)                                | 300-900 <sup>c</sup>  | - -   |
| U <sub>3</sub> O <sub>8</sub> (to converters) | 1.0   | 1.50  |
| UF <sub>6</sub> (to enrichers)                | 1.48  | 2.24  |
| Enriched UF <sub>6</sub> (to fabricators)     | 0.286 <sup>d</sup>  | 0.58  |
| Fuel (to reactors)                            | 0.275 <sup>e</sup>  | 1.01  |
| High-level waste (to repositories)            | 0.275 <sup>e</sup>  | 1.45  |
| Low-level waste (to burial sites)             | 1.26  | 1.45  |

<sup>a</sup> From U.S. Congressional Research Service (1977).

<sup>b</sup> From Rotty et al. (1975).

<sup>c</sup> The CRS estimates 500. The Nuclear Assurance Corporation Report, contained in the CRS report, estimates 606. Data in the EIA, *Uranium Industry Annual 1987* (1988) indicate that this ratio has varied from 300 (in 1986) to 900 (in 1984), depending on the concentration of uranium in the ore, with the average being about 800 from 1978 to 1987. (Note that the U.S. Bureau of the Census figures in Table I.1, which cover mining *and* milling, presumably include the use of energy to transport ore from the mine to the mill.)

<sup>d</sup> The ratio of the unenriched to the enriched UF<sub>6</sub> factors, 1.48:0.286 (about 5), is consistent with the fact that the percentage of U-235 content is increased by a factor of about 5 in the enriching process.

<sup>e</sup> Based on the total weight of the fuel, not just the uranium weight.

My estimates of the mileage from enrichers to fuel fabricators, fuel fabricators to reactors, and reactors to waste disposal sites are the same as the estimates in Rotty et al. (1975). They estimate 800 miles from mills to converters and 800 miles from converters to enrichers.

### 1.3.3 Btu/Ton-Mile

The estimate is based on the data of Table E.2 and is the same for all trucks.

My assumptions for transport are shown in Table I.5.

## 1.4 Energy Used to Enrich Uranium

To estimate greenhouse gas emissions due to uranium enrichment, per unit of electricity output from nuclear power plants, one must know the amount and kind of energy used to enrich uranium, per unit of output from nuclear plants. The amount of energy used to enrich uranium is a function of the enrichment technology and the degree of enrichment desired. In the following paragraphs, I analyze the amount of energy (electricity) required to enrich uranium, per unit of electricity output from power plants (using current technology), and the source of the electricity used for enrichment. I also discuss future enrichment technology.

There are at least two ways to estimate the amount of electricity required to enrich uranium (using current technology), per unit of electricity output from nuclear power plants. One way is to correlate total energy use by uranium-enrichment facilities over a period of years with total electricity output from nuclear power plants over the same period of years. The other way is to estimate electricity requirements per unit, called a separate work unit (SWU), and then estimate the relationship between SWUs and electricity output.

### 1.4.1 Method 1

Table I.6 shows the electricity consumed (in MWh) by the three DOE gaseous diffusion plants (GDPs) from October 1, 1979, to September 30, 1989 (data transmitted by Lee Ewing, EIA, Washington D.C., October 12, 1989). The consumption data are for fiscal years, October 1-September 30. However, these data do not represent total enrichment services required by U.S. nuclear power plants, because, on the one hand, it appears that about 8% of the enrichment service at the GDPs is for the military, not for power plants (USDOE, *Uranium Enrichment Enterprise, Operating Plan*, 1989), and that about 30% is for foreign customers (EIA, *World Nuclear Fuel Cycle Requirements 1990*, 1990). On the other hand, about 12% of the total U.S. enrichment requirements are handled by EURODIF in France. I adjust the total electricity consumption at the GDPs accordingly and divide by net nuclear electricity generation in the United States. The results are shown in Tables I.6 and I.3.

TABLE I.5 Nuclear Transportation by Truck

|                               |            |   |            |
|-------------------------------|------------|---|------------|
| <b>Mill to converter</b>      |            | <b>Fabricator to reactor</b>            |            |
| Tons of $U_3O_8$ moved        | 17,500     | Total tons/tons $U_3O_8$                | 1.010      |
| Total tons/tons $U_3O_8$      | 1.500      | Average miles                           | 500        |
| Average miles                 | 1,000      | Calculated ton-miles                    | 8,837,500  |
| Calculated ton-miles          | 26,250,000 | Btu/ton-miles                           | 2,500      |
| Btu/ton-miles                 | 2,500      | Calculated quads                        | 0.000022   |
| Calculated quads              | 0.000066   |   |            |
| <b>Converter to enricher</b>  |            | <b>Reactor to burial</b>                |            |
| Total tons/tons $U_3O_8$      | 2.240      | Total tons/tons $U_3O_8$                | 1.450      |
| Average miles                 | 500        | Average miles                           | 1,000      |
| Calculated ton-miles          | 19,600,000 | Calculated ton-miles                    | 25,375,000 |
| Btu/ton-miles                 | 2,500      | Btu/ton-miles                           | 2,500      |
| Calculated quads              | 0.000049   | Calculated quads                        | 0.000063   |
| <b>Enricher to fabricator</b> |            | <b>Reactor to repository</b>            |            |
| Total tons/tons $U_3O_8$      | 0.580      | Total tons/tons $U_3O_8$                | 1.450      |
| Average miles                 | 800        | Average miles                           | 1,200      |
| Calculated ton-miles          | 8,120,000  | Calculated ton-miles                    | 30,450,000 |
| Btu/ton-miles                 | 2,500      | Btu/ton-miles                           | 2,500      |
| Calculated quads              | 0.000020   | Calculated quads                        | 0.000076   |
|                               |            | Total quads used                        | 0.000297   |
|                               |            | Total quads used/<br>quads power output | 0.000192   |

Notes: The tons/ton  $U_3O_8$  are from Table I.4. The mileage data are from maps and Rotty et al. (1975). The Btu/ton-miles are based on data in Rose (1979).

#### 1.4.2 Method 2

The work required to separate or enrich uranium is expressed in SWUs. The SWU is defined mathematically in terms of the concentration of U-235 in the input uranium stream, the concentration in the output uranium fuel (enriched) stream, and the concentration in the output waste (depleted) stream. The greater the difference between the concentration of U-235 in the waste (tails) and product streams (that is, the more separation required), the more SWUs are required.

Rotty et al. (1975) reviewed estimates of the amount of electricity required to produce an SWU and came up with a range of 2.3-2.8 MWh, with 2.4 being the best estimate for future plants. Davis et al. (1982) also use 2.4 MWh/SWU. The DOE's operating plan for uranium enrichment (USDOE, *Uranium Enrichment Enterprise, Operating Plan*, 1989) assumes about 2.4 MWh/SWU.



TABLE I.6 Electricity Consumption at DOE Gaseous Diffusion Plants

| Fiscal Year <sup>a</sup>   | Oak Ridge (MWh) | Paducah (MWh) | Portsmouth (MWh) | Total (MWh)                      |
|--|-----------------|---------------|------------------|----------------------------------|
|  | 7,223,485       | 11,670,256    | 6,466,896        | 25,360,637                       |
|  | 6,156,606       | 9,361,670     | 6,872,044        | 22,390,320                       |
|  | 6,151,119       | 9,392,777     | 6,869,443        | 22,413,339                       |
|  | 6,154,676       | 9,417,035     | 6,875,144        | 22,446,855                       |
|  | 6,190,048       | 9,275,480     | 9,668,732        | 25,134,260                       |
|  | 3,149,289       | 7,537,087     | 13,270,483       | 23,956,859                       |
|  | 0               | 6,435,620     | 11,348,198       | 17,783,818                       |
|  | 0               | 5,168,770     | 12,350,134       | 17,518,904                       |
|  | 0               | 4,641,663     | 8,969,234        | 13,610,897                       |
|  | 0               | 6,390,212     | 13,394,543       | 19,783,755                       |
|  | 0               | 10,385,566    | 16,591,959       | 26,077,525                       |
| -----  |                 |               |                  |                                  |
| Total  |                 |               |                  | $2.375 \times 10^8$              |
| -----  |                 |               |                  |                                  |
| Adjustment factor (accounting for military use and foreign enrichment) |                 |               |                  | 0.0705 <sup>b</sup>              |
| Net MWh generation, 1980-1990  |                 |               |                  | $4.277 \times 10^9$ <sup>c</sup> |
| MWh enrichment/MWh generation  |                 |               |                  | 0.0392 <sup>d</sup>              |

<sup>a</sup> The fiscal year (FY) is October 1 to September 30. The data shown are from October 1, 1979, to September 30, 1990.

<sup>b</sup> Not all of the energy used at the GDPs went to enrich energy for U.S. power plants, and not all U.S. utility-uranium is enriched at the U.S. GDPs. This factor accounts for this. It appears that about 30% of the SWUs provided by the U.S. GDPs are for foreign utilities, primarily Japanese (based on data in EIA, *World Nuclear Fuel Cycle Requirements 1990, 1990*), and that about 8% of the SWUs are for the military (USDOE, *Uranium Enrichment Enterprise, Operating Plan, 1989*). On the other hand, U.S. utilities have about 12% of their uranium enriched overseas (EIA, *Uranium Industry Annual 1987, 1988*). This indicates that 62% of the work of the U.S. GDPs (100% minus 30% for foreign utilities, minus 8% for military) went to provide 88% of the U.S. total nuclear power generation (100% minus the 12% derived from foreign enrichment). ( $0.62/0.88 = 0.705$ )

<sup>c</sup> From Table I.3. The data are from January 1, 1980, to December 31, 1990. This period is shifted four months ahead of the FY period data for enrichment, but this is acceptable because there is a lag between enrichment and generation.

<sup>d</sup> MWh enrichment multiplied by the adjustment factor, divided by MWh generation.

Notes: Electricity consumption data from Lee Ewing (1989, 1991).

It is more difficult to estimate the relationship between SWUs and net nuclear generation. The SWUs, of course, cost money, and there is a trade-off between SWU cost and natural uranium cost: one can produce a given amount of U-235 with a lot of SWUs and a little natural uranium, or with a lot of natural uranium and a few SWUs. If SWUs are cheap and natural uranium is expensive, it is worthwhile to use a lot of SWUs to get as much U-235 from the natural uranium as possible and thereby minimize the amount of natural uranium required. On the other hand, if natural uranium is cheap and SWUs are expensive, then it is better to conserve SWUs by feeding a lot of natural uranium to the process and separating it less. (This discussion is illustrative; in practice, there are upper and lower limits on the concentration of U-235 in the enriched uranium, and these bound the cost trade-off. The cost trade-off is very real, however, and genuinely complicates predictions of SWU requirements.)

Because of these trade-offs, any relationship between SWUs and electricity output must be built on economic models. One of the most detailed models available is the EIA's International Nuclear Model (INM), which projects the SWU and uranium requirements associated with the amount of net nuclear generation projected by the EIA's World Integrated Nuclear Evaluation System (WINES) model (see notes to Table I.3). Table I.3 shows the EIA's historical (back-projected) and projected relationships among  $U_3O_8$ , SWUs, and net nuclear generation. Note that the EIA projects that fewer and fewer SWUs will be needed to produce a MWh of nuclear power. This is partly because the EIA projects that utilities will use enriched fuel more efficiently by increasing their burn-up rate, and partly because the EIA assumes no new capacity additions through 2010.

Method 2, using MWh-enrichment/SWU and SWU/MWh-net-generation data, yields a slightly higher MWh-enrichment/MWh-net-generation value than does Method 1 (Table I.3). Because of the uncertainty of the adjustments of Method 1, I use the Method 2 results. Specifically, I use the EIA projections of SWUs required and MWh generated from 1990 to 2010 to calculate my year-2000 base-case values.

Part of the difference between the two methods is that the EIA model does not allow for uranium stocks, whereas the actual demand for SWUs incorporates changes in uranium stocks. Technically, one should count stocks, since stock requirements are "real" and a form of consumption. That is, one should assign to electricity generation not only the amount of uranium (and SWUs) actually consumed in reactors over a period of time but also the total average uranium stock maintained. For practical purposes, stocks can be ignored if (a) the average stock level is small compared with the aggregate consumption over many years or (b) if it can be assumed that eventually stocks will be consumed. I ignore stocks.

### 1.4.3 Future Enrichment

As noted above, enrichment technologies other than gaseous diffusion are available (gas centrifuge) or under development (laser isotope separation). Both of these processes use considerably less electricity to enrich uranium than does gaseous diffusion, which requires considerable electricity to drive the compressors to move the uranium gas through the filters.

According to Davis et al. (1982), centrifuge and U-AVLIS technologies use about 0.1 MWh/SWU, compared with 2.4 MWh/SWU for gaseous diffusion.

Because U-AVLIS probably will not come on line before the turn of the century, I assume that in the year 2000, all enrichment will be done at GDPs. However, new enrichment capacity would be required in a large nuclear-power program in the future, and this would likely be supplied partly by U-AVLIS technology or something similarly efficient. I consider the use of U-AVLIS in scenario analyses for hydrogen and electric vehicles using nuclear energy.

#### **I.4.4 Improvements in the Efficiency of Generating Plants**

There is ample room for nuclear utilities to increase the amount of electricity they generate from a unit of heavy metal input (EIA, *World Nuclear Fuel Cycle Requirements, 1990, 1990*). The two basic ways to improve this measure, called "the burn-up rate," are to increase the concentration of U-235 and to redesign the fuel rods. Increasing the concentration of U-235 requires work, in the form of extra SWUs, but the energy payoff in greater efficiency generally exceeds the energy cost of the extra SWUs. The EIA's projections for SWU use and electricity use assume a steady improvement in the burn-up rate. Hence, efficiency improvements are built into the year-2000 estimates used here.

#### **I.4.5 Electricity Mix for Uranium Enrichment**

The mix of fuel input to the electricity plants supplying the DOE enrichment facilities can be estimated quite accurately. According to DOE (USDOE, *Uranium Enrichment Enterprise, Operating Plan, 1989*), the Portsmouth facility contracts with the Ohio Valley Electric Corporation (the contract will be renewed in 1992), and the Paducah facility has a contract with Electric Energy Inc. through the year 2005. Each of these utilities owns one large coal-fired plant (EIA data transmittal, 1990). The DOE facilities have access through these utilities to regional power markets, but about 90% of the power in Ohio and Kentucky comes from coal (see Table D.1). Thus, it appears that the DOE gaseous diffusion facilities will be using nearly 100% coal-based power for the foreseeable future.

As noted above, the GDP of EURODIF satisfies about 12% of the U.S. enrichment needs. I assume that EURODIF draws power from the French national-average power mix, which is dominated by nuclear power (EIA, *Energy Balances of OECD Countries 1986-1987, 1989*). The model thus weights the Kentucky power mix by 88% and the French power mix by 12%. The final results are shown in Table I.7.

For simplicity, I assume that this mix will remain the same in the future, even if new enrichment technologies come on line. This amounts to assuming that U-AVLIS plants would be located where the electricity mix is the same as in the area of the GDPs.

TABLE I.7 Net Energy Analysis of Nuclear Power: Results of Rotty et al. (1975) and Mortimer (no date)

| Stage in the Cycle                              | 10 <sup>6</sup> Btu of Total Energy <sup>a</sup> per 10 <sup>6</sup> Btu of Electricity from a Nuclear Power Plant <sup>b</sup> |                                 |             |
|---|---|---------------------------------|-------------|
|   | Rotty et al. (1975)   | Mortimer (no date) <sup>c</sup> | This Report |
| Mining and milling                              | 0.0101  | 0.078                           | 0.0053      |
| Conversion                                      | 0.0118  |                                 |             |
| Enrichment                                      | 0.0469  |                                 | 0.0396      |
| Fabrication                                     | 0.0044  |                                 |             |
| Power plant (construction and auxiliary power)  | 0.0292  |                                 |             |
| Waste storage                                   | 0.0003  |                                 |             |
| All fuel and waste transportation               | 0.0005  |                                 | 0.00019     |
| Conversion + enrichment + fabrication + storage | 0.0634  | 0.048                           | 0.0415      |

<sup>a</sup> Electricity counted at 3,412 Btu/kWh.

<sup>b</sup> For a 1,000-MW pressurized-water reactor (PWR) operating for 30 years at 75% of rated capacity (in the Rotty et al. report and this report) and a 1,000-MW PWR operating for 35 years at 62% (in the Mortimer report). The capacity and lifetime differences do not matter, because the energy input/output ratio is of interest and if the output changes, the input should change proportionately.

<sup>c</sup> Mortimer (no date) estimates that fuel enrichment and fabrication produces  $6.71 \times 10^6$  metric tons of CO<sub>2</sub>, and uranium mining and processing produces  $0.689 \times 10^6$  metric tons over the life of a 1,000-MW PWR. He uses 210 metric tons CO<sub>2</sub>/TJ-electric for the electricity in the United Kingdom and 64 metric tons/TJ for thermal fuels, on average. Assuming a 45/55 power/thermal-fuel mix for the mining and milling stage (Table I.1) and a 95/5 mix for the enrichment and fabrication stage, I back-calculate 33,100 TJ/yr for fuel enrichment and fabrication and 5,312 TJ/yr for mining and milling. The total plant output is 683,618 TJ/yr. Mortimer assumes that 90% of the uranium is enriched by gaseous diffusion and 10% by gas centrifuge.

Notes: My estimates (this report) are from EIA publications, DOE (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*, 1983), and other sources (see text).

## **1.5 Fuel Used by Conversion and Fabrication Facilities, Auxiliary Boilers, and Standby Generators at Nuclear Power Plants**

The DOE (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*, 1983) gives data on fuel consumption by conversion and fuel fabrication plants. Rotty et al. (1975) estimated a considerably higher figure, but they included energy embodied in chemicals used at the facilities and in the materials of the facilities. I use the DOE values. My assumptions and the findings of Rotty et al. (1975) are compared in Table I.7.

Nuclear power plants use auxiliary steam generators, running on diesel fuel, to provide clean steam for start-up and in-plant heating. In addition, the Nuclear Regulatory Commission (NRC) requires periodic testing of on-site diesel generators to provide power for safety equipment in the event of a loss of power from the reactor (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*, 1983). The DOE (USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*, 1983) cites an estimate of 109 tons of sulfur oxide ( $\text{SO}_x$ ) per year from diesel-fuel generators and boilers. This means that, given its assumption of 0.5% sulfur and 100% sulfur dioxide ( $\text{SO}_2$ ),  $3.1 \times 10^6$  gal of diesel fuel were burned, producing about 1,500 g  $\text{CO}_2/10^6$  Btu of power from the plant. Similarly, Meridian Corporation (1989), using a 1981 version of the DOE *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors* (1983), estimates 1,558 g  $\text{CO}_2/10^6$  Btu of power produced by the reactor. However, Rotty et al. (1975) stated that a 1,000 MW pressurized-water reactor operating at 75% capacity would use only 90,900 gal of diesel fuel per year, which would result in only 40 g  $\text{CO}_2/10^6$  Btu of net power from the reactor.

I follow the DOE *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors* (1983) and assume that 0.15 gal of diesel fuel are used per  $10^6$  Btu of power produced from the plant. I multiply this fuel use by the full fuel-cycle  $\text{CO}_2$ -equivalent emission factors for diesel-fuel industrial boilers (Table A.2). Note that the contribution of the diesel generator is much less than the contribution of enriching uranium.

## **1.6 The Relationship between Tons of $\text{U}_3\text{O}_8$ and Nuclear Power Plant Output**

### **1.6.1 Overview**

In the section about the amount of energy required to transport uranium, estimates of tonnage carried by trucks were expressed relative to a unit amount of  $\text{U}_3\text{O}_8$ . To complete that calculation and determine the total tonnage carried per unit of net nuclear power generated, one must know how many weight units of  $\text{U}_3\text{O}_8$  are required to produce a unit of power. Knowing this, one can calculate the weight of  $\text{UF}_6$ , fabricated fuel, and spent fuel that is carried per unit of power, because the weights of  $\text{UF}_6$ , fabricated fuel, and spent fuel are known relative to the weight of  $\text{U}_3\text{O}_8$ . Knowing the total tonnage carried at each step of the cycle, per unit of power

output, allows one to calculate total energy consumption and thus total emissions of greenhouse gases, per unit of nuclear electricity delivered to the end-user.

There are two ways to calculate the relationship between  $U_3O_8$  and electricity output: compare historical uranium consumption with historical nuclear electricity generation or use future-projected and back-projected uranium requirements and historical and projected nuclear power generation. The latter is done by the EIA with INM and WINES. The results of the EIA's modeling are shown in Table I.3. In terms of generating capacity, the result is 242 tons  $U_3O_8$ /GW of capacity (70% capacity factor) for 1977-1978, and 201 tons  $U_3O_8$ /GW of capacity for the 1990-2010 period. I use the 1990-2010 figures here because I use the same EIA modeling results to determine the relationship between SWUs and electricity output, and because the historical EIA modeling results are reasonably close to other results.

### **1.6.2 Comparison of the EIA Modeling Results with Other Estimates of $U_3O_8$ Requirements per Electricity Output**

The EIA modeling estimates of yearly uranium requirements can be compared with a short data series of actual uranium requirements, and the EIA-data-based tons  $U_3O_8$ /GW-annual capacity can be compared with other estimates of the same value.

#### **1.6.2.1 Actual Uranium Use**

Actual usage of  $U_3O_8$  can be calculated as the amount of uranium sent by utilities to domestic and foreign enrichers, plus any natural uranium exchanged for enriched uranium, plus imported enriched uranium or fabricated fuel, less exports of enriched uranium or fabricated fuel. The EIA (EIA, *Uranium Industry Annuals* for 1984 through 1988, 1985-1989) reports the uranium sent to domestic and foreign enrichment plants, including exchanges of natural for enriched uranium, for the years 1984 to 1988. They do not report imports or exports; however, I assume that these are near zero. Table I.8 shows the actual uranium requirements calculated from the EIA data.

The INM back-estimates of uranium requirements for the years 1984-1988 (the only years for which there are data on the total amount of uranium enriched for U.S. utilities) are close to the actual amount of uranium enriched for those years — as close as were the utility projections for each of those of years — projections that were made the year before the actual occurrence (Table I.8). For this reason, I use the INM forward- and back-projections for both SWUs and uranium requirements.

#### **1.6.2.2 Other Estimates of Tons of $U_3O_8$ /GW**

Table I.9 compares the EIA-based estimate with other estimates of tons of  $U_3O_8$ /GW. The EIA value for 1977 to 1988 is consistent with other estimates. The projected improvement for 1990-2010 is due to the projected increase in the burn-up rate and the absence of new capacity.

TABLE I.8 Actual and Projected Uranium Enrichment Requirements, 1984-1988 (10<sup>3</sup> tons)

| Year | Amount of Uranium Actually Enriched <sup>a</sup> | Back-Projection of INM <sup>b</sup> | Utility Projection Made the Prior Year <sup>a</sup> |
|------|--|-------------------------------------|---|
| 1984 | 14.15  | 15.0                                | 17.0  |
| 1985 | 17.00  | 16.3                                | 19.1  |
| 1986 | 15.35  | 18.3                                | 16.2  |
| 1987 | 14.50  | 17.5                                | 18.0  |
| 1988 | 15.40  | 18.5                                | 17.0  |

<sup>a</sup> EIA, *Uranium Industry Annual* (various years).

<sup>b</sup> EIA, *World Nuclear Fuel Cycle Requirements 1988* (1989).

Notes: The data for 1983 are incomplete (EIA, *Survey of United States Uranium Marketing Activity 1983, 1984*): imports and exports are not shown, and it is not clear if there were any deliveries to foreign enrichers and, if so, if they were included. For 1977-1982, the EIA, in *Survey of United States Uranium Marketing Activity 1983* (1984), reports only deliveries of uranium to DOE enrichment plants by domestic utilities and inventory levels. It is not clear if the data on delivery to DOE enrichment plants from 1977-1982 actually include deliveries to foreign enrichment plants, if there were any such deliveries (from 1984-1988, about  $3 \times 10^6$  lb of U<sub>3</sub>O<sub>8</sub>-equivalent were sent to foreign enrichment plants), or if the data include exchanges of natural for enriched uranium (the 1984-1988 data do not include this information).

### I.7 Adjusted Net Nuclear Electricity Consumption (or, Nuclear Power Available for the Transportation Sector)

Recall that the ultimate objective is an estimate of grams of greenhouse gases emitted per 10<sup>6</sup> Btu of nuclear power available to power automobiles. The amount of nuclear power available to transportation is slightly less than the amount of nuclear power generated because a portion of nuclear generation is used in the nuclear fuel cycle itself to mine, mill, convert, enrich, fabricate, and dispose of uranium. This internal or "own" use of nuclear power must be deducted from net generation to arrive at the amount of nuclear power that actually leaves the system and is available for cars.

TABLE I.9 Tons of U<sub>3</sub>O<sub>8</sub>/GW Capacity (70% capacity factor)

| Reference  | Estimate          |
|--|-------------------|
| USDOE, <i>Energy Technology Characterizations Handbook, Environmental Pollution and Control</i> (1983) | 214               |
| USDOE, <i>Status of the Uranium Industry</i> (1985)  | 215 <sup>a</sup>  |
| USDOE, <i>Energy Technologies and the Environment, Environmental Information Handbook</i> (1988)       | 215 <sup>b</sup>  |
| U.S. Congressional Research Service (1977)   | 225 <sup>c</sup>  |
| EIA, <i>World Nuclear Fuel Cycle Requirements</i> (1989), data for 1977-1988                           | 242               |
| EIA, <i>World Nuclear Fuel Cycle Requirements</i> (1989), data for 1990-2010                           | 201               |
| Nuclear Assurance Corporation (U.S. Congressional Research Service, 1977)                              | 267               |
| Rotty et al. (1975)  | ~280 <sup>d</sup> |
| Nuclear Assurance Corporation (U.S. Congressional Research Service, 1977), pre-1976                    | 348 <sup>e</sup>  |

<sup>a</sup> It is not clear if initial core loading is included in this estimate.

<sup>b</sup> Drawing on information similar to that in USDOE, *Energy Technology Characterizations Handbook, Environmental Pollution and Control* (1983), this source states that 33-34 tons of enriched UO<sub>2</sub> (containing 3.3% U-235) are needed for one GW (70% capacity factor). Given that (a) the enrichment process increases the weight percentage of U-235 about 5 times above its natural value, (EIA, *Uranium Industry Annual*, 1989), (b) 10-15% of the tons are lost during enrichment (USDOE, *Status of the Uranium Industry*, 1985), and (c) uranium is 84.7% of U<sub>3</sub>O<sub>8</sub> (but 88.1% of UO<sub>2</sub>), about 200 tons of U<sub>3</sub>O<sub>8</sub> would be required for the GW of power (apparently excluding the initial loading). Adding an initial loading of about 500 tons, spread over 30 years, brings the total to about 215 tons/GW.

<sup>c</sup> It states that 35 metric tons of enriched uranium are needed to supply one GW of power, but it apparently assumes an 80% capacity factor. Scaling this down linearly to 70%, converting to English tons, and converting from uranium to UO<sub>2</sub> gives 38 tons of UO<sub>2</sub> per GW, or about 225 tons U<sub>3</sub>O<sub>8</sub>. It is not clear if the initial loading is included.

<sup>d</sup> The value depends on the type of nuclear power plant, the tails assay, and more. This is a roughly representative number.

<sup>e</sup> This is not an estimate of the lifetime average ton/GW requirement; it is an estimate of the actual tons loaded/GW prior to 1976. An estimate like this, which covers the first few years of the life of power plants, will be higher than an average estimate covering the whole life, because more fuel is loaded initially, in the first year, than is consumed in subsequent years (about 25% of the initial loading is replaced every year). By 1976, most plants were relatively new, and none had reached the end of their lives. Thus, the high estimate here reflects the influence of the initial core loading.

Notes: Estimates include initial core loading and are estimates for the lifetime of a power plant, unless otherwise noted.



The EIA (EIA, *Commercial Nuclear Power 1989, Prospects for the United States and the World*, 1989) reports and projects net generation by nuclear power plants. Net generation is power that leaves the plant and is available for off-site users. It is equal to the gross production coming from the generators minus electricity use by the nuclear power station, which is about 5% of gross production. All of the EIA's electricity figures are based on net generation.

The amount of nuclear-based electricity used in the mining, processing, enrichment, and disposal of nuclear fuel is equal to the total amount of electricity used at each of these steps multiplied by the share of the total from nuclear power plants. The total amount of power used to mine and mill uranium is shown in Table I.1. Data on the share of enrichment power from nuclear power plants is shown in Table 7. (For uranium mining, I assume the national average power mix.)

### **I.8 Net Energy Analysis of Nuclear Power: Comparison with Rotty et al. (1975) And Mortimer (No Date)**

In 1975, Rotty et al. published a comprehensive energy analysis of the nuclear power cycle. In this analysis, for every stage from mining through disposal of nuclear waste, they counted direct energy inputs; energy embodied in manufacturing, assembling, and transporting materials; energy used in construction; and energy embodied in the chemicals used in uranium mining (sulfuric acid) and treating wastewater. If their study were up to date, I would have used most of their results without doing any original calculations. Unfortunately, the study is rather old, but it is still useful to compare the results of their analysis with the numbers calculated here (see Table I.7).

The estimates of energy requirements calculated here are somewhat lower than the other estimates of Table I.7. There are several reasons for this. First, my estimates are based on the EIA projections of SWU and uranium requirements and electricity output for the year 2000, and the EIA projects that nuclear power plants will use nuclear fuel increasingly more efficiently. This reduces the amount of uranium required to produce a unit of power from the plant, and so reduces the amount of uranium that must be mined, transported, and processed, per unit output.

Second, the EIA projections of uranium and SWU requirements are for existing plants that are well beyond their initial core loading, whereas the other estimates are for the average uranium and SWU requirements over the life of a nuclear plant. The life-cycle estimate will be higher because it accounts for the initial core loading, and the initial loading requires more uranium than subsequent core replacements. Since the EIA assumes no new capacity through 2010, its estimates effectively exclude the effect of the initial core loading. This also reduces the amount of uranium required to produce a unit of power from the plant.

In addition, the difference between the estimates for transportation are due in part to the use of a higher Btu/ton-mi figure for trucks in Rotty et al. (1975). The difference between the combined figures for conversion, enrichment, and fabrication is due partly to the much higher value for conversion in Rotty et al. (1975), which results from their inclusion of the energy

required to make the conversion plant. Finally, the difference between the estimates for mining and milling are due partly to my use of the relatively low figure for 1987.

In a scenario analysis, I consider a lower average burn-up rate, the addition of new power plant capacity, and the 1982 mining and milling energy requirements.

Mortimer (no date) has published the results of a net energy and carbon dioxide (CO<sub>2</sub>)-emission analysis of the nuclear fuel cycle. Although the paper does not contain details (details are included in his earlier papers), his results are close to mine (Table I.7).

The analysis of energy use and CO<sub>2</sub> emissions in Mortimer (no date) is especially interesting because it shows how quickly energy use and emissions increase as uranium ores of progressively lower quality are used. As the concentration of uranium in the ore decreases, the energy required to mine and process the ore increases dramatically. In fact, Mortimer (no date) shows that a nuclear fuel cycle based on very low-grade ore, less than 100-ppm uranium oxide, or 0.01% (0.1-0.3% typical values for today), will produce as much CO<sub>2</sub> as a fossil-fuel cycle with the same electricity output. This suggests that it may be energetically and environmentally unsound to use very-low-grade uranium ores.

**Appendix J:**  
**Methanol from Coal and Natural Gas**



## **Appendix J:**

### **Methanol from Coal and Natural Gas**

#### **J.1 Overview**

Methanol is now the most widely promoted alternative transportation fuel in the United States, but this popularity is very recent. Throughout the 1970s and early 1980s, the preferred option for replacing petroleum was petroleumlike synthetic fuels made from coal and oil shale. Methanol was considered an inferior option partly because it was thought that, because natural gas was in short supply, methanol would have to be made from coal. The main argument against methanol, though, was that it was too different from petroleum. Methanol would require new or modified distribution systems and vehicles, whereas synthetic crude could simply be added to natural crudes at refineries, helping oil companies maintain the usefulness of present investments and insulating consumers from change.

In the early 1980s, perceptions began to shift, motivated by three new insights: first, the cost of manufacturing petroleumlike fuels was greater than had been anticipated; second, natural gas was more abundant than had been thought; and third, petroleumlike synthetic fuels did not help reduce persistent urban air pollution. Today, the air quality problem is perhaps most salient, and many cities and the Environmental Protection Agency (EPA) are turning to methanol in the hope that it can help reduce urban ozone levels.

##### **J.1.1 Feedstocks**

At present, economic and environmental considerations favor natural gas over coal and biomass as a methanol feedstock. The least expensive natural gas is remote natural gas (RNG), which is gas in foreign (usually third-world) countries remote from readily accessible markets that is priced at about \$1.00 per  $10^6$  Btu or less. Initially, methanol would be made in these low-cost, gas-rich countries and imported to the United States. Eventually, the price would be high enough to make domestic gas, and then coal and biomass, competitive as feedstocks. The location of the natural gas feedstock is important in a greenhouse analysis because it determines how far methanol must be transported and how much energy is used.

##### **J.1.2 Greenhouse Gas Emissions from Methanol Use**

Greenhouse gases are emitted from the production and transmission of the feedstock coal or gas, the conversion of the coal or gas to methanol, and the distribution of the methanol to end-users, primarily by ship and truck. Each of these is discussed in the following sections.

## J.2 Greenhouse Gas Emissions from the Recovery and Transport of Feedstock

Greenhouse gas emissions from the recovery and transport of feedstock are estimated as:

$$G_{m-s} = G_{c,n-s} \times E \times (1 + T) \times (1 + L)$$

where:

- $G_{m-s}$  = grams of greenhouse gases at stage s (recovery or transport of the feedstock) per energy unit of methanol consumed by vehicles,
- $G_{c,n-s}$  = grams of greenhouse gases emitted at stage s per energy unit of coal or natural gas delivered to conversion facilities,
- $E$  = coal or natural gas energy required per unit of methanol energy produced,
- $T$  = energy units of methanol consumed by delivery trucks per energy unit of methanol delivered to vehicles, and
- $L$  = amount of methanol lost to evaporation per energy unit of methanol delivered to vehicles.

These variables are treated as follows:

1. The calculation of  $G_{c,n-s}$ , greenhouse gas emissions from the recovery and transport of coal and natural gas per unit of energy made available to end-users, is detailed in the appendices on coal and natural gas. In this case, the methanol conversion facility is treated as an end-user of coal and natural gas. In the calculation of the amount of energy required to transport natural gas to a methanol plant, I assume a shorter transmission distance from a gas field to a methanol plant than from a typical gas field in the United States to a typical end user. ICF Resources, Inc. (ICF, *Estimates of the Cost of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990) estimates that there would be 400 to 1,000 miles of pipeline from a field flaring gas to a methanol-production plant, a distance that is considerably less than the distance from the major gas fields in the Gulf Coast of the United States to major end users in the northeastern United States. ICF also assumes that the amount of energy consumed by a pipeline compressor is proportional to the transmission distance. Accordingly, I assume that pipelines delivering gas to methanol plants would be 40% as long as pipelines currently delivering gas to end users in the United States, and that energy consumption by pipeline compressors is proportional to the total transmission distance.

I assume that methanol plants would not be connected to low-pressure distribution lines.

In the coal-to-methanol case, I assume that the methanol plant would be located at a major coal field in the United States.

2. The amount of coal or natural gas required per unit of methanol produced is estimated in the following sections in this appendix, which analyzes a large body of literature.
3. The variable T, which reflects the use of methanol to deliver methanol, is, of course, unknowable today. I leave it as a variable in the model. In the base case, I assume no methanol is used.
4. The variable L, the liquid loss factor, is calculated from an estimate of the amount of methanol spilled or evaporated from ships, marine terminals, bulk terminals, trucks, and service stations, per gallon of methanol delivered. This factor is estimated in Appendix B.
5. The  $\text{g}/10^6$  Btu estimate,  $G_{m-s}$ , is converted to  $\text{g}/\text{mi}$  by multiplying by  $10^6$  Btu/mi. ( $10^6$  Btu/mi is calculated as described in Appendix A.)

### J.3 The Conversion of Natural Gas to Methanol

The conversion of natural gas to methanol produces carbon dioxide ( $\text{CO}_2$ ) from the use of natural gas as a process fuel, methane ( $\text{CH}_4$ ), nitrous oxide ( $\text{N}_2\text{O}$ ), carbon monoxide ( $\text{CO}$ ), and nonmethane hydrocarbons (NMHC). The use of purchased electricity also produces greenhouse gas emissions.

$\text{CO}_2$  emissions from the methanol-production facility are calculated as:

$$3.66666 \times (C_n - C_m - C_0)$$

where:

$C_n$  = carbon in the input natural gas per unit of methanol output,

$C_m$  = carbon in a unit of methanol output,

$C_0$  = carbon emitted in  $\text{CH}_4$ ,  $\text{CO}$ , and NMHC per unit of methanol output.

The difference between the carbon in the input natural gas and the carbon in the output methanol can be calculated from the ratio of the natural gas energy input to methanol energy output, which is discussed in considerable detail below.

Methane, CO, NMHC, nitrogen oxide (NO<sub>x</sub>), and N<sub>2</sub>O emissions per unit of fuel output are calculated as the product of emissions per energy unit of feedstock input and the ratio of input energy to output energy. Intech (1990) reports CO, NO<sub>x</sub>, and hydrocarbon (HC) emissions from methanol plants. I use these values here. Data on methane, NO<sub>x</sub>, CO, and NMHC emissions from plants producing methanol and other products (Texas Air Control Board, 1990), combined with data on the production capacity of methanol facilities (U. S. Department of Commerce, 1985), indicate that the Intech (1990) estimates may be low. Nevertheless, I use the Intech (1990) estimates.

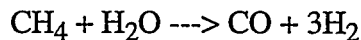
There are no published data on emissions of N<sub>2</sub>O and methane from methanol production plants. Steam-reforming and the burning of natural gas as a process fuel will produce some N<sub>2</sub>O. Because large amounts of natural gas are handled, there will be some methane emissions. The numbers in Table A.2 are rough estimates. Note that I assume lower N<sub>2</sub>O emissions from methanol production plants than from petroleum refineries.

My assumptions (in g/10<sup>6</sup> Btu-input; the values given above are in g/10<sup>6</sup> Btu-output) are shown in Table A.2. I subtract the carbon emitted as CO, NMHC, and methane from the input carbon before calculating CO<sub>2</sub> emissions.

Note that the efficiency of the conversion of natural gas to methanol is doubly important: it determines the amount of CO<sub>2</sub> emissions from the conversion process and the amount of natural gas that must be produced and transported, per unit of methanol output. Because of this importance, I discuss the conversion process and its efficiency in detail.

### J.3.1 Description of the Conversion Process

In most modern methanol plants, methanol is produced in three major steps: gasification, methanol synthesis, and distillation. In the first step, natural gas is reformed with steam into CO and water:

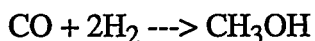


This production of synthesis gas via steam reforming requires relatively high-pressure steam and high reaction temperatures. These high pressures and temperatures are generated by burning supplemental natural gas, excess hydrogen, and purged synthesis gas and by recapturing waste heat from the reforming process.

The initial steam reforming produces a gas with a 3:1 hydrogen-to-carbon ratio. Since methanol synthesis requires a 2:1 ratio, the reformed gas is actually carbon deficient. In general, there are two ways to make up this deficiency: either add carbon, typically in the form of CO<sub>2</sub>, which is attractive if a cheap source of CO<sub>2</sub> is available (methanol plants are sometimes integrated with ammonia plants, because the manufacture of ammonia is similar and produces excess CO<sub>2</sub>), or burn the excess hydrogen to provide heat for the steam reforming reaction.



In any case, because of the scarcity of carbon, the methanol synthesis reaction (the second major stage of the process) is repeated several times until about 90% of the carbon in the CO in the synthesis gas is converted to carbon in the methanol product. The methanol synthesis reaction is:



In this reaction, the syngas is passed over a catalyst that accelerates the conversion of the reactants to methanol. First-generation methanol plants used relatively ineffective catalysts and had to operate at 250-350 bars and 320-400°C, in the synthesis stage, to convert syngas to methanol at an acceptable rate. Modern plants use catalysts active at lower temperatures and pressures: 50-100 bars and 230-280°C (Chem Systems, 1988).

The methanol synthesis reactor converts about half of the synthesis gas to methanol on the first pass, thus producing a mixture of gaseous methanol and unconverted syngas. The mixture of unconverted syngas and gaseous methanol is cooled, and the methanol condenses out and is removed. The unconverted syngas is then reheated and pressurized and passed back through the reactor. This recycling continues until most of the carbon is converted to methanol. In most systems, synthesis gas and waste heat provide the energy, including electrical energy, needed to reheat and repressurize the unconverted syngas.

In the third stage, minor unwanted components are removed from the raw liquid methanol (out of the synthesis reactor) to provide methanol of chemical-grade purity. The volatile components (CO, methane, aldehydes, ketones, etc.) are removed from the raw methanol in a "topping" column, and the water, ethanol, and higher alcohols are removed in a refining column. The refining column uses much more energy (primarily low-pressure steam) than the topping column (Thiagarajan and Ilgner, 1984).

The natural gas and power requirements of current-technology methanol production plans are shown in Table J.1.

### **J.3.2 Areas for Process Efficiency Improvement**

There are several major ways to improve the efficiency and/or lower the cost of methanol production: develop catalysts that are more effective at lower temperatures and pressures; use waste heat and purge gases more efficiently and remove the heat of the methanol synthesis reaction more effectively; and increase the conversion of syngas to methanol.

#### **J.3.2.1 Catalysts**

The yield of methanol from the synthesis reaction increases as pressure increases and temperature decreases. At atmospheric pressure, the synthesis reaction is thermodynamically favored (has negative free energy and proceeds spontaneously) at temperatures below 140°C. However, current catalysts are not very active below 140°C (Sheldon, 1983). The upshot is that

TABLE J.1 Energy Use of Natural Gas-to-Methanol Plants

| Process Description   | Btu Energy In/<br>Btu Methanol Out |                     | O <sub>2</sub> | Grade of<br>Methanol <sup>a</sup> | Reference  |
|---|------------------------------------|---------------------|----------------|-----------------------------------|--|
|   | Feedstock                          | Power               |                |                                   |  |
| Conventional steam reforming  | 1.65 <sup>b</sup>                  | I                   | NU             | F?                                | Korchnak (1988)  |
| Conventional steam reforming  | 1.56                               | 0.0029              | NU             | F?                                | Salmon (1986)  |
| Conventional steam reforming  | 1.43-1.65 <sup>c</sup>             | <sup>d</sup>        | NU             | C                                 | Chem Systems (1988)  |
| Conventional steam reforming plus low pressure synthesis  | 1.51 <sup>b</sup>                  | ?                   | NU             | C                                 | <i>Hydrocarbon Processing</i> ,<br>November (1989)                     |
| Steam reforming plus ICI synthesis  | 1.54 <sup>e</sup>                  | ?                   | NU             | F?                                | Kuo (1987)   |
| Steam reforming plus ICI synthesis, maximum CO <sub>2</sub> addition  | 1.47 <sup>e</sup>                  | ?                   | NU             | F?                                | Kuo (1987)   |
| Steam reforming plus Lurgi low-pressure synthesis   | 1.60 <sup>b</sup>                  | ?                   | NU             | C                                 | Marschner and Moertel (1986)   |
| Combined steam and autothermal reforming  | 1.30-1.38 <sup>c</sup>             | ?                   | ?              | C                                 | Chem Systems (1988)  |
| Combined steam and autothermal reforming  | 1.53 <sup>b</sup>                  | I                   | I              | F?                                | Korchnak (1988)  |
| Lurgi combined steam and autothermal reforming<br>(reforming at 780°C, 40 bar; synthesis at 240-270°C,<br>70-100 bar) | 1.49 <sup>b</sup>                  | I                   | I              | C                                 | <i>Hydrocarbon Processing</i> ,<br>November, p. 79 (1987) <sup>f</sup> |
| Catalytic partial oxidation plus tube-cooled methanol<br>synthesis  | 1.50 <sup>b</sup>                  | I                   | I              | F?                                | Korchnak (1988)  |
| Advanced partial oxidation scheme   | 1.33-1.43 <sup>c</sup>             | ?                   | ?              | C                                 | Chem Systems (1988) <sup>g</sup>                                       |
| Partial oxidation with once-through liquid-phase synthesis  | 1.60                               | -0.024              | I              | C                                 | Chem Systems (1990)  |
| Direct partial oxidation  | 1.37-1.45 <sup>e,h</sup>           | ?                   | I              | F?                                | Kuo (1987)   |
| Partial oxidation/low-temperature liquid catalyst (248°F<br>and 194-psi in the synthesis section)                     | 1.39 <sup>i</sup>                  | -0.012 <sup>i</sup> | NU             | F?                                | O'Hare et al. (1988)   |
| Gas-Solid-Solid Trickle Flow Reactor (about 500 K in the<br>synthesis section)  | 1.37 <sup>k</sup>                  | I                   | NU             | C                                 | Westerterp et al. (1988)   |

See next pages for footnotes.

TABLE J.1 (Cont.)

- a If the reference does not state the grade of methanol or imply a fuel grade, I assume chemical grade, since most, if not all, plants currently produce chemical-grade methanol.
- b Based on an LHV of 56,700 Btu/gal.
- c Based on the  $10^6$  Btu-natural gas/gal-methanol requirements reported in the reference (p. 12). However, the thermal efficiencies reported by Chem Systems and the  $10^6$  Btu-natural gas/gal-methanol requirements are not consistent on an HHV basis, which is the basis that Chem Systems claims to use. For example, Chem Systems associates 62% thermal efficiency with  $0.092 \times 10^6$  Btu-natural gas/ $10^6$  Btu-methanol on an HHV basis. However, on the basis of methanol's HHV of 64,500 Btu/gal, 0.092 implies an efficiency of  $0.0645/0.092 = 70\%$ . Conversely, 62% efficiency and 0.092 imply a heating value for methanol of about 57,000 Btu/gal, which is the LHV of methanol. Thus, Chem Systems either made a mistake in its thermal efficiency calculations, used LHVs, or did not calculate thermal efficiency and  $10^6$  Btu-natural gas/gal-methanol requirements in the same way. The Chem Systems numbers (which, when interpreted as I have here, result in high efficiencies) should be considered with this in mind.
- d A spreadsheet shows a "0" entered under "Utilities," which Chem Systems defines to be primarily purchased power.
- e Based on LHV.
- f The authors show a dash ("-") under "kWh of Electricity Consumed." This probably means that no (or a negligible amount of) power is purchased. The authors write that the natural gas process consumes 29.7 GJ of natural gas per metric ton of methanol; I have assumed they use LHVs. See also Marschner and Moertel (1986).
- g Chem Systems expects that advanced plants designed to minimize capital costs will be slightly less efficient than combination reforming plants.
- h Higher figure includes energy credit for surplus steam.
- i The plant produces a small amount of electricity for export. The value is based on O'Hare et al.'s assumption of 64,500 Btu/gal. (The HHV of gas is not specified.)
- j The process diagram shows a single distillation tower, which may mean a single column producing a fuel-grade product. Also, the article is about methanol as a fuel.
- k Based on the author's claim that the process will reduce consumption of raw materials by 10-12% (I assume 11%) compared with the Lurgi low-pressure process, and assuming  $1.54 \times 10^6$  Btu-natural gas/ $10^6$  Btu-methanol for the Lurgi process.

TABLE J.1 (Cont.)

Notes: LHV = lower heating value; HHV = higher heating value.

An "I" in the "Power" column means that the electrical energy consumption is included in the feedstock energy consumption (part of the gas feed generates all of the power requirements on-site). A "?" in the "Power" column means that the amount is not specified, and that it is not clear if the power is purchased or provided by the feedstock. Power is calculated as 3,412 Btu/kWh. A negative sign in front of the figures in the "Power" column means that the process produces net power for export. In all cases, the feedstock fuel provides all of the energy needed to generate steam. An "I" in the "O<sub>2</sub>" column means that the energy required to make oxygen is included under "Power" or "Feedstock." A "?" in the "O<sub>2</sub>" column means that oxygen is used, but it is not clear if the energy required to make the electricity to make oxygen is included in the power consumption or feedstock consumption figures. An "NU" in the "O<sub>2</sub>" column indicates that oxygen is not used in the process.

I assume 22.7 kJ/g or 64,500 Btu/gal HHV for methanol, and 19.95 kJ/g and 56,700 Btu/gal LHV.

the temperature must be high for the catalyst, and the pressure must be high to compensate for the thermodynamic unfavorability of the higher temperature. The successful development of a catalyst that is active at low temperatures would allow the use of lower pressures, which would save compression energy and extend the life of the plant.

### **J.3.2.2 Heat Management**

Heat management is quite important. The synthesis reaction produces a great deal of heat which, if not removed, will degrade the catalyst. Recovering the heat effectively protects the catalyst and provides process heat for other sections of the plant.

### **J.3.2.3 Conversion to Methanol**

Only about half of the carbon in the syngas is converted to carbon in methanol in the first pass through the reactor, so that the syngas must be recycled through the synthesis reactor. Increasing the conversion of syngas to methanol in each pass will reduce the energy used to recompress and reheat the unconverted syngas that is sent back to the synthesis reactor.

## **J.3.3 New Conversion Technologies**

Several efficient new conversion technologies have been developed to address the issues presented in Section 3.2.

### **J.3.3.1 The Lurgi Low-Pressure Combined Reforming Process**

The methanol synthesis reaction is highly exothermic, and if the heat it produces is not removed, the reaction slows, the catalysts deteriorate, and unwanted products form. The Lurgi process addresses this problem by wrapping the synthesis reactor in a cooling jacket filled with water; the reaction heat is transferred to the water, which boils and provides the steam to run the process. Because the temperature is reduced, the methanol content is increased and the syngas does not have to be pressurized as much to produce a given amount of methanol (compared with higher-temperature processes). Thus, the Lurgi process makes more effective use of the waste heat from the reactor and reduces compression energy requirements.

The Lurgi process also combines conventional steam reforming with a catalytic autothermal reaction: half of the natural gas feed is sent to the steam reformer, and the other half is combined with the syngas output of the reformer and reacted with oxygen over a nickel catalyst at very high temperatures (1700°C) (Chem Systems, 1988). The final syngas has a 2:1 hydrogen-to-carbon ratio, as required for methanol synthesis. It thus makes fuller use of the methane feed and is attractive in cases where feedstock costs are high. Also, the oxidation reaction provides process heat for the reforming stage and eliminates the furnace needed to provide the heat for reforming in reforming-only processes (Energy and Environmental Analysis, *Methanol's Potential as a Fuel for*

*Highway Vehicles*, 1988). However, the autothermal reaction does require oxygen, and power is required to separate oxygen from the air. This must be accounted for in an energy balance.

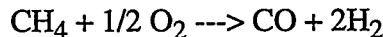
### J.3.3.2 Better Methanol Removal Systems

With conventional conversion technology, methanol removal requires water to cool the gas coming out of the reactor and energy to recompress and reheat the syngases for recycling. Dutch researchers have developed ways of removing methanol without cooling and reheating (Westerterp et al., 1988). In one system, called the Gas-Solid-Solid Trickle Flow Reactor (GSSTFR), the product formed at the catalyst surface is removed continually by a solid adsorbent, which trickles over the catalyst bed. With uniform distribution of the adsorbent and the proper flow rate, all of the methanol will be removed. This allows the reaction to progress toward completion (since the methanol is being removed as it is made) so that essentially all of the syngas can be converted in one pass. The developers estimate that the GSSTFR system reduces consumption of raw materials (presumably feed syngas gas) by 10-12% and water by 50% and produces excess steam for export.

In a similar concept, the Reactor System with Interstage Product Removal (RSIPR), methanol is removed from the product gas mixture after it passes over the catalyst (as opposed to *while* it is passing over the catalyst, as in the GSSTFR system), but at the inlet temperature of the reactor, so that the product stream does not have to be cooled. The methanol is adsorbed by a selective liquid, and the unconverted syngas passes on to a second smaller reactor (smaller because there is less gas) located just downstream of the first.

### J.3.3.3 Partial Oxidation of Natural Gas\*

The partial oxidation reaction:



produces hydrogen and carbon in exactly the proportions needed to synthesize methanol, so that there is no need to add CO<sub>2</sub>, delete hydrogen, or add an autothermal reaction (see the Lurgi low-pressure process, above) to produce the proper ratio, as there is with steam reforming. Moreover, the partial oxidation reaction is exothermic, so no fuel is required to run the reaction.

The partial oxidation reaction runs fine with air as the source of the oxygen. However, if air is used, nitrogen will be present in the syngas mixture (inert, but present), and this will make the second step, methanol synthesis, less efficient. (Recall that syngas must be recompressed after every pass through the reactor.) If the syngas contains a lot of inert gas (like nitrogen), then a lot of work is spent to heat and compress material that does not make methanol. To use partial oxidation, either the recycling must be eliminated from the methanol synthesis stage, or oxygen

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\*From O'Hare et al. (1988).

must be separated from air before the partial oxidation stage. Oxygen separation is expensive and wipes out the energy savings of the partial oxidation route.

Brookhaven National Laboratory has designed a low-temperature liquid catalyst system that converts 90% of the CO in the syngas to carbon in methanol in one pass through the reactor. This means that no recycling is necessary, which in turn means that the presence of nitrogen in the feed stream is of less consequence. The conversion rate is high because the catalyst is active at very low temperatures, and the lower the temperature, the higher the conversion. The unconverted gas is burned in a gas turbine that generates more power than the plant needs. All of the energy required to operate the plant is obtained from the natural gas.

#### **J.3.3.4 Liquid Phase Methanol Synthesis**

Compared with a conventional catalyst, a liquid catalyst removes the heat of the synthesis reaction better and allows a more complete conversion of syngas to methanol in one pass. This reduces the cost and complexity of conventional heat management systems and eliminates the economic and energy cost of recycling. Air Products and Chemicals (Brown et al., 1989) is testing a liquid-phase catalyst (solid catalyst powder, slurried in a hydrocarbon liquid) in a "once through" methanol synthesis plant in La Porte, Texas. The catalyst works particularly well with synthesis gas produced from coal gasification. No estimates of overall efficiency are available.

#### **J.3.3.5 Direct Methane Conversion**

As discussed above, the conventional natural-gas-to-methanol process has two steps, reforming and synthesis. However, it is possible to directly convert methane to methanol without the energy-intensive reforming step via direct partial oxidation, a process in which methane is reacted with an oxidant (typically oxygen or  $N_2O$ ) either catalytically or noncatalytically. In one of the more promising processes, methane and oxygen react in a glass-lined, noncatalytic reactor at 65 bars and 458°C. If high yields of methanol can be sustained from this process, it may be more efficient and less costly than conventional reforming. The best results to date show that about 83% of the natural gas can be converted to methanol (Gray et al., 1988).

Methane also can be directly converted to methanol by biological processes. Certain organisms, called methanotrophs, derive energy by oxidizing methane to  $CO_2$  and water. Under normal conditions, methanol is an intermediate, not a final, product in this process. However, the process can be manipulated so that methanol accumulates as the final product. This conversion process has several potential advantages: it takes place at ambient temperatures and pressures, is not capital-intensive, and can convert nearly all methane to methanol. Work in this area is underway (Corder et al., 1988).

Table J.1 summarizes the energy requirements of most of these new and developing technologies. Note that all of them use less energy than conventional steam-reforming and methanol synthesis. These technologies are featured in scenario analyses.

### **J.3.4 Issues in Calculating the Energy Consumption of Natural Gas-to-Methanol Plants**

Before the energy efficiency estimates of Table J.1 can be applied to making methanol as a motor fuel, three issues must be addressed: power requirements, oxygen requirements, and the difference between chemical-grade and fuel-grade methanol.

#### **J.3.4.1 Power Requirements**

Methanol plants may purchase electricity or use waste heat to boil water to run a steam generator. Technically, one should estimate the power consumption of plants that purchase electricity and include it in the overall energy efficiency estimate, both for the sake of completeness and for fair comparison with the plants that generate their own power. However, power consumption at methanol plants is such a small portion of total energy use that this exercise probably would not be worthwhile. The U. S. Department of Commerce (USDOC) (1985) notes that "fed with natural gas, a methanol plant requires little additional external energy" (p. 7). Researchers at Davy McKee (Smith et al., 1984) show that the power used by a methanol plant producing 2,750 metric tons per day is only 0.58-0.744% of the energy content of the methanol product. Because power consumption is so small, I have ignored it where it is not included in the overall efficiency estimates.

#### **J.3.4.2 Oxygen Requirements**

Some conversion schemes, such as direct oxidation and autothermal reforming, require pure oxygen. A greenhouse or energy-use analysis should count the electricity consumed by the electric motors that separate oxygen from air (electricity requirements are shown in Table J.2). In all of the estimates of Table J.1, with the possible exception of the estimates based on the Chem Systems data, either oxygen is not used or the energy of separation is accounted for in the statistics on power use or natural gas consumption.

#### **J.3.4.3 Fuel-Grade Versus Chemical-Grade Methanol**

It takes slightly less energy to make fuel-grade methanol than to make chemical-grade methanol, because the higher alcohols and ethers can be left in the methanol if it is to be used as a fuel. This permits the use of a single distillation column rather than the two required to distill chemical-grade methanol (Chem Systems, 1988). Eliminating a distillation column frees up low-pressure steam. If this steam can be used in other parts of the plant or exported, and so displace other steam or energy use or provide an energy credit, total energy consumption should decrease, albeit only slightly. In theory, then, plant producing fuel-grade methanol should be slightly more efficient than plants producing chemical-grade methanol.



The energy analysis of Rosen et al. (1986) shows that the energy in the steam sent to the distillation columns constitutes 2% of the energy in the input natural gas. At most, then, making fuel-grade methanol rather than chemical-grade methanol could reduce energy consumption by about 2%. This difference should be kept in mind when considering the data of Table J.1, where I have used the results for fuel-grade methanol.

#### J.3.4.4 Conclusion: Estimating the Efficiency of Natural Gas-to-Methanol Plants

The amount of feedstock consumed by a natural gas-to-methanol plant is a critical factor in the calculation of greenhouse gases and must be estimated carefully. In estimating this efficiency, it is important to keep in mind two things. First, the efficiency of future methanol plants will depend in part on the expected cost of the feedstock. If the gas is cheap, and expected to stay cheap, it may not pay to invest extra money in energy-efficient technologies. Chem Systems (1988) notes that "it is not uncommon for recent natural gas reforming plants built in areas of the world where gas is inexpensive to be designed to consume up to 32 mmBtu/metric ton [of methanol]" (p.11), which is about 10% more than what Chem Systems reports for most modern methanol plants. Moreover, gas is usually cheapest in remote or relatively undeveloped countries, and the plants built in these places will probably rely on established, reliable technology instead of innovative and efficient unproven designs.

Second, even if future plants are considerably more efficient than the best current plants, the future average efficiency will be closer to the current efficiency until most of the plants are new. This probably will take quite some time unless there is a crash methanol development and technology-improvement program.

The upshot of this is that it is certainly *not* reasonable to assume, as an average future efficiency, the highest projected efficiencies of the best, most advanced technologies under development. In fact, for the foreseeable future, it is almost certain that new plants will use the best of proven, current technology, not the best of the unproven (technically and economically) new technologies.

The data of Table J.1 clearly indicate that the current state-of-the art efficiency is about 65% for fuel-grade methanol. An important issue to note is that the current *average* efficiency probably is noticeably less. I assume that by the year 2000 (my base-case analysis), the average efficiency will equal the current state of the art, so that methanol plants will consume  $1.54 \times 10^6$  Btu of natural gas for every  $10^6$  Btu of methanol produced. However, I do test the effects of assuming very efficient, advanced technologies ( $1.4 \times 10^6$  Btu/ $10^6$  Btu).

TABLE J.2 Electricity Required to Make Oxygen

| kWh power/lb<br>100% O <sub>2</sub> | Reference                  |
|-------------------------------------|----------------------------|
| 0.211                               | Brown et al. (1982)        |
| 0.207                               | Paul et al. (1983)         |
| 0.204 <sup>a</sup>                  | Lacey and Stroud<br>(1983) |
| 0.189                               | Deane et al. (1984)        |

<sup>a</sup> Given as 2,250 Btu of fuel per pound of oxygen. I assumed that 2,250 Btu of fuel produces 700 Btu of power (31% efficiency).

The reasonableness of the base-case assumptions used here is further demonstrated by comparing them with the efficiency assumptions used in several recent estimates of the future production cost of methanol. (Estimates of the cost of methanol must include an assumption regarding the efficiency of natural gas-to-methanol conversion, because the contribution of the feedstock to the production cost of methanol is the product of the  $\$/10^6$  Btu cost of the feedstock and the ratio of  $10^6$  Btu-feedstock to  $10^6$  Btu-methanol.) Table J.3 shows several such estimates, including those done for California (Bechtel, 1989) and the U. S. Department of Energy (DOE) (Chem Systems, 1988). Their assumptions are consistent with mine.

For a long-run, best case for methanol, I assume a conversion efficiency of 71.4% ( $1.4 \times 10^6$  Btu of natural gas per  $10^6$  Btu of methanol produced).

#### J.4 Using Flared Gas to Make Methanol or Liquefied Natural Gas

A small amount of the gas produced in association with oil production has no use and is simply flared and, hence, wasted. If this gas were put to work instead, the work would be accomplished with virtually no emissions of greenhouse gases, assuming that the gas would have been flared were it not put to work (e.g., made into LNG or methanol). In fact, if one subtracts all of the  $\text{CO}_2$  originally contained in flared natural gas from the life-cycle  $\text{CO}_2$ -equivalent grams-per-mile emissions from methanol vehicles, on the grounds that it would have been emitted anyway, the total fuel-cycle  $\text{CO}_2$ -equivalent emissions are greatly reduced (Table 12, Scenario 18-e).

This flared gas could be made into methanol or liquefied natural gas (LNG) for use by motor vehicles. Given the possibility of making very low greenhouse-gas-emitting methanol or LNG from flared gas, it is worth determining how much flared gas is available. If the gas is made into methanol, the amount available to the U. S. transportation sector, as a percentage of highway fuel use in the United States, can be calculated as:

$$P_y = 100 \times T_y \times P \times E_c \times US \times C \times E_f / H_y$$

where:

$P_y$  = percentage of highway fuel demand satisfied in year Y by methanol from vented and flared gas,

$T_y$  = total amount of vented and flared gas in year Y (in quads) in the absence of the policy to make methanol from remote gas,

$P$  = fraction of  $T$  in countries that are willing to sell vented and flared gas to the United States and from which the United States is willing to buy (politically available variable),

$E_c$  = fraction of politically available vented and flared gas that is worth recovering and converting to methanol (economics variable),

TABLE J.3 The Efficiency of Natural Gas-to-Methanol Conversion (as assumed in several recent cost studies)

| Study   | Process                        | 10 <sup>6</sup> Btu Natural Gas/<br>10 <sup>6</sup> Btu Methanol |
|---|--------------------------------|--|
| <i>California Fuel Methanol Cost Study</i><br>(Bechtel, 1989) <sup>a</sup>                                      | Conventional steam reforming   | 1.52   |
| <i>California Fuel Methanol Cost Study</i><br>(Bechtel, 1989) <sup>a</sup>                                      | Catalytic partial oxidation    | 1.50   |
| <i>California Fuel Methanol Cost Study</i><br>(Bechtel, 1989) <sup>a</sup>                                      | Combined reforming             | 1.43   |
| <i>California Fuel Methanol Cost Study</i><br>(Bechtel, 1989) <sup>a</sup>                                      | Fluidized-bed synthesis        | 1.40   |
| SRI International (Schumacher,<br>1989)   | Uses Bechtel study             | 1.52   |
| EPA, <i>Analysis of the Economic and<br/>Environmental Effects of Methanol as<br/>an Automotive Fuel</i> (1989) | Uses Bechtel and other studies | 1.52   |
| USDOE (Chem Systems, 1988)  | Conventional steam reforming   | 1.55 <sup>b</sup>  |
| USDOE (Chem Systems, 1988)  | Advanced schemes               | 1.40 <sup>b</sup>  |
| Brandman Associates (1987)  |                                | 1.55 <sup>c</sup>  |
| American Petroleum Institute<br>(Lareau, 1989)  |                                | 1.55   |
| California Energy Commission<br>(Koyama and Darling, 1988)  | Catalytic partial oxidation    | 1.46-1.55 <sup>d</sup>   |
| Amoco (Wagner and Tatterson, 1987)  | Conventional steam reforming   | 1.50   |

<sup>a</sup> Based on  $1.2 \times 10^9$  gal/day capacity, as reported in the text, and a 95% capacity factor, as told to me by one of the study authors.

<sup>b</sup> They assume 100,000 Btu-natural gas/gal of methanol for conventional schemes and 90,000 for advanced schemes, such as combined reforming and partial oxidation, and appear to be using HHVs. I have assumed 64,500 Btu/gal HHV for methanol (Table J.1, footnote c).

<sup>c</sup> The authors assume 100,000 Btu natural gas/gal of methanol; I assume that they are using HHVs.

<sup>d</sup> The low end is for high-cost feedstock.

US = fraction of the economically and politically available gas that the United States will be able to capture (U. S. competition variable),

C = ratio of methanol energy delivered to the United States to methanol energy in the feedstock,

Ef = factor to account for the efficiency advantage of methanol, and

H<sub>y</sub> = projected quads of petroleum highway fuel in year Y.

What is the highest percentage that variable P<sub>y</sub> could be? Imagine an aggressive U. S. program to convert the highway fleet to methanol and develop remote methanol from natural gas. It would take 20 years to get a significant number of plants planned, built, and running worldwide and to get enough cars built and bought to use the methanol.

What is variable T likely to be in 20 years? In 1987 and 1988, world oil producers vented and flared about 3 quads of gas (EIA, *International Energy Annual*, 1989, 1991), much less than in the 1970s. This quantity will continue to decline as more and more flared gas is reinjected, exported via pipeline, exported as LNG, or used locally in developing countries. In a recent analysis of the availability of vented and flared gas, ICF (*Estimates of the Costs of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990) notes that Canada and the United Kingdom are likely to find uses for gas presently being flared; Malaysia recently has made use of most of the gas it had previously flared; Iran is planning to reinject or export more currently flared gas; Algeria is planning to increase its reinjection capability; and Nigeria is trying to discourage flaring.

The United Nations projects that in 2010, half as much gas will be flared as in 1986. This suggests that less than 2 quads will be available. I will assume 2 quads (variable T<sub>y</sub>) to be somewhat favorable to policies emphasizing the use of vented and flared gas.

Large amounts of gas are located in countries that either will not do business with the United States or are so unstable that they make potential investors leery. The U.S.S.R., Iran, Iraq, Libya, and perhaps other countries in the Middle East might fall into this category. Thus, more than 20% of vented and flared gas may be unattractive or unavailable for political reasons. However, I assume that only 15% of the economically available gas is politically excluded, so P = 85%.

Not all of the gas will be economically attractive. After all, gas is vented and flared either because there is not enough of it (in the right place, at the right pressure) to justify recovery and use, or because there is not enough capital to develop the infrastructure needed to use the gas (see ICF, *Estimates of the Costs of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990, for examples). Presumably, much of the gas vented and flared in industrialized areas of Western countries is not worth recovering for any use. However, some natural gas-to-methanol technologies can be economical on a small scale. I will suppose that 85% (= variable E<sub>c</sub>) of the flared gas can be economically converted to methanol.

The United States will not be the only country interested in methanol (or LNG) as a transportation fuel. Other countries will compete for the methanol, and this demand will be in addition to the factors that have reduced and will continue to reduce the quantity of wasted gas in the 1980s. Assume, though, that the United States receives 75% (variable US) of the wasted gas available for methanol (this is much larger than the U. S. share of transportation energy among the industrialized countries concerned about air quality and energy security).

Not all of the energy in the flared gas ends up in the product methanol. Some of the flared gas is used to lift, process, and transport the rest of the gas, and much energy is lost at the methanol plant. Depending on the situation and the efficiency of the methanol plant, 60-65% of the energy in flared gas will end up as energy in methanol delivered to the United States. I assume 62% (variable C).

A quad of methanol will replace more than a quad of petroleum, however, because methanol can be used more efficiently. I assume a 15% efficiency advantage (variable Ef; Appendix B).

As for variable  $H_y$ , let us assume that improvements in vehicular efficiency keep pace with increasing vehicle miles traveled (VMT) and the desire for larger, heavier, more powerful cars, so that overall highway fuel consumption remains at 16.6 quads of petroleum (Davis and Hu, 1991).

With these probably favorable assumptions, variable P, unfortunately, is fairly small -- about 5%. With pessimistic assumptions, variable P would be more on the order of 2 or 3%.

The point of this is not that we should not put otherwise wasted gas to work. We should. The point is that not much of this particular type of wasted gas is available to the United States when total U. S. demand for transportation fuels is considered.

Another promising option, from a greenhouse standpoint, is the use of landfill gas. I do not consider this here.

## **J.5 The Conversion of Coal to Methanol\***

Emissions of CO<sub>2</sub> are calculated here following the method used to calculate CO<sub>2</sub> emissions described in Section J.3 (from the difference between input and output carbon, and accounting for emissions of non-CO<sub>2</sub> greenhouse gases).

Note that this method assumes that all coal carbon that does not end up in methanol, methane, CO, or NMHC emissions, ends up as CO<sub>2</sub>. Actually, there are two nonoxidation fates for the remaining coal carbon: particulate matter or entombed tar. Particulate matter emissions are negligible. Some carbon may end up in tar, but if the tar is burned or otherwise exposed to air, the carbon will eventually end up as CO<sub>2</sub>. The amount of carbon in tar (from coal to methanol plants)

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\* See Section J.3 for an explanation about the importance of the efficiency of the conversion of coal to methanol.

that is never burned or oxidized is probably negligible, too. I ignore these nonoxidation fates (although the model has the capacity to consider them).

The discussion of the use of electricity and oxygen applies here as well.

### J.5.1 General Description of the Processes

Like the natural-gas-to-methanol process, the coal-to-methanol process proceeds in two stages: gasification and synthesis. The synthesis stage here is the same as the synthesis stage in the natural gas scheme. The main difference between the coal-to-methanol and natural gas-to-methanol processes is in the gasification process. The coal-to-methanol process uses much more energy than does the natural gas-to-methanol process, because the feed coal and the syngas it produces must be processed more intensively.

Several coal-conversion technologies have been commercialized or are under development. Because the widespread use of coal-to-methanol is probably a long way off, I will not discuss these technologies in detail. Instead, I will identify current commercial technology, advanced technology, and promising technologies under development and note their energy use (coal requirements per unit of methanol produced). For details on coal gasification, see Brown et al., *Eighth Annual EPRI Conference on Coal Gasification*, EPRI GS-6485, August 1989; Nowacki (ed.), *Coal Gasification Processes*, 1981; and Figueiredo and Moulijn (ed.), *Carbon and Coal Gasification*, 1986.

The so-called "first-generation" plants use the Lurgi, Winkler, or Koppers-Totzek processes. All three are commercially proven and used on a large scale. They use different grains of coal, different types of gasification beds, and operate at different temperatures and pressures. In most designs, the input coal supplies all of the energy needed for process fuel, electricity, and steam generation, as well as for gasification (see the many processes reviewed by Nowacki [ed.], *Coal Gasification Processes*, 1981). The received coal is divided into two streams. One stream is gasified, and the other stream is burned to generate process heat, steam, and electrical energy. Because all of the process energy is provided by the input coal, energy accounting is much easier. The coal requirements of first-generation gasification plants are shown in Table J.4.

The "second generation" of coal conversion technology uses a gasification scheme developed by Texaco and a synthesis scheme developed by Imperial Chemical Industries (ICI). Fluor Engineers and Constructors (Buckingham et al., 1981) provides a very detailed description of methanol production via Texaco gasification and ICI synthesis. Its analysis details the production and consumption of power, oxygen, steam, and fuel gas. All energy requirements, from steam to the electricity used to clean coal, are ultimately provided by the feed coal, whose energy and carbon contents are stated. The energy requirements of this process, along with the energy requirements for a generic second-generation coal-to-methanol plant and for a Texaco-gasification/Lurgi-synthesis plant, are shown in Table J.4.

TABLE J.4 Energy Use of Coal-to-Methanol Plants

| Process Description   | Btu Energy In/<br>Btu Methanol Out |        | Moisture-Free<br>Coal |      | Grade of<br>Methanol <sup>a</sup> | Reference  |
|---|------------------------------------|--------|-----------------------|------|-----------------------------------|--|
|   | Feedstock                          | Power  | O <sub>2</sub>        | % C  |                                   |  |
| Lurgi gasification and Lurgi synthesis  | 2.11                               | I      | I                     | NS   | NS <sup>b</sup>                   | Salmon (1986)                                      |
| Lurgi low-pressure process  | 2.04                               | I      | ?                     | NS   | NS                                | <i>Hydrocarbon Processing</i> ,<br>November (1987) |
| Lurgi gasification and ICI synthesis  | 1.77 <sup>c</sup>                  | I      | I <sup>d</sup>        | 53.6 | 11,818 <sup>e</sup>               | Salmon (1986)                                      |
| First generation coal gasification (generic)  | 1.88                               | I?     | I?                    | NS   | 11,240                            | Chem Systems (1988) <sup>f</sup>                   |
| Texaco gasification   | 1.88                               | I      | I <sup>d</sup>        | 69.5 | 12,589 <sup>e</sup>               | Salmon (1986)                                      |
| Texaco gasification and Lurgi synthesis   | 1.87                               | I      | I                     | 69.8 | 12,670                            | Paul et al. (1983)                                 |
| Second generation coal gasification (generic)   | 1.81                               | ?      | ?                     | NS   | 11,240                            | Chem Systems (1988) <sup>f</sup>                   |
| High-rate entrained-flow gasification   | 1.78                               | 0.0014 | I                     | 70.7 | 12,425                            | Mountain Fuel<br>Resources, Inc. (1985)            |
| Texaco gasification and ICI synthesis   | 1.71                               | I      | I                     | 69.8 | 12,670                            | Buckingham (1981)                                  |
| Once-through methanol with Texaco gasification<br>and ICI methanol synthesis in an IGCC plant             | 1.75                               | I      | I                     | 70.5 | 12,774                            | Deane et al. (1984) <sup>g</sup>                   |
| Once-through methanol with Texaco gasification<br>and liquid-phase methanol synthesis in an IGCC<br>plant | 1.48                               | I      | I                     | 69.5 | 12,771                            | Brown et al. (1982)                                |
| Once-through methanol with Texaco gasification<br>and liquid-phase methanol synthesis in an IGCC<br>plant | 1.43 <sup>h</sup>                  | I      | I                     | NS   | 11,240                            | Chem Systems (1988) <sup>f</sup>                   |
| Once-through methanol with Texaco gasification<br>and liquid-phase methanol synthesis in an IGCC<br>plant | 1.41 <sup>i</sup>                  | I      | I                     | NS   | 11,241                            | Chem Systems (1990)                                |

<sup>a</sup> F = fuel grade; C = chemical grade. If the reference does not state the grade of methanol or imply a fuel-grade, I assume chemical grade.

<sup>b</sup> 6,576 Btu/lb as received.

TABLE J.4 (Cont.)

- <sup>c</sup> Includes an HHV of the minor amount of nonmethanol fuel products, such as synthetic natural gas (SNG) and diesel oil.
- <sup>d</sup> The report states that plants are "grass-roots plants, self-sufficient in steam and electricity" (p. 23). This indicates that everything, including oxygen production, is done on site.
- <sup>e</sup> On an m.a.f. basis, the (Illinois #6) coal fed to the Texaco gasification was 77.6°C and 14,050 Btu/lb (HHV), and the (Western) coal fed to the Lurgi process was 74.5°C and 12,720 Btu/lb (HHV). As received, the Illinois #6 coal was 11,160 Btu/lb, and the Western coal was 8,509 Btu/lb.
- <sup>f</sup> It seems, but is not clear, that in the Chem Systems designs, all oxygen and power is produced on site. There is no "Power" subcategory under "Utilities" in its cost spreadsheets, except for the once-through/IGCC process, where power is exported. I assume Chem Systems uses HHVs throughout. A remark on page 52 indicates that the coal is "moisture-free."
- <sup>g</sup> Coal was 61.2°C, 11,241 Btu/lb as received (including moisture and ash).
- <sup>h</sup> Based on Chem System's allocation of coal to methanol in the coproducing plant. I checked this by scaling the electricity-only IGCC plant (described in the Chem Systems analysis) down to the power output of the coproducing plant and assigning the difference in coal use to methanol. The result was  $1.40 \times 10^6$  Btu-coal/ $10^6$  Btu-methanol.
- <sup>i</sup> Chem Systems states that 19% of the 5,544 tons/day coal feed goes to produce 977.6 tons/day methanol, which, at  $25.5 \times 10^6$  Btu/ton HHV for the Illinois #6 coal (dry), amounts to  $1.41 \times 10^6$  Btu-coal/ $10^6$  Btu-methanol.
- Notes: LHV = lower heating value; HHV = higher heating value; "m.f." means moisture-free and refers to dry, but not ash-free, coal; NS = not specified; "m.a.f." means moisture- and ash-free.  
 An "I" in the "Power" column means that part of the coal feed generates all of the power requirements on-site. A "?" in the "Power" column means that it is not clear if the power is purchased or provided by the feedstock. An "I" in the O<sub>2</sub> column means that the energy required to make oxygen is included under either "Power" or under "Feedstock." A "?" in the "O<sub>2</sub>" column means that oxygen is used, but it is not clear if the energy required to make the electricity to make oxygen is included in the power consumption or feedstock consumption figures. Power is calculated as 3,412 Btu/kWh. In all cases, the feedstock fuel provides all of the energy needed to generate steam. All figures are calculated on the basis of the assumption that 1 gal of methanol generates 64,500 Btu, except for the figure from *Hydrocarbon Processing*, p. 79 (1987), which assumes an LHV of 56,700 Btu/gal.



### J.5.2 Once-Through Methanol (OTM) with Liquid-Phase Methanol (LPM) Synthesis in an IGCC Plant (coproduction of methanol and electricity)

This process, in which methanol and electricity are coproduced, results in the lowest emissions of greenhouse gases from any coal-to-methanol process (Wright, 1989). The basic idea is to gasify coal, convert some of the gas to methanol, burn the unconverted gas to produce electricity, and use the methanol as a peaking fuel or sell it as a transportation fuel. "Once through" means that the synthesis gas from coal gasification passes over the methanol synthesis catalyst only once (in conventional methanol synthesis the syngas is passed over the catalyst many times). It is possible to use only one pass because the liquid-phase catalyst converts more syngas to methanol in one pass than does an ordinary catalyst, and because the unconverted syngas is not wasted but is sent to the combined-cycle power plant to produce electricity. Moreover, the syngas coming from the gasification section does not have to be shifted to the 2:1 hydrogen:carbon monoxide ratio required for ordinary methanol synthesis. The process thus saves energy when compared with an ordinary coal-to-methanol process, because it eliminates the energy of recycling the syngas through the catalyst (while still making full use of the syngas), eliminates the energy of shifting the syngas composition, and uses the heat released by methanol synthesis to raise steam (Brown et al., 1982). (The energy benefit of not having to shift the hydrogen-to-carbon monoxide composition of the syngas can be seen by comparing the energy consumption of the once-through integrated gasification combined-cycle [IGCC] process with that of the liquid-phase catalyst [Brown et al., 1982], which works with unshifted syngas, with the efficiency of the once-through IGCC process with ordinary ICI synthesis [Deane et al., 1984], which requires shifted syngas; Table J.4.)

Utilities will be interested in this process because it reduces the cost and maximizes the use of the gasification unit. These savings result from the capability to downsize the gasifier capacity to 80% of what the power generation system can accept and to operate the gasifier at capacity most of the time. The gasifier can be smaller (in capacity) than the power train, because, when the power train is running at 100% of its capacity -- which is well above the capacity of the gasification unit -- the extra fuel requirement (20%) can be met by using the methanol that was made when the gasifier was coproducing electricity and methanol. Thus, the gasification unit can operate near capacity all the time, producing excess methanol when the demand from the power train is less than the maximum gasification capacity and sending the excess to the power train when the demand from the power train is more than the gasifier can meet. This efficient coproduction and use of methanol should reduce electricity costs (Weinhold, 1987; Brown et al., 1989).

Emissions of greenhouse gases from coproduced methanol depend on how one treats the fact that there are two major products. The correct accounting depends on which product, electricity or methanol, is deemed to be the primary one. As discussed below, electricity will generally be the major product, since utilities will produce the methanol to use as a peaking fuel or to sell on the side. If one assumes that electricity will be the major product, then one should compare the energy (coal) consumption of the coproducing IGCC plant with the energy (coal) consumption of the coal-based electricity-only IGCC plant that would have been built to produce the same amount of electricity as the coproducing plant (if the coproducing plant were not built). That is, in the "with methanol" scenario, a utility must meet an electricity demand of X units but also sell excess methanol as a transportation fuel; in the "without methanol" scenario, the utility must still meet the X units of electricity demand but is not interested in producing methanol. The

difference in energy consumption between the two facilities is attributable to methanol production. In the two coproduction cases shown in Table J.4, in which electricity is the major output (Brown et al., 1982; Deane et al., 1984), the authors assigned energy consumption to methanol in precisely this way: by subtracting the coal consumption of an electricity-only IGCC plant from the coal consumption of the IGCC plant coproducing the same amount of power. I believe this to be the correct method.

In this analysis, I assign to methanol production the difference between coal consumption at a coproducing plant and a noncoproducing plant, using the data of Table J.4.

It is possible that a coproducing plant would be built primarily to sell methanol and only secondarily to sell power. In this case, the "with methanol" scenario represents a plant selling methanol (as a transportation fuel) and a minor amount of electricity; the "without methanol" scenario represents no plant at all because, hypothetically, there is no market for methanol. In the "without methanol" scenario, someone other than the would-be methanol producer must generate the minor amount of electricity that would have been sold had the coproducing plant been built. In calculating the greenhouse gas emissions attributable to methanol production, the energy used to generate the electricity in the "without methanol" scenario must be subtracted from the total energy used by the coal-to-methanol plant in the "with methanol" scenario. Since the generator (in the "without methanol" scenario) is not necessarily the company that would have built the coal-to-methanol plant, one cannot assume that coal is used to generate the (minor amount of) exported electricity. Thus, in the "with methanol" case, one must make an assumption about what fuel would have been used to generate the exported electricity had the coproducing plant not been built. If one assumes the fuel is coal, the result would be the same as in the case where electricity, not methanol, is the major product (see above). Otherwise, the result would be different and dependent on the particular assumptions. I consider this situation to be unlikely.

How much OTM/LPM/IGCC methanol would be available? The potential supply depends on two factors: how much of the coal energy would go into methanol rather than electricity, and how much IGCC/methanol capacity would be installed.

It is expected that electricity would be the major output of a power/methanol coproduction plant because, as discussed above, coproduction of methanol reduces the cost of electricity. For example, in a recent proposal, the Cool Water IGCC plant would be modified to produce about 80% electricity and 20% methanol on an energy basis (Brown et al., 1989). In the two analyses by the Electric Power Research Institute (EPRI) shown in Table J.4, the split is about 60/40 in favor of electricity, counting power at 3,142 Btu/kWh (Brown et al., 1982; Deane et al., 1984). In the Chem Systems (1988) analysis, the split is 70/30 electricity, and in the most recent Chem Systems report (1990), 81% of the coal goes to make electricity. In Wright's (1989) analysis, the split is 75/25 electricity/methanol.

Furthermore, only a portion of this methanol produced would be available for transportation, because these plants are supposed to produce methanol during off-peak hours for use as a peaking fuel by the plant.

Only a portion of the projected requirement for new capacity in the United States will be satisfied by coal IGCC power plants; nuclear, gas turbine, conventional coal, solar technologies, and others will also contribute. It appears, then, that only a limited amount of OTM/LPM/IGCC is available.

### **J.5.3 Emissions of Methane, Nitrous Oxide, Carbon Monoxide, Nitrogen Oxide, and Nonmethane Hydrocarbons from Coal-Conversion Plants**

The combustion of coal as a process fuel, the gasification of coal to produce methanol, and other processes within a coal-to-methanol plant would produce some non-CO<sub>2</sub> greenhouse gases. (See Table A.2 and notes for estimates.)

## **J.6 Methanol Transport\***

### **J.6.1 General Method**

The amount and kind of energy used to distribute a unit of methanol energy is a function of the amount of methanol moved by each mode of transport, the length of haul by each mode, and the Btu/ton-mi energy intensity of each mode. All of these factors must be known or estimated to calculate the distribution energy requirements for methanol.

The Btu/ton-mi energy consumption values of the various modes are known (see Table E.2). However, because essentially no methanol is used in transportation today, there are no historical data available to tell us how much methanol is likely to be shipped, how far it would be shipped, or the shipment mode in a large-scale methanol program. To calculate the energy requirements of methanol distribution, then, one must make some assumptions about where the methanol would come from, where it would be consumed, and how it would be shipped. Where the methanol comes from depends, of course, on whether the feedstock is coal, gas, or biomass, and separate sets of assumptions have to be made for each feedstock. I have done this here. In the following paragraphs, I explain the general method I use to construct a hypothetical distribution system for methanol and then follow with my specific numerical assumptions. The discussion of the general method also applies to the distribution of ethanol or methanol from wood. In the following paragraphs, I refer to "alcohols," meaning ethanol as well as methanol.

Recall that the object here is to estimate the amount and kind of energy required to distribute a unit of alcohol fuel. It is important that the distribution energy requirements are expressed relative to a unit of alcohol fuel delivered; it means that it does not matter, mathematically, how much alcohol one assumes is being distributed. In other words, we are not interested in projecting absolute, total distribution energy requirements; we are interested in calculating energy requirements per unit of fuel delivered. Thus, I start by assuming that X tons of methanol or ethanol are to be produced and distributed, where X is any value. I then assume that a certain

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\* See Table E.1.

fraction of X is distributed by tanker on international water, a certain fraction by truck, a certain fraction by pipeline, and so on. I estimate average haul lengths for each of these modes. Finally, I calculate net consumption of alcohol fuel as X less the fraction of X used by trucks to deliver alcohol fuel.

With these assumptions, the amount of energy used to deliver one energy unit of methanol or ethanol can be calculated as:

$$(\text{SUM [over all m]} X \times F_m \times D_m \times E_m) / (C \times (X - O \times X))$$

where:

X = amount of methanol or ethanol produced and distributed, in tons (an arbitrary number),

$F_m$  = fraction of total production distributed by mode m (estimated),

$D_m$  = average length of shipment by mode m, in miles (estimated),

$E_m$  = average energy intensity of mode m, in Btu/ton-mi (Table E.2),

C = Btu/ton of alcohol fuel (from the data of Table C.1), and

O = fraction of alcohol used by trucks to deliver alcohol.

(Parameterized: the model allows the user to specify any combination of alcohol and diesel trucks distributing alcohol; anywhere from 0% to 100% of the total alcohol-fuel ton-miles by truck could be transported by alcohol-burning heavy-duty trucks. The Btu/ton-mi efficiency of alcohol-distributing, alcohol-burning trucks is calculated automatically on the basis of data in Table 2 relating the efficiency of alcohol-burning trucks to the efficiency of diesel trucks. This procedure is the same for methanol from biomass and ethanol).

The important thing to note here is that X, the total alcohol fuel produced and distributed, can be factored out of the numerator and denominator of the equation and canceled. This means that the calculation can be done either without X or with any value for X. Although it is mathematically purer to do the calculation without X, it is more understandable to include an arbitrary assumption about total methanol or ethanol production and distribution, so I have kept X and defined it as  $100 \times 10^6$  tons (the result would be the same if X were  $10^9$  tons or 6 tons). I have then estimated the amount of tonnage shipped by each mode relative to this  $100 \times 10^6$ -ton starting point.

Note that no more than X can be distributed by any one mode, but that the sum of tonnages distributed by all modes generally will exceed X. This is because most fuel is shipped by more than one mode.

Finally, two more general notes on constructing hypothetical fuel and feedstock transport systems. First, it is important to try to project, as realistically as possible, the relative tonnage shares of pipelines and trucks, because pipelines consume the least Btu/ton-mi and trucks consume the most of all transport modes (tankers and trains rank between pipelines and trucks). Thus, assumptions about pipeline and truck traffic strongly determine the overall energy requirements of fuel distribution. Pipelines ship large batches of fuel relatively long distances from large producers to large markets; trucks ship very small batches to very dispersed, small end-users. This means that assumptions about the structure of a fuel distribution system depend in part on the size and location of producers and markets; the size and location of producers depend in part on the density, location, collection, and transport of the feedstock. I consider these issues qualitatively in my construction of fuel distribution systems for methanol from natural gas, coal, and wood and for ethanol from corn and wood.

Second, assumptions about feedstock transport must be consistent with assumptions about product transport. For example, if it is deemed most economical to site a plant near its feedstock but far from its markets, it will take relatively little energy to transport the feedstock and a lot of energy to transport the product.

#### **J.6.2 Assumptions for Methanol from Natural Gas**

It is widely believed that by the year 2000, most methanol will come from low-cost gas in South or Central America, the Middle East, or the South Pacific/Indonesia area. In the base case, I assume that 75% of all methanol is made from "remote" natural gas in foreign countries. In the scenario analyses (Table 12), I consider a case in which all methanol is made from foreign sources and a case in which all methanol is made from domestic gas.

I assume that the plants would be located on coasts, where the product methanol could be loaded directly onto tankers for export to the United States. The plants would be located over coastal gas fields or connected by pipelines to large inland fields. I assume that, on average, natural gas would be collected and shipped a relatively short distance via pipeline to the methanol plant (compare the energy required to ship foreign natural gas to methanol plants with the energy required to ship domestic natural gas to end-users, shown in Table 3). Then the methanol would be shipped to the United States, an average distance of about 5,500 miles (Table E.1), in a tanker fleet similar in size to the current petroleum-product tanker fleet (Table E.5).

In the United States, the distribution system for a large methanol program would eventually be similar to that for petroleum products. (It is probably optimistic to assume that this would occur by the year 2000.) Once foreign methanol is landed, some of it would be delivered inland by pipeline or domestic waterways, or both, (assuming a large market in places like Chicago, Denver, Phoenix, St. Louis, Ohio, and Atlanta) and some would be delivered by truck directly to end-users in port cities. In addition, any methanol produced in the United States and Canada would be distributed largely by pipeline and domestic waterways (again, assuming a substantial methanol program). Thus, a fair amount of methanol would move by pipeline or domestic waterway (but probably less than would move on international waters). I assume that about 40% of total methanol production would move by pipeline at some point (either as a second leg for foreign

methanol or a first leg for North American methanol) and that 40% would move by domestic waterways.

Very little methanol would move by rail for the same reasons that very little crude and petroleum products now move by rail: pipelines and tankers are more economical for large shipments, and trucks are more flexible for delivery to widely dispersed end-users (Sperling, 1988).

Finally, I assume that all of the methanol produced would be shipped in the final leg by truck to the end-user. Since very few, if any, end-users of transportation fuels are large enough to support direct delivery by pipeline, rail, or tanker, this assumption seems reasonable. My mileage and tonnage assumptions, given an arbitrary production of  $100 \times 10^6$  tons of methanol, are shown in Table E.1.

### **J.6.3 Assumptions for Methanol from Coal**

The distribution of methanol from coal would be quite different than the distribution of methanol from natural gas. The most important difference is that very little methanol from coal would be imported. The United States has a substantial amount of low-cost coal. Methanol made from this coal would likely always be cheaper than imported methanol from coal, at least in part because the imported methanol would incur an additional shipping cost relative to domestic methanol from coal. Therefore, I assume no importation of methanol from coal and, hence, no distribution of methanol by international water.

A second difference is that coal-to-methanol plants would be large enough to support a considerable pipeline distribution system, at least according to simple, rule-of-thumb economic criteria. However, Sperling (1988) points out that there are considerable risks to investing in a new pipeline network, and these risks may convince producers to use existing rail lines and waterways. Nevertheless, I assume that if any methanol was made in large coal plants by the year 2000, most of it would be shipped via pipeline, either directly from the coal-to-methanol plant or as the second leg of a journey begun on domestic water. Coal not initially shipped by pipeline presumably would be shipped by water or, in some cases where plants and markets are relatively small, by rail cars.

Coal-to-methanol plants would probably be located in coal-mining areas because it would be cheaper to transport the product methanol long distances by pipeline than to transport coal by rail from the mine to a methanol plant close to an urban area (Sperling, 1988). Some feasibility studies of coal-to-methanol processes have assumed plants are located at the minemouth. Thus, I assume that virtually no energy would be used to transport coal to the plant, but that product transport by pipeline, tanker, and rail would be a relatively lengthy proposition (see Table E.1).

Finally, as I assumed in the methanol-from-natural-gas case, I assume that all methanol would travel in the final leg to the end-user via truck. My assumptions are shown in Table E.1.

Note that the model allows one to specify that methanol (from natural gas or coal) should be delivered to end-users by methanol-burning trucks. The need to produce the extra methanol consumed by the delivery trucks is accounted for in the model by the own-use distribution factor. In the base case, I have assumed that all fuel distribution trucks use diesel (none use methanol). In sensitivity analyses not shown in this report, I have determined that this assumption is not important.

I have not allowed for the possibility of methanol-burning trucks delivering coal to methanol plants, because energy use by coal-delivery trucks is small compared with energy use by coal-delivering trains.





**Appendix K:**

**Biofuels (Ethanol from Corn; Ethanol,  
Methanol, and Synthetic Natural Gas from Wood)**



## Appendix K:

### Biofuels (Ethanol from Corn; Ethanol, Methanol, and Synthetic Natural Gas from Wood)\*

#### K.1 Overview

(Parts of this overview are adapted from Sperling and DeLuchi, 1989).

Biological matter (biomass) can be a feedstock for the production of a range of liquid and gaseous fuels. Although biomass has been used to make transportation fuels since the 19th century, major biomass transportation fuel activities were not initiated until the late 1970s, when Brazil and the United States fermented sugar cane and corn, respectively, into ethanol. In the United States, the ethanol is mixed in a 10/90 blend with gasoline so that it can be burned in conventional, unmodified gasoline-powered vehicles.

Biomass fuels are attractive because the feedstocks are renewable and domestically available, and could therefore permanently displace imported petroleum. The use of biofuels in transportation can reduce CO<sub>2</sub> emissions from the transportation sector; the amount of the reduction depends on the amount and kinds of fuels used at the various stages of processing.

While virtually all current biomass transportation fuel activities involve the fermentation of crops and food wastes containing large amounts of starch and sugar, the more promising option is the use of lignocellulosic material, especially wood pulp. Lignocellulosic material is more abundant and generally less expensive than starch and sugar crops. The most promising processes for converting lignocellulose (hereafter referred to as wood) into high-quality transportation fuels are thermochemical conversion into methanol or hydrolytic conversion into ethanol; less promising are pyrolysis processes that convert biomass into low-grade petroleum-like liquids. Biomass may also be thermochemically gasified and then cleaned and upgraded into a clean medium or high-Btu gas.

##### K.1.1 Resource Availability

How much biomass energy is available? The answer depends on the biomass feedstock: there certainly is not enough corn to fuel the entire highway fleet, but there is, potentially, enough biomass of all kinds to replace virtually all gasoline use. Ferchak and Pye (1981, part I) argue that by 2000, current and modified agricultural practices could produce more than 30 10<sup>9</sup> gal/yr of ethanol from starch and sugar crops. Conversion of agricultural, forestry, and municipal solid wastes, and conversion of lignocellulose, could provide at least 100 10<sup>9</sup> gal/yr. This total (130 10<sup>9</sup> gal) would be sufficient to fuel most of the U. S. highway fleet. Similarly, Lynd

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\* For ease in use, all Appendix K tables appear at the end of the appendix.

(1989) reviews several estimates of the availability and composition of biomass (from waste, silviculture, and agriculture) and estimates that  $140 \times 10^9$  gal/yr could be produced — about enough to replace all motor gasoline use in the United States. A recent interlaboratory "white paper" on renewable energy states that woody and herbaceous biomass could produce 8.5-27.5 quads of ethanol (the whole highway sector currently consumes about 15 quads/yr) (*The Potential of Renewable Energy*, 1990). The paper projects that an intensive R & D effort, focusing in large part on wood-to-fuel technology, could provide 8.0 quads of liquid fuels from energy crops, 0.40 quads of ethanol from corn, and 10.4 quads of bioenergy for other energy-using sectors by 2030. It appears, then, that biomass has a lot of potential (cost, environmental, and institutional and political considerations aside).

### K.1.2 Cost

Perhaps the most crucial uncertainty about biofuels is how much they will cost. Although all biofuels are expensive now, compared with petroleum-based fuels (and corn-derived ethanol probably never will be as cheap as gasoline), wood-based biofuels may someday be economical. For example, Hinman et al. (1989) estimate that with current technology, ethanol can be produced from wood by converting the xylose for \$1.23/gal (plant gate cost). Hinmen et al. also show that if the xylose is not converted to ethanol, but is burned in the boiler instead (about 0.66 kWh/gal), excess electricity is produced. SERI (Stevens, 1989) believes that today methanol can be produced from wood for \$0.75/gal (at the plant gate). Considering the energy density and combustion efficiency of ethanol and methanol, this translates to about \$1.60/gal of gasoline in the case of ethanol, and \$1.30/gal of gasoline in the case of methanol. These gasoline-equivalent prices do not include distribution, retailing, and taxes; with these included, the final gasoline equivalent prices will be on the order of \$2.00/gal. However, SERI (Stevens, 1989) believes that, in the future, ethanol can be produced from wood by enzymatic hydrolysis for \$0.60/gal (plant gate production cost; about \$0.77/gal gasoline equivalent), and that methanol can be produced for \$0.55/gal (plant gate cost). At these production prices, ethanol and methanol from biofuels could compete with gasoline retailing for less than \$1.00/gal.

For general discussions of the production, economics, environmental impacts, and the R&D status of biofuels, see Klass (1987), Anderson et al. (1988), Segal et al. (1987), Stevens (1987), Gaines et al. (1987), and *The Potential of Renewable Energy* (1990). For a review of progress in enzymatic hydrolysis, see Wright (1988).

## K.2 Energy Used to Process Biomass and Biofuels: Ethanol from Corn

There has been considerable debate recently about whether the use of ethanol will reduce or increase emissions of greenhouse gases compared with gasoline (Segal, 1989; Ho, 1989; Marland and Turhollow, 1990; EPA *Analysis of the Economic and Environmental Effects of Ethanol as a Vehicle Fuel*, 1990).

These reports disagree on several issues: the amount of fertilizer required by corn crops, the energy invested in fertilizers, the amount of on-farm energy consumed, the correct way to handle the problem of multiple products, the energy requirements of corn-to-ethanol plants, and more. None of the current reports estimate the amount of energy invested in machinery and plant equipment, do detailed scenario analyses, or consider emissions of N<sub>2</sub>O from fertilizers (an unpublished draft report circulated by Acurex considers N<sub>2</sub>O and, in fact, was the first to do so).

This report addresses these and other issues. Specifically, it:

- Attempts to resolve the controversy regarding fertilizer use and the productivity of corn acreage by calculating fertilizer use per bushel directly;
- Properly accounts for the small amount of acreage that is not fertilized at all;
- Considers current and future energy requirements in the manufacture of nitrogenous fertilizers;
- Uses a mix of fuel for electricity generation that is characteristic of that in the corn belt states;
- Considers in detail N<sub>2</sub>O emissions from denitrification of fertilizer (Appendix N);
- Details original calculations of the amount of energy used to farm corn-growing land, specifically (based on actual energy cost and price data for corn farming), and finds that the energy requirements of corn farming generally have been overestimated;
- Points out that new corn-conversion technologies will not be used merely because they are more energy efficient: cost, availability, reliability, environmental standards, and other factors also will be more important considerations;
- Considers natural gas (NG) as well as coal as the source of process heat;
- Considers the use of corn stover instead of coal to provide process heat (this greatly reduces CO<sub>2</sub> emissions because the stover is a biofuel);
- Emphasizes that because we are examining the consequences of an ethanol-promotion policy, the conceptually correct way to allocate emissions to the multiple products of the corn-to-ethanol process is to first assign all process

emissions to ethanol, and then deduct emissions from the production and use of the products displaced by the by-products of the corn-to-ethanol process;

- Calculates the co-product credit (deduction) in two ways, to establish high and low ranges;
- Examines emissions from the use of wood as a feedstock to make methanol, ethanol, synthetic natural gas (SNG), and gasoline;
- Offers a wide range of sensitivity analyses; and
- Reviews estimates of the energy embodied in farm equipment, and finds that the energy is a large source compared with the energy embodied in equipment used in petroleum, gas, coal, and uranium cycles (Appendix P).

### K.2.1 Fertilizer Requirements

Corn farming uses large amounts of nitrogen, phosphorus, and potassium fertilizers. Nitrogen fertilizers embody a lot of energy as NG, and so total emissions of greenhouse gases from the corn-to-ethanol cycle are sensitive to assumptions about fertilizer use.

Recently, Ho (1989) and Marland and Turhollow (Segal, 1989) presented sharply different views on the total energy required to produce corn. One issue at the heart of their debate is a disagreement about how many bushels of corn will be harvested from an acre. Marland and Turhollow and Ho needed to know this because they calculated energy use per bushel of corn as the product of energy use per acre and acres per bushel. Energy use per acre in turn is the sum of energy embodied in fertilizer use per acre and farm-fuel energy used per acre. Now, this method is correct only if the acres-per-bushel estimate corresponds to the fertilizer-per-acre and fuel-per-acre estimate; that is, if the amount of fertilizer and fuel used per acre, as assumed in the analysis, is the amount used to produce the assumed amount of bushels of corn per acre. It is not right to use a generic bushel/acre figure with a generic fertilizer/acre figure; there is a real relationship between bushels of corn produced and amount of fuel and fertilizer used, and this relationship should be used in the analysis.

We can see, then, that the number we are after is pounds of fertilizer and amount of fuel per bushel of corn. This number can be calculated directly, year-by-year, from available data. It turns out that the amount of fertilizer used to produce a bushel of corn has been nearly constant over the last 20 years (the mix of fertilizers used also has remained relatively stable, especially over the last 10 years).

The relationship between fertilizer input and bushel output can be demonstrated two ways. First, the data in Table K.1 show that from 1969 to 1988, the 5-year bushel-corn/lb-fertilizer

averages do not vary much. Farmers get about as many bushels of corn out of 1 lb of fertilizer today as they did in 1970. There was an increase for 1985-1987, but this does not indicate a trend. In 1988, the ratio dropped again.

Second, multiple regressions run to explain bushel per acre yield show that pounds per acre fertilizer use is a significant explanatory variable (Table K.2), under a range of model specifications. (Note, though, that Teigens' (1989) more detailed analysis found no coherent overall fertilizer effect.)

Therefore, in this analysis I sidestep the debate over bushels per acre by using bushels per pound of fertilizer directly. I use the 20-year average, which is the same as each 5-year average through 1983, and would be the same as the 5-year 1984-1988 average if it were not for the anomalously high three years. I believe this satisfactorily resolves the fertilizer-use issue.

Note that the data in Table K.1 show yield per acre actually harvested for grain, and compute fertilizer use with proper accounting for nonfertilized acreage.

Lime, sulfur, micronutrients, and manure are applied to some corn-growing land. In 1988, lime was applied to 6% of corn land, sulfur to 10%, micronutrients to 11%, and manure to 18% (USDA, *Agricultural Resources...*, 1989). Sulfur was applied at the rate of 11 lb/acre, and lime at 1.9 ton/acre; no application rate was given for micronutrients and manure (USDA, *Agricultural Resources...*, 1989). With these data, and data on acreage harvested for grain, and bushels of corn harvested for grain in 1988 (Table K.1), one can calculate pounds of lime and sulfur applied per bushel of corn, on average, for 1988. With data on the energy content of lime (620 Btu/lb; Blankenhorn et al. 1985) and sulfur (443 Btu/lb; Hudson 1980), one can calculate the embodied energy in and hence greenhouse gas emissions from the lime and sulfur fertilizer. The value for sulfur turns out to be trivially small; the value for lime is small but not insignificant, because such huge amounts of lime are used (note the application rate of 1.9 tons/acre, on those acres receiving lime).

The energy embodied in and emissions from the use of lime and sulfur are included in the results of this analysis (Tables 6, 9, and K.7). I have ignored the use of micronutrients since there is a lack of data on the application rate, energy content, and use of manure, because manure presumably has no energy cost (aside from the energy required to apply the manure, which is included in the farming energy requirements of Table K.6).

### **K.2.2 N<sub>2</sub>O and NO<sub>x</sub> Emissions from Nitrogen in Fertilizer**

This is a relatively large source. See Appendix N for estimates.

### K.2.3 Energy Invested in Fertilizers

Although there has been little debate over the amount of energy embodied in fertilizer, there is legitimately more room for disagreement here than in the question of the amount of fertilizer used. I will discuss two relatively detailed estimates of the energy embodied in fertilizers, one by TRW (1980), and one by Turhollow (1989). Note that all the fuel used, including NG used as the chemical base, should be counted because it all ends up as CO<sub>2</sub> (and presumably would not have ended up as CO<sub>2</sub> had it not been used in fertilizer manufacture). First, I summarize the results of the detailed analysis by TRW (1980):

*Energy required to mine 100 ton of potash or phosphate rock:*

17,400 kWh  
 361 gal diesel fuel  
 40 gal lube oil  
 27 gal gasoline

*Energy required to produce 1,000 lb of P<sub>2</sub>O<sub>5</sub> (as 70% H<sub>3</sub>PO<sub>4</sub>), wet process phosphoric acid:*

3,060 lb phosphate rock  
 840 lb molten sulfur  
 112.5 kWh

*Energy required to make 1,000 lb of anhydrous ammonia (NH<sub>3</sub>) at feedstock*

5,740 SCF NG as fuel  
 6.54 kWh

*Energy required to make 1,000 lb nitric acid (HNO<sub>3</sub>):*

292 lb NH<sub>3</sub>  
 4.5 kWh  
 130 lb steam

*Energy required to make 1,000 lb ammonium nitrate (NH<sub>4</sub>NO<sub>3</sub>):*

281 lb NH<sub>3</sub>  
 805 lb HNO<sub>3</sub>  
 20 kWh  
 1,250 lb steam

*Energy required to make 1,000 lb diammonium phosphate (NH<sub>4</sub>)<sub>2</sub>HPO<sub>4</sub>:*

230 lb NH<sub>3</sub>  
 1,175 lb H<sub>3</sub>PO<sub>4</sub> (40% P<sub>2</sub>O<sub>5</sub>)  
 1.5 gal fuel oil  
 10 kWh



These results can be compounded into values that are comparable to those compiled by Turhollow (1989). Table K.3 compares the two reports and also includes estimates by several others. The differences between the estimates may be due in part to the difference between older and newer technology (Turhollow's numbers come from relatively old sources). Turhollow (1989) cites a 1985 source that states that new ammonia plants can produce nitrogen twice as efficiently as old plants by using only 15,170 Btu/lb nitrogen (counting electricity at about 10,400 Btu/kWh.) King (1983) states that modern ammonia plants consume 30 megaJoules (MJ) of NG/kg of ammonia produced, or 15,600 Btu/lb, which is consistent with Turhollow's source. King also claims that by the time the ammonia is converted to a typical solid fertilizer like ammonium nitrate, and allowance is made for building the plants, packaging, transportation, and application of the fertilizer, the total energy consumed is about 60 MJ/kg of nitrogen, or 26,000 Btu/lb of nitrogen. Ferchak and Pye (1981) cite a 1976 estimate that the energy requirement for medium supplements is 20,000 Btu/lb.

Today, fertilizer is probably produced with a mix of new and old plants. In the future, most fertilizer will be produced by new plants. Therefore, in my base-case scenario, I pick values between those for new and old plants.

A very small amount of energy is required to transport fertilizers. Assuming a 500-mi haul by train, at 500 Btu/ton-mi, and a 50-mi haul by truck, at 2,000 Btu/ton-mi, 350,000 Btu will be required to move a ton of fertilizer, or 175 Btu to move 1 lb. This is less than 1% of the energy required to make the fertilizer, and so it can be assumed to be subsumed under fertilizer-manufacturing energy.

Multiplying Btu-input per pound of fertilizer by pound-fertilizer/bushel-corn, and dividing by gallon-ethanol/bushel and Btu/gallon, gives Btu-fertilizer/Btu-ethanol. The result is shown in Table K.7. My estimate is at the low end of the range of estimates in the literature. This is due to a lower fertilizer/bushel requirement, rather than a lower Btu/pound-fertilizer requirement.

#### K.2.4 Energy Use on the Farm

For two reasons, I have done an original calculation of energy used in corn farming rather than use existing estimates. First, Table K.7 shows that existing estimates of energy use in corn farming vary widely. Second, data are available to allow a direct calculation of diesel, gasoline, LPG, and NG used by farms to produce corn, specifically, without referring to bushel per acre corn yields. These data allow one to resolve the discrepancies in the literature with reasonable accuracy.

The calculation proceeds by several steps, using three data sets specific to farming or corn farming. I begin with USDA data on the amount of money that corn-producing farms spent on fuel and electricity, including fuel used for drying and electricity used for irrigation, per acre of corn planted (USDA, *Costs of Production*, "Cost of Production" and "Farm Costs and Returns" surveys). These dollars-per-acre figures are shown in Table K.4. Then, I disaggregate this total

dollars-per-acre figure into dollars per acre for each fuel type, by multiplying the total dollars-per-acre figure by the ratio of:

$$(\text{expenditure on fuel X}) : (\text{total expenditures for all energy})$$

for each fuel. The expenditure data come from the USDA *Farm Production Expenditures* reports (various years) that show the total amount of money that farms in the corn belt states spend on diesel fuel, gasoline, LPG, NG, electricity, motor oils, and other fuels (coal, kerosene, wood...I treat these as coal). The expenditure data are shown in Table K.5. Next, the dollar-each-fuel per acre-planted figures are divided by the dollar million Btu price of the fuels, to give million Btu-each-fuel/acre-planted. The price data are from the USDA's *Agricultural Prices* reports (various years), which report prices paid by farmers for specific fuels (data shown in Table K.4), and from fuel expenditure and quantity data in USDA's *Farm Production Expenditures* (various years). Finally, the million Btu/acre figure for each year is matched with year-by-year corn production (Table K.1), to give million Btu/bushel for each year. The results of this analysis are shown in Table K.6.

Neither the on-farm energy-consumption figures in Table K.6, nor the fertilizer-energy estimates include the energy embodied in seeds, pesticides, and herbicides. Marland and Turhollow (1990), Giampietro and Pimentel (1990), and another unpublished source indicate that the energy embodied in insecticides is less than 5% of the energy embodied in fertilizer; however, Giampietro and Pimentel (1990) show that the energy embodied in seeds and herbicides is 18% of the energy embodied in the fertilizer. This relatively high value is supported by expenditure data, which show that corn farmers spend nearly as much on chemicals and seeds as they do on fertilizers (USDA, *Costs of Production*, various years). (Pimentel [1990] estimates that energy embodied in seeds, herbicides, and insecticides is 25% of the energy embodied in fertilizer.) I believe that these higher values are more accurate, and so I multiply fertilizer energy requirements by 1.2 to account for all other seeds and chemicals. (This assumes that the energy embodied in chemicals and seeds is mostly NG, as is the energy embodied in fertilizers.)

The resultant fertilizer and farm-energy totals are shown in Table K.7, along with several other estimates. My estimate of farm energy is lower than most of the others, which I attribute to my use of detailed, recent, corn-specific data. For example, Pimentel's (1990), relatively high estimates assume very high energy requirements per pound of fertilizer, assumptions which are probably based on relatively old technology.

#### **K.2.5 Energy Use on the Farm in a Large Ethanol Program**

If, as Ho (1989) argues, a large ethanol program will require the use of less productive farmlands, then the incremental corn production will require more energy for irrigation, cultivation, and fertilization than the current average production that is estimated here. The Renewable Fuels Association (1989) counters that  $8.6 \times 10^6$  set-aside acres of land of "not poor quality" (and not

in the conservation reserve) can be brought in production to yield  $5.7 \times 10^9$  gal of ethanol, without reducing domestic use or exports of corn.

However,  $5.7 \times 10^9$  gal of ethanol will replace less than 5% of U. S. gasoline consumption. A much larger ethanol program will not only bring marginal corn lands into production, it will probably subtract from domestic uses and exports of corn. It is difficult to predict the extent to which this will occur because at some point it will become more economical to switch feedstocks than to eke out further production from corn lands. So, while it is clear that a very large ethanol program will be more energy intensive, on average, than the current small program, it is not at all clear how much more intensive. Moreover, Marland and Turhollow (1990) cite a USDA report that concludes that a large ethanol program will reduce by-product credits, which would result in an increase in greenhouse gas emissions.

To address these possibilities, I construct a scenario analysis in which marginal farming energy requirements are higher than the average calculated here and fewer by-products can be sold.

#### **K.2.6 Energy Used to Transport Corn to the Conversion Plant**

More than two-thirds of the of total U. S. ethanol (from corn) production capacity is located in major corn-growing states, Illinois and Iowa (Klass, 1990). Ethanol plants are located near feedstocks, rather than near major markets for the fuel because feedstock transport costs are greater than fuel transport costs, and by-product markets are located in corn-growing areas (Anderson et al., 1988). Katzen (1979) sited the plant in their analysis in Illinois near both coal and corn. These facts suggest that corn is transported from the field to the plant primarily by truck, with perhaps some shipment by rail.

To estimate the energy requirements of transporting corn to the biofuel plant, I typically assume that a truck, consuming 2,144 Btu/ton-mi of truck travel (see Table E.2), travels 40 miles one way (80 mi round trip) from the field to the conversion facility or to a train depot, resulting in 171,520 Btu/ton. Occasional train transport, I assume, brings the total to 200,000 Btu/ton (Btu/ton-mile data are shown in Tables E.1 and E.2), or 100 Btu/lb of corn. At 56 lb/bu of corn (U. S. *Statistical Abstract*), the result is 5,600 Btu/bu. This relatively large value (a sizable percentage of the farming energy per bushel) is due to the low effective-energy density of a bushel of corn: at 56 lb/bu, 2.6 gal ethanol/bu (my assumption throughout; typical yields are between 2.5 and 2.7 gal/bu), and 84,600 Btu/gal-ethanol, corn has an effective energy density of 3,928 Btu/lb, about one-fifth that of crude oil (even if the energy in the corn-fermentation by-products are counted, the density is still only about 40% that of crude oil).

The few other estimates of transport energy for corn are considerably higher than mine (see Table K.7). However, those estimates are not detailed and it is impossible to evaluate their quality. Given that corn-to-ethanol plants will be located near corn fields, it does not seem reasonable to assume much longer truck or train hauls than I have assumed here, and so it does not seem reasonable to use higher transport energy requirements.

### K.2.7 Energy Consumed by the Corn-to-Ethanol Conversion Process

Although there has been considerable debate over the corrective assumption regarding the amount of energy required to turn corn into ethanol, the disagreements center not so much around the energy requirements of a particular technology, but rather around which technologies should be chosen as representative of a future industry average. Table K.7 shows several estimates of the amount and kind of energy used by conversion plants to produce one unit of ethanol energy (and, in most cases, to dry the by-products). The range in Table K.7 primarily reflects differences among technologies, not differences in the estimates for a particular technology. Wayman and Parekh (1990) show that the energy requirements of corn-to-ethanol plants can vary by nearly a factor of 3, the main determinants being the configuration of the distillation system, the concentration of alcohol in the beer, and the technology.

The data in Table K.7 suggest that the current industry average energy consumption is least 0.55 Btu of energy per Btu of ethanol out of the plant (e.g., data from Jones, 1989; Keim, 1989). However, the data also show that the conversion process can be considerably more efficient than this (e.g., Marland and Turhollow, 1990; Wayman and Parekh, 1990; Energy Fuels Development Corp., 1989). (I note, however, that Jones, 1989 states that the processes he describes make extensive use of energy-saving technologies.) The question, then, is what industry energy consumption would look like in the future in a larger corn-to-ethanol program.

The use of more efficient technologies and techniques will depend on many factors including: the capital cost of energy-efficient equipment; the rate of payback in lower energy and operating expenses; the effect of more efficient technologies and techniques on the types, quantity, and quality of output, and on other plant operations; the reliability of the energy-efficient equipment and practices; the extent to which producers know about ways to improve efficiency; and more.

It is not possible to quantify the development and adoption of energy-efficient conversion technologies and processes. It would seem, though, that there is considerable room for improvements in energy efficiency, both because the current industry performance is well below the state of the art and because the state of the art itself probably can be improved significantly by further R & D. In my base case, I assume an energy consumption toward, but not at, the low end of the range of current practice. I consider higher and lower energy consumption values in scenario analyses.

### K.2.8 Energy Used to Dry Residues

The energy consumption estimates in Table K.7 include energy used to dry the residue from the distillation process. The residue is dried so that it will not spoil when it is shipped to feedlots. However, if the residue is fed to livestock at the ethanol plant, it need not be dried (Henneke, 1991; Chambers et al., 1979). This can save 16,000-28,000 Btu drying energy per gallon of ethanol (Henneke, 1991; EPA, *Analysis of the Economic and Environmental Effects of Ethanol as an Automotive Fuel*, 1990; Keim, 1989; Chambers et al., 1979). In this analysis, I

consider a no-drying scenario, in which total process energy is reduced by 0.30 Btu-process energy/Btu-ethanol, but the by-product credits remain the same.

### **K.2.9 Use of Natural Gas as a Process Fuel**

It is possible, though not likely, that NG, not coal, will provide the process heat for some ethanol plants. The use of NG would reduce considerably emissions of greenhouse gases from ethanol production because of the much lower carbon/Btu content of NG. However, NG is much more expensive than coal and is available only via a gas pipeline. Most likely, NG would be used only if it were too costly to meet very strict effluent standards (for SO<sub>x</sub>, particulates, and metals) with coal.

### **K.2.10 Use of Corn-Field Residue as a Process Fuel**

Corn stalks and cobs can be collected and burned for fuel. The use of corn residue produces much less greenhouse gas than does the use of coal because CO<sub>2</sub> emitted from the combustion of corn does not count as a net emissions. There is more than enough energy in the residues to run the corn-to-ethanol conversion process.

Chambers et al. (1979) and White (1980) estimate energy credits for the use of corn-crop residue (also called stover). However, current calculations (Ho, 1989; Marland and Turhollow, 1990; draft unpublished report by Acurex) do not include the energy value of the stover, probably because most plants would have to modify their burners to use crop residue. Also, some crop residues have alternative uses. Nevertheless, this report considers the use of corn residues as a fuel because they can so strongly affect the greenhouse impact of corn-to-ethanol. According to Starr et al. 1978), residues are being used as a fuel in some situations.

There are several issues concerning the use of corn-crop residues as a fuel: the amount of residue that can be removed without causing erosion or depleting nutrients; the energy required to collect, transport, and prepare the residue; and the energy required to replace any nutrients or soil lost due to removal of the stover.

Some crop residue must be left on the soil to maintain fertility, reduce evaporation, recycle minerals, increase the content of organic matter, promote biological activity, and aerate soil (Flaim, 1979; Pimentel et al., 1981). Removing corn mulch can increase soil loss and water runoff by a factor of 10 (Flaim, 1979), which in turn can cause sedimentation and pollution (Pimentel et al., 1981). Table K.13 shows the amount of residue produced from corn farming and the amount of residue that can be removed without causing unacceptable soil erosion.

Pimentel et al. argue that "even with proper management practices, severe soil degradation problems can result from residue removal." (1981, p. 1114). Their analysis accounts for nutrients

lost from residue and excess soil loss and decreased productivity due to soil loss. The losses depend on the slope of the land and the farming practices; the losses are greater on steeper slopes. Table K.13 shows the results of Pimental et al.'s (1981) calculations.

There are other considerations. SERI (Flaim, 1979) notes that residues left on the soil can also depress germination rates, increase pesticide requirements, and increase the potential for disease. I do not account for this.

Maurya et al. (1980) point out that residue harvest could interfere with other farm operations. They found that at worst, residue harvest could delay replanting and reduce crop yields by 2.1%, but noted that simple changes could reduce these losses to negligible levels.

Green (1975) noted that the use of corn stalks as a supplemental boiler fuel increased particulate emissions and calculated that, with 60% corn stalks by volume, particulate emission standards would be exceeded. It is likely, though, that modern control technology can reduce PM emissions to acceptable levels.

My assumptions are as follows. First, note that the data in Table K.13 indicate that even under unfavorable assumptions, corn residue can provide more than enough energy, including energy for electricity generation, for converting corn to ethanol (at least  $22.5 \times 10^6$  Btu-residue/acre are available, and not more than  $20 \times 10^6$  Btu/acre are required to convert corn to ethanol). Therefore, availability is not a constraint, and I assume that as much residue as is needed is used, with any residue available in excess of energy requirements remaining on the land. I assume that collection consumes 3 gal of diesel fuel/ton residue (Starr et al., 1978; Table K.13 here), and I calculate transport requirements by assuming that the residue is transported by the same mode and for the same distance as the corn grain. The fertilizer needed to replace nutrients lost in removed residue and eroded soil (Table K.13) is added to total fertilizer requirements. Finally, the reduction in corn yield due to soil loss is handled by increasing the Btu-process energy per Btu-output factor accordingly (Table K.13).

The burning of the corn residue will produce some non-CO<sub>2</sub> greenhouse gases. Because there are no emissions data for the combustion of corn residue exclusively, data for combustion of wood and waste are used here (Table A.2). (Burning the corn stover in the field also will produce non-CO<sub>2</sub> emissions. I do not estimate these here.)

#### **K.2.11 Emissions of Non-Carbon Dioxide Greenhouse Gases**

Emissions of CO, CH<sub>4</sub>, N<sub>2</sub>O, NO<sub>x</sub>, and NMHCs from corn-to-ethanol plants are calculated as the sum of emissions from fuel use, and emissions from all other process areas. Emissions from fuel use are calculated from data on the amount of each kind of fuel used, and the emission factors for industrial boilers using the particular fuels (Table A.2). Emissions of CO and NMHCs from other process areas are estimated by subtracting fuel-use emissions from total,

plant-wide emissions of CO and NMHCs (Table A.2). Emissions of CH<sub>4</sub> from nonfuel-use process areas are estimated as a fraction of NMHC emissions. I assume no NO<sub>x</sub> and N<sub>2</sub>O emissions from the nonfuel-burning parts of the plant.

#### **K.2.12 Mix of Fuels Used to Generate Electricity at Corn-to-Ethanol Plants**

Ethanol production plants can use a lot of electricity, and so one's assumptions about the mix of fuels used to generate that electricity can significantly affect the overall results. The mix of fuels, of course, depends on where the plants are located. As noted above, ethanol plants will generally be located near large supplies of corn and coal because it is cheaper to transport the product long distances to markets than the feedstocks long distances to conversion plants. The major corn-growing states are Iowa, Illinois, Nebraska, Minnesota, Indiana, Ohio, Wisconsin, South Dakota, and Missouri (USDA, *Crop Production*, 1990); of these, Illinois, Indiana, and Ohio are major coal-producing states (EIA, *Coal Production*, 1990). Presently, most corn-to-ethanol production capacity is located in Illinois and Iowa (Klass, 1990; Anderson, 1988).

I assume that the Midwest will continue to produce large amounts of both corn and coal, and so it will be home to future corn-to-ethanol plants. My specific assumptions, which roughly follow the current distribution of ethanol production capacity (Klass, 1990), are shown in Table D.1. Note that coal dominates the electricity mix in the current ethanol-producing regions. Moreover, both NERC (1990) and the EIA (*Annual Outlook for U. S. Electric Power*, 1990) project that coal will continue to dominate the mix for the next 10-20 yr. I have used the average of the EIA and NERC projections for the likely ethanol-producing states. This projected regional mix has much more coal than has the national average mix, which means that calculations based on the national average mix likely will understate total CO<sub>2</sub> emissions from corn-to-ethanol plants.

#### **K.2.13 Distribution of Ethanol from the Plant to the End-User**

To calculate greenhouse gas emissions from the distribution of ethanol, the greenhouse gas emissions model requires input assumptions about the amount and distance of ethanol movement by pipeline, truck, train, international tanker, and domestic tanker. These input assumptions (see Table E.1) are scaled to an arbitrarily chosen  $100 \times 10^6$ -ton/yr level of ethanol production. The calculation is explained in detail in the section "Methanol Transport" at the end of Appendix J (as explained there, the level of production does not matter because everything in effect is scaled by the level of production). The absolute tonnages are not by themselves meaningful; they are meaningful only relative to the arbitrarily chosen level of total production (again, see the discussion in Appendix J). Here, I explain my specific assumptions regarding the length of shipments, and the amount of total production shipped by each mode.

Presently, most ethanol is transported from the fermentation plant to the blending terminal by truck or train (Anderson et al., 1988). The Kentucky Agricultural Energy Corporation ethanol plant distributes its ethanol by rail, and the South Point Ethanol Plant ships ethanol by truck, rail,

and river barge (Jones, 1989). This situation is not likely to change, even in a large ethanol program, because ethanol plants will probably not be large enough to support a pipeline distribution system, or even shipment by tanker. Both of these modes typically require throughput of at least 300 million gallons per year (Sperling, 1988), which is more than the largest ethanol plant in the U. S. can produce, and 5 times more than what most plants produce (Anderson et al., 1988). Sperling (1988) concludes that "tanker trucks and railcar-size shipments provide the best match with biomass plants..." (p. 232). Thus, as shown in Table E.1, I assume that most of the ethanol produced will move several hundred miles by rail. I assume that no ethanol will be imported, and so no ethanol will be transported by international tanker, but a small amount will move via domestic waterways.

Presumably, all ethanol will be transported to the end user by truck; therefore, as in the methanol distribution analyses, the amount of ethanol moved by truck equals the amount produced. However, in the case of ethanol, I assume that a considerable amount of fuel will be transported directly from the plant to end users, who likely will be more than 100 mi distant (one-way), on average. Hence, I assume a relatively long average ethanol haul by truck.

All mileage, tonnage, and Btu per ton-mile assumptions (given an arbitrary ethanol production of  $100 \times 10^6$  tons) are shown in Table E.1.

#### **K.2.14 Handling of Multiple Products: The By-Product-Credit Problem**

More than just ethanol comes out of the ethanol production process, and so one must ask how total greenhouse gas emissions from the process should be allocated among the different products. The answer to this is straightforward, at least conceptually, once one recognizes that the whole point of calculating greenhouse gas emissions from the manufacture and use of ethanol is to help answer the question, "Should we make ethanol from corn?" That is, we are interested in seeing what happens if we make ethanol from corn — compared, by default, to not making it, and using gasoline, or some other fuel, instead.

We may, therefore, begin by saying, "If the United States endorses ethanol from corn, it will build and operate a large number of additional ethanol plants; if it does not endorse ethanol, it will not, and will make something else (probably gasoline) instead." We wish to compare these with and without scenarios: we wish to estimate whether the ethanol world produces more or less greenhouse-gas emissions than the gasoline world. In the "with" scenario, we have emissions from most or all of the ethanol production-and use-cycle. In the "without" scenario, we have all the emissions from the production and use of the work-equivalent amount of gasoline, plus the emissions from the production and use of the products (call these the "by-product substitutes") that would have been displaced by the by-products of the ethanol production process. The difference between the with and without scenarios is the result of the ethanol policy.

Now, if we wish to compare emissions from the ethanol case with emissions from a baseline gasoline case, we must move the emissions associated with the by-product substitutes



from the gasoline side of the ledger to the ethanol side of the ledger, by subtracting these emissions from the fuel-cycle totals for ethanol. To do this, one must know what the ethanol by-products would displace, and how much of what kind of energy would have been used to make the by-products.

Unfortunately, the problem of the by-product credit is difficult to resolve, for three reasons. First, the amount and kind of by-products available depend on the conversion technology ("wet milling" produces different by-products than "dry milling") and the operating conditions of the particular technology, and these are difficult to specify "on average." Certainly, there can be many by-products, including animal protein feed, corn oil, CO<sub>2</sub>, fusel oil, and fertilizer. Second, it is very hard to predict how much of which kinds of by-products actually will be sold; not all will be sold all the time, because of lack of buyers, lack of infrastructure to connect buyers and sellers, saturation of by-product markets, inertia on the part of producers, inhibiting regulations, or ignorance about the utility of the by-products. Third, even if an average set of salable by-products can be identified, it is not easy to figure out exactly what the by-products displace, and how much of what kind of energy would have been used to make whatever is displaced.

What is required, then, is a very detailed engineering and economic and political analysis; the economic part is probably more important because it does little good to identify by-products without determining if they can or will be sold. However, this is beyond the scope of my effort here. Instead, to encompass the likely range of values of the by-product credit, I estimate it in two entirely different ways and run the model using both kinds of estimates.

In the first method, I count the by-product credit as the energy value of products displaced by three major by-products: distillers dried grains and solubles (DDGS; displaces soybean meal as animal protein), fusel oil (displaces coal process fuel), and ammonium sulfate (displaces fertilizer). I use this method in the base-case analysis. In the second method, I will follow Marland and Turhollow in their draft report (Segal, 1989), the Renewable Fuels Association (1989), and Environmental Resources Limited (1990) and estimate the by-product credit based on the energy or market value of all the residue of the fermentation process.

Note that method 1 is a more direct approach to the conceptually correct method. However, one can argue quite easily that each of the by-products identified would not in fact displace what they have been assumed to displace here (e.g., that something other than soybean meal would be used were DDGs not available) or that different by-products would be produced. I do not address these questions. Method 2 (based on energy value or market value) should not be viewed as a directly, conceptually valid alternative, but rather as an indirect way of getting at the right answer (to be used if one feels that the assumptions of method 1 are too unpalatable). The upshot is that as yet, there is no entirely satisfactory way of estimating by-product credits.

I. *Method 1*: specific credits for DDGS, ammonium sulfate, and fusel oil (and N<sub>2</sub>O emissions from fertilizer, as discussed in Appendix N on N<sub>2</sub>O).

The dried, nonfermented residue of the alcohol-making process can displace soy meal as a protein. Table K.8 shows several estimates of the energy credit from displacing soy meal (the amount of energy which would have gone to produce the food-equivalent amount of soy protein.) The data are in reasonable agreement, and indicate that the by-product credit for DDGS should be between 7,000 and 10,000 × 10<sup>6</sup>Btu/ 10<sup>6</sup> gal of ethanol (HHVs); I assume 8,000 Btu/gal. I also assume that the greenhouse gas emissions from transporting the DDGS cancel the emissions that would have resulted from transporting the soymeal. Incidentally, DDGS is the only major by-product reported by the Kentucky Agricultural Energy Corporation, and the South Point Ethanol Plant (Jones, 1989).

TRW (1980) stated that then-current ethanol productions could be increased nine-fold before the market for DDGS was saturated. The OTA (U. S. Congress, 1990) states that the U. S. market for by-products would become saturated at a few billion gallons of ethanol per year but that perhaps by-products could be sold overseas.

Ammonium sulfate scrubbed from the flue gases of the ethanol facility can be used as a fertilizer and can thereby reduce the amount of NG-based fertilizer used by farms growing corn for ethanol plants. The Katzen process (1979) produces 60.75 tons of ammonia per million gallons of ethanol, of which, according to TRW (1980), 87% is available for use as a fertilizer. This results in 0.106 lb of NH<sub>3</sub>/gal of ethanol. (TRW calculates that this amount of ammonia used as a fertilizer will save 1,685 × 10<sup>6</sup> Btu of NG, 4 × 10<sup>6</sup> Btu of coal, 1 × 10<sup>6</sup> Btu of residual fuel, and 21 × 10<sup>6</sup> Btu of diesel fuel. However, to avoid calculating the energy value of the credit fertilizer differently than that of the input fertilizer, I deduct the ammonia directly from the fertilizer requirements, and then figure the energy required to make the remaining required fertilizer). Assuming that sulfur will have to be scrubbed from all future coal-burning ethanol facilities, and that there always will be a market for the by-product fertilizer (which seems reasonable, since the fertilizer market is huge compared to the amount of by-product), it is reasonable to assume that this by-product will always be produced and salable.

The amount of ammonia produced is proportional to the sulfur content of the coal. The Katzen design analyzed by TRW assumes high-sulfur coal (greater than 3% sulfur by weight, according to the EIA's *Quarterly Coal Report*).

In Illinois, where most ethanol facilities will be located, the average sulfur content of coal delivered to power plants in 1987 was 1.93%; in Iowa, it was 0.86%; and in other ethanol-producing states, it was about 2.4% (EIA, *Cost and Quality of Fuels for Electric Utility Plants 1987, 1988*). The weighted average would be about 1.75% sulfur by weight. Restrictions on sulfur emissions may force the use of lower-sulfur coal, or require sulfur removal before combustion. I assume that the average sulfur content of coal delivered to ethanol plants will be half that of the Katzen analysis, and hence that ammonia production will be half that calculated by TRW

(this factor-of-two change in ammonia production results in a 1% change in grams-per-mile greenhouse gas emissions for the ethanol cycle).

Note that if NG or crop residue is used as a fuel instead of coal, this credit will not be available because these fuels have much less sulfur than coal. I account for this in the scenario analyses using these fuels.

Finally, higher alcohols and esters (called "fusel oil") and aldehydes are produced as a by-product, and these can be added to the ethanol product or burned as process fuels along with the coal (other uses of fusel oil may be more valuable). The Katzen design produces 0.0304 lb of fusel oil (0.00448 gal) per gallon of ethanol. Wayman and Parekh (1990) report 0.134 lb of fusel oil per gallon of ethanol. At about 33 Btu/g of C<sub>3</sub> to C<sub>5</sub> alcohols (*CRC Handbook*, 1975), the result is about 500-2,000 Btu of fusel oil/gal of ethanol. Ho (1989) assumes that fusel oil and aldehydes from an unspecified process displace 3,000 Btu of coal/gal of ethanol. The data used here result in about 2,000 Btu/gal.

At the Kentucky Agricultural Energy Corporation Plant and the South Point Ethanol Plant, CO<sub>2</sub> from fermentation is sold to adjacent or on-site users (Jones, 1989). Whether or not this sale and use of by-product CO<sub>2</sub> constitutes a CO<sub>2</sub> credit for ethanol production depends on where the CO<sub>2</sub> would have come from had it not been provided by the ethanol facilities. If the CO<sub>2</sub> would have come from the atmosphere, either directly or via plants, then the use of CO<sub>2</sub> from ethanol facilities provides no benefit, because the atmospheric concentration of CO<sub>2</sub> is the same in either case (because the source of the CO<sub>2</sub> is the same). However, if the biomass-derived CO<sub>2</sub> displaces fossil-derived CO<sub>2</sub>, there is a CO<sub>2</sub> benefit to using the ethanol, unless the fossil-derived CO<sub>2</sub> is a by-product that simply will be vented if it is not used.

These complications make it difficult to estimate a CO<sub>2</sub> credit for ethanol production. Moreover, it seems that any sizable ethanol fuel program would quickly saturate any local demands for CO<sub>2</sub>. I assume that, in a national ethanol program, nearly all CO<sub>2</sub> from the fermentation area would be vented. In any case, CO<sub>2</sub> from fermentation appears to be only a small portion of total CO<sub>2</sub> from ethanol production, with most CO<sub>2</sub> coming from coal combustion.

*II. Method 2.* This method estimates an energy credit based on the total energy value of the part of the corn that is not turned into alcohol. Marland and Turhollow (Segal, 1989) cite a recent USDA analysis that shows that 48.9% of the cost of corn was born by the by-products, and the remainder by the ethanol. Then they allocate energy inputs (farm production energy and ethanol-plant conversion energy) to by-products and ethanol using the same proportions. This results in a rather sizable credit of around 32,000 Btu/gal of ethanol (counting electricity at 10,400 Btu/kWh, and using their lower bound estimate of the amount of energy required to convert corn to ethanol). Similarly, the Renewable Fuels Association (1989) notes that 55% of the corn kernel is turned into ethanol, and the remainder into (potentially) usable by-products. They conclude from this that 55% of the total energy input to corn production and processing be assigned to ethanol production and 45% to by-products.