5--NET ENERGY ANALYSIS OF SYNTHETIC LIQUID FUELS PRODUCTION

By Robert V. Steele

A. Introduction

The concept of net energy has recently been introduced into the area of energy policy in an attempt to understand the efficiency with which society uses energy in obtaining new energy supplies. Net energy can be expressed as a measure of the energy return that is obtained per unit of energy invested in the energy-producing sectors of the economy, although analogies with capital investment are not strictly appropriate.

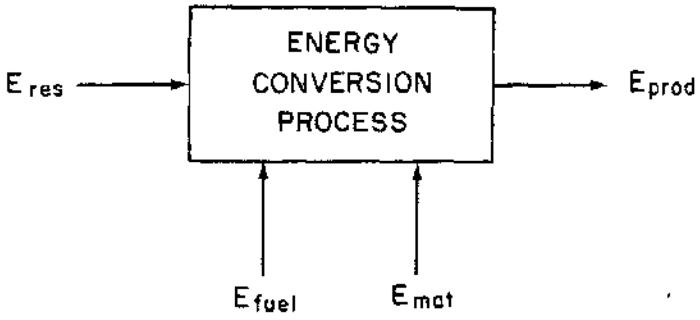
The concept of net energy can be illustrated by the use of an input/output analysis[1] to calculate the energy cost of producing different forms of energy. For example, the petroleum refining sector of the economy provided 44 percent of U.S. energy needs in 1963. However, this sector also consumed 6.4 percent of the petroleum products, 1.3 percent of the electricity, and 5.6 percent of the natural gas produced in the United States during that same year,[1] as well as various chemicals and materials. Consequently, approximately 0.2 unit of resource energy (coal, crude oil, natural gas, and nuclear and hydro-power equivalents) was consumed for each energy unit of petroleum products delivered to the U.S. economy. Thus, the energy return per unit of energy expended in the petroleum refining sector was approximately 5-to-1 in 1963.

The rationale behind the concept of net energy is that new sources of energy or new energy conversion activities can be examined to determine those that provide the highest return per unit of energy invested. If there are two or more competing technologies for accomplishing the same result, then net energy analysis provides a basis for choosing one over another. There are, of course, other basic considerations such as cost, environmental impact, social disruption, and so forth, which will be taken into account in deciding the technology that should be employed. However, in an age in which energy resources are in great demand and supplies are dwindling, net energy analysis can be an important policy consideration in determining how energy resources can be used wisely.

In principle, net energy analysis should clarify discussions of the resource utilization efficiency of various energy technologies. In practice, however, probably as much confusion has been generated as understanding. This is due, in part, to the varying definitions of net energy used by different sources, and in part to the various advocacy positions that net energy calculations are called on to support. In this chapter, we will attempt to define carefully what is meant by net energy and to set forth clearly the processes by which numerical values are obtained.

Often, net energy is defined as the energy value of the products delivered to society by an energy-producing or conversion process minus the energy required to carry out the production or conversion. The intent of this definition is to allow one to determine how much energy is actually made available to society by a process if one also counts the energy that is consumed, or made unavailable, as a result of carrying out the process. It has been common practice to express the energy consumed in carrying out the process in terms of the energy value of the energy resources that are consumed to provide fuel, materials, and so forth, to run the process. Thus, the net energy figure is expressed as the difference between energy in the form of deliverable products and energy in the form of raw resources. This is somewhat akin to subtracting apples from oranges, although both energy figures are expressed in Btu or the equivalent. The problem has to do not so much with the thermodynamic "quality" of the energy form (expressed as availability, or the ability to do work), although this may occasionally be an important factor, as it does with the "quality" of the energy form as measured by its usefulness to society. The social utility of a Btu of gasoline is obviously much higher than that of a Btu of crude oil in the ground. Thus, it is desirable to express net energy in a way that makes clear the nature of the units specified.

The mathematical formulation of net energy used throughout this chapter is explained with the help of the energy flow diagram shown in Figure 5-1. In this diagram, the quantity E_{res} is defined as the energy content or heating value of the resource that is converted to a useful product. It is sometimes called the "primary" resource energy. E_{prod} is defined as the energy content or heating value of the product that is produced by the conversion process. Since there is always some energy



$$\text{NET ENERGY RATIO} = \frac{E_{prod}}{(E_{res} - E_{prod}) + E_{fuel} + E_{mat}}$$

FIGURE 5-1. FLOW DIAGRAM FOR DEFINITION OF NET ENERGY RATIO loss during conversion, E_{prod} is always less than E_{res}. (The conversion efficiency of a process is sometimes referred to as the ratio of E_{prod} to E_{res}.) The quantity ($E_{res} - E_{prod}$) represents the resource energy lost during the conversion process. Other energy inputs to the process include any externally supplied fuel, which is consumed to provide steam, heat and electricity for running the process, and the energy consumed in building the plant and in fabricating the materials used in operating and maintaining the plant facilities. These energy inputs are represented by E_{fuel} and E_{mat}, respectively. (The quantity E_{fuel} is sometimes called the ancillary energy.) It is important to note that E_{fuel} includes, in addition to the energy value of the fuel itself, all the energy consumed in extracting and processing the fuel as well as distributing it to the point of use.

With these definitions we have the tools to formulate a working relationship for the net energy ratio of a process: it is defined simply as the useful <u>product</u> energy output of the process divided by the <u>resource</u> energy that has been lost during conversion or consumed in the form of fuel or materials input to the process.

$$\text{Net energy ratio} = \frac{E_{prod}}{(E_{res} - E_{prod}) + E_{fuel} + E_{mat}} .$$

As an example, if 20 billion Btu per day are consumed in the form of fuel and materials to convert 130 billion Btu per day of primary resource energy into 100 billion Btu per day of product energy, then the net energy ratio is:

$$\text{Net energy ratio} = \frac{100}{30 + 20} = 2.$$

This result tells us that for every two units of product energy produced, one unit of resource energy was expended. Thus, the net energy ratio is merely a measure of the quantity of energy that is made available to society in a particular form per unit of resource energy consumed in the conversion process.

It is clear from the discussion above that the net energy ratio can have any value between zero and infinity. Higher net energy ratios are more desirable than lower net energy ratios since a greater energy return on energy investment is achieved. Net energy ratios less than one mean that the break-even point for return on investment has not been attained; more energy was consumed than was produced as product energy. However, this does not necessarily mean that the technology in question should not be employed. For example, the production of electricity, which supplies a large fraction of the nation's energy needs, has a net energy ratio of about 0.36 (1967 data).[3] Society is willing to expend nearly three units of resource energy to obtain one unit of electricity since electricity is a convenient, clean, transportable, and efficient energy form relative to the resources from which it is obtained. Thus, net energy considerations have a relatively small impact on society's judgment about the development and use of this energy source.

With respect to the development of new technologies (such as those for producing synthetic fuels for automotive transportation) in which several different processes are capable of meeting the same end-use needs, net energy analysis can provide a valuable input to decision making regarding the most efficient use of resources.

B. Methodology

With the definition of net energy established, there remains the task of obtaining the appropriate data to calculate numerical values of the net energy ratios for coal liquefaction, methanol from coal, and oil shale processing. These data are generally available in the literature or from published reports on conceptual designs for synthetic fuel plants. The data are generally of two types. One is simply the energy value of the resource input, ancillary fuel requirement, and product output of the process in question. These values can be used directly in the net energy calculation with one exception: any fuel that must be purchased from external sources (i.e., is not generated within the process itself) must have its energy content multiplied by the appropriate factor to account for the resource energy that is required to extract, process, and transport that particular fuel. External energy sources to which this correction applies are natural gas, refined petroleum products, and electricity. The fuel-to-resource conversion factors are shown in Table 5-1.

Table 5-1

FACTORS FOR CONVERTING ENERGY CONTENT OF PURCHASED FUELS OR ELECTRICITY INTO RESOURCE ENERGY*

Fuel	Conversion Factor (Btu/Btu)
Refined petroleum products	1.208
Natural gas	1.101
Electricity	3.796

Source: Reference 2.

The second class of data is that in which inputs of materials into the construction or operation of a plant are given in dollar values. These values can also be converted to resource energy equivalents by using the energy input/output table in Reference 2. This table lists the energy input (in the form of direct fuel and materials purchases from all other sectors of the economy) per unit dollar output for each of 360 sectors in the U.S. economy for 1967 (the latest year for which complete input/output data are available). To account for inflation, the appropriate deflator is applied to convert from costs applicable to the year in which the dollar estimates were made to 1967 costs. These deflators are obtained from the Plant and Equipment Cost Indices published monthly in Chemical Engineering.

It would be preferable to obtain the energy embodied in materials inputs by knowing the quantities of materials involved and multiplying by the appropriate value of resource energy required to produce a unit quantity of material. However, in many cases either the quantities of materials are not readily available or the energy required for producing the materials is not known. This is why the input data in Reference 2 are particularly useful. However, it is important to realize that the Btu per dollar figure for a given sector averages over many different types of products whose energy inputs per unit quantity and dollar values per unit quantity may vary widely. Thus, these numbers should be considered only a gross estimate for a given type of material input. The roughness of this estimation is considerably mitigated, however, because the energy embodied in material inputs is generally a small fraction (2 to 5 percent) of the total energy input to synthetic fuels production. Thus, considerable error in these estimates leaves the net energy ratio hardly affected.

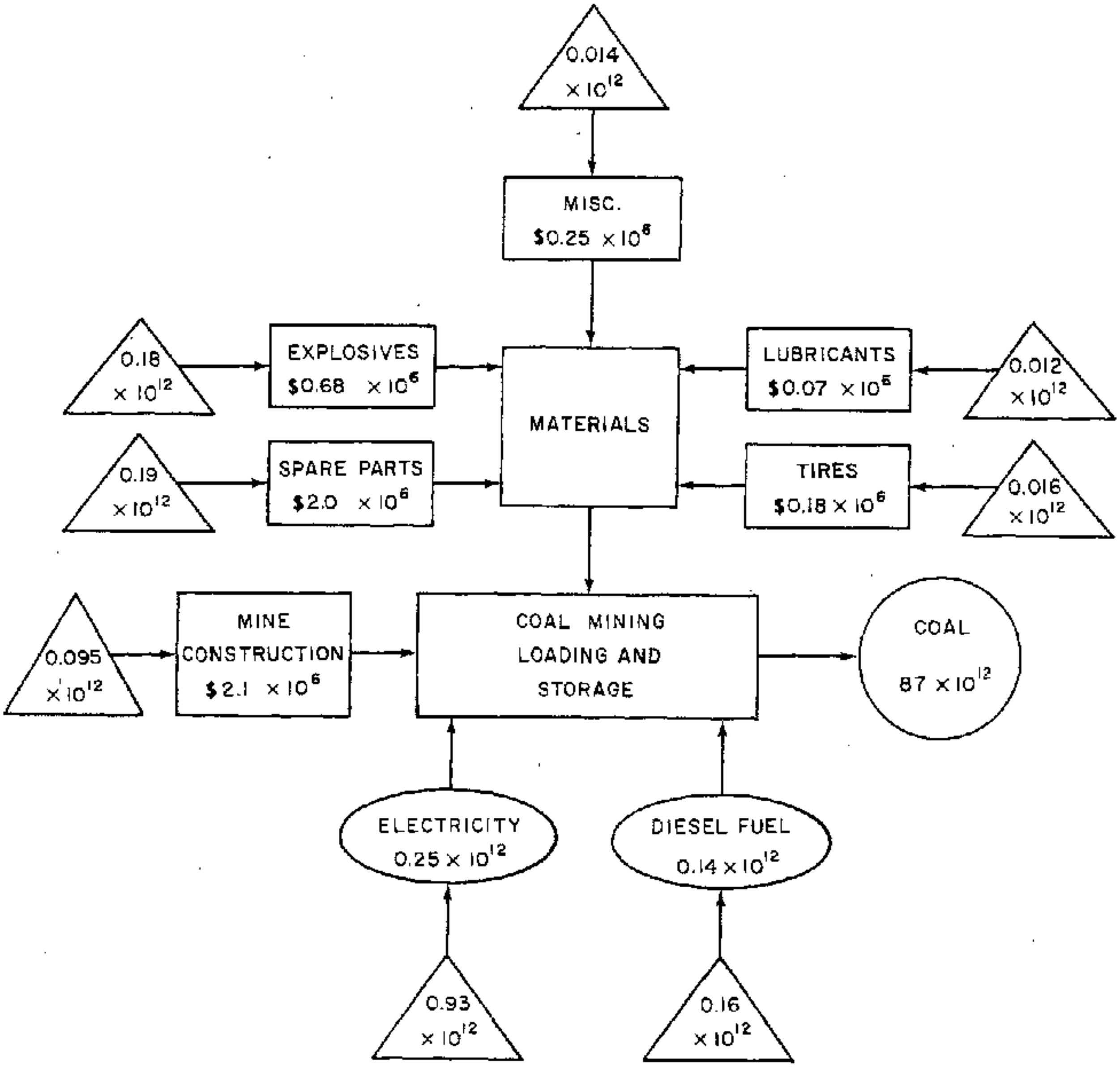
The method of performing net energy calculations can be illustrated by calculating the net energy ratio for surface coal mining in the southwestern United States.

The net energy of surface coal mining is important for synthetic fuels net energy calculations since this is the first step in the set of activities by which coal is converted to methanol or synthetic crude oil. The data for surface coal mining were obtained from Bureau of Mines information[3] as well as from plans by El Paso Natural Gas Company for supplying coal to its proposed Burnham, New Mexico, coal gasification plant.[4]

Since the coal seam thickness tends to be lower, and stripping ratios higher, for southwestern coal deposits than those in the Northern Great Plains area, the energy required to extract a given quantity of coal is significantly higher for the Southwest than for other major western coal areas. Thus, the net energy ratio calculated for surface coal mining may be considered to be at the lower end of the range of possible values for western coal.

Figure 5-2 shows all the annual material and fuel inputs required for the operation of a 5-million ton/year (4.5×10^9 kg/yr) surface coal mine. The electricity figure includes the electric power required to operate the dragline, conveyor belts for coal loading and all other electrical equipment. The diesel fuel figure includes the fuel requirements for coal trucks, bulldozers, reclamation equipment, and all other mine vehicles. Both of these energy requirements have been converted to resource energy using the conversion factors shown in Table 5-1. In Figure 5-2 and in subsequent figures, fuel inputs are shown as ellipses, materials inputs are shown as squares, and resource energy inputs are shown as triangles.

To calculate the resource energy embodied in the materials utilized in the coal mining operation, dollar figures for these quantities (shown in the appropriate squares in Figure 5-2) were taken from Reference 3 and subsequently converted to resource energy inputs by using the 1967 input-output table of Reference 2. Since this table is broken down into



NOTES: All resource energy inputs and product outputs are in Btu
All dollar figures are in 1969 dollars per year

FIGURE 5-2. ANNUAL ENERGY INPUTS FOR CONSTRUCTING AND OPERATING A 5 MILLION TON/YEAR SURFACE COAL MINE IN THE SOUTHWESTERN UNITED STATES only 360 sectors, it is not always possible to find a sector that exactly matches a particular material. In this case, the Btu-per-dollar figure for the sector that seemed the most appropriate was used. For example, the spare parts input has no exact equivalent in the table since the nature of the parts is not specified. However, there is a fabricated metal products sector, and this was deemed appropriate for this case.

In Figure 5-2 the dollar figure and resource energy figure for mine construction are both based on the total mine capital investment amortized over the assumed 20-year life of the mine. The capital investment for mine construction includes both the initial capital investment of $28.6 million (1969) and a deferred investment of $0.716 million (1969) yearly.[3] The resource energy associated with the various material inputs or other energy consuming activities are shown in Table 5-2. These inputs or activities were derived from total capital cost estimates in Reference 3 using a module approach to capital cost estimation[5] to break out dollar values of individual components of the total cost such as equipment, labor, and so forth.

Other costs not included in the table are labor, engineering, overhead, various indirect costs, interest, fees, etc. Resource energy inputs due to deferred investment contribute another 0.64×10^{12} Btu (0.68×10^{15} J) to the total shown in Table 5-2.

Using all the resource energy inputs to the coal mining operation shown in Figure 5-2, it is possible to calculate a net energy ratio for this activity. The breakdown of energy inputs and the results of the calculations are shown in Table 5-3. There is no entry for energy lost during "conversion." For example, coal left in the ground due to inefficiencies of the extraction process is not counted as "lost" energy. The calculated net energy ratio of 54 indicates that surface coal mining is a very efficient activity, requiring slightly less than 2 percent of

Table 5-2

ENERGY INPUTS FOR CONSTRUCTION OF A 5-MILLION TON/YEAR SURFACE COAL MINE*

Components of Construction	Resource Energy 10^{12} Btu	Resource Energy 10^{15} J
Mining machinery		
Equipment ($11.4 million)	0.75	0.79
Materials ($3.1 million)	0.28	0.30
Exploration, roads and buildings ($2.2 million)	0.14	0.15
Unit train loading facilities ($0.75 million)	0.046	0.049
Freight ($0.73 million)	0.052	0.055
Total	1.27	1.34

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*Investments in 1969 dollars.

Table 5-3

ANNUAL ENERGY INPUTS AND OUTPUT FOR A 5-MILLION TON/YEAR SURFACE COAL MINE

	Resource or Product Energy 10^{12} Btu	Resource or Product Energy 10^{15} J
External energy inputs		
Electricity	0.93	0.98
Diesel fuel	0.16	0.17
Materials	0.41	0.43
Construction and equipment replacement	0.10	0.11
Total	1.60	1.69
Mined coal output	87	92

$$\text{Net energy ratio} = \frac{87}{1.6} = 54$$

the resource energy made available to be consumed in extraction. However, this does not include the energy consumed in transporting the coal away from the mine or otherwise making it available for end use.

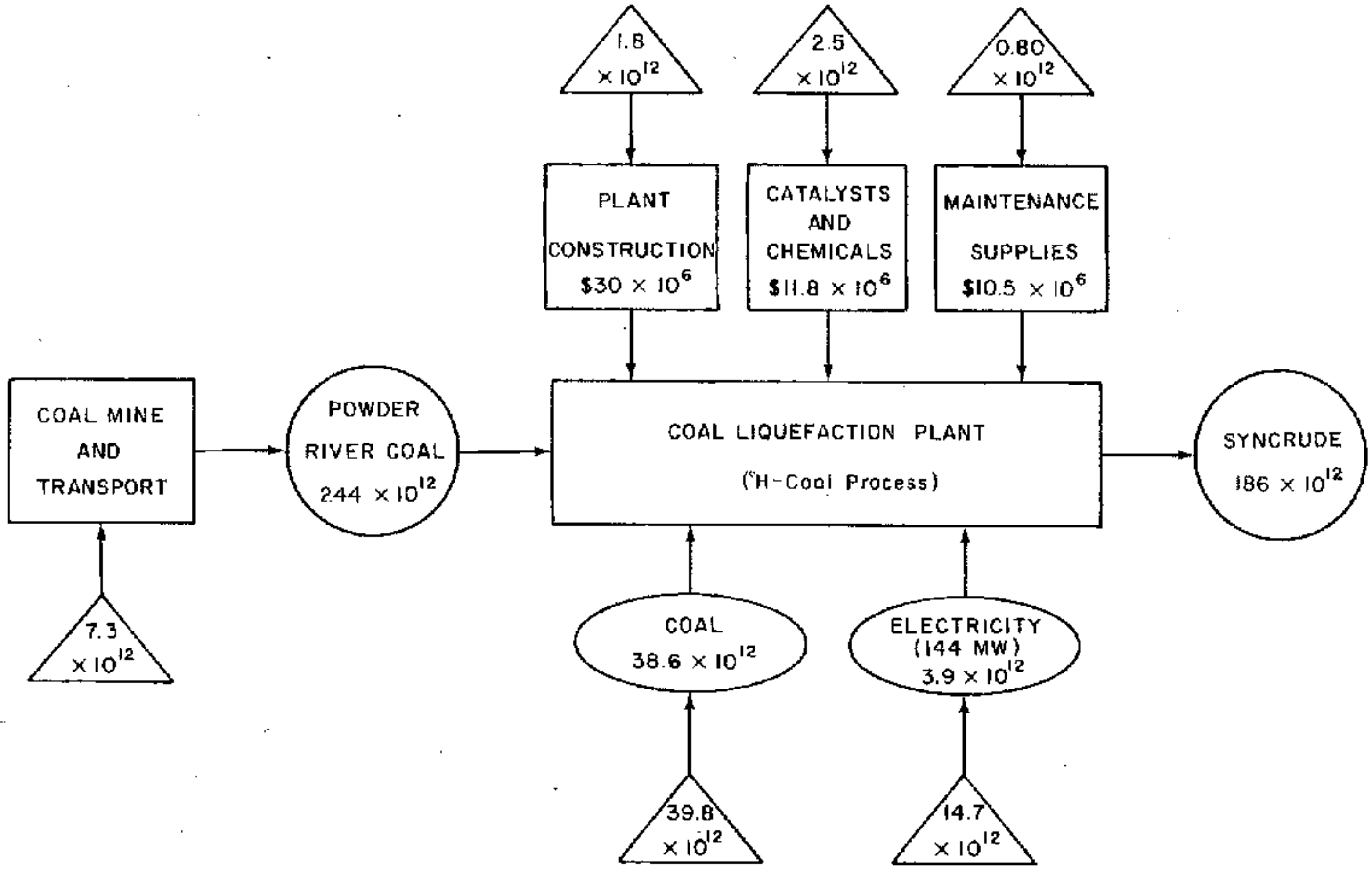
C. Analysis of Synthetic Fuel Processes

1. Coal Liquefaction (H-Coal Process)

The conversion of western coal to synthetic crude oil via the H-Coal process is an energy intensive activity characterized by approximately a 25-percent loss of resource energy during processing and consumption of ancillary resource energy equivalent to nearly 30 percent of the product energy output.[8] Much of the energy lost during processing is in the form of byproduct gases, which are consumed as additional plant fuel or steam reformed to provide hydrogen for liquefaction. Additional loss occurs in the form of char and vacuum bottoms (derived from fractionation of the product), which are gasified to produce hydrogen.

Relatively little of the ancillary energy contribution is in the form of materials or plant construction. The coal input, product output, and energy inputs from all other sources are shown in Figure 5-3. The resource energy input for coal mining and transport is derived from the data in Figure 5-2 and the additional assumptions that the coal is hauled by trucks 5 miles (8 km) to the plant, and that 1 percent of the coal is lost during loading and unloading. The resource energy inputs for catalysts, chemicals, and maintenance supplies have been calculated as previously described.

Two different methods were used to calculate the resource energy inputs for plant construction. The first method was similar to that used to calculate the coal mine construction energy inputs. Capital costs from Reference 6 were used in conjunction with plant construction module data from Reference 5 to break out dollar figures for various



NOTES: All resource energy inputs and product outputs are in Btu
All dollar figures are in late 1973 dollars per year

FIGURE 5-3. ANNUAL ENERGY INPUTS FOR CONSTRUCTION AND OPERATION OF A 100,000 B/D H-COAL PROCESS COAL LIQUEFACTION PLANT equipment, materials, and other construction components. The total construction energy input calculated by this method was 21×10^{12} Btu (22×10^{15} J). The second method simply involved taking the total plant capital investment figure (late 1973 dollars deflated to 1967 dollars by a factor of 1.35) and multiplying by the conversion factor in the table of Reference 2 for the public utilities construction sector. This sector was chosen since it most nearly represents the construction of the type of energy conversion facility required for a coal liquefaction plant. The energy input obtained by this method is 36×10^{12} Btu (38×10^{15} J). Since the first method of energy accounting tends to underestimate the construction energy input due to the inability to account for all categories, it was decided to use the figure derived from the second method. This provides a simple and direct method of computing construction energy inputs and is probably a more complete one since the input/output method takes into account energy inputs from all sectors that contribute to the construction of the plant.

Table 5-4 shows the resource energy lost during conversion, along with the breakdown of ancillary resource energy inputs and the calculation of the net energy ratio for coal liquefaction.

The table indicates that the liquefaction of western coal is a fairly energy consumptive process, returning only about 50 percent more useful product energy than was invested in the conversion process. However, for midwestern coal, the more favorable composition of the organic portion of the coal results in a somewhat lower ancillary energy consumption during liquefaction;[6] the net energy ratio in this case is about 1.8.

2. Methanol from Coal

The conversion of coal to methanol is a two-step process which involves the gasification of coal by reaction with steam and oxygen followed by the catalytic conversion of the resulting synthesis gas to methanol. Due to inefficiencies in both steps, the overall conversion efficiency for the process is only about 59 percent. In addition, a considerable quantity of coal is consumed as fuel to provide heat, steam, and electricity to run the process. In the process design on which the net energy calculation was based,[7] it was assumed that to meet environmental regulations the coal is gasified to form a clean, low-Btu fuel gas, rather than being burned directly. This method of utilizing coal as an ancillary fuel requires the consumption of about 50 percent more coal than would burning it directly.

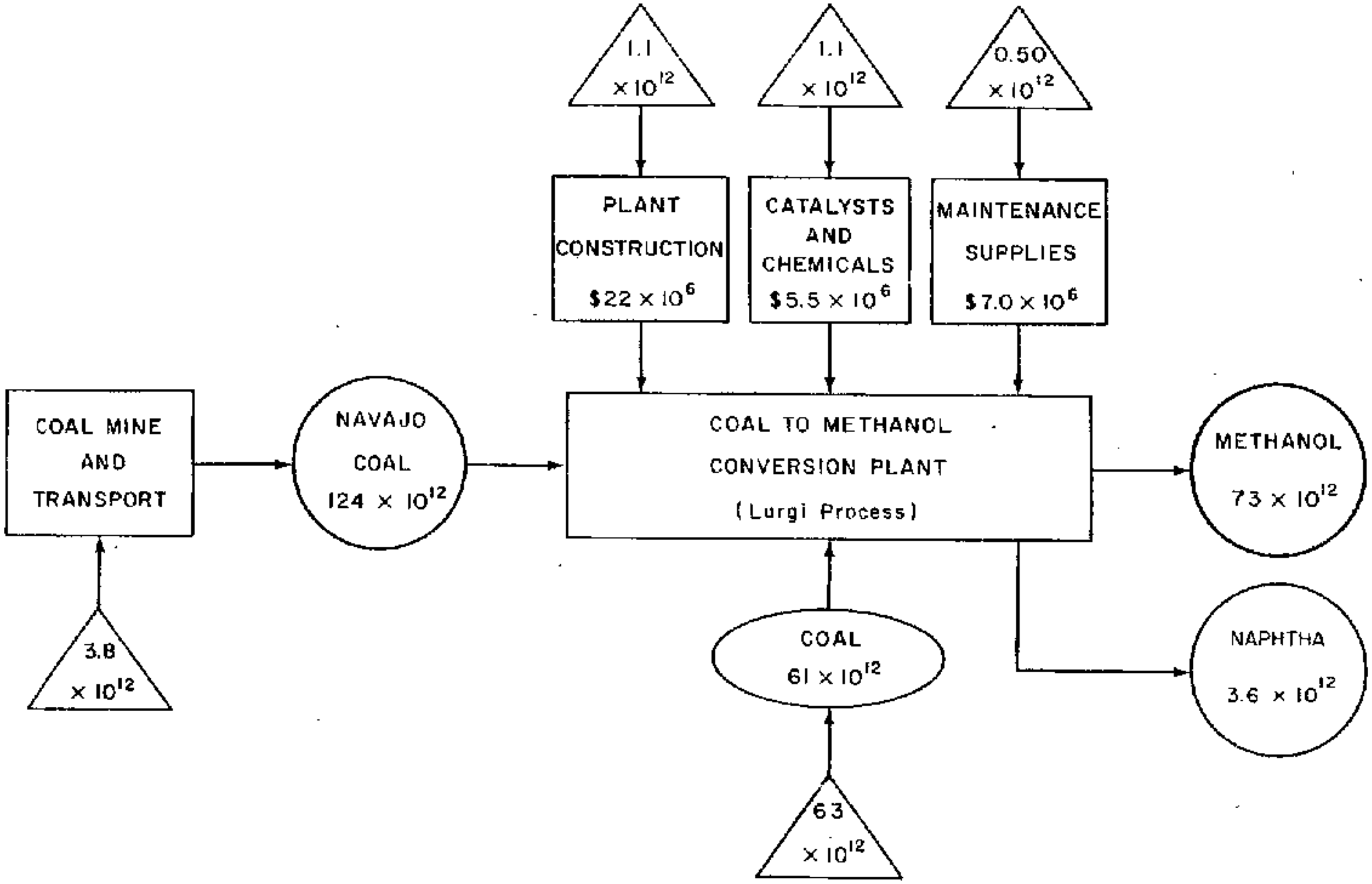
Table 5-4

ANNUAL ENERGY INPUTS AND OUTPUT FOR A
100,000-B/D COAL LIQUEFACTION PLANT

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss	58	61
External energy inputs		
Coal	40	42
Electricity	15	16
Materials and construction	5.1	5.4
Coal mining and transport	7.3	7.7
Total	125	132
Syncrude output	186	196

$$\text{Net energy ratio} = \frac{186}{125} = 1.5$$

The energy inputs required for the production of 81,400-B/D (13,000 m^3/D) of methanol from Navajo coal are shown in Figure 5-4. The



Notes: All resource energy inputs and product outputs are in Btu
All dollar figures are in 1974 dollars per year

FIGURE 5-4. ANNUAL ENERGY INPUTS FOR CONSTRUCTION AND OPERATION OF AN 81,433 - B/D COAL-TO-METHANOL PLANT types of inputs are the same as for coal liquefaction, except that all the electricity required to run the process is produced on-site, and the energy requirement is included in the ancillary coal input. The production of 2000 B/D (320 m^3/D) of byproduct naphtha is included in the output since this is a high quality product suitable for refining to gasoline and other fuels.

Not shown on the output end of methanol production in Figure 5-4 is the 25×10^{12} Btu/yr (26×10^{15} J/yr) of tar and tar oil, which are produced as additional byproducts of Lurgi gasification. These products are of low quality and are not suitable for refining to other fuels. Although there is some possibility that they could be used as boiler fuel, it is more likely that they will be used in nonfuel applications. Other gasification technologies, such as the Koppers-Totzek process, yield essentially no byproducts. Nearly all of the coal is converted to synthesis gas. However, an analysis of methanol production using the Koppers-Totzek gasifier has shown that the overall coal-to-methanol conversion efficiency is roughly the same as that of the Lurgi gasifier.[8] The ancillary fuel requirement, however, is slightly less.[8]

Table 5-5 shows a tabulation of the conversion energy losses and external energy inputs along with the calculation of the net energy ratio for the conversion of coal to methanol. The fact that the net energy ratio is less than one for this process indicates that more energy is consumed in conversion than is provided to society as methanol product. By comparison with coal liquefaction, the conversion of coal to methanol appears to be a relatively inefficient use of resources. However, the coal liquefaction product must be further refined before it can be used as an automotive fuel, while methanol can be used directly. The net energy ratio for the entire coal-to-refined products system is examined in a later section.

Table 5-5

ANNUAL ENERGY INPUTS AND OUTPUT FOR
AN 81,000-B/D COAL-TO-METHANOL PLANT

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss	47	50
External energy inputs		
Coal	63	66
Construction and materials	2.7	2.8
Coal mining and transport	3.8	4.0
Total	117	124
Methanol output	73	77
Naphtha output	3.6	3.8

$$\text{Net energy ratio} = \frac{77}{117} = 0.66$$

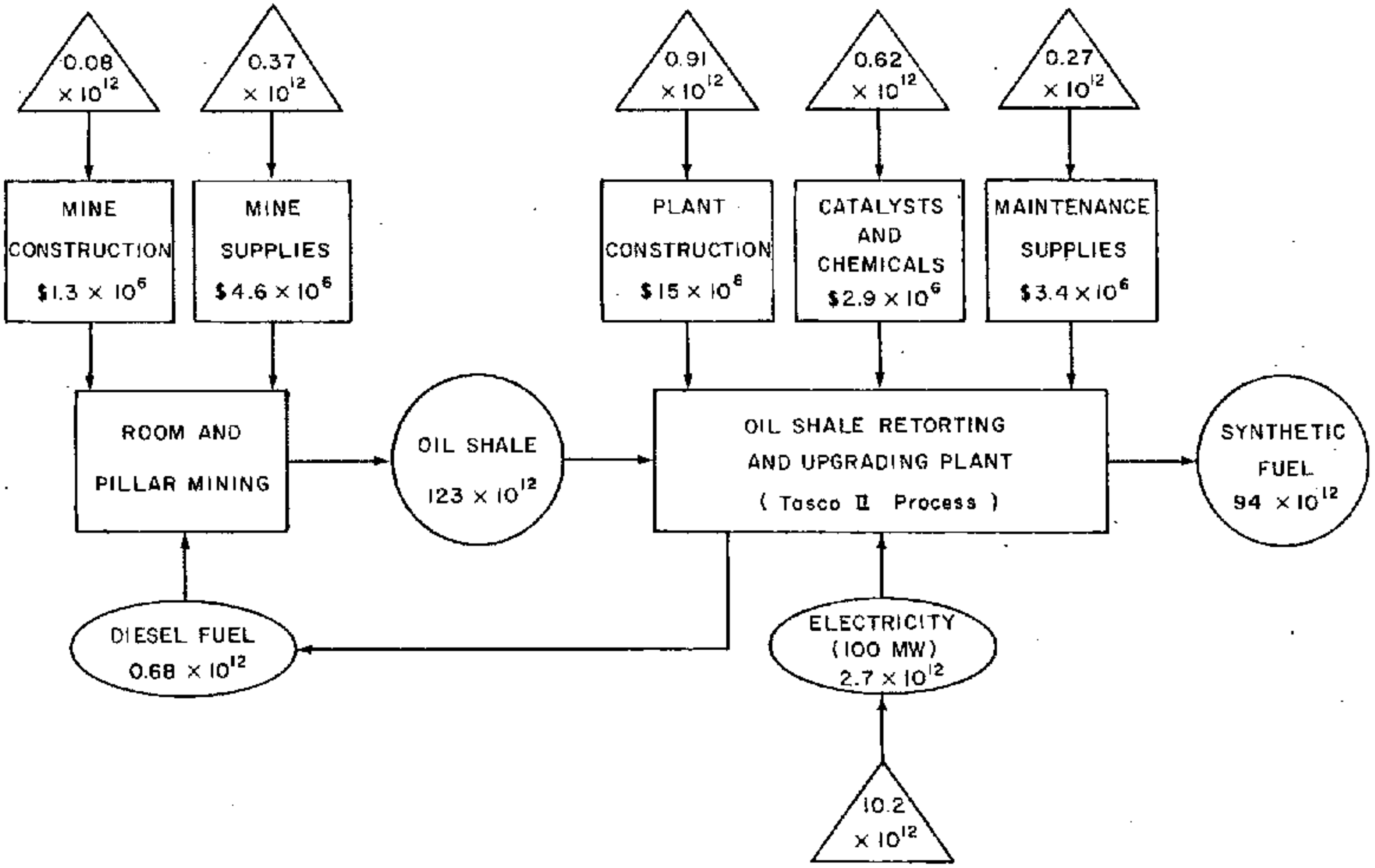
3. Oil Shale

Oil shale is a resource that is not used directly as a fuel. It must first be processed to extract the organic portion of the shale rock (about 11 percent by weight for 35 gal/ton shale), which must then be upgraded to be suitable as a refinery feedstock or fuel oil. The retorting process by which shale oil is extracted is very energy intensive and involves the heating of large quantities of shale to 900°F (480°C). However, much of the organic material in the shale can be recovered; the TOSCO II retorting process recovers essentially all of it.

Because oil shale is unusable in its raw form, a certain amount of care must be taken in computing the net energy ratio for mining, retorting, and upgrading. Unprocessed oil shale has a heating value that can be measured, but in computing the energy loss during retorting and upgrading this value is not used as the energy content of the resource. Instead, the energy content of the products of retorting is used as the basis for the energy loss because the energy contained in the shale is not useful until it has been extracted as a liquid or gaseous hydrocarbon. In practice, the only energy-containing material that cannot be extracted from the shale is a carbon residue which remains on the spent shale after retorting.

Figure 5-5 shows the annual energy inputs for oil shale mining,[9] retorting,[10] and upgrading.[10] As mentioned above, the resource energy input for oil shale includes only the heating value of the hydrocarbon products actually recoverable by retorting. As shown in Figure 5-5, the diesel fuel consumed by the mining equipment is obtained as a byproduct from shale oil upgrading.[10] This fuel consumption is counted as a conversion loss. Other conversion losses occur mainly in the form of the combustion of retort gases as well as some fuel oil to provide heat and steam for retorting and upgrading. The product from oil shale retorting and upgrading is simply called synthetic fuel since the process design on which the analysis is based was for the production of fuel oil and liquified petroleum gas (LPG) rather than synthetic crude oil.[10] The production of synthetic crude oil probably would not result in a significantly different net energy ratio.

Table 5-6 shows the breakdown of conversion energy loss and external energy inputs, as well as the computation of the net energy ratio, for a 50,000-B/D (8000 m^3/D) oil shale complex. The net energy ratio of 2.3 for oil shale processing is the highest of the three different alternatives that have been examined for producing synthetic fuel, probably because oil shale (or at least the organic portion of it) in its raw form is closer in composition to the final product that is coal, which results in less severe (less energy consumptive) processing. In



Notes: All resource energy inputs and product outputs are in Btu
All dollar figures are in 1973 dollars per year

FIGURE 5-5. ANNUAL ENERGY INPUTS FOR CONSTRUCTION AND OPERATION OF A 50,000-B/D OIL SHALE MINING, RETORTING, AND UPGRADING COMPLEX addition, it appears that retorting methods such as gas combustion or in-situ may have been even higher net energy ratios, although the calculations have not been fully carried out due to insufficient data.

Table 5-6

ANNUAL ENERGY INPUTS AND OUTPUT FOR A 50,000-B/D
OIL SHALE MINING, RETORTING, AND UPGRADING COMPLEX

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss	29	31
External energy inputs		
Electricity	10.2	10.8
Plant construction and materials	1.8	1.9
Mine construction and materials	0.45	0.47
Total	41.5	43.8
Synthetic fuel output	94	99

$$\text{Net energy ratio} = \frac{94}{41.5} = 2.3$$

D. Coal-to-Refined Products System

The production of synthetic crude oil from coal, of course, is not the final step in converting coal into liquid fuels usable by society. The syncrude must be transported to a refinery to be processed to yield gasoline, diesel oil, heating oil, and other products. Both the transport and the refining process are energy consumptive and consequently decrease the net energy ratio of the final products.

The energy consumed in transporting crude oil via pipeline has been calculated assuming a 24-inch (61 cm) diameter pipeline 1000-miles (1600 km) long, corresponding to shipment of syncrude from eastern Montana or Wyoming to the Midwest for refining. The motive power requirement for this diameter pipeline is 151 horsepower/mile (70 kW/km), corresponding to a capacity of 14 million tons per year (1.3×10^6 kg/yr).[11] The resource energy requirement is calculated to be 780 Btu/ton-mile (560 J/kg-km) for diesel engines or 1020 Btu/ton-mile (740 J/kg-km for electric motors. An average figure of 900 Btu/ton-mile (650 J/kg-km) has been used in the net energy calculation. In addition, the energy required to produce the 500,000 tons (4.5×10^8 kg) of steel used in the pipeline has been included in the pipeline energy requirement (assuming a 20-year pipeline life). This contribution represents about 10 percent of the total.

The energy losses (due mostly to internal use) and external resource energy consumption during refining are calculated from data in Reference 2 as 7.1 percent and 6.5 percent of the crude oil energy input, respectively. These figures correspond closely with the figures of 6.8 percent and 6.7 percent obtained from nationwide refinery energy efficiency and external energy use data.*[12]

The annual resource energy inputs required for the entire coal-to-refined products system are shown in Figure 5-6. The size of the system is scaled to a 100,000-B/D (16,000 m^3/D) coal liquefaction plant. Table 5-7 tabulates the data from Figure 5-6 and shows the net energy

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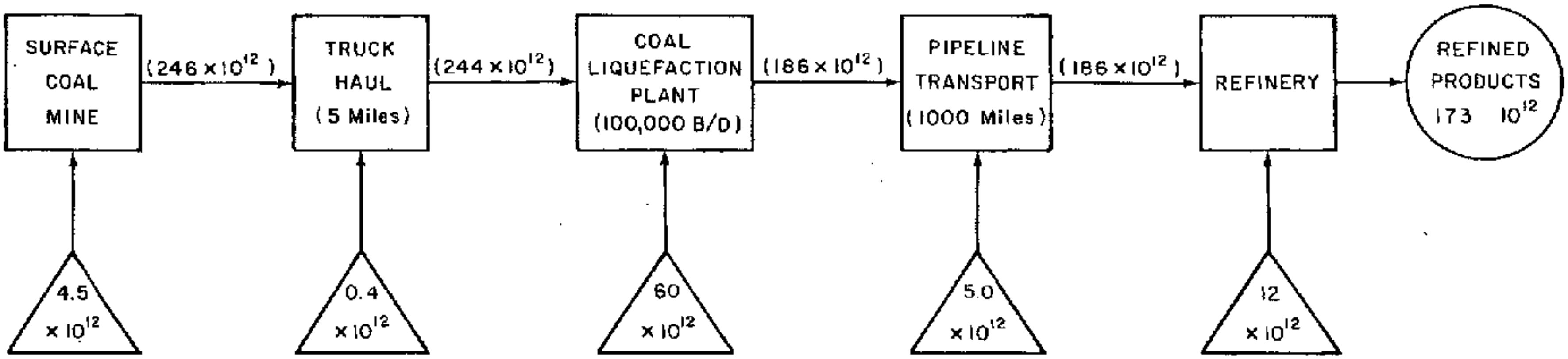
*The results of a recent SRI study[6] indicate that the internal loss is 2 percent and the external resource energy use is 12 percent for refining a 50-50 blend of syncrude and natural crude. The total energy consumption is about the same as quoted above, however.



Note: All resource energy inputs and product outputs are in Btu

FIGURE 5-6. ANNUAL ENERGY INPUTS FOR CONVERTING WESTERN SURFACE-MINED COAL TO REFINED PRODUCTS IN THE MIDWEST ratio calculations for the system. The net energy ratio of 1.1 indicates that nearly as much energy is expended in obtaining refined fuels from coal than is contained in the fuels themselves.

Table 5-7

ANNUAL ENERGY INPUTS AND OUTPUT FOR A
COAL-TO-REFINED PRODUCTS SYSTEM
(Based on a 100,000-B/D Coal Liquefaction Plant)

	Resource or Product Energy	
	10^{12} Btu	10^{15} J
Internal conversion loss		
Coal transport	2.4	2.5
Coal liquefaction	58	61
Refinery	13	14
External energy inputs		
Coal mine	4.5	4.7
Coal transport	0.4	0.42
Coal liquefaction plant	60	63
Pipeline	5.0	5.3
Refinery	12	13
Total	155	164
Refined products output	173	183

$$\text{Net energy ratio} = \frac{173}{155} = 1.1$$

A similar calculation for the oil shale-to-refined products system results in a net energy ratio of 1.6. For methanol the only additional step required in the system is transportation since no further refining is necessary. Adding transportation reduces the net energy ratio for methanol only slightly, to 0.65.

E. Summary

The net energy ratios for three different synthetic fuel processes, as well as for coal mining and the entire resource-to-end products systems, have been calculated. These ratios are a measure of the product energy that is made available per unit of resource energy consumed in the synthetic fuel conversion process. The net energy ratio calculations for the three synthetic fuel processes are summarized in Table 5-8 along with the calculations for the three resource-to-fuels systems.

The main conclusion to be drawn from Table 5-8 is that the conversion of coal to automotive and other fuels via coal liquefaction is a more efficient use of resources than is the conversion of coal to methanol. This remains true even when the additional energy inputs and losses incurred in refining the syncrude product are taken into account. On the basis of converting western subbituminuous coal, about 1.8 times as much resource energy is consumed in converting coal to methanol as there is in converting coal to refined products via coal liquefaction.

In considering the conversion of oil shale to refined products, the comparisons are not as straightforward. On the basis of total resource consumption, oil shale conversion is clearly the most efficient use of resources. However, due to the distinctly different nature of the resource, it is difficult to draw conclusions regarding the attractiveness of oil shale with respect to coal liquefaction on the basis of total resource utilization. Unlike coal, oil shale has no other practical uses, and some energy penalty must be exacted just to convert the shale to a usable form. However, most of the energy consumed in this conversion is provided by the oil shale itself, in the form of products of retorting. On the basis of the consumption of resources other than oil shale, the conversion of oil shale to synthetic crude oil appears to be especially attractive compared with the coal conversion technologies.

Table 5-8

SUMMARY OF NET ENERGY CALCULATIONS FOR SYNTHETIC LIQUID FUELS

Technology	Conversion Process*				Resource-to-Fuels System†			
	Internal Loss (10^{12} Btu/yr)‡	External Input (10^{12} Btu/yr)‡	Product Yield (10^{12} Btu/yr)‡	Net Energy Ratio	Internal Loss (10^{12} Btu/yr)‡	External Input (10^{12} Btu/yr)‡	Product Yield (10^{12} Btu/yr)‡	Net Energy Ratio
Coal liquefaction								
H-Coal process, Powder River coal, 100,000 B/D	58	67	186	1.5	71	84	173	1.1
H-Coal process, Illinois coal, 100,000 B/D	81	27	195	1.8	98	42	182	1.3
Methanol from coal								
Lurgi process, Navajo coal, 81,433 B/D	47	70	77	0.66	47	72	77	0.65
Oil shale								
TOSCO II process, 35-gal/ton shale, 50,000 B/D	29	12.5	94	2.3	35	20	88	1.6

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*Includes mining of resource.

†Includes 1000 miles of pipeline for shipment of syncrude or methanol.

‡10^{12} Btu/yr = 1.06 × 10^{15} J/yr.

There are several sources of error in computing the values displayed in Table 5-8. First, it is impractical to account for all the energy inputs into a given system. However, since it is possible to account for the most important inputs, the net energy ratios quoted above are expected to be in error by no more than 5 to 10 percent due to such oversights. Several inputs or activities such as research and development, engineering, etc., which are energy consumptive were not added into the total simply because the insignificance of the contributions (much less than 1 percent of the total) was not worth the additional effort expended in deriving the numbers. Neglecting such contributions represents a real, though very small, source of error.

Moreover, errors may occur in assigning energy values to aggregated dollar values for certain types of inputs such as construction or maintenance. Whenever possible, these figures were compared with calculations of energy inputs associated with a known subcategory of input as a check on the reasonableness of the total value. For example, the energy consumed in the production of roof bolts for room-and-pillar oil shale mining might be expected to contribute significantly to the total energy consumption for this activity since large numbers of roof bolts are required for such a mine (nearly 1000 tons per year or 9×10^5 kg/yr or a mine supplying a 50,000-B/D plant or 8000 m^3/D). The energy required for producing steel roof bolts is about 0.05×10^{12} Btu/yr (0.05×10^{15} J/yr). This compares with the total energy input calculated for mine supplies of 0.37×10^{12} Btu/yr (0.39×10^{15} J/yr).

Much more work needs to be done on expanding the data base for net energy calculations to provide straightforward data on as many types of energy inputs as possible. More information is needed on other types of synthetic fuel processes as well to facilitate the comparison of different processes that accomplish the same objective. The net energy calculations in this chapter provide a starting point for understanding the total energy picture for synthetic fuels development.

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6--MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO FOR SYNTHETIC LIQUID FUELS FROM COAL AND OIL SHALE

By Evan E. Hughes, Robert V. Steele

A. Introduction

Many speculations have been advanced in recent years concerning future levels of production of synthetic fuels from coal and oil shale. To set an upper limit on the possible impacts that would result from production of these fuels, this study requires an implementation scenario that sets forth the maximum credible rate at which the synthetic fuels industry (coal and oil shale syncrudes, methanol from coal) could be expected to develop. This maximum implementation scenario is the subject of this chapter. It is extremely important to recognize that this scenario is *not a prediction of what will occur* but is an attempt to elucidate the maximum possible impact situation.

B. Implementation Schedule

The maximum credible implementation scenario is derived from a hypothesized growth schedule for a synthetic liquid fuel industry presented in Table 6-1.* The growth schedule indicates a slow start for synthetic

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*Approximate conventional-to-metric unit conversion factors relevant to this chapter are the following:

100,000 B/D is about 16,000 m^3/D
1000 AF/Y is about 1.2 × $10^6 m^3$/Y
10^3 tons/Y is about 900 × 10^6 kg/Y
1000 acres is about 4.0 × $10^6 m^2$.

Table 6-1

HYPOTHESIZED GROWTH SCHEDULE OF SYNTHETIC LIQUID FUELS INDUSTRY

	Number of Plants Producing				
	Year				
Fuel Description*	1980	1985	1990	1995	2000
Syncrude from coal					
30,000 B/D plant	0	3	7	7	0
100,000 B/D plant	0	0	3	13	40
Total production (10^6 B/D)	0	0.09	0.5	1.5	4.0
Syncrude from oil shale					
50,000 B/D plant	2	2	2	0	0
100,000 B/D plant	0	4	14	20	20
Total production (10^6 B/D)	0.1	0.5	1.5	2.0	2.0
Methanol from coal					
50,000 B/D plant	2	2	2	0	0
100,000 B/D plant	0	5	19	50	80
Total production† (10^6 B/D oil equivalent)	0.05	0.3	1.0	2.5	4.0

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*Note that 100,000 B/D is about 16,000 m^3/D.

†To a close approximation, the energy content of a barrel of methanol is half that of a barrel of oil.

liquid fuels with negligible production before 1985, followed by a rapid growth until the year 2000. The relatively slow start stems from the present situation in the oil industry: (1) the increased activity to find and produce energy from conventional petroleum sources, and (2) the steady increase in cost estimates for synthetic fuel plants. As a result, the oil industry can be expected to postpone construction of synthetic liquid fuel plants in favor of investment in more familiar resources.

The scenario projects accelerated growth for oil shale processing after 1980 and for the coal-based fuels after 1985. Such growth, of course, assumes that the first plants are successful, both technically and economically. This assumption is made solely to facilitate construction of a scenario that depicts the maximum rate at which an industry could be deployed subject only to physical and general economic constraints. Of course, other real world constraints, such as water availability, would lead to a lower actual rate of deployment.

The rapid increases in synthetic fuel production shown in Table 6-1 have been derived on the basis of several considerations:

- The impact study would be most instructive if it included a scenario that showed synthetic liquid fuels playing a major role in meeting U.S. requirements for liquid fuels.
- The rates of growth projected during early years of the commercial production of the alternative fuels should be reasonable for a new industry.
- The requirements for economic and physical resources to build and operate the plants should be realistic.

The maximum credible implementation scenario reflects several judgments regarding the relative states of development of the three basic synthetic liquid fuel technologies: Oil shale technology is ready for commercial deployment. Tests have been made on a scale large enough to confirm the feasibility of the technology and guide the design of a large plant. Future improvements in the technology (excluding the possibly significant case of <u>in-situ</u> technology) are not expected to be pronounced enough to render obsolete a plant begun today. Hence, our maximum credible scenario for oil shale shows two 50,000 B/D plants in 1980 and an addition of four 100,000 B/D plants by 1985. The commercial production of methanol and syncrude are restrained relative to oil shale to reflect the anticipated benefits of further research, development, and demonstration work on processes of making syncrude from coal and the market uncertainties concerning introduction of methanol for large-scale use as a fuel. The status of the technology for production of methanol from coal is similar to that of syncrude from shale--basically ready for first generation commercial production. The more advanced development of methanol compared with coal syncrude production derives from the similarities of producing methane and methanol from coal, and the greater attention that SNG technology has received in the last decade compared with coal liquefaction technology. Oil shale production is shown leveling off as a reflection of anticipated water shortages.

C. Comparison with the National Academy of Engineering Scenarios

The National Academy of Engineering (NAE) projection of the maximum production of synthetic fuels possible in the next 10 to 12 years[1] is compared with those of this study in Table 6-2.

Table 6-2

MAXIMUM POSSIBLE PRODUCTION OF SYNTHETIC LIQUID FUELS IN 1985: NAE AND SRI PROJECTIONS

Fuel	NAE (million B/D oil equivalent)*	SRI (million B/D oil equivalent)*
Syncrude from coal	0.3	0.09
Methanol from coal	0.3	0.3
Syncrude from shale	0.5	0.5
Total synthetic liquid fuel in 1985	1.1	0.89

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*Note that one million B/D is about 160,000 m^3/D.

The NAE projections were based on the lead times required to plan and construct the facilities and on the resources of capital and labor that must be mobilized to build and operate them. The lower level of production of syncrude from coal reflects the need for more prototype plant testing of coal liquefaction plants before beginning the commitment to commercial plants. Oil shale technology is taken to be well enough developed to justify commitment to a commercial facility now. Although the NAE Task Force on Energy viewed the technology for producing methanol from coal as adequately developed to justify commitment to commercial sized plants, it, too, apparently felt that uncertainties in the uses of methanol as a fuel on a commercial scale would limit the estimated maximum production in 1985 to a level comparable to the estimate for syncrude from coal and below the estimate of syncrude from oil shale.

As Table 6-2 shows, the SRI study's schedule for the maximum credible implementation of syncrude from coal is lower than the NAE level for 1985 reflecting our judgment that the expectation of great improvement in technology, combined with the uncertainties inherent in all of the synthetic fuels, makes the postponement of commitments to commercial-scale coal liquefaction facilities inevitable. The situation was succinctly described by a vice president of Exxon Research and Engineering Company in a talk at Stanford University: Coal liquefaction differs from other synthetic fuel processes (coal gasification and oil shale production) in that substantial savings are expected from second generation technology compared to that presently available. In particular, while the 10 or 15 percent savings expected from improvements in gasification technology over the next five years are not sufficient to justify postponement of construction, the larger (but unspecified) savings expected from advanced liquefaction technology warrant a go-slow attitude. Because it is technologically reasonable to deploy present technology for production of methanol from coal or syncrude from oil shale, these are suitable levels for a maximum credible implementation scenario. Therefore, our schedule in Table 6-1 puts methanol and oil shale production at the levels projected in the NAE study.

In both the oil shale and the methanol cases the actual realization of the schedules of Tables 6-1 and 6-2 requires that present uncertainties be resolved soon in a way that encourages development of the synthetic fuels. Several recent events make it questionable whether the maximum credible production levels for 1985 can still occur: (1) The recent announcement by the Colony Development Company that it will not start the construction originally planned for spring 1975 on its 50,000 B/D oil shale plant at Parachute Creek in Colorado, (2) the lack of enthusiasm for oil shale displayed in the "Project Independence Blueprint" recently published by the Federal Energy Administration (FEA),[2] and (3) commercial scale uses of methanol as a fuel will have to be apparent soon to justify the deployment of the 300,000 B/D (oil equivalent) production level by 1985. The most likely candidate uses of methanol emerging before 1985 are fuel for electric utilities (especially as fuel for gas turbine or combined cycle generators) and automotive fuel for fleet vehicles.

D. Scenarios and Scaling Factors

The projected fuel production schedules shown in Table 6-1 have been assigned the hypothetical locations shown in Table 6-3 in proportion to reported reserves of surface and underground minable coal and have been used to derive the scenarios in Tables 6-4 through 6-7. The scaling factors shown in the tables are used to account for the quantities of capital, labor, steel, and land required for the construction and operational phases of each of the building blocks used in these scenarios.

Table 6-3

HYPOTHESIZED LOCATIONS OF PLANTS FOR PRODUCING SYNTHETIC LIQUID FUEL FROM COAL

Units for table entries are as follows:

Coal syncrude plants:	S = 30,000 B/D L = 100,000 B/D*	Surface mine:	5 million tons/year
		Underground mine:	1 million tons/year*
Methanol plants:	S = 50,000 B/D (methanol) L = 100,000 B/D (methanol)	Water:	10^3 acre-ft/year*

State	Cumulative Quantities				
	Year				
	1980	1985	1990	1995	2000
Wyoming					
Coal syncrude	0	2S	3S, 2L	3S, 5L	13L
Methanol	0	0	2L	8L	13L
Surface mines	0	2	14	42	81
Water	0	58	116	297	584
Montana					
Coal syncrude	0	0	1S	1S, 3L	11L
Methanol	0	0	1L	5L	10L
Surface mines	0	0	4	25	66
Water	0	0	24	174	479
North Dakota					
Methanol	1S	1S, 2L	1S, 5L	13L	21L
Surface mines	2	9	20	47	76
Water	8	39	86	202	326
New Mexico					
Methanol	0	1L	3L	4L	4L
Surface mines	0	3	8	10	10
Water	0	15	46	62	62
Illinois					
Coal syncrude	0	1S	1S, 1L	1S, 3L	7L
Methanol	0	1L	4L	9L	14L
Surface mines	0	1	3	8	14
Underground mines	0	9	40	93	161
Water	0	29	98	231	415
Kentucky					
Coal syncrude	0	0	1S	1S, 1L	4L
Methanol	1S	1S, 1L	1S, 3L	7L	10L
Surface mines	1	1	3	7	13
Underground mines	0	10	23	52	87
Water	8	23	62	144	288
West Virginia					
Coal syncrude	0	0	1S	1S	2L
Methanol	0	0	1L	3L	5L
Surface mines	0	0	1	2	4
Underground mines	0	0	9	24	56
Water	0	0	24	54	134
Ohio					
Coal syncrude	0	0	0	1L	3L
Methanol	0	0	0	1L	3L
Surface mines	0	0	0	1	4
Underground mines	0	0	0	18	49
Water	0	0	0	44	133

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*Note that 100,000 B/D is about 16,000 m^3/D, 1 million tons/year is about 900 million kg/year, and 1 acre foot is about 1200 m^3/year.

Table 6-4

SYNCRUDE FROM COAL: MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Data and Assumptions	Scenario for Year 1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million B/D)	0	0.09	0.5	1.5	4.0
Number of Plants					
Small (30,000 B/D)	0	3	7	7* ↘	0
Large (100,000 B/D)	0	0	3	13	40

Inputs and Outputs: Items	Units	Scaling Factors for a 100,000 B/D Plant (in units specified)	Year 1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^9 1973 $	0.67	0	0.60	3.4	10	27
Labor	10^3 man-years	7.3	0	6.6	37	110	290
Steel	10^3 tons	110	0	100	560	1700	4400
Land	10^3 acres	1	0	0.9	5.1	15	40
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	130	0	120	650	2000	5200
Labor force	10^3 people	1.4	0	1.3	7.0	21	56
Coal (Western)	10^6 tons/year	18	0	16	90	270	720
Water	10^3 acre-ft/year	29	0	26	145	435	1160
Electric power	MW	140	0	130	700	2100	5600

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*Arrow indicates that small plants are enlarged and enter large plant classification.

Table 6-5

SYNCRUDE FROM OIL SHALE: MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Data and Assumptions	Scenario for Year 1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million B/D)	0.1	0.5	1.5	2.0	2.0
Number of Plants					
Small (50,000 B/D)	2	2	2*	0	0
Large (100,000 B/D)	0	4	14	20	20

Inputs and Outputs Items	Units	Scaling Factors for a 100,000 B/D Plant (in units specified)	Year 1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^9 1973 $	0.75	0.75	3.8	11.3	15.0	15.0
Labor	10^3 man-years	5.4	5.4	27	81	108	108
Steel	10^3 tons	90	90	450	1350	1800	1800
Land	10^7 acres	0.6	0.6	3.0	9.0	12	12
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	80	80	400	1200	1600	1600
Labor force	10^3 people	1.7	1.7	10.2	25.5	34.0	34.0
Shale	10^6 tons/year	54	54	270	810	1080	1080
Water	10^3 acre-ft/year	16	16	80	240	320	320
Electric power	MW	170	170	850	2250	3400	3400
Land	10^3 acres/year	0.15	0.15	0.750	2.25	3.0	3.0

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*Arrow indicates that small plants are enlarged and enter large plant classification.

Table 6-6

METHANOL FROM COAL: MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Data and Assumptions	Scenario for Year 1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million B/D oil equivalent)*	0.05	0.3	1.0	2.5	4.0
Number of Plants					
Small (50,000 B/D)	2	2	2†	0	0
Large (100,000 B/D)	0	5	19	50	80

Inputs and Outputs Items	Units	Scaling Factors for a 100,000 B/D Plant* (in units specified)	Year 1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^9 1973 $	0.59	0.59	3.5	11.8	29.5	47.2
Labor	10^3 man-years	7.5	7.5	4.5	150	375	575
Steel	10^3 tons	100	100	600	2000	5000	8000
Land	10^3 acres	1	1	6	20	50	80
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	70	70	420	1400	3500	5600
Labor force	10^2 people	0.9	0.9	6.4	18	45	72
Coal (Western)	10^6 tons/year	13	13	78	260	650	1040
Water	10^3 acre-ft/year	15	15	90	300	750	1200
Electric power	MW	100	100	600	2000	5000	5000

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*The energy of a barrel of methanol is half that of a barrel of oil.

†Arrow indicates that small plants are enlarged and enter large plant classification.

Table 6-7

SURFACE COAL MINES NEEDED FOR SYNCRUDE PLUS METHANOL PRODUCTION*

Data and Assumptions	Scenario for Year 1980	1985	1990	1995	2000
Production Schedule					
Cumulative capacity (million tons/year)	13	94	350	920	1760
Number of mines (5 million tons/year)	3	19	70	184	352

Inputs and Outputs: Items	Units	Scaling Factors for a 5 Million Ton/Year Surface Mine (in units specified)	Year: 1980	1985	1990	1995	2000
			Cumulative Amount				
Construction							
Capital	10^9 1973 $	0.03	0.09	0.57	2.1	5.5	10.6
Labor	10^3 man-years	0.25	0.75	4.75	17.5	46.0	88.0
Steel	10^3 tons	3	9	57	210	552	1060
Land†	Acres	10	30	190	700	1840	3520
			Annual Amount				
Production							
Operating costs	10^6 1973 $/year	12	26	228	840	2210	4220
Labor force	10^3 people	0.1	0.3	1.9	7	18	35
Water	10^3 acre-ft/year	0.15	0.45	2.85	10.5	27.6	52.8
Electric power	MW	10	30	190	700	1840	3520
Land	10^3 acres/year	0.25	0.75	4.75	17.5	46	88

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*Assumes all of the coal requirements for syncrude and methanol plants are supplied by surface mines.

†Land for buildings, storage and handling facilities, parking, etc.; this is not land for mining.

E. Resources

By far, the majority of the commercially significant oil shale reserves (25 to 30 B/ton of shale or 4.4 to 5.3 $m^3/10^3$kg) are found in the Piceance Basin in western Colorado. Unlike oil shale, coal is widely distributed in the nation. Table 6-8 shows a recent tabulation of strippable coal reserves and the number of coal liquefaction plants that these reserves could sustain. Since synthetic fuels will require low cost feedstocks to be economically competitive (at least initially) with conventional petroleum fuels, strippable coal has been emphasized. Clearly, strippable reserves would be able to sustain this study's maximum credible production scenario for several plant lifetimes. However, when other coal demands are also taken into account, there is a good chance that early in the 21st century, strippable reserves will be nearing depletion.* This suggests the need to develop both in-situ recovery techniques and improved methods of underground mining (especially since present methods cannot efficiently mine the very thick, deep seams of coal found in the West).

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*However, it is important to note that distinction between resources and reserves. Reserves are the fraction of resources that are economically recoverable with state-of-the-art technology at any given time. Hence, both changes in the market price of a mineral, and the technology available can alter estimates of reserves, while resource estimates can be changed only with new discoveries.

Table 6-8

STATES AND REGIONS WITH STRIPPABLE COAL RESERVES SUFFICIENT TO SUPPORT A LARGE SYNTHETIC FUELS INDUSTRY

States and Regions	Strippable Reserves 10^9 Tons*	Number of 100,000 B/D Plants Sustainable for 20 Years at 20 MT/Year
Montana	43	110
Wyoming	24	60
North Dakota	16	40
Illinois/Western Kentucky	16	40
West Virginia/ Eastern Kentucky	8.7	22

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*Note that one ton is about 900 kg.

Source: Reference 3, "Demonstrated Reserve Base," U.S. Bureau of Mines (1974).

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