CHAPTER 4 : SYNTHETIC FUEL PROCESSES CONVERSION COST AND PRODUCT ECONOMICS

4.1 CONVERSION COSTS AND PRODUCT ECONOMICS

The following evaluation of a wide range of alternate fuels produced from coal attempts to build upon prior work in the field that has, successively, estimated the plant construction and operating costs for each process, standardized the bases of estimation (time of construction, size of plant, location, financing methods, etc.) and evaluated the quality of product produced.

Such work has been sponsored by the Department of Energy since the early 1970's. The most recent work was performed by the Engineering Societies Commission on Energy, Inc. (ESCOE).[1] That work collected prior analyses performed for DOE and others, made adjustments in each to account for differing assumptions regarding input prices, plant scale, financing methods and costs, and thus reevaluated them on a more common basis. The differences in product quality were factored for value based on current price relationship among natural petroleum products.

Our approach will differ in several regards:

First of all we shall use the baseline ESCOE plant models, capital costs and operating cost relationships, updated to a uniform 1980 dollar basis.

Second we shall scale all plants to a common output plant size[2] in order to retain comparability at other, downstream stages of processing and use.

Third we shall deal with differences in product quality directly, and on a cost of product basis, by considering the additional costs required to upgrade lower quality products and make them comparable with the higher grade synfuels.

Fourth we shall then examine the methods and costs of further processing and transporting the generic synfuel products to make them available to end use markets.[3]

The ESCOE capital estimates were all adjusted to a 1980 dollar basis by the use of the Wholesale Price Index - Industrial Commodities Index. Others have frequently used the Chemical Engineering Plant Index, however we feel that no significant historical difference exists and the WPI Index basis is a more suitable bench mark for further forecasting since it is a component

[1]Coal Conversion Comparison, ESCOE Report FE-2468-51, July, 1979.

[2]ESCOE scaled all plants to a common input size in order to simplify the costs - auxiliaries and off-sites are normalized.

[3]We did not examine differences in end use efficiency that exist or are possible. This should be subsequently examined.

of Us. macro-economic forecasting models and the Chemical Construction Index is not.

Exhibit 4-1 displays the original capital cost estimates of ESCOE. Exhibit 4-2 updates these estimates to a uniform 1980 cost basis.

Operating costs are more complex. The major cost categories are:

- Coal
- Utilities
  - Water
  - Power
- Catalysts and Chemicals
- Labor
- Overhead
- Maintenance

Coal prices are uniform to all processes - as are assumed costs of water, power and labor. The costs of overhead are a uniform fraction of operating and maintenance labor - they include administrative personnel costs as well as G&A expenses. The maintenance rule is made uniform among systems-although differences should exist on the basis of system approach.

The original ESCOE operating cost variables are shown on Exhibit 4-3. These unit prices provide the bases for updating the ESCOE costs to the values shown on Exhibit 4-4.[4]

The cost of producing hydrogen for product upgrading is partially imbedded in other estimates. The uniform condition is that hydrogen is demanded at a greater level then could be supplied from excess char, residue, or filtrate from the process plant. Therefore a hydrogen plant must be built at the upgrading plant site. This plant is designed to reform synthesis gas.[5] The cost of hydrogen can then be based on the hydrogen plant's costs - including syngas feed at the estimated syngas product costs of our companion syngas plant. Alternately we could capitalize a coal gasification plant in this area, however that seems to be an even more unrealistic mode of system optimization.

In the long run, as product slate demand for synthetic coal liquids becomes clarified, the optimization of an integrated coal-to-product plant can be designed in a much more sophisticated manner.

[4] The input costs were in certain instances drawn from original sources cited by ESCOE.

[5] Or reform synthetic fuel product - the cost is comparable $6.25 - 6.75/MM BTU.

EXHIBIT 4-1

PLANT CAPITAL REQUIREMENTS
MAJOR ON-SITE PLANT COST IN MILLIONS OF MID 1978 $

Category Process	SRC-II	EDS	H-FO	H-Syn	FT	M	Lur.	West. Syn.
Coal Preparation	63	63	84	84	63	63	90	63
H_2 or Gasification	253	190	138	158	228	228	143	22
O_2 Plant	129	-	67	87	117	175	114	80
Gas Shift	-	-	30	35	-	40	30	-
Acid Gas and Sulfur Plants	60	60	57	57	57	57	136	57
Reactor Section	195	180	140	210	55	106	90	-
Conversion	-	-	-	-	100	75	20	42
Gas Plant	30	-	30	25	25	10	12	-
Flexicoker	-	160	-	-	-	-	-	-
Pollution Systems	44	44	40	40	40	40	55	24
Solvent Hydro. or Catalyst Prep.	-	82	-	-	3	-	-	-
Compression	-	-	-	-	-	-	28	-
Total less Int. Including Indirects	1262	1270	955	1134	1121	1212	1151	684

Notes:
1. M includes HF Alkylation.
2. Some EDS cost included in Flexicoker.
3. All costs shown above are considered bare cost and have not been confirmed with process developer.

SOURCE: E. J. Bentz & Associates

EXHIBIT 4-2

TOTAL CONVERSION PLANT INVESTMENT - 50,000 BBL LIQUIDS/DAY PLANT BASIS

(Million 1980 Dollars)

Coal Liquids	ESCOE Basis 1978 $	ESCOE Basis[1] 1980 $	50,000 BBL/ Day Output Basis	Capital Cost/ Daily BBL	Total BTU E14/Yr.	Capital Cost/ MM BTU/ Yr.	Reference: Tons of Coal/Day
Direct Liquefaction							
SRC-II	$1,262.	$1,565.	1310.8	$26,210	1.081	$12.13	20,938
EDS	1,279.	1,574.	1422	28,440	1.072	13.26	22,584
H-Coal Syn. Oil	1,134.	1,407.	1252	25,040	1.115	11.23	22,242
H-Coal F.O.	955.	1,185.	980.9	19,620	1.048	9.36	20,695
Indirect Liquefaction							
Fischer/Tropsch	1,121.	1,391.	1730	34,600	1.112	15.56	31,095
Mobil 'M'	1,212.	1,676.	1396.4	27,930	8016	17.42	20,833
Methanol	1,195.	1,482.[2]	608.4	12,170	428	14.20	10,263
Methanol/SNG	1,587.	2,225.	2132.9	42,650	905	23.57	26,174
Coal Gasses							
High BTU							
Lurgi	1,151.	1,427.	1313.1	(26,260)[3]	1.067[3]	12.30	23,000
Low BTU							
Westinghouse	684.	851.	889.5	(11,790)[3]	1.067[3]	5.58	17,313
Shale Oil							
Surf. Retort.	700.[4]	798.	798.	15,960	.953[5]	11.93	N.A.

[1] ESCOE - 25,000 tons coal/day input basis revised to reflect 20% contingency vs. 10% and 1980 dollars.

[2] Mobil Research Center Basis - $ 1977 - 27,300 ton coal input revised $ 1980 and 1.73% markup of plant.

[3] Evaluated at average heating value of coal 1 quids 6.5 MM/BTU/bbl. x 50,000 bbl./day = 325 billion BTU/day (1.067 E14 BTU /yr.)

[4] OTA Basis - 3rd quarter 1979, 50,000 bbl. basis.

[5] Evaluated at average daily value of 5.8 MM/BTU/bbl.

SOURCE: E. J. Bentz & Associates

EXHIBIT 4-3

COST DATA
(ESCOE)

Process	Capital C	Fuel 1	Catalyst & Chem. 2a	Labor 2b	Maintenance 2c	Local Tax & Ins. 2d	Total M 2
		OPERATING & MAINTENANCE COST					
SRC-I	1092	246.	3.0	13.8	33.	55.	104.8
SRC-II	1262	246.	6.0	12.2	38.2	53.	119.0
EDS	1270	246.	6.0	12.2	38.5	64.	121.0
H Coal: Fuel Oil	955	246.	6.0	12.2	29.	48.	95.0
Syncrude	1134	246.	7.0	12.2	34.3	57.	111.0
FT	1121	246.	7.0	12.2	34.	56.	109.0
Methanol	1195	246.	7.0	12.2	34.	60.	113.2
M-Gasoline	1212	246.	8.5	12.2	35.5	65.	121.0
CO_2 Acceptor SNG	1084	246.	5.9	12.7	34.6	54.	107.0
Syngas	942	246.	3.2	12.7	22.5	47.	73.0
HYGAS	980	246.	4.8	12.2	23.4	49.	69.0
BIGAS	998	246.	5.8	12.2	23.9	50.	91.9
Synthane	870	246.	4.5	12.9	24.3	44.	82.0
Lurgi	1151	246.	4.5	12.7	36.7	58.	112.0
CE Power	1268	246.	3.0	12.0	38.	63.	116.0
West Power	1066	246.	3.0	12.0	32.	53.	100.0
Westinghouse Syngas	684	246.	4.5	12.2	20.5	34.3	71.4
Shale Oil	793	-	-	-	-	-	-

SOURCE: E. J. Bentz & Associates

EXHIBIT 4-4

ANNUAL OPERATING COST - 50,000 BBL LIQUIDS/DAY PLANT

(Million 1980 Dollars)

Synthetic Coal Liquids	Capital Charges @ 30% of Capital	Feedstock: Coal (Shale) @ $30/Ton (10)	Other Operating Costs: Catalysts & Chems. (escalated @ 20%)	Other Operating Costs: Labor	Other Operating Costs: Maintenance 3% of Total Capital	Other Operating Costs: Utilities & Supplies (50% of Chem.)	Other Operating Costs: Taxes & Ins. 3%	Other Operating Costs: Total Other	Total Operating Cost	Average Cost/ BBL Liq.	Cost/ MM/BTU
Direct Liquefaction											
SRC-II	393.2	206.3	6	11.9	39.3	3	39.3	99.5	699.	42.557	6.47
EDS	426.6	222.6	6	13.	42.7	3	42.6	107.3	756.5	46.058	7.06
H-Coal S	375.6	219.2	7	12.7	37.6	3.5	37.5	212.6	807.4	49.157	7.24
H-Coal F.O.	294.3	203.9	6	11.8	29.4	3	29.4	79.6	577.8	35.178	5.51
Indirect Liquefaction											
Fischer-Topsch	519.	306.4	7	17.7	51.9	3.5	51.9	132.	957.4	58.29	9.61
Mobil 'M'	418.9	205.3	7	11.9	41.9	3.5	41.9	106.2	730.4	44.469	9.11
Methanol	182.5	101.1	3.5	5.9	18.3	mAm	18.3	48.	331.6	20.189	7.75
Methanol/SNG	639.9	256.9	6	13.7	64.0		64.	150.7	1047.5	(63.775)	11.57
Synthetic Gas											
Hi BTU Lurgi	393.9	226.7	4	13.7	39.4	2	39.4	98.5	719.1	·43.78)	6.74
Med. BTU Westinghouse	266.9	170.6	3	10.3	26.7	1.5	26.7	68.2	505.7	(30,788)	4.74
Shale Oil											
Surf. Retort.	239.4	230.0	-	-	-	-	–	322.3	791.7	48.20	8.31

SOURCE: E. J. Bentz & Associates

4.2 SCALE OF PRODUCTION

Chemical process plant economics are highly sensitive to scale. Typical scaling factors or rules, are of the order of **60%** - 70%. This means that as plant size doubles the cost only increases by 60% - 70%. In the case of decreased scale - the factor works in the opposite direction, a decrease in scale to l\2 plant scale leads to only about l\3 decrease in cost, which in turn leads to almost 30% more capital being required per unit of output. In very capital intensive processes, the importance of this to product cost is great. Coal conversion processes typically have 1/2 of their costs derived from capital charges, therefore a doubling of scale could reduce total unit costs by as much as 15% - 20%.

For this reason the question of plant scale must be very carefully examined. ESCOE, in ordering the various estimates to the values shown in Exhibit .4-1 applied "typical chemical engineering scaling factors". It is beyond the scope of the present effort to audit that undertaking. However, it is incumbent upon us to avoid the distortion of fairly presented uniform cost data by another exponential adjustment of capital costs. We must rescale the liquids' plants since they have been standardized on an 'input' basis, whereas we must examine costs on a plant 'output' basis, since we are also examining downstream processes and costs, which in turn require uniform scale assumptions.

Several difficulties are present:

1. The optimal size of plant and vessels for various systems is not known, due to the fact that most processes are now being explored at 5 - 10% pilot plant scale.

2. In a shift from uniform input scale to a uniform output scale, the most efficient processes will suffer the greatest penalty for their relative downsizing. This is not realistic.

3. We are not aware of the relative changes that took place in the initial (ESCOE) standardization, hence are blind to the compound effect of a second scaling adjustment.

For these reasons, with the emphasis upon the above factors, in order of their ranking, we have chosen to restate costs on an output basis through a linear method of cost adjustment.

The principal justification for this apparently unsound procedure is found in the first factor above - there is no evidence of commercial scale economy available in the case of any processes, with the exception of gasification plants (or gasifier reactors). In that case, multiple train plants appear at sub-commercial plant scale. In general, the bulk of the solid feed stock is so great, that initial reactor vessel sizes become limited by available fabricating (rolling, bending, heat-treating) facilities, as well as transportation constraints. Subsequent plant stage economics do not determine. The gasifier-reactor vessel size limitations are such that returns to scale may be limited at a relatively low level of output.

For this predominant reason, we have used a unitary cost scaling factor to shift from uniform input sized plants (25,000 tons of coal per day) to a uniform output basis - 50,000 bbl. per day. A normal procedure would otherwise unfairly penalize the most efficient processes. In the final analysis, efficiency will determine economic advantage.

4.3 PRODUCT QUALITY (Reference No. 38)

The issue of product quality was resolved in a somewhat indirect manner by ESCOE. Their 'rating scale' value system (a measure of ordinal utility or value) which was based on present product price relationships is not a suitable method for long range economic analyses. During the long-run,. values change, end use patterns and conversion technology developments can create a surplus of a once premier product, or contrariwise, create a shortage of a previously unwanted by-product. Distillates and gasoline have traded places once and are perhaps posed to trade places again in their relative values.

The setting of widespread synthetic fuels production and use creates an entirely new framework for evaluating the 'normal˜ refinery slate of petroleum derived products. We have created a slate of products that to some degree reflects the range of compounds present in crude oil and in some degree reflects the technology (now) available to separately produce these compounds. In some instances the products were specifically sought, in other cases markets were sought for by-products that were available.

When coal is introduced in lieu of crude oil to a substantial degree, the available range of products and by-products may be the same, but the proportions of availability will be quite different, as will be the cost of producing different fractions. "

The proportion of each fraction that can be derived from crude oils is highly variable depending upon the nature of the feedstock and the nature of the refining processes used. In general, increasing the lighter fraction (-350°F) involves more severe reforming, and higher cost. The use of a heavy, sour feedstock crude oil worsens this condition. The use of coal as the feedstock significantly exaggerates this condition in certain synthetic processes - such as direct liquefaction. Indirect liquefaction processes are specific for alcohols, gasolines and the light ends.

It is reasonable to visualize a population of crude oil and coal "refineries" with individually more specialized or limited product slates than are found in the universe of conventional refineries.

Broad slate coal synthetic liquids plants are unlikely to be widely deployed. This can be expected for several reasons:

1. Product upgrading is difficult and expensive once outside of the basic process.

2. A fair range of limited slate coal-conversion processes are becoming available, that more selectively produce various fractions.

The costs of achieving a given level of product quality increases in a slightly non-linear fashion as the percent hydrogen is increased or the boiling range is lowered. Exhibit 4-5 shows this relationship graphically. Benchmark products and costs are shown for several direct and indirect liquefaction processes. The indirect processes - which catalytically synthesize liquids from synthesis gas are specific for gasolines, alcohols and LPG. The direct catalytic hydrogenation processes tend to produce naphthenes and crude oil equivalent range compounds. The hydrogen solvent systems tend to produce a more limited range of product with a substantial (20 - 35%) naphtha fraction, the majority product in the distillate boiling range (350°F - 750°F).

Increased yield of the higher quality products can be achieved by:

- Increased coking of bottoms
- Adding more hydrogen
  - To process stream
  - By hydrotreatment of products

The cost of the former is seen in the difference between SRC II and EDS on Exhibit 4-4. The Exxon donor solvent system cokes the bottoms (or heavy distillates) to yield more naphtha and LPG as follows:

	SRC II			EDS	
(18%)	13,000	bbl Naphtha	(36%)	27,500	Naphtha
(8%)	6,400	bbl #2 Fuel Oil	(15%)	10,000	LPG
(73%)	52,900	bbl Distillate	(49%)	37,200	bbl Distillate
	72,300			75,400	

Similarly changing the H Coal process from a fuel oil to a synthoil mode increases cost as it lowers the average boiling range.

The distribution of product quality that is typical of each process is shown on the following page. (Exhibit 4-5).

EXHIBIT 4-5

SYNTHETIC PLANT PRODUCT YIELDS

QUANTITY - BBLS/DAY OUTPUT

		Direct Liquids				Indirect Liquids				Synthetic Gas[3]		Shale Oil
	Approx. API°	SRC-II	EDS	H Coal (Syn.)	H Coal Fuel Oil	Fischer/ Tropsch	Mobil 'M'	Meth- anol	Meth- anol SNG	Lurgi H BTU	West. Lo BTU	Shale Bit. (Surf.)
SNG (Low) MM BTU/Day											880	
Methanol (High) MM BTU/Day									140	300		
LPG	125°	4,610				23,380	6,080					
Propane (C_3)	148°		2,950									
Butane (C_4)	110°		3,160									
Methanol	NA							50,000	48,740			
Gasoline (C_5)	62°					82,640	43,920					
Naphtha (C_{5+})	40°	10,625	17,970	28,380	15,070	1,490[1] 2,490[2]			1,260	2,025		
Fuel Oil (Heavy Distillate)	18°+	35,000		21,620	34,930							50,000[4]
Fuel Oil (Resid.	5°		25,920									

[1] Light (Diesel) Fuel Oil API-56°, [2] Heavy Fuel Oil API-41°.

[3] 1.067 E14 BTU/yr. is equivalent to 50,000 BBL/day of typical Synthetic Liquids ≤ 6.5 Million BTU/bbl.

[4] Synthetic light crude oil equivalent - approx. 20° API.

SOURCE: E. J. Bentz & Associates

The range of quality is not entirely a function of the API gravity, the boiling range or hydrogen content, however, these related indices are sufficient for our purposes. We can relate the cost of producing a synthetic fuel to this scale. Exhibit 4-6 shows a graph of the production cost of the whole liquid product from various synthetic processes versus the average (50% distillation) boiling range of the synthetic product.

This chart shows the increase in average cost per million btu's as the average distillation range of the liquid is lowered. Thus gasoline costs more to produce via indirect processes such as Mobil 'M' or Fischer Tropsch, than naphthas, distillates and fuel-oils.

This scale[6] illustrates the relative costs of the ESCOE liquid fuel processes. It also contrasts the (1978) earlier ESCOE cost estimates with later estimates of shale oil costs developed by the Office of Technology Assessment (1980). The oil shale liquids, which reside in a higher boiling range than the coal liquids, appear significantly more expensive on this scale. In order to reconcile this discontinuity it is necessary to digress briefly.

4.4 ESTIMATING METHODS

The accuracy of complex systems cost estimating has been the subject of several studies. These studies have been primarily behavioral rather than conceptual. As larger, more complex systems projects have been conceived, -the amount of unknown and untried system components have necessarily increased due to the great cost of large system prototypes. Pilot or process demonstration units and models are developed at extremely small scale for the same economic reasons; the subsequent scale-up is of a high order. Estimates drawn from bench or small scale pilot plants are subject to much greater estimating error.

Two overriding conclusions have been reached in this matter:

1. Cost estimates tend to decrease in variation from actual costs as the elapsed time between estimate and construction is shortened.
2. The accuracy of the estimate is related to the degree of detail of the design engineering.

Chemical process plants,[8] public works,[9] and weapons systems[10] development and estimating histories have been analyzed, with

[6] Syngas (fuels) are not suitable related to boiling point measurement.

[7] "An Assessment of Oil Shale Technologies", OTA - June 1980.

[8] A Review of Cost Estimates in New Technologies: Implications for Energy process Plants, Rand Corp. for the Dept. of Energy July 1979.

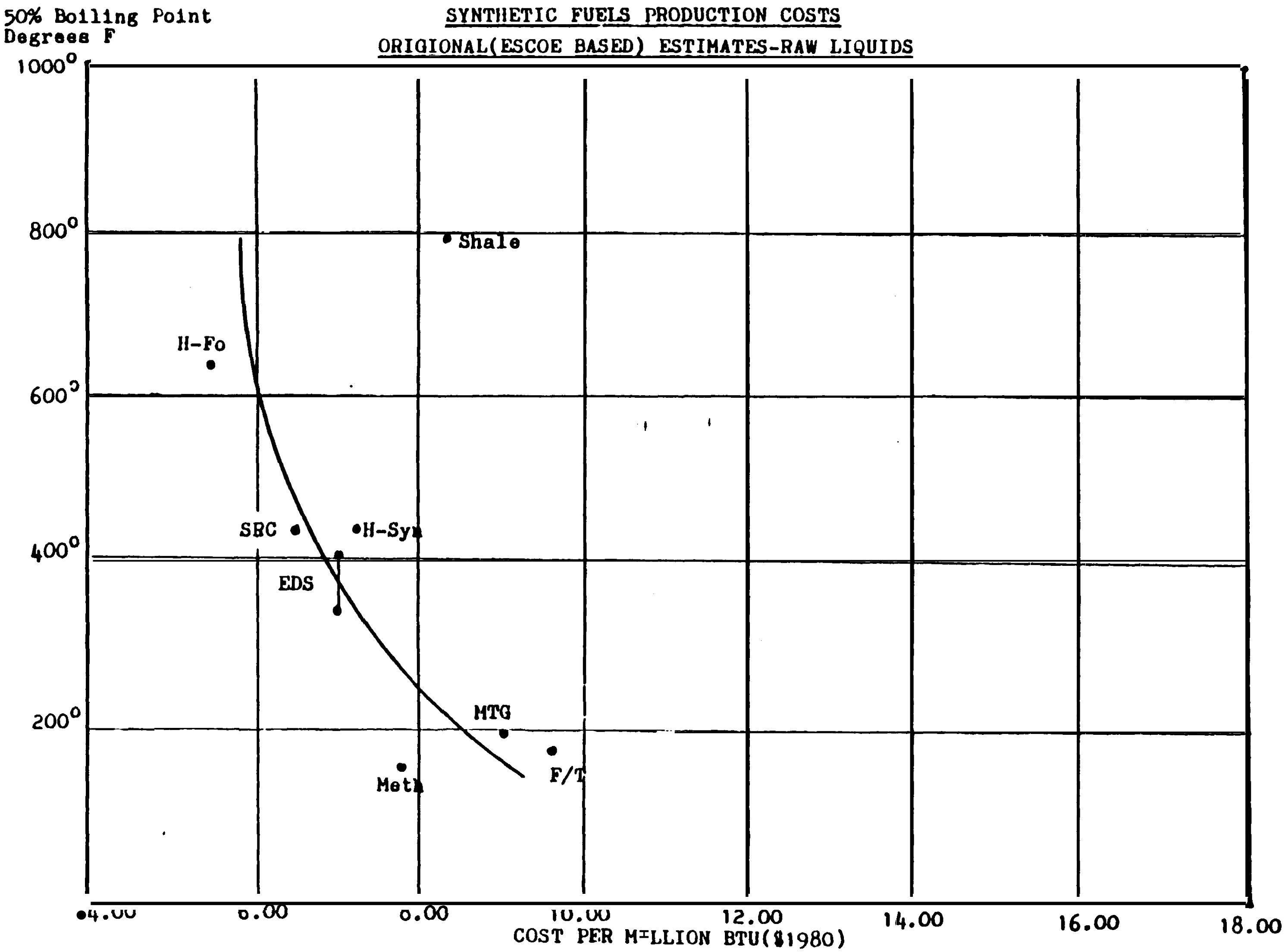
[9] "Systematic Errors in Cost Estimates for Public Investment Projects", Hufschmidt & Gerin, in The Analysis of Public Output, Columbia Univ. Press 1970.

[10] The Weapons Acquisition Process: An Economic Analyses, Peck & Scherer, Harvard Univ. 1962.

EXHIBIT 4-6

SYNTHETIC FUELS PRODUCTION COSTS

ORIGIONAL(ESCOE BASED) ESTIMATES-RAW LIQUIDS



SOURCE: E. J. Bentz & Associates, Springfield, Virginia

essentially the same range of variances found between early estimates and actual results - growth in costs have occurred of the order of 2-3 times the oriqinal estimate. The average of actual to estimated costs($\frac{C_a}{C_e}$), were found to be as follows:

System Type	Actual Cost/ Estimated Cost (Ratio)
Weapons System	**1.40 - 1.89**
Public Works	**1.26 - 2.14**
Major Construction	***2.18***
Energy Process Plants	***2.53***

The weapons system cost overruns were higher in the ***1950's (1.89)*** than in the 1960's (1.40) most likely, because of the greater degree of pioneering efforts and the greater lack of experience with large weapons systems at that time.

Exhibit 4-7 below shows the cost growth experience in pioneering energy systems as a function of the type of estimate employed (or available at that time). It can be seen that the preliminary estimates were nearly double that of the initial estimates - (84% above the first estimate) and the definitive estimates increased almost as much again from the preliminary estimates (134% above the first, or 50% above the preliminary estimate) .

The ESCOE data were largely taken from preliminary estimates, based on Process Demonstration Unit (PDU) development experience, in one or two cases from pilot plant experience (at less than 1% scale) or from foreign commercial experience under different site and environmental conditions. The OTA shale oil values were derived from a very highly definitized engineering analysis. The degree of evolution which that estimate had undergone can be seen on Exhibit 4-E.

If the other ESCOE liquid synfuel plants were to increase by as much as have typically occurred between preliminary and definitive estimates, the costs would increase by about another ***50%.***[12] That would result in a shift of the cost line on Exhibit 4-6 as shown on Exhibit 4-9.

Such an interprelation of the quality of the ESCOE estimates would resolve the discrepancy between the ESCOE estimates and the OTA estimates (for oil, shale liquids) and produce a more continuous scale of synfuel cost relationships.

An alternative method of calibrating the various estimates for consistency with respect to the status of process estimates as well as the methods employed in the estimating process? would be to select

[11] Average increase from preliminary to definitive cost estimates for energy process plants.

[12] P3 - Reference 3.

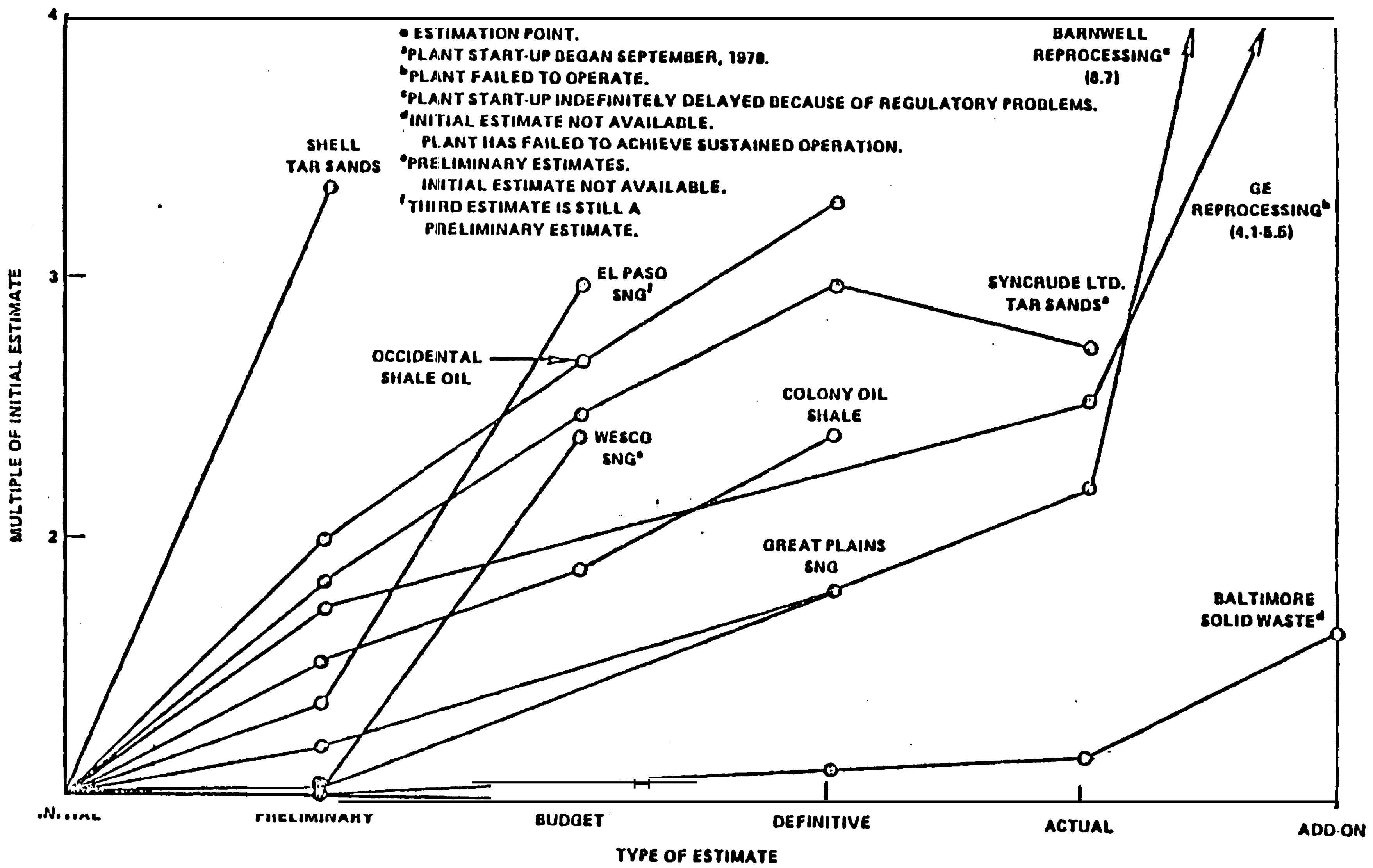


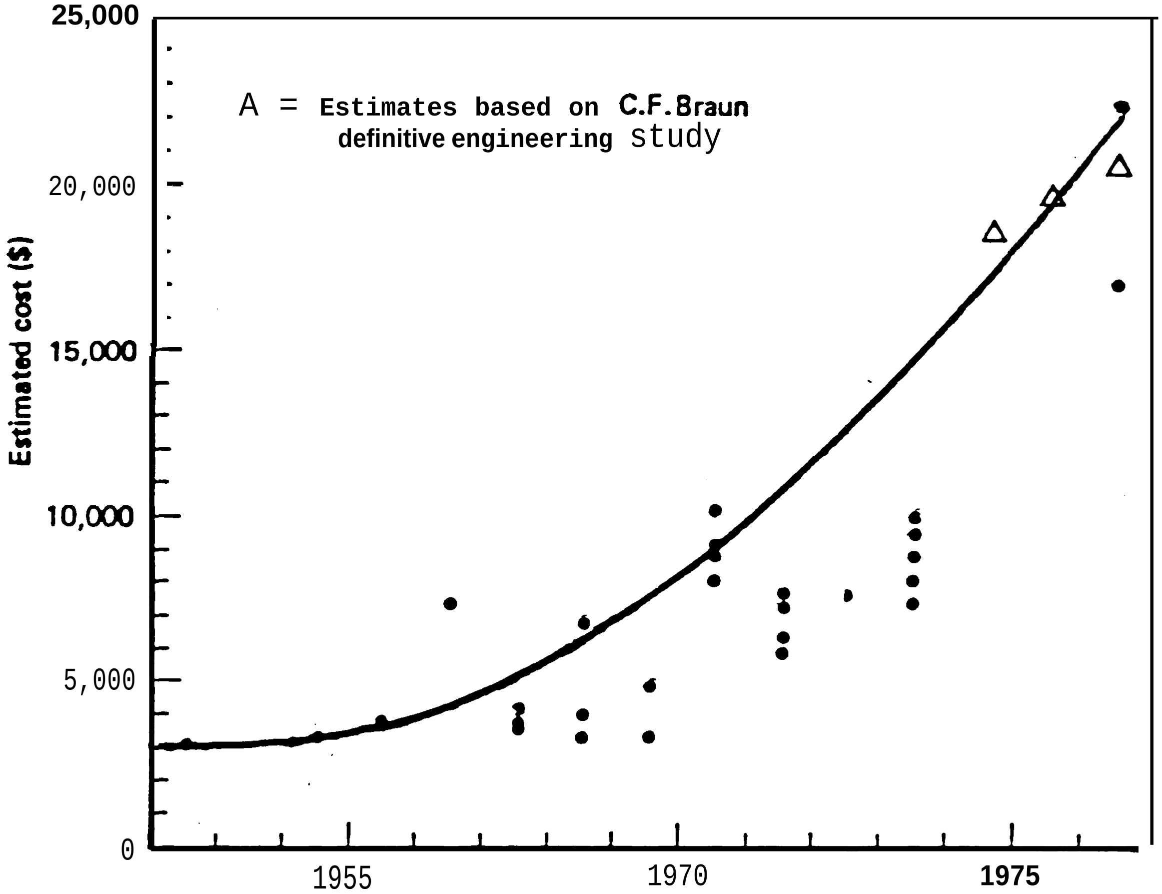
EXHIBIT 4-7

COST GROWTH IN PIONEER ENERGY PROCESS PLANTS (CONSTANT DOLLARS)

Source: "A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants,", DOE, E-24-81, July 1979.

EXHIBIT 4-8

HISTORY OF SHALE OIL CAPITAL COST ESTIMATES



Estimated surface shale oil facility contruction costs
(capital costs/barrel/ca!endur day; constant $ 1977)

a sub-set of processes that were developed on the basis of the same level of engineering definition or maturity - preferably the most advanced projects in this sense.

There have been more recent, updated design and estimating efforts undertaken in the case of:

1) Indirect Liquefaction - Mobil MTG.[13]
2) Methanol[13]
3) High BTU Gasification[14]
4) Direct Liquefaction - H-Coal[15]

These estimating efforts are essentially comparable with the (OTA) Oil Shale estimates in terms of the relative engineering and development maturity of the process plants involved.

Exhibit 4-9 also reflects the liquid fuel costs of 'generic" synfuel processes based on the selected "best estimates" noted above. These are not meant to be truly generalized processes (or generic processes) , they are nonetheless representative, advanced members of each synthetic liquid product class.

The costs of these processes are shown in detail on Exhibit 4-1o.

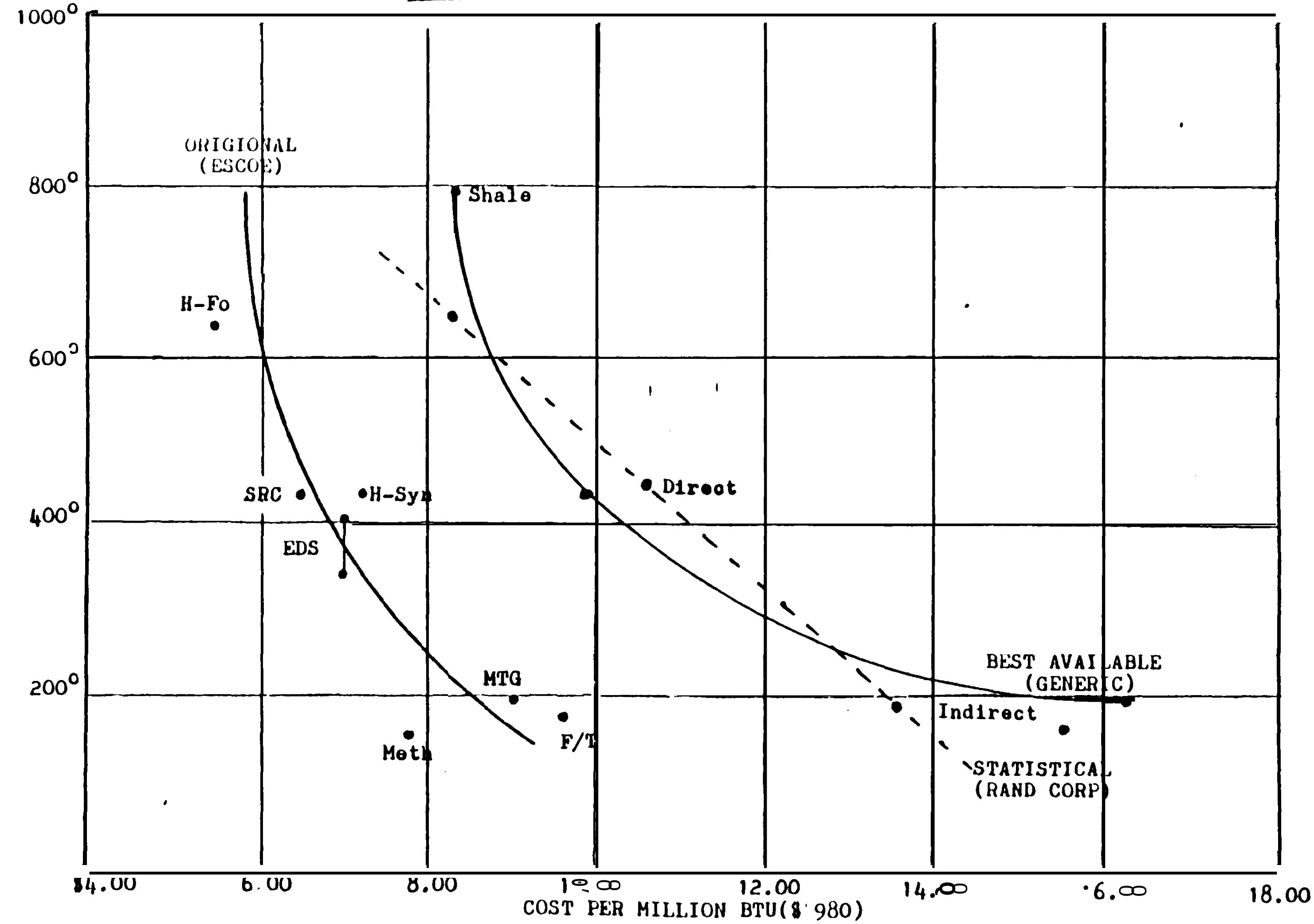
The effect of using the latest, or best estimates is approximately the same as was achieved by the use of the Rand Corp. (and others) cost estimating error factors. The original ESCOE values are increased by about 50% on average.

The satisfactory conjunction of factored cost estimates arrived at by the use of statistical variances derived from past estimating histories with the "generic" estimates taken from the most advanced projects, gives us an improved measure of confidence in the adjustment of ESCOE synfuel production costs to the higher levels displayed on Exhibits 4-9 and 4-10. The revised functional form of the liquid fuels is displaced to the right on Exhibit 4-9 by about $3.00-$4.00 per million BTU's. The relative costs are not appreciably affected considering the probable differences in residual (estimating) error contained in these estimates. It seems most reasonable, however, to presume that the majority of the estimating errors have been accounted for, and the values we are employing are normalized to the greatest practical degree possible at the present time: i.e., barring further engineering or demonstration plant design and construction experience.

[13] Liquefaction Technology Assessment - Phase 1 ORNL-5664 Feb. 1981.
[14] Unpublished Analyses
[15] Rand Corporation - Unpublished Analyses.

EXHIBIT 4-9

SYNTHETIC FUELS PRODUCTION COSTS
FACTORED COST ESTIMATES-GENERIC RAW LIQUIDS



SOURCE: E. J. Bentz & Associates, Springfield, Virginia

EXHIBIT 4-10

BEST AVAILABLE ESTIMATES - TYPICAL SYNFUEL PROCESSES

	Revised Capital Est. $ 1979	Revised Capital Est. $ 1980	Capital Recovery @ 30%	Feedstock Cost (From 4-4)	Other* Oper. Costs (From 4-4)	Total Revised Estimate	Cost Per Barrel $ 1980	Cost Per MM BTU $ 1980	Cost 1 Gal. $ 1980
Direct Liquids									
H Coal (Synfuel)	$2,200	$2,200	$ 660	$219.2	$212.6	$1,091.8	$66.47	$ 9.79	$ 1.58
Indirect Liquids									
Mobil MTG (Lurgi)	2,685	3,054	916.2	205.3	159.8	1,281.3	78.01	16.18	1.86
SNG/Methanol (ICI-Lurgi)	1,849	21,035	631.1	256.9	160	1048 688. SNG 360.	11.88	15.53	1.00
High BTU Gas									
Lurgi (BGC)	1,600	1,820	546.	226.7	113.7	886.4	-	8.30	-

*Adjusted for capital cost changes.

SOURCE: E. J. Bentz & Associates

The H-coal process (in the synfuel mode) has been used as a surrogate for direct coal liquids. Updated estimates of an unpublished nature were used that draw from the cumulative pilot plant histories and the most recent demonstration plant estimates. The Mobil Methanol-to-Gas (MTG) and methanol estimates were drawn from a recently published study by Fluor Corporation for Oak Ridge National Laboratory of indirect liquefaction processes. The study provided a (nearly) 100% gasoline option which virtually eliminates the by-product costing problems. The methanol estimates were Menthanol/SNG joint production process schemes. The systems could have been adjusted in keeping with the 100% gasoline MTG process scheme by eliminating the direct costs of methanol to gasoline stages. Alternately the by-product value of SNG could be directly priced by using the high BTU gas plant costs from the SNG estimate below. Both synthesis gas processes are Lurgi systems.

The SNG process estimate was taken from unpublished estimates drawn from advanced commercial design and estimating efforts. An advanced Lurgi gasifier - the British Gas Corporation slagging bed version - is used.

The costs of direct and indirect liquids - increase by about 50% - to remain in approximately the same relative cost relationship that the ESCOE based data displayed. The hi-BTU gas estimates only increased about 25% above the earlier ESCOE values. This appears to be reasonable considering the relatively more mature status of (Lurgi) gasification technology. The OTA oil shale liquids estimate of $48.20\bbl reflects the precommercial stage of development. The level that we are attempting to standardize at, versus the development stage of the foregoing direct and indirect liquid systems.

Continuing Cost Escalation

The earlier analyses of Rand Corp. and others suggested that the potential cost increase from even a definitive estimate to the actual project costs of pioneer plants and major developmental systems is typically another twenty percent increase in cost. We can add that increment to arrive at an upper value for all systems.

There have been and continue to be other relevant post-commercial trends of commercial series production plants that were not considered by the authors of the cost escalation - studies cited above.

Historical data regarding the chemical process industry and petroleum refining industry demonstrates a strong pattern of capital productivity improvement or technology advance, during post-development years. This can be demonstrated for the entire sector as well as in the micro-industrial setting of a single chemical industry segment.

A capital productivity rate of less then 2%/year can return the 20% (actual cost to definitive cost estimate potential increase during the first 10 years of commercial deployment. In 20 years at least a 35% reduction in the capital outlay per barrel of product can be expected.[16]

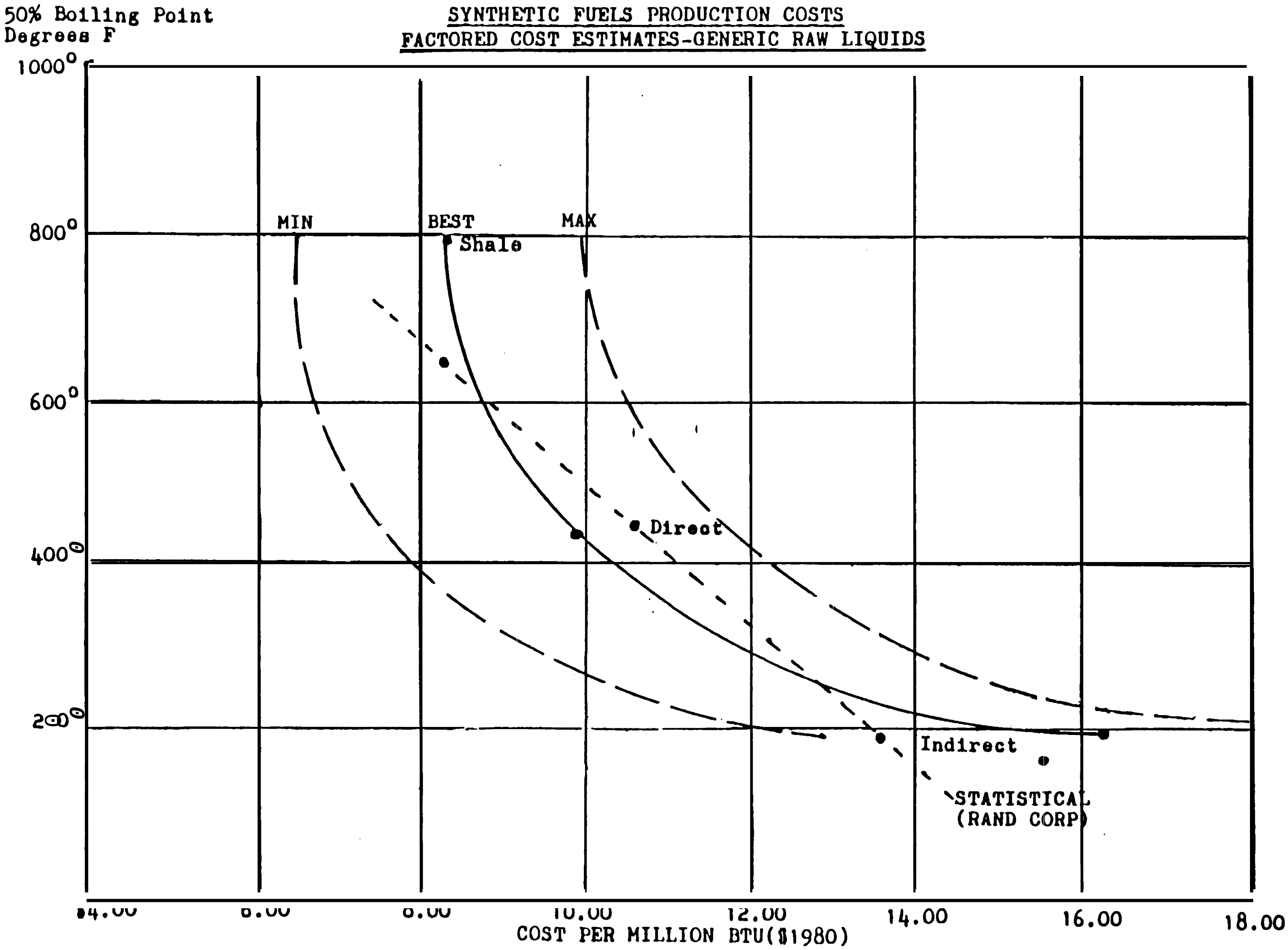
These two viewpoints provide us with minimum and maximum estimates of the most probable range of expected production costs for synthetic fuels. Exhibit 4-11 illustrates the range of expected values for synfuel liquids based on these estimating limits.

This scale of values will be used to provide individual product (or by-product) costs. The presence of a significant amount of petroleum in the total supply equation, for as far as we can see, creates many cost and pricing complexities. We do not wish to complicate synthetic fuel supply economics with World Oil Price disruptions, or any free-market or administered market conditions. We will close our eyes to all of these dimensions and construct our cost schedule on the basis of coal based liquid, gas and solid fuel options or opportunity costs.

[16] This rate (1.4%) has been experienced by the entire chemical industry throughout the entire post war period (1949 to date). Specific industry sectors have experienced much greater rates of productivity improvement; viz, synthetic methanol experienced more than a 4% / year productivity gain for over 20 years.

EXHIBIT 4-11

SYNTHETIC FUELS PRODUCTION COSTS
FACTORED COST ESTIMATES-GENERIC RAW LIQUIDS



SOURCE: E. J. Bentz & Associates, Springfield, Virginia

4.5 PRODUCT UPGRADING (References 39, 40)

The typical (direct liquefaction) coal liquids possess several characteristics that require upgrading in order to:

- Provide product stability
- Permit mixture with conventional petroleum liquids . . . or
- Permit common use of pipelines and other infrastructure

The principal differences result from:

Lower levels of hydrogen - 9 - 10% versus 11 14% for petroleum and 11 - 12% for shale oils.

Higher levels of heteroatoms in both liquids and shale oil (nitrogen and oxygen compounds) than are found in petroleum feedstocks.

The lower hydrogen and higher heteroatom conditions are resolved together by hydrotreatment. Raising the hydrogen levels up above 10% results in the removal of most of the nitrogen and oxygen heteroatoms, and also decreases the aromaticity of the coal liquids and shale oils.

The high aromatic content of coal liquids makes the naphthas excellent high octane blending stock - however the high nitrogen and oxygen percent (2 - 3%) in the heavy naphtha range requires the use of fairly severe hydrotreatment to remove the diolefins and heteratoms - which are present in the form of phenols and cresols (oxygen).

In the synfuel distillates the nitrogen level is higher and results in unstable compounds with rapid gum formation, making this a very unsatisfactory fuel unless upgraded.

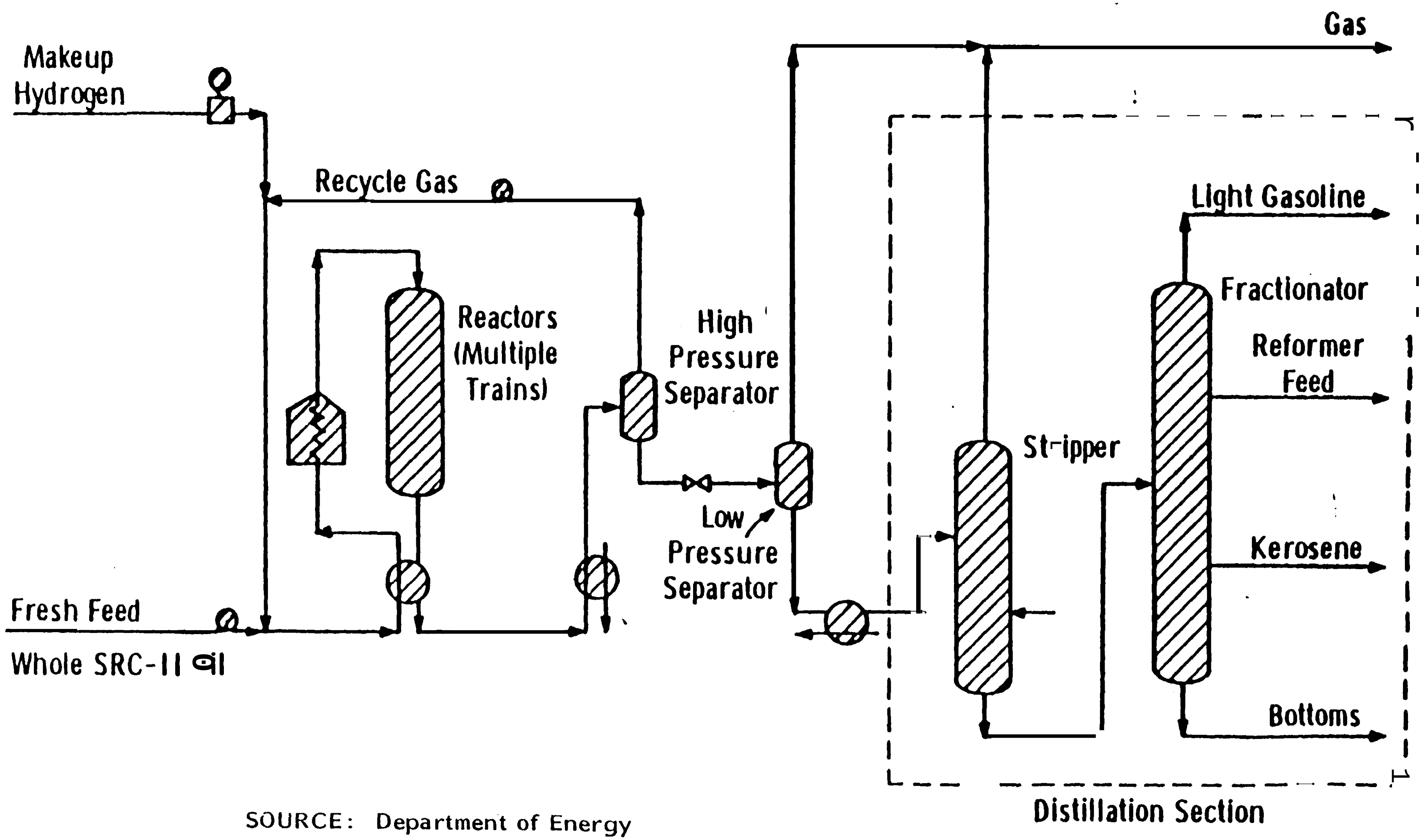
There have been a succession of studies of synthetic liquids upgrading processes sponsored by DOE. They have been conducted on both shale oil and direct coal liquids.

The principal measures examined include:

- Hydrotreating (Exhibit 4-12)
- Hydrocracking
- Fluid Catalytic Cracking

Catalytic reforming as well as hydrocracking are subsequently used to upgrade (naphthas) to finished transportation fuels. (See Exhibit 4-12 below) .

EXHIBIT 4-12: SIMPLIFIED FLOW DIAGRAM OF CHEVRON FIRST STAGE HYDROTREATER REFINING OF SRC-II OIL



SOURCE: Department of Energy

Consideration has also been given to variation in the hydrogen source for hydrotreaters - the partial oxidation of raw coal liquids, reforming of refinery products and overheads, or outside gasses.

An additional issue is the location of upgrading facilities; at the coal liquids (or shale oil - retort) plant, or at a conventional refinery, or both.

The factors which favor the synthetic oil plant location are:

- available residue for hydrogen manufacturing
- local upgrading permits common carrier transportation
- upgraded synthetic product can be blended with petroleum feedstock (in pipelines and at refineries)

The factors that favor a refinery location for upgrading are:

- Superior prospects for system optimization
- Availability of hydrogen from naphtha reformers
- Uses available refinery capacity idled by lack of petroleum feedstock.

An alternative approach could be to perform a minimum amount of upgrading at the synfuels plant to facilitate transportation and storage, with product finishing and blending performed at a larger refinery site. The coal liquids in general do not require further cracking because they lie in the atmospheric gas-oil and naphtha range. The shale oils require cracking to produce more usable product from the higher distillate range such as jet fuel and diesel oils. The heavy distillates from coal liquids; if heavily hydrotreated (to 11% H by wt) can be used as a feedstock for a fluid catalytic cracker (FCC) where the product can be significantly upgraded.

Exhibit 4-13 illustrates the cost of upgrading various direct liquid process cuts.

The raw liquids versus the upgraded liquids are compared below in hydrogen content.

	Raw Liquid	Upgraded
SRC Naphtha	11.33%	11.6%
SRC Distill.	7.71	11.0
H Coal Distillate	10.1	11.4
H Coal Fuel Oil	7.37	10.0

These cases cover the general conditions experienced by the range of most direct coal liquids - the samples being drawn from experimental laboratory investigations performed by Mobil Research and Development Corporation upon SRC light and heavy fractions and

EXHIBIT 4-13

DIRECT LIQUIDS UPGRADING COST

50,000 BBL) – 1980 $

	SRC-II		H Coal Svn. Crude or Fuel Oil		
	Naphtha	Heavy Distillate	Naphtha	Distillate	Fuel Oil
Operating Labor	.0639	.0855	.0639	.086	.085
Maintenance	*1606	*5830	◦1606	≡409	*593
Administration & Support	.0394	.0992	.0394	.077	.100
G&A	.1828	.5757	.1828	.420	.585
	.4467	1.3434	.4467	.992	1.363
Fuel	.3517	.6691	.3517	.525	.154
Utilities	.1089	.9716	.1089	.577	.946
Cat. & Chem.	.0194	.9829	.0194	1.650	1.358
Hydrogen	.5586	6.836	.5586	2.390	7,355
	1.◦38≤	9.4895	1.6386	5.142	9.813
Capital Recovery (30%)	2.577	8.484	2.577	5.449	7.933
Total Upgrading Cost	4.062	19.32	4.◦≤23	11.58	19.109
Product					
API	37.5	24.5	Same as	25.7	12.5
H Content (wt %)	11.6	11.0	SRC II	11.4	10.0
BTU/lb.	18,500	18,780	Naphtha	18,970	18,400
Plant Investment					
Total in Million	$141	$464.5	$141	$298	$434
$/BBL	$8.59	$28.28	$8.59	$18.16	$26.44

SOURCE: E. J. Bentz & Associates

H-coal distillate and fuel oil fractions. This pretty well covers the range of liquids produced by SRC and H-Coal (synfuel and fuel oil mode) and can be extrapolated to the EDS case.

Additional work performed by U.O.P., Chevron and Suntech confirm the general upgrading needs and the best approach - hydrotreatment.

The plant investment required varies from $140 million dollars for the mild hydrotreatment required of the naphtha cuts (C_5 - 400°F) to as much as $465 million for a hydrotreatment plant for the heavy distillate or residual SRC fraction and nearly that for the fuel oil fraction of H Coal fuel oil process plants.

The average upgrading cost is about $2.00 per million BTU's - varying from $4.00-to nearly $20.00 per barrel. The latter figure represents an economic limit which suggests either a lower grade utilization of the heavier products or a different refining approach.

The direct liquids upgrading cost analysis can be compressed to a single representative-or "generic" upgraded coal liquid.

The general costs of upgrading are shown on Exhibit 4-14:

Naphtha's	**$ 4.06**
L. Distillates	**11.58**
Heavy Distillates '- Fuel Oil	**19.21 (19.11-19.32)**

Individual processes such as EDS SRC-II and H-Coal (fuel oil mode) will differ in raw liquid base costs, but since the quality of product tends to vary in a reasonable relationship to their costs[17], the costs of upgrading, which are increasly related to quality, lend to cause a clustering of upgraded direct llquid costs.

If we utilize the costs of H Coal production of raw liquids developed above as a base, the 'generic' costs for upgraded products would be as follows on Exhibit 4-14. The estimated costs of nearly $75.00 per barrel or over $12.00 per million btu's is for a product that is equivalent to a high grade refining crude oil feed.

The upgrading of shale oil to a suitable refinery syncrude has been estimated by Chevron to cost $10.00 per barrel (in 1980 dollars) or $1.72 per million btu. If this is added to the cost of raw shale-oil liquids at the retort, the total cost of shale oil "syncrude" is:

[17] See Exhibit 4-6 above.

EXHIBIT 4-14

DIRECT LIQUIDS UPGRADED COSTS/BARREL

($ 1980)

	Barrels/Day	Cost/BBL	Total Daily Cost
Naphtha	28,380	$ 4.06	$115,223
Distillate	21,620	11.58	250,360
	50,000		$365,583 = $7.31 Avg.
Raw Liquid Cost (per barrel)			66.47
Total Upgraded Fuel Cost Per Barrel			$73.78
Total Upgraded Fuel Cost Per MM/BTU			$12.30

SOURCE: E. J. Bentz & Associates

OIL SHALE LIQUIDS COST

($1980)

	Per Barrel	Per Million BTU
Retorted Shale Oil	**$48.20**	$ 8.31
Upgrading	10.00	1.72
	$58.20	$10.03

These compare favorably with upgraded direct liquefaction production in the 'syncrude' class as shown below:

SYNCRUDE PRODUCTION COSTS

($1980)

	Per Barrel	Per Million BTU
Shale Oil	$58.20	$10.02
Direct Coal Liquids	21.12	18.5%
Shale Oil Advantage	12%	9%

The shale oil has about a 21%-cost advantage as a refinery feed-Stock. This is reduced to less then a 20% cost advantage on a heating value basis. However heating values are not the principal criterion to be applied to refinery feedstocks - quite the opposite - the lighter crude demands a premium. In certain instances the coal liquid with higher aromatic content will be preferred, at other refineries the shale oil, with a higher hydrogen content, and a greater yield of distillate product will be sought.

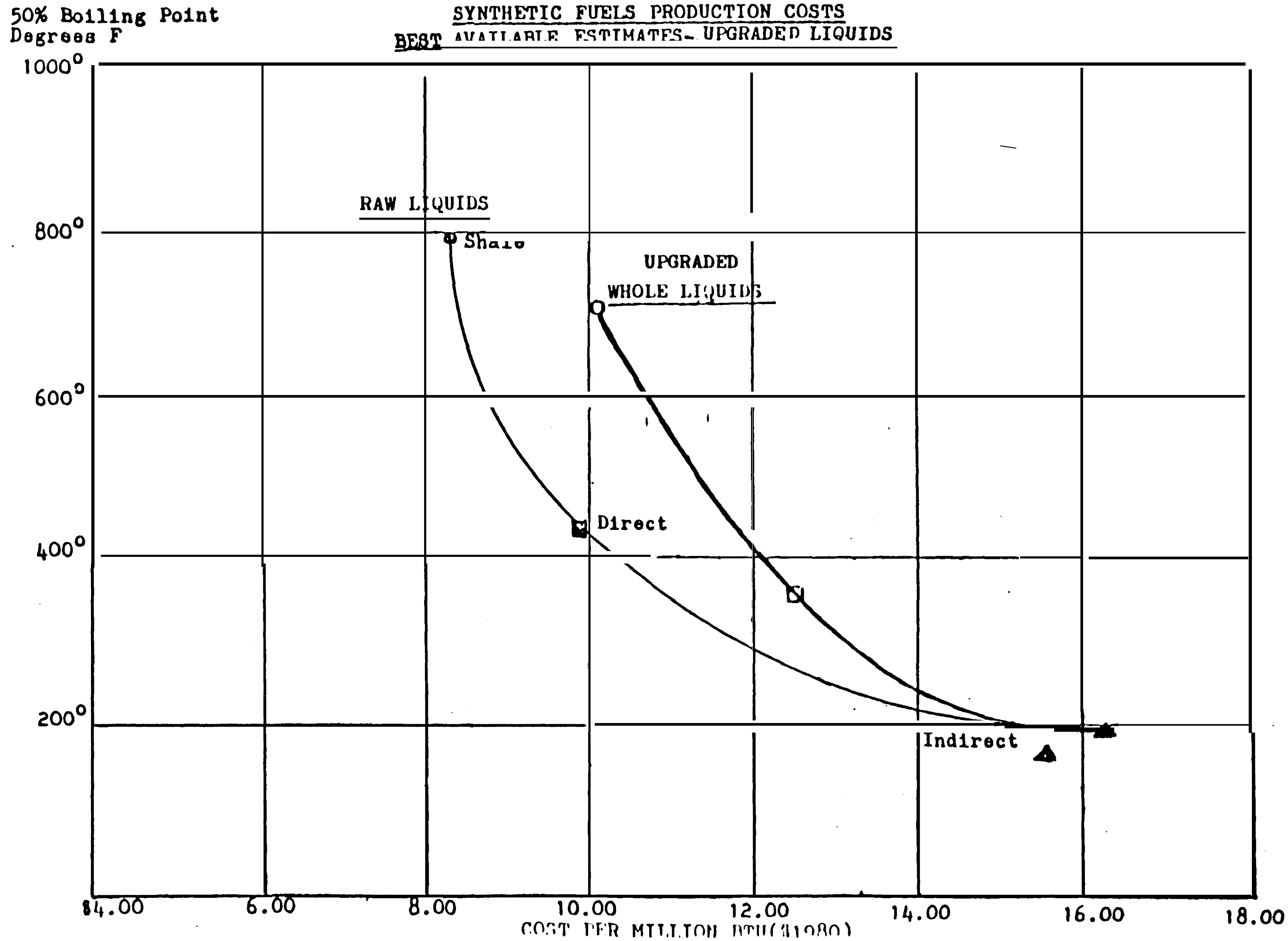
Exhibit 4-15 illustrates how the process of upgrading shifts the cost of oil shale and coal based synthetic crudes upward by $1.75 - 2.50 per barrel.

4.6 REFINING SYNTHETIC LIQUIDS

The direct liquefaction and oil shale synfuels have to be further upgraded to end-use product quality in order to be comparable with indirect liquid products such as methanol from coal or gasoline from methanol (from coal). In a wider sense, this is also desirable in order to achieve comparability with synthetic natural gas (SNG) which can be used for a wide range of end use applications in its 'raw' manufactured state.

The indirect processes produce refinery output (or intermediate) grade products, without the need for the "refining" of crude liquids. In order to compare direct liquids and shale liquids with indirect process liquids, we must bring the former

EXHIBIT 4-15



SOURCE: E. J. Bentz & Associates, Springfield, Virginia

into a state that is comparable. This requires the refining of the synthetic liquids to finished fuels.

Refining of shale oils and coal liquids will vary in cost depending upon the size, location and degree of integration of the refinery complex. We will assume that this is not done in an existing refinery (perhaps modified to better handle these feedstocks), but is performed at a new refinery integrated at the retort or conversion plant site. Such a refinery is under-scale (50,000 bbl/day) and remote from chemical complexes that might make better use of by-products and hence provide higher (by-product) credits or other similar economic benefits.

The costs of upgrading the raw coal and shale liquids to high grade (transportation) fuels is shown below:

REFINERY COSTS FOR SYNTHETIC (RAW) LIQUIDS

($1980)

	Cost Per Barrel	Cost Per Million BTU
Shale Oil (Hydrotreat & Hydrocrack)	$18.50	$3.19
Coal Liquids (Hydrotreat)	$18.29	$4.02

The costs of refining synthetic liquids cannot truly be determined without specifying the product slate produced. The costs of refining a particular feedstock can vary depending upon the product cuts sought. The basis used above is not strictly comparable between the processes. It tends to slant the refinery approach to the type of slate that is favored by the feedstock - Light distillates in the case of shale oil, and gasolines and distillates in the case of coal liquids.

Exhibit 4-16 illustrates the potential variation.

These costs can be seen to vary dramatically if different product slates are sought. If the highest grade transportation fuels are maximized, to provide the highest degree of comparability with indirect liquids. The costs are as follows:

REFINERY SYNTHETIC UNITS TO 100% TRANSPORTATION FUEL

($ 1980)

	Shale		Coal	
	$/BBL	$/MM BTU	$/BBL	$/MM BTU
Raw Liquid	$48.20	$ 8.31	$66.47	$ 9.79
Upgrading	18.50	N.A.	18.28	N.A.
Total	$66.70	- $11.50	$84.75	- $14.61
Average Heat Content\ BBL	5.8 Million BTU		5.8 Million BTU	

EXHIBIT 4-16

PROCESS AND SLATE

(1980 $)

Feedstock	Hydrotreat & Hydrocrack	Severe Hydrotreat	Moderate Hydrotreat
Coal Liquids*			
Product	Motor Gasoline	Motor Gasoline Plus Jet Fuel	Motor Gasoline Plus #2 Fuel Oil
Slate	(100%)	(1/3 - 2/3)	(1/3 - 2/3)
Cost	$20.70	$18.29	$12.55
Shale Liquids	Hydrotreat & Hydrocrack	Hydrotreat-FCC	Coking Hydrotreat
	3/4 - 1/4		(4/5 - 1/5)
Product Slate	Motor Gasoline Plus Jet Fuel	Jet Fuel Plus Motor Gasoline	Jet Fuel
Cost/BBL	$18.50	$17.00	$16.00

*SRC-II

SOURCE: E. J. Bentz & Associates

By comparison, indirect liquid (methanol to gasoline) costs are about $78.00 per barrel; approximately in the middle of this range. The cost per million BTU's is lower for shale and coal liquids, refined to a transportation slate consisting of gasoline and distillate fuels (jet fuel and diesel oil). If direct liquids are refined to a 100% gasoline slate the costs would increase to $87.17 per barrel or above $19.00 per million BTU's.

Exhibit 4-17 graphically displays the finished fuels in a framework which relates the product quality to the finished fuel cost.

Exhibit 4-18 calculates the total cost of refining coal liquids. A 50,000 barrel per day refinery for coal liquids would cost between $420 million and $690 million. The lower case represents a moderate hydrotreatment plant producing #2 fuel oil and gasoline, the upper case represents a hydrotreatment and hydrocracking plant that produces 100% gasoline.

Instead of using other indirect measures of product value,[18] we can use a cost based scale. The lighter fractions cost more to produce from both coal and shale, whether by direct or indirect means. By-product credits do not have to be assigned to determine the cost of a single cut liquid. Upgrading plant has been assigned to individual fractions so that the full cost of the beneficiated product cut is known. The costs of fully refining the product are developed incrementally by determining the cost of creating a 100% gasoline yield, and two subsequently lower grade mixtures.

The alternate product slate refinery costs of Exhibit 4-18 can be used to develop a measurement of the direct costs of products in a multi-product refinery run. The principal cost differences result from the increased capital (per unit of product yielded) and the increased consumption of hydrogen associated with higher grade product slates.

If we take the per barrel cost of producing a 100% gasoline slate. and assign it to the gasoline fraction of a mixed slate as the appropriate cost of that portion of the output, the remainder of the total cost divided by the number of barrels of the other product (jet fuel or #2 fuel oil) will give us the unit cost of the "secondary product".

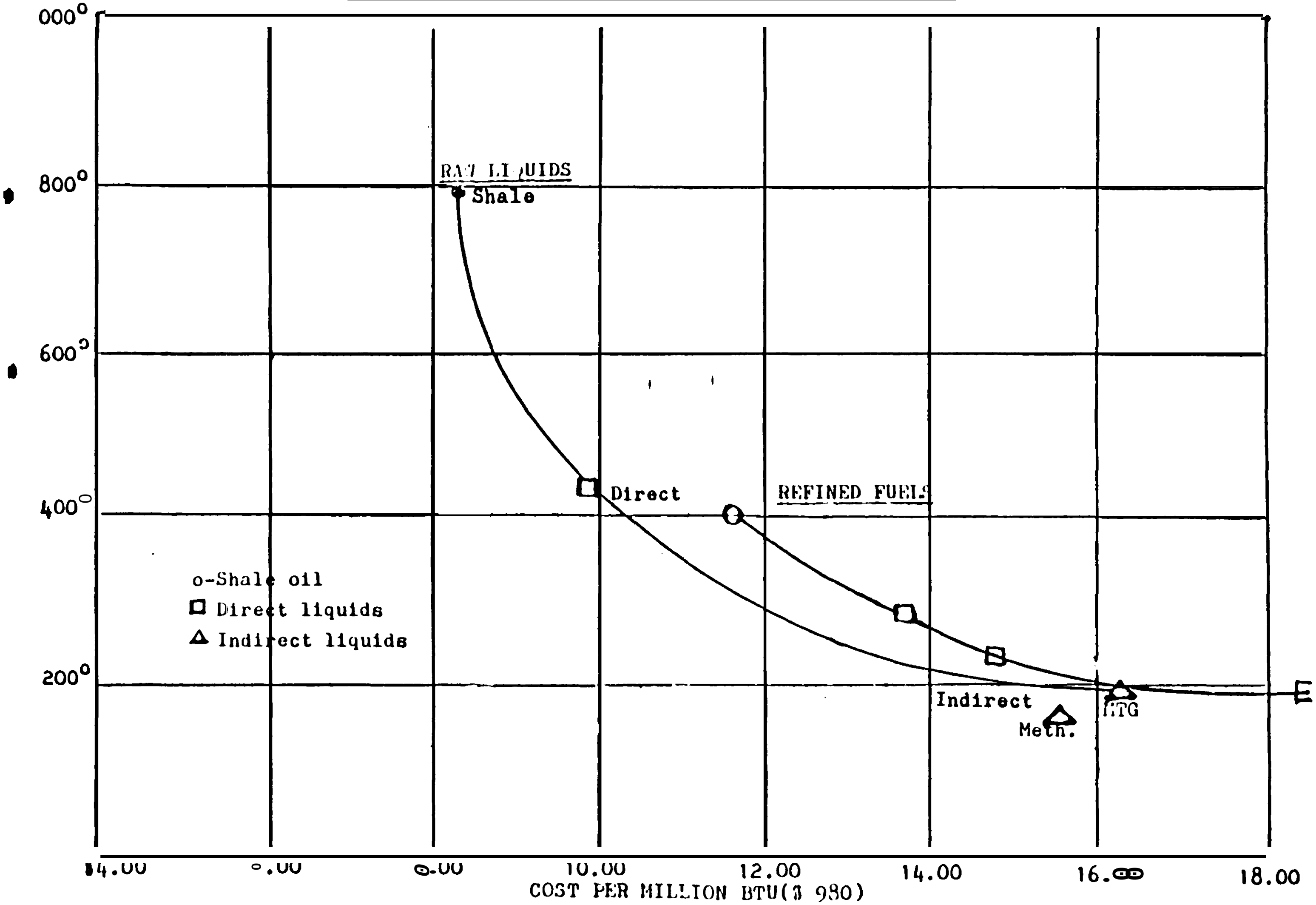
Exhibit 4-19 shows this costing procedure for the slates presented for direct liquids refining in Exhibit 4-17.

By using this method, we are not artificially lowering the cost of gasoline production by assuming a market equilibrium price

[18] Product value ratios are commonly used. They are of absolutely no meaning in a long-term and discontinuous supply context. The use of such ratios is a major violation of the most elementary laws or principles of economics as a measure of utility.

EXHIBIT 4-17

SYNTHETIC FUELS PRODUCTION COSTS
BEST AVAILABLE COST ESTIMATES– REFINED LIQUID FUELS



SOURCE: E. J. Bentz & Associates, Springfield, Virginia

EXHIBIT 4-18

DIRECT LIQUIDS (SRC-II) REFINING

(50,000 BBL/Day) 1980 $ per BBL.

$/BBL	Motor Gasoline (Hydrotreat Plus Hydrocrack)		Motor Gasoline Plus Jet Fuel (Severe Hydrotreating)		Motor Gasoline Plus #2 Oil (Moderate Hydrotreat)	
Operating Labor	.244		.183		.183	
Maintenance	.791		.669		.487	
G&A	.852	1.887	.670	1.522	.487	1.157
Fuel	.183		.304		.122	
Utilities	.183		.122		.122	
Cat. & Chem.	.304		.365		.244	
Hydrogen	5.540	6.210	5.750	6.541	3.230	3.718
Capital Recovery @ 30%/Yr.		12.603		10.228		7.67
		$20.70		$18.291		$12.545

SOURCE: E. J. Bentz & Associates

EXHIBIT 4-19

SRC II REFINED TO PRODUCT COSTS

		Barrels/Day		Cost/BBL*	Total Daily Cost
CASE I	Motor Gasoline	50,000	@	$87.17	$4,358,500
CASE II	Motor Gasoline	15,395	@	87.17	1,341,982
	Jet Fuel	34,605	@	(83.69) **	(2,896,018)**
	Total	50,000	@	$84.76	$4,238,000
CASE III	Motor Gasoline	16,995	@	$87.17	$1,481,454
	#2 Oil	33,005	@	(74.74)**	(2,466,796)**
	Total	50,000	@	$78.965	$3,948,250

Product Costs

Motor Gasoline	=	$87.17/bbl	(4.95)	$17.61/MM BTU
Jet Fuel	=	$83.69/bbl	(5.67)	$14.36/MM BTU
#2 Oil	=	$74.74/bbl	(5.825)	$12.83/MM BTU

*Cost from 4-17 plus 4-9.

**Values in parenthesis inferred from weighted average value of motor gasoline and total product.

SOURCE: E. J. Bentz & Associates

for a lower grade (by) product. The method used is entirely an assignment of marginal cost to products. It would be more desirable to operate in a reverse manner, i.e., from the lowest product, assigning incremental costs to the higher product on a marginal basis. We, unfortunately, do not have a process estimate for a single slate of the lowest value product. The distillation range of all products is too broad to produce such an artificiality. Therefore we have begun with the marginal gasoline cost and assigned it as a by-product price to the lower value (mixed) slates, permitting us to infer the marginal cost of the lower grade products.

The results of this cost analysis are related to the costs of indirect liquefaction end products and shale products on Exhibit 4-20. The cost series increase as average distillation point is lowered. The average distillation point of most useful transportation fuels lies between 180° - 400 F, with the majority of the compounds contained lying within this range.

There is a persistence of the earlier noted relationship between product quality (as measured by average boiling point) and production costs of finished products. The relationship shows less than unitary cost increases per barrel, all greater then unitary cost increases per million BTU. The latter case is due to the generally lower heating value of the premier fuels that have increased hydrogen content. The increases in cost are about 7 1/2cents per barrel of liquids for every degree farenheit that the boiling range is lowered.

Exhibit 4-21 is a flow sheet of a process (examined by Chevron Research) for hydrotreating and hydrocracking of direct coal liquid (SRC-II) whole oil to produce 100% motor gasoline product. This is the first case on Exhibit 4-16. Exhibits 4-22 and 4-23 illustrate the refining process used to upgrade the whole liquid to ‘ gasoline and jet fuel by severe hydrotreating alone, and to a lower quality slate of gasoline and heating oil created by less severe hydrotreating of direct (SRC-II) liquids.

The latter case is more comparable to an upgrading process.

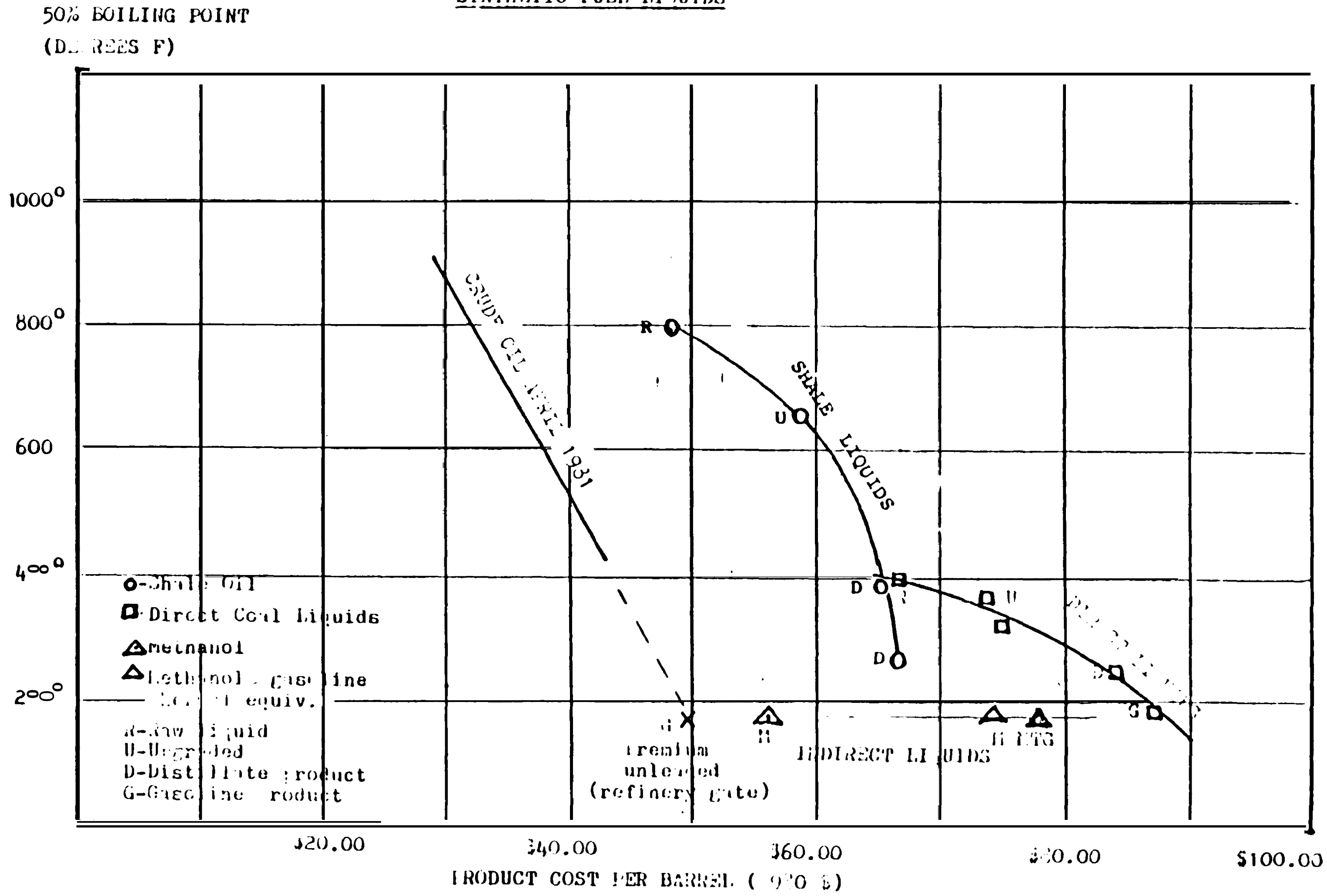
4.7 TRANSPORTATION AND OTHER INFRASTRUCTURE COSTS (Reference 41)

Although we have differentiated between coal liquid’s plant site upgrading facilities and finished product refineries, we have really not selected the site for refining. The upgrading must in most cases be done at the site of the coal liquids plant. The degree of upgrading we have embraced (Exhibit 4-15) is sufficient to permit the fuels to be used in as high a use as a combustion turbine, or transported without creating contamination or incompatible sediments.

Transportation costs are directly related to the distance involved, and indirectly related to the quantity moved or flow rate.

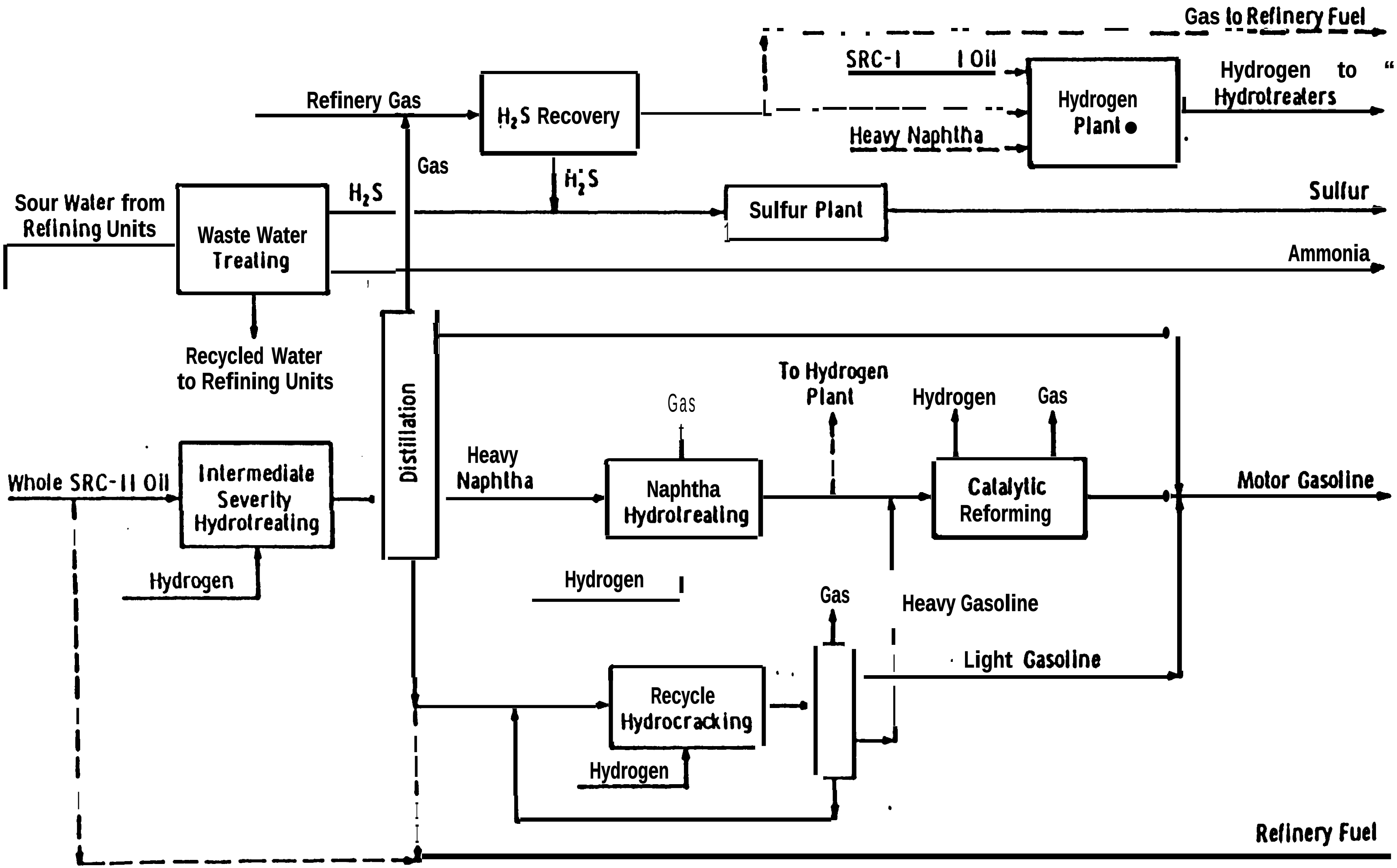
EXHIBIT 4-20

SYNTHETIC FUEL LIQUIDS



SOURCE: E. J. Bentz & Associates, Springfield, Virginia

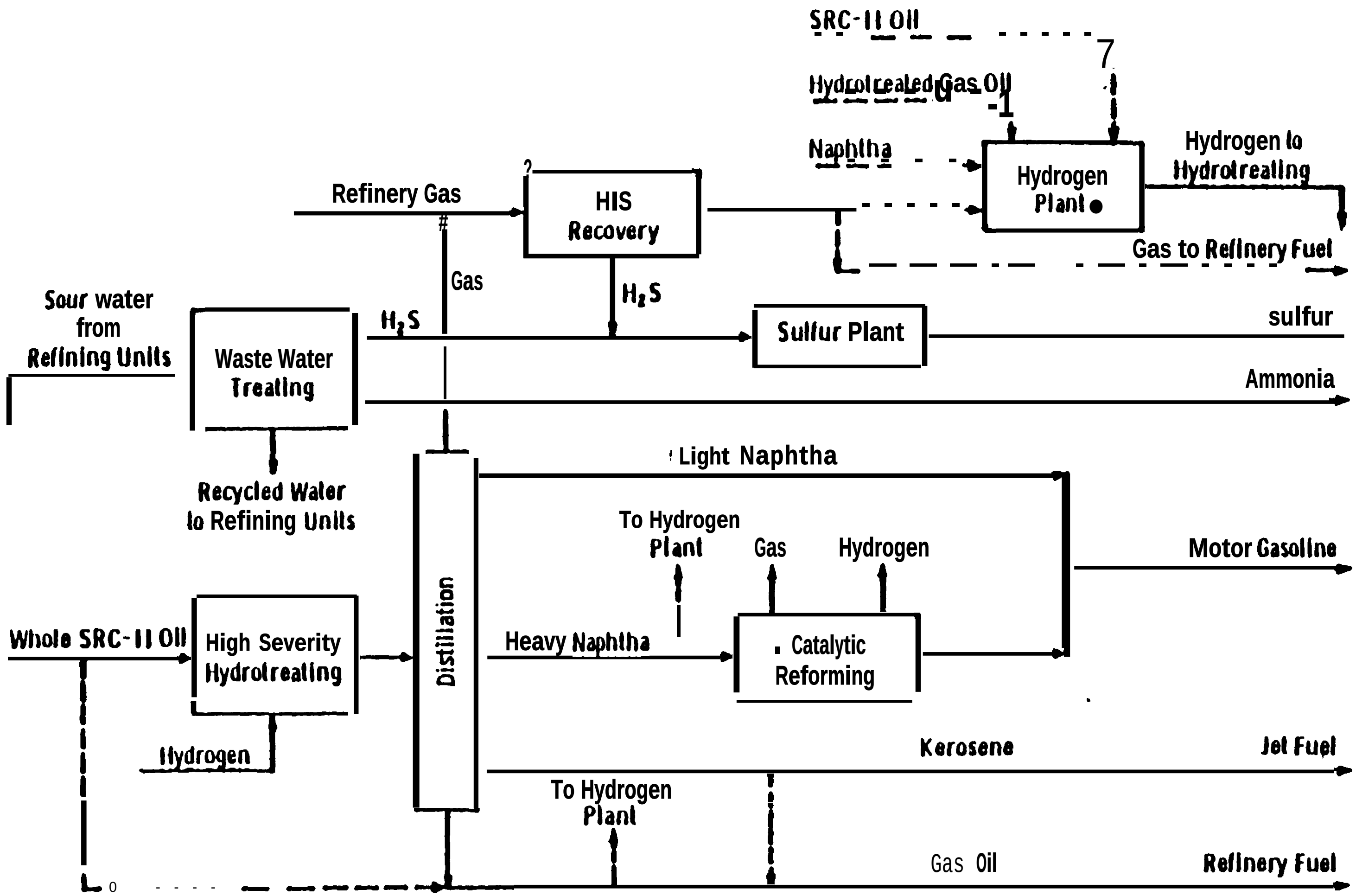
EXHIBIT 4-21: SCHEMATIC FLOW DIAGRAM REFINING OF SRC-11 OIL BY . HYDROTREATING AND HYDROCRACKING - CASE I



* Steam reforming feeding gas and anphtha in Cases 4A, 4B, and 4D.
Partial oxidation feeding SRC-II oil in Case 4C.

SOURCE : Department of Energy

EXHIBIT 4-22: **SCHEMATIC F1OW DIAGRAM REFINING Of SRC-II OIL BY HIGH SEVERITY HYDROTREATING - CASE II**

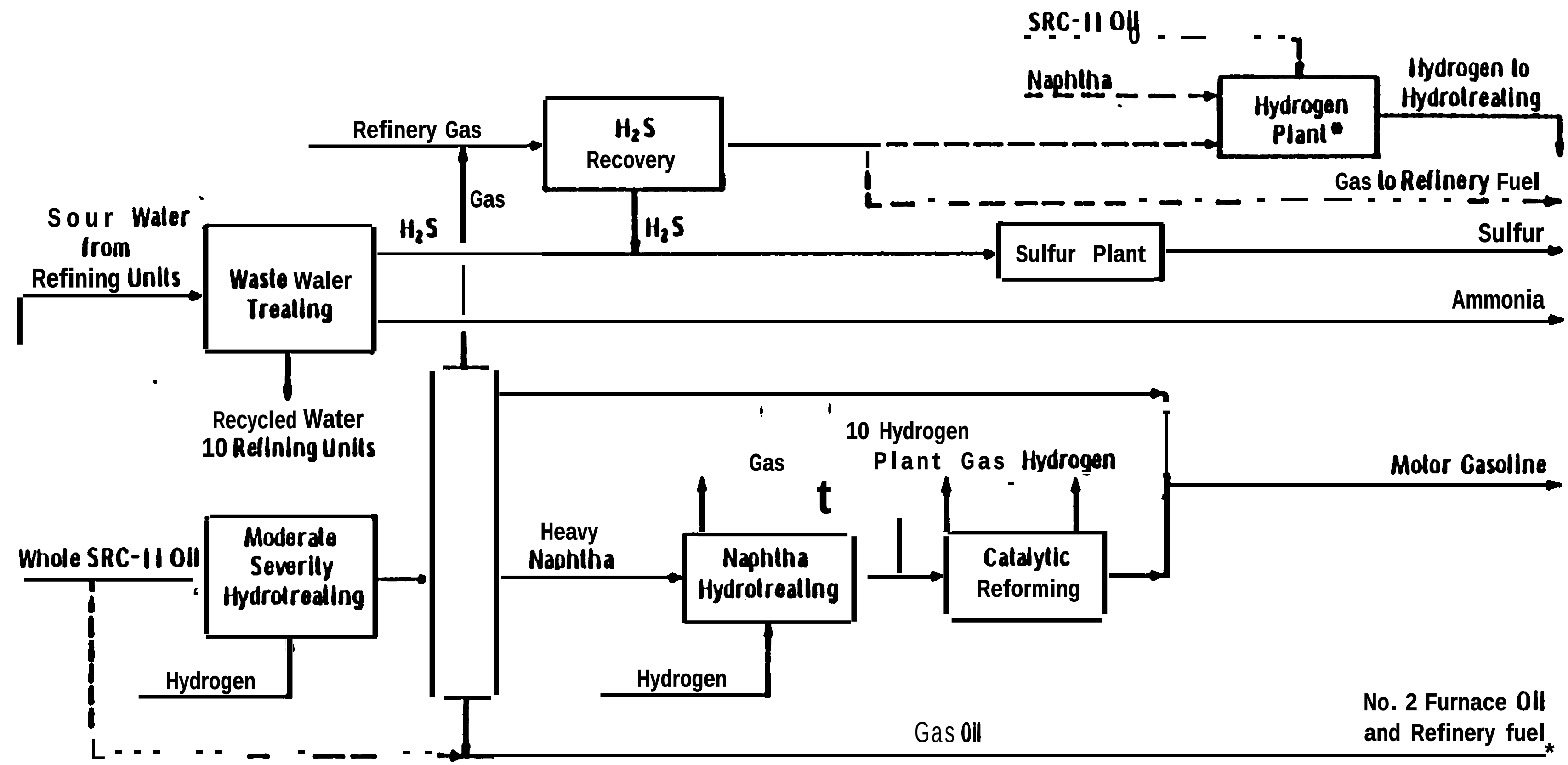


● Steam reforming feeding gas and naphtha In Cases IA, IB, and ID
Partial oxidation feeding gas oil and SRC-II oil In Case IC.

SOURCE : Department of Energy

ej b&a

EXHIBIT 4-23: SIMPLIFIED F1OW DIAGRAM
REFINING OF SRC-II OIL BY
MODERATE SEVERITY HYDROTREATING - CASE III



* Steam reforming feeding gas and naphtha in Cases 5A, 5B, and SD.
Partial oxidation feeding SRC-II oil in Case SC.

SOURCE : Department of Energy

e:b&a

We cannot visualize any other form of transportation for these upgraded liquids, or for further refined products except by pipeline. The daily volume required to support a 6" or 8" pipeline is approximately the size of one or two 50,000 bbl/day plants. Considering the geographical concentration of coal and shale deposits it is not difficult to visualize a mining-conversion center adequate to support either:

. An upgraded liquids pipeline to a refining center

or

. A product pipeline to major pipeline junctions or product distribution terminals

The general location of all coal and shale resources is such that deep draft water transportation does not figure prominently in synfuels distribution patterns.

Without siting specific plants and conducting the refinery trade-offs - which would have to be done in context with both the balance of foreign and domestic petroleum supplies and the slate of (regional) demand for all liquids - we cannot develop very meaningful insights into either the operating (product) costs of transportation and distribution, or the capital requirements.

We will have to make some nominal assumptions and then establish unitary relationships. The future energy transportation patterns and infrastructure requirements are impossible to determine without a specific scenario. We shall briefly examine a *cases:

. Pipelining from Souther Illinois to Houston of syncrudes.

. Pipelining from Wyoming to St. Louis

. Pipelining from Western Colorado to L.A. of shale oil.

Southern Illinois to Houston

Raw Liquids (upgraded)	33c/MM BTU

Western Colorado to L.A.

Shale Liquids	40$/MM BTU

Wyomina to St. Louis

Raw Liquids m ' * '	30 $/MN! BTU
Methanol	68c/MM BTU
MTG - Gasoline	37$/MM BTU

The additional capital investment required for synthetic fuel transportation is highly speculative to a greater degree. There is a great deal of existing product and crude liquid pipeline as well as gas pipeline in place, that can equally serve the synthetic fuels industry. In all cases the pipelines are connected to either markets or distribution terminals at the delivery end. In most cases, the input end is originally either at a major refinery (and production) location or at a port location. The refinery connection argues for upgrading of liquids (coal and shale) at mine mouth conversion plant locations, and transportation to the existing refinery districts for product finishing. Such a general pattern would involve the construction of a minimum number of new "crude" synfuel pipelines from coal fields to refining districts.

We assume that the ultimate conditions would lead to the construction of several large diameter pipelines in such a pattern.

Methanol, which does not require refining, obviously will move in different patterns from coal field to the major terminals and markets.

Pipelines of that size (10-12") would cost an average of $100,000 per mile, considering material, labor, and right of way and other expenses. Terrain would influence the cost, generally increasing construction costs but reducing right of way costs in some cases by an equivalent amount. 20" or greater diameter pipelines would cost $250,000/mile.

A total construction budget of 50,000 miles of new pipeline of 12" diameter to 20" diameter would cost between $5 billion and $12 billion.

4.8 ADDENDUM TO CHAPTER 4: BASIS FOR COST ASSUMPTIONS

1) Basic Conversion Plant (ESCOE)

- Capital Costs

Year: Mid (June-July) 1979 dollars
Scale: 25,000 tons of coal input
Base Plant to installed battery limits: 1.63
Contingency: 10%
Scaling exponential rule: $\frac{C_2}{C_1} = G$

λ = .65 for vessel size
λ = .9 with trains

Outlay of Capital: instantaneous plant

- Revisions to Capital Assumptions in This Report

Year: Mid 1980 (June-July)
Scale: 50,000 bbl/day liquids output
Plant to Battery Limits: 1.73
Contingency: 20%
Scaling: Linear
Outlay of Capital: Instantaneous plant

- Operating costs

Coal Feedstock: $30/ton (delivered)
Coal: Illinois #6
Catalysts and Chemicals and Operating Supplies:
at cost for amounts proscribed by process designer's material balance.

Labor Cost	#		Rate/Hr
Plant Operators	120		$ 10.00
Operating Supervisors	25		15.00
Maintenance Labor	150		12.00
Maintenance Labor Supervisors	30		16.00
Administration	30		11.00
Total	355	@	$11.79/hr avg.

Fringes @ 35%--changed to 40% = total labor rate of $16.50/hr

Maintenance Cost (Materials & Contracts)

3% of total plant capital cost

G & A

Local taxes and insurance, 5% capital cost changed to total G&A - 5% capital cost

Capital Charge Rate

ESCOE basis not used. **30%** of capital used as recovery rate (as per guidance of OTA staff) .

On-Stream Rate

90%--328.5 days/year

2. Assumptions for Product Upgrading

- Capital

  Basis --Instantaneous Plant, mid-1980 dollars
  On-stream factor 90% 328.5 stream days.

- Hydrotreater

  capitalized for each separate product stream.

- Hydrogen Feedstock Plant Capital

  Not included, only cost feedstock "across the fence" from the plant complex.

- Hydrogen Reformer or manufacturing plant capital included

- Battery Limits

  Includes hydrotreaters, waste water treatment, sulphur plants (commercial grade)

- Contingency

  General -- 25%
  Battery Limits--l5%
  Engineer---4% of investment capitalized
  Working Capital--45 days receivables; 30 day chemicals catalysts; 30 day feedstocks

- Operating costs

Hydrogen Feedstock:	Syngas @ $6.74/mmbtu raw gas liquids @ $6=50/mmbtu includes recovery of production plant capital.
Hydroqen Pressure:	500 PSIG for SRC light (naptha) product--2000 PSIG all other cases.
Plant Size:	20,000 bbl/day upgraded to 50,000 bbl/day for each product cut

- Royalties

500 PSIG Hydrotreating	-o-
1500 PSIG Hydrotreating Fixed Bed	$30/bst feed
Sulphur plant	-o-
Waste Water	
Initial project	$75,000
First 5,000 units	$14.70\unit
Next 5000-25,000 units	$7.35/unit
Next 25,000 + units	$5.25/unit

- Sales Tax

5% of equipment cost

- Maintenance

4% of depreciated capital/year

- Operating Labor

$11.00/hr

- Labor Burden

45%

- Administrative and Support Labor

30% of operations and maintenance labor

- G & A

60% of operations and maintenance labor plus property-tax of 2-1/2% of plant investment

- Utilities

  Fuel $4/mmbut
  Steam $3.50/1000 lbs
  Electricity 4c/kwh
  Water (make-up) 40c/1000 gal

- Hydrogen Bleed was assumed to be:

  50 SCP/bbl @ 500 PSIG
  100 SCP/bbl @ 2000 PSIG

- By-product Credits

  Ammonia (anhydrous) $100/ton
  Hydrogen and Hydrocarbon off gasses (C_1-C_4)
  $4/mmbtu ($1. 30/MSCF)

3. Refining Cost Assumptions (Chevron Basis)

- 1980 costs: Instantaneous plant (first quarter adjusted to June/July)

- Mid-Continent Location

- Cost correlations based on actual experience of Standard Oil of California, 1960-1970s adjusted for:

  Lower field productivity
  Increased safety
  Improved efficiency and reliability
  Additional energy conservation
  Stricter environmental regulations

- 10% Contingency

- Utilities

  Water 30c/1000 gal
  Boiler fuel, coal or refinery fuel
  power 3$/kwh

- Maintenance

  2-1/2%/yr of both on-plant and off-plant facility investment

- G&A
  Property taxes @ 21/2% of both on-plant and off-plant/yr

- Labor

  Operating-- $110,000 per shift position/hr
  ($18.30/hr including fringes)
  Support Labor (Administrative, security, technician) 65% of Direct Labor