CHAPTER 2

INTRODUCTION TO PART II

The purpose of Part II is to display and explain the estimates of synfuel production costs used later in the three market analyses. Cost estimates were developed for the following synthetic fuel processes:

- Indirect Coal Liquefaction
  - Methanol From Coal
  - Mobil Gasoline From Coal
- Direct Coal Liquefaction
  - H-Coal
  - Exxon Donor Solvent
  - Solvent Refined Coal II

In addition, refinery costs were estimated for upgrading liquid products from the direct liquefaction processes so that they satisfied normal petroleum product specifications. Costs were also developed for the production of methanol from natural gas to afford a comparison with the costs of producing methanol from coal.

Production costs for synthetic fuel plants, especially those involving yet-to-be demonstrated technologies, have tended to be seriously underestimated. While some of that can be explained by overoptimism on the part of sponsors, much of the underestimation occurs simply because the technical specifications for the plants have not been defined fully. The lack of well-defined specifications persists, in turn, because few if any commercial-scale synfuel facilities have been built.

The instantaneous investment cost estimates presented here are judged to be the best available at present, but they still suffer from this lack of actual construction and operating experience, as do all synfuel estimates. Most of the cost information falls into what the Rand Corporation has termed preliminary estimates.1/ That is, an estimate based primarily on pilot

1/ A Review of Cost Estimation In New Technologies: Implications For Energy Process Plants.

plant experience and published equipment price lists. Such estimates are used for a go/no-go decision on plant construction and, according to Rand, are generated with the intention of being within 25 percent of the actual plant expense; while they are intended to be in this range these estimates may actually be off by a much greater extent. The next step up would be to prepare a budget estimate, intended to be within 15 percent of the actual, which is used to begin site preparation, equipment orders, and capital allocation. A final definitive estimate, intended to be within 5 percent of actual construction cost, is developed when design and engineering specifications are just about complete and full equipment cost quotes are available.

Even with brief discussions of coal-based synfuel technologies the reader will see just how large and elaborate the facilities are likely to become. Still, to keep the subject in perspective it should be remembered that these complex processes have one simple purpose--to convert coal into a fuel which looks and performs very much like naturally occurring oil or natural gas. To do this, the two key differences between coal and oil or natural gas must be eliminated. Coal is a solid and not a liquid because it has much more mineral matter (ash) and much less hydrogen than oil or natural gas. For this reason, the primary function of synfuel processes is to add hydrogen, while removing ash. By adding different amounts of hydrogen under different process conditions (temperatures and pressures), a variety of liquid and gaseous products can be made.

In chapter three which follows immediately, key assumptions common to all the estimates of production costs are stated and explained. Chapter four, presents product cost estimates for each of the selected technologies.

Before proceeding, a very important difference between the indirect and direct technologies studied herein should be noted and kept in mind throughout the report. The difference is that the indirect processes yield one principal product while the direct liquefaction processes yield an array of products. This point is especially important when comparing auto fuels. Essentially the entire output from a methanol or a Mobil-M plant could, if demand warrants, be used for automobiles. In contrast, only a portion of the product yield from the direct processes is gasoline. Table 2-1 displays the yields of the three direct liquefaction technologies studied herein.

This difference will be, perhaps, one of the more important criterion on which indirect and direct processes are compared. If synfuels are viewed as primarily automobile fuel, the indirect processes would seem to have an advantage. Distillate and resid could, however, be refined further into gasoline stock and the distillate could be a basis for diesel transport. If a full product slate is reqired from synfuels, direct processes may be more appropriate if the resid and distillate are cheaper to use in the relevant cases. That is, if the resid and distillate are cheaper as boiler, turbine, or home heating fuels.

TABLE 2-1

PRODUCT YIELDS FOR
DIRECT LIQUEFACTION TECHNOLOGIES[a/]
WITH REFINING
(barrels per stream day)

	SRC-II	EDS	H-Coal
Gasoline	8,963	18,511	15,070
Distillate	-	-	19,436
Resid	41,024	27,001	10,689
LPG	4,500	6,690	6,506

a/ The three plants are about the same size--each produces about 50,000 barrels per stream day. These are the product yields from the direct liquefaction processes with the extent of refining we assumed. The crudes could be upgraded further, but would of course be more expensive.

CHAPTER 3

ASSUMPTIONS COMMON TO ALL THE ESTIMATES

A great number of assumptions go into an estimate of synfuel cost and only some could be specified by ICF since published reports were the primary source of data. For those under ICF's control, two classes of assumptions can be distinguished. The first concern raw capital and operation cost estimates and the second concern the translation of that raw data into product cost estimates. These two classes of assumptions are discussed in the first two sections of this chapter, as is our procedure for estimating plantgate costs. A final section on the assumed cost of transporting fuels is then presented.

RAW COST DATA

Five of the most significant assumptions affecting the raw cost data concern the following: contingencies; construction schedules; working capital; utilization rates; and real construction cost escalation. These five are discussed in turn and then a long list of other key assumptions is displayed.

Contingencies

All engineering cost studies include an estimate of what is termed contingency expense to cover expected but undefined construction needs. All of the estimates herein include a project contingency of 15 percent In addition, because some equipment in the synfuel technologies remains unproven, process contingencies, based purely on ICF's best judgment, are also included as follows:

- a 15 percent contingency on all second generation gasifiers;
- a 10 percent contingency on the methanol conversion equipment used in the Mobil-M process.
- a 20 percent contingency on the reactors used in direct liquefaction technologies.

The project contingency equals 15 percent of total investment expense while the process contingencies are applied only to the investment for the particular piece of equipment in question. In the broadest sense, this approach to contingencies reflects the (optimistic) belief that the synfuel technologies will work. The uncertainty embodied in the contingency arises when one asks how much it will cost to make them work.

Construction Schedule

Large synfuel plants will take several years to construct. It is important to specify the pattern of construction expenditures so that the financial analysis can be done correctly. The key point is that investors will have committed funds to the project, but returns will not be realized until construction is complete and sales begin. Table 3-1 displays the assumed schedule for construction expenditures on three sizes of plants. As will be illustrated in the next chapter, construction delays because of design changes, court actions, and the like can increase costs considerably.

TABLE 3-1

ASSUMED CONSTRUCTION SCHEDULES
(In Percent Of Total Investment)

	Million Of Dollars of Plant Investment		
Year Prior To Operation	200	200-1,200	1,200 And Above
-1	0	0	0
-2	31	15	7
-3	56	34	10
-4	13	30	23
-5	-	14	27
-6	-	5	18
-7	-	2	12
-8	-	-	3

Working Capital

When a plant begins operation, considerable amounts of capital will be tied-up in coal stockpiles, inventories of process materials, product inventories, and accounts receivable. The term applied to such expense is working capital and components are assumed to be as follows:

- Thirty-day coal stockpile valued at the price of coal.

- Thirty days of materials and supplies valued at t‵ cost of those items.

- Fifteen days of product inventory valued at the coal price plus operating cost.

- Forty-five days of accounts receivable valued at the coal price plus operating cost.

Annual working capital expense is the interest charge on these liquid assets.

Utilization Rates

Utilization rate is the portion of the time the plant is assumed to be in full operation. For these product cost estimates an annual rate of 90 percent is assumed; that is, the plant operates at full capacity 330 days per year. A lower utilization rate would mean the fixed costs would be spread over fewer units of product and therefore, product costs would be higher.

Real Cost Escalation

Construction costs have risen faster than the general rate of inflation in recent years and therefore, real construction costs have increased. For example, while the GNP deflator rose at an annual rate of 7.2 percent during the 1970 to 1979 period the producer's price index for materials and components for construction rose at a rate of 9.4 percent and the rate of price increase for machinery and equipment was 8 percent.[1/]

Such real increases were not seen in the 1960's and it is difficult to say if they will be seen in the 1980's and 1990's. If one focuses only on synfuel plant construction costs, however, it would seem reasonable to expect some real increase in cost. With the rapid commercialization envisioned under the Energy Security Act of 1980, synfuel construction would have to command the attention of a considerable portion of the nation's engineers, constructors, equipment manufacturers, and the like. An attempt to concentrate these resources would probably bid prices upward.

As will be seen, one's guess at real cost escalation is very important to product price estimates, especially in later years. All of the estimates herein reflect a 2 percent annual increase in real construction costs.

1/ Economic Report of the President, January 1980, Appendix B. Table B-3 for the GNP deflator, B-54 for materials and components for construction, and B-56 for machinery and equipment.

Other Assumptions

Other key assumptions can be stated as follows:

- Plant Estimate - Shown in 1980 dollars. The Chemical Engineering Plant Cost Index was used to adjust estimates originally developed for other time periods.

- Paid Up Royalties - 0.5% of Process Plant Cost. This represents the cost of acquiring proprietary information.

- Raw Makeup Water - 40¢/M gallon except for production of methanol from natural gas where 15¢/M gallon was assumed.

- Ash Disposal Cost - $1.50/ton.

- Maintenance - Estimated as a percent of the equipment costs for each plant component. These percentages are shown in Table 3-2.

- Maintenance Labor Materials Ratio - All of the Maintenance Costs are considered to be fixed costs. Forty percent of these cost are for labor, sixty percent for material.

- Operating Labor - Priced at $10.50/hour plus 35% for fringe benefits for a total of $14.20/hour.

- Overhead Charges - Overhead charges include the following items:

  - Administrative and Support Labor, estimated as 30 percent of operating and maintenance labor (including fringe benefits).

  - General and Administrative Expenses, estimated as 60 percent of operating and maintenance labor (including burden).

- Catalyst and Chemicals - Operating costs for catalyst and chemicals were escalated to a 1980 basis at 8%/year from prior year estimates determined in the literature.

TABLE 3-2

ANNUAL MAINTENANCE COST ESTIMATES[a/]

Item	Percent of Component Equipment Cost
- Gasification and Quench	6
- Shift Conversion	3
- Acid Gas Removal	3
- Methanol Synthesis	4
- Sulfur Recovery	3
- Methanol Conversion	4
- Steam Reforming	3
- Solids Disposal	3
- Sour Water Stripping	3
- Ammonia Recovery	3
- Bio-Oxidation	3
- Oxygen Plant	3
- Utility Plant	3
- General Facility	2-1/2
- Downstream Refinery Upgrading Facilities	4

a/ Annual, real maintenance costs are assumed to equal these percentages of the relevant component of capital cost.

- <u>By-Product Ammonia Sale Price</u> - $190 per short ton.
- <u>By-Product Sulfur Sale Price</u> - $50 per short ton.
- <u>By-Product Phenol Sale Price</u> - $600 per short ton.
- <u>Electricity Price</u> - $.04 per kilowatt-hour

<u>PRODUCT COST ESTIMATES</u>

All of the raw cost data can be gathered and, with a few additional pieces of information, translated into product cost estimates. It's very important to understand what these figures represent.

- First, they are entirely cost-based. That is, over the life of each plant all costs would be recovered including the assumed rate of return on investment.
- A second key point is the costs are financial averages. That is, equipment, O&M, and coal costs are each represented by an annuity - equal annual payments which have the same present value as the actual uneven stream of costs.
- Third, the prices are all in 1980 dollars per million Btu. That is, they are expressed in real terms and would be assumed to keep pace with economy-wide inflation. Increases in these real prices are caused by assumed increases over time in real construction costs and coal prices.

One way to summarize these three points is to say the prices might be those charged for a long-term contract between a synfuel producer and a large synfuel user. As with long-term contracts between coal producers and electric utilities, the contract price could be a cost-based price, constant in real terms over the life of the mine.

It should also be noted that these are not necessarily the prices for which the products would be sold. Unless long-term contracts or government regulations force synfuels to be sold at a cost-based price, each product will be sold at the market price. Those market prices, in turn, will probably be determined by OPEC for the foreseeable future. The point is that if a synfuel cost-based price is shown to be lower than an assumed OPEC oil price, it is not necessarily true the synfuel will be sold at the lower price. The comparison simply shows that the synfuel could be sold at a profit under assumed market conditions.

With these broad points in mind, the process can be explained by which raw cost data are translated to product cost estimates. The steps in the calculation are straightforward - estimate annual capital and operation costs, sum to get total annual cost, and divide total annual cost by total, annual product yields to get a price per MMBtu.

Only two complications are encountered. The first is quite simple: In most processes by-products such as ammonia and sulfur are generated and can be sold. That sales revenue is deducted from total annual cost to reflect a credit for by-product sales.

The second complication is peculiar to prices for the products from direct liquefaction processes. As noted, those products are first produced and then upgraded in a refinery. Total annual cost is calculated for both production and upgrading.

A problem arises because several products are produced and one cannot easily allocate total annual costs among them. In other words, there are common and joint costs; one piece of equipment can be used in the production of all the products (common costs) and in some cases, one piece of equipment produces the products simultaneously (joint costs). There are several allocation procedures available and the choice among them is crucial to the product cost estimates. In this study total annual costs have been allocated among the direct liquefaction products by assuming a fixed relationship among four product prices. In other words, with the direct liquefaction processes the total, annual cost is assumed to be recovered by selling four products at prices which have the following relationship:

- Naphtha price equals $G per MMBtu, where G is subsequently determined.
- Distillate oil price equals $ (.82) G per MMBtu.
- Low sulfur residual oil price equals $ (.77) G MMBtu.
- The price for Liquid Petroleum Gases and Isobutane is also $ (.77) G per MMBtu.

This price relationship is based on ICF's study of refining operations. The allocation is entirely cost based, it does not reflect a particular view on future petroleum markets. For example, if today's glut of residual oil persisted, producers using direct liquefiction technologies would have to recover a greater portion of their costs with naphtha; that is, the price of naphtha would be set at higher level.

The fifteen steps in the calculation of product costs are shown in Table 3-3. Most of the steps are self-explanatory, but those concerning annual capital and annual coal costs require elaboration.

TABLE 3-3

PROCEDURE FOR THE
CALCULATION OF PRODUCT COSTS

Line No.	Item
1.	Total instantaneous capital cost
2.	Adjustment factor for year of construction
3.	Total adjusted capital cost (line 2 x line 1)
4.	Capital charge rate
5.	Annual capital cost (line 4 x line 3)
6.	Annual coal cost
7.	Annual variable O&M cost
8.	Working Capital Cost
9.	Annual fixed O&M cost
10.	Annual cost other than capital (sum lines 6, 7, 8, and 9)
11.	Total annual cost (Sum lines 5 and 10)
12.	By product credits Electricity Sulfur Ammonia Phenols
13.	Total Annual Cost Less By product credits (line 11 minus line 12)
14.	Annual product yields in Million Btu
15.	Primary product price in $1980 per MMBtu (equals line 13 divided by line 14)

Annual Capital Cost

The first item in Table 3-3 is the estimate of instantaneous investment costs; that is, total capital costs determined as if the plant could be built and then operated immediately. Line number two is the adjustment factor necessary to reflect the assumption that eight years are required for plant construction. The adjustment factor is used to increase total capital costs so they include interest during construction and reflect the fact that real construction costs are assumed to be rising at a rate of 2 percent per year. Interest during construction is measured as the opportunity cost of the funds committed during construction; that cost is calculated using the real, after-tax cost of capital.

An illustration of the adjustment factor calculation for a large plant is shown in Table 3-4. Shown is the case of a plant for which construction begins in 1983 and is completed in 1990. In 1983, the first year, 3 percent of the construction will take place. By that year, real construction costs have risen by 6.1 percent and this is reflected by multiplying by the factor $(1.02)^3$. Furthermore, those first-year funds will be committed for eight years so the opportunity cost or interest during construction will accumulate or compound at a rate of 5.7 percent per year; thus the factor $(1.057)^8$. These weighted adjustment factors are calculated for each of the eight years and summed to the total adjustment factor of 1.49. In other words, by 1990, a total of $1.49 billion would have been spent on a plant for which instantaneous investment cost was $1 billion.

All of the adjustment factors used herein are displayed in Table 3-5. Two different costs of capital are used so two sets of adjustment factors are shown.

The next step in the product cost calculation is to annualize the capital cost using what is termed a capital charge rate. The multiplication of the total adjusted capital costs by the capital charge rate yields an estimate of the annual cost of paying dividends, interest, income taxes, property taxes and the like on synfuel plant investments.1/ The key assumptions in

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1/ The capital charge rate is calculated by first listing all the capital charges incurred in each year of the plant's life because of each dollar of investment. Those charges include book depreciation (the return of capital), dividends and interest (the return on capital), income tax, property tax, insurance, and general administration. The present value of those charges is then determined. By dividing the present value by the sum of the discount factors, an annuity is calculated; that is, equal annual payments are determined which have the same present value as the actual, uneven stream of charges.

TABLE 3-4

ILLUSTRATION OF THE ADJUSTMENT FACTOR CALCULATION

Year	Portion of Instant Investment	Adjustment For Increases In Real Cost	Adjustment For Interest During Construction	Weighted Adjustment
1983	.03	$(1.02)^3$	$(1.057)^8$	.0499
1984	.12	$(1.02)^4$	$(1.057)^7$	.1914
1985	.18	$(1.02)^5$	$(1.057)^6$	.2771
1986	.27	$(1.02)^6$	$(1.057)^5$	.4051
1987	.23	$(1.02)^7$	$(1.057)^4$	.3297
1988	.10	$(1.02)^8$	$(1.057)^3$	.138
1989	.07	$(1.02)^9$	$(1.057)^2$	.0934
1990	0	$(1.02)^{10}$	$(1.057)^1$	0
Total	1.0			1.485

TABLE 3-5

CAPITAL ADJUSTMENT FACTORS
FOR LARGE PLANTS

Construction Completed In	Assumed Cost of Capital	
	5.7 Percent	9.8 Percent
1990	1.49	1.79
1995	1.64	1.98
2000	1.81	2.18
2010	2.20	2.66

calculating the charge rate are the return on equity and the rate of interest on long-term debt. With the 15 percent rate, these assumptions are based on historical averages. In a report by Ibbotsen and Sinquefield, the average rate of return on common stocks over the 1926 to 1978 period was found to be 8.9 percent and average interest on long-term corporate bonds was 4 percent. Inflation during that period averaged 2.5 percent so the real return on equity is 6.2 percent and real interest rate is 1.5 percent.1/ The very high portion of equity in the financial structure - 90 percent - is meant to reflect the added risk of synfuel investments. Assumptions for the 21 percent capital charge rate were chosen simply to show what might be implicit in a capital charge rate considerably higher than one based on historical rates of return.

In the next chapter, product costs will be shown using two capital charge rates - 15 and 21 percent. Table 3-6 displays the key assumptions underlying those estimates.

Annual Coal Costs

All of the plants considered here are assumed to use high sulfur midwestern coal. The plants are constructed at the mine-mouth and pay long-term contract prices for their coal. Those prices are $1.32, $1.39, $1.46, and $1.61 per MMBtu for contracts signed in 1990, 1995, 2000, and 2010 respectively; the coal has 22.2 million Btu per ton.2/

SYNFUEL TRANSPORTATION

All of the synfuels discussed herein are assumed to be produced at the minemouth. The purpose of this section is to present our rough estimates of the cost of transporting synfuels from the point of production to the point of consumption.

For the long haul transportation of liquids between these origins and destinations, the following rates have been assumed; all of them are based on a report by Exxon.3/

1/ Ibbotsen and Sinquefield, Stocks, Bonds, Bills, and Inflation Historical Returns (1926-1978), 1979 p.12.

2/ Prices are based on ICF's Coal and Electric Utilities Model. The very slow (about 1 percent) rise in real contract prices reflects the extensive resource base for high sulfur Illinois coal; that is, the supply curve is found to be very flat so that substantial increases in production can be achieved without rapid increases in production costs.

3/ See Exxon Research and Engineering, Alternate Energy Sources for Non-Highway Transportation, Volume III-B, 1978. For all of the estimates the following Btu contents are assumed in MMBtu per barrel: 2.65 for methanol; 5.3 for gasoline; 5.8 for distillate; 6.3 for residual. In addition, a barrel is assumed to hold 42 gallons.

TABLE 3-6

KEY FINANCIAL ASSUMPTIONS
FOR THE CAPITAL CHARGE RATE (CCR)

Assumptions	CCR = 15%	CCR = 21%
Inflation Rate	9%	9%
Project Life	30 yrs	30 yrs
Equity Financing	90%	80%
Debt Financing	10%	20%
Return on Equity Real/after tax	6.2%	12%
Nominal/after tax	15.8%	22%
Interest, Nominal Rate/before tax	10.6%	10.6%
Real Rate/before tax	1.5%	1.5%
G&A and Insurance, Real	1%	1%
Property Tax Rate, Real	3%	3%
Income Tax Rate	50%	50%
Investment Tax Credit	10%	10%
Method of Depreciation	Sum of Year's Digits	

- Railroad - for a trip of 1,000 miles a rate of $.15 per gallon is assumed. Based on this assumption the cost per million Btu is

  - Methanol, $2.38 per MMBtu
  - Gasoline, $1.19 per MMBtu
  - Distillate, $1.08 per MMBtu
  - Residual, $1.00 per MMBtu

- Pipeline - for a trip of 1,000 miles a rate of $.04 per gallon is assumed. Based on this assumption the cost per million Btu is

  - Methanol, $.63 per MMBtu
  - Gasoline, $.32 per MMBtu
  - Distillate, $.29 per MMBtu
  - Residual, not allowed.

In addition, transport and terminaling costs for movement by the regional bulk dealer to either a large user or to a retail dealer is also included in the market analyses shown later. Movement to a large user, such as an electric utility is assumed to be 5.5¢ per gallon while movement to all others is assumed to be 9¢ per gallon.[1/] When methanol or gasoline is assumed to be sold by service stations, retailing cost of $.20 per gallon and excise tax of $.13 per gallon is added.

1/ See Methyl Alcohol Fuel Supply and Demand 1980-2000, prepared for National Alcohol Fuels Commission, March 1980.

CHAPTER 4

PRODUCT COST ESTIMATES

The purpose of this chapter is to present product cost estimates for the selected synfuel technologies. Cost estimates were developed with the assumptions presented in Chapter 3 and the raw cost data presented herein (that data is shown with much greater detail in Appendices A and B). The first section of the chapter presents product cost estimates actually used in the market analysis shown later. A second section illustrates the effect on those costs of altered assumptions.

PRODUCT COST ESTIMATES

The first necessary data are the instantaneous investment costs presented in Table 4-1. Four estimates were found for methanol. As can be seen, the Badger methanol estimate is presented for three different levels of coal use as is their estimate for Mobil-M gasoline; the large size is the original from which ICF made estimates for the two smaller sizes.

Three estimates are displayed for direct liquefaction process and each has a two component investment cost. The first component is for the total facility while the second bracketed number is the investment assumed to be necessary for refining the direct liquefaction syncrudes.

Except for the Koppers-Totzek methanol system none of the technologies have yet been proven on a commercial scale. Although the actual technology for methanol synthesis is proven, the other methanol systems considered all involve second-generation gasifiers. For the Mobil-M system, both the gasifier and the process by which methanol is converted to gasoline are second-generation systems. Finally, all of the direct liquefaction technologies are also at the pilot plant or demonstration plant stage of the research, development, demonstration, and commercialization process.

With these investment costs plus the many assumptions listed earlier, annual costs can be estimated. To give some indication of the relative importance of capital, coal and O+M costs, Table 4-2 displays the six components of annual costs for each technology in 1990 using a 15 percent capital charge rate. In later years only the capital and coal costs will change; the assumed escalation in real construction costs is 2 percent per year and for coal prices the real escalation is about 1 percent.

TABLE 4-1

ESTIMATES OF INSTANTANEOUS INVESTMENT[a/]
(in millions of $1980)

TECHNOLOGY/ESTIMATE	INVESTMENT
METHANOL	
KOPPERS-TOTZEK	$2,540
BADGER	
--Small	1,214
--Medium	2,111
--Large	5,121
TEXACO	1,895
BGC/LURGI	1,522
DIRECT LIQUEFACTION [b/]	
Solvent Refined Coal II	1,820 (291)
Exxon Donor Solvent	1,674 (239)
H-COAL	1,541 (206)
MOBIL-M	
BADGER	
--Small	1,425
--Medium	2,499
--Large	6,084

a/ The three Badger plants consume 12,950, 25,900, and 77,700 tons of coal per stream day respectively. All other methanol plants use about 22,000 to 24,000 tons of coal per stream day while the direct liquefaction plants use 16,000 to 20,000 tons per stream day.

b/ Numbers in brackets are investment for refining already embodied in the total.

TABLE 4-2

1990 ANNUAL COSTS OF PRODUCTION WITH
A 15 PERCENT CAPITAL CHARGE RATE

	Adjusted Capital	Coal	Variable O&M	Fixed O&M	Working Capital	Total	Byproduct Credits
METHANOL							
KOPPERS TOTZEK	568	238	10	123	3	942	13
BADGER							
--Small	271	125	21	57	2	477	6
--Medium	472	250	43	93	4	862	13
--Large	1,145	751	128	217	12	2,253	38
TEXACO	424	214	10	100	3	750	12
BGC/LURGI	340	222	10	80	3	655	14
DIRECT LIQUEFACTION a/							
SRC-II	404 (62)	205	130 (122)	99 (17)	5 (2)	843 (203)	37+9
EDS	372 (51)	193	97 (88)	97 (15)	4 (1)	763 (155)	17+7
H-COAL	342 (44)	165	73 (56)	83 (14)	4 (1)	667 (115)	30+2
MOBIL-M							
BADGER							
--Small	318	125	29	64	2	538	6
--Medium	558	250	62	105	4	980	13
--Large	1,360	751	187	237	13	2,549	38

a/ Numbers in brackets are refining costs already embodied in the total.

Note that the costs for direct liquefaction are separated, as in the previous table, into those for the total facility production and those for subsequent refining shown in brackets.

With the methanol processes, capital charges accounts for about 55 percent of total annual costs and coal costs accounts for about another 30 percent. With direct liquefaction, capital costs are about 50 percent of the total while coal accounts for 25 percent. The large variable O&M costs with upgrading of direct liquefaction products can be attributed to the assumption that natural gas is the source of the hydrogen for those facilities. The natural gas price is assumed to be $5.39, $7.22, $8.45 $10.33 per MMBTU in 1990, 1995, 2000, and 2010 respectively.[1/]

Table 4-3 presents product cost estimates at the plantgate for each technology assuming a 15 percent capital charge rate. Notice two points concerning the direct liquefaction estimates. First, separate estimates are shown for gasoline and for residual or distillate. Second, two numbers are shown--the top number is the total product cost estimate while the bracketed number is the portion of that total which can be traced to refining.

Showing the prices in terms of dollars per million Btu is necessary for the market analyses in later chapters, but other methods of presentation are also useful. Since synfuels are intended to be substitutes for imported oil, it's interesting to show these prices as crude oil equivalents. Table 4-4 presents such prices.

It's important to understand the notion of crude oil equivalence used here. The figures shown are the costs per barrel of average crude oil that, by ICF estimates, would yield gasoline at the synfuel product costs estimated earlier. For example, in Table 4-4 methanol from the Koppers-Totzek process had a product cost of $8.94 per million Btu in 1990. According to ICF's refinery model, a crude oil cost of $40.52 per barrel would have yielded such a gasoline price so $40.52 is presented as the crude oil equivalent of the Koppers-Totzek methanol cost estimate.

It is not correct to base a final cost comparison on the figures in these product cost tables. Costs over the entire fuel cycle must be compared. As will be seen, costs of delivering and using these synthetic fuels are substantial and can affect significantly the cost comparisons.

1/ These prices are tied to oil prices which assume a crude oil cost of $32 per barrel in 1980 and a 2 percent real escalation thereafter. The assumed relationship is as follows: in 1990 gas price is 5¢ below high sulfur resid; in 1995 it's 10¢ below low sulfur resid; in 2000 it's 10¢ below distillate; and in 2010 it's equal to be distillate price.

TABLE 4-3

PLANTGATE
PRODUCT COST ESTIMATES
WITH 15 PERCENT CAPITAL
CHARGE RATE
(in $1980 per Million Btu)

Technology/Estimate	Year Construction Completed			
	1990	1995	2000	2010
Methanol				
Koppers-Totzek	8.94	9.62	10.36	12.06
Badger				
Small	7.78	8.34	8.96	10.37
Medium	7.02	7.52	8.09	9.33
Large	6.10	6.53	7.00	8.07
Texaco	7.10	7.62	8.19	9.50
BGC/LURGI	6.16	6.61	7.10	8.20
Direct Liquefaction-Gasoline a/				
SRC-II	9.15	10.17	11.12	13.09
	(2.23)	(2.74)	(3.11)	(3.78)
EDS	8.58	9.43	10.26	11.97
	(1.72)	(2.09)	(2.37)	(2.85)
H-COAL	7.71	8.41	9.16	10.69
	(1.36)	(1.58)	(1.82)	(2.17)
Mobil M				
Badger				
Small	10.05	10.79	11.60	13.45
Medium	9.15	9.81	10.54	12.19
Large	7.91	8.47	9.08	10.48
Direct Liquefaction- Distillate, Resid a/				
SRC-II RESID	7.04	7.83	8.56	10.08
	(1.72)	(2.11)	(2.40)	(2.91)
EDS RESID	6.60	7.26	7.90	9.22
	(1.32)	(1.61)	(1.82)	(2.19)
H-COAL RESID	5.94	6.47	7.05	8.23
	(1.05)	(1.22)	(1.40)	(1.67)
DISTILLATE	6.32	6.89	7.51	8.77
	(1.12)	(1.30)	(1.50)	(1.78)

a/ Numbers in brackets are refining costs already embodied in the total product cost.

TABLE 4-4

CRUDE OIL EQUIVALENT COSTS
WITH 15 PERCENT CAPITAL[a/]
CHARGE RATE
(In $1980 Per Barrel)

Technology/Estimate	1990	1995	2000	2010
Methanol				
Koppers-Totzek	40.52	43.79	47.35	55.52
Badger				
Small	34.94	37.63	40.62	47.39
Medium	31.29	33.69	36.43	42.39
Large	26.87	28.93	31.19	36.34
Texaco	31.67	34.17	36.91	43.21
BGC/LURGI	27.15	29.32	31.67	36.96
Direct Liquefaction-Gasoline				
SRC-II	41.53	46.43	51.00	60.47
EDS	38.79	42.88	46.87	55.09
H-Coal	34.61	37.97	41.58	48.93
Mobil-M				
Badger				
Small	45.86	49.41	53.31	62.20
Medium	41.53	44.70	48.21	56.14
Large	35.57	38.26	41.19	47.92
DIRECT LIQUEFACTION-				
SRC II - RESID	41.27	46.09	50.54	59.80
EDS - RESID	38.59	42.61	46.51	54.56
H-COAL - RESID	34.56	37.79	41.33	48.52
DISTILLATE	34.54	37.87	41.50	48.87

a/ These are estimates of the crude oil costs that would yield the product costs shown in Table 4-3.

THE EFFECT OF CHANGING ASSUMPTIONS

There is, by no means, a consensus on product costs for synthetic fuels. Much of the disagreement concerns the cost of capital for synfuel investments, the construction schedule for synfuel plants, and the reliability of plant operation. This section is meant to give some perspective to the sensitivity of the product cost estimates to changes in the assumptions concerning these three topics.

Cost of Capital

As explained in Chapter 3, the 15 percent capital charge rate incorporates a required rate of return on equity and an interest rate which are equal to the historical averages for returns on common stock and interest on long-term corporate bonds. It is often argued that a much higher return on equity would be demanded for synfuel investments because of greater technological and market risks. To illustrate the effect of requiring a higher return, consider the case where the required real return is almost doubled--taken from 6.2 to 12 percent. As noted in Chapter 3, this 12 percent return is the basis for a 21 percent capital charge rate.

With a 21 percent capital charge rate the annual capital cost grow in importance as a component of total annual cost. Note that the use of the higher charge rate implies a higher cost of capital, about 9.7 percent and therefore, the higher adjustment factors shown in Chapter 3 are also used. The effects of these two assumptions on product cost estimates are shown in Table 4-5.

With these changes in assumptions, annual capital costs increase by about 68 percent; there is a 20 percent increase in the adjustment factor and a 40 percent increase in the capital charge rate which are compounded. For methanol the effect of the change is to increase product costs by about 37 percent. For direct liquefaction products, the increase is about 34 percent.

Table 4-6 displays costs in terms of crude oil equivalent.

Construction Schedule

In the product cost estimates shown thus far, the synfuel plants have all been assumed to be constructed in eight years. There is the possibility, especially in the early stages of synfuel development, that construction will be delayed because of changes in plant design or court actions, or for many other reasons.

Increased construction time means increased product costs for two reasons. First, there is an increase in the interest during construction or the opportunity cost of the funds committed to the project. Second, with rising construction costs a delay means some portion of the plant will be built at greater expense.

Table 4-7 shows the effect on product costs of a five year delay in construction. That is, for a plant intended to be built in 1990 construction is halted for a five year period after sixty percent of the plant is built and the plant finally comes on-line in 1995. That delay has a considerable effect on product costs. In most cases, product costs are increased by 14 percent or more in real terms.

TABLE 4-5

PRODUCT COST ESTIMATES
WITH 21 PERCENT CAPITAL
CHARGE RATE
(in $1980 per Million Btu)

Technology/Estimate	1990	1995	2000	2010
Methanol				
Koppers-Totzek	12.69	13.79	14.94	17.67
Badger				
Small	10.86	11.77	12.73	14.99
Medium	9.70	10.51	11.35	13.35
Large	8.28	8.95	9.66	11.32
Texaco	9.90	10.74	11.62	13.69
BGC/LURGI	8.42	9.12	9.85	11.57
Direct Liquefaction - Gasoline a/				
SRC - II	12.29 (2.67)	13.66 (3.23)	14.95 (3.65)	17.79 (4.44)
EDS	11.50 (2.09)	12.68 (2.48)	13.83 (2.81)	16.35 (3.39)
H-Coal	10.55 (1.72)	11.58 (1.98)	12.60 (2.22)	14.91 (2.66)
Mobil-M				
Badger				
Small	14.19	15.39	16.65	19.64
Medium	12.76	13.85	14.97	17.62
Large	10.86	11.75	12.69	14.89
DIRECT LIQUEFACTION - RESID, DISTILLATE a/				
SRC II - RESID	9.46 (2.06)	10.52 (2.49)	11.51 (1.27)	13.70 (3.42)
EDS - RESID	8.85 (1.65)	9.77 (1.53)	10.65 (2.17)	12.59 (2.61)
H-Coal - RESID	8.13 (1.33)	8.92 (1.53)	9.70 (1.71)	11.48 (2.05)
DISTILLATE	8.66 (1.42)	9.49 (1.62)	10.33 (1.82)	12.22 (2.18)

a/ Numbers in brackets are refining costs already embodied in the total product cost.

TABLE 4-6

CRUDE OIL EQUIVALENT COST
WITH 21 PERCENT CAPITAL
CHARGE RATE a/
(In $1980 Per Barrel)

Technology/Estimate	1990	1995	2000	2010
Methanol				
Koppers-Totzek	58.55	63.84	69.37	82.49
Badger				
Small	49.75	54.13	58.74	69.61
Medium	44.17	48.07	52.11	61.72
Large	37.35	40.57	43.98	51.96
Texaco	45.13	49.17	53.40	63.36
BGC/LURGI	38.02	41.38	44.89	53.16
Direct Liquefaction- Gasoline				
SRC-II	56.63	63.21	69.41	83.07
EDS	52.83	58.50	64.03	76.14
H-Coal	48.26	53.21	58.12	69.22
Mobil M				
Badger				
Small	65.76	71.53	77.59	91.96
Medium	58.88	64.13	69.51	82.25
Large	49.75	54.03	58.55	69.13
Direct Liquefaction - Resid, Distillate				
SRC-II	56.02	62.49	68.52	81.88
EDS-REDID	52.30	57.91	63.28	75.11
H-Coal RESID	47.91	52.73	57.49	68.34
Distillate	48.22	53.08	57.99	69.04

a/ These are estimates of the crude oil costs that would yield the product costs shown in Table 4-5.

TABLE 4-7

1990 PLANTGATE a/
PRODUCT COST ESTIMATES
WITH A FIVE-YEAR DELAY
IN CONSTRUCTION

Technology/Estimate	$ Per MMBTU	Crude Equivalent b/
Methanol		
Koppers-Totzek	10.32	47.15
Badger		
Small	8.91	40.38
Medium	8.02	36.10
Large	6.93	30.86
Texaco	8.14	36.67
BGC/LURGI	7.03	31.34
Direct Liquefaction - Gasoline		
SRC - II	10.70	48.98
EDS	9.93	45.28
H-Coal	8.93	40.47
Mobil-M		
Badger		
Small	11.56	53.12
Medium	10.48	47.92
Large	9.02	40.90
DIRECT LIQUEFACTION - RESID, DISTILLATE		
SRC II - RESID	8.24	48.59
EDS - RESID	7.65	44.99
H-Coal - RESID	6.88	40.29
Distillate	7.32	4.39

a/ Because of the five year delay, the products are not ready until 1995, rather than 1990 as orginally planned.

b/ These are estimates of the crude oil costs that would yield the product costs shown in the preceding column.

Utilization Rate

All of the estimates thus far assume the synfuel plants are successfully operated ninety percent of the time. Unanticipated operating problems, slack demand, and the like could lower significantly this assumed utilization rate or service factor. A lower rate means higher product costs because fixed capital and operating costs, by definition, do not fall as utilization declines. The same fixed costs must be recovered no matter how much product is produced.

Table 4-8 displays the results of a drop in the utilization rate from 90 to 70 percent. The effect on product costs is considerable. Most of the estimates increase by more than 19 percent.

TABLE 4-8

1990 PLANTGATE
PRODUCT COST ESTIMATES
WITH A 70% UTILIZATION RATE

Technology/Estimate	$ Per MMBTU	Crude Equivalent [a]
Methanol		
Koppers-Totzek	10.84	49.65
Badger		
Small	9.34	42.44
Medium	8.35	37.68
Large	7.17	32.01
Texaco	8.54	38.60
BGC/LURGI	7.31	32.68
Direct Liquefaction - Gasoline		
SRC - II	10.80	49.46
EDS	10.12	46.19
H-Coal	9.19	41.72
Mobil-M		
Badger		
Small	12.11	55.76
Medium	10.94	50.13
Large	9.35	42.49
Direct Liquefaction - Resid, Distillate		
SRC II - RESID	8.31	49.01
EDS - RESID	7.79	45.84
H-Coal - RESID	7.07	41.07
Distillate	7.53	41.61

a/ These are estimates of the crude oil costs that would yield the product costs shown in the preceding column.