6.2 WORKING CAPITAL

6.2.1 Bases

The working capital bases outlined in the Guidelines yield a working capital which can be classified as incremental, or is appropriate for large integrated corporations. For smaller, "single product" companies, the working capital probably should be larger.

The working capital calculation bases are:

(a) Coal Inventory @ 30 days - Generally, in coal processing studies of this type, a coal dead storage of 30 days is assumed.

(b) Intermediate and Product Inventory @ one-half storage capacity - There is no gas storage. SNG storage is assumed to be included in the natural gas pipeline distribution system.

(c) Materials and Supplies @ 0.9 percent of contractor cost - A portion of the total is shifted to Capitalized Spare Parts in the Depreciable Investment.

(d) Net Receivables @ 1/24th of annual product revenue.

(e) Cash-on-Hand @ 3 weeks coal and operating costs - This item, omitted in the Guidelines, is generally included in the working capital estimate.

For the purposes of determining the product revenue, or product/intermediate values, the following simplified calculation on an annual basis is used:

Product Revenue = Coal Cost + Operating Cost - Byproduct

Credit + Capital Charges @ 20 percent of Plant Investment

No feedback of the actual capital charges as determined by the specific bases used for the economic calculation is employed. Intermediate product values are prorated approximately from the calculated product value.

6.2.2 Study Cases

The following working capital estimates have been developed for the study cases:

Case	Working Capital, MM $
I	58
I-A	50
I-B	76
I-C	57
II	60
II-A	52

Breakdowns of the base case working capitals are given in Table 6.2.1.

TABLE 6.2.1
WORKING CAPITAL BREAKDOWNS FOR BASE CASES

Base Case	I	II
Item, MM $		
Coal Inventory	6	6
Intermediate/Product Inventory	11	9
Warehouse Inventory	8	8
Net Receivables	22	24
Cash-on-Hand	11	12
Platinum Inventory*	0	1
	58	60

*For Reforming Unit 255 catalyst

6.3 COAL AND OPERATING COSTS

6.3.1 Coal Price

The cost of Wyoming strip sub-bituminous coal delivered to a neighboring conversion plant is assumed to be \$7.00/T, based on available price data for Gillette strip coal.

6.3.2 Operating Labor

The estimated hourly operating manpower for the base cases is shown in Table 6.3.1.

The greater complexity of units required by the Fischer-Tropsch technology results in almost a 50 percent greater operating labor requirement.

The estimates of the total hourly operating manpower for the sensitivity cases are:

Sensitivity Case	Manpower, Men
I-A	241
I-B	257
I-C	259
II-A	290 (no catalyst plant)

In Sensitivity Case II-A, the less complex product upgrading required for the Mobil direct conversion technology reduces this sector's manpower from the 62 men required in Base Case II to 7 men.

An annual wage of \$22,000 is used. It is based on the Guidelines hourly rate of \$6.70/hr (1/76), escalated to \$7.85 (10/77) at 9%/yr, and includes a burden factor of 35 percent. In addition, supervision is added at 20 percent yielding an equivalent annual rate of \$26,450.

6.3.3 Maintenance

The annual maintenance cost factors identified in the Guidelines have been adopted:

		Factor, %
(a)	Coal preparation, gasification and ash handling	6.0
(b)	Shift conversion, gas cooling, purification, byproduct recovery, methanation, SNG compression and drying, oxygen plant, stack gas treating and water treating	3.0
(c)	All other	1.0

TABLE 6.3.1
OPERATING MANPOWER FOR BASE CASES

Unit	Description	Manpower Shift*	Manpower Day
	BASE CASE I		
128	Coal Preparation & Storage	27.5	-
101,102,103,104 & 129	Gasification and Syn Gas Shift and Cooling	80	4
105,106 & 141	Syn Gas Purification	17.5	-
110,112,113 & 114	Methanol & SNG Synthesis	13.5	-
111,150,151,152, 153 & 154	Gasoline Synthesis	27	2
107,108,109,135 & 136	Effluent Water Treating	49.5	-
121,122, etc.	O_2 Plant, Utilities, etc.	36	4
	Total	251	10
	BASE CASE II		
228	Coal Preparation & Storage	27.5	-
201,202,203,204 & 229	Gasification and Syn Gas Shift and Cooling	80	4
205,206 & 241	Syn Gas Purification	17.5	-
250,252	F-T Synthesis	45	4
211,251,253 thru 262	Product Upgrading	62	2
210,212,213 & 214	SNG Synthesis	13.5	-
207,208,209,235 & 236	Effluent Water Treating	49.5	-
221,222, etc.	O_2 Plant, Utilities, etc.	36	4
271	F-T Catalyst Preparation	28	13
	Total	359	27

*Shift conversion factor is 4.5 to allow for weekends, vacations, sickness, etc.

The following, additional factors have been assumed:

Unit	Factor, %
Methanol Synthesis	3.0
Autothermal Reformer	3.0
Methanol Conversion	4.0
F-T Synthesis	5.0
F-T Catalyst Preparation	6.0
Direct Synthesis	5.0
Hydrocarbon Upgrading	3.0
Coal Boiler, etc.	3.0

The composite factors for the study cases are as follows:

Case	Factor, %
I	3.5
I-A	3.5
I-B	3.5
I-C	3.5
II	3.6
II-A	3.6

The annual maintenance is calculated and composed as follows:

Total, MM \$/yr = (Contractor Cost, MM \$ + 15% Estimating Allowance) X (Maintenance Factor)

Labor = 60%; Materials = 40%

No extras are added for supervision, burden, freight, sales tax, etc.

6.3.4 Catalyst and Chemicals

The following annual catalyst and chemical expenses have been estimated for the study cases:

Case	Cat. & Chem. Expenses, MM \$/yr
I	5.1
I-A	4.6
I-B	6.0
I-C	5.1
II	3.8
II-A	3.4

In addition, the cost of the iron ore (magnetite) raw material for F-T Catalyst Preparation Unit 271 in Base Case II has been estimated only as the transportation cost of the ore from Minnesota and the transportation cost of spent catalyst (iron pigs) back to Chicago. No iron loss and relative ore value shift to a steel mill have been assumed. This cost amounts to 2.1 MM $/yr.

The difference between the two base cases is principally the methanol synthesis catalyst make-up cost.

No catalyst costs have been included for the Mobil technologies.

6.3.5 Other

The bases for other operating cost elements are as follows:

(a) Water - Guidelines $0.40/M gal (1/76) escalated to $0.45/M gal (10/77) at 6%/yr

(b) Purchased Power - 1.65 ¢/KWH

(c) Supplies - 30% of operating labor + maintenance materials

(d) Administration and General Overhead - 60% of total labor, including supervision

(e) Local Taxes and Insurance - 2.7% of total depreciable capital less royalty

6.3.6 Study Cases

The following coal and operating costs are calculated for the study cases:

Case	Costs, MM $/yr Coal	Operating
I	64.3	131.7
I-A	64.3	121.9
I-B	64.5	149.2
I-C	64.3	128.2
II	65.3	151.5
II-A	64.3	133.8

Items of the operating costs for the base cases are listed in Table 6.3.2.

TABLE 6.3.2
BREAKDOWNS OF OPERATING COSTS FOR BASE CASES

Base Case	Operating Cost, MM $/yr I		Operating Cost, MM $/yr II	
Item				
Labor plus Supervision				
Operating	6.9		10.2	
Maintenance	29.5	36.4	33.2	43.4
Water		1.4		1.4
Supplies				
Operating	1.7		2.5	
Maintenance	19.7	21.4	22.2	24.7
Catalyst & Chemicals		5.0		5.9
Administration & General Overhead		21.9		26.1
Local Taxes & Insurance		45.6		50.0
Total		131.7		151.5

6.4 BYPRODUCT CREDITS

6.4.1 Bases

The following bases for the byproduct credit calculations are used in the cost estimation:

(a) Sulfur - Guidelines 25 $/long T escalated to 25 $/short T @ 6%/yr

(b) Ammonia - Guidelines 140 $/T escalated to 155 $/T @ 6%/yr

(c) Power - 0.0045 $/KWH - Value is estimated to be only equivalent to backing out coal in an existing power plant.

(d) Coal Fines - 5.25 $/T @ Guidelines 75% of coal price

6.4.2 Study Cases

The following byproduct credits are calculated for the study cases:

Case	Byproduct Credits, MM $/yr
I	8.2
I-A	8.7
I-B	5.9
I-C	8.8
II	6.0
II-A	6.5

Cases having the higher byproduct credits are those showing a surplus of coal fines, as shown in Table 6.4.1 in which the byproduct credit breakdowns for the base cases are presented.

TABLE 6.4.1
BREAKDOWNS OF BYPRODUCT CREDITS FOR BASE CASES

Base Case	Byproduct Credits, MM $/yr I	II
Item		
Sulfur	0.5	0.5
Ammonia	5.4	5.4
Power	0.2	0.1
Coal Fines	2.1	0.0
	8.2	6.0

SECTION 7
ECONOMIC EVALUATION

7.1 BASES

7.1.1 Scope

As recommended in the Gas Cost Guidelines, unit costs for each case are developed for both equity-and utility-type financing. For each type of financing, unit costs are calculated on both a thermal product and a multiple products basis. In the former, the unit cost is based on the total thermal (Btu) product yield. This cost assumes each Btu shares equally the plant cost. In the multiple products calculation, values for products other than gasoline are projected, and the gasoline unit cost is then calculated. Again, the principal on which the bases have been adopted is to yield realistic unit costs. Pertinent factors are analyzed in a fairly detailed sensitivity development around Base Case I.

7.1.2 Equity Financing Bases

The following bases are used in the equity financing calculation:

(a) Plant Operating Life @ 20 years

(b) Depreciable Life @ 13 years, ADR

(c) Construction Timing @ 6 years - This timing assumes year 1 is required for environmental studies, year 2 is required for impact reports and plant design and engineering, and years 3 through 6 are required for plant construction. Investment payout is:

Year	% of Investment
1	0, 1 MM $ for environmental studies
2	5, 1 MM $ for environmental studies
3	24
4	30
5	25
6	16

(d) Other Expenditures - Royalty in year 6
Working Capital in year 7 with recovery in last year.
Catalyst & Chemical Fill in year 7

(c) Investment Credit @ 7% in year of expenditure

(f) Depreciation Method - The sum-of-the-year digits procedure is used. The "half-rate in first year" convention is practiced. (Independent of when the plant qualifies for depreciation during the first year of operating the allowable depreciation taken is one-half the full year rate.)

(g) Income Taxes - Federal @ 48%
State @ 7.5%
Total @ 51.9%

(h) Start-Up Penalty - Only one-half production is assumed in first operating year with full expenses, except for the variable costs, such as coal, water, supplies, etc., which are expensed at one-half rate.

(i) Unit Cost Basis @ 12% DCF

The calculation procedure is not the same as outlined in the Guidelines and the bases are significantly different.

7.1.3 Utility Financing Bases

The following bases are used in the utility financing calculation:

(a) Plant Operating Life @ 20 years

(b) Depreciable Life @ 20 years

(c) Construction Timing @ 5 years - The investment payout factors are 5/24/30/25/16 as percent of the plant investment. With simple interest at 9%, the average spending period becomes 2.77.

(d) Investment Credit - Not used

(e) Depreciation Method - Straight Line

(f) Income Taxes @ 51.9%

(g) Start-Up Penalty @ 20% of the sum of the annual coal and operating costs

(h) Debt/Equity Ratio @ 75/25

(i) Unit Cost Basis @ 9% interest on debt capital and 15% return after taxes on equity capital

The calculating procedure is the same as outlined in the Guidelines and only the income tax and average spending period bases differ than those recommended.

7.1.4 Product Pricing Bases

The following product pricing bases have been adopted when calculating the economics in the multiple products mode:

(a) SNG: Since over 50 percent of the thermal product is SNG in the coproduction cases, the selection of the plant gate price for SNG is quite critical. The basis chosen is the cost of SNG from an equivalent Wyoming coal, Lurgi gasification plant. To arrive at the prices cited below, a sensitivity case was developed as described in Appendix D.

Equity Basis	-	6.17 $/MM Btu
Utility Basis	-	4.51 $/MM Btu

(b) C_3 LPG: Since this product is expected to be marketed for heating, the plant gate SNG prices have been assigned.

Equity Basis		6.17 $/MM Btu
Utility Basis	-	4.51 $/MM Btu

(c) Butanes: The butanes can be used for fuel, gasoline blending or alkylation feed. It has been assumed that their end use will be gasoline. Historically, butanes for this use have a lower refinery plant gate value than posted for 10 RVP gasoline, e.g., $0.25/Bbl. If this delta is used with the high cost gasolines in this study, however, the butanes will then have a thermal value higher than calculated for the gasoline. This situation is unreasonable. Consequently, an arbitrary 30 ¢/MM thermal value delta below gasoline has been assumed.

(d) Diesel and Fuel Oils: For these Fischer-Tropsch products, typical refinery gate differences between motor gasoline and heavier products have been assumed.

		Delta, $/Bbl
Diesel Oil	-	1.70
Fuel Oil	-	3.50

(e) Alcohols: The estimated plant gate value for the Fischer-Tropsch refined alcohol mixture is 15 ¢/lb without any market restrictions. (With market restrictions, this value could drop to about 13 ¢/lb.) The basis is projected Gulf Coast prices with transportation from Wyoming backed out.

The above bases should be considered only as one of the possible scenarios for the market place from 10 to 15 years in the future. They do indicate, however, the effect on the gasoline unit cost when values or prices are superimposed on the coproducts.

Because of the uncertainty in extrapolating historical refinery price deltas at the current price levels for product quality differences to deltas for the high cost coal derived products, this consideration has been omitted. For example, credit should be recognized for the above target octanes of the gasolines produced by the Mobil technologies and, perhaps, for the excellent quality F-T diesel and fuel oils.

7.2 INTER-STUDY COMPARISONS

In the development of the study bases, considerable effort has been made not only to identify technical and economic differences between the Fischer-Tropsch and Mobil methanol conversion technologies, but also to obtain with available technology a realistic gasoline cost in current dollars. Except for the Mobil technology, scale-up from laboratory or bench-scale data for second generation technology and "conceptual" engineering have not been incorporated into the plant designs. Moreover, items such as construction time, start-up difficulty, construction camp, construction labor premium and Wyoming environment have been introduced into the economic bases. Consequently, direct inter-study comparisons are, at best, extremely difficult.

We specifically caution making economic comparisons between the results in this report and other results reported in the literature. Literature reported studies frequently have been developed to provide rough scoping type estimates useful for planning and technology sales. The cost data are generally rough estimates, are often computer based, reflect unproven "conceptual" engineering without an engineering contingency factor and do not reflect realistic market place costs. With these bases costs are usually very optimistic, especially if the economic bases follow the Gas Cost Guidelines. The costs in this study have been developed together by a contractor <u>and</u> an operating company, and hence, we believe they do represent realistic bottom line data. If comparisons to other technologies are needed, it is suggested that the cases be developed on a consistent bases, preferably by the same analyst.

To aid in inter-study comparisons, Base Case I economics have been reworked following the Gas Cost Guidelines. These data are included in Sub-Section 7.4.

7.3 BASE CASES

The unit costs calculated for the base cases are reported in Table 7.3.1.

Economics favor the Mobil methanol conversion technology from 3 to 15 $/Bbl of gasoline, depending upon the cost calculating and product pricing bases. Placing the assumed price restrictions on the coproducts gives the new technology a substantial advantage over the less selective Fischer-Tropsch technology.

The breakdowns of the thermal unit costs clearly show the capital intensive nature of coal processing; from 60 to 65 percent of the unit cost can be attributed to capital charges. The relatively inexpensive strip coal results in a coal cost of only about 10 percent. Eventhough the annual operating expenses are quite substantial, they only amount to 20-30 percent of the unit cost.

Cash flows representing the 12% DCF cost calculation for the base cases are given in Tables 7.3.2 and 7.3.3.

TABLE 7.3.1
UNIT COSTS FOR BASE CASES

Base Case	I	II
Equity Bases @ 12% DCF		
Thermal Product, $/MM Btu		
Capital Charges	4.59	5.07
Start-Up Penalty	0.35	0.38
Coal Cost	0.70	0.72
Operating Expenses	1.44	1.68
Byproduct Credit	(0.09)	(0.07)
Total	6.99	7.78
Equivalent Gasoline Unit Cost, ¢/gal	85	93
Multiple Products		
Gasoline Unit Cost, ¢/gal	98	133
Utility Basis		
Thermal Product, $/MM Btu		
Capital Charges	2.98	3.28
Start-Up Penalty	0.05	0.06
Coal Cost	0.70	0.72
Operating Expenses	1.44	1.68
Byproduct Credit	(0.09)	(0.07)
Total	5.08	5.67
Equivalent Gasoline Unit Cost, ¢/gal	62	68
Multiple Products		
Gasoline Unit Cost, ¢/gal	71	94

TABLE 7.3.2
EQUITY CASH FLOW FOR BASE CASE I
(12% DCF)

DCFCASH DETAIL ($/MM Btu = 6.99)

YEAR	GROSS REVENUE MM $	DEPR. INVEST MM $	OP.EXP. + FEED MM $	INCOME TAX MM $	SALE TX +SEV.TX MM $	WORKING CAPITAL MM $	NETCASH INFLOW MM $	DEPRE-CIATION MM $
1	.000	.000	1.000	-.519	.000	.000	-.481	.000
2	.000	84.550	1.000	-6.866	.825	.000	-79.509	.000
3	.000	405.840	.000	-30.463	3.959	.000	-379.335	.000
4	.000	507.300	.000	-38.079	4.948	.000	-474.169	.000
5	.000	422.750	.000	-31.733	4.124	.000	-395.141	.000
6	.000	287.560	.000	-20.309	2.639	.000	-269.890	.000
7	324.871	.000	160.830	21.819	.000	58.000	84.222	122.000
8	649.742	.000	195.960	113.748	.000	.000	340.035	234.615
9	649.742	.000	195.960	123.489	.000	.000	330.293	215.846
10	649.742	.000	195.960	133.230	.000	.000	320.552	197.077
11	649.742	.000	195.960	142.971	.000	.000	310.811	178.308
12	649.742	.000	195.960	152.713	.000	.000	301.070	159.538
13	649.742	.000	195.960	162.454	.000	.000	291.328	140.769
14	649.742	.000	195.960	172.195	.000	.000	281.587	122.000
15	649.742	.000	195.960	181.936	.000	.000	271.846	103.231
16	649.742	.000	195.960	191.677	.000	.000	262.105	84.462
17	649.742	.000	195.960	201.419	.000	.000	252.364	65.692
18	649.742	.000	195.960	211.160	.000	.000	242.622	46.923
19	649.742	.000	195.960	220.901	.000	.000	232.881	28.154
20	649.742	.000	195.960	230.642	.000	.000	223.140	9.385
21	649.742	.000	195.960	235.513	.000	.000	218.269	.000
22	649.742	.000	195.960	235.513	.000	.000	218.269	.000
23	649.742	.000	195.960	235.513	.000	.000	218.269	.000
24	649.742	.000	195.960	235.513	.000	.000	218.269	.000
25	649.742	.000	195.960	235.513	.000	.000	218.269	.000
26	649.742	.000	195.960	235.513	.000	-58.000	276.269	.000
TOT	12669.973	1708.000	3886.070	3545.463	16.495	.000	3513.945	1708.000

TABLE 7.3.3
EQUITY CASH FLOW FOR BASE CASE II
(12% DCF)

DCFCASH DETAIL ($/MM Btu = 7.78)

YEAR	GROSS REVENUE MM $	DEPR. INVEST MM $	OP.EXP. + FEED MM $	INCOME TAX MM $	SALE TX +SSV.TX MM $	WORKING CAPITAL MM $	NETCASH INFLOW MM $	DEPRE-CIATION MM $
1	.000	.000	1.000	-.519	.000	.000	-.481	.000
2	.000	92.500	1.000	-7.474	.924	.000	-86.950	.000
3	.000	444.000	.000	-33.382	4.435	.000	-415.053	.000
4	.000	555.000	.000	-41.727	5.544	.000	-518.817	.000
5	.000	462.500	.000	-34.773	4.620	.000	-432.347	.000
6	.000	309.000	.000	-22.255	2.957	.000	-289.702	.000
7	355.278	.000	176.790	23.571	.000	60.000	94.917	133.071
8	710.635	.000	216.810	123.479	.000	.000	370.345	255.907
9	710.635	.000	216.810	134.105	.000	.000	359.720	235.434
10	710.635	.000	216.810	144.730	.000	.000	349.095	214.962
11	710.635	.000	216.810	155.355	.000	.000	338.469	194.489
12	710.635	.000	216.810	165.980	.000	.000	327.844	174.015
13	710.635	.000	216.810	176.606	.000	.000	317.219	153.544
14	710.635	.000	216.810	187.231	.000	.000	306.594	133.071
15	710.635	.000	216.810	197.856	.000	.000	295.968	112.599
16	710.635	.000	216.810	208.481	.000	.000	285.343	92.126
17	710.635	.000	216.810	219.107	.000	.000	274.718	71.654
18	710.635	.000	216.810	229.732	.000	.000	264.093	51.181
19	710.635	.000	216.810	240.357	.000	.000	253.467	30.709
20	710.635	.000	216.810	250.982	.000	.000	242.842	10.236
21	710.635	.000	216.810	256.295	.000	.000	237.530	.000
22	710.635	.000	216.810	256.295	.000	.000	237.530	.000
23	710.635	.000	216.810	256.295	.000	.000	237.530	.000
24	710.635	.000	216.810	256.295	.000	.000	237.530	.000
25	710.635	.000	216.810	256.295	.000	.000	237.530	.000
26	710.635	.000	216.810	256.295	.000	60.000	297.530	.000
TOT	13857.336	1853.000	4298.180	3855.214	18.480	.000	3822.462	1863.000

7.4 INTER-STUDY COMPARISON SUB-CASE

As a guide in making inter-study economic comparisons, a sub-case has been developed from Base Case I data following exactly, except for two items, the economic bases and calculations outlined in the Gas Cost Guidelines. The two exceptions are the usage of a 7 $/T price for Wyoming strip coal and October, 1977 costs. The results are briefly described below:

Total Investment, MM $	1,295
Equity Basis @ 12% DCF	
Thermal Product	
Equivalent Gasoline, ¢/gal	69 (5.65 $/MM Btu)
Multiple Product	
Gasoline, ¢/gal	78 (SNG @ 4.98 $/MM Btu)
Utility Basis	
Thermal Product	
Equivalent Gasoline, ¢/gal	49 (4.03 $/MM Btu)
Multiple Product	
Gasoline, ¢/gal	56 (SNG @ 3.58 $/MM Btu)

Investment items omitted include overtime premium and project management. A construction camp cost, however, has been included. Working capital is reduced. Construction costs are based on Gulf Coast prices and productivity. Construction worker base wage rate is 10.54 $/hr. Timing does not reflect the requirement for environmental studies, etc. Economic bases include income tax at 48%, no investment credit and 16 year depreciable life. The stream factor is reduced to 90 percent. These bases result in about a 20 percent reduction in the unit costs derived from the bases adopted for this study.

We are not suggesting that the above gasoline costs be used without reservation in inter-study comparisons, but offer them to show that the basic study data can, indeed, lead to relatively low gasoline costs. The study assumptions to arrive at realistic costs for a Wyoming location plant have a severe effect on the venture economics.

7.5 BASE CASE I ECONOMIC SENSITIVITIES

Since Base Case I has the better economics, economic sensitivities have been developed only for this case. Because of the similar nature between the study cases, the Base Case I effects described below would also be generally applicable to all cases.

7.5.1 Economic Bases

Table 7.5.1 is a listing of the unit cost sensitivity towards the various economic bases under equity financing. The effect of the DCF rate of return is shown in Figure 7.5.1. Utility financing sensitivities are given in Table 7.5.2. Because in most sensitivities, e.g., operating life, coal price, debt/equity ratio, etc., it seems meaningless to calculate a gasoline cost at the sensitivity basis while using an SNG cost at the standard basis, sensitivities for the multiple products calculation have not been made.

Most important in the multiple products calculation is the SNG market price assumed. The sensitivity of the gasoline cost to this item is presented in Figure 7.5.2. It is applicable to both financing methods.

7.5.2 Construction Timing

We estimate that approximately 36 million manhours would be required to erect each plant complex. If the construction period assumed is four years (study basis), then at a 40 hour week, about 5,200 men would be required. With a 14 hour overtime premium (study basis) about 4,000 men would be required. These numbers represent an average; actually, the manpower rises and falls with the job requirements, peaking, generally at about 20 to 30% above the average. In a remote area as Wyoming, a more pessimistic assumption for manpower availability might be an average of only 2,000 men, thereby increasing the construction timing to 8 years.

The effect of construction timing on economics is shown in Table 7.5.3.

The stretchout of plant construction from 4 to 8 years has a calamitous effect on the gasoline cost, even though the deltas shown <u>do not</u> reflect any escalation. If this factor were introduced, they would be even more dramatic. Also, the time-value effect in the DCF calculation results in a more severe, but realistic, effect for a construction stretchout.

TABLE 7.5.1
SENSITIVITIES FOR BASE CASE I
EQUITY FINANCING
(12% DCF)

Calculation Basis	Unit Cost Delta: Thermal Product, \$/MM Btu	Unit Cost Delta: Equivalent Gasoline, ¢/gal*
25 yr. Operating Life (+5 yr.)	-0.24	-3
No Investment Credit	+0.47	+5½
10 year Depreciable Life	-0.15	-2
16 year Depreciable Life	+0.14	+1½
35% FIT (-13%)	-0.66	-8
± 20% Depreciable Investment (± 338 MM \$)	±0.94	±11½
Triple Working Capital (+ 116 MM \$)	+0.30	+3½
± 2 \$/T Coal Price	±0.20	±2
± 25% Operating Cost (± 33.0 MM \$/yr.)	± 0.36	±4½

*At 5.1 MM Btu/Bbl

TABLE 7.5.2
SENSITIVITIES FOR BASE CASE I
UTILITY FINANCING

Calculation Basis	-----Unit Cost Delta----- Thermal Product, $/MM Btu	Equivalent Gasoline, ¢/gal*
12% Interest on Debt (+3%)	+0.46	+5½
20% Return on Equity (+5%)	+0.33	+4
50/50 Debt/Equity Ratio	+0.70	+8½
60/40 Debt/Equity Ratio	+0.42	+5
35% FIT (-13%)	-0.25	-3
± 20% Depreciable Investment (± 338 MM $)	±0.56	±7
Triple Working Capital (+116 MM $)	+0.18	+2
± 2 $/T Coal Price	±0.20	±2
± 25% Operating Cost (± 33.0 MM $/yr.)	±0.30	±4½

*At 5.1 MM Btu/Bbl

FIGURE 7.5.1

EFFECT OF DCF RATE OF RETURN ON UNIT COSTS
(BASE CASE I)

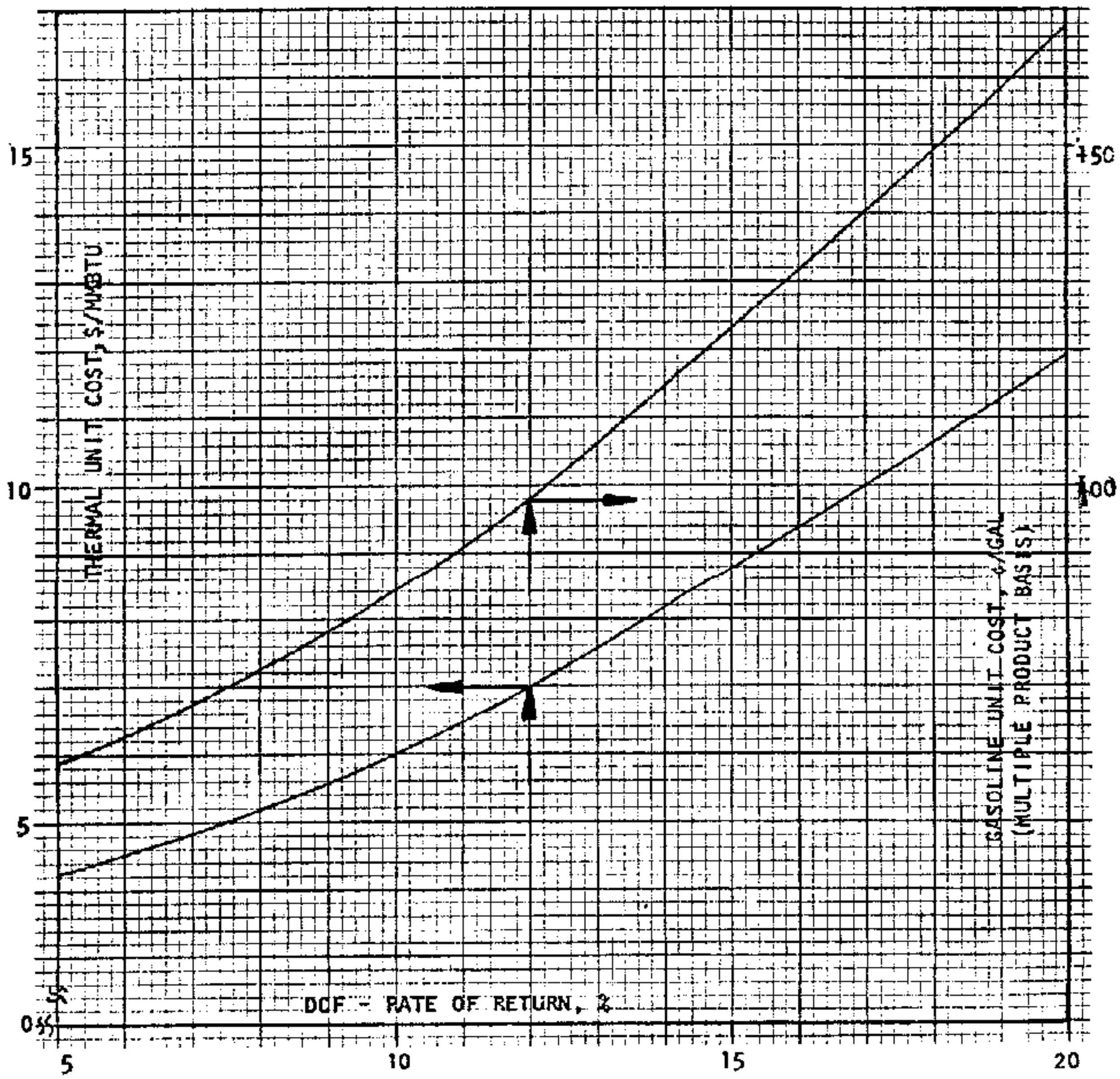
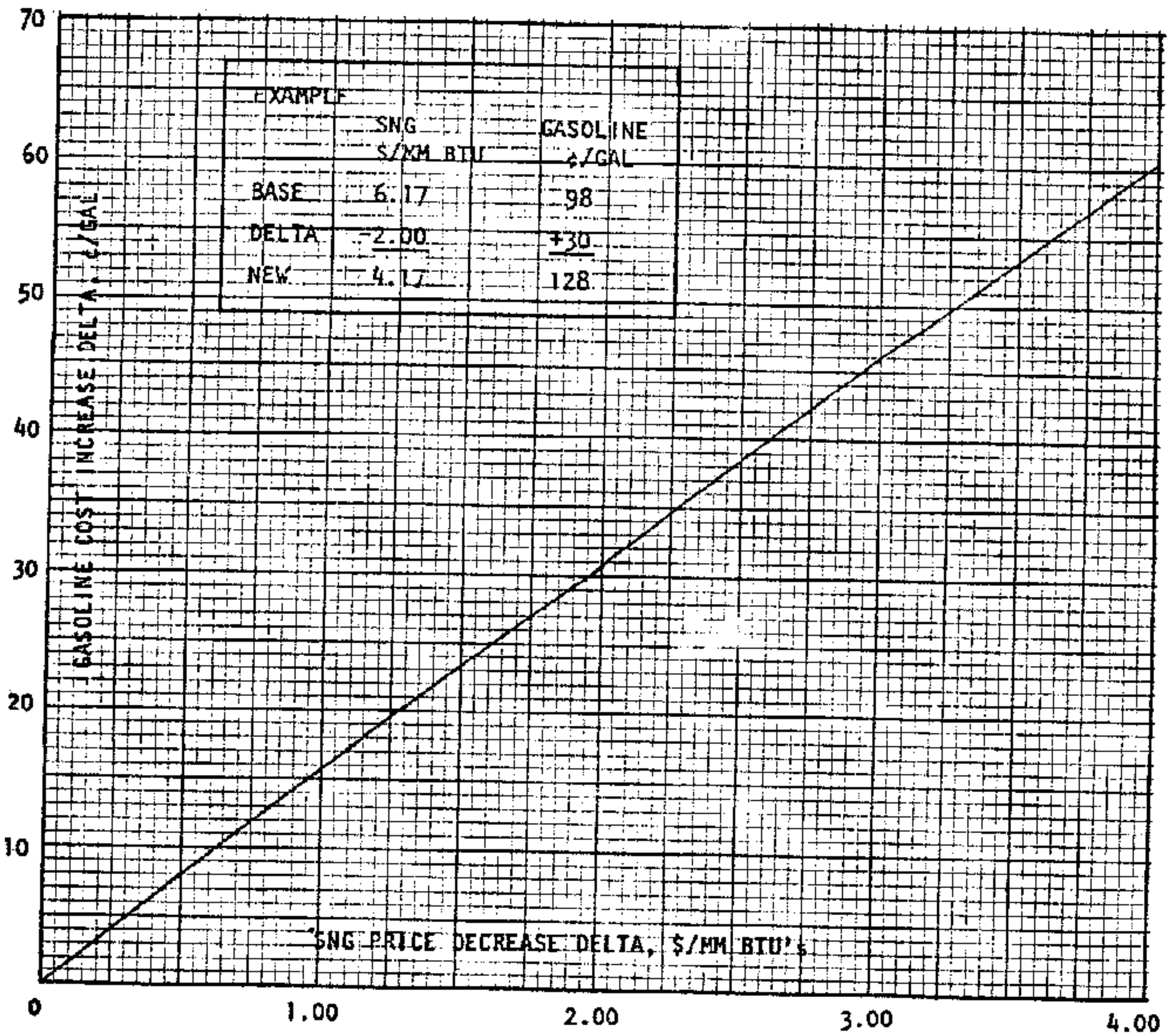


FIGURE 7.5.2
EFFECT OF SNG PRICE ON GASOLINE UNIT COST
(BASE CASE I)



Two questions, therefore, arise: (1) Can 4,000 men (study basis) ever be enticed into Wyoming? (2) Are the 14 hour overtime premium and construction camp monies sufficient inducements? We believe that, without further industrialization in the Montana, North Dakota and Wyoming area, these large scale coal processing plants might find it difficult to attract such large work forces. Moreover, an additional bonus will probably be required to ensure that the workers stay for a reasonable period. A definitive construction environment study would be made before any project funding decision.

7.5.3 Start-Up Penalty

The effect of the assumed start-up penalty on the unit cost is shown below:

Equity Financing @ 12% DCF

	-----Unit Cost Delta-----	
Calculation Basis	Thermal Product, \$/MM Btu	Equivalent Gasoline, ¢/gal
No Penalty	Base	Base
Gas Cost Guidelines Basis	+0.06	+½
Study Basis	+0.35	+4

We believe it is unrealistic to assume that during the last year of construction, the complete plant operating personnel will be trained and all the initial operating and maintenance problems will be solved to achieve 100 percent product manufacture in the first year of operation. Past experience for first syn fuels plants, i.e., Great Canadian Oil Sands and Sasol I, indicates start-ups are slow and difficult. Although first plant learning should reduce start-up problems, the second tar sands project, Syncrude of Canada, currently under construction, has been projecting a gradual build-up in production capacity through the early operating years.

7.5.4 Use of Lurgi Gasifier Tar and Oil Products

The study bases call for the combustion of the Lurgi gasifier oil and tar in the boiler and process steam superheater. A sensitivity case has been roughly developed for backing out these materials from the boiler in Base Case I. (The separate process steam superheater, Unit 124, remains oil fired.) Additional hydrogen is removed from the methanol synthesis unit purge gas in H_2 Recovery Unit 111 for hydrotreating.

TABLE 7.5.3
CONSTRUCTION TIMING SENSITIVITY FOR BASE CASE I

Calculation Basis	Unit Cost Delta — Equity Basis: Thermal Product, $/MM Btu	Equity Basis: Equivalent Gasoline, ¢/gal(2)	Utility Basis: Thermal Product, $/MM Btu	Utility Basis: Equivalen Gasoline, ¢/gal(2)
1 yr. Construction	-1.18	-14½	-0.36	-4½
8 yr. Construction: Timing, % at 0/4/15/20/16/12/11/10/7/5(1) (all purchasing in early years)	+2.41	+29	+0.55	+6½
8 yr. Construction: Timing, % at 0/4/12/14/16/14/13/11/10/6(1)	+2.06	+25	+0.47	+5½

(1) Year 1 is for environmental studies; year 2 is for engineering and design.

(2) At 5.1 MM Btu/Bbl.

The hydrotreating requirements were based on in-house information for upgrading an H-Coal 400+ material from 7.4 wt. % to 10.0 wt. % hydrogen into a marketable fuel oil. Approximately 5,700 B/SD of fuel oil is estimated to be produced. The overall plant thermal efficiency is increased by about 2 percent to 64 percent.

Relative to Base Case I, the coal, operating and capital costs increase about 2%, but the thermal product yield increases by 11%. The result is a 50 to 60 ¢/MM Btu reduction in the unit cost (equity basis), or about 7 ¢/gal in the equivalent gasoline cost. Consequently, in future studies, it appears economically advantageous to expand the hydrogen recovery unit and increase the hydrotreating capacity for the inclusion of the tar and oil as well as the naphtha.

In downstream processing situations where there is a purge gas stream whose quantity is determined by the nitrogen (inerts) present, this purge gas is often used as boiler fuel. We believe that a more expensive 99+ oxygen purity plant, thereby reducing the purge gas stream, would prove to be economical.