EVALUATION OF TECHNOLOGICAL DATA IN THE
DFI AND PIES MODELS

N. BHAGAT, M. BELLER, A. HERMELEE,
J. WAGNER, AND J. LAMONTAGNE

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By the
TECHNOLOGY ASSESSMENT GROUP
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS

BROOKHAVEN NATIONAL LABORATORY
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ABSTRACT

This report evaluates the data used in two of the models available to the Energy Information Administration (EIA). Specifically, the study involves updating, reviewing, and documenting the technological data on primary energy conversion, transportation, distribution and end-use conversion. The major focus is upon data used in the Decision Focus, Inc. (DFI), LEAP model. This is an abbreviated version of the Gulf-Stanford Research, Inc., energy model developed to assess the potential future impacts of synthetic fuels in the U. S. energy system. A parallel effort assesses the data used in the model commonly known as the Project Independence Evaluation System (PIES).

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I. INTRODUCTION

The purpose of this report is to verify the data used in two of the models available to the Energy Information Administration (EIA). The data under study are primarily technological, pertaining to capital construction costs, operating and maintenance costs, conversion efficiencies, and technological change limits (i.e., increased efficiencies and cost reductions anticipated as a result of experience gained during the construction and operation of complex devices). Although the structure of the models and the potential market penetration of new technologies are also under study for a specific model, they will be reported upon in a separate document.

This analysis covers two of the models under review by EIA. The major focus is upon data used in the Decision Focus, Inc. (DFI), LEAP model. This is an abbreviated version of the Gulf-Stanford Research, Inc., energy model developed to assess the potential future impacts of synthetic fuels in the U.S. energy system. The data used in the DFI model are referred to as Stanford Research Institute (SRI) data in this report since they were derived from that source.¹ A parallel effort assesses the economic data used in the model commonly known as the Project Independence Evaluation System (PIES). The data for the two models under study in this task are to be placed under a common basis.

Process economics data from the SRI report for the following broad sectors have been analyzed in this report:

- Electric power generation
- Synthetic fuels
- Oil refining
- Transportation and distribution
- End-use conversion

These sectors have been dealt with individually in separate sections. Suggested data have been presented in tabular form along with the corresponding SRI data. A range of estimates is presented for suggested data for future technologies and a specific value, furnished for all technologies, is either documented or derived by using a methodology discussed in the text. The format of the data tables is essentially the same for all sectors. The five variables, explicitly contained in the tables, are briefly defined as follows (refer to SRI report for detailed discussion):

- Specific capital cost (SCC): capital cost of representative plant divided by annual output of representative plant. Units are dollars per million Btu per year. The SRI value is presented in 1975 dollars as it appears in ref. 1 and also in 1977 dollars, in which all other data are expressed.
- Unit size: rated capacity of the representative plant upon which the data are based.
- Total capital investment (TCI): capital cost of the representative plant, inclusive of owner's costs, specifically, interest during construction (IDC). Although this variable is not used in the SRI report, it is included in the tables because capital cost is generally expressed in this form.

- Specific operating cost (SOC): the operating and maintenance cost of the representative plant per unit output of the plant, in dollars per million Btu.
- Efficiency: total energy content of primary products divided by total energy content of primary feedstocks. If there are two or more inputs or outputs, auxiliary efficiency is defined in a similar way.

Some variables, considered in the SRI report but not explicitly included in data tables in this report, are the following:

- Year of availability: the year in which a viable industry using the particular technology could begin.
- Technological change on capital and efficiency: a variable defined by a pair of two-parameter exponential learning curves applied to capital cost and to efficiency. The two parameters applied to capital cost are

$$\text{Technological change limit} = \frac{\text{ultimate capital cost}}{\text{capital cost in year of availability}},$$

$$\text{Technology change rate} = \text{annual percentage change between capital cost in year of availability and ultimate capital cost.}$$

- Equity fraction: percent of capital financed by equity capital.
- Years to construct plant.
- Tax life: time over which original plant is depreciated for tax purposes.

Since evaluation of most of the above variables is judgmental, the SRI data were generally found satisfactory; therefore, in order to keep the tables compact, these variables were commented on only in cases of unacceptable values.

The PIES data, limited in scope because of their applicability only to short-term analysis, form a subset of SRI data. These are compared with estimates generated during the course of SRI data evaluation in separate tables. All the costs in this report are expressed in 1977 dollars. The Marshall and Swift (M&S) equipment cost index was used to convert capital and also operations and maintenance costs to a 1977 basis.

The capital cost information used in the DFI model is input in terms of specific costs expressed as \$/10⁶ Btu/yr and does not include interest during construction (IDC). IDC is computed internally in this model assuming certain values for various financial parameters, and is added to specific capital cost (SCC) to compute total capital investment (TCI). In this report, the suggested values for capital costs are expressed in terms of both SCC and TCI. SCC values can be used directly in the DFI model in conjunction with exogenously specified values of financial parameters for the computation of IDC. TCI values, although not applicable in the context of the DFI model, are supplied to make the suggested data consistent with capital cost data generally available in most sources and thereby to facilitate comparison of the suggested data with other data. The IDC values for the suggested data have been computed on the basis of an interest rate of 3% (in terms of constant dollars) across-the-board for all technologies. Although this interest rate is realistic, it is to be treated

only as a representative value and not as a forecast. The actual interest rate in a given year is a function of a variety of economic factors and should be developed in the context of the situation under consideration. Alternative assumptions regarding future interest rates during construction would, of course, significantly modify the TCI figures. Nevertheless, uncertainty in interest rates would not affect the capital cost information expressed in this report in terms of SCC which is independent of the vagaries of interest rates. In view of the above assumption concerning interest rates during construction, whenever capital cost information in terms of TCI was used from a given source, it was adjusted with regard to IDC. For technologies with a known schedule of expenditures, IDC based on the above rate could be computed precisely. But most data sources do not spell out a schedule of expenditures and, for technologies with these data sources, IDC was computed using the assumption that all the capital is spent instantaneously at a point two-thirds of the way through the construction period. This assumption would yield the following equation relating TCI and SCC:

$$TCI = SCC(1 + i)^{B/3} \times \text{annual plant output}$$

where,

- i = interest rate during construction (assumed to be 0.03) and
- B = length of construction time of facility in years.

The SRI capital cost data are available only in terms of SCC and are expressed in 1975 dollars. A computational step is described, and the corresponding financial parameters are specified in the SRI report to convert SCC to TCI by accounting for IDC. These values of financial parameters, although resulting in interest rates different (higher) than the 3% assumed for the suggested data, were left unchanged when used in conjunction with SRI data. Obviously, this resulted in different TCI values even if the SCC values were the same as per SRI data and suggested data. This inconsistency should cause no concern if one keeps in mind that SCC values do not depend on existing interest rates but TCI values do and the latter can be adjusted according to exogenously specified values for interest rate. The actual steps involved in reducing SRI data to the form presented in this report are as follows:

- Inflate the specific capital costs (SCC) and the specific operating costs (SOC) to 1977 dollars by using Marshall and Swift's (M&S) equipment cost inflators. The M&S inflation factor for converting 1975 dollars to 1977 dollars is 1.14.
- Multiply the SCC (\$/10⁶ Btu/yr) by annual output (name plate capacity x stream factor) of representative plant on which the cost estimate is based to obtain the total capital cost (TCC) for the plant.
- Incorporate interest during construction by using the following equation as stated in the SRI report:

$$TCI = TCC \left(\frac{1 + r}{1 + f} \right)^{B/3}$$

where

TCI = total capital investment including IDC
r = current dollar discount rate
 = 12% for utility companies
 = 15% for industrial/residential/commercial end-use processes
f = inflation rate, assumed to be 5% as suggested in the SRI report,
 and
B = construction time in years

The above equation assumes that all the capital is spent instantaneously at a point two-thirds of the way through the construction period.

The Bechtel² data base was one of the principal data sources used in this study. Because the accounting systems used in the Bechtel report were incompatible with those in other data sources, it was necessary to adjust the Bechtel data. Specifically, capital cost data in the Bechtel report purporting to be in 1977 dollars are actually the sum of different year dollars; that is, the capital cost figure represents the estimated sum of dollar expenditures, in current terms, over the span of construction of a particular facility with construction starting in 1977. This is done by using a construction cost escalation rate of 7%/yr, and an interest rate of 9%/yr, which actually represent current dollar rates and not constant dollar rates. In order to derive capital cost data in constant 1977 dollars from Bechtel data it was assumed that (a) construction cost escalation is 2.3% over and above the general inflation rate for the computation of escalation during construction (EDC), and (b) as before, the real interest rate is 3%/yr, for the computation of interest during construction (IDC). These assumptions amount to taking approximately two-thirds each of EDC and IDC values as given in the Bechtel report and subtracting them from the corresponding Bechtel capital cost total to arrive at capital cost figures in constant 1977 dollars.

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1. Fuel and Energy Price Forecasts, Stanford Research Institute, EPRI EA-433, Vol. II, Feb. 1977.
2. Gallagher, J.M. et al., Resource Requirements, Impacts, and Potential Constraints Associatd With Various Energy Futures and supplementary annual operating cost printout, Bechtel National Inc., PAE-3794-9, March 1978.

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II. ELECTRIC POWER GENERATION

Economics of the electric power generation processes are summarized in Tables II-1 and II-2 for SRI and PIES data respectively. Because of uncertainties regarding plant configuration and various design parameters, the suggested data are based on nominal or representative plants for each given technology. For certain variables a range of values is given because of the uncertainty in data estimates. SRI's data on capital costs and efficiencies for this sector generally seem reasonable, but their operations and maintenance (O&M) costs seem low. PIES data, available at the regional level, were first judged with respect to regional variation and then averaged to a single value for each variable for comparison with the suggested data.

In this sector most of the suggested data were extracted directly from the references noted in the tables. Relationships between SRI data for similar processes, wherever considered appropriate, were used for data for which no suitable reference could be found. Judgment based on communication with experts in the field was used to derive the data in the remaining cases.

SRI Data

SRI process economics data are provided for coal-fired steam-electric plants; coal-fueled combined cycles; oil- and gas-fueled steam-electric, combustion turbines, and combined cycle systems; nuclear light-water reactor, high-temperature gas reactor, and liquid-metal fast-breeder reactor systems; a solvent-refined coal-fired steam-electric plant; methanol-fueled combined cycle plant; biomass steam-electric plant; solar steam-electric facility; pumped-storage system; and geothermal (both geyser and hot water) steam-electric plant. Although hydroelectric power is treated as a negative end-use demand in the SRI model, explicit data have been suggested for this process in this report. Advanced future generation technologies such as fluidized bed combustion, MHD, and fuel cells have been indirectly incorporated in the SRI data in terms of technological change rates and limits on capital costs and efficiencies for certain existing technologies. Since these technologies are quite different from existing technologies and cannot be treated as extensions of them, the future technologies should be dealt with individually by spelling out process economics data for each. Data for these processes and additional new processes, such as photovoltaics, wind, and ocean thermal, are given in Table II-1.

The unit used for total capital investment (TCI) in this sector, unlike that in other sectors, is \$/kWe rather than a total dollar amount for a facility of a given size, in order to make TCI data directly comparable with the corresponding data as quoted in most sources. Note that TCI in this form still differs from specific capital cost (SCC) in that it includes interest during construction (IDC). The specific capital costs (in Table II-1) for all electric plants, expressed in $\$/10^6$ Btu/yr, are based on a capacity factor equal to one. Actual capacity factors are assigned internally in the model to the generation facilities on the basis of regional capacity factors, except in the case of mine-mouth supply region power generation from coal, for which the model selects one of the coal-based power technologies operating at a capacity factor of 75% rather than one based on the average regional capacity factor. In the SRI data the capital costs were adjusted to take into account reliability or availability of technologies in selecting the generating facilities. Capability ratios, based on a particular method of calculating effective

Table II-1
Process Economics Data^a
Sector: Electric Power Generation

Technology/ Process	Unit Size ^b (mWe)	SRI Data					Suggested Data ^g				Comments ^h
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC (\$/10 ⁶ Btu/yr)	TCI ^d (\$/kWe)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (\$/kWe)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
1. LS coal steam- electric	800	14.07	16.04	505	0.44	0.38	15.02	480 ¹	0.83	0.35	Difference between LS and HS coal steam-electric is due to the sulfur oxide removal system included in the HS coal case. This system uses Wellman-Lord process and produces sulfur as a by-product. SRI : Y = 4 Suggested: Y = 5
2. HS coal steam- electric	800	18.54	21.14	600	0.77	0.36	20.02	635 ¹	1.53	0.32	
3. LS coal combined cycle	500	19.36	22.07	685	1.11	0.30	20.33	650 (600- 700)	0.95 ^{7,8}	0.42 ^{7,8} (0.38- 0.46)	System consists of low-Btu gasifier integrated with open cycle gas turbine, waste heat boiler and steam bottoming cycle. SRI : CL=0.65-0.62; EL=1.45; t = 1975; Y=4 Suggested: CL=0.85; EL=1.25; t = 1990; Y=5
4. HS coal combined cycle	500	21.48	24.49	760	1.17	0.30	22.53	720 (650- 800)	1.00	0.42 (0.38- 0.46)	
5. LWR nuclear	1200	20.16	22.98	750	0.38	0.32	22.93	775 ¹ (700- 850)	0.68	0.32	IDC and other owner costs constitute significant portion of total cost because of longer construction period (9 years) assumed in the case of suggested data. SRI efficiencies for HTGR and LMFR reflect both thermal efficiency and fuel cycle economics. SRI : Y = 6 Suggested: Y = 9
6. HTGR nuclear (advanced)	1500	20.16	22.98	750	0.38	0.65	24.79	840 ¹ (750- 920)	0.57	0.39	
7. LMFR nuclear	1500	24.33	27.74	910	1.00	10.00	30.71	1040 ¹ (950- 1150)	0.97	0.40	
8. HBtu gas steam- electric	800	7.85	8.95	335	0.18	0.36	10.14	320	0.69 ¹	0.35 ¹	Based on 500 mW system consisting of 300 mW gas turbine and 200 mW steam turbine. SRI : CL = 0.7 CR = 0.07 ER = 0.1 Y = 2 Suggested: CL = 0.85 CR = 0.05 ER = 0.05 Y = 4
9. HBtu gas combined cycle	500	7.07	8.06	275	0.30	0.41	8.08	255 ¹	0.82	0.46 ^{7,8}	
10. HBtu gas combustion turbine	100	4.78	5.45	175	0.66	0.30	6.12	185 ¹	1.96	0.30	

Table II-1 (Continued)
Process Economics Data^a
Sector: Electric Power Generation

Technology/ Process	Unit Size ^b (mWe)	SRI Data					Suggested Data ^g				Comments ^h
		SOC ^c (\$/10 ⁶ Btu/ yr)	SCC (\$/10 ⁶ Btu/yr)	TCI ^d (\$/kWe)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SCC (\$/10 ⁶ Btu/yr)	TCI (\$/kWe)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
11. Distillate combined cycle	500	7.07	8.06	275	0.38	0.40	8.08	255 ¹	0.90	0.46 ^{7,8}	{ SRI : CL = 0.7 CR = 0.07 ER = 0.1 Y = 2 Suggested: CL = 0.85 CR = 0.05 ER = 0.05 Y = 4
12. Distillate combustion turbine	100	4.78	5.45	175	0.96	0.30	6.12	185 ¹	2.20	0.30	{ SRI : CL = 0.72 ER = 0.10 Suggested: CL = 0.85 ER = 0.05
13. LS residual steam- electric	800	9.56	10.9	375	0.21	0.38	11.27	360 ¹	0.85	0.35	{ SRI : Y = 4 Suggested: Y = 5
14. LS residual combustion turbine	100	5.02	5.72	185	1.30	0.30	6.45	195	2.98	0.30	{ SRI : CL = 0.72 ER = 0.10 Suggested: CL = 0.85 ER = 0.05
15. Utility coal residual steam- electric	800	9.56	10.9	375	0.21	0.38	11.27	360 ¹	0.85	0.35	{ SRI : Y = 4 Suggested: Y = 5
16. Methanol combined cycle	500	7.07	8.06	275	0.38	0.40	8.08	255	0.90	0.46	{ SRI : CL = 0.7 CR = 0.07 ER = 0.1 Y = 2 Suggested: CL = 0.85 CR = 0.05 ER = 0.05 Y = 4
17. SRC steam- electric	800	11.47	13.08	425	0.21	0.38	12.52	400	0.70	0.35	{ SRI : Y = 4 Suggested: Y = 5
18. Biomass steam- electric	565	19.67	22.42	700	0.55	0.34	20.81	665	1.04	0.31	{ SRI : Y = 4 Suggested: Y = 5
19. Solar steam- electric	100	53.50	60.99	1990	0.50	0.33	56.31	1800 (1500- 2100 ³)	1.00 ²	0.25	{ The data is associated with a location in the west. SRI : CR = 0.10 Y = 4 Suggested: CR = 0.05 Y = 5
20. Pumped- storage	1000	5.85	6.67	220	0.22	0.65	9.42	300 ² (175 ² - 415 ¹)	0.43 ²	0.65	{ Wide range for capital cost results from strong site-dependence for this technology. SRI : Y = 4 Suggested: Y = 5

Table II-1 (Continued)
Process Economics Data^a
Sector: Electric Power Generation

Technology/ Process	Unit Size ^b (mWe)	SRI Data					Suggested Data ^g				Comments ^h
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC (\$/10 ⁶ Btu/yr)	TCI ^d (\$/kWe)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (\$/kWe)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
21. Geyser steam- electric	50	7.67	8.74	280	0.33	0.17	21.43	685 ² (550 - 850)	0.70	0.17	Wide range for capital costs results from strong site-dependence for these technologies. SRI : Y = 3 Suggested: Y = 4
22. Hot water steam- electric	50	18.06	20.59	655	0.90	0.10	35.98	1150 ² (700 - 1600)	1.16	0.10	
23. Hydro- electric	200	-	-	-	-	-	19.10	600 (400 - 775 ¹)	0.50 ¹	-	Wide range for capital cost results from strong site-dependence for this technology Suggested: CL = 0.9 CR = 0.05 EL = 1.10 ER = 0.05 F = 0.45 B = 30 T = 22 No corresponding SRI values
24. Fluidized bed coal steam- electric:											
Atmospheric	800	-	-	-	-	-	14.23	455 ² (400 - 500)	1.10	0.36 (0.35- 0.37)	Atmospheric fluidized bed boiler with conventional steam turbine power plant. SOC value from reference 2 was adjusted upwards by a factor of 1.5 to make it consistent with the corres- ponding value for process #1. This factor is roughly equal to the ratio of sug- gested SOC value and refer- ence 2 SOC value for pro- cess #1. t = 1990; Y = 5
Pressurized	800	-	-	-	-	-	16.11	515 ² (460 - 570)	1.15	0.39 (0.37- 0.41)	Pressurized fluidized bed boiler with gas turbine and steam turbine system. SOC value from reference 2 was adjusted upwards by a factor of 1.5 for the same reason as stated above. t = 1993; Y = 5
25. Fuel cell	26	-	-	-	-	-	14.24	435 ¹ (400- 500)	2.35	0.40 (0.37 ¹ - 0.44 ⁵)	Included are cells, fuel reformer, DC-AC inverter transformer, switch gear and various controls. SOC value from reference 1 was adjusted to reflect 5000 hrs/year of fuel cell operation instead of 2000 hrs/year. Suggested: CL = 0.9 CR = 0.05 EL = 1.10 ER = 0.05 t = 1985 F = 0.45 Y = 1.25 B = 30 T = 22 No corresponding SRI values

Table II-1 (Continued)
Process Economics Data^a
Sector: Electric Power Generation

Technology/ Process	Unit Size ^b (mWe)	SRI Data					Suggested Data ^g				Comments ^h
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC (\$/10 ⁶ Btu/yr)	TCI ^d (\$/kWe)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency	SOC (\$/10 ⁶ Btu/yr)	TCI (\$/kWe)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
26. MHD	1000	-	-	-	-	-	16.74	535 ² (475- 600)	0.75	0.47 (0.45- 0.50)	Systems consists of coal-fired MHD with steam bottoming cycle. SOC value from reference 2 was adjusted by a factor of 1.5 for the same reason as cited for process #24. Suggested: CL = 0.9 CR = 0.05 EL = 1.10 t = 1997 ER = 0.05 F = 0.45 Y = 5 B = 30 T = 22 No corresponding SRI values
27. Photovoltaic	100	-	-	-	-	-	40.55	1250 (1000- 1500)	1.00 ²	0.08 (0.07- 0.11)	Based on plant favorably sited in southwest. Suggested: CL = 0.8 CR = 0.05 EL = 1.3 ER = 0.05 t = 1995 F = 0.45 Y = 2 B = 30 T = 22 No corresponding SRI values
28. Wind	50	-	-	-	-	-	40.55	1250 ² (1000- 1500)	0.67	-	System consists of modular units of -1 mW each. Capital cost is dependent on the design speed. Suggested: CL = 0.8 CR = 0.05 F = 0.45 t = 1984 B = 30 Y = 2 T = 22 No corresponding SRI values

Table II-1 (Continued)
Process Economics Data^a
Sector: Electric Power Generation

Technology/ Process	Unit Size ^b (mWe)	SRI Data					Suggested Data ^g				Comments ^h
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC (\$/10 ⁶ Btu/yr)	TCI ^d (\$/kWe)	SOC ^e (\$/10 ⁶ Btu)	Effi- ^f ciency	SOC (\$/10 ⁶ Btu/yr)	TCI (\$/kWe)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
29 Ocean thermal	100	-	-	-	-	-	59.44	1900 ² (1500- 2300)	1.00	0.026	Cost based on a binary cycle operating in a favor- able gulf stream site. Suggested: CL = 0.8 CR = 0.05 EL = 1.30 ER = 0.05 t = 1995 F = 0.45 Y = 5 B = 30 T = 22 No corresponding SRI values

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which Total Capital Investment (TCI) is based.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating and Maintenance Cost.

^fThis refers to the overall conversion efficiency.

^gIn some cases range of current estimates is shown in the parenthesis. Superscripts denote the references for the data. Unless specified otherwise, reference shown for capital cost data was also used for other data items for a given technology. See the text for unreferenced data.

^hUnless otherwise specified, the following SRI variables were found to be acceptable: Technological Change Limit on Capital (CL), Technological Change Rate on Capital (CR), Technological Change Limit on Efficiency (EL), Technological Change Rate on Efficiency (ER), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T).

load-carrying capacity, were developed and used to increase or decrease capital costs of the generating facilities. The suggested cost data are independent of reliability considerations, which should be incorporated in the model rather than in the input data. The suggested operating and maintenance cost data are based on typical capacity factors of the respective plants and are assumed to remain constant over a normal range of capacity factors.

Recommended data items that are referenced were extracted directly from the noted sources and converted to the required form by the methodology described in Section I. Assumptions used in estimating the suggested process data that are not referenced are summarized below. The numbers in parentheses correspond to process numbers in Table II-1.

LS Coal Combined Cycle (3). Although capital cost for this technology is available in many data sources,^{2,7,8} it was decided not to use these sources to ensure consistency with capital cost associated with the conventional coal steam electric process (1). SRI capital cost estimates for the LS coal combined cycle (3) and the conventional coal steam-electric process (1) seem reasonable in a relative sense, and therefore the ratio between the two was used to compute the capital cost for this process on the basis of the suggested capital cost for process 1.

HS coal combined cycle (4). Data for this process were derived in such a way that the respective variables have the same relationship with the corresponding variables in process 3 (LS coal combined cycle) as in SRI data.

HBtu gas steam-electric (8). Since the Bechtel¹ capital cost data for this process appear low, the capital cost was derived from that for process 13 (oil steam-electric) by retaining the SRI ratio of capital costs for the two processes.

LS residual combustion turbine (14). Data for this process were derived from those for process 12 (distillate combustion turbine) by retaining the SRI ratios of the corresponding variables for the two processes.

Methanol combined cycle (16). Since this process is almost identical to the distillate combined cycle (11), the same data were used.

SRC steam-electric (17). The LS coal steam-electric process (1) is the closest approximation to this process. SRI ratios of capital cost and efficiency values for the two processes were used to compute capital cost and efficiency data for SRC steam-electric on the basis of suggested data for process 1. O&M cost was estimated to be ~15% lower than that for process 1.

Biomass steam-electric (18). Judging from data based on Swedish experience with this process, SRI data for biomass steam-electric appear quite reasonable relative to LS coal steam-electric process (1) data. The SRI data relationship between the two processes was therefore used to estimate data for this process.

PIES Data

PIES regional data were averaged for each variable and compared with the suggested data derived earlier. Both the regional variation and the absolute magnitude of PIES capital cost and heat rate data generally seem within reasonable range, with the following exceptions:

- O&M costs in PIES data are consistently lower than the suggested O&M costs.
- The heat rate for bituminous coal steam-electric (with scrubber) is low, especially in view of the higher heat rate value for the corresponding without-scrubber case.
- PIES capital costs for nuclear plants for certain regions are unrealistically low. Although these costs refer to deferrable plants, defined as projects that have sunk ~ 10% of their capital requirements, the discrepancy is not explained by a cost reduction of this order of magnitude. The stated PIES cost seems to comprise the additional expenditure needed to complete the projects after a significant portion of capital cost has already been incurred for some regional plants. This made it difficult to determine PIES capital costs data for new nuclear plants. In Table II-2, the region 2 capital cost figure - which looks most reasonable - is shown for comparison with the suggested data.

Table II-2
Process Economics Data^a
Sector: Electric Power Process Economics

Technology/ Process	Unit Size ^b (mWe)	PIES Data				Suggested Data ^f			Comments
		CC ^c ('75 \$/kWe)	CC ^c ('77 \$/kWe)	SOC ^d (mills/kWh)	Heat Rate ^e (10 ³ Btu/ kWh)	CC (\$/kWe)	SOC (mills/kWh)	Heat Rate (10 ³ Btu/ kWh)	
1. Residual-fired steam	800	374 (346 - 407)	426	1.03	9.97 (9.65-10.3)	360 ¹	2.90	9.75	PIES capital cost data generally seem within reasonable range. Heat rate for Bituminous coal (with scrubber) case appears low especially in view of higher heat rate value in the corresponding without-scrubber case. Heat rate values in case of distillate-combined cycle may also be too optimistic.
2. Bituminous coal (with scrubber)	800	502 (465 - 546)	572	3.19	10.07 (9.84-10.3)	595 ¹ (540-650)	5.20	10.67	
3. Bituminous coal (without scrubber)	800	402 (373 - 439)	458	1.25	10.11 (9.87-10.35)	440 ¹ (400-480)	2.80	9.75	
4. Sub-bituminous coal (with scrubber)	800	537 (505 - 576)	612	2.28	10.47* (10.23-10.71)	675 ¹ (610-740)	5.20	10.67	
5. Sub-bituminous coal (without scrubber)	800	436 (406 - 476)	497	1.25	10.47* (10.23-10.71)	520 ¹ (470-570)	2.80	9.75	
6. Lignite coal (with scrubber)	800	553	630	2.28	10.75 (10.5-11.0)	675 ¹ (610-740)	5.20	10.67	
7. Distillate-fired simple cycle	100	151	172	3.13	10.25 (10.0-10.5)	185 ¹	6.80	11.38	
8. Distillate-fired combined cycle	500	290	330	1.42	7.75 (7.5- 8.0)	255 ¹	3.05	7.42	
9. Gas-fired steam	800	299 (265 - 325)	340	0.57	10.38 (10.01-10.76)	320	2.35	9.75	The PIES capital cost shown here corresponds to the region 2. See text for explanation.
10. Hydro-electric (pumped storage)	200	294 (180 - 390)	335	0.80	-	300 ² (200-400)	1.45	-	
11. Nuclear (deferrable)	1200	596 (211 - 596)	680	1.88	not available	775 ¹	2.30	10.66	

*This heat rate value seems to be the average of with and without scrubber cases.

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which suggested Capital Cost (CC) is based.

^cCC: Capital Cost including Interest During Construction for the given unit size. The range in PIES data reflects the regional variation.

^dSOC: Specific Operating and Maintenance Cost.

^eThis refers to the overall process heat rate. In PIES data range refers to operation of plants in different load categories.

^fIn some cases range of current estimates is shown in the parenthesis. Superscripts denote the references for the data. Unless specified otherwise, reference shown for capital cost data also applies to other data items for a given technology. See the text for unreferenced data.

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III. SYNTHETIC FUELS

Economics of the synthetic fuel production processes are summarized in Table III. Suggested process economics are based on the process details noted in the "comments" column but can be considered representative of an average or nominal plant configuration required to accomplish the particular conversion. Because of the potential availability of more than one process in every synfuel technology and uncertainty associated with future technology characteristics, a range is given for investment costs, operating and maintenance (O&M) costs, and conversion efficiencies. SRI investment costs were found to be generally low and O&M costs somewhat high. The effect of sulfur content of coal on costs seems reasonable, and so do the conversion efficiencies.

For a given technology, both SRI and suggested data have been adjusted to correspond to facilities of the same size to eliminate economy-of-scale effects. Except for biomass-synfuel conversion, all processes correspond to facilities of 250×10^9 -Btu/day rated capacity. Since all the adjustments involved only marginal changes from the size on which the original data were based, it seemed reasonable to use a linear relationship between cost and facility size.

The SRI data on synfuel processes are disaggregated with respect to coal types (e.g., high sulfur or low sulfur coal) and status of technology (e.g., first or second generation). With such detailed classification, it was not feasible to find a data source for each process. Note that no commercial synfuel plants are in operation in the U.S; therefore, current data estimates, based on conceptual designs only, are limited to representing only the order of magnitude of actual values. This precludes definitive data estimates for minor process variations which fall within the band of uncertainty of data on primary processes. However, certain judgments can be made about the direction and magnitude of changes in data resulting from such process variations. Judgmental estimates, based on communication with experts in the field, were made for some of the processes for which no reliable reference could be located. For some others, relationships found in SRI data for similar processes were useful in estimating the suggested data. As an example, no data were found on conversion of low-sulfur coal to methanol and hydrogen although data on such conversion of high-sulfur coal are available. Since the basic gasification step in the latter is the same as in high-Btu gas conversion, the relationship between data on low- and high-sulfur coal conversion to high-Btu gas was used to estimate data on low-sulfur coal conversion to methanol and hydrogen.

Consistency of data between processes was an important consideration in compiling the suggested data. Although the degree of processing complexity varies greatly, depending on the type and composition of the feedstock and product fuel type and quality, the various synfuel processes have some strong similarities. It would therefore seem that data for various synfuel processes should have some relationship with each other, at least in a directional sense. Yet it is not uncommon to find different information sources quoting widely varying figures for essentially similar processes because of differences arising from varied conceptual design considerations and systems definitions. In the

Table III
Process Economics Data^a
Sector: Synthetic Fuels

Technology/ Process	Unit Size ^b (10 ⁹ Btu/ day)	SRI Data					Suggested Data ^g				Comments ^h
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC (\$/10 ⁶ Btu/yr)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
1. HBtu gas (1 st gen.) from LS/L Btu coal	250	8.55	9.75	875	1.00	0.64	14.23	1230 ¹ (1100- 1350)	0.54 ² (0.45- 0.65)	0.65 (0.63- 0.67)	Based on Lurgi oxygen gasification and includes oxygen plant and sulfur recovery facilities. Ma- jor fuel byproducts in- clude tar, tar oil and naphtha and constitute 18% of the heating value of the total output. SRI : t = 1990 Suggested: t = 1985
2. HBtu gas (1 st gen.) from HS/H Btu coal	250	9.50	10.83	970	1.05	0.58	15.62	1350 ⁴ (1200- 1500)	0.57 (0.45- 0.70)	0.62 (0.60- 0.64)	
3. HBtu gas (2 nd gen.) from LS/L Btu coal	250	6.52	7.43	665	0.82	0.68	12.11	1045 ² (940- 1250)	0.59 ² (0.50- 0.70)	0.70 (0.68- 0.72)	Based on IGT Hygas pro- cess coupled with the steam-oxygen process for hydrogen production and includes oxygen plant and sulfur recovery facili- ties. SRI : R = 0.08 Suggested: R = 0.05
4. HBtu gas (2 nd gen.) from HS/H Btu coal	250	6.90	7.87	705	0.83	0.67	12.98	1120 ⁴ (1000- 1300)	0.60 (0.50- 0.70)	0.69 (0.67- 0.71)	
5. LBtu gas (1 st gen.) from LS/ LBtu coal	250	7.08	8.07	720	0.72	0.70	11.05	955 ¹ (850- 1050)	0.39 (0.30- 0.45)	0.76 (0.74- 0.78)	Based on Lurgi air blown system with gas treatment and sulfur recovery fac- ilities. Major fuel by- products include tar, tar oil and naphtha and con- stitute 20% of the heat- ing value of the total output. SRI : t = 1990 Suggested: t = 1985
6. LBtu gas (1 st gen.) from HS/ HBtu coal	250	7.20	8.21	735	0.74	0.69	11.57	1000 (900- 1100)	0.40 (0.30- 0.50)	0.75 (0.73- 0.77)	
7. LBtu gas (2 nd gen.) from LS/ LBtu coal	250	5.11	5.83	520	0.65	0.74	9.37	810 (730- 890)	0.43 (0.35- 0.50)	0.76 (0.74- 0.78)	Advanced gasifier concept such as multistage pres- surized operation should result in improvements as compared to first genera- tion processes. SRI : R = 0.08 Suggested: R = 0.05
8. LBtu gas (2 nd gen.) from HS/ HBtu coal	250	5.63	6.42	575	0.67	0.70	9.84	850 (760- 940)	0.44 (0.35- 0.55)	0.75 (0.73- 0.77)	
9. Methanol from LS/ LBtu coal	250	11.35	12.94	1160	1.32	0.43	20.12	1775 (1600- 1950)	0.71 (0.55- 0.85)	0.50 (0.48- 0.52)	Suggested data corres- ponds to Koppers-Totzek O ₂ - blown gasification and includes oxygen plant and sulfur recovery fac- ilities. The lower capi- tal cost figures in the parenthesis refer to ad- vanced gasification pro- cess. For Process #11 and 12 SRI : L = 0.9 Suggested: L = 0.85
10. Methanol from HS/ HBtu coal	250	11.80	13.45	1205	1.25	0.45	21.20	1870 ¹ (1700- 2050)	0.67 (0.55- 0.80)	0.52 ³ (0.50- 0.54)	
11. Hydrogen from LS/ LBtu coal	250	9.55	10.89	975	1.06	0.59	16.11	1420 (1280- 1560)	0.57 (0.45- 0.70)	0.61 (0.59- 0.63)	
12. Hydrogen from HS/ HBtu coal	250	9.80	11.17	1000	1.08	0.59	16.62	1465 ³ (1320- 1600)	0.58 (0.45- 0.70)	0.61 (0.59- 0.63)	

Table III (Continued)
Process Economics Data^a
Sector: Synthetic Fuels

Technology/ Process	Unit Size ^b (10 ⁹ Btu/ day)	SRI Data					Suggested Data ^g				Comments ^h
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC (\$/10 ⁶ Btu/yr)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
15. LS fuel oil from LS/HBtu coal	250	7.95	9.06	810	0.87	0.68	10.73	950 (825- 1075)	0.47 (0.40- 0.55)	0.67 (0.65- 0.69)	Based on Synthoil catalytic coal liquefaction process. SRI : R = 0.10; Y = 4 Suggested: R = 0.05; Y = 5
16. LS fuel oil from HS/HBtu coal	250	7.80	8.89	795	0.81	0.69	10.45	925 ¹ (800- 1050)	0.44 (0.35- 0.55)	0.68 (0.66- 0.70)	
17. SRC from LS/LBtu coal	250	7.05	8.04	720	0.77	0.73	8.43	720 (650- 800)	0.42 (0.35- 0.50)	0.73	
18. SRC from HS/HBtu coal	250	6.85	7.81	700	0.73	0.72	8.20	700 ¹ (650- 800)	0.40 (0.30- 0.50)	0.72	Major fuel byproducts include naphtha and LBtu fuel gas. They constitute ~6% and ~12% respectively of the heating value of the total output. Suggested process input consists of raw shale oil and oil shale constituting 65% and 35% respectively of the total input in terms of heating value. Process involves shale sizing, retorting and disposal as well as raw oil upgrading.
19. Shale Syncrude (upgrading)	250	1.98	2.26	200	0.27	0.90	4.07	360 ¹ (320- 400)	0.33 ¹	0.90	
20. Biomass HBtu gas	50	9.50	10.83	194	1.00	0.65	15.81	275 (225- 325)	0.54 (0.45- 0.65)	0.65 (0.63- 0.67)	
21. Biomass methanol	50	14.60	16.64	300	1.63	0.43	22.13	390 (300- 500)	0.88 (0.70- 1.05)	0.50 (0.48- 0.52)	Conceptual advanced pyrolysis or gasification system.
22. Methanol from nat- ural gas	250	5.05	5.76	515	0.55	0.57	7.81	665 ³	0.30 (0.25- 0.35)	0.55	
23. Propane/ air mixture	-	1.71	1.95	-	0.11	0.97	1.95	-	0.06	0.97	Blending operation.

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which Total Capital Investment (TCI) is based.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating and Maintenance Cost.

^fThis refers to the overall conversion efficiency.

^gIn some cases range of current estimates is shown in parenthesis. Superscripts, although shown only for capital cost data, denote the references for the efficiency data as well for the corresponding processes. See the text for operating cost data and other unreferenced data.

^hUnless otherwise specified, the following SRI variables were found to be acceptable: Technological Change limit on Capital (L), Technological Change Rate on Capital (R), Equity fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T), Year Available (t).

synfuel sector, Bechtel¹ data were used as the standard for all data except O&M costs. For processes for which the available data were out of line compared with Bechtel data on related processes, these data were not used; instead, data were developed from the Bechtel report by using a relationship between the corresponding processes' data based on the SRI report or other sources. A similar approach was adopted for processes for which no data source could be located. Operation and maintenance costs were found to vary greatly from one reference to another even after normalization to a similar basis. SRI data on O&M costs are at the high end of the range, Bechtel data seem unrealistically low, and those from other sources fall in between. In this report O&M costs were developed for representative conversion processes mainly on the basis of a Braun report,² and data for other processes were derived from these figures by using the SRI relationships between the corresponding variables for similar processes.

Economic and design assumptions similar to those in the SRI study were made for the synthetic fuel processes. Important assumptions are highlighted below:

- The stream factor for all synthetic plants is 90%.
- Plant investments and operating costs do not include process development costs.
- All plants meet current emission standards.
- Energy value of major fuel by-products such as naphtha in the SRC process is included in the thermal efficiency, specific capital, and operating cost calculations.
- Although the energy value of minor nonfuel by-products such as ammonia and sulfur is not included in calculating process thermal efficiency, their value is credited against operating costs.
- The thermal efficiencies, as in other sectors, refer to overall plant efficiencies, i.e., they take into account the output fuel used internally for operation of the plant.

The following comments relate to computation of specific data included in Table III.

SRI Data

Data corresponding to processes required for conversion of the following resource or feedstock into the indicated synthetic fuel are considered in the SRI report.

Resource or process feedstock
High-sulfur bituminous coal

Low-sulfur sub-bituminous coal
Remote natural gas
Raw shale oil
Biomass

Synthetic fuel

High-Btu gas, commercial process
High-Btu gas, advanced process
Low-Btu gas, commercial process
Low-Btu gas, advanced process
Solvent-refined coal (SRC)
Low-sulfur fuel oil (coal resid.)
Syncrude
Methanol fuel
Hydrogen
All the above synthetic fuels
Methanol fuel
Shale oil syncrude
Methanol, advanced process

SRI data along with the suggested data are shown in Table III. Suggested data items that are referenced were taken directly from the sources and converted to the required form by the methodology described in Section I. Assumptions used in estimating the unreferenced suggested process data are summarized below (The numbers in parentheses are process numbers in Table III.)

LBtu gas (1st generation) from HS/HBtu coal (6). Intuitively, one expects the cost differential between HS/HBtu coal and LS/LBtu coal as feedstock to be greater for high-Btu than for low-Btu gasification because low-Btu gasification does not require oxygen, but high-Btu gasification would require more oxygen and therefore higher investment for oxygen plant with HS/HBtu coal than with LS/LBtu coal.

The Capital cost for this process is assumed to be 5% higher than for process 5, which involves LBtu gasification of LS/LBtu coal. This seems appropriate in view of a 10% cost differential between processes 1 and 2. The efficiency was obtained by adjusting process 5 efficiency such that the two efficiencies are in the same proportion as in SRI data.

LBtu gas (2nd generation) from LS/LBtu coal (7). The Braun report² gives the breakdown of component costs for processes 1 and 3. The cost differential between these two processes was adjusted by excluding the portion attributable to methanation and shift conversion steps, and the net differential was used to compute a cost figure for process 7 from the corresponding value for process 5.

LBtu gas (2nd generation) from HS/HBtu coal (8). The capital cost for this process (using HS/HBtu coal) is assumed to be 5% higher than that for process 7 (using LS/LBtu coal). This differential is the same as for the first-generation processes. The efficiency was computed from process 7 efficiency such that the two efficiencies have the same ratio as in SRI data.

Methanol from LS/LBtu coal (9). The capital cost in this case (LS/LBtu coal) was assumed to be 7.5% less than for process 10 (HS/HBtu coal). The efficiency was computed such that its relationship with that of process 10 was the same as in SRI data.

Hydrogen from LS/LBtu coal (11). The data for this process (LS/LBtu coal) were derived such that the variables have the same relationship with the corresponding variables in process 12 (HS/HBtu coal) as in SRI data.

Syncrude from LS/LBtu coal and HS/HBtu coal, and LS fuel oil from LS/LBtu coal(13, 14, and 15). Data for these processes were derived from the data for process 16 (fuel oil from HS/HBtu coal) by retaining SRI data relationships between the corresponding variables.

SRC from LS/LBtu coal (17). SRI data relationships between the corresponding variables were used to derive data for this process, from the data for process 18 (HS/HBtu coal).

HBtu gas and methanol from biomass (20, 21). Although data from a reputable source⁶ were available for these processes, they were not used because of inconsistency with data for similar processes from other sources including Bechtel¹ and the reason for the inconsistency could not be determined. For biomass conversion to HBtu gas, SRI data appeared consistent with data for a similar coal conversion process, and therefore the methodology used above was adopted to develop data for process 20. For biomass conversion to methanol, the SRI specific capital cost is ~ 30% higher than for coal conversion. This differential seems too high, especially in view of only ~10% cost differential between biomass and coal conversion to HBtu gas, because, once feedstock (be it coal or biomass) has been gasified, the cost of conversion to methanol should be the same. A 10% higher capital cost for biomass than for coal conversion to methanol was considered appropriate in computing the capital cost for process 21.

Propane/air mixture (23). This is a blending operation such that the mixture can be used directly as a substitute for natural gas. SRI data appear reasonable for this process and have been adopted without any change.

PIES Data

Some PIES data are available in the synthetic fuel sector, but they are expressed only in terms of unit product cost with no information on break down into the component capital and O&M costs. For comparison, our suggested data on plant investment costs and O&M costs were converted to unit product costs. A capital charge rate of 15% was used to compute the capital cost component. PIES unit product costs appear too high when compared with the suggested costs, as illustrated below:

Product costs, excluding raw material costs
('77 \$/bbl oil equivalent)

<u>Synthetic fuel</u>	<u>PIES</u>	<u>Suggested</u>
1. Coal to HBtu gas	23.92	16.80 ^{1,4}
2. Coal to syncrude	22.02	14.50
3. Shale oil	14.48	6.55 ¹

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IV. OIL REFINING

The DFI model classifies refineries by yield and sulfur content. Capital costs are given for refineries with high, medium, and low gasoline yield as defined in Table IV-1. Because the cost of refining is higher for sour (high-sulfur) crude oil than for sweet (low-sulfur) crude oil, different economics are provided for these two types of refineries.

Table IV-1
Product Yields for Refineries (Btu basis)

Product	Low gasoline yield	Medium gasoline yield	High gasoline yield
Gasoline	0.17	0.45	0.61
Distillate	0.38	0.33	0.33
Residual	0.45	0.22	0.06
Total	1.00	1.00	1.00

There are two tables in this section that specify capital costs for refineries. Table IV-2 lists capital costs for sweet and sour crude refineries of low, medium, and high gasoline yield. Table IV-3 lists capital costs for refineries in the format that is actually input into the refinery model. In this table, the front-end refinery economics are the same as the low gasoline yield refinery economics. The front-end product upgrading refinery economics are given by the difference between the economics of the medium and low gasoline yield refineries. The medium yield upgrading refinery economics are given by the difference between the economics of high and medium yield refineries. By specifying refinery economics in this incremental format, the yield of existing refineries can be modified, and trade-offs between building new refineries in new locations and modifying existing refineries can be evaluated. Lubricants, asphalts, and miscellaneous petroleum products are modeled as a fixed ratio of distillate and residual product yields. This approximation is adequate for present uses of the model because refinery costs are not a large element in the total cost of petroleum products.

The range of suggested capital costs shown in Table IV-2 and Table IV-3 are for refineries varying in capacity from 100,000 to 250,000 bbl/day. Economies of scale were apparent in two analyses by Turner, Mason & Solomon.³ In the first, the specific capital cost was \$1.02/10⁶ Btu/yr for a 250,000-bbl/day refinery; in the second, it was \$1.15/10⁶ Btu/yr for a 150,000-bbl/day refinery. The difference is explained by economies of scale. In view of the reduced costs inherent in larger sizes, the SRI data appear reasonable for a 100,000-bbl/day refinery. In computing the specific capital cost (SCC), it is assumed that a refinery is in operation 345 days/yr.

Table IV-2
Process Economics Data^a
Sector: Refining

Technology/ Process	Unit Size ^b (1000 bbls/ day)	SRI Data					Suggested Data ^g				Comments
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC ^c (\$/10 ⁶ Btu/yr)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
Sweet Crude Refinery — Low Gasoline Yield	100	0.67	0.76	172	0.049	0.975	0.76 (0.60- 0.80)	158	0.04	0.97	SRI capital cost data ap- pears reasonable. The range of capital costs shown are for refineries varying from 100,000-250,000 bbls/ day capacity. Considering econ- omies of scale inherent in these larger refineries the SRI data appears reasonable for a 100,000 bbl/day capa- city refinery. The follow- ing SRI data for the refin- ing sector appears satisfac- tory and is therefore not explicitly listed in the table: Year of Availabil- ity, Auxiliary Efficiency, Technological Rate of Change and Limit on Capital, Equity Fraction, Years to Con- struct, Book Life, and Tax Life. SRI SOC and effi- ciency data for oil refin- eries have been adjusted to reflect data given in refer- ences 1 and 3.
Sour Crude Refinery — Low Gasoline Yield	100	1.03	1.17	264	0.109	0.960	1.17 (1.02- 1.61)	243	0.08	0.96	
Sweet Crude Refinery — Medium Gasoline Yield	100	1.11	1.26	285	0.068	0.956	1.26 (1.10- 1.30)	262	0.06	0.95	
Sour Crude Refinery — Medium Gasoline Yield	100	1.48	1.68	380	0.137	0.941	1.68 (1.60- 1.70)	350	0.11	0.94	
Sweet Crude Refinery — High Gasoline Yield	100	1.44	1.64	370	0.124	0.936	1.64	341	0.10	0.93	
Sour Crude Refinery — High Gasoline Yield	100	1.82	2.07	468	0.187	0.922	2.07 (1.90- 2.10)	431	0.15	0.92	

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which total Capital Investment (TCI) is based.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for a given unit size.

^eSOC: Specific Operating Cost.

^fOverall conversion efficiency.

^gIn some cases range is shown in parentheses below the suggested data.

Table IV-3
Process Economics Data^a
Sector: Refining

Technology/ Process	Unit Size ^b (1000 bbls/ day)	SRI Data					Suggested Data ^{g, h}				Comments
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC ^c (\$/10 ⁶ Btu/yr)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
Sweet Crude Refinery -- Front-end	100	0.666	0.758	172	0.049	0.975	0.758 (0.60- 0.80)	158	0.04	0.97	SRI capital costs appear reasonable. The range of capital costs shown is for refineries varying from 100,000 - 250,000 bbls/day capacity. Considering economics of scale inherent in these larger refineries, the SRI data appears reasonable for a 100,000 bbl/day capacity refinery. SRI SOC and efficiency data for oil refineries have been adjusted to reflect data given in references land 3.
Sour Crude Refinery -- Front-end	100	1.031	1.173	264	0.109	0.960	1.173 (1.02- 1.61)	243	0.08	0.96	
Front-end Product Upgrading	100	0.428	0.487	110	0.024	0.980	0.487 (0.45- 0.50)	101	0.02	0.98	
Medium Yield Product Upgrading	100	0.314	0.357	81	0.048	0.980	0.357 (0.33- 0.38)	74	0.04	0.98	

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which Total Capital Investment (TCI) is based

^cSOC: Specific Capital Cost excluding Interest during construction (IDC)

^dTCI: Total Capital Investment including IDC for a given unit size

^eSOC: Specific Operating Cost

^fOverall conversion efficiency

^gIn some cases range is shown in parenthesis below the suggested data

^hThe following SRI data for the refining sector appear satisfactory and are therefore not explicitly listed in the table: Year of Availability, Auxiliary Efficiency, Technological Rate of Change and Limit on Capital, Equity Fraction, Years to Construct, Book Life, and Tax Life

PIES Refinery Data

The PIES refinery investment cost data⁴ evaluated here are the most recent in the PIES model. They are expressed as annualized investment cost in 1975 \$/bbl and converted from 1975 to 1977 dollars in Table IV-4. Total capital investment (TCI) is computed from the annualized investment cost by using a capital recovery factor (CRF) of 23% and a 90% plant factor:

$$TCI = \frac{\text{annualized capital cost}}{\text{bbl}} \times \frac{1}{\text{CRF}} \times \text{annual output (bbl)}.$$

The PIES capital cost data given in Table IV-4 are broken down into average costs in each of the PIES refining regions. From these data, the average specific capital cost (weighted by refining capacity) across all regions of the U.S. is \$1.53/10⁶ Btu/yr. The typical refinery modeled in PIES is a 200,000 bbl/day sour crude refinery of medium gasoline yield. The suggested specific capital cost in Table IV-2 for a 100,000 bbl/day sour crude medium gasoline yield refinery is \$1.68/10⁶ Btu/yr with a range of 1.60 to 1.70. Considering the size refinery modeled by PIES (200,000 bbl/day) and by the DFI model (100,000 bbl/day) and economies of scale, the PIES specific capital costs appear to be a reasonable estimate of the actual capital required to build a 200,000-bbl/day refinery.

Table IV-4
PIES Refinery Investment Costs (1977 \$)

Refinery region (PAD district)	Annualized capital cost (1975 \$/bbl)	Annualized capital cost (\$/bbl)	TCI 200,000 bbl/ day (10 ⁶ \$)	SCC (\$/10 ⁶ Btu/yr)
1A	2.12	2.41	688	1.74
2A	1.94	2.21	631	1.59
3	1.75	1.99	568	1.43
4	1.89	2.15	614	1.55
5	1.93	2.20	628	1.58
1B	2.12	2.41	688	1.74
2B	1.94	2.21	631	1.59

REFERENCES

1. Gallagher, J. S. et al., Resource Requirements, Impacts, and Potential Constraints Associated With Various Energy Futures, Bechtel National, Inc., PAE-3794-9, March 1978.
2. Aalund, Leo, U.S. refining industry still tied to sweet crude, Oil & Gas, 75, 42 (42), (Oct. 10, 1977).
3. Turner, Mason & Solomon, Assessment of the Relative Profitability of Three Classes of Refiners, Feb. 24, 1977.
4. Tukenmez, E., PIES Refinery Model Update: Refinery Investment Costs, DOE Internal Memo.

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V. TRANSPORTATION AND DISTRIBUTION

SRI Transportation Data

Introduction. The SRI transportation sector comprises processes used for long-distance transport of energy between various regions of the United States; distribution refers to short-distance transport. The SRI transportation processes represent seven modal categories: electrical transmission, unit train, slurry pipeline, liquids pipeline, gas pipeline, barge, and tanker (ship). These categories are further disaggregated on the basis of characteristics (energy densities and initial locations) of specific energy forms being transported.

The SRI data⁷ contain information on 35 transportation processes. Four of these are not analyzed here: 18-U.S. metallurgical coal transportation; 26-metallurgical coal export transportation; 28-nuclear fuel transportation; and 31-imported crude oil tanker. These processes have zero transportation costs because (a) metallurgical coal does not compete with fuels in the energy system and therefore is outside the scope of the model; (b) nuclear fuel transportation costs are insignificant relative to the energy throughput; and (c) the transportation costs for imported crude are already embodied in the price of the fuel at the point where it enters the system.

The purpose of this analysis is to develop suggested values for items appearing in the SRI data base,⁷ and to provide documented support for the suggested values. Within the transportation sector the first step in the analysis was to examine the physical description of each SRI process to determine its reasonableness in terms of distances, throughput capacities, and equipment specifications. In some cases the system described by SRI was found not to be the most appropriate representation of the real world, and new process descriptions were developed.

The second part of the analysis consisted of a search for data bases containing data for similar processes. The Bechtel data base² has by far the most comparable transportation data. Since it is more current than the SRI data base and contains considerable detail, it was often given preference in developing suggested values for the SRI data base.

The rest of this section is concerned with some of the less obvious considerations involved in the development of the data given in the tables. The discussion covers the processes sequentially, with similar processes grouped together under appropriate headings. Except where specified otherwise, the following comments apply to all the processes being analyzed:

- All transportation cost components are assumed to be directly proportional to system length.
- The SRI values for technological change limit on capital, technological change rate on capital, year available, equity fraction, years to construct, book life, and tax life are considered reasonable, and new values are not suggested.
- SRI energy conversion factors are used where possible. These include the following:

Liquid fuels	(10 ⁶ Btu/bbl)
Crude oil	5.8
Gasoline	5.25
Distillate	5.85
Residual fuel oil	6.25
LPG	4.0
LNG	3.5
Methanol	2.67
Gaseous fuels	(Btu/ft ³)
Natural gas	1035
Hydrogen	325
Solid fuels	(10 ⁶ Btu/short ton)
High-sulfur coal (HS)	24.5
Low-sulfur coal (LS)	16.3
Solvent-refined coal (SRC)	31.8

Electric Power Transmission. The SRI and Bechtel data are not strictly comparable. The SRI system is a 600-kV line extending 1000 miles with only 71% of the output capacity of the Bechtel system; the latter operates at a different voltage and extends 800 miles. It is suggested that the Bechtel system description be adopted with its attendant cost data and reduced build period. This approach results in the dc transmission data in Table V-1.

The SRI nominal system for ac transmission has a length of 1000 miles, but since the SRI model does not use ac transmission for distances of 400 miles or more,^{7a} the length of the nominal system should be reduced. A distance of 200 miles was arbitrarily chosen for use in developing the data in Table V-1. These are SRI data adapted to the new system length by using the SRI-defined equation relating efficiency to system length (in this case, $e_{200} = 0.79 \cdot 2 = 0.95$). It was assumed that capital costs are proportional to distance and that the construction time was now 2 years instead of 3. Similar calculations with Bechtel data yielded results within 3% of the SRI values. Bechtel data were used for specific operating cost (SOC) because they are more inclusive and better documented.

Unit Train. Although SRI segregated Eastern from Western unit trains, they did not assign different average lengths of haul (ALH) to trains in the different regions. Instead it was assumed that a nominal unit train travels 1000 miles one way. A shorter ALH for Eastern unit trains is probably more realistic, and it is suggested that this ALH be set arbitrarily at 500 miles.

The SRI data also lacked detailed assumptions about train speeds and loading/unloading time. The TERA documentation⁸ is much better in this respect and it is suggested that it be relied on to derive further data. TERA assumptions about car and locomotive costs are also considered usable, after conversion to 1977 dollars.

The TERA assumption about the number of locomotives per 100 cars, however, does not appear credible, being only about half that of either SRI⁷ or Bechtel.² The TERA ratio is perhaps underestimated due to inclusion of both moving and stationary cars in the calculation, rather than only moving cars. The SRI value

Table V-1
Process Economics Data^a
Sector: Transportation (Electric Power Transmission)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data ^g					Comments ^h
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency ^f	Unit Size ^b	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/1000 miles)	Effi- ciency	
DC transmission	28.1 x 10 ¹² Btu/yr/ 1000 miles	12.56	14.32	365	0.239	0.94	40.1 x 10 ¹² Btu/yr/ 800 miles	17.16	484	0.080	0.90	Changed nominal system, including Y = 2. (Y = 3).
AC transmission	23.1 x 10 ¹² Btu/yr/ 1000 miles	19.92	22.71	486	0.331	0.79						
AC transmission	28.4 x 10 ¹² Btu/yr/ 200 miles	19.92	22.71	114	0.331	0.95	28.4 x 10 ¹² Btu/yr/ 200 miles	22.71	112	0.076	0.95	Changed nominal system, including Y = 2. (Y = 3).

^aAll costs are in 1977 dollars unless specified otherwise. In some cases, noted in the comments column, the nominal system has been changed. The revised system is described on the following page.

^bSize on which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to overall conversion efficiency.

^gTCI for AC transmission reflects suggested change in IDC as discussed in Chapter I. Elsewhere where suggested data differs from SRI data, source is Reference 2.

^hUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

REVISED PROCESS DESCRIPTIONS FOR ELECTRIC TRANSMISSION

DC Transmission

Previous Description:

1,000 mile 600 kV DC transmission line. Input 1,000 mW/day, output 940 mW/day, load factor 85%, operating 365 days/year, 3 years to construct.

Revised Description:

800 mile ±400 kV DC, single circuit, aluminum clad steel reinforced cable, includes rectifier and inverter stations, converts output to 230 kV AC to supply eight distribution feeders, 1500 mW input capacity, load factor 85%, 2 years to construct, losses: 2% at rectifier, 1% per hundred miles, 1% at inverter.

AC Transmission

Previous Description:

1,000 mile 500 kV AC transmission line. Input 1,000 mW/day, output 790 mW/day, load factor 85%, operating 365 days/year, 3 years to construct.

Revised Description:

200 mile 500 kV transmission line. Input capacity 1000 mW, output capacity 950 mW, load factor 85%, operating 365 days/year, 2 years to construct.

for locomotives per 100 cars is considered reasonable, but SRI makes no allowance for equipment downtime. Bechtel allows 9.5% spare cars and 7.5% spare locomotives, figures which appear realistic. The SRI value for availability (252 days, or 69%) is considered low, and it is recommended that the TERA value of 90% be adopted instead, to better reflect the near-continuous movement inherent in the proper design of a unit train system.

As a result of the foregoing, new process descriptions were developed for unit trains. These descriptions were used in developing the data in Table V-2, and they appear on the page following that table. Note that the data in the table do not include any costs associated with track upgrading or track additions. The suggested SOC data in Table V-2 were derived from Bechtel data.

Slurry Pipelines. It was difficult to compare SRI values to those from other data bases. The Bechtel values are for a slurry pipeline which has 2.5 times the throughput capacity and which extends only 15% as far as the SRI pipeline. If one assumes directly proportional relationships between system cost and system length, and between system cost and system throughput, the Bechtel data show a TCI_e (total capital investment less interest during construction) only 5% higher than the SRI value.

This result is based on the additional assumption that the Bechtel system enjoys no economies of scale relative to the SRI system. Rather than make such an assumption over so large a range of system throughputs, it is suggested that the Bechtel data be adopted. The only change is to convert the Bechtel data to reflect costs associated with a 1000-mile system. This recalculation is straightforward since the portion of the system cost that varies with system length is independently displayed in the Bechtel data. Bechtel O&M costs, similarly converted, were used to calculate the suggested SOC data in Table V-3. An additional recommendation is that the technological change rate on capital for SRC slurry pipelines should probably be changed to 0.10 to be consistent with that for other slurry pipelines.

Lower 48 Liquids Pipelines. The Bechtel data refers to a 150-mile 800,000-bbl/day crude oil pipeline, whereas the SRI data refers to a 1000-mile 600,000-bbl/day line. Assuming linear proportionality between capital cost and both distance and throughput, the Bechtel data yield a TCI_e only 1.1% higher than the SRI value. Thus SRI and Bechtel agree on the capital costs/bbl-mile of pipelines in the 600,000 to 800,000-bbl/day range, and it is suggested that the SRI data be retained. Because the processes involved are similar, it seems equally reasonable to retain the SRI capital data for gasoline, distillate, methanol, and LPG pipelines. (See Table V-4.)

The Bechtel data base, for reasons already mentioned, was again relied on in the development of suggested SOC values. The SOC for crude oil pipelines was calculated first, with adjustments for differences in the physical capacities of the SRI and Bechtel pipelines. The SOC values for the other pipelines were then adjusted to preserve the relative SOC relationships that exist in the original SRI data.

Alaskan and Canadian Pipelines. The SRI data on Alaskan and Canadian pipelines were compiled before completion of the first trans-Alaska crude oil pipeline (the Alyeska pipeline). The first pipeline has since been completed, and

Table V-2
Process Economics Data^a
Sector: Transportation (Unit Trains)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data ^g					Comments ^h
		SOC ^c (75 \$/ 10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency ^f	Unit Size ^b	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/1000 miles)	Effi- ciency	
Western unit train	15.6 x 10 ¹² Btu/yr/ 1000 miles	0.65	0.74	8.0	0.467	1.00	15.3 x 10 ¹² Btu/yr/ 1000 miles	0.46	6.4	0.524	1.00	Changed nominal system, including Y = 0. (Y = 1)
Eastern unit train	23.4 x 10 ¹² Btu/yr/ 1000 miles	0.43	0.49	8.0	0.433	1.00	35.8 x 10 ¹² Btu/yr/ 500 miles	0.40	6.4	0.449	1.00	Changed nominal system, including Y = 0. (Y = 1)
SRC eastern unit train	30.4 x 10 ¹² Btu/yr/ 1000 miles	0.33	0.38	8.0	0.331	1.00	46.4 x 10 ¹² Btu/yr/ 500 miles	0.31	6.4	0.346	1.00	Changed nominal system, including Y = 0. (Y = 1)
SRC western unit train	30.4 x 10 ¹² Btu/yr/ 1000 miles	0.33	0.38	8.0	0.239	1.00	29.9 x 10 ¹² Btu/yr/ 1000 miles	0.24	6.4	0.269	1.00	Changed nominal system, including Y = 0. (Y = 1)

^aAll costs are in 1977 dollars unless specified otherwise. In some cases, noted in the comments column, the nominal system has been changed. The revised system is described on the following page.

^bSize on which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specified Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to the overall conversion efficiency.

^gSOC from Reference 2. See text for sources for capital cost data. Cost data does not include cost of track upgrading or new track.

^hUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

REVISED PROCESS DESCRIPTIONS FOR UNIT TRAINS

Western Unit Trains (including SRC trains)

Previous Description:

100 car train with 5 locomotives hauling 10,000 short tons on a 3.8 day cycle, operating 252 days per year for an annual throughput of 663,000 short tons, one year to construct.

Revised Description:

100 car train with 5 locomotives, plus 9.5% spare cars and 7.5% spare locomotives. Delivering 10,000 short tons 94 times per year at capacity. One-way distance 1000 miles, load factor 90%, zero years to construct.

Eastern Unit Trains (including SRC trains)

Previous Description:

100 car train with 5 locomotives hauling 10,000 short tons on a 3.8 day cycle, operating 252 days per year for an annual throughput of 663,000 short tons, one year to construct.

Revised Description:

100 car train with 5 locomotives, plus 9.5% spare cars and 7.5% spare locomotives. Delivering 10,000 short tons 146 times per year at capacity. One-way distance 500 miles, load factor 90%, zero years to construct.

Table V-3
Process Economics Data^a
Sector: Transportation (Slurry Pipelines)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data ^g					Comments ^h
		SOC ^c (\$/10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency ^f	Unit Size ^b	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC \$/10 ⁶ Btu/1000 miles)	Effi- ciency	
Western slurry pipeline	167 x 10 ¹² Btu/yr/ 1000 miles	3.92	4.47	795	0.171	1.00	417 x 10 ¹² Btu/yr/ 1000 miles	2.01	819	0.113	1.00	Changed nominal system.
Eastern slurry pipeline	250 x 10 ¹² Btu/yr/ 1000 miles	2.60	2.96	795	0.114	1.00	625 x 10 ¹² Btu/yr/ 1000 miles	1.34	819	0.075	1.00	Changed nominal system.
SRC slurry pipeline	325 x 10 ¹² Btu/yr/ 1000 miles	2.00	2.28	795	0.085	1.00	813 x 10 ¹² Btu/yr/ 1000 miles	1.03	819	0.058	1.00	Changed nominal system. R = 0.10 (R = 0.07)

^aAll costs are in 1977 dollars unless specified otherwise. In some cases, noted in the comments column, the nominal system has been changed. The revised system is described on the following page.

^bSize on which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to the overall conversion efficiency.

^gData derived from Reference 2.

^hUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

REVISED PROCESS DESCRIPTION FOR SLURRY PIPELINES

Previous Description:

30" pipeline, 1000 miles long, with input and output of 10 million short tons/year, operating 357 days/year (28,000 short tons/day).

Revised Description:

38" pipeline, 1000 miles long, with input and output of 25 million short tons/year, operating 357 days/year (70,000 short tons/day).

Table V-4
Process Economics Data^a
Sector: Transportation (Lower 48 Liquids Pipelines)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data ^{g, h}				
		SOC ^c (175 \$/ 10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency	Unit Size ^b	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/1000 miles)	Effi- ciency
Pipeline:											
Gasoline	1150 x 10 ¹² Btu/yr/ 1000 miles	0.34	0.39	470	0.035	1.00	1150 x 10 ¹² Btu/yr/ 1000 miles	0.39	450	0.025	1.00
Distillate	1280 x 10 ¹² Btu/yr/ 1000 miles	0.32	0.36	480	0.032	1.00	1280 x 10 ¹² Btu/yr/ 1000 miles	0.36	460	0.023	1.00
Crude oil	1270 x 10 ¹² Btu/yr/ 1000 miles	0.32	0.36	480	0.032	1.00	1270 x 10 ¹² Btu/yr/ 1000 miles	0.36	460	0.023	1.00
Methanol	585 x 10 ¹² Btu/yr/ 1000 miles	0.60	0.68	420	0.062	1.00	585 x 10 ¹² Btu/yr/ 1000 miles	0.68	400	0.045	1.00
LPG	121 x 10 ¹² Btu/yr/ 1000 miles	0.83	0.95	120	0.091	1.00	121 x 10 ¹² Btu/yr/ 1000 miles	0.95	110	0.065	1.00

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize upon which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for a given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to the overall conversion efficiency.

^gSOC derived from Reference 2. SRI data adopted for other variables. TCI reflects suggested change in IDC as discussed in Chapter I.

^hUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T).

its capital cost data have been reported in the Oil & Gas Journal (O&G).⁴ It is recommended that the SRI data base be changed to be consistent with this more recent information.

This involves incorporating the O&G construction cost into the SRI data for an Alaska crude pipeline. The only adjustment needed is to increase the O&G number for the greater length of the SRI system. From the O&G cost breakdown for the Alyeska line, it is estimated that $\$7200 \times 10^6$ of the cost of this 800-mile line varies proportionately with system length. This variable component would thus increase to $\$9000 \times 10^6$ for the 1000-mile SRI system. To this must be added $\$1500 \times 10^6$ in construction costs which do not vary with system length. This raises the 1000-mile construction cost to $\$10,500 \times 10^6$, versus $\$8700 \times 10^6$ for the Alyeska line. Increasing Alyeska's IDC by the same ratio results in IDC of $\$1600 \times 10^6$ for the 1000-mile line. TCI for this longer line is thus $\$12,100 \times 10^6$. This represents a 57% increase over the original SRI value of $\$7700 \times 10^6$ (including IDC). It is recommended that TCI for SRI's Alaska methanol pipeline, Alaska/Canada gas pipeline, and trans-Canada pipeline be likewise increased by 57%. SCC for these systems should also undergo the same percentage increase as the SCC of the Alaskan crude line.

Bechtel data were used to calculate SOC for the Alaska crude pipeline, and SOC for the other systems was adjusted so that its relationship to that of the Alaskan line did not change when compared with the original SRI data.

The rest of the SRI data were generally found to be reasonable; however, it is recommended that the technological change limit on capital for the trans-Canada crude pipeline be changed to be consistent with that for the trans-Alaska crude pipeline. It is also suggested that the technological change rate on capital for the Alaska methanol pipeline be changed to be consistent with that for other pipelines. All the suggested changes for Alaskan and Canadian pipelines are shown in Table V-5.

Lower 48 Gas Pipelines. The Bechtel data base contains information about a natural gas pipeline. Aside from the small difference in efficiency (95% vs. SRI's 94%) and the difference in system length (150 miles vs. SRI's 1000 miles) the line is identical to the SRI high-Btu gas pipeline. Since Bechtel does not indicate the variation of efficiency with system length, it was assumed that the efficiency shown is an average value for the range of distances (150 to 1500 miles) for which Bechtel indicates proportionality of costs. For simplicity the Bechtel line was assumed to have the same efficiency at a distance of 1000 miles as does the SRI line. It was then possible to calculate the high-Btu pipeline capital costs which appear as suggested data in Table V-6. Specific operating costs were likewise derived from the Bechtel data.

No data were found comparable to SRI's H₂ pipeline data, but, in view of the suggestions made concerning high-Btu gas pipelines, it is recommended that the H₂ pipeline data be adjusted so that H₂ pipelines maintain the same capital and operating costs relative to high-Btu gas pipelines.

Tankers. The SRI values of TCI for crude oil tankers and products tankers appear to be low compared with values derived from Maritime Administration data.⁵ It is suggested that the latter values be adopted.

The TCI for the LNG tanker in the SRI data likewise appears low. Bechtel and GAO⁹ both present capital cost data for LNG tankers. Since these are 125,000-cubic-meter tankers, one would expect them to cost more than the SRI

Table V-5
Process Economics Data^a
Sector: Transportation (Alaskan and Canadian Pipelines)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data ^g					Comments ^h
		SOC ^c (175 \$/ 10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/1000 miles)	Effi- ciency		
Pipeline:												
Alaska crude	4230 x 10 ¹² Btu/yr/ 1000 miles	1.71	1.95	7700	0.018	1.00	4230 x 10 ¹² Btu/yr/ 1000 miles	2.92	12100	0.013	1.00	
Alaska methanol	1950 x 10 ¹² Btu/yr/ 1000 miles	3.42	3.90	7090	0.036	1.00	1950 x 10 ¹² Btu/yr/ 1000 miles	5.85	11100	0.026	1.00	R = 0.07. (R = 0.09)
Trans-Canada crude	4230 x 10 ¹² Btu/yr/ 1000 miles	0.86	0.98	3850	0.017	1.00	4230 x 10 ¹² Btu/yr/ 1000 miles	1.47	6050	0.012	1.00	L = 1.16. (L = 1.09)
Alaska-Canada natural gas	1240 x 10 ¹² Btu/yr/ 1000 miles	2.63	3.00	3430	0.070	0.94	1240 x 10 ¹² Btu/yr/ 1000 miles	4.50	5390	0.051	0.94	

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize upon which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to the overall conversion efficiency.

^gTCI and SOC derived from Reference 4. SOC derived from Reference 2. SRI data adopted for efficiency values.

^hUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (Y), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

Table V-6
Process Economics Data^a
Sector: Transportation (Lower 48 Gas Pipelines)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data ^{a, h}				
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency ^f	Unit Size ^b	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/1000 miles)	Effi- ciency
High-Btu gas pipeline	299 x 10 ¹² Btu/yr/ 1000 miles	1.49	1.70	534	0.108	0.94	299 x 10 ¹² Btu/yr/ 1000 miles	2.16	653	0.066	0.94
H ₂ pipeline	214 x 10 ¹² Btu/yr/ 1000 miles	2.44	2.78	622	0.160	0.90	214 x 10 ¹² Btu/yr/ 1000 miles	3.53	761	0.098	0.90

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize upon which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to the overall conversion efficiency.

^gDerived from Reference 2. SRI data adopted for efficiency values.

^hUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T).

75,000-cubic-meter tanker, and they do. However, after adjusting for the size difference by assuming proportionality of costs, the Bechtel and GAO tankers are still respectively 19% and 42% more expensive than the SRI tanker. In making these comparisons it was assumed, to be consistent with SRI, that the Bechtel tanker had interest during construction (IDC) appropriate for a 3-yr build period. In reality the above percentages would be even larger because the assumed proportionality of costs tends to understate the cost of the Bechtel and GAO tankers relative to that of the SRI tanker. Reducing vessel size by 40% (from 125,000 to 75,000 cubic meters, in this case) generally results in a cost reduction of less than 40%. This supports the argument that the SRI value of TCI is too low.

It is recommended that the Bechtel value for TCI be adopted. The value shown in Table V-7 is the Bechtel value adjusted to include IDC for a 3-yr build period (the original data had zero IDC). It is further recommended that the description of the nominal system be changed to be consistent with Bechtel.

Bechtel is also the source of the recommended values of SOC for crude oil and LNG tankers. For products tankers it is recommended that the SRI values for SOC be adjusted so that their relationship to the SOC of crude oil tankers remains unchanged.

It is also recommended that the technological change limit on capital for all tankers be changed to unity. The SRI data apparently reflect the assumption that the specific capital cost of tankers will decrease substantially in future decades. This assumption is realistic considering (a) the present trend towards ever-larger tankers, (b) the future use of offshore terminals and/or lightering techniques designed to overcome the absence of U. S. ports deep enough to handle large tankers, and (c) the inverse relationship between vessel size and specific capital costs. However, it is probable that these factors will be offset to some extent by government regulations that could substantially increase the cost of a tanker of any given size, such as requirements for double-hull construction, substantial auxiliary power backup, double rudders, twin screws, and other features intended to improve the reliability and safety of tankers serving the U. S. market. It is therefore more prudent to adopt a technological change limit on capital that will have a neutral effect on future economics.

Barges. The barge systems described in the Bechtel data are physically identical to those in the SRI data. It is suggested that Bechtel values for TCI and SOC be adopted. (See Table V-8.)

Terminal and Storage Costs. Data generally were not available to validate the SRI terminal and storage costs. Since these costs typically represent minor portions of total transportation costs, little risk is involved in continuing to use the SRI values, except for LNG liquefaction and regasification. Terminal and storage costs for LNG are substantial and, as in the case of LNG tankers, the SRI values for TCI are substantially below those of other references. The suggested TCI values for LNG in Tables V-9 and V-10 are adapted from GAO data.⁹

PIES and SRI Energy Transportation Cost Appraisal

Transportation Considerations for Energy Modeling. In attempting to represent source-to-user transportation costs for energy modeling purposes, regional centroids are selected to represent groups of producers and users, and

Table V-7
Process Economics Data^a
Sector: Transportation (Tankers)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data					Comments ⁱ
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency	Unit Size ^b	SOC ^g (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI ^g (10 ⁶ \$)	SOC ^h (\$/10 ⁶ Btu/1000 miles)	Effi- ciency	
Crude oil Tanker (Alaska)	107 x 10 ¹² Btu/yr/ 1500 miles	0.26	0.30	50	0.026	1.00	107 x 10 ¹² Btu/yr/ 1500 miles	0.32	51	0.043	1.00	L = 1.00. (L = 0.70)
Domestic Products												
Tanker: Distillate	39.8 x 10 ¹² Btu/yr/ 2000 miles	0.34	0.39	32	0.040	1.00	39.8 x 10 ¹² Btu/yr/ 2000 miles	0.45	35	0.066	1.00	L = 1.00. (L = 0.60)
LS Residue	39.1 x 10 ¹² Btu/yr/ 2000 miles	0.37	0.42	32	0.042	1.00	39.1 x 10 ¹² Btu/yr/ 2000 miles	0.46	35	0.069	1.00	L = 1.00. (L = 0.60)
Gasoline	41.9 x 10 ¹² Btu/yr/ 2000 miles	0.33	0.38	32	0.038	1.00	41.9 x 10 ¹² Btu/yr/ 2000 miles	0.43	35	0.063	1.00	L = 1.00. (L = 0.60)
Methanol	19.9 x 10 ¹² Btu/yr/ 2000 miles	0.67	0.76	32	0.080	1.00	19.9 x 10 ¹² Btu/yr/ 2000 miles	0.90	35	0.132	1.00	L = 1.00. (L = 0.60)
LNG tanker ^j	64.2 x 10 ¹² Btu/yr/ 1500 miles	0.70	0.80	79	0.052	0.93	107 x 10 ¹² Btu/yr/ 1500 miles	1.01	157	0.065	0.93	Changed nominal system, including L = 1.00. (L = 0.60)

^aAll costs are in 1977 dollars unless specified otherwise. In some cases, noted in the comments column, the nominal system has been changed. The revised system is described on the following page.

^bSize upon which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to the overall conversion efficiency.

^gData for crude oil tankers and domestic products tankers derived from Reference 5. Data for LNG tanker derived from Reference 2. Revised nominal system for LNG tanker is described on the following page. SRI data adopted for efficiency values.

^hDerived from Reference 2.

ⁱUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

^jExcludes liquefaction and regasification facilities.

Previous Description:

75,000 cubic meter U.S. built and flag LNG tanker, operating 340 days/year, moving 2.72 million cubic meters/year, over a trading distance of 1500 miles, 3 years to construct.

Revised Description:

125,000 cubic meter U. S. built and flag LNG tanker, operating 340 days/year, moving 4.53 million cubic meters/year, over a trading distance of 1500 miles, 3 years to construct.

Table V-8
Process Economics Data^a
Sector: Transportation (Barges)

Technology/ Process	Unit Size ^b	SRI Data					Suggested Data ^g					Comments ^h
		SOC ^c (1975 \$/ 10 ⁶ Btu/ yr/1000 mi)	SOC (\$/10 ⁶ Btu/yr/ 1000 mi)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/1000 miles)	Effi- ciency ^f	Unit Size ^b	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/1000 miles)	Effi- ciency	
LS resid Transportation	16.4x 10 ¹² Btu/yr/ 1000 miles	0.22 ⁱ	0.25	4.2	0.054	1.00	16.4 x 10 ¹² Btu/yr/ 1000 miles	0.31	4.8	0.101	1.00	Y = 0. (Y = 1)
Utility coal resid Transportation	16.4 x 10 ¹² Btu/yr/ 1000 miles	0.22 ⁱ	0.25	4.2	0.054	1.00	16.4 x 10 ¹² Btu/yr/ 1000 miles	0.31	4.8	0.101	1.00	Y = 0. (Y = 1)
SRC coal Barge	19.5 x 10 ¹² Btu/yr/ 1000 miles	0.25	0.28	5.2	0.114	1.00	19.5 x 10 ¹² Btu/yr/ 1000 miles	0.30	5.6	0.082	1.00	Y = 0. (Y = 1)
HS coal Barge	15.0 x 10 ¹² Btu/yr/ 1000 miles	0.31	0.35	5.2	0.148	1.00	15.0 x 10 ¹² Btu/yr/ 1000 miles	0.39	5.6	0.107	1.00	Y = 0. (Y = 1)
LS coal Barge	10.0 x 10 ¹² Btu/yr/ 1000 miles	0.44	0.50	5.2	0.228	1.00	10.0 x 10 ¹² Btu/yr/ 1000 miles	0.58	5.6	0.161	1.00	Y = 0. (Y = 1)

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize upon which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size.

^eSOC: Specific Operating Cost.

^fThis refers to the overall conversion efficiency.

^gCost data derived from Reference 2.

^hUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

ⁱSRI value is three times the value shown here. SRI value is intended to reflect 20% rail movement at three times barge costs.

Table V-9
Process Economics Data^a
Sector: Transportation (Terminal and Storage Costs: Loading)

Technology/ Process	Unit Size ^b (10 ¹² Btu/yr)	SRI				Suggested Data ^f			Comments ^g
		SOC ^c (\$/10 ⁶ Btu/yr/ 1000 miles)	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/ 1000 miles)	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/ 1000 miles)	
Liquids pipeline	not given	0.04	0.05	-	0.003	0.05	-	0.003	
High-Btu gas pipeline	299.0	0.05	0.06	18.0	0.003	0.06	18.0	0.003	Y = 1. (not given)
LPG pipeline	121.0	0.08	0.09	11.0	0.001	0.09	11.0	0.001	Y = 1. (not given)
H ₂ pipeline	214.0	0.08	0.09	20.0	0.006	0.09	19.0	0.006	Y = 1. (not given)
Alaska/Canada gas pipeline	1240.0	0.08	0.09	114.0	0.006	0.09	109.0	0.006	Y = 2. (not given)
Crude and products - tanker	not given	0.04	0.05	-	0.0004	0.05	-	0.0004	
LNG liquefaction and regasification	64.2	0.64	0.73	46.0	0.041	3.18	194.0	0.041	Y = 2. (not given)
Resid transportation	16.4	0.08	0.09	1.5	0.001	0.09	1.4	0.001	Y = 1. (not given)
Coal barges	not given	0.024	0.027	-	0.0002	0.027	-	0.0002	

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize upon which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year. Where possible, an assumption has been made that SRI matched the size of terminal and storage facilities to the size of corresponding transportation systems appearing in previous tables.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size. Assumed build period is same as in comments column.

^eSOC: Specific Operating Cost.

^fLNG data from Reference 9. Unable to verify other data. TCI changes reflect suggested changes in IDC as discussed in Chapter I.

^gUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

Table V-10
Process Economics Data^a
Sector: Transportation (Terminal and Storage Costs: Discharging)

Technology/ Process	Unit Size ^b (10 ¹² Btu/yr)	SRI				Suggested Data ^f			Comments ^g
		SOC ^c (\$/10 ⁶ Btu/yr/ 1000 miles)	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu/ 1000 miles)	SOC (\$/10 ⁶ Btu/yr/ 1000 miles)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu/ 1000 miles)	
Liquids pipeline	not given	0.04	0.05	-	0.003	0.05	-	0.003	
High-Btu gas pipeline	299.0	0.10	0.11	33.0	0.007	0.11	33.0	0.007	Y = 1. (not given)
LPG pipeline	121.0	0.08	0.09	11.0	0.001	0.09	11.0	0.001	Y = 1. (not given)
H ₂ pipeline	214.0	0.16	0.18	39.0	0.01	0.18	38.0	0.01	Y = 1. (not given)
Alaska/Canada gas pipeline	1240.0	0.16	0.18	228.0	0.01	0.18	218.0	0.01	Y = 2. (not given)
Crude and products tanker	not given	0.04	0.05	-	0.0004	0.05	-	0.0004	
LNG liquefaction and regasification	64.2	0.16	0.18	11.0	0.010	0.95	58.0	0.010	Y = 2. (not given)
Resid transportation	16.4	0.08	0.09	1.5	0.001	0.09	1.4	0.001	Y = 1. (not given)
Coal barges	not given	0.024	0.027	-	0.0002	0.027	-	0.0002	

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize upon which Total Capital Investment (TCI) is based. Output size when operating at 100% load factor, 365 days per year. Where possible, an assumption has been made that SRI matched the size of terminal and storage facilities to the size of corresponding transportation systems appearing in previous tables.

^cSOC: Specific Capital Cost excluding Interest During Construction (IDC).

^dTCI: Total Capital Investment including IDC for the given unit size. Assumed build period is same as in comments column.

^eSOC: Specific Operating Cost.

^fLNG data from Reference 9. Unable to verify other data. TCI changes reflect suggested changes in IDC as discussed in Chapter I.

^gUnless otherwise specified, changes are not suggested for the following SRI variables: Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Year Available (t), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T). SRI values are shown in parentheses in the case of revised variables.

transportation costs are calculated on the basis of these centroids. In reality, transportation costs are specific to each individual producer/consumer pair, as costs are route specific and depend on many variables (for instance, in the case of rail transport, circuitry, grade, return of empties, unique terminal facilities, etc.). Any approach that does not define transportation costs by route-specific methods is by definition only a broad approximation to actual costs. A high degree of precision in calculating centroid-to-centroid costs is usually not justified, since the route-specific economics of the centroid are generally different from the economics of each producer or consumer represented by the centroid. Nevertheless, some approximation of relative transportation costs for various supply and demand centroids is necessary for analyses utilizing energy models.

Generalized correlations, such as those developed by Bechtel,¹⁰ are often used in the calculation of centroid-to-centroid costs, rather than attempt to define the route-specific economics for each supply/demand centroid pair. Ease of calculation, coupled with the uncertainty introduced by aggregating individual demands to centroids, provides partial justification for this approach. Also, since the data base necessary for estimating route specific costs is often not available, the only practical option is to use generalized transportation cost correlations.

Coal Transportation - PIES. PIES coal transportation costs (rail) are calculated on the following basis:

$$\begin{aligned} \$/\text{ton} &= 1.60 + 0.0094D \text{ for unit train (utility demand only),} \\ \$/\text{ton} &= 2.50 + 0.0094D \text{ for others,} \end{aligned}$$

where D is the rail distance in miles between supply and demand centroids. Rail transport costs calculated from the above formulas agree reasonably well with another generalized method^{11,12} (see Figures V-1 and V-2).

Back calculation of rail distances from costs used in PIES and the above formulas (Tables V-11 and V-12) also yields reasonable results, except for short-haul lignite movements and movements that include waterborne shipments. The data required to analyze these movements are not readily available; PIES data disaggregation for transportation links that include barge movements or lignite is not provided.

Like rail transport, coal transport by water is subject to route-specific factors (e.g., tow size, barge size, current, etc.). The stated PIES methodology for cost calculations for such links is consistent with that in another major source.¹³ Although domestic inland waterborne coal shipments comprise a significant fraction of total coal traffic, rail movement is expected to remain the most important coal transport mode (see below).

Total U. S. Bituminous Coal Shipments to U. S. Destinations - 1976

	<u>10⁶ Tons</u>	<u>Percent</u>
All-rail movements	331.0	54.0
River and ex-river	107.5	17.5
Truck	69.4	11.3
Great Lakes	33.1	5.4
Tidewater	5.3	0.9
Tramway, conveyor, and private cars	66.7	10.9
Total	613.0	100.0

Figure V-1. Coal transportation cost - unit train.

Figure V-2. Coal transportation cost - spot rail.

Table V-11
Coal Transportation - Rail Cost
(1975 Dollars per short ton)

Coal Region	Destination										
	Boston	New York	Baltimore Philadelphia	Pittsburgh	Miami	Atlanta	Cincinnati South	Cincinnati North	Detroit	Chicago	St. Louis East
North Appalachia	8.30	6.89	5.14	1.69	14.77	8.04	3.44	3.44	4.47	6.08	6.33
Central Appalachia	9.24	6.83	5.08	6.97	11.72	4.89	4.00	4.00	8.31	5.76	4.07
South Appalachia	13.67	11.26	9.51	10.73	8.88	3.16	7.76	7.76	9.63	7.08	9.39
Midwest	12.65	10.24	8.49	9.99	11.66	7.10	3.02	3.02	6.25	3.70	2.01
Central West	15.90	13.49	11.74	9.18	14.27	8.85	6.27	6.27	7.34	4.79	3.10
Gulf	19.38	16.97	15.22	13.71	14.55	8.87	10.80	10.80	11.87	9.32	7.63
NE Great Plains	21.14	18.73	17.11	13.75	19.64	14.22	11.64	11.64	11.91	9.36	8.47
NW Great Plains	24.55	22.14	20.52	17.16	23.05	17.63	15.05	15.05	15.32	12.77	11.88
Rockies	24.61	22.20	20.45	17.80	23.05	17.56	14.98	14.98	16.05	13.50	11.81
Southwest	27.71	25.30	23.55	21.28	23.93	17.20	18.37	18.37	19.44	16.89	15.20
Northwest	33.88	31.47	29.85	26.49	32.38	26.96	24.38	24.38	24.65	22.10	21.21
Alaska	41.79	39.38	37.76	34.40	40.29	34.87	32.29	32.29	32.56	30.01	24.12
	St. Paul Minneapolis	New Orleans	Baltimore Houston	Pittsburgh Dallas	Miami St. Louis, W	Atlanta Kansas	Cincinnati Denver	Cincinnati Los Angeles	Detroit San Francisco	Chicago Seattle	St. Louis East
N. Appalachia	9.30	8.00	8.28	10.76	6.33	8.52	14.49	23.70	28.11	26.20	
Central Appalachia	8.40	6.05	8.22	10.70	4.07	6.26	12.23	23.64	26.17	24.40	
South Appalachia	9.72	3.35	6.76	9.24	5.39	7.58	13.55	22.18	26.59	28.12	
Midwest	6.34	2.47	5.88	8.36	2.01	4.20	10.17	21.30	24.11	22.74	
Central West	6.20	5.08	8.49	6.64	3.10	1.69	7.66	20.26	21.60	22.60	
Gulf	10.48	5.36	1.95	1.12	7.63	5.97	8.96	14.64	19.29	24.73	
NE Great Plains	5.60	10.45	13.86	15.00	8.47	10.50	9.88	23.61	22.74	14.28	
NW Great Plains	9.05	13.86	14.99	12.51	11.88	10.64	4.67	18.40	18.65	14.26	
Rockies	12.50	13.79	14.50	18.02	11.81	10.15	4.18	12.68	13.06	15.55	
Southwest	15.89	15.34	11.93	9.45	15.20	13.54	7.57	12.78	17.19	23.34	
Northwest	18.38	23.19	26.60	24.42	21.21	22.55	16.58	14.85	10.44	1.98	
Alaska	26.29	31.10	34.51	32.33	29.12	30.46	24.49	22.76	18.35	9.49	

Table V-12
Coal Transportation - PIES Rail Distances (Miles)

Coal Region	Destination										
	Boston	New York	Baltimore Philadelphia	Pittsburgh	Miami	Atlanta	Cincinnati South	Cincinnati North	Detroit	Chicago	St. Louis East
North Appalachia	819	563	377	10	1401	685	196	196	305	477	503
Central Appalachia	813	556	370	571	1077	361	255	255	714	443	263
South Appalachia	1284	1028	841	971	882	166	655	655	854	583	403
Midwest	1176	919	733	467	1070	585	151	151	495	223	44
Central West	1521	1265	1079	806	1348	771	497	497	611	339	160
Gulf	1891	1635	1449	1288	1378	773	979	979	1093	821	642
NE Great Plains	2079	1822	1650	1293	1919	1343	1068	1068	1097	826	731
NW Great Plains	2441	2185	2013	1655	2282	1705	1430	1430	1460	1188	1094
Rockies	2448	2191	2005	1733	2274	1698	1423	1423	1537	1266	1086
Southwest	2778	2521	2335	2094	2376	1660	1784	1784	1898	1627	1447
Northwest	3434	3178	3005	2648	3274	2698	2423	2423	2452	2181	2086
Alaska	4276	4019	3847	3489	4116	3539	3265	3265	3294	3022	2928
Coal Region	Destination										
	St. Paul Minneapolis	New Orleans	Houston	Dallas	St. Louis, W	Kansas	Denver	Los Angeles	San Francisco	Seattle	
N. Appalachia	872	681	711	974	503	736	1371	2351	2820	2617	
Central Appalachia	723	473	704	968	263	496	1131	2345	2614	2468	
South Appalachia	864	186	549	813	403	636	1271	2189	2659	2609	
Midwest	504	93	455	719	44	277	912	2096	2395	2249	
Central West	489	370	733	526	160	10	645	1985	2128	2234	
Gulf	945	400	37	51	541	465	783	1409	1878	2461	
NE Great Plains	430	941	1304	1426	731	910	881	2341	2249	1349	
NW Great Plains	793	1304	1424	1161	1094	962	327	1787	1810	1347	
Rockies	1160	1257	1372	1109	1086	910	274	1179	1219	1484	
Southwest	1520	1462	1099	835	1447	1270	635	1189	1659	2313	
Northwest	1785	2299	2660	2428	2086	2229	1594	1410	940	40	
Alaska	2627	3138	3501	3269	2928	3070	2435	2251	1782	882	

Omission of slurry pipelines from consideration is probably justified for 1985 and perhaps for 1990. A recent DOT study indicates that "... under the most favorable circumstances, pipelines are likely to play only a minor role in the transportation of coal through 1985."¹⁴

In summary: (1) The generalized methodology used to calculate coal transportation costs for PIES is reasonably consistent with another generalized methodology, and (2) the distances used in applying this generalized methodology are also plausible.

Given the status of the available coal transportation data base and the relative complexity of the PIES transportation network, the approach used to obtain PIES coal transportation costs seem reasonable and justifiable.

It is recommended that the following escalation rates¹⁵ be applied in converting PIES coal transportation costs from 1975 to 1977 dollars:

9.5%/year for Rail and 9.0%/year for Barge

Coal Transportation - SRI. "Clearly, transportation costs are not simply proportional to distance due to large fixed cost components and economies of scale. However, for longer distances, proportionality is a reasonable assumption. We assume that capital and operating costs are proportional to distance, and handle short distance transportation under the category of distribution, which is discussed in a separate section."¹⁶

Analysis of coal transportation cost data indicates that significant economies of haul do exist for longer versus shorter distances.¹⁷ Regression analysis of available data shows that these economies take the general shape of the curves in Figures V-1 and V-2.

SRI uses a basis of 1000 miles for unit train transportation of coal to electric utilities and assumes a linear extrapolation of costs for distance variations. For long-distance hauls, this assumption introduces a small degree of error, but, for shorter distances the error can be considerable (see Figure V-3). Linear extrapolation of costs based on 1000 miles to significantly shorter distances leads to a lower transportation cost for short hauls than can be reasonably expected. For instance, for a distance of 300 miles (see Figure V-3), the SRI methodology gives a unit cost ~ 5 mills/ton-mile less than that predicted by a method based on data regression (PIES); this translates to a cost difference of approximately \$1.50/ton. Since the number of coal resource regions (4) and demand regions (11) are small in the SRI model, most distances between regional centroids are large. Therefore, the SRI assumption of linear cost behavior for long distance hauls will lead to significant error only in the few cases where shorter distances are a factor.

Of more concern are the distance and coal quality errors associated with the small number of coal resource regions. An insufficient number of coal supply regions overstates the distances associated with coal transportation and thus places coal at a disadvantage relative to other fuels. Since solid fuel transport by rail is far more expensive than liquid and gas transport by pipeline, adequate representation of transport distances is more important for coal than for other fuels. A distance error of 500 miles, e.g., Southern Appalachia (Alabama) production represented as originating in West Virginia, leads to a

Figure V-3. Coal transportation cost - unit train,
SRI vs. PIES.

great distortion (~\$5.00/ton) in the cost of this coal delivered to any Southern U. S. location. In addition, this restricted SRI coal supply representation completely ignores several important coal resources (e.g., Texas lignite).

The SRI coal supply representation would be greatly improved by increasing the number of coal resource regions (PIES has 11) and by adopting a method for calculating transportation costs which takes into account the relative economics of long and short hauls.

The above SRI methodology applies to utility coal only; the following charges for distribution are added for industrial coal:

	<u>\$/10⁶ Btu</u>	<u>\$/Ton</u>
Low sulfur, low Btu	0.31	5.05
High sulfur, high Btu	0.27	6.62

These charges, combined with interregional transportation costs, yield the cost/distance profile shown in Figure V-4. Compared with the costs (spot rail) for industrial coal transportation derived from other data regression analyses, the SRI costs seem exaggerated. The use of a lower \$/ton handling charge (e.g., \$3.00) would remedy this discrepancy.

Natural Gas Transportation. "For practical purposes, currently all of the domestic natural gas used in this county is delivered via pipelines."¹⁸ Even liquefied natural gas (LNG), received via tanker, is regasified and moved by pipeline. Purchase prices for imported LNG and Canadian gas are delivered city-gate prices; consequently, the only natural gas transportation charges represented explicitly in PIES are for pipeline movements.

In PIES, natural gas transportation by pipeline is charged as \$0.033/MCF per 100 miles for existing transportation links; other links are charged at \$0.04/MCF per 100 miles. PIES cost data for existing pipelines are based on a weighted average of transportation costs for eight large gas pipelines; the cost basis for other lines is not provided. Comparison of these costs with costs based on other sources is shown below:

Natural Gas Transportation Costs (1975\$/10³ SCF/1000 mi)

	<u>PIES</u>	<u>SRI¹⁹</u>	<u>Bechtel ESPM²⁰</u>	<u>Bechtel RESPON²¹</u>
Existing	0.33			
New	0.40	0.295	0.281	0.288

The PIES cost for existing pipelines is close to other data for new pipelines; the PIES cost for new pipelines is considerably higher than other estimates. It is recommended that (1) a rate of 0.30 (1975\$/10³ SCF/1000 mi) be charged to all natural gas pipeline shipments, and (2) this cost be escalated by 7.9%/yr to convert 1975\$ to 1977\$²² for new pipelines and by 2.5%/yr for existing pipelines.

As shown above, the natural gas transportation cost calculated from SRI capital and O&M data is consistent with that in the other cited sources.

Crude Oil Transportation: Pipelines. "Due to the location of refineries and the extensive network of pipelines in existence, ~ 90 percent of all crude oil shipments between domestic locations move via pipelines."²³

Figure V-4. Coal transportation cost - industrial, SRI vs. PIES.

PIES crude oil pipeline transportation costs are based on ICC tariffs for existing pipelines, and \$0.06/bbl per 100 miles for other (new) pipelines. In the absence of NPC Region (source)/refinery region (destination) distance data, it is not possible to evaluate PIES cost data for existing pipelines against generalized correlations. Comparison of the PIES cost of moving crude oil via new pipeline links versus costs derived from other sources is shown below:

Crude Oil Transportation Cost (1975 \$/bbl/100 mi)

<u>PIES</u>	<u>SRI</u> ²⁴	<u>Bechtel ESPM</u> ²⁵	<u>Bechtel RESPONS</u> ²⁶
0.060	0.047	0.042	0.040

Since cost is a function of pipeline diameter, terrain, etc., there is no single "correct" cost for new pipeline charges, but, the consistency among sources other than PIES for the cost of crude oil movements via large-diameter pipelines implies that the PIES cost is higher than necessary. It is suggested that: (1) PIES cost for new pipelines be revised to 0.04 (1975 \$/bbl 100 mi) for consistency with other sources, and (2) this cost be escalated by 8.1%/yr for conversion of 1975 to 1977 \$.

"Because of its capital intensity, a high proportion of pipeline costs is of a fixed character. In a typical large pipeline, fixed costs are often as much as 80 percent of total costs. As much as two-thirds of every revenue dollar may be required to service debt, pay taxes, and provide return on investment."²⁸ To escalate costs for crude oil transportation via existing pipelines, an overall escalation rate of 2.5%/yr is suggested.

The crude oil pipeline transportation cost (ex. Alaska) calculated from SRI capital and O&M costs (see above) shows good correspondence with other available data. Costs for crude transportation via the trans-Alaskan pipeline for PIES and SRI do not agree: PIES uses a charge of \$3.40/bbl, whereas calculations using SRI capital and O&M give \$2.30/bbl. The current tariff rate, \$4.62/bbl, is expected to decline somewhat with full pipeline utilization; the PIES cost appears more realistic.

Crude Oil Transportation: Barge and Tanker. Few interregional transportation links for barge and tanker movements of crude oil are included in PIES. Given that pipeline movements in PIES (other than the trans-Alaskan) have no capacity constraints and that over half the barge and tanker links duplicate lower-cost pipeline transportation options, the only barge and tanker movements of any importance in PIES are the links between PAD 1A and PAD 1B (Northeast and Atlantic) to the West Gulf Basin, Gulf of Mexico, Atlantic Coast, and Atlantic Ocean. Since the distances assumed for these links are not provided, comparison with costs from generalized methods is not possible. Costs are 10 to 30% lower than for comparable pipeline links and are therefore probably of the correct order of magnitude. Escalation of 9.7% per year²⁹ is suggested.

Interregional movements for crude oil via barge are not included in the SRI model, and only two tanker links are included (Alaska/California and U.S. Gulf Coast/Northeast). Tanker cost basis is provided only for the Alaska/California link, and calculations using this data yield a cost of \$0.35/bbl. This cost is lower than the cost in PIES (\$0.60/bbl) and possibly should be revised upward. However, in the absence of information concerning PIES tanker size and terminal and storage charges, this difference is not readily explainable. Nevertheless, tanker charges are small compared with the trans-Alaskan pipeline tariff (see above).

Petroleum Product Transportation: Pipeline and Barge. In general, the above comments about transportation of crude oil pertain also to that of petroleum products and it is suggested that the same escalation factors be applied.

SRI Distribution Data

The SRI data base contains distribution costs for various forms of energy. The data are disaggregated by type of fuel being distributed, by economic sector of fuel consumer, and in some cases by geographic region. In total, data are provided for 57 fuel/sector/region combinations. No other data bases were found containing this level of detail. Despite the sparse data, some recommendations can be made. These are discussed below.

High-Btu Gas. The average SRI specific capital cost (SCC) in 1975 dollars for high-Btu gas distribution is \$3.72 per million Btu for residential/commercial customers and \$0.76 for industrial customers. Assuming that additions to gas distribution facilities are evenly spread over all regions and all customers, these two numbers can be averaged to give \$2.24 per million Btu. Inflating to 1977 dollars yields an average SCC of \$2.55 per million Btu.

The Bechtel data base also provides information about gas distribution. The nominal Bechtel system delivers 50 million cubic feet per day to a 24-square-mile urban area. It has a SCC (1977 dollars) of \$2.48 per million Btu, which compares favorably with the average SRI value. Therefore the only change recommended for SCC is that the SRI data be restated in 1977 dollars. It is further suggested that Bechtel's specific operating cost (SOC) data for gas distribution be adopted because they are more inclusive than SRI's SOC data and are more consistent with the suggested data presented in the transportation discussion. In Table V-13, the SRI regional and sectoral dispersion of SOC values has been used as a source of weighting factors needed to regionalize and sectorialize the Bechtel value for SOC.

Hydrogen and Low-Btu Gas. No data were found for comparison with SRI's hydrogen and low-Btu gas distribution data. It is suggested that SRI's SCC data be retained and that the SOC data be revised upwards to the same degree that SOC was increased for high-Btu gas. (See Table V-14.)

Electricity. No electricity distribution data were found that were disaggregated in the manner used by SRI. Therefore an analysis was performed by first aggregating the SRI data. Combining the SCC values for electricity distributed to residential/commercial, industrial, and transportation users, gives an arithmetic average SRI value for SCC (1977 dollars) of \$7.00 per million Btu. Use of an arithmetic average in this context is based on the presumption that future additions to electricity distribution networks will deliver equal amounts of electricity to each of four service categories: residential/commercial space heat; residential/commercial other than space heat; industry; and transportation. SRI does not specify a load factor for the nominal system, and this makes comparisons with other data sources difficult. Assuming that the SRI load factor is similar to the FPC electrical generation capacity factor,³⁰ it was decided to presume a load factor of 50%.

Bechtel presents data for an electrical distribution system having an SCC of \$10.70 per million Btu for aerial lines with a load factor of 50%. The system distributes 58.4% of the electricity to industrial, 17.5% to commercial, and

Table V-13
Process Economics Data
Sector: Distribution of High-Btu Gas

	SRI Data			Suggested Data ^a	
	SCC ^b	SCC ^c	SOC ^d	SCC ^c	SOC ^d
Residential/Commercial					
New England	6.24	7.11	0.445	7.11	1.046
Mid Atlantic	4.83	5.51	0.353	5.51	0.830
South Atlantic	4.43	5.05	0.319	5.05	0.750
East South Central	3.36	3.83	0.239	3.83	0.562
East North Central	3.11	3.55	0.239	3.55	0.562
West South Central	2.79	3.18	0.205	3.18	0.482
West North Central	2.79	3.18	0.205	3.18	0.482
Mountain	2.79	3.18	0.205	3.18	0.482
Pacific	3.11	3.55	0.228	3.55	0.536
Industrial					
New England	2.71	3.09	0.194	3.09	0.456
Mid Atlantic	1.39	1.58	0.103	1.58	0.242
South Atlantic	0.65	0.74	0.046	0.74	0.108
East South Central	0.33	0.38	0.019	0.38	0.045
East North Central	1.07	1.22	0.080	1.22	0.188
West South Central	0.04	0.05	0.011	0.05	0.026
West North Central	0.09	0.10	0.011	0.10	0.026
Mountain	0.09	0.10	0.011	0.10	0.026
Pacific	0.49	0.56	0.019	0.56	0.045

^aUnless otherwise specified, changes are not suggested for the following SRI variables: Year Available (t), Thermal Efficiency (e), Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T).

^bSpecific Capital Cost ('75 \$/10⁶ Btu/yr).

^cSpecific Capital Cost ('77 \$/10⁶ Btu/yr). SRI data adopted for suggested data.

^dSpecific Operating Cost ('77 \$/10⁶ Btu). Derived from Reference 2.

Table V-14
Process Economics Data
Sector: Distribution of Fuels Other Than High-Btu Gas

	SRI Data			Suggested Data ^a	
	SCC ^b	SCC ^c	SOC ^d	SCC ^c	SOC ^d
Residential/Commercial					
Hydrogen	12.00	13.68	1.140	13.68	2.679
Electricity (except space heat)	13.47	15.36	2.497	23.48	1.169
Electricity (space heat)	5.10	5.81	0.958	8.88	0.449
Distillate	0.00	0.00	0.821	0.00	0.821
LPG rural	0.00	0.00	0.821	0.00	0.821 ^e
Distillate rural	0.00	0.00	1.459	0.00	1.459 ^e
LS residual	0.00	0.00	0.274	0.00	0.274
Industrial					
Hydrogen	6.00	6.84	0.627	6.84	1.473
Electricity	1.81	2.06	0.342	3.15	0.160
Distillate	0.00	0.00	0.068	0.00	0.068 ^e
LS residual	0.00	0.00	0.137	0.00	0.137 ^e
LS/LBtu coal	0.00	0.00	0.353	0.00	0.353 ^e
HS/HBtu coal	0.00	0.00	0.308	0.00	0.308 ^e
LS SRC	0.00	0.00	0.182	0.00	0.182 ^e
LBtu gas	5.65	6.44	0.615	6.44	1.445
Transportation					
Gasoline and diesel	0.00	0.00	0.878	0.00	0.878
Methanol	0.00	0.00	0.980	0.00	0.980 ^e
Jet and marine fuel	0.00	0.00	0.00	0.00	0.00
Electricity	4.18	4.77	0.798	7.29	0.374
Hydrogen vehicle	0.00	0.00	1.687	0.00	1.687 ^e

^aUnless otherwise specified, changes are not suggested for the following SRI variables: Year Available (t), Thermal Efficiency (e), Technological Change Limit on Capital (L), Technological Change Rate on Capital (R), Equity Fraction (F), Years to Construct (Y), Book Life (B), Tax Life (T).

^bSpecific Capital Cost ('75 \$/10⁶ Btu/yr).

^cSpecific Capital Cost ('77 \$/10⁶ Btu/yr). SRI data adopted except in the case of electricity distribution costs, which were derived from Reference 2 using the method discussed in the text.

^dSpecific Operating Cost ('77 \$/10⁶ Btu). Suggested data derived from Reference 2 or adopted from SRI data unless otherwise specified.

^eUnable to verify.

24.1% to residential customers. The Bechtel system thus has a larger share of industrial service than does the "average" SRI system, for which an SCC of \$7.00 per million Btu was calculated. The Bechtel SCC, all other things being equal, should be lower than that stated by SRI, since industrial electrical distribution has the lowest SCC of any distribution service category. Since this is not the case, it is suggested that the SRI values of SCC be discarded and the better documented Bechtel value be adopted instead. It is suggested also that Bechtel SOC data be adopted. The electricity distribution values shown in Table V-14 were arrived at by using the original SRI data to weight the Bechtel values in the disaggregation.

Jet and Marine Fuel. The distribution costs for jet and marine fuel are shown as zero for the same reasons that certain transportation costs were set at zero. (See Introduction to Section V.)

Other SRI Fuel Categories. Very few data were found that were comparable with the rest of SRI's distribution data. The fuels in question have generally been marketed in the present manner for many years, and the technology of delivering them is not expected to change significantly in future decades. Thus, historical data adjusted to 1977 dollars should be suitable as sources of suggested data for the distribution data base. The problem is that these distribution channels are characterized by a large number of relatively small suppliers whose capital and operating costs are inadequately documented.

SRI did not attempt to develop separate SCC and SOC values for these categories, but showed all distribution costs as SOC. Following this convention, some of the SRI values were compared with dealer margins given by DOE.³¹ (see Table V-15). In that dealer costs presumably represent the bulk of distribution costs, the SRI values appear reasonable. The gap between the SRI and the DOE values probably represents distribution costs incurred by wholesalers and other intermediaries between major transportation nodes and the final consumer. It is therefore recommended that the SRI values be retained.

Table V-15
Comparison of SRI Data and DOE Data

SRI Data		DOE Data ^b	
Category	SOC ^a	Category	Dealer Margin ^c
Residential/Commercial:			
Distillate	0.821	Residential heating oil ^d	0.567
LS resid	0.274	LS resid (retail)	0.186
Transportation:			
Gasoline	0.878	Regular gasoline ^e	0.66
Diesel	0.878	Truckstop diesel	0.51

^aSpecific Operating Cost ('77 \$/10⁶ Btu).

^bReference 31. June 1977 data unless otherwise specified.

^c'77 \$/10⁶ Btu.

^d1975 percentage margin applied to June 1977 purchase price.

^eAverage 1977 value for full service stations.

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VI. END-USE CONVERSION

End-use conversion processes cover a broad range of technical devices, which are among the most visible in the energy system and include such consumer products as automobiles, air conditioners, water heaters, and space heaters. End-use conversion processes in the residential/commercial sector tend to be geographically diverse, that is, both capital investment and annual energy consumption depend on the specific region in which the device is located.

End-use conversion processes are categorized into the following sectors:

- Industrial direct heat
- Industrial indirect heat
- Miscellaneous industrial
- Residential/commercial space heating
- Miscellaneous residential/commercial
- Transportation

Industrial Direct Heat Sector

Little information has been published on costs related to direct heating in industry. The data available are crude and are not sufficiently disaggregated to provide a thorough understanding of capital costs in the industrial direct heat sector.

SRI costs are for burners and for fuel handling and storage equipment only and are classified by three industry categories based on fuel usage. The first category, Clean Fuels, (gas and electricity only) includes industries in which fuel cleanliness is of the utmost importance (such as the food and glass industries.) The other extreme, Any Fuel, includes the stone and clay industries for which any fuel can be used because cleanliness is of little concern. In between is the No Coal/Resid category which includes metals, chemicals, and all other industries that can use distillate fuel oil in addition to clean fuels.

These three industry categories are not sufficient for adequate estimation of burner and fuel handling and storage capital costs because of the wide variety of different processes included in this sector. Costs can vary by several orders of magnitude depending upon the specific application. The ISTUM³ model developed by EEA begins to attack this problem by disaggregating nonboiler uses of natural gas, oil and coal into more than a dozen specific applications. The usefulness of the nonboiler technology data in the ISTUM model is still severely limited because of the unavoidable inclusion of certain cost components not directly related to the specific energy technology employed. For example, the application of direct heat to a solid material requires sophisticated equipment to pass the material through the furnace. A steel reheat furnace may use a conveyor with water circulating through its wheels to prevent them from heating up to the furnace temperature. The costs associated with this type of equipment are not directly attributable to the energy system. The EEA analysis is currently being refined by eliminating these non-energy-related costs and thus normalizing the data base.

In view of the level of disaggregation of industries by category and the cost data available at this level, the burner and fuel handling and storage

capital costs given by SRI are satisfactory (see Table VI-1A). It is recommended that as data become available they be incorporated into the direct heat sector of the DFI model so that capital costs reflect more accurately the actual technologies employed by industry.

Industrial Indirect Heat (Steam) Sector

Although the industrial indirect heat sector includes steam generation as well as other indirect heat processes such as steam reforming and indirect drying, the DFI model assumes steam generation to be representative of all uses of indirect heat. This assumption appears reasonable because process steam dominates the indirect heat sector and adequate cost data is lacking for other indirect heat processes. Capital costs for industrial boilers are defined for a nominal or average size boiler for each fuel type (see Table VI-1B). SRI assumed variations in capital costs due to economies of scale to be small compared with variations due to fuel type. This assumption is adequate for the applications this model was intended for (decisions other than those related to specific industrial processes). There are, however, definite economies of scale for boilers up to 1600×10^6 Btu/hr capacity; for larger boilers, unit costs remain about constant as capacity increases. To compute the total capital investment from the specific capital cost given by SRI, it is assumed that the nominal or average industrial boiler has a capacity of 100×10^6 Btu/hr and operates at a 90% plant factor (7884 operating hrs/yr).

Industrial steam generation excludes industrial on-site power generation. The steam generated in industrial boilers is assumed to be used for its thermal energy only. All power generated by industry is included in the DFI model as utility generated power. Specific operating costs given by SRI for industrial boilers are low. They have been set at 5% to 10% of the specific capital cost as shown in the table. The industrial indirect heat sector in the model includes all equipment necessary to transfer heat to the water in the following items:

- On-site fuel storage (if required)
- On-site fuel handling and delivery
- Burner
- Water and steam handling equipment
- Heat-exchange facility
- Ash disposal and stack-gas desulfurization (if necessary)

Miscellaneous Industrial Sector

The miscellaneous industrial category includes fossil fuels consumed in the petrochemical feedstock industry and electricity consumed by industrial electromechanical and electric transportation processes. The DFI model assumes that the fuels consumed in these processes are all nonsubstitutable. The economics of these processes are not estimated in the model. The model expresses demand for industrial electromechanical, petrochemical and electric transportation processes in terms of delivered products, which is satisfactory for the strategic energy related decisions for which the model was intended.

Table VI-1A
Process Economics Data^a
Sector: Industrial Direct Heat

Technology/ Process	Unit Size ^b (10 ⁶ Btu/ hr)	SRI Data					Suggested Data ^g				Comments
		SOC ^c (75 \$/ 10 ⁶ Btu/ yr)	SOC ^c (\$/10 ⁶ Btu/yr)	TCI ^d (\$)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (\$)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
Electricity											
Clean fuels	10	0.15	0.17	6800	0.00	0.80	0.17	6800	0.02	0.80	
No coal/resid.	10	0.15	0.17	6800	0.00	0.70	0.17	6800	0.02	0.70	
High-Btu gas											
Clean fuels	10	0.15	0.17	6800	0.00	0.60	0.17	6800 ^h	0.02	0.60	
No coal/resid.	10	0.15	0.17	6800	0.00	0.60	0.17	6800 ^h	0.02	0.60	
Any fuel	10	0.15	0.17	6800	0.00	0.60	0.17	6800	0.02	0.60	
Low-Btu gas											
Clean fuels	10	0.15	0.17	6800	0.00	0.75	0.17	6800	0.02	0.75	
No coal/resid.	10	0.15	0.17	6800	0.00	0.75	0.17	6800	0.02	0.75	
Any fuel	10	0.15	0.17	6800	0.00	0.75	0.17	6800	0.02	0.75	
Distillate											
No coal/resid.	10	0.20	0.23	9200	0.00	0.60	0.23	9200 ^h	0.02	0.60	
Any fuel	10	0.20	0.23	9200	0.00	0.60	0.23	9200	0.02	0.60	
Low-sulfur resid.											
Any fuel	10	0.25	0.28	11200	0.00	0.60	0.28	11200	0.03	0.60	
SRC											
(large facility)	100	0.35	0.40	16000	0.00	0.77	0.40	16000	0.04	0.77	
Low-sulfur coal											
Any fuel	50	0.57	0.65	26000	0.10	0.60	0.65	26000	0.07	0.60	
High-sulfur coal											
Any fuel	50	0.57	0.65	26000	0.10	0.60	0.65	26000	0.07	0.60	
Hydrogen											
Clean fuels	10	0.15	0.17	6800	0.00	0.70	0.17	6800	0.02	0.70	
No coal/resid.	10	0.15	0.17	6800	0.00	0.70	0.17	6800	0.02	0.70	

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which Total Capital Investment (TCI) is based.

^cSOC: Specific Capital Cost.

^dTCI: Total Capital Cost.

^eSOC: Specific Operating Cost.

^fOverall conversion efficiency.

^gThe following SRI data for the industrial direct and indirect heat sectors appear satisfactory and are therefore not explicitly listed in the table: Year of Availability, Penalty, Technological Rate of Change and Limit on Capital, Technological Rate of Change and Limit on Efficiency, Equity Fraction, Years to Construct, Book Life, and Tax Life. Range of estimates is provided for some TCI values.

Table VI-1B
Process Economics Data^a
Sector: Industrial Indirect Heat (Steam)

Technology/ Process	Unit Size ^b (10 ⁶ Btu/ hour)	SRI Data					Suggested Data ^g				Comments
		SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC ^c (\$/10 ⁶ Btu/yr)	TCI ^d (10 ⁶ \$)	SOC ^e (\$/10 ⁶ Btu)	Effi- ciency ^f	SOC (\$/10 ⁶ Btu/yr)	TCI (10 ⁶ \$)	SOC (\$/10 ⁶ Btu)	Effi- ciency	
High-Btu gas	100	1.95	2.22	1.75	0.06	0.80	3.17	2.50 ¹ (2.33- 2.50)	0.20 ¹	0.80	SRI TCI computed from SOC assuming a 100 x 10 ⁶ Btu/hour capacity boiler. All SOC in the Indirect Heat Sector are calculated from a 90% (7884 operating hours per year) plant factor. SRI efficien- cy has been adopted in this sector.
Low-Btu gas	100	2.20	2.50	1.97	0.06	0.80	3.30	2.60	0.20	0.80	
Distillate	100	1.46	1.80	2.21	0.11	0.75	3.42	2.70	0.25	0.75	
Low-sulfur residual	100	2.77	3.15	2.48	0.11	0.75	3.55	2.80 ¹ (2.50- 2.90)	0.25 ¹	0.75	
Low-sulfur coal	100	6.04	6.87	5.41	0.11	0.70	5.96	4.70 ¹	0.25 ¹	0.70	
High-sulfur coal	100	8.65	9.84	7.75	0.34	0.70	9.26	7.30 ¹ (6.90- 7.30)	0.60 ¹	0.70	
SRC (large facility)	100	3.65	4.15	3.27	0.20	0.82	4.15	3.27	0.30	0.82	

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which Total Capital Investment (TCI) is based.

^cSOC: Specific Capital Cost.

^dTCI: Total Capital Investment.

^eSOC: Specific Operating Cost.

^fOverall conversion efficiency.

^gThe following SRI data for the industrial direct and indirect heat sectors appear satisfactory and are therefore not explicitly listed in the table:
Year of Availability, Penalty, Technological Rate of Change and Limit on Capital, Technological Rate of Change and Limit on Efficiency, Equity
Fraction, Years to Construct, Book Life, and Tax Life. Range of estimates is provided for some TCI values.

Residential/Commercial Space Heating Sector

Capital costs in the residential/commercial space heating sector are defined by fuel for nominal or average space heating processes. It is assumed that these heating systems are double oversized, that is, the rated output of the furnace is twice the design heating load of the structure. This is standard practice in residential construction, though unnecessary. The design heating load of single-family residential housing units is assumed to be 42.3 Btu/hr in northern and western regions of the nation, and 33.3 Btu/hr in the South. Gas furnaces are rated at 84,700 Btu/hr in the northern and western regions and at 66,600 Btu/hr in the South. Since oil furnaces are commercially available only at a rated output of 80,000 Btu/hr or greater, the rated output of oil-fired systems is assumed to be uniform across all geographic regions at 84,700 Btu/hr.

Space heating demands depend upon geography. In warm southern regions, space heaters operate for only a small portion of the year and, in effect, at a low load factor. In northern climates space heaters are required much of the year and operate at larger load factors. The DFI model specifies two regions for space heating - low load factor regions (warm) and high load factor regions (cold) -

- High load factor
 - New England
 - Middle Atlantic
 - East North Central
 - West North Central
 - Mountain
 - Pacific
- Low load factor
 - South Atlantic
 - East South Central
 - West South Central

The average annual heating load per residence given by SRI is 49.7×10^6 Btu in the low load factor region and 94.7×10^6 Btu in the high load factor region. These do not agree with other published data and have been revised to 31.9×10^6 and 57.8×10^6 respectively, as shown in Table VI-2.⁶

The DFI model assumes a single collector size for all solar space heating systems in the nation. The percent contribution of solar heat is varied according to geographic location as indicated in Table VI-3. This assumption results in a 34% contribution by solar heat in the Northeast. Considering the large capital investment required for solar collectors, a system contributing substantially less than 50% to meet the heating load may not warrant the initial capital investment. The collector size recommended in the suggested data varies with location such that at least 50% of the heating load is met by solar heat as shown in Table VI-3.

The thermal efficiencies given in the SRI data for gas and oil space heating processes appear low when compared with overall efficiencies reported in other sources^{5,11} and have been revised to reflect actual efficiencies observed in oil and gas space heating equipment as shown in Table VI-4. Gas and oil space heating efficiencies are projected to increase from 0.65 to 0.80 for gas and 0.55 to 0.75 for oil over the next 25 years, with an exponential growth rate according to the following equation defined by SRI:

Table VI-2
Process Economic Data^a
Sector: Residential/Commercial Space Heating

Technology/Process	SRI Data								Suggested Data ^{g, h}				
	Unit Energy Demand (10 ⁶ Btu/yr)	Unit Size ^b	SOC ^c ('75 \$/ 10 ⁶ Btu/ yr)	SOC ^c (\$/10 ⁶ Btu/yr)	TCI ^d (\$)	SOC ^e (\$/10 ⁶ Btu)	Efficiency ^f Prim. Aux.		Unit Energy Demand (10 ⁶ Btu/ yr)	SOC (\$/ 10 ⁶ Btu/ yr)	TCI (\$)	SOC (\$/10 ⁶ Btu)	Efficiency Prim. Aux.
High-Btu gas heating													
Low load factor	49.7	66,600 Btu/hr	34.65	39.42	1959	0.59	0.49	-	31.9	47.02	1500 ^{5,8}	0.92	0.65 -
High load factor	94.7	84,700 Btu/hr	18.18	20.68	1959	0.39	0.49	-	57.8	27.68	1600 ^{5,8} (1400-1700)	0.64	0.65 -
Hydrogen heating													
Low load factor	49.7	66,600 Btu/hr	34.65	39.42	1959	0.59	0.90	-	31.9	47.02	1500	0.92	0.65 -
High load factor	94.7	84,700 Btu/hr	18.18	20.68	1959	0.39	0.90	-	57.8	27.68	1600 (1400-1700)	0.64	0.65 -
Distillate heating													
Low load factor	49.7	84,700 Btu/hr	47.00	53.46	2657	0.68	0.45	-	31.9	59.56	1900 ^{5,8}	1.06	0.55 -
High load factor	94.7	84,700 Btu/hr	24.67	28.06	2657	0.48	0.45	-	57.8	34.58	2000 ^{5,8} (1650-2100)	0.79	0.55 -
Low sulfur residual heating													
Low load factor	49.7	84,700 Btu/hr	47.00	53.46	2657	0.68	0.45	-	31.9	59.56	1900	1.06	0.55 -
High load factor	94.7	84,700 Btu/hr	24.67	28.06	2657	0.48	0.45	-	57.8	34.58	2000 (1650-2100)	0.79	0.55 -
Resistance heating													
Low load factor	47.9	14 kW	30.18	34.33	1706	0.68	1.00	-	31.9	53.48	1706	1.06	1.00 -
High load factor	94.7	-	6.48	7.37	698	0.33	1.00	-	57.8	12.07	698	0.54	1.00 -
Heat pump													
Low load factor	49.7	3 tons	71.20	80.99	4025	2.05	1.51	1.78	31.9	94.04	3000 ⁸ (2500-3500)	3.19	1.70 -
Rural heat													
Electric	94.7	15 kW	7.50	8.53	808	0.52	1.00	-	57.8	12.07	698	0.54	1.00 -
Distillate	94.7	84,700 Btu/hr	24.67	28.06	2657	0.55	0.45	-	57.8	34.58	2000 ^{5,8} (1650-2100)	0.79	0.55 -
LPG	94.7	84,700 Btu/hr	18.18	20.68	1958	0.44	0.49	-	57.8	25.93	1500 ^{5,8} (1400-1600)	0.64	0.65 -
Solar Collectors With:													
Electric Backup													
Northeast location	-	(Refer to Solar Space Heating Table VI-3)	59.00	67.00	4550	0.80	1.50	1.00	64.8	158.00	10256 ¹⁰	0.85	2.27 0.61
Southeast location	-		109.00	124.00	4550	1.65	4.20	0.43	31.9	195.00	6208 ¹⁰	1.72	2.86 0.52
Western location	-		89.00	101.00	4550	1.35	3.30	0.47	37.8	198.00	7470 ¹⁰ (+10%)	1.46	4.00 0.45
Gas backup													
Northeast location	-		62.00	71.00	4550	0.80	0.91	2.00	64.8	155.00	10050 ¹⁰	0.85	1.68 0.61
Southeast location	-		113.00	129.00	4550	1.65	2.50	0.46	31.9	187.00	5950 ¹⁰	1.72	2.11 0.52
Western location	-		93.00	106.00	4550	1.35	2.00	0.86	37.8	191.00	7210 ¹⁰ (+10%)	1.46	2.96 0.45
Distillate backup													
Low load factor	49.7		113.00	129.00	4550	1.65	1.29	0.46	31.9	201.00	6400 ¹⁰	2.04	1.86 0.52
High load factor	94.7		55.00	63.00	4550	0.80	0.85	2.10	57.8	171.00	9866 ¹⁰ (+10%)	1.12	1.67 0.56

Notes

^aSRI capital costs appear high by a factor of about one third for fossil systems. Suggested costs for solar systems vary with climate. The following SRI data for the residential/commercial space heating sector appears satisfactory and is therefore not explicitly listed in the table: Year of Availability, Penalty, Technological Rate of Change and Limit on Capital, Equity Fraction, Years to Construct, Book Life, and Tax Life. See the text for changes to the Technological Rate of Change and Limit on Efficiency.

Estimates of the SOC and efficiency of a space heating system are based on personal communications with dealers and manufacturers of heating equipment. See text for solar efficiency definition.

^aAll costs are in 1977 dollars unless specified otherwise.

^bSize on which Total Capital Investment (TCI) is based.

^cSOC: Specific Capital Cost.

^dTCI: Total Capital Investment.

^eSOC: Specific Operating Cost.

^fConversion efficiency of primary (auxiliary) system.

^gSuperscripts denote references for the data.

^hIn some cases range is shown in parenthesis below the suggested data.

The efficiency of a process describes the energy loss in that process and is defined by SRI as follows:

$$\text{efficiency} = \frac{\text{total energy content of primary products}}{\text{total energy content of primary feedstocks}}.$$

When a process is described in terms of two inputs and a single output two efficiencies are defined, primary and auxiliary:

$$\text{primary efficiency} = \frac{\text{total energy content of product}}{\text{total energy content of first (primary) input}}.$$

$$\text{auxiliary efficiency} = \frac{\text{total energy content of product}}{\text{total energy content of second (auxiliary) input}}.$$

The efficiency of a solar heating system is defined in terms of a primary efficiency, which measures the energy loss in the backup system, and an auxiliary efficiency which measures the energy loss in the solar system. With the above SRI definition of efficiency, the energy loss of a solar space heating system can be described in terms of its primary and auxiliary efficiencies as

$$\text{primary efficiency (backup system)} = \frac{1}{L_F/e_F}$$

$$\text{auxiliary efficiency (solar system)} = \frac{1}{L_S/e_S}$$

where,

- L_S = solar load factor (percent contribution of solar in meeting the heating load; (Table VI-3),
- L = fossil load factor (percent contribution of the fossil or electric backup system in meeting the heating load; $L = 1 - L_S$),
- e_F = efficiency of the backup system in 1978 (see Table VI-4), and
- e_S = efficiency of the solar system ($e_S = 0.34$).

Miscellaneous Residential/Commercial Sector

The miscellaneous residential/commercial sector includes air conditioning and domestic hot water heating. Domestic hot water heating is accounted for in the miscellaneous heat category shown in Table VI-5. The DFI model assumes the costs and performances of miscellaneous heat processes such as clothes drying and cooking to be the same as those of typical water heating processes, which comprise the largest of these demands.

Capital costs for gas, oil, electric, and solar domestic hot water heating systems are based on currently available commercial systems. SRI assumes that 70% of the energy requirements in a solar hot water heating system are met by solar and 30% by the backup system. The suggested capital costs are based on a solar system that meets 75% of the energy requirements as shown in Table VI-6.

$$e_t = e_o [\text{Limit} + (1 - \text{Limit})(1 - \text{Rate})^{t-t_o}]$$

where,

- e_t = Efficiency in projection year t ,
- e_o = Efficiency in year of availability,
- Limit = Technological limit on efficiency, and
- Rate = Technological rate of change on efficiency.

Table VI-3
Solar Space Heating

Location	SRI data		Suggested data	
	Unit size (sq. ft.)	Contribution of solar in meeting heating load (%)	Unit size (sq. ft.)	Contribution of solar in meeting heating load (%)
Northeast	200	34	475	56
Southeast	200	76	250	65
Western	200	70	320	75
Low load factor	200	-	250	65
High load factor	200	-	437	61

Table VI-4
Gas and Oil Space Heating Efficiency Projections

	1975	1978	1980	1985	2000	Limit	Rate
SRI projections							
Gas	0.49	0.61	0.65	0.69	0.70	1.42	0.26
Oil	0.45	0.57	0.60	0.64	0.65	1.44	0.26
BNL projections							
Gas	0.65	0.74	0.77	0.79	0.80	1.23	0.20
Oil	0.55	0.65	0.68	0.73	0.75	1.36	0.20

Table VI-5
Process Economic Data^a
Sector: Miscellaneous Residential/Commercial

Technology/Process	Unit Energy Demand (10 ⁶ Btu/yr)	Unit Size ^b	SRI Data					Suggested Data ^{g, h}				
			SOC ^c (175 \$/ 10 ⁶ Btu/yr)	SOC ^c (\$/10 ⁶ Btu/yr)	TCI ^d (\$)	SOC ^e (\$/10 ⁶ Btu)	Efficiency ^f Prim. Aux.	SOC (\$/ 10 ⁶ Btu/ yr)	TCI (\$)	SOC (\$/10 ⁶ Btu)	Efficiency Prim. Aux.	
Resistance miscellaneous heat	20.00	50 gallons	9.23	10.50	210	0.0	0.88 -	20.00	400 ⁸ (350 - 450)	0.0	1.00 -	
High-Btu gas miscellaneous heat	20.00	50 gallons	15.38	17.50	350	0.0	0.57 -	22.50	450 ⁸ (350 - 550)	0.0	0.70 -	
Hydrogen miscellaneous heat	20.00	50 gallons	15.38	17.50	350	0.0	0.48 -	22.50	450 (350 - 550)	0.0	0.70 -	
Distillate miscellaneous heat	20.00	50 gallons	16.92	19.25	385	0.0	0.65 -	23.75	475 ⁸ (350 - 550)	0.0	0.60 -	
Solar/Electric miscellaneous heat												
Northeast location	20.00	(Refer to Solar Domestic Hot Water Heating Table VI-6)	67.50	76.78	1536	1.14	3.33 4.33	85.00	1700 ¹⁰ (1500-1900)	1.14	4.00 0.45	
Southeast location	20.00		52.50	59.72	1194	1.14	3.33 4.33	63.75	1275 ¹⁰ (1100-1500)	1.14	4.00 0.45	
Western location	20.00		52.50	59.72	1194	1.14	3.33 4.33	76.25	1525 ¹⁰ (1300-1700)	1.14	4.00 0.45	
Solar/Gas miscellaneous heat												
Northeast location	20.00		70.00	79.63	1593	1.14	1.90 0.81	87.85	1757 ¹⁰ (1500-2000)	1.14	2.80 0.45	
Southern & western locations	20.00		55.00	62.56	1251	1.14	1.90 0.81	71.60	1432 ¹⁰ (1200-1600)	1.14	2.80 0.45	
Electric air-conditioning												
Low load factor (central unit)	16.0	3 tons	14.98	17.04	654	0.34	2.40 -	42.00	1600 ⁹ (1400-1800)	0.38	2.40 -	
High load factor (room unit)	4.3	1 ton	31.10	35.38	365	0.68	2.40 -	66.00	500 ⁸ (400 - 600)	0.53	1.75 -	

Notes

^aCosts and performances are for water heating and A/C. Unit energy demand for A/C is in terms of delivered electricity. The specific capital cost for air conditioners computed as follows:

$$SOC = \frac{TCI}{\text{Unit Demand} \times \text{Efficiency}}$$

A/C capital costs in the low load factor region are for central units excluding ductwork. A/C capital costs in the high load factor region are for room units. The following SRI data for the miscellaneous residential/commercial sector appears satisfactory and is therefore not explicitly listed in the table: Year of Availability, Penalty, Technological Rate of Change and Limit on Capital, Equity Fraction, Years to Construct, Book Life, and Tax Life.

Estimates of the SOC and efficiency of a domestic hot water heater, room A/C and central A/C are based on personal communications with dealers and manufacturers of the equipment. No operating cost is assumed for conventional hot water heaters. See text for solar efficiency definition.

^aAll costs are in 1977 dollars unless specified otherwise

^bSize on which total capital investment (TCI) is based

^cSOC: Specific Capital Cost

^dTCI: Total Capital Investment

^eSOC: Specific Operating Cost

^fConversion efficiency of primary (auxiliary) system

^gSuperscripts denote the references for the suggested data

^hIn some cases range is shown in parenthesis below the suggested data

Table VI-6
Solar Domestic Hot Water Heating

Location	SRI data	Unit size (sq. ft.)	Suggested data
	Contribution of solar in meeting heating load (%)		Contribution of solar in meeting heating load (%)
Northeast	70	67	75
Southeast	70	50	75
Western	70	60	75
Southern & Western	70	55	75

The efficiency of a solar domestic hot water heating system, like that of a space heating system (see above), is defined in terms of a primary efficiency, which measures the energy loss in the backup system, and an auxiliary efficiency, which measures the energy loss in the solar system. The value for 1975, rather than 1978, was used for the efficiency of the backup system.

SRI capital costs for air conditioners in the low load factor region (warm climates) are for central air conditioners excluding ductwork. The equipment and installation costs for ductwork are included in the space heating sector. Capital costs for air conditioners in the high load factor region (cold climates) are for room units. The nominal or average central air conditioner capacity is assumed to be three tons (one ton = 12,000 Btu/hr), with a coefficient of performance (COP) of 2.40, corresponding to an energy efficiency ratio (EER)* of 8.2. The average room unit capacity is assumed to be one ton with a COP of 1.75 (EER = 6.0). These capacities and efficiencies are typical of present day air conditioners. The specific capital cost (SCC) for air conditioners is expressed as a function of the total capital investment (TCI), the COP, and the unit demand, where unit demand is expressed in terms of delivered electricity:

$$SCC = \frac{TCI}{\text{unit demand} \times COP}$$

This definition of unit demand differs from that used in other end-use conversion sectors, where unit demand is expressed as the net energy required to provide a given level of service and is equal to the product of the delivered energy and the efficiency.

*The EER is the rating system used by the industry and is a generally accepted measure of air conditioner efficiency; $8.2 \text{ Btu/watt-hr} = 2.40 \times 3.4128 \text{ Btu/watt-hr}$.

The electromechanical category in the miscellaneous residential/commercial sector comprises processes for which the model assumes no interfuel substitution. Such processes cover refrigerators, freezers, washing machines, televisions, lighting, and other miscellaneous electric appliances. The model expresses demand for residential/commercial electromechanical processes in terms of delivered products, which is satisfactory for the strategic energy related decisions for which this model is intended.

Transportation Sector

Automotive. The automotive transportation sector includes two types of driving, intercity driving (point-to-point travel) and intracity driving. The specific capital cost (SCC) for automotive transportation assumes a vehicle is driven 10,000 mi/yr (see Table VI-7). Standard size autos are assumed for point-to-point travel and compacts for intracity travel. Included in operating and maintenance costs for all types of vehicles are (1) repairs and maintenance, (2) replacement tires, (3) insurance, (4) garaging, parking and tolls, and (5) registration and titling. Vehicles equipped with Diesel engines are assumed to have an initial cost \$300 to \$400 more than that of conventional ICE vehicles.

The electric car is assumed to be a four-passenger zinc-chlorine vehicle with a range of 100 km and a curb weight of 1250 kg. Its characteristics are more fully described in an EPRI report.¹² The four-passenger suburban vehicle was chosen rather than the two passenger urban runabout because it is more comparable with the compacts used in intracity travel for which it is competing.

The efficiency improvements for automobiles projected by SRI are shown in Table VI-8. The fuel economy of conventional autos in point-to-point travel is projected to increase from 14.2 mpg in 1975 to 31.5 in 2000 and that of conventional autos in intracity travel from 11.1 in 1975 to 24.6 in 2000. These efficiency projections as well as those for Diesel and gasoline/methanol vehicles appear reasonable and have not been changed in the suggested data. Efficiencies are projected to increase at an exponential growth rate according to the following equation defined by SRI:

$$e_t = e_o [\text{Limit} + (1 - \text{Limit})(1 - \text{Rate})^{t-t_o}]$$

where,

- e_t = efficiency in projection year t ,
- e_o = efficiency in year of availability,
- Limit = technological limit on efficiency, and
- Rate = technological rate of change on efficiency.

Table VI-7
Process Economic Data^a
Sector: Automotive Transportation

Technology/ Process	Year Avail- able	VMT ^b	SRI Data						Suggested Data ^f				
			SOC ^c (1975 \$/veh-mi/yr)	SOC (\$/ veh-mi/yr)	TCI ^d (\$)	SOC ^e (\$/veh-mi)	Effi- ciency (veh-mi/ 10 ⁶ Btu)	Tech. limit on effi- ciency	SOC (\$/ veh-mi/yr)	TCI (\$)	SOC (\$/veh-mi)	Effi- ciency (veh-mi/ 10 ⁶ Btu)	Tech. limit on effi- ciency
Point-to-Point		10,000 miles per vehicle per year											
Auto	1975		0.442	0.503	5030	0.175	114.0	2.23	0.525	5245 ^{14,16}	0.112 ¹⁴	114.0	2.23
Diesel auto	1980		0.455	0.518	5180	0.175	200.0	1.39	0.565	5645 ^{14,16} (5445-5945)	0.112 ¹⁴	200.0	1.39
Gasoline/ methanol auto	1980		0.442	0.503	5030	0.175	228.0	1.40	0.525	5245	0.112	228.0	1.40
Intracity													
Auto	1975		0.337	0.429	4290	0.151	89.0	2.22	0.414	4138 ^{14,16}	0.101 ¹⁴	89.0	2.22
Diesel auto	1980		0.387	0.429	4290	0.151	200.0	1.39	0.444	4438 ^{14,16} (4338-4838)	0.101 ¹⁴	200.0	1.39
Gasoline/ methanol auto	1980		0.377	0.429	4290	0.151	178.0	1.39	0.414	4138	0.101	178.0	1.39
Secondary battery electric car	1985	0.814	0.926	9260	0.131	554.0	1.00	0.767	7671 ¹² (3892-8010)	0.096 ¹²	500.0 ¹²	1.00	

Notes

Standard size auto assumed for point-to-point travel. Compact size auto assumed for intracity travel. The electric car is assumed to be a four passenger zinc-chlorine vehicle. SRI efficiencies have been adopted for conventional and diesel powered vehicles.

The following SRI data for the automotive transportation sector appears satisfactory and is therefore not explicitly stated in the table: Penalty, Auxiliary Efficiency, Technological Rate of Change and Limit on Capital, Equity Fraction, Years to Construct, Book Life, and Tax Life.

^aAll costs are in 1977 dollars unless specified otherwise.

^bVehicle miles traveled per vehicle per year.

^cSpecific Capital Cost. (assuming 10,000 miles driven per year)

^dTotal Capital Investment.

^eSpecific Operating Cost.

^fRange of estimates is provided for some TCI values.

Table VI-8
Projected Improvements in Automobile Efficiency

	1975	1985	2000	Technological change on efficiency	
				Limit	Rate
Point-to-point Auto	114.0* (14.2)**	239.0 (29.7)	254.0 (31.5)	2.23	0.20
Diesel auto	200.0 (25.0)	270.0 (33.7)	278.0 (34.7)	1.39	0.20
Gas/auto	228.0 (28.5)	309.0 (38.6)	319.0 (39.9)	1.40	0.20
Intracity auto	89.0 (11.1)	186.0 (23.1)	198.0 (24.6)	2.22	0.20
Diesel auto	200.0 (25.0)	270.0 (33.7)	278.0 (34.7)	1.39	0.20
Gas/auto	178.0 (22.2)	240.0 (30.0)	247.0 (30.9)	1.39	0.20

*Efficiency expressed in terms of vehicle-miles/10⁶ Btu.

**Efficiency expressed in terms of mpg.

Barge-Rail-Truck Freight Transport. The present version of the DFI model has only one category for freight transportation. It includes rail Diesel, barge, and Diesel truck. Data for these three freight modes are listed separately in Table VI-9, to allow for future expansion of the model, in addition to the combined rail-barge-truck data for the DFI model. In the combined category, total ton-miles, are the sum of rail, barge, and truck ton-miles, and all other parameters are computed from a weighted average of the values for each mode.

Values for the parameter ton-miles (passenger-miles) per unit per year are not published by the various trade associations and had to be constructed for each mode. The several approaches available yielded different results. After discussions with trade association members, and considering the reliability of data and the reasonableness of results, a methodology was selected, but is subject to considerable variation since there is no generally accepted method to derive it.

Rail Diesel. The average freight train in 1977 consisted of 67.2 cars and 3.2 locomotives. Railroad freight traffic reached 826,202 million ton-miles in 1977 or 43 million net ton-miles per freight train. Ton-miles per freight train is calculated as a function of total ton-miles, average number of cars in service, and number of cars per freight train. This calculation results in a

Table VI-9
Process Economics Data^a
Sector: Transportation

Technology/Process	Ton-Miles/ ^b Unit/Year	Total Ton-Miles (10 ⁹)	SOC ^c (\$/Ton-Mile/Year)	TCI ^d (10 ³ \$)	SOC ^e (\$/Ton-Mile)	Efficiency (Ton-Mile/10 ⁶ Btu) [(Btu/Ton-Mile)]	Technological Change on Capital Limit Rate	
Rail diesel	43 x 10 ⁶	826	0.090	3870 ¹⁸	0.023 ¹⁷	1495 ¹⁹ (669)	1.0	0.0
Barge	215 x 10 ⁶	363	0.026	5600 ¹⁷	0.005 ¹⁷	2320 ²² (431)	1.0	0.0
Diesel truck	675,000	561	0.147	99.4 ²⁴	0.089 ¹⁷	384 ²⁶ (2604)	1.0	0.0
Rail-barge-truck	65 x 10 ⁶	1750	0.095	3020	0.040	1310 (763)	1.0	0.0
Technology/Process	Pass.-Miles/ Aircraft/Year	Total Pass.-Miles (10 ⁹)	SOC (\$/Pass.-Mile/Yr)	TCI (10 ³ \$)	SOC (\$/Pass.-Mile)	Efficiency (Pass.-Mile/10 ⁶ Btu) [(Btu/Pass.-Mile)]	Technological Change on Capital Limit Rate	
Air passenger	311 x 10 ⁶	194	0.161	50000 ²⁷	0.013 ²⁸	182 ²⁸ (5500)	1.0	0.0

Technology/Process	Technological Change on Efficiency Limit Rate		Equity Fraction	Years to Construct	Book Life	Tax Life	Comments
Rail diesel	1.10	0.30	0.70	1	30	20	Capital cost for a typical freight train with 67.2 cars and 3.2 locomotives. Inland waterways tow configuration: 15 barges each having a capacity of 1400 tons: one 4200 hp towboat. Capital costs for a 76,000 lb. G.W tractor trailer combination. Assumes typical common carrier carries a ratio of trailers to tractors of 2.5 to 1.0. Total ton-miles is sum of rail barge and truck. Other parameters represent average values for rail, barge, and truck weighted by ton-miles.
Barge	1.0	0.0	0.17	1	30	20	
Diesel truck	1.3	0.30	0.20	0	7	5	
Rail-barge-truck	1.10	0.30	0.50	1	25	17	

Technology/Process	Technological Change on Efficiency Limit Rate		Equity Fraction	Years to Construct	Book Life	Tax Life	Comments
Air passenger	1.1	0.30	0.20	1	15	10	Boeing 747-100, 350 seats, and 55.4% load factor.

^aAll costs are in 1977 dollars unless specified otherwise. Superscripts refer to data references.

^bSize on which total capital investment is based.

^cSOC: Specific Capital Cost.

^dTCI: Total Capital Investment.

^eSOC: Specific Operating Cost.

lower figure than if average ton-miles per "loaded" car is used in the calculation. Freight train efficiency, measured in terms of Btu/ton-mile, averaged 669 in 1977. Coal is the largest single commodity moved by rail, representing about 30% of all rail tonnage.

Barge. The barge and towing industry carried 610 million tons of freight in 1975, about 65% of total domestic marine traffic. Barge traffic moves on the inland waterways, within ports, on the U.S. coastal waters and on the Great Lakes. The number of barges in a tow can vary from 2 to 30 or 40; the configuration assumed here consists of 15 barges each having a capacity of 1400 tons and one towboat of 4200 horsepower. This configuration is assumed to carry 215 million ton-miles per year at an efficiency of 431 Btu/ton-mile. Other vessels engaged in domestic waterborne commerce include tankers, freighters, and dry bulk vessels. Tankers carry primarily petroleum products, which are handled in the energy transportation sector of the DFI model. Freighters and dry bulk vessels are engaged primarily in the ocean shipping sector, which does not compete with other transportation modes in the model.

Diesel Truck. Trucks are generally categorized into eight weight classes, from class 1, which includes trucks under 6000 lb GVW, to class 8, which includes trucks over 33,000 lb. class 8 is further disaggregated into classes 8a through 8h. Class 8e (70,001 to 80,000 lb GVW) accounts for over 50% of the ton-miles carried by trucks and includes combination tractor-trailers. A 76,000-lb GVW tractor-trailer was chosen to represent truck transport. This includes a three-axle Diesel tractor with a capital cost of \$52,000 and a 45-ft dry van or flat bed with a capital cost of \$15,000 (a refrigerated unit is valued at \$27,000). One-third of the trailers are assumed to carry perishables and to have refrigeration units. The ratio of trailers to tractors is assumed to be 2.5, typical of many regular route common carriers.

Air Passenger. The aircraft modeled in the air transport sector is a Boeing 747-100 with a seating capacity of 350 and a passenger load factor of 55.4% (1976 scheduled airline average). Passenger-miles per aircraft per year (311 million) are calculated for a Boeing 747 from the average daily hours in flight (9.63), block-to-block average speed (456 mph), and average number of passengers per flight (194).²⁸ Total passenger-miles include scheduled service for both domestic and international flights on U. S. airlines. The efficiency given for a Boeing 747 (5500 Btu/pass.-mile) is the average efficiency for 1975 and is dependent on passenger load factor and stage length.

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