Appendix B

ENERGY AND ECONOMIC EVALUATION OF ELECTRIC VEHICLES AND SYNFUEL-POWERED VEHICLES*

A. Costs of Automotive Transportation

Table B-1 presents the 1975 costs of the synfuel system (syncrude/gasoline) as they appear to the consumer of the product--the owner and operator of the automobile. Table B-2 presents similar data for the electric automobile. If the synfuel car achieves a 30 miles per gallon (mi/gal) fuel economy, the two cases show essentially the same cost, slightly less than 9 cents per mile, for the purchase and operation of the automobile. Other costs not included in Tables B-1 and B-2 add 3 or 4 cents per mile to the total. These are charges for taxes, registration, and insurance, taken to be the same for the synfuel and electric automobiles.

1. Life Cycle Costs of Alternatives

Table B-3 compares the two cases showing only the complete life cycle (10 years and 100,000 miles) costs of those items that can contribute to a significant difference between total costs of operating the synfuel and electric cars. The assumption that $500 can be saved on the engine-drive train subsystem [i.e., $400 for the electric versus $900 for the internal combustion engine (ICE) with emission controls], represents an optimistic view of electric car costs. Still, the price of $5200 for the electric car is characteristic of an intermediate or full-sized car, not the subcompact, in today's market. The 30 mi/gal fuel economy for the ICE is optimistic for a uniform charge Otto cycle engine meeting the statutory emission standards. At 25 mi/gal the fuel

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*Excerpted from: E. E. Hughes, et al., "Long Term Alternatives for Automotive Propulsion—Synthetic Fuel Versus Battery Electric System," Stanford Research Institute (August 1976).

Table B-1

OPERATING COSTS FOR SYNTHETIC FUELED SUBCOMPACT CAR

	Years 1-3 (39,000 miles)	Years 4-10 (61,000 miles)	Total 100,000 miles
Depreciation	$1,250	$2,050	$3,300
Repairs and maintenance	420	1,900	2,320
Tires	50	280	330
Accessories	10	50	60
Gasoline*	975	1,525	2,500
Oil	50	110	160
Total costs	$2,750	$5,950	$8,700
Cost per mile	0.071	0.097	0.087

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*Assuming 30 mi/gal and $0.75/gal. At 25 mi/gal the figures would be:

Gasoline	1,170	1,830	3,000
Total	2,965	6,255	9,200
Cost per mile	0.075	0.101	0.092

Note: Totals may not add because of rounding.

Sources: 1975 Pinto Blue Book Price: $3,300, 2500 lb.
Federal Highway Administration, "Cost of Operating an Automobile" (April 1974).

1974 prices adjusted by appropriate price indices.

Table B-2

OPERATING COSTS FOR ELECTRIC CAR WITH ADVANCED BATTERY*

	Years 1-3 (39,000 miles)	Years 4-10 (61,000 miles)	Total 100,000 miles
Depreciation			
Vehicle	$1,090	$1,710	$2,800
Battery	900	1,500	2,400
Repairs and maintenance	250	750	1,000
Tires	70	350	420
Accessories and oil	15	60	75
Electricity	700	1,100	1,800
Total costs	$3,025	$5,470	$8,500
Cost per mile	0.078	0.090	0.085

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*Assumptions:

Vehicle - 1975 Pinto less $200 for pollution control devices, and $300 savings on rest of engine and power train.

Battery - 40 kWh capacity costing $60/kWh and having a lifetime of 1000 cycles or 10 years. Weighs 570 lbs. No salvage value is assumed.

Repairs and maintenance - Estimate compiled from several sources.

Tires - Costs for seven new regular tires and four snow tires over 10 years.

Accessories and oil - Estimate based on Federal Highway Administration data.

Electricity - Total usage 0.45 kWh/mi at cost of $0.04/kWh (1.8¢/mile).

Note: Totals may not add because of rounding.

Table B-3

COMPARISON OF AUTOMOBILE TRANSPORTATION COSTS

Cost Element	Total Cost (Over 10 Years and 100,000 miles) Synfuel	Electric
Automobile		
Battery	$ 0	$2400
Engine and drive train	900	400
Vehicle body	2400	2400
Total Automobile	$3300	$5200
Financing charges[*]	880	1390
Fuel or electricity	2500[†]	1800[‡]
Repairs and maintenance	2300	1000
Total[§]	$8980	$9390

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[*] Approximate costs for 5-year loan on 80 percent of total automobile cost at 12 percent interest rate.

[†] Assuming 30 mi/gal and $0.75/gal.

[‡] Assuming 0.45 kWh/mi and $0.04/kWh.

[§] Other costs are approximately 4¢/mi for each vehicle.

cost would be $3000 over the 10 years, and the bottom line would read $9400 instead of $8900. The electric car has been credited with substantial (factor of 2) savings over the synfuel ICE on maintenance and repair costs. Uncertainties in any of the four basic cost terms listed—automobile, financing, energy, and repairs and maintenance—are large enough to cause one or the other alternative to have a slight advantage at the bottom line of Table B-3. The most significant uncertainty is the initial cost of the electric automobile.

2. Analysis of Cost Inputs

The sensitivity of the cost picture of Table B-3 to the results of energy R&D programs can be illuminated by specifying the terms that have contributed to the battery and energy costs in the table. The $2400 battery cost is based on a 40-kWh lithium-sulfur battery sold to the consumer at $60/kWh after being manufactured at a cost of about $30/kWh. The battery lifetime of 1000 deep discharge cycles is sufficient to last the full 10 years at 10,000 miles per year. A five-year lifetime for a battery costing the same amount to manufacture would mean a doubling of the amortization and financing costs of the battery to $5950 ($4800 for amortiziation plus $1150 for financing), therby contributing 6¢/mi rather than 3¢ per mi to the total operating costs of about 13¢/mi (allowing 4¢/mi for costs not included in Table B-3). The costs in Table B-3 are based on a battery characterized as $6/kWh-year and result in a 3¢/mi transportation cost. Other cost-life combinations can be scaled accordingly.

The coal liquefaction plant is the major contributor to the $0.75/gal gasoline cost used in Table B-3. To compare the contributors to this gasoline price with the contributors to the energy price of the electric alternative, the dollar flow, or value-added, along both energy supply routes is shown in Table B-4. The coal price used in the table ($10/ton) includes delivery and could be set at other values, ranging from as low as $5/ton to as high as $20/ton. At a price of $15/ton the coal and nuclear generating costs would both be about 2¢/kWh.

From the cost figures presented in Table B-4 it is apparent that the energy advantage of the electric alternative, which is demonstrated in Part B of this Appendix, does not translate into an economic advantage because the cost of coal contributes less than one-fifth of the cost of the energy delivered to the automobile. When the influence of the cost of coal is further diluted by considering the other factors contributing to total transportation costs, it becomes apparent that extremely large increases in the cost of coal would be required to

Table B-4

CONTRIBUTORS TO SYNFUEL AND ELECTRIC ENERGY COSTS

Part I

DOLLAR FLOW FOR SYNTHETIC FUEL SYSTEM

System Component	Cumulative Value Added: Price in Units Characteristic of Component	Cumulative Value Added: Dollars per 10^6 Btu	Value Added in Dollars per 10^6 Btu of Delivered Energy
Coal (mine plus transport)	$10/ton	$0.63	$0.89
Liquefaction plant	$18/barrel	3.10	2.54
Refinery	$0.60/gal	4.75	1.33
Transportation and distribution system	$0.75/gal	5.95	1.19
Total (price used in Table B-3)	$0.75/gal		$5.95

Part II

DOLLAR FLOW FOR ELECTRIC ENERGY SYSTEM

System Component	Cumulative Value Added: Price in Units Characteristic of Component	Cumulative Value Added: Dollars per 10^6 Btu	Value Added in Dollars per 10^6 Btu of Delivered Energy
Fuel			
Coal (mine plus transport)	$10/ton	$0.63	$1.98
Uranium (entire cycle)	$65/lb (3.5 mills/kWh)	0.32	1.17
Power generation			
Coal-fired plant	16 mills/kWh	4.70	3.33
Nuclear plant	19 mills/kWh	5.55	5.10
Transmission and distribution	4¢/kWh	11.70	5.43
Total (price used in Table B-3)	4¢/kWh		$11.70 (nuclear) $10.70 (coal)

the energy content of the resources in the ground required to supply the fuels or electricity consumed in construction, operation, and so forth.

In the case of the two automotive energy alternatives, the appropriate figure of merit will be Btu per vehicle-mile of transportation (Btu/VMT). To account for all the resource energy required to deliver transportation, the energy content of the primary coal resource will be summed with the energy content of additional coal, crude oil, wellhead natural gas, and nuclear and hydropower equivalents required to construct and operate the conversion plants, refineries, transmission lines, automobiles, and so forth, that make up the coal-to-transportation systems.

2. Comparison of Alternatives

The total energy requirements for the synfuel system and the electric system, respectively, are shown in Figures B-1 and B-2. The numbers beneath each box (representing system components) show the direct flow of energy through the system in 10^{12} Btu/yr. The numbers in the triangles show the additional resource energy requirements for construction, maintenance, and operation of the system components. The total energy consumption per VMT is calculated by adding the energy content of the original coal resource (E_{coal}) that was processed through the system to provide motive power to the sum of all the additional energy inputs (E_I) and dividing by the total vehicle-miles traveled. As shown in the two figures, the total resource energy requirement for the electric vehicle, 7360 Btu/mi, is about 23% less than the synfuel vehicle requirement, 9540 Btu/mi. These values are based on propulsion energy requirements of 0.033 gal/mi (30 mi/gal) and 0.45 kWh/mi for the synfuel-powered and battery-powered vehicles, respectively.

To obtain the results in Figures B-1 and B-2, other components of the coal-to-vehicle transportation system were analyzed in a manner similar to that used in Reference 1 for coal liquefaction. Published information on the efficiency, costs, or materials requirements were used for calculations of the energy inputs and outputs of the pipeline[2], refinery[3], and distribution[3] components of the synfuel system, and the electric generation[4], transmission[4], and distribution[5] components of the change the energy advantage of the electric alternative into a significant economic advantage.

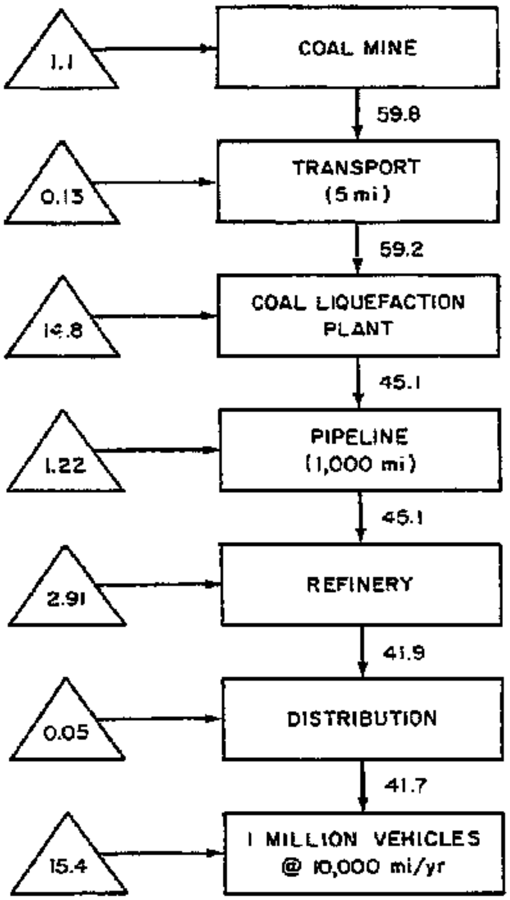
B. Energy Efficiency

To compare the energy resource utilization efficiency of the synfuel and electric alternatives, we have attempted to place the systems supporting these two transportation modes on common ground. In the systems chosen for analysis, the primary resource is subbituminous coal surface mined in the Powder River Basin of Wyoming. The coal is assumed to be converted to electricity or synthetic crude oil near the minemouth. The electricity or syncrude is then transported 1000 miles (corresponding roughly to Chicago or St. Louis) by high voltage power line or pipeline. The electricity is distributed to homes or businesses, where it is used to charge vehicles utilizing lithium-sulfur batteries. The syncrude is refined to gasoline and other products, and the gasoline is distributed to filling stations for use in conventional automobiles. In both cases, the end use is assumed to be 1 million vehicles operating for one year over an average distance of 10,000 miles, a total of 10 billion VMT.

The gasoline required for propulsion of the conventional vehicles could be provided by refining the syncrude from a coal liquefaction plant of about 50,000-B/D capacity, assuming a typical refinery gasoline output of 50%. In the case of electric vehicles, the required electricity could be produced by a 750 MW power plant operating at 70% of capacity.

1. Method of Calculating Energy Resource Consumption

The calculation of the energy resource consumption efficiency of automobile transportation proceeds in a manner similar to that used in the calculation of the net energy yields of synthetic liquid fuel technologies in Reference 1. In that study, the appropriate figure of merit was the "net energy ratio," which is defined as the ratio of the energy content of the product of an energy conversion process to the sum of the energy inputs for constructing, operating, and maintaining the conversion facilities, and including the energy lost during the conversion process. These energy inputs are expressed in the form of resource energy, that is,

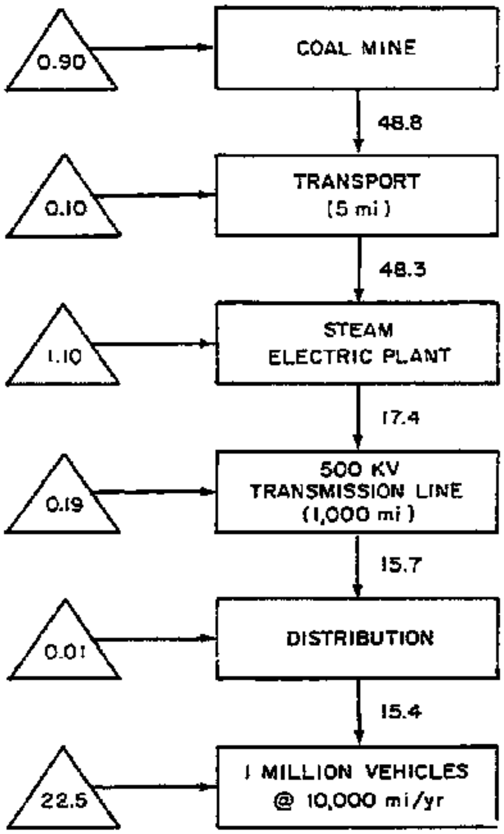


$$\text{OVERALL VEHICLE ENERGY EFFICIENCY} = \frac{E_{coal} + \Sigma E_i}{10^{10}\ \text{vehicle-mi}} = \frac{(59.8 + 35.6) \times 10^{12}}{10^{10}} = 9540\ \text{Btu/mi}$$

Note: All energy values are in 10^{12} Btu/yr
E_i refers to energy inputs in triangles.

Rectangles represent system components. Triangles represent energy requirements for construction, operation, and maintenance of components. Vertical arrows represent flows of energy through the system, while horizotal arrows represent external energy inputs.

FIGURE B-1. ENERGY CONSUMPTION OF COAL-TO-SYNFUEL VEHICLE SYSTEM



$$\text{OVERALL VEHICLE ENERGY EFFICIENCY} = \frac{E_{coal} + \sum E_i}{10^{10}\ \text{vehicle - mi}} = \frac{(48.8 + 24.8) \times 10^{12}}{10^{10}} = 7360\ \text{Btu/mi}$$

Note: All energy values are in 10^{12} Btu/yr

E_i refers to energy inputs in triangles.

Rectangles represent system components. Triangles represent energy requirements for construction, operation, and maintenance of components. Vertical arrows represent flows of energy through the system, while horizontal arrows represent external energy inputs.

FIGURE B-2. ENERGY CONSUMPTION OF COAL-TO-ELECTRIC VEHICLE SYSTEM electric system. An important component of the energy use is that required for the production and maintenance of the automobile. The energy requirements for manufacture of conventional automobiles has been calculated by Berry and Fels.[6] Their number has been used directly, except that the energy requirement for the vehicle considered in this report has been scaled by the ratio of the weight of the vehicle considered here (2000 lb) to the vehicle weight they used (3500 lb). Energy requirements for vehicle maintenance, oil, tires, and so forth were taken from Reference 7.

The calculation of the manufacturing energy requirements of the battery powered vehicle is more difficult. Basically, we have assumed that the conventional vehicle is modified by removing the engine and drive train and adding the 570-lb lithium-sulfur battery, electric motor, and controllers. The quantities of materials removed from the conventional vehicle and added for the electric vehicle (with the exception of the battery) were obtained from Reference 8. Energy requirements for these materials are readily calculated. The most difficult, and least certain calculation of energy requirements is for the lithium-sulfur battery. This is because the lithium-sulfur battery represents an area of advance technology that is currently only in the R&D stage. In Reference 9, however, the materials requirements and approximate expected costs (in late 1973 dollars) for a production model lithium-sulfur battery were estimated. Using these figures, an energy requirement of 80 million Btu was estimated for the manufacture of a 570-lb lithium-sulfur battery. This figure represents approximately one-half of the total energy estimated for production of the electric car (155 million Btu). The battery estimate is expected to have large error limits, on the order of ± 50%. The maintenance and tire replacement energy requirements were assumed to be the same as for the conventional vehicle. The engine oil requirement was omitted.

Figure B-3 shows the parametric variation of total resource energy requirements with propulsion energy requirements. This figure displays the sensitivity of total energy consumption to attainment of the vehicle design goals. The sensitivity of the electric vehicle total energy requirement to propulsion energy requirement is about 73% greater

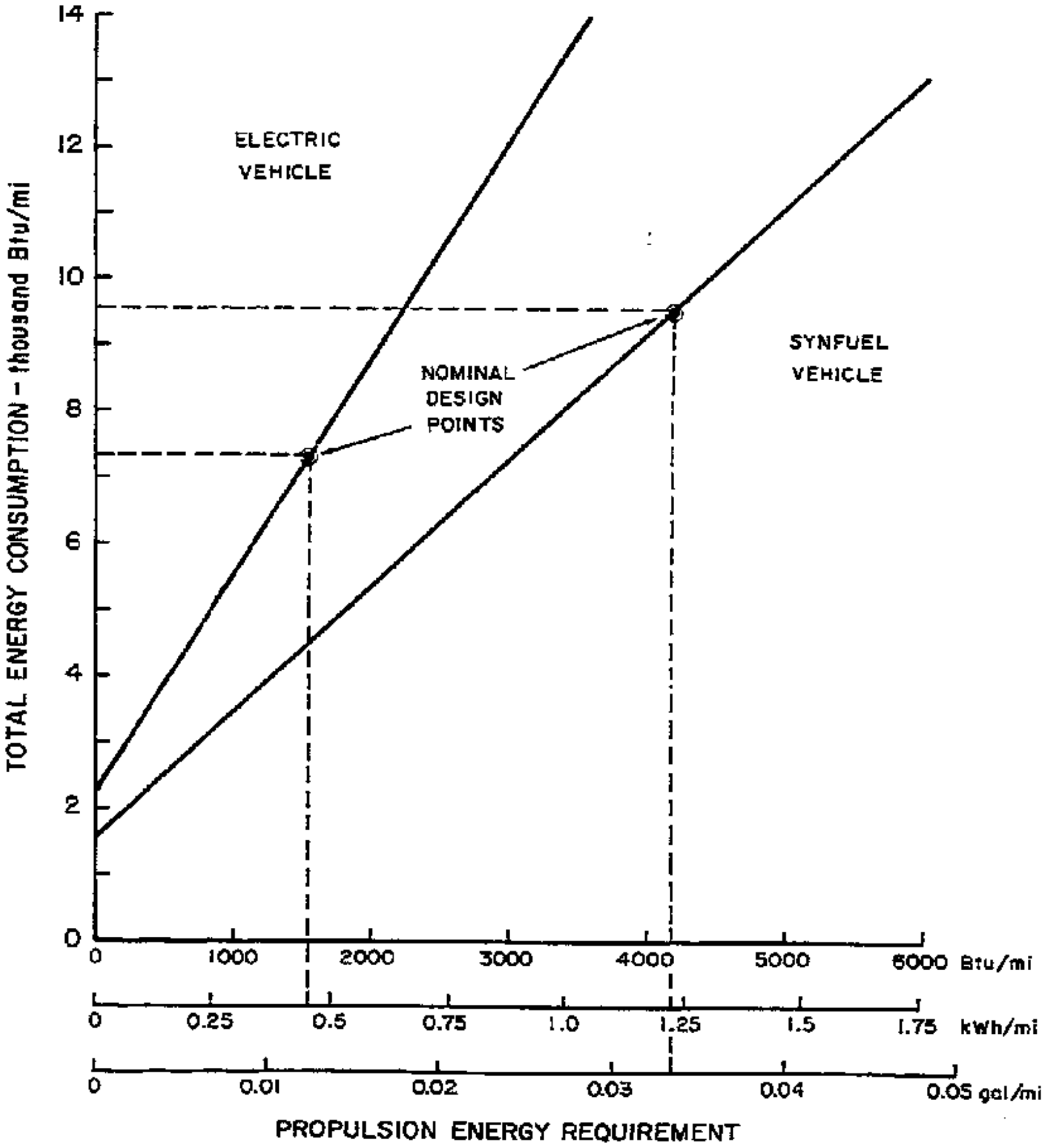


FIGURE B-3. TOTAL ENERGY COMPARISON OF ELECTRIC- AND SYNTHETIC FUEL-POWERED VEHICLES than for the synfuel vehicle, primarily because of the inefficient coal-to-electricity conversion step.

Changes in design goals could have significant effects on the relative resource energy consumption of the two systems. For example, a conventional vehicle achieving an average 40 mi/gal fuel economy would consume about the same resource energy as an electric vehicle requiring 0.50 kWh/mi. These figures represent a substantial improvement over current conventional vehicle capabilities and a relatively small slippage in battery design goals.

The achievement of the 0.45 kWh/mi design goal for electric cars will mean a significant improvement in overall energy consumption compared with synthetic fuel-powered vehicles attaining an average fuel economy of 30 mi/gal. The battery-powered vehicle will consume 23% less resource energy per mile. If one considers only the direct coal input into electric power plants or liquefaction plants for the purpose of vehicle propulsion, the energy consumption is less by 18% for the electric vehicle.

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APPENDIX B

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Appendix C

SENSITIVITIES OF DELIVERED AUTOMOTIVE ENERGY COSTS TO CHANGES IN THE COSTS OF SYSTEM COMPONENTS

Figures C-1 to C-6 show the sensitivity of the total energy cost to the changes in the value used for various cost components. These displays also indicate the degree to which the total cost is sensitive to the changes in component costs. Using the information presented in these displays, we can determine the impact of uncertainty in the cost estimate for each component on the total cost. Additionally, the displays reveal when improved information will produce greater payoffs. For example, Figure C-1 indicates that the total cost of supplying gasoline derived from syncrude is most sensitive to the estimates of coal conversion cost, followed by cost for product distribution, refining, coal extraction, coal transportation, product transportation, and crude transportation. Therefore, additional resources expended to improve the cost estimates for coal conversion and product distribution will be more worthwhile than attempting to improve the information on the costs to transport crude petroleum.

Comments about the sensitivity of the total cost of supplying automobile fuel from each option with reference to each figure follow. These comments, as well as the figures, correspond to the maximum cost pathway for each option.

Syncrude--Figure C-1

The total cost is most sensitive to the estimate of cost for coal conversion. In fact, the sensitivity to the coal conversion cost is more than twice that of all other components put together. The total cost is not so sensitive to coal transportation as it is generally thought to be.

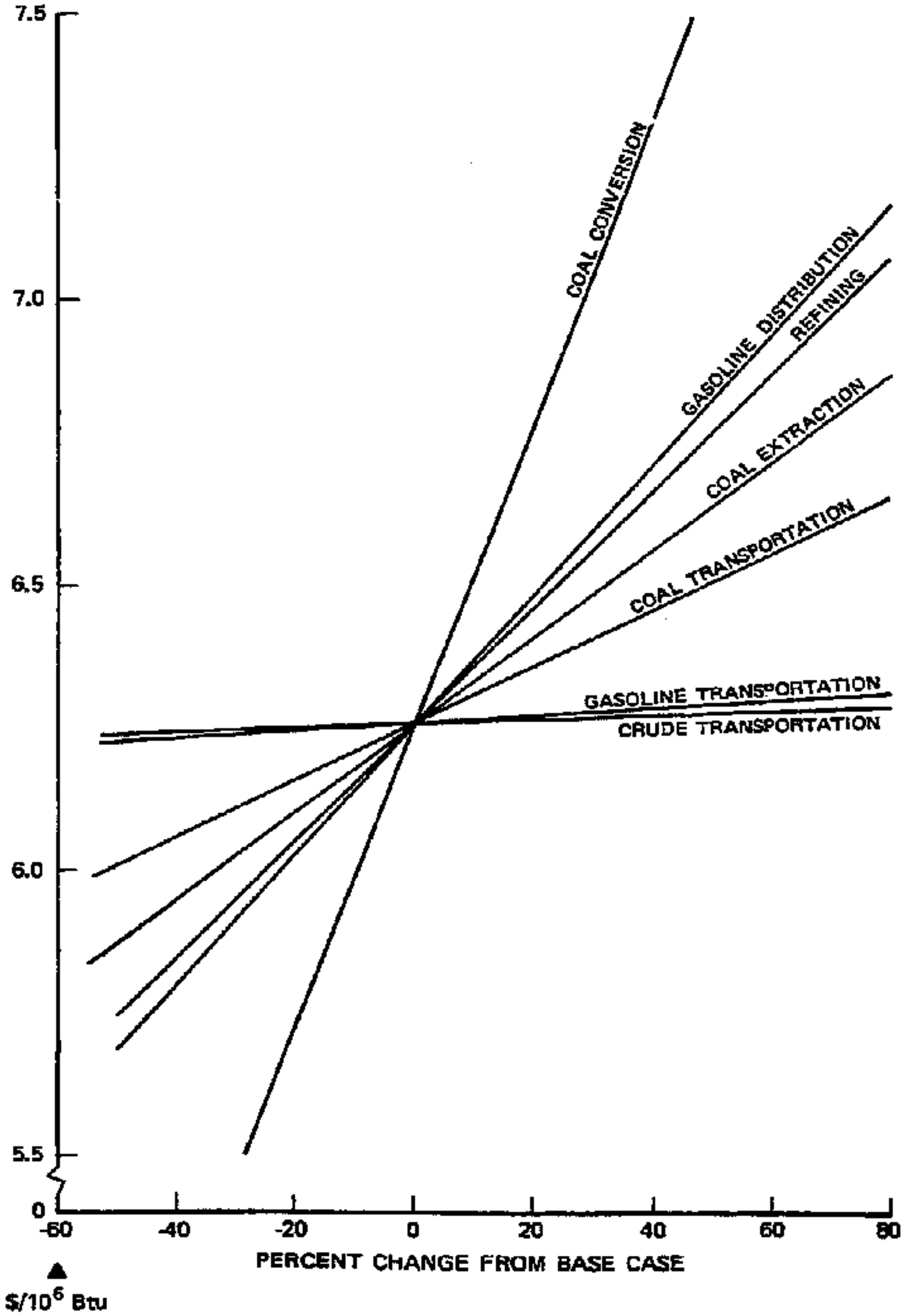

FIGURE C-1. COST SENSITIVITY: SYNCRUDE PLANT IN BEAUMONT, TEXAS USING APPALACHIAN UNDERGROUND COAL

Methane--Figure C-2

The total cost is most sensitive to the changes in the cost of coal conversion, followed by product distribution, methane liquefaction, coal extraction, coal transportation, and product transportation. However, differences in the sensitivity to the changes in coal conversion cost and other component costs are not so great as for syncrude.

Much can be gained by improving the estimate for coal conversion, methane liquefaction, and liquefied methane distribution.

Methanol--Figure C-3

The total cost is most sensitive to the variation in coal conversion cost, followed by costs of product distribution, coal extraction and transportation, and product transportation. In fact, the sensitivity to change in coal conversion cost is more than twice that of all other components combined.

Fischer-Tropsch Gasoline--Figure C-4

The total cost is most sensitive to cost of coal conversion, followed by product distribution, coal transportation, coal extraction, and product transportation. Again, the sensitivity to changes in coal conversion cost predominate, but the differences in sensitivity among changes in coal extraction, coal transportation, and product distribution are not significant.

Hydrogen--Figure C-5

The total cost is almost equally sensitive to the changes in costs for liquefaction, liquefied product distribution, and coal conversion. The total cost is practically insensitive to changes in cost for coal transportation and extraction.

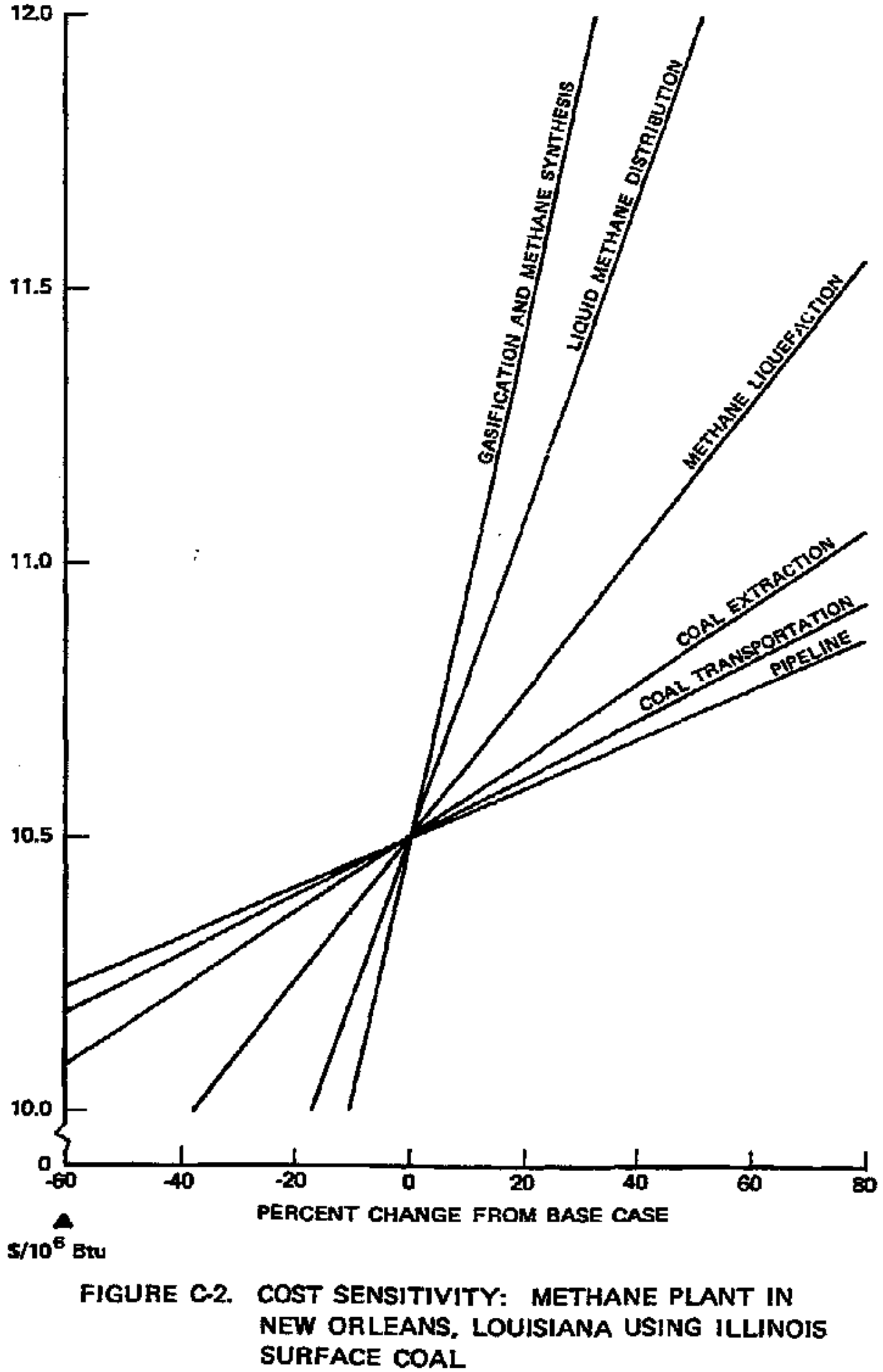

FIGURE C-2. COST SENSITIVITY: METHANE PLANT IN NEW ORLEANS, LOUISIANA USING ILLINOIS SURFACE COAL

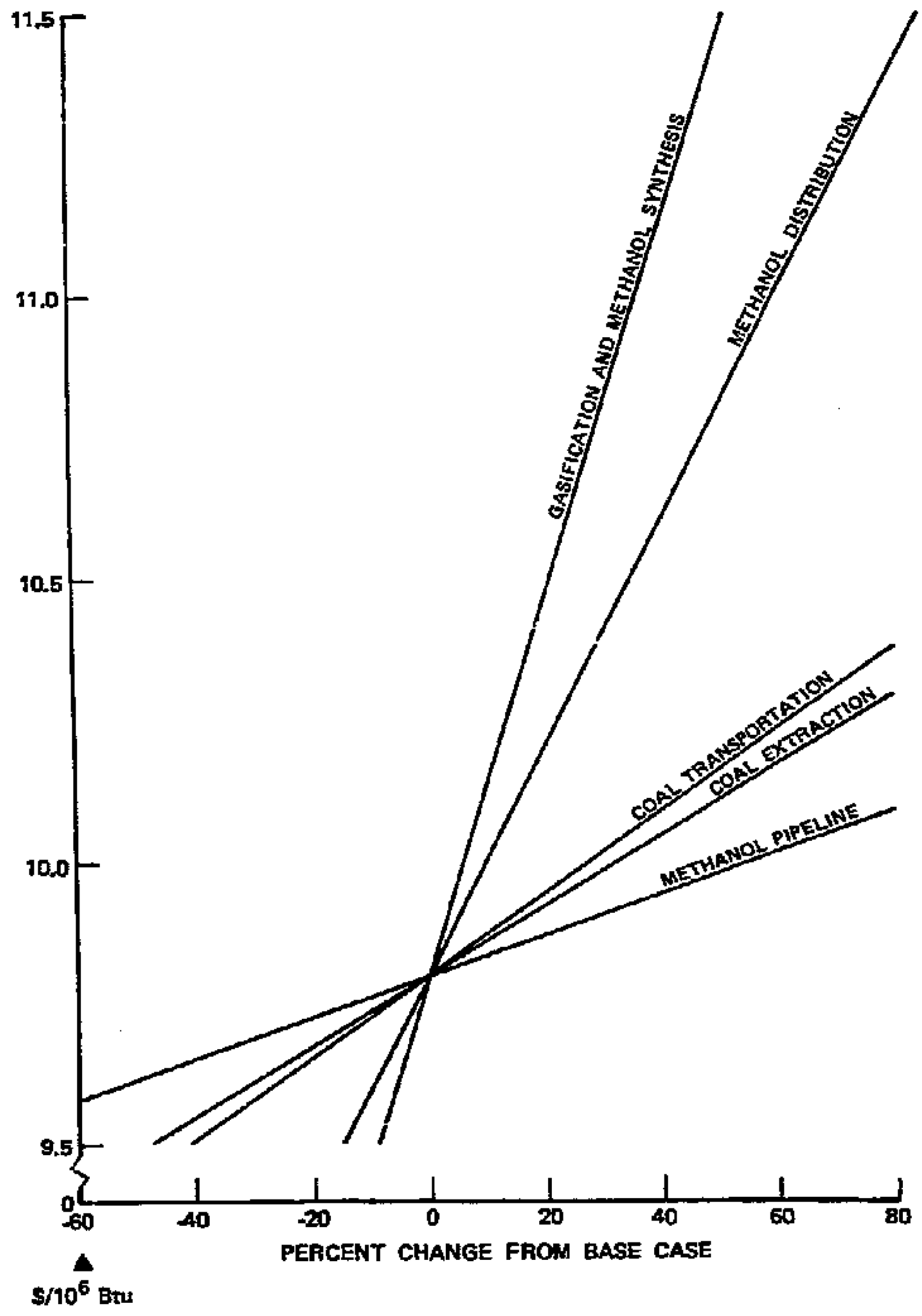

FIGURE C-3. COST SENSITIVITY: METHANOL PLANT IN GALVESTON, TEXAS USING APPALACHIAN SURFACE COAL

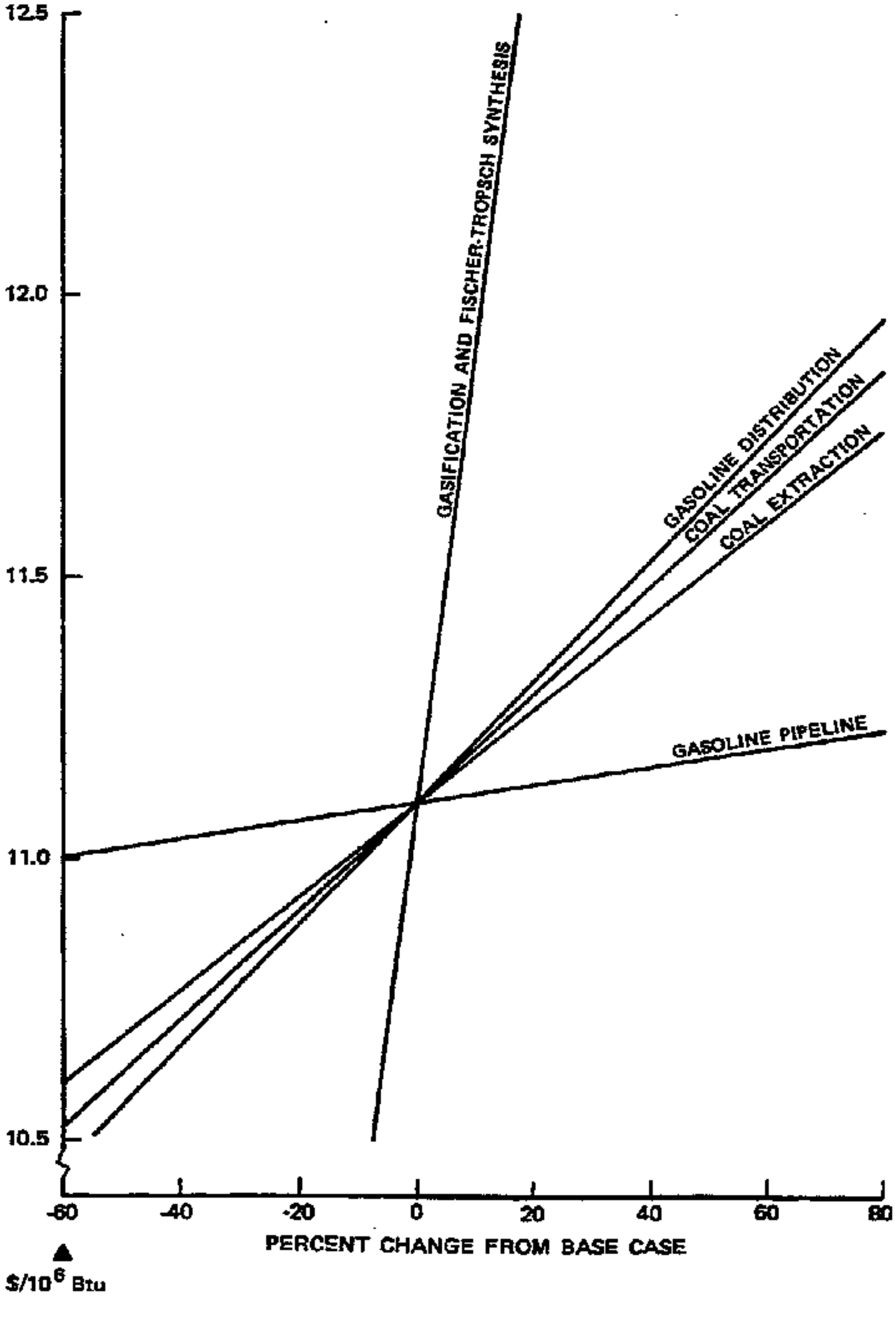

FIGURE C-4. COST SENSITIVITY: FISCHER–TROPSCH GASOLINE PLANT IN GALVESTON, TEXAS USING APPALACHIAN SURFACE COAL

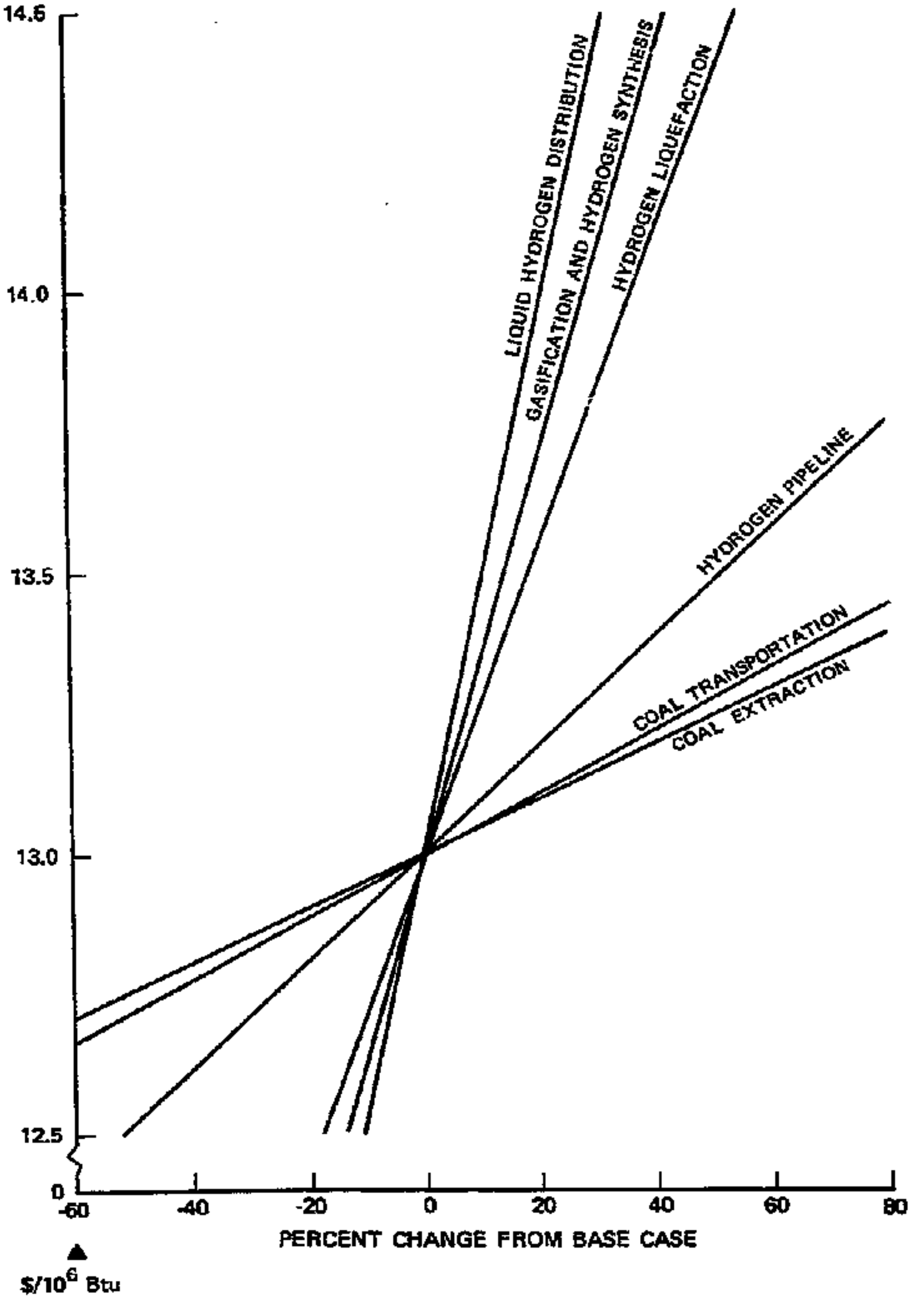

FIGURE C-5. COST SENSITIVITY: HYDROGEN PLANT IN GALVESTON, TEXAS USING APPALACHIAN SURFACE COAL

Electricity--Figure C-6

The total cost is most sensitive to changes in costs of transmission and distribution, followed by generation cost, and coal transportation and coal extraction costs.

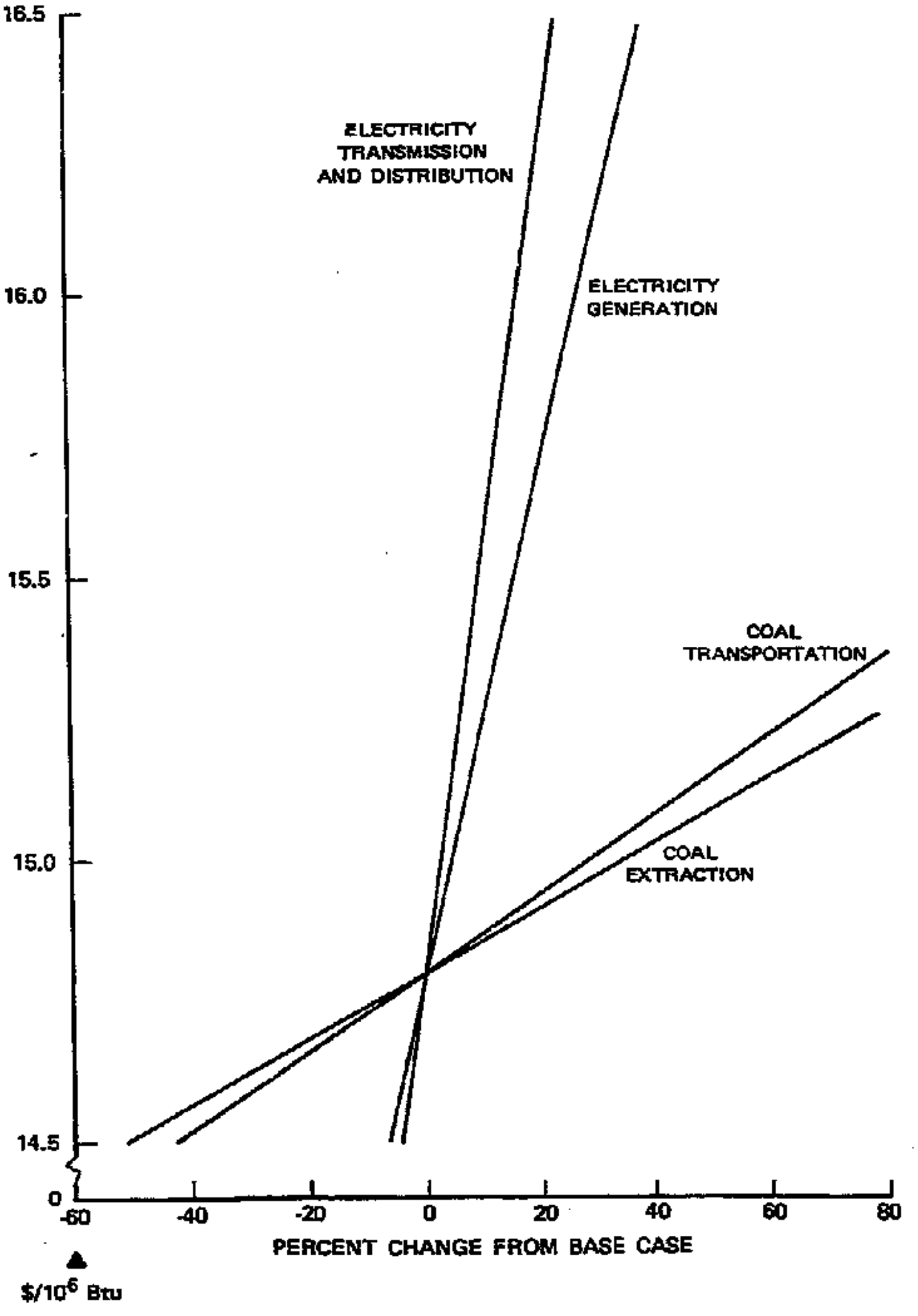

FIGURE C-6. COST SENSITIVITY: COAL FIRED POWER PLANT IN BOSTON, MASSACHUSETTS USING APPALACHIAN SURFACE COAL

Appendix D

CALCULATIONS OF ENERGY REQUIREMENTS FOR COMPONENTS OF AUTOMOTIVE ENERGY SUPPLY SYSTEMS

Coal Mining

In Chapter 5 of Volume II of this series, it was determined that for a western surface mine of moderate stripping ratio, the primary energy resource input requirement is about 1.6×10^{12} Btu for a 5×10^6 ton/yr coal mine.[1] Therefore, the energy input per 10^6 Btu of coal recovered is 3.2×10^5 Btu/HV, where HV is the heating value of the coal in 10^6 Btu/ton. Development Sciences, Inc., has calculated an energy input requirement of 1.6×10^{12} Btu for a 6.7×10^6 ton/yr surface mine,[2] or 2.4×10^5 Btu/HV per 10^6 Btu of coal. Although there are wide differences among various surface mines, including stripping ratios, ease of reclamation, and the like, we use an average figure of 2.8×10^5 Btu/HV per 10^6 Btu of coal mined.

For underground mining, Development Sciences, Inc., has calculated a figure of 1.7×10^{12} Btu energy input for a 5×10^6 ton/yr underground mine employing conventional room and pillar mining to recover coal from a 6-ft seam.[2] This figure translates to 3.4×10^5 Btu/HV per 10^6 Btu of coal mined.

Coal Transport

The four coal transportation modes considered are truck, unit train, slurry pipeline, and barge. The last three modes would be employed in long-distance coal transport, whereas trucks would only be used when the conversion facility is within a few miles of the mine.

Fuel consumption for trucks varies widely, depending on the size of the truck, distance traveled, road conditions, and similar considerations. For large trucks, we have assumed a generally accepted total energy input of 2000 Btu/ton-mi. Thus, the energy consumed in a hauling application is (2000 x L/HV) Btu per 10^6 Btu hauled, where L is the haul distance in miles.

For unit trains, many conflicting data exist. However, three analyses which were carefully carried out yielded figures of 430, 340, and 290 Btu/ton-mi of diesel fuel consumption for long-distance unit trains.[2,3,4] Because we have no firm basis for choosing one over the other, we use an average of 385 Btu/ton-mi. Converting this figure to primary resource consumption and adding 30 Btu/ton-mi for train construction and maintenance, as well as track maintenance, the total is 490 Btu/ton-mi.[2]

The energy inputs for a coal slurry pipeline are based on an analysis of the proposed 1000-mi Wyoming-Arkansas pipeline, which would have a capacity of 25 x 10^6 ton/yr. The electric pumps and coal slurrying equipment would consume 0.054 kWh/ton-mi.[3,5] Converting this to primary resource consumption gives 680 Btu/ton-mi. The construction and maintenance of the pipeline add another 75 Btu/ton-mi, for a total of 760 Btu/ton-mi.

Energy inputs for coal barges are based on a diesel fuel consumption of 220 Btu/ton-mi.[6] Converting to primary resource energy and adding barge construction and maintenance result in a total of about 300 Btu/ton-mi.

Coal Conversion

For our analyses, the energy consumption by coal conversion technologies may be expressed by two quantities: the efficiency of the process, and the direct and indirect ancillary energy required to construct and operate the conversion facility. The process energy efficiency is not simply the thermal efficiency of the coal-to-product conversion. Rather, it is a total energy efficiency, defined as the heat content of the product divided by the heat content of all the coal used in the facility, including that burned to provide steam and heat. This definition is arbitrary because the coal used as plant fuel could be just as easily included in the ancillary energy requirement. However, this definition is consistent with our cost analysis, which uses total energy efficiency to determine the contribution of coal cost to the total conversion cost. When the engineering analysis of a particular technology assumes the purchase of electricity for plant operation, the coal required to produce this electricity has been assigned to the energy input requirements, based on a coal-to-electricity thermal efficiency of 35%.

Coal liquefaction using the H-coal process and coal-to-methanol conversion using Lurgi gasification have been analyzed in Volume II. For coal liquefaction, the overall coal-to-syncrude efficiency is 0.63 for western subbituminous coal, and 0.68 for eastern bituminous coal. In both cases, the indirect ancillary energy requirement is 2.7×10^4 Btu per 10^6 Btu of product.

For methanol production using subbituminous coal, the overall energy efficiency is 0.41, including by-product naphtha in the output. The indirect ancillary energy requirement is 3.5×10^4 Btu per 10^6 Btu of product. An engineering analysis of methanol production from Illinois bituminous coal using a Koppers-Totzek gasifier has been carried out.[7] Based on this analysis, the overall energy efficiency is calculated to be 0.40, and the indirect ancillary energy requirement is 4.5×10^4 Btu per 10^6 Btu of product.

We have derived energy requirements for converting coal to SNG from data published on the planned construction of two SNG plants in New Mexico.[8,9] The plant designs are based on the use of Lurgi gasification technology. The resulting energy conversion efficiency is about 0.56. A published engineering cost analysis has been used to derive an indirect energy requirement of 2.7×10^4 Btu per 10^6 Btu of SNG produced.[10] There are no equivalent analyses for the gasification of eastern bituminous coal. However, estimates of energy efficiency for more advanced gasifiers are suitable for eastern coal. These efficiences range from around 55 to 62%.[11] However, in the absence of more substantial data, the energy requirements for eastern bituminous coal gasification are assumed to be the same as those for western subbituminous.

The use of advanced gasification technology on different processing schemes, such as the regasification of byproduct tars and oils, could increase the overall efficiency from both eastern and western coal. However, the figure presented here will be retained since it is consistent with the cost estimates discussed in Chapter 3.

The production of hydrogen from coal is a simpler operation than the production of SNG. Because the products of coal gasification are primarily CO and H_2, the only major remaining steps are the further reaction of CO with the steam to produce H_2 and CO_2, followed by the removal of CO_2 and other impurities. The overall efficiency for coal-to-hydrogen conversion is 0.59,[12] assuming the use of low-pressure, high-temperature gasifiers that minimize methane production. The other indirect energy requirements amount to 3.7×10^4 Btu per 10^6 Btu of hydrogen produced.[13]

Coal gasification, followed by Fischer-Tropsch synthesis to produce gasoline and chemical by-products, is inefficient. Under optimum conditions, the processing of gasifier by-products--tar, tar oil, and naphtha--produce additional gasoline; the overall efficiency for producing motor fuels, including a small amount of diesel fuel, is about 0.30.[10] Due to the high capital and operating costs for this process, the indirect energy requirement is correspondingly high in relation to other conversion technologies--4.9×10^4 Btu per 10^6 Btu of motor fuel.

Using coal-fired boilers and steam turbines to generate electricity is a well-established technology for which it is relatively easy to estimate energy consumption figures. The thermal efficiency for such plants can approach 40%. However, due to the power requirements for ancillary equipment such as stack gas scrubbers, the net efficiency can be as much as 10% lower. We have used a conservative estimate of 0.35 net efficiency for a modern base load steam electric plant. This figure applies to both low-sulfur, low-heating value western coal and to high-sulfur, high-heating value eastern coal.[14] The larger coal-handling requirements in the former case tend to balance out the stack gas scrubbing requirements in the latter case as they affect net efficiency. The indirect energy requirement per 10^6 Btu of electricity generated is 6.3×10^4 Btu.[14]

In-Situ Gasification

The gasification of coal in place by injection of steam and oxygen is known as in-situ gasification. This process has the potential for substantially reducing both the costs and environmental impacts of producing clean fuels from coal. The expenses and impacts of coal mining are eliminated, as is the requirement for highly capital-intensive aboveground gasification equipment. After synthesis gas has been produced, however, it must be brought to the surface for purification and subsequent production of methane, methanol, or other products with conventional equipment.

The Lawrence Livermore Laboratory (LLL) has performed conceptual engineering and cost analyses of producing methane[15,16] and methanol[17] by in-situ gasification of deep, thick western coal seams. They consider this method a promising alternative to the mining of these seams, for which there is as yet no suitable technology. Because little development has been carried out on the LLL in-situ method, the quantitative aspects of the technology must be considered speculative.

In the LLL analysis of producing SNG (or methane) by in-situ gasification, the overall coal-to-methane efficiency of the process is 0.76. This figure excludes the mined coal required to produce steam and power. Because of the different nature of this coal source, its energy value is added to the indirect ancillary energy requirement of 4.1×10^4 Btu for a total ancillary energy requirement of 2.3×10^5 Btu per 10^6 Btu of methane product.*

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*The additional coal requirement specified in Reference 15 was derived from a coal requirement for steam and power for an aboveground Lurgi gasification plant that was one-third too low. Therefore, the coal requirement was increased by 50% for this analysis. The methanol coal requirement in Reference 17 was also too low and was ratioed to the methane coal requirements by the ratio of ancillary coal requirements for aboveground conversion plants.

For methanol, the overall efficiency of converting in-situ coal to the final product is 0.65. The ancillary energy requirement, including additional coal to produce steam and power, is 4.6×10^5 Btu per 10^6 Btu of methanol.

The efficiencies quoted above are based on the coal actually affected by gasification. They do not include the coal that must be left in place to form barriers between the underground gasification chambers. The inability to recover this coal is analogous to conventional underground mining in which some coal is left in place to support the mine roof.

Product Transportation

All liquid and gaseous fuels discussed in this section can be transported via pipeline. Indeed, pipelines are currently the most common form of shipment for crude oil, petroleum products, and natural gas. Methanol, which has about the same density as gasoline, could easily be shipped through existing pipelines. Hydrogen could be shipped through natural gas pipelines, although some modifications would be required, and the operating conditions would be different.

The calculation of energy requirements for crude oil pipelines is based on national statistics that indicate that the average pipeline diameter is about 18 in.[18] The average motive power requirement is 154 hp/mi for this size pipeline.[19] Nationally, about 76% of pipeline pumping requirements are met by electric motors, 16% by diesel-powered motors, and 8% by gas-driven motors.[18] Assuming an electric motor power efficiency of 80%, and an energy consumption for gas- and diesel-powered engines of 9250 Btu/hp-hr,[2] the total resource energy requirement is 1720 Btu/ton-mi, or 48 Btu/10^6 Btu-mi. The latter figure includes 1.2 Btu/10^6 Btu-mi for pipeline construction and maintenance.[2] Crude oil is assumed to have a density of 7.5 lb/gal, which corresponds to a light (bottoms-free) syncrude oil.

The pipeline transport of refined products such as gasoline requires about 60 hp/mi, for an 18-in. pipeline.[19] If the total resource energy requirement is calculated like that for crude pipelines results, a figure of 540 Btu/ton-mi, or 15 Btu/10^6 Btu-mi for gasoline, including pipeline construction and maintenance, results. For a methanol pipeline, it is assumed that the energy requirements per ton-mile are the same as for gasoline. However, because methanol has approximately half the energy content as a comparable unit weight of gasoline, the resulting energy consumption is approximately 30 Btu/10^6 Btu-mi.

For natural gas pipelines, compressors use some of the gas as fuel. Thus, transportation energy consumption can be expressed as a transmission efficiency dependent on the pipeline length. For typical gas pipelines with diameters of 30 to 36 in. the transmission energy requirement is about 36 Btu/10^6 Btu-mi, assuming a compressor efficiency of 9250 Btu/hp-hr.[2] Thus, the gas pipeline transmission efficiency may be expressed as $1.0 - 3.6 \times 10^{-5}$ L. The ancillary energy requirement for gas pipelines (construction plus maintenance) is about 4 Btu/10^6 Btu-mi.[2]

For a hydrogen pipeline operating at the same pressure as a natural gas pipeline but otherwise optimized to carry hydrogen, a 25% increase in diameter and a 43% increase in compressor power are required to deliver the same amount of energy.[20] The resulting fuel requirement is 52 Btu/10^6 Btu-mi. Assuming that hydrogen is used as the compressor fuel, the effective pipeline efficiency is $1.0 - 5.2 \times 10^{-5}$ L. The construction and maintenance energy requirement is about 5 Btu/10^6 Btu-mi.

The transmission and distribution of electricity have an average efficiency of 0.91, based on national statistics.[21] Because regional data were not available, this figure was used in all calculations. The construction and maintenance requirements for a high-voltage transmission line loaded at 1000 MW is approximately 12 Btu/10^6 Btu-mi.[14] The average transmission distance is assumed to be 500 mi.

Refineries

To calculate refinery energy consumption, we can use either data from the analysis of individual refineries or nationwide refinery statistics. Considerable variation from one refinery to the next occurs, and modifications in refinery operations required for refining syncrude would vary considerably depending on the type of crude the refinery accepts, the usual product slate of the refinery, and so forth. Therefore, to average such variations, we use nationwide refinery statistics available in the U.S. Bureau of Mines Mineral Industry Survey's Annual [1973] Petroleum Statement.[22] In addition, the indirect energy requirements for refinery construction and operation have been calculated by Development Sciences, Inc.[2]

In 1973, 4.58 billion barrels of crude petroleum (including a small amount of imported unfinished oils) were refined in the U.S. The refining of this petroleum, plus the blending of 308 million barrels of natural gas liquids and other hydrocarbons such as tetraethyl lead, produced 5.06 billion barrels of refined products. The typical, slight volume expansion that occurred was due to processes such as hydrotreating in which heavy oils were converted to lower density products.

Of the 5.06 billion barrels produced, 488 million barrels consisting mainly of fuel oil and refinery gases, were consumed as fuel in refinery operations. In addition, 1.11 trillion cubic feet of natural gas, 41 million barrels of liquefied petroleum gases (LPG), 7.9 million tons of coal, 80 billion kWh of electricity, and 41 billion lb of steam were purchased for refinery operations. Assigning the heating values to crude oil and products specified in the Bureau of Mines Annual Petroleum Statement and adding the indirect energy requirements calculated by Development Sciences, Inc., we arrive at the following figures: On the basis of crude oil refined to products (blending of natural gas liquids is not included), the energy efficiency of refining is 0.96, and the external requirement is 6.2×10^4 Btu per 10^6 Btu of products. This latter figure is based on net yield of products, and does not include those products consumed as refinery fuel in the denominator. (See Appendix A for a more detailed accounting.)

Approximately half of the product yield from crude refining is gasoline or diesel fuel used in automotive transportation. For the calculations in this Appendix, we assume that the energy consumed in refining is attributable to all products equally and is apportioned according to their relative energy contents. Although, this is undoubtedly not the case in actual refining operations, the calculation of energy consumption based on each type of product produced would be an extremely complicated task, and the results would be sensitive to individual refinery and crude oil parameters. Thus, the figures derived from aggregate refinery statistics appear to be the most reasonable for our purposes.

Methane and Hydrogen Liquefaction

To use methane or hydrogen as automotive fuels requires storage of these chemicals within the vehicle in a way which minimizes weight and volume requirements. The storage of gases in high-pressure cylinders—the method employed in many industrial applications—is generally unsuitable for automotive applications because of the excessive weight and volume of the cylinders. The major alternative is the storage of methane or hydrogen as a liquid in a cryogenic vessel, although metal hydride storage of hydrogen has also been considered. When stored as a liquid, methane has a somewhat higher energy content per unit weight than gasoline, and hydrogen has 3 times the energy content. However, the volumetric requirements for storage of these fuels would be considerably greater than that for gasoline on an energy equivalent basis—5.5 times greater for liquid methane and 3.5 times greater for hydrogen.

To liquefy methane and hydrogen for automotive fuel exacts a considerable energy penalty. For storage as a liquid, methane requires a temperature of 112K (-259°F), whereas hydrogen must be cooled to 20K (-423°F). To produce liquefied natural gas (LNG) from gas at pipeline pressure requires an amount of fuel equal to about 17% of the gas input.[11] Because the gas itself is typically used as a fuel in such liquefaction plants, this energy requirement affects the liquefaction efficiency, which is thus 0.83 because other losses are negligible. The indirect energy requirements for plant construction and operation, plus a small electricity requirement, amount to 0.6×10^4 Btu per 10^6 Btu of liquified methane.[23]

For hydrogen, the liquefaction energy requirement is much higher because of the greater refrigeration requirement. The energy input required for hydrogen liquefaction is about 30% of the energy content of the hydrogen itself.[24] This figure varies with plant capacity, but it would be typical for the medium-size plants that would supply automobile filling stations. Typically, electricity supplies the energy for hydrogen liquefaction facilities. Referring the electricity consumption to fossil fuel requirements results in an overall consumption of resource energy of 1.1×10^6 Btu per 10^6 Btu of hydrogen liquefied. Indirect energy requirements are on the order of 1% of the hydrogen energy content and thus do not add appreciable amounts to the previous figure. The energy efficiency of liquefaction is essentially 1.0 because hydrogen boil-off is captured and reliquefied.

Fuel Distribution

The calculation of energy consumption for distributing fuels to their final use point is made difficult by the lack of data and the many variations in fuel distribution networks. In any case, requirements for this part of the system are likely to be small.

A calculation of fuel consumption for gasoline tank trucks delivering fuel in the Denver metropolitan area indicates that, on the average, 0.2×10^4 Btu of diesel fuel is consumed for every 10^6 Btu of gasoline delivered.[4] This is equivalent to 0.24×10^4 Btu of resource energy. If the indirect-energy consumption in the fuel distribution system (including bulk storage facilities, tank trucks, and filling stations) is at most no greater than the direct fuel requirement, we may assume an upper limit of 0.5×10^4 Btu of energy consumed per 10^6 Btu of fuel delivered. Although some small losses take place in the system, we assume that the energy efficiency is essentially 1.0.

For methanol distribution, we assume twice the direct fuel requirement because of the low energy density of methanol. Thus, 0.7×10^4 Btu is consumed per 10^6 Btu of methanol delivered.

For liquid methane and hydrogen distribution, the energy requirements are somewhat greater because of the necessity of cryogenic storage facilities and tank trucks. In addition, boil-off from storage vessels results in greater energy losses. Storage of hydrogen in large cryogenic vessels suitable for filling stations (50,000 - 100,000 gal) results in boil-off losses on the order of 0.1% per day.[12] If an average storage time of 1 week and additional losses of 1% due to transfer and transportation are assumed, an energy efficiency of 0.98 seems reasonable. We assume a distribution efficiency of 0.99 for liquid methane because its boiling point is higher and its boil-off rate less.

We arbitrarily assume that the indirect energy requirements for liquid methane and hydrogen are about twice those for gasoline—1.0×10^4 Btu per 10^6 Btu delivered.

For electricity distribution, the main energy losses are in the step-down transformers that reduce the high line voltage used in long-distance transmission to the 110 V used in homes and businesses. These losses are included in the transmission and distribution efficiency of 0.91 discussed above. The indirect energy requirements are expected to be small—on the order of 0.1×10^4 Btu per 10^6 Btu delivered.

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