3.2 FUTURE CHEMICAL INDUSTRY H_2/CO/SYNGAS CAPACITY REQUIREMENTS, 1988-2000

Projections of H_2, CO, and syngas markets over the period 1988-2000 have two key areas of uncertainty associated with the results:

1. Projection of the various market demands for a particular chemical.
2. Projection of the raw materials costs in new chemical synthesis technologies involving H_2, CO, and syngas vs. raw material costs used in existing chemical synthesis technologies.

For these reasons the analyses done in the following sections is much less detailed than the analyses in Section 3.1. Conclusions of the 1988-2000 market evaluation are shown in Table 3.29.

Table 3.29

ESTIMATE OF 1988-2000 H_2/CO/SYNGAS REQUIREMENTS FOR CHEMICAL PRODUCTION
(MM SCFD)

	Major Requirements Plants	Oxo Alcohols	Polyurethanes	Fibers	Other Chemicals
Gulf Coast	870/130	53/27	40/20	20/7	20/40
Mid-Atlantic	--	--	--	--	--
Ohio Valley	870/130	--	10/5	--	--
Other	870/130	--	--	--	--
Totals	2610/390*	53/27**	50/25	--	--

*780/390 as syngas
**as syngas

3.2.1 MAJOR REQUIREMENTS PLANTS

Conclusions on ammonia plant capacity additions during the 1978-1987 period were negative. This result basically reflects the increasing gap between cheap offshore natural gas and U.S. energy supply.

Implementation of tariffs has been recommended by some U.S. ammonia producers as a means of protecting U.S. ammonia plant operators. There is no basis for predicting whether tariffs on imported ammonia will or will not be used. Based on present U.S. sentiment toward increased use of Canadian and Mexican energy supplies, imported vs. U.S. ammonia supply is likely to be a much less important issue in the 1990's than it is today. For the purposes of 1988-2000 projections, the import situation is projected to follow the coal-based vs. natural gas-based hydrogen costs with domestically produced ammonia capacity additions averaging 75% of the increased demand during the 1988-2000 period. A total increased U.S. demand of 10 million annual tons is projected for 1988-2000. Using the 75% figure for domestic share, approximately 1,500 million SCFD of H_2 will be required.

Methanol demand during the 1978-1987 period was projected to grow at about 6.5% annually in Section 3.1. Using a 5.0% growth rate during the 1988-2000 period results in increased capacity requirements of 1,500 million annual gallons during the 1988-2000 period. Increased syngas requirements for methanol production are therefore estimated at 1,500 MM SCFD.

Increased hydrogen plant capacity additions for production of benzene from toluene were projected at a low level during the 1983-1987 period. They are not expected to be significant compared to ammonia and methanol requirements during the 1988-2000 period. The same is true of ethanol based upon poor competitive economics as a U.S. gasoline pool extender.

3.2.2 OXO ALCOHOLS

Heavy commitments to oxo-alcohol capacity additions in the mid-1970's substantially reduced syngas capacity additions for oxos in the 1978-1982 period. Projected capacity additions were just over 20 MM SCFD during that period. That figure increased to about 60 MM SCFD during the 1983-1987 period. Total oxo growth during the 1988-2000 period is expected to be approximately equal to growth during the 1978-1987 period and the same capacity addition figure of 80 MM SCFD is projected.

3.2.3 POLYURETHANES

Hydrogen and carbon monoxide capacity additions for polyurethanes amounted to about 45 MM SCFD H_2 and 21 MM SCFD CO during the 1978-1987 period. Total growth is expected to be only slightly greater during the 1988-2000 period. Estimated capacity additions during that period are 50 MM SCFD H_2 and 25 MM SCFD CO.

3.2.4 FIBERS

The projected economics for new technology to manufacture fibers intermediates using H_2, CO, syngas were unfavorable compared to existing technology for 1987 plant start-up. Only acetic anhydride technology was projected to be competitive. Similar results were projected for plant start ups in 2000. Estimates for the 1988-2000 period therefore include only CO at 7 MM SCFD.

Hydrogen requirements for fibers production during the 1988-2000 period will increase as follows. The total nylon market is projected to grow by about 1,500 million pounds with 1,000 million as nylon 6,6 and the remainder as nylon 6. The HMDA capacity for 6,6 production will require about 20 MM SCFD H_2. The existing 1,900 million pounds of adipic acid capacity will support nylon 6,6 capacity additions into the 1990's. Adipic acid from butadiene is expected to be cheaper than adipic acid from cyclohexane at that point and no hydrogen capacity for adipic acid expansion is projected. Finally, the 500 million pounds of nylon 6 capacity projected for the 1988-2000 period will require approximately the same quantity of cyclohexane. With no cyclohexane-based adipic acid expansions, no expansions for cyclohexane capacity will be needed.

3.2.5 OTHER CHEMICALS

About two-thirds of the H_2/CO/syngas requirements for production of other chemicals in the 1978-1987 period resulted from increased acetic acid requirements. New syngas technology could substantially affect the future CO requirements for acetic. However, the key acetic acid derivative involved is vinyl acetate (VAM) and new VAM technology was not evaluated in this study. The total H_2, CO market in the other chemicals category declined from about 40 MM SCFD capacity additions in the 1978-1982 period to less than 20 MM SCFD in the 1983-1987 period. A 60 MM SCFD market is projected for the 1988-2000 period.

3.3 ECONOMIC COMPARISON OF H_2 AND SYNGAS PRODUCTION COSTS USING COAL GASIFICATION TECHNOLOGY VS. EXISTING PRODUCTION METHODS

Part of Task I includes providing an economic assessment of three representative systems for the production of hydrogen and syngas. The product slates for these systems are 150 MMSCFD of H_2, 150 MMSCFD of syngas (2 H_2:1 CO), and 40 MMSCFD of the same syngas. The objective is to compare three technologies, steam reforming of natural gas, partial oxidation of oil and coal gasification in order to project product prices for the various product slates. In addition to the base cases described earlier, a "piggyback fuel case" was developed. This plant consisted of a 150 MMSCFD syngas from coal plant with a supplementary 150 MMSCFD of clean, unshifted synthesis gas produced for use as a medium BTU fuel. The feedstock used was a bituminous coal. The required product fuel cost was determined by taking the incremental capital and operating requirements for the entire plant above those for the stand alone syngas plant.

The economic comparisons done in this study are constant 1978 dollars. Construction costs, operating labor and other non-energy related costs are held constant in real terms for this study. In other words a new plant cost that is determined for a 1978 start-up date, which would include escalation during the three year construction period (1975-1978), would cost the same in 1982, 1987 or 2000.

Energy costs are allowed to escalate in real terms at different rates for different feedstocks. The energy cost projections used in this Task I work are from the Draft JPL Energy Scenario. The rapid oil price increases put into effect by oil exporting countries in early 1979 substantially exceeded the projections in the early years of the JPL Scenario. Therefore, an updated energy scenario was constructed as Task IV of this contract and sensitivity cases based on that update are presented in Section 3.3.3 below.

Product costs were calculated to yield an after-tax return on investment of 9% in the initial year of production. Subsequent years' prices were evenly escalated over the project life in order to give a 15% discounted cash flow return to the equity investor for the project as a whole.

3.3.1 METHODOLOGY

3.3.1.1 CAPITAL COST ESTIMATES

Economic comparison results developed in this study are based on a proprietary computer program. The program internals consist of capital and operating cost information on process blocks such as shift unit, CO_2 removal systems, coal gasifiers, etc., applicable to capital cost estimation for plants to produce H_2 and syngas.

The input to the computer program consisted of parameters that were considered most relevant to each individual unit. For example, an input variable to the air separation unit block would be the quantity of oxygen to be produced. The program then uses its data base to scale the capital and operating costs according to the customary formula:

$$C_2 = C_1 \; (Q_2/Q_1)^N$$

where C_1 = known cost to produce Q_1 quantity

C_2 = desired unknown cost

N = cost exponent

Q_1 = quantity produced for C_1 cost

Q_2 = desired quantity of production

Note that the C_1, Q_1 pair does not necessarily represent a specific data point, but may be any convenient point along a best fit log-log plot of available data. Note also that N can be set differently for each process block. N is less than one for most capital costs as a result of economies of scale. Also, in the case of operating costs, N is usually equal to one except where economies of scale make energy conservation cost effective for larger plants.

The program was used to compute the capital and operating costs for each process block and a total for all blocks. This information was printed out in a form suitable for use in the proprietary financial analysis program in determining the comparative economics of the various technologies.

The process block components of the computer data base necessarily have varying degrees of certainty with regard to their accuracy. At one extreme are the O_2-blown high pressure coal gasification units of which no commercial scale plant has been built -- at least at the time this study was done. Hence, all the costs associated with these plants must come from design studies. On the other hand, a great deal is known about the costs associated with some process blocks such as air separation units. Cost information was based upon contractor-owner confidential data that has been developed over several years of experience as an owner/operating company.

Air Separation Units - ASU's are required for partial oxidation of oil and both high and low pressure coal gasification. The program is designed to differentiate between high and low pressure supply of oxygen and to adjust the capital and operating costs appropriately.

Reformers - H_2 and CO are produced by the steam reforming of natural gas. The desired reaction is $CH_4 + (2-n)\ H_2O \longleftrightarrow n\ CO + (1-n)\ CO_2 + (4-n)\ H_2$. When H_2 is the final product, the effluent from the reformer is sent to a shift unit to convert CO and H_2O to H_2 and CO_2. Then the CO_2 is removed leaving H_2 product. In the cases where 2:1 H_2 to CO is desired, reformer effluent is first sent to a CO_2 removal unit to recover CO_2 for recycle to the reformer inlet. The CO_2 free gas then goes to a cryogenic separation unit which produces the 2:1 product stream and a waste H_2/CH_4 stream which is used as part of the fuel to the reformer.

Partial Oxidation - In this case, a H_2-CO stream is produced by the reaction of oil with steam and oxygen at high temperature and pressure. The raw effluent contains H_2S and CO_2 which is removed and sent to a sulfur recovery system. The lean gas has an excess of CO whether syngas or hydrogen is the required product. Hence, the appropriate quantity of gas must be sent to shift and CO_2 removal to produce the final product slate.

Coal Gasification - Coal, steam and O_2 are reacted to produce H_2 and CO. The base case was a bituminous coal feed to an atmospheric pressure, oxygen blown gasifier. In coal gasification, the ratio of H_2S to CO_2 is such that it is necessary to selectively remove the H_2S to permit economical disposal. Otherwise, the downstream processing is basically the same as in the partial oxidation cases. An appropriate adjustment in stream flows must be made due to the different ratio of H_2 to CO.

In addition to the base case, a lignite feed to the atmospheric gasifier is calculated for the Gulf Coast Region. Also, a high pressure oxygen blown gasifier is studied as an example of new technology.

Shift - The purpose of the shift unit is to convert CO and H_2O to H_2 and CO_2. Both high and low temperature shift options are included in the program. High temperature is advantageous for bulk shift of CO to H_2. However, the reaction equilibrium will allow a few percent of the CO to leak through. Low temperature shift is used after high temperature shift in the H_2 production cases to provide for a purer product stream.

CO_2 Removal - Three types of CO_2 removal were considered in this study - MEA, hot potassium carbonate and a physical solvent. The physical solvent was used in the partial oxidation and coal gasification cases. This is because byproduct nitrogen is available at low cost for stripping which makes this alternative attractive. In the reformer cases, hot carbonate was chosen as the economic choice over MEA for bulk removal of CO_2.

Cryogenic H_2/CO Separation - This unit performs a cryogenic distillation of the H_2, CO and CH_4 in the reformed gas. The only base case where this was required was the $2H_2$/1CO reformer case. Flexibility was originally included for both high pressure as well as low pressure byproduct hydrogen. However, when the decision was made to treat this hydrogen at fuel value rather than chemical value, only the low pressure H_2 case was used.

Regional Costs

Part of this study was to examine the market and economics for three regions - Gulf Coast, Mid-Atlantic and Ohio Valley. The regional energy cost differences were provided by JPL. For purposes of the study, regional capital costs were assumed to differ only to the extent of the difference in regional labor costs, including base pay, fringe benefits and productivity. For actual projects, of course, site specific considerations can significantly affect capital costs.

3.3.1.2 MAJOR OPERATING COST ESTIMATES

Major operating costs consist of the following:

Natural Gas - This was used as the feed to the reformer unit as well as for any net fuel required in the reformer cases. It was assumed to be available from a pipeline at 150 psia.

Residual Oil - This is used as feedstock to the partial oxidation unit.

Distillate Oil - This is the fuel used for any net energy requirements in either the partial oxidation or coal gasification plants.

Coal - Two types of coal are considered - bituminous and lignite. The only time that lignite is used is for the atmospheric pressure gasifier in the Gulf Coast Region. The cost of these coals is assumed to be the same in $/MMBTU although different in $/ton.

Power - Power is imported from a utility network when required rather than attempting to produce all of it internally.

Steam - One must be careful when assigning a value to import/export steam because the availability of a supplier/customer is very site specific. The cost of transportation accentuates the problem. In this study, it was decided that there was a reasonable probability that the purchaser of the hydrogen or syngas product would be a large user of steam. As such they would be willing to sell/purchase steam at incremental pricing. The value assigned to steam is the average cost of production from a one million pound per hour coal fired boiler. There is also an adjustment for the pressure at which steam is supplied.

$\underline{CO_2/N_2}$ - The value of CO_2/N_2 products is even more site specific than steam. For this study no credit was given for these byproducts.

Chemicals, Lubricants and Maintenance - The annual costs for these requirements were computed by taking a percentage of the capital cost of the facility.

3.3.2 DISCUSSION OF RESULTS COMPARING H_2 AND SYNGAS PRODUCTION COSTS

The key production cost issues addressed in this study are:

1. Can coal compete with oil and natural gas in the production of hydrogen and syngas?
2. What types of financial incentives will be required to make gasified coal competitive as a chemical feedstock in the 1980's?

This section answers the first question using a) the Original JPL Energy Scenario as a source of future energy costs, b) the capital and operating cost methodology defined in the previous section and c) a financial analysis procedure so that product price could be compared on a consistent basis. Appendix A defines the financial analysis approach used. The second issue is discussed in the recommendation section of this study.

It should be noted that future markets for hydrogen and syngas are expected to be limited geographically, and characterized by a limited number of regional buyers and sellers purchasing specified quantities of hydrogen and syngas at prices established according to long term contractural agreements. As a result, this market is not expected to operate according to the normal interaction of supply and demand. Instead, the selling price will be determined through a bargaining process, and set at a level enabling the producers to earn a minimum required return to their investment over the life of the project. Therefore, due to the nature of this industry, the contracted market selling price will depend on the production technology adopted. Thus, the prices estimated in this report are expected to approximate the market selling prices that would be established through the bargaining process.

3.3.2.1 RESULTS FOR H_2 AND SYNGAS PRODUCTION - ORIGINAL ENERGY SCENARIO

The results of H_2 and syngas price comparisons are shown in Tables 3.30, 3.31, and 3.32 for the product slate/plant sizes evaluated. Figures 3.4 through 3.9 illustrate the results for a Gulf Coast location. Conclusions on future competitiveness of coal vs. natural gas/oil using the Original JPL Energy Scenario are as follows:

1. Coal is not price competitive in year 1 of operation for any future plant start-up date evaluated regardless of plant size/slate and geographic region.
2. The competitive position of coal depends more on product slate than plant size.
   a. Coal is least competitive with the H_2 slate.
   b. Coal is more competitive at 40 MM SCFD syngas than at 150 MM SCFD H_2.
   c. The 1982 price premium for syngas from coal is about 60% averaged over regions at 40 MM SCFD and about 50% averaged over regions at 150 MM SCFD.
3. The higher escalation rates of natural gas and oil vs. coal show up in the steadily declining premium for coal-based H_2 or syngas product vs. the least costly alternative. The "year one" premium for both product slates and all regions averages about 60% in 1982 and declines to less than 20% in 2000.
4. Real annual escalation rates average about five times higher for natural gas compared to coal (3% vs. 0.6%) and about three times higher for oil compared to coal (1.7% vs. 0.6%). The effect of these escalation rates can be seen in the graphs which follow later in this report.
5. Lignite and bituminous coal types were compared for both product slates in the Gulf Coast region. Lignite results in about a 10% product price premium compared to bituminous.

6. Product slate determines the least costly feedstock option, natural gas vs. oil. With the exception of 1987 and 2000 start-up in the mid-Atlantic region, natural gas results in the lowest product price in year of plant start-up for 150 MM SCFD H_2. Oil is the preferred feedstock in all regions and all start-up years for production of syngas at 150 MM SCFD. Partial oxidation of oil results in the least cost technology for production of syngas at 40 MM SCFD in all cases except the Gulf Coast region for 1982 start-up. Natural gas resulted in lower product price for that region in that time period.

Table 3.30

ECONOMIC COMPARISONS FOR 150 MM SCFD SYNGAS
($/MSCF)

Start-Up Year	1982			1987			2000		
Region	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*
Gulf Coast									
Natural Gas	$1.86	2.5%	--	$2.15	2.1%	--	$3.06	--	--
Oil	$1.77	1.8%	--	$1.96	1.7%	--	$2.68	--	--
Coal - Lignite	$2.77	1.2%	--	$3.00	0.5%	--	$3.34	--	--
Coal - Bituminous	$2.53	1.0%	43%	$2.72	0.4%	39%	$2.99	--	12%
Ohio Valley									
Natural Gas	$1.92	3.2%	--	$2.33	2.4%	--	$3.39	--	--
Oil	$1.81	2.1%	--	$2.04	1.9%	--	$2.82	--	--
Coal	$2.66	0.5%	47%	$2.79	0.3%	37%	$3.05	--	8%
Mid-Atlantic									
Natural Gas	$2.16	4.2%	--	$2.72	3.7%	--	$4.41	--	--
Oil	$1.85	1.9%	--	$2.06	1.9%	--	$2.84	--	--
Coal	$2.82	0.7%	52%	$2.98	0.4%	45%	$3.30	--	16%

*In year 1 of plant operation.

FIGURE 3.4

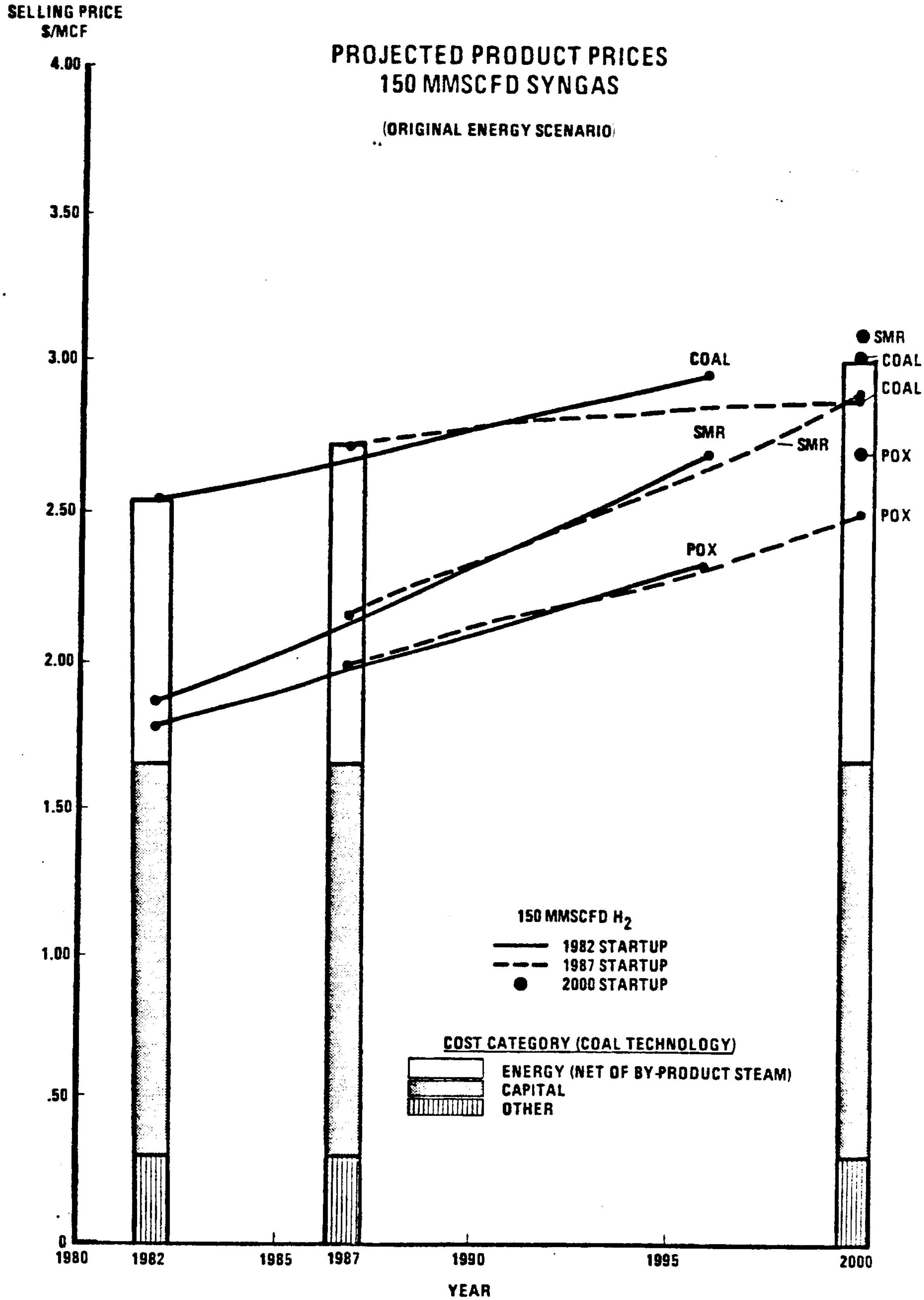

SELLING PRICE $/MCF
PROJECTED PRODUCT PRICES
150 MMSCFD SYNGAS
(ORIGINAL ENERGY SCENARIO)
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
COAL
SMR
POX
SMR
COAL
COAL
SMR
POX
POX
150 MMSCFD H_2
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY (NET OF BY-PRODUCT STEAM)
CAPITAL
OTHER

FIGURE 3.5

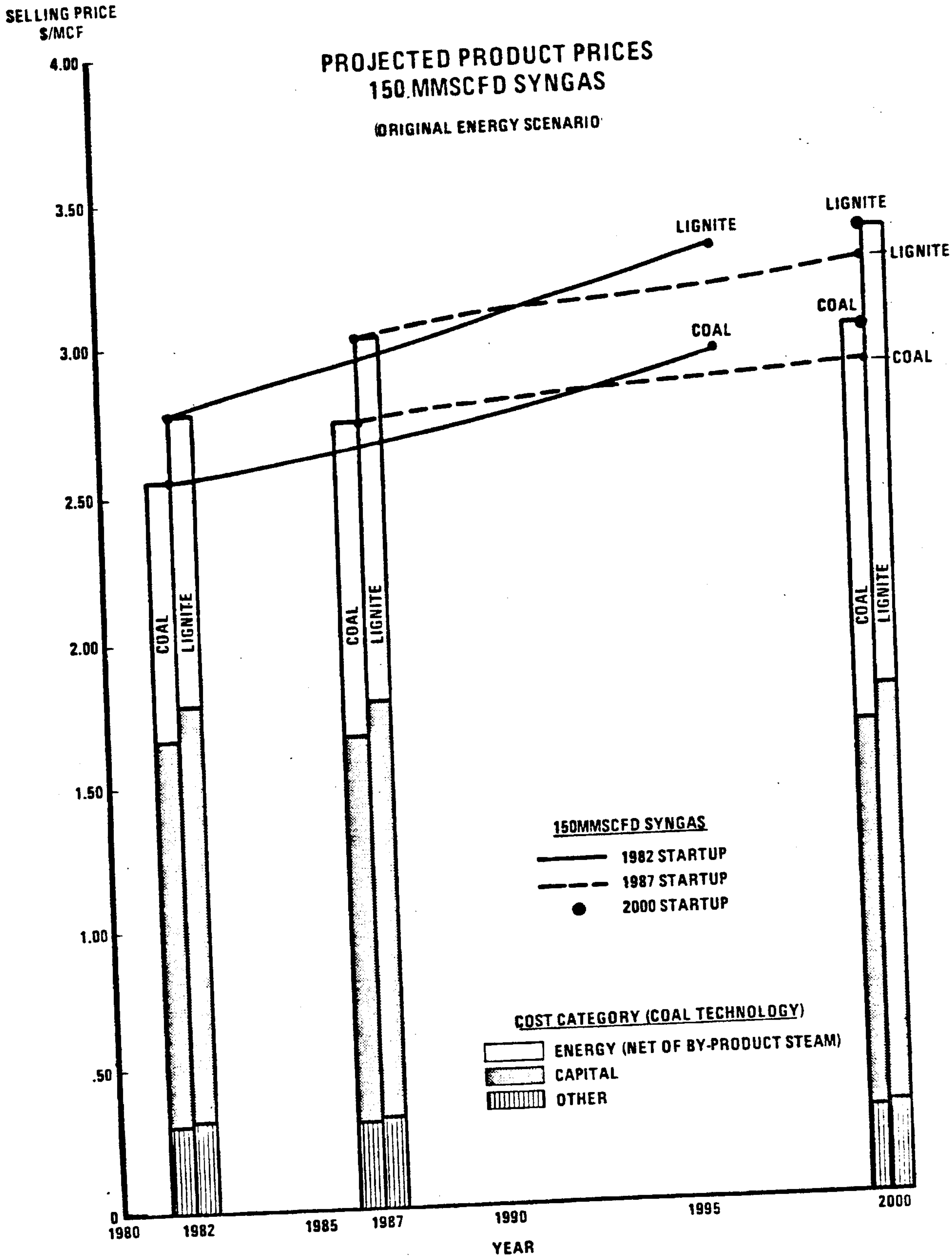

SELLING PRICE
$/MCF
PROJECTED PRODUCT PRICES
150 MMSCFD SYNGAS
(ORIGINAL ENERGY SCENARIO)
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
LIGNITE
COAL
LIGNITE
LIGNITE
COAL
COAL
COAL
LIGNITE
COAL
LIGNITE
COAL
LIGNITE
150MMSCFD SYNGAS
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY (NET OF BY-PRODUCT STEAM)
CAPITAL
OTHER
1980
1982
1985
1987
1990
1995
2000
YEAR

Table 3.31

ECONOMIC COMPARISONS FOR 150 MM SCFD H_2
($/MSCF)

Start-Up Year	1982			1987			2000		
Region	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*
Gulf Coast									
Natural Gas	$1.55	2.7%	--	$1.81	2.2%	--	$2.58	--	--
Oil	$2.01	1.8%	--	$2.24	1.7%	--	$3.01	--	--
Coal - Lignite	$2.93	1.3%	--	$3.21	0.5%	--	$3.59	--	--
Coal - Bituminous	$2.67	1.1%	72%	$2.89	0.4%	60%	$3.20	--	24%
Ohio Valley									
Natural Gas	$1.62	3.3%	--	$1.96	2.4%	--	$2.85	--	--
Oil	$2.06	1.8%	--	$2.29	1.6%	--	$3.06	--	--
Coal	$2.83	0.6%	75%	$2.97	0.5%	52%	$3.27	--	15%
Mid-Atlantic									
Natural Gas	$1.82	4.2%	--	$2.30	3.7%	--	$3.70	--	--
Oil	$2.13	1.9%	--	$2.37	1.7%	--	$3.22	--	--
Coal	$3.00	0.9%	65%	$3.18	0.5%	38%	$3.54	--	10%

*In year 1 of plant operation.

FIGURE 3.6

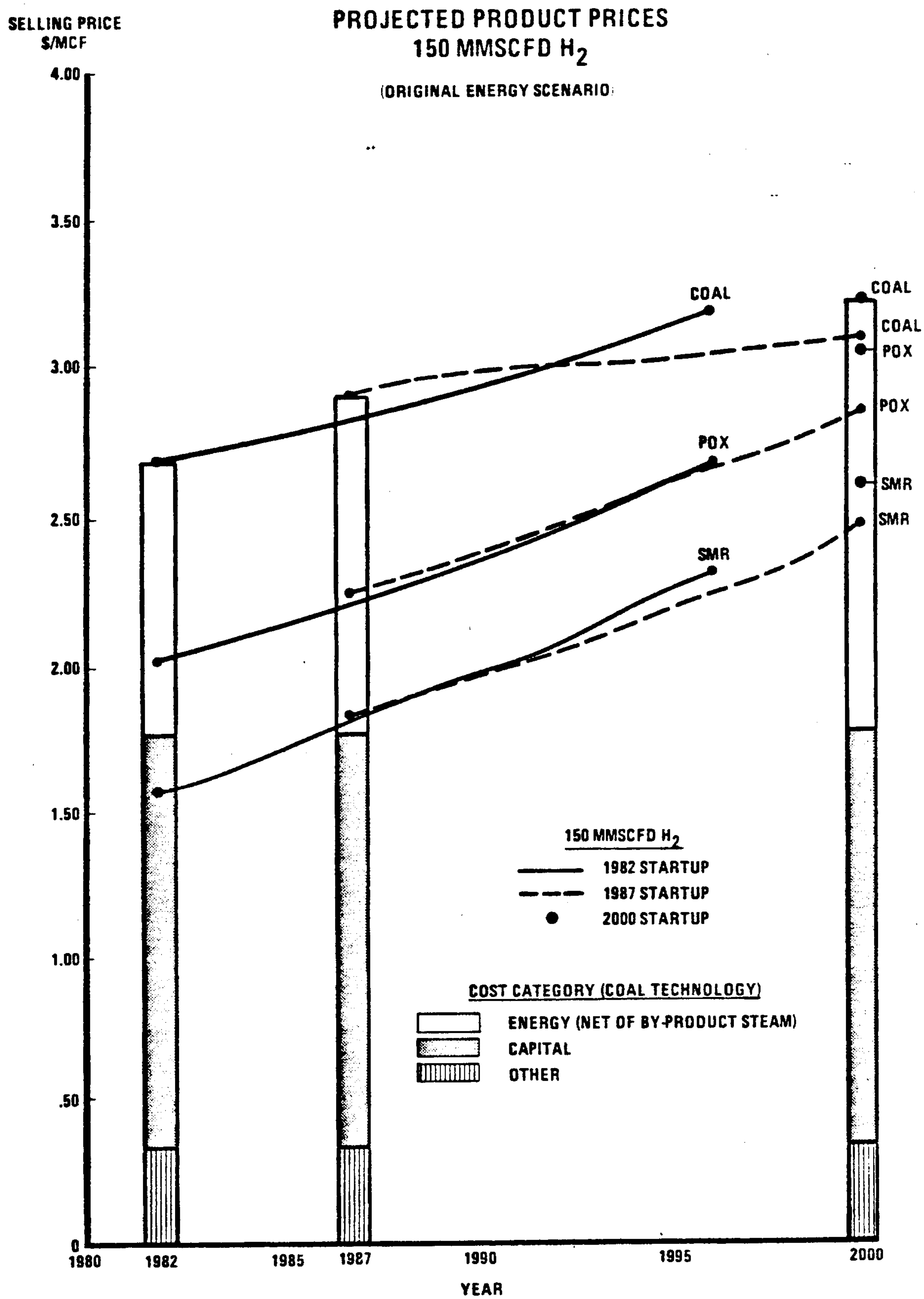

SELLING PRICE
$/MCF
PROJECTED PRODUCT PRICES
150 MMSCFD H_2
(ORIGINAL ENERGY SCENARIO)
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
COAL
POX
SMR
150 MMSCFD H_2
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY (NET OF BY-PRODUCT STEAM)
CAPITAL
OTHER

FIGURE 3.7

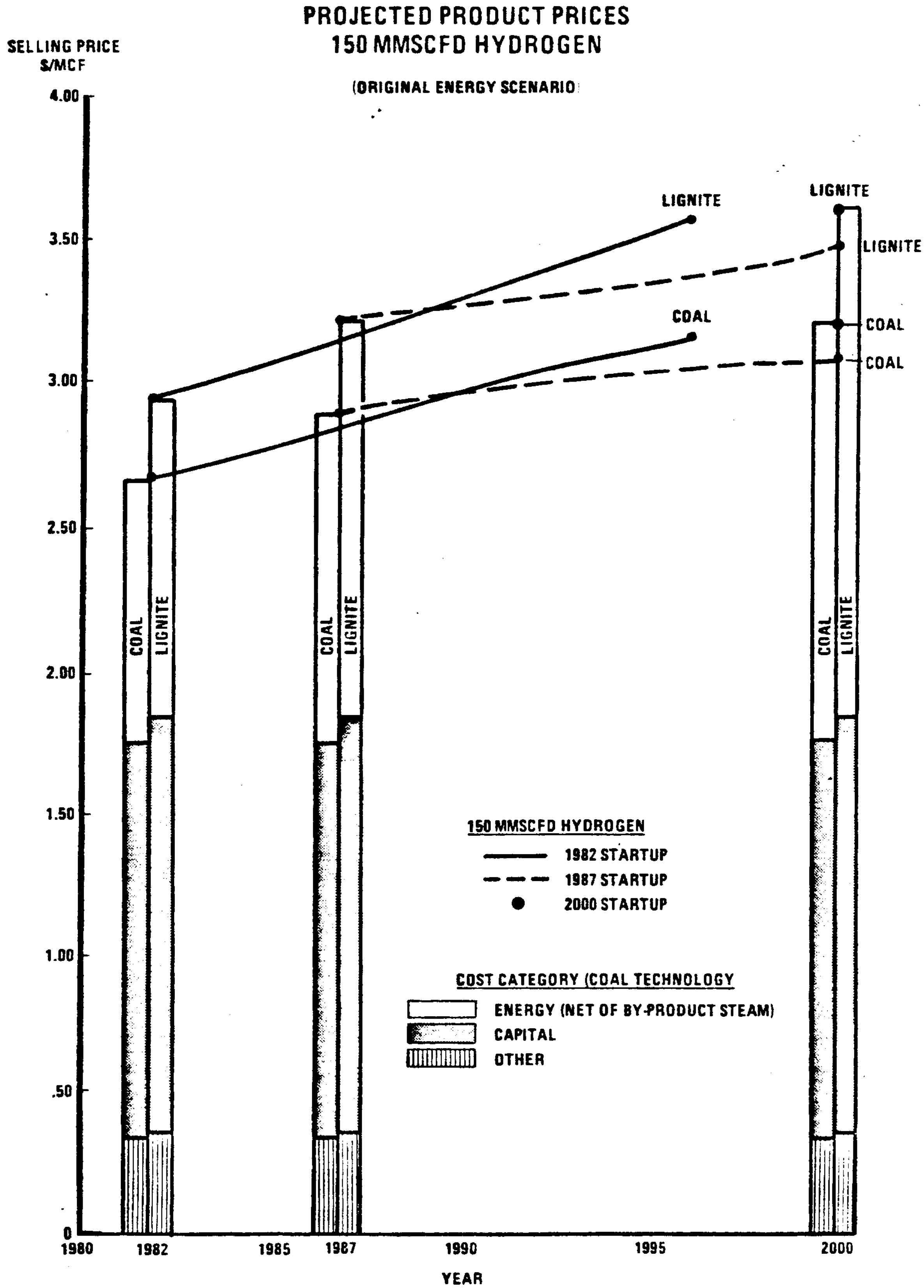

PROJECTED PRODUCT PRICES
150 MMSCFD HYDROGEN
(ORIGINAL ENERGY SCENARIO)
SELLING PRICE $/MCF
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
LIGNITE
LIGNITE
LIGNITE
COAL
COAL
COAL
COAL
LIGNITE
COAL
LIGNITE
COAL
LIGNITE
150 MMSCFD HYDROGEN
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY
ENERGY (NET OF BY-PRODUCT STEAM)
CAPITAL
OTHER
1980
1982
1985
1987
1990
1995
2000
YEAR

Table 3.32

ECONOMIC COMPARISONS FOR 40 MM SCFD SYNGAS
($/MSCF)

Start-Up Year	1982			1987			2000		
Region	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*
Gulf Coast									
Natural Gas	$2.11	2.4%	--	$2.61	2.0%	--	$3.61	--	--
Oil	$2.29	1.5%	--	$2.50	1.4%	--	$3.23	--	--
Coal - Lignite	$3.75	0.7%	--	$3.99	0.3%	--	$4.32	--	--
Coal - Bituminous	$3.48	0.6%	65%	$3.67	0.2%	47%	$3.94	--	22%
Ohio Valley									
Natural Gas	$2.35	2.9%	--	$2.78	2.1%	--	$3.90	--	--
Oil	$2.37	1.6%	--	$2.60	1.5%	--	$3.40	--	--
Coal	$3.66	0.3%	56%	$3.78	0.2%	45%	$4.04	--	19%
Mid-Atlantic									
Natural Gas	$2.62	3.7%	--	$3.22	3.3%	--	$4.99	--	--
Oil	$2.38	1.5%	--	$2.60	1.5%	--	$3.40	--	--
Coal	$3.78	0.5%	59%	$3.94	0.2%	52%	$4.26	--	25%

*In year 1 of plant operation.

FIGURE 3.8

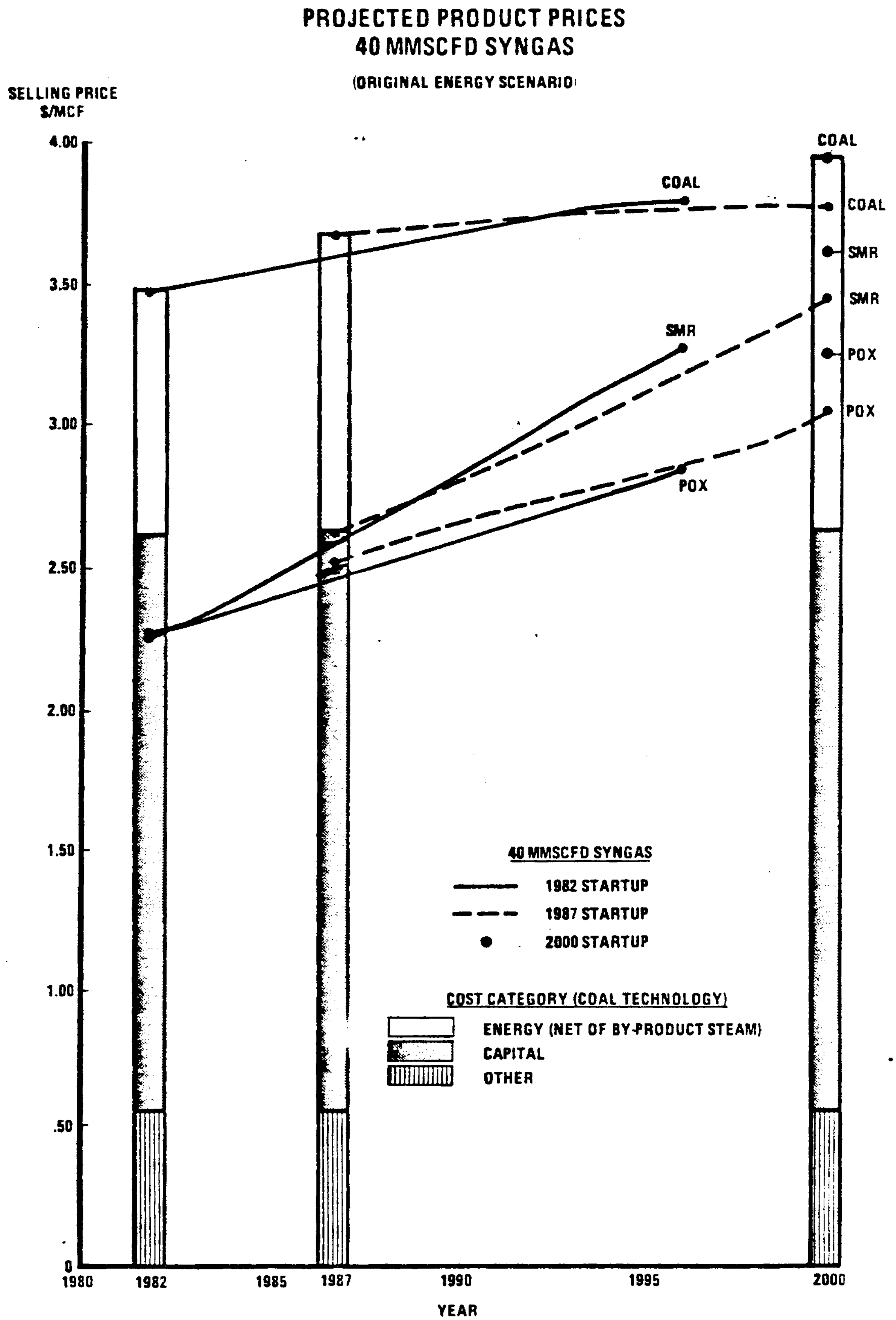
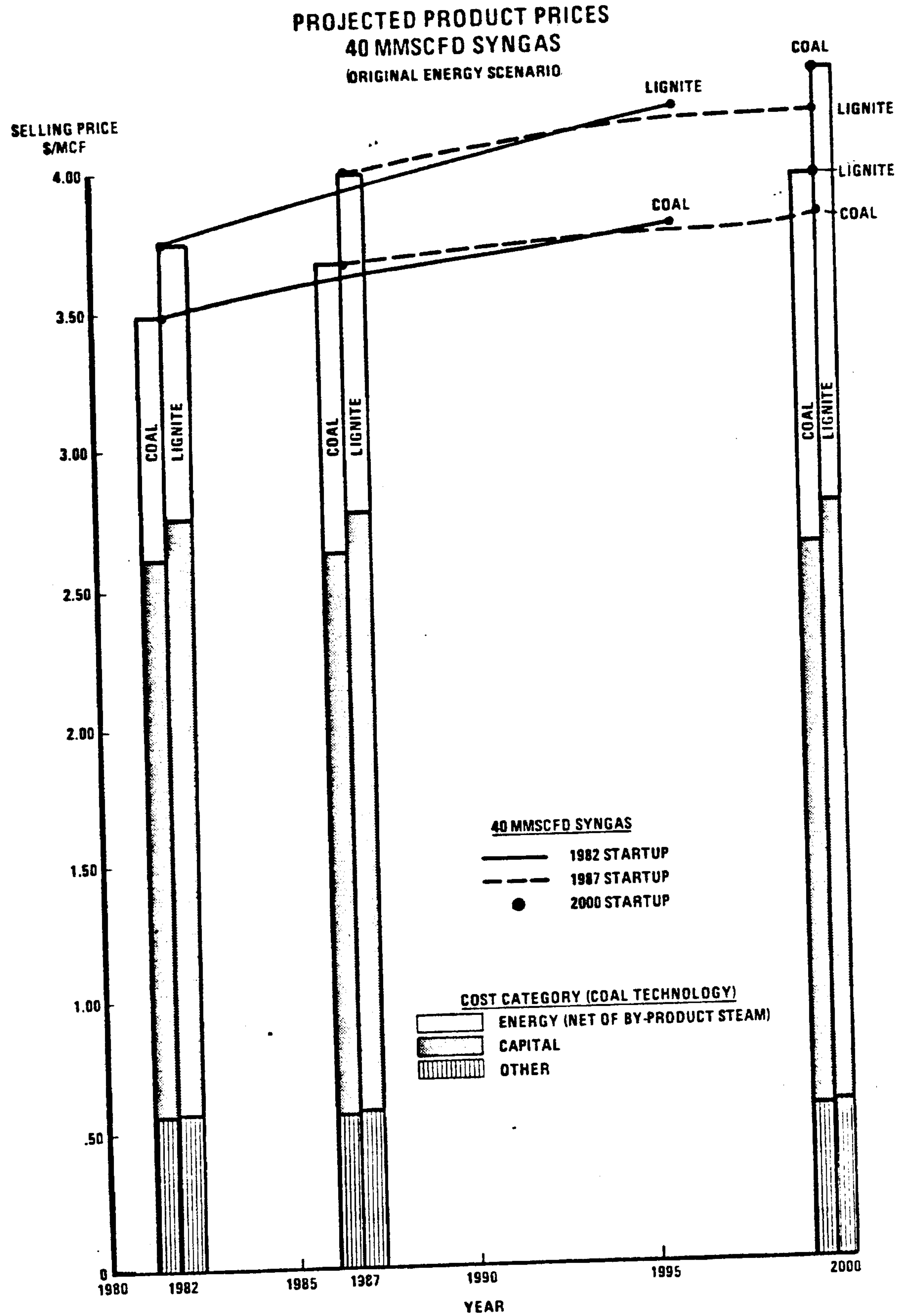

PROJECTED PRODUCT PRICES
40 MMSCFD SYNGAS
(ORIGINAL ENERGY SCENARIO)
SELLING PRICE
$/MCF
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
COAL
COAL
COAL
SMR
SMR
SMR
POX
POX
POX
40 MMSCFD SYNGAS
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY (NET OF BY-PRODUCT STEAM)
CAPITAL
OTHER

FIGURE 3.9


PROJECTED PRODUCT PRICES
40 MMSCFD SYNGAS
(ORIGINAL ENERGY SCENARIO
SELLING PRICE
$/MCF
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
COAL
LIGNITE
COAL
LIGNITE
COAL
LIGNITE
LIGNITE
COAL
LIGNITE
LIGNITE
COAL
COAL
40 MMSCFD SYNGAS
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY (NET OF BY-PRODUCT STEAM)
CAPITAL
OTHER
1980
1982
1985
1987
1990
1995
2000
YEAR

3.3.2.2 PRESSURIZED VS. ATMOSPHERIC COAL GASIFICATION

Cost evaluations have been completed comparing atmospheric pressure and elevated pressure coal gasification technology for production of synthesis gas delivered at pressure (350 psig). The evaluations were done for a Gulf Coast location and considered synthesis gas produced at plant scales of 40 MM SCFD and 150 MM SCFD.

Results shown in Table 3.33 indicate a price advantage for pressurized gasification at 40 MM SCFD. The price advantages are 13.4% and 13.5% for start-up in 1982 and 1987, respectively. At 150 MM SCFD price advantages for pressurized gasification are 14.2% and 14.0% for 1982 and 1987 start-up.

3.3.2.3 EVALUATION OF CO-PRODUCING FUEL AND SYNGAS

An economic evaluation has been made of fuel gas economics. The calculation procedure assumes incremental fuel gas production capacity is added to a 150 MM SCFD chemical syngas plant which has already been justified solely on the basis of its syngas feedstock products. The incremental capacity is approximately the Btu equivalent of 50 MM SCFD natural gas. Therefore, only incremental capital and operating cost directly related to fuel gas output are charged to the fuel gas price. As results in Table 3.34 show, substantial price premiums in both 1982 and 1987 would be necessary for fuel gas from coal vs. alternate clean fuel prices.

3.3.3 DISCUSSION OF REVISED ENERGY SCENARIO SENSITIVITY CASES

As mentioned in the introduction section, this study was undertaken during a period, early 1979, of virtual chaos in the world oil markets. By mid-1979 the results of oil exporting countries actions earlier in the year had become clearer. At that time it was recommended that JPL consider an alternative energy scenario which would more closely resemble the expected direction of future energy prices as of mid-1979.

Table 3.33

COMPARISON OF ATMOSPHERIC AND PRESSURIZED COAL GASIFICATION FOR SYNGAS PRODUCTION

40 MM SCFD SYNGAS
(Gulf Coast Location)

	1982			1987		
	Initial Price	Annual Escalation	Pressurized Advantage*	Initial Price	Annual Escalation	Pressurized Advantage*
Atmospheric	$3.48	0.6%	--	$3.67	0.2%	--
Pressurized	$3.01	0.8%	13.5%	$3.18	0.3%	13.4%

150 MM SCFD SYNGAS
(Gulf Coast Location)

	1982			1987		
	Initial Price	Annual Escalation	Pressurized Advantage*	Initial Price	Annual Escalation	Pressurized Advantage*
Atmospheric	$2.53	1.0%	--	$2.72	0.4%	--
Pressurized	$2.17	1.1%	14.2%	$2.34	0.4%	14.0%

Table 3.34

EVALUATION OF FUEL GAS PRICES CO-PRODUCED WITH SYNGAS

150 MM SCFD "MEDIUM BTU" FUEL GAS
(50 MM SCFD Natural Gas Equivalent)
Dollars per MM BTU

	1982		1987	
	Price	Disadvantage of Medium Btu Fuel Gas*	Price	Disadvantage of Medium Btu Fuel Gas*
Medium Btu Fuel Gas	$5.52	--	$5.82	--
Natural Gas	$2.53	$2.99	$2.76	$3.06
Fuel Oil	$3.29	$2.23	$3.74	$2.08

*In year 1 of plant operation.

An alternate energy scenario was constructed near the end of the current contract using the following assumptions:

a) The appropriate form for petroleum price trajectories is logarithmic (as opposed to exponential) due to the step function increase that has occurred in price during 1979. A simple compound growth rate between the end points of 1978 and 2000 will understate projected prices during the mid term period 1980-1990.

b) A similar logarithmic representation for coal prices is also not unreasonable, especially if current administration efforts to promote coal use are successful in increasing coal demand (and pressure on prices) earlier than it would develop if unpromoted.

c) Due to continued restraint of natural gas prices (relative to petroleum) arising out of the Natural Gas Policy Act of 1978, the natural gas price trajectory will be exponential during the 1978-1985 period with increases in new gas prices tied to inflation (plus incentive). With new natural gas deregulated in 1985-1987, gas prices are projected to reach parity with #2 fuel by 1988-1990.

d) For purposes of deriving functional relationships, let:

y = price

x = year, 1978 = 1, 1979 = 2 . . . 2000 = 23

The results of this analysis are shown below:

Functional Form: $y = a + b \ln(x)$

	Estimated Values:		
	a	b	r^2
#2 Fuel Oil:	2.575	1.017	.983
#6 H.S. Oil:	1.510	.901	.931
Coal - E. North Central (H.S. Bituminous)	.995	.250	.997
Coal - W. South Central (Lignite)	.628	.199	.999

Functional Form: $y = ae^{bx}$

	Estimated Values: a	b	r^2
Natural Gas (1978-1985):	1.966	.048	.988
Natural Gas (1986-2000):	For natural gas during the period 1988-2000, assume parity with #2 fuel oil. Interpolate between 1985 and 1988 to obtain intermediate years.		

A comparison of the energy projections and fitted curves is shown in Figure 3.10.

FIGURE 3.10

ENERGY PRICE PROJECTIONS, WITH FUNCTIONAL REPRESENTATIONS