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PRODUCTION ECONOMICS FOR HYDROGEN, AMMONIA AND METHANOL DURING THE 1980-2000 PERIOD

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ABSTRACT

Refinery hydrogen, ammonia and methanol, the principal industrial hydrogen products, are now manufactured mainly by catalytic steam reforming of natural gas or some alternative light hydrocarbon feed stock. Anticipated increases in the prices of hydrocarbons are expected to exceed those for coal, thus gradually increasing the incentive to use coal gasification as a source of industrial hydrogen during the 1980-2000 period. Although the investment in industrial hydrogen plants will exceed those for reforming by a factor of 2 or more, coal gasification will provide lower production costs (including 20%/yr. before tax return) for methanol manufacture in the early 1980's and for ammonia 5 years or so later. However, high costs for transporting coal to major refining centers will make it difficult to justify coal gasification for refinery hydrogen production during the 1980-2000 period. By the year 2000, 40-45% of the U.S. industrial hydrogen requirements will be provided by coal gasification thus conserving natural gas and light hydrocarbon feed stocks equivalent to about 600,000 B/D of crude oil.

Electrolytic hydrogen production costs will be reduced by improved electrolysis technology such as the solid polymer electrolyte process. These improved processes will reduce electrolysis plant investments by a factor of 2 or more and reduce electricity requirements by about 20%. Although the production cost, including return for electrolytic hydrogen, will continue to exceed those for reforming and coal gasification, the use of electrolytic hydrogen will be attractive for many small users when the new technology is available in the early 1980's. Electrolytic hydrogen now about 0.7% of total U.S. industrial hydrogen requirements will probably increase to about 1.2% of the total by the year 2000.

EXECUTIVE SUMMARY

The principal requirements for industrial hydrogen are for use in petroleum refining, for the manufacture of ammonia and methanol, and for a wide variety of small uses including chemicals manufacture, metallurgy, welding, etc. Nearly all U.S. industrial hydrogen is now manufactured by catalytic steam reforming of natural gas or some other light hydrocarbon feed stock. Some industrial hydrogen, particularly in Europe, is produced by the partial oxidation of resid. Outside the U.S., significant amounts are produced by the Koppers-Totzek coal gasification process. Small quantities of hydrogen are produced by electrolysis in the U.S. and in many other foreign countries for small user hydrogen requirements.

U.S. industrial hydrogen requirements expressed as the heating value of refinery hydrogen and the heating value of the hydrogen contained in ammonia and methanol were 0.58 Quads/year in 1975 (0.58×10^{15} Btu/yr). By 1980 these requirements are expected to be about 0.78 Quads/yr. and by the year 2000 this figure is likely to be 1.77 Quads/yr corresponding to a growth rate during the 1980-2000 period of 4.2%/yr. These requirements are summarized in Table S-1.

In 1975 natural gas (or other light hydrocarbon feed stock) required to produce these U.S. industrial hydrogen requirements was equivalent to about 450,000 B/D of crude oil. By 1980 this requirement will probably increase to 612,000 B/D. If natural gas reforming were used to produce all industrial hydrogen in the year 2000, the crude oil equivalent would be about 1.4 million B/D. This would correspond to 6% of the projected crude oil imports in 1980 and 15% in the year 2000. However, by the year 2000 it is likely that coal gasification will be used to provide 40-45% of U.S. industrial hydrogen requirements. Coal requirements for hydrogen production by gasification will then be 58 M ST/yr corresponding to 4% of the U.S. projected coal consumption for the year 2000. Assuming coal gasification is used to this extent, 615,000 B/D of natural gas (crude equivalent) will be saved in the year 2000; this saving will correspond to 7% of the U.S. gas consumption, or 3% of total U.S. crude requirements, or 6% of projected U.S. imports of crude oil. Feed stock requirements for industrial hydrogen for the years 1980 and 2000 are summarized in Table S-2.

Steam reforming is now the most attractive process for manufacturing refinery hydrogen, ammonia and methanol in the U.S. Although resid partial oxidation is used for a small portion of refinery hydrogen manufacture in the U.S. and is used more extensively in Europe, it appears that this process will not be attractive in the U.S. during the 1980-2000 period except for the special situations where resid stocks can be obtained at prices substantially less than those assumed in this study. As natural gas and light hydrocarbon feed stocks become more expensive relative to coal, industrial hydrogen production will shift from reforming to coal gasification even though the investments for coal gasification hydrogen plants will be more than 2 times those for steam reforming. By 1982, production costs (including 20%/yr before tax return) for methanol manufacture by reforming and coal gasification will be equal, and thereafter costs by coal gasification will be lower. For ammonia the break-even year will be about 1989. Refinery hydrogen production will be more attractive by reforming throughout the 1980-2000 period due in part to very large incremental investments for coal gasification and in part to the high transportation costs required to deliver coal to major U.S. refining centers. The economics for these processes and products for the years 1980 and 2000 are summarized in Table S-3.

These economics data assume that an improved coal gasification process will replace the Koppers-Totzek system which is now used commercially. This improved process has been extensively developed during the past several years, but as yet has not been demonstrated commercially. This improved process will probably provide investments about 10% lower than those for K-T and will require about 7% less coal compared to K-T. These savings are provided by the use of 400-500 psig pressure on the gasification reactor compared to atmospheric pressure used in the K-T process. It appears that this improved process (hereafter called new coal) will be available for commercial use by 1982-83.

Electrolysis is now used to provide 0.004 Quad/yr of industrial hydrogen in the U.S. This is equivalent to about 0.7% of the total industrial hydrogen produced in the U.S. or 17% of the "small user" hydrogen category. The remainder of the small user hydrogen market is provided by on site manufacture in small reformers or from large reformers through over the fence deliveries by pipeline, or by truck delivery in pressure cylinders or as a liquid. The increased cost and difficulty of obtaining light hydrocarbon feed stocks for reforming will increase the economic incentive for using electrolysis. By the year 2000 electrolysis is expected to provide 25% of the small user hydrogen market or 0.02 Quad/yr. This will then be about 1.2% of the total U.S. industrial hydrogen requirements. The small user hydrogen requirements and production processes are summarized in Table S-4.

Electrolytic hydrogen production costs are very high compared to those for reforming in large plants. However, for the small user, production costs in small capacity reformers may be even greater than by electrolysis. Procuring hydrogen by purchase from a nearby reformer by pipeline or truck delivery may therefore be the optimum procedure for many small users.

Investments for electrolysis plants are now about \$500-750/kw of hydrogen product over a broad range of plant capacity (1980\$). Production costs including 20%/yr before tax return are about \$21/MBtu of hydrogen assuming electricity can be obtained at 2.7¢/kwhr. Development work currently in progress employing a solid polymer electrolyte (SPE) is likely to lower the investment to \$200/kw and production cost to about \$13/MBtu. If off-peak electricity could be obtained for say 10 hours per day at 1.0¢/kwhr, the production cost would be about \$11/MBtu but the hydrogen product would be produced intermittently. The corresponding cost for producing hydrogen in large reformers (100 MSCF/SD) is \$6.12/MBtu. Electrolysis economics data are summarized in Table S-5.

An important economic difficulty in producing electrolytic hydrogen is that the efficiency of converting primary fuel (coal, oil or nuclear energy) to electrolytic hydrogen is very low compared to that for converting these feed stocks to hydrogen by reforming or coal gasification. The thermal efficiency for converting coal, nuclear or oil fuels to electricity is about 35% and that for converting electricity to electrolytic hydrogen may be 90% for the new electrolysis processes. The overall efficiency of converting coal (or nuclear fuel or oil) to electrolytic hydrogen is, therefore, about 32%. The corresponding thermal efficiency for converting natural gas to hydrogen by reforming is 70% and for converting coal to hydrogen by the K-T process is 61% and by the new coal gasification process is 66%. Electrolysis involves this low overall thermal efficiency and there is no foreseeable way to reduce this large conversion loss. Electrolysis therefore requires essentially twice as much primary energy as reforming or coal gasification. However, electrolysis provides the only available procedure for converting hydro or nuclear energy to a gaseous fuel.

The economic values developed in this study are based on the estimated cost of process plants constructed for startup in 1980 expressed in 1980$. It was assumed that construction costs, coal, electricity, chemicals, catalyst, and operating labor would escalate during the 1980-2000 period at 5%/yr, the assumed general inflation rate. Thus, all these costs are assumed to remain constant during this 20 year period when expressed in 1980$. Costs of natural gas and resid feed stocks were assumed to escalate at 6.5%/year due to decreasing supplies of these petroleum feed stocks and the probability that the cost of imported hydrocarbons will increase in step with the world inflation rate which will be somewhat greater than that for the U.S. The prices assumed for coal, natural gas, resid and electricity are summarized in Table 2.02, page 51.

Throughout these economic studies, the cost comparisons of one production system versus another were calculated to show the effect of several sensititivities. These calculations indicate that a reasonable change in these variables will not change the basic conclusions that were developed for the most likely (base) case. the following factors were studied in these sensitivity calculations:

- Higher feed stock costs
- Lower feed stock costs
- 10% increase in investment
- Construction costs escalate 1%/yr above general inflation
- Construction costs escalate 1%/yr below general inflation
- Coal prices escalate 1%/yr above general inflation
- Coal prices escalate 1%/yr below general inflation

TABLE S-1

U.S. Industrial Hydrogen Requirements

	1980	2000	Growth Rate %/yr
Refinery hydrogen, MSCF/CD	1780	4725	5.0
Ammonia, MST/yr	21.3	41.8	3.4
Methanol, MST/yr	5.3	15.3	5.4
Small user hydrogen, MSCF/CD	261	700	5.0
Total, Quads/yr of H_2	0.78	1.77	4.2

TABLE S-2

Hydrocarbon and Coal Feed Stocks for U.S. Industrial Hydrogen Production

	1980	2000
Natural gas required if all U.S. industrial hydrogen were produced by reforming, KB/D crude equivalent	613	1401
Natural gas saved by coal gasification, KB/D crude equivalent	-	615
Coal required for gasification, MST/yr	-	58

TABLE S-3

Economics for Industrial Hydrogen Production

1980 $

		Natural Gas Reforming	Resid Partial Oxidation	New Coal Gasification
Investment, $ Millions (1980-2000)				
Refinery hydrogen, 100 MSCF/SD plants		63	159	200
Ammonia, 2000 ST/SD plants		181	281	362
Methanol, 2000 ST/SD plants		135	231	310
Production Cost Including 20%/yr Before Tax Return				
Refinery hydrogen, $/MBtu	1980	6.12	8.14	8.17
" " , "	2000	7.54	9.19	8.17
Ammonia, $/ST	1980	210	248	227
" , "	2000	248	283	227
Methanol, $/ST	1980	195	221	198
" , "	2000	236	255	198

TABLE S-4

U.S. Small User Hydrogen Requirements

	Btu/yr x 10^{12}		
	1975	1980	2000
Supplied by electrolysis	4	4	21
" by reforming	20	27	41
" by new coal gasification	—	—	21
Total	24	31	83

TABLE S-5

Economics of Electrolytic Hydrogen Manufacture

1980 $

	Electrolysis			Steam
	Current	SPE	SPE	Reforming
Hours per year operation	7920	7920	3300	7920
Investment, $ per 7920 kwhr per year hydrogen product	750	206	494	148
Production Cost, $/MBtu				
Electricity @ 2.7¢/kwhr	10.44	10.19	-	-
" @ 1.0¢/kwhr	-	-	3.77	-
Natural gas @ $3.15/MBtu	-	-	-	4.09
Other operating costs	1.19	0.38	0.80	0.31
Capital charges inc. return	9.36	2.65	6.08	1.72
Total	20.99	13.22	10.65	6.12

RECOMMENDATIONS

Reducing the future consumption of natural gas and/or light hydrocarbon feed stocks for the manufacture of industrial hydrogen can best be achieved during the 1980-2000 period by employing coal gasification to replace steam reforming in ammonia and methanol manufacture. Processes such as the thermal disassociation of water using nuclear energy and the catalytic photolysis of water are at an early stage of development and probably will not be available for commercial use before the end of this century.

The pressurized coal gasification process is in an advanced stage of development, and this process appears to offer attractive advantages over current K-T technology. Although the pressurized gasification process has been studied extensively in pilot plants it must be demonstrated in a full scale plant to assure that commerciel use is feasible. Several other coal gasification processes (such as steam/iron) are also being developed.

To assure that an improved coal gasification process is available for commercial use at an early date, the pressurized coal gasification process for hydrogen manufacture should be demonstrated as soon as possible. Such a demonstration may be in the planning stage at present and may be conducted without delay. However, if such a demonstration is not being planned, ERDA should consider a program of cost-sharing with industry to assure that the demonstration is conducted without delay.

It is beyond the scope of this study to determine the status of the several coal gasification processes that are likely candidates for the demonstration program. Organizations that may be involved in planning such a demonstration are Texaco, Shell, Koppers, IGT and possibly others. In June, 1976 ERDA published a Program Opportunity Notice, PON-FE-6 for a commercial plant to produce hydrogen by coal gasification.

ERDA is supporting the development of improved electrolyzers, including the solid polymer electrolyte process. Although electrolysis will probably not be attractive for the production of refinery hydrogen, ammonia or methanol, it will gradually become more attractive as a supply source for small user hydrogen requirements. Also, several new uses are likely to provide attractive opportunities for the use of an improved electrolysis process capable of reducing investments and increasing thermal efficiencies. These new uses include the conversion of off-peak hydro and nuclear produced electricity to hydrogen; the conversion of remote hydro power to hydrogen for ammonia manufacture at sites too far from population centers to permit economic delivery of electricity; and the conversion of ocean thermal energy to electrolytic hydrogen and/or ammonia. ERDA should continue to support the development of improved electrolysis processes.

INTRODUCTION

Hydrogen has been widely considered as an energy carrier because it can be produced from nuclear, hydro or solar energy and thus reduce the consumption of fossil fuels. The hydrogen energy system has been discussed by many groups (References 1-6). It has been suggested that in the near term hydrogen manufacture should employ coal or lignite as a means of conserving natural gas or petroleum feed stocks. Low Btu coal deposits in remote locations might be converted to substitute natural gas (SNG) or hydrogen and the gas could be transported to distant population centers by pipeline. In the longer term solar or nuclear energy resources might be used to replace fossil fuels now used for industrial hydrogen production. These concepts are of considerable interest to ERDA because of the administration's responsibility of providing RD and D programs directed to reducing the consumption of natural gas and petroleum.

Today large quantities of industrial hydrogen are used in petroleum refining; for the manufacture of ammonia, methanol, and other chemicals; and for many small volume uses such as vegetable oil hydrogenation, metals processing, etc. In the U.S. almost all of the hydrogen for these industrial uses is currently manufactured by steam reforming of a light hydrocarbon such as natural gas or the partial oxidation of a heavy petroleum feed stock. However, small quantities of hydrogen are produced by water electrolysis.

In this study published information has been used:

- to predict the quantities of hydrogen that will be needed in the U.S. during the 1980-2000 period for these current industrial uses;
- to determine the most economic method of hydrogen manufacture during this period;
- to predict the quantities of hydrogen that are likely to be made by the various processes assuming new facilities installed during this period are selected on the basis of their manufacturing costs including return; and
- to identify technology developments that could have a significant impact in reducing the consumption of natural gas and petroleum for hydrogen manufacture during this period.

From this work suggestions have been made regarding programs that ERDA could sponsor as a means of accelerating the use of coal for manufacturing industrial hydrogen during the 1980-2000 period thereby reducing the consumption of natural gas and liquid petroleum feed stocks.

ABBREVIATIONS/DEFINITIONS/CONVERSION FACTORS

bbl = petroleum barrel, 42 U.S. gallons
Btu = British thermal unit, 252 g cal
Heating Value = heat of combustion (gross)
= 23860 Btu/lb for methane
= 61100 Btu/lb for hydrogen
= 4345 Btu/lb for carbon monoxide
lb = pound, 454 grams
M = millions (10^6)
k = thousands (10^3)
gal = U.S. gallon, 3.785 liters
resid = petroleum residuum
CD = calendar days
SD = stream days
SCF = standard cubic feet (60°F, 1.0 atm)
ton or ST = 1.0 U.S. ton, 2000 pounds, 908000 grams

1.0 bbl	crude oil	=	5.56×10^6 Btu Gross
1.0 "	resid fuel oil	=	6.37×10^6 " "
1.0 "	gasoline or naphtha	=	4.80×10^6 " "

1.0 Quad = 1.0×10^{15} Btu

1.0 kwhr = 3415 Btu

1.0 MB/D crude oil = 2.0294×10^{15} Btu/year

Hydrogen = 2.016 molecular weight
= 61100 Btu/lb gross heat of combustion
= 322 Btu/scf " " " "

Methanol = 6.63 lbs/gal
= 9760 Btu/lb gross heat of combustion

CONVERSION FACTORS - ENGLISH TO METRIC (SI) UNITS

	English Units	Metric Equivalent
Length	in	2.54 cm
	ft	0.305 m
Area	in^2	6.45 cm^2
	ft^2	0.0930 m^2
Volume	in^3	16.39 cm^3
	ft^3	28.32 l
	US gal	3.785 l
Mass	oz	28.35 g
	lb	453.6 g
	ton (short)	907.2 kg
Pressure	lb/in^2	6.89 kN/m^2
	ft H_2O (60°F)	3.38 kN/m^2
Temperature	°F	1.8 (°C) + 32
	°R	1.8°K
Energy	Btu	1.055 kJ
	cal	4.184 J
Power	Btu/s	1.055 kw
	HP	0.746 kw

1. FUTURE U. S. REQUIREMENTS FOR INDUSTRIAL HYDROGEN

Industrial hydrogen is currently used for petroleum refining, for the manufacture of ammonia and methanol and for dozens, possibly hundreds, of other uses including chemical synthesis (chemicals other than ammonia and methanol), metallurgy, semi-conductor manufacture, vegetable oil hydrogenation, etc. Present U. S. consumption of hydrogen for these uses has been estimated to the year 2000.

In addition to the current requirements, new uses for hydrogen will develop in the future for synthetic fuels manufacture, iron ore direct reduction, and possibly as automotive and aircraft fuels. These new uses have not been included in the estimates of future requirements prepared in this study.

Table 1.01 summarizes the future requirements to the year 2000. Current requirements are about 0.58 Quad/yr; by the year 2000 requirements are estimated to be 1.77 Quad/year, an annual growth rate of about 4.5%.

Nearly all industrial hydrogen is currently manufactured in the U. S. using catalytic steam reforming of natural gas or some other light hydrocarbon feed stock. Table 1.01 also shows the natural gas required to produce all current and future U. S. industrial hydrogen requirements assuming all this hydrogen is made by steam reforming. The natural gas feed stock is expressed as crude oil equivalent. Currently (1975) the natural gas requirement is equivalent to 451 thousand B/D of crude. If all the industrial hydrogen required in the year 2000 were produced by reforming the light hydrocarbon feed stock would be equivalent to 1.4 million B/D of crude oil. However, as will be explained in later sections, coal gasification is likely to be used after 1985 for some of this industrial hydrogen production thereby saving natural gas or other hydrocarbon feed stocks.

Future industrial hydrogen requirements were estimated by the Jet Propulsion Laboratory in 1975 (Reference 2). Table 1.02 compares the JPL estimates with those prepared in this study. The two estimates agree reasonably well for the hydrogen required for petroleum refining; however, the JPL estimates are substantially higher than those from this study for the other hydrogen requirements.

Hydrogen for Petroleum Refining

The quantity of hydrogen required for petroleum refining depends on the quantity of crude oil processed in U. S. refineries, the quality of the crudes processed, the type of processing used and the product slate required.

Future crude oil requirements have been prepared by several groups (References 7, 8, 9, and 10). The estimates prepared by Exxon Co. USA (Reference 9) and Texaco, Inc. (Reference 10) have been used as the basis of the data developed in this study.

Future U. S. energy requirements to the year 2000 are shown in Table 1.03. Total U. S. energy consumption increased by about 4.0%/year during the 1960-73 period. Future growth rates will be less than this because of the higher current and future prices of energy products and the resulting conservation and efficiency improvement measures. These projected growth rates are as follows:

1974-80 - 2.1%/yr.
1980-90 - 2.8%/yr.
1990-2000 - 2.1%/yr.

Nuclear energy will be the most rapidly growing segment in the future. It will grow from 1.2 Quad/yr. in 1974 to 34.5 Quad/yr in the year 2000, an average growth rate over this period of about 14%/yr.

Natural gas supplies from various domestic and foreign sources were 23.5 Quad/yr in 1974 and are expected to decrease to 19.2 Quad/yr in 1980. Gas requirements will remain about constant during the period 1980-2000 and are estimated to be 18.1 Quad/yr in the year 2000.

Coal provided 14.8 Quad/year or 19% of the total U. S. energy requirements in 1974. Coal consumption is expected to increase to 18.2 Quad/year in 1980 and to 32.1 Quad/year by the year 2000; it will then provide 23% of the total energy requirements.

Table 1.03 also shows forecasts of projected U. S. requirements for oil. Liquid petroleum will remain the leading source of energy for the U. S. throughout this period. This component will increase from 34 Quad/year in 1974 to 41.3 Quad/year in 1980 and 50.3 Quad/year by the year 2000. However, oil's share of the total energy supply will decrease from 44% in 1974 to 36% in the year 2000.

Table 1.04 shows projected U. S. supplies of liquid petroleum and synthetic crudes. U. S. crude oil production has decreased slightly since 1970 and this trend is expected to continue until about 1980. At this time crude production from the Alaskan North Slope will begin to increase overall U. S. production. By the late 1980's crude production should again reach the levels achieved in the early 1970's assuming additional reserves are discovered as expected. Over half of the U. S. crude production in 1990 must come from as yet undiscovered reserves. Energy supplied by crude oil will reach its peak about 1990. Thereafter its availability is expected to decrease in the U. S. and in the world as a whole.

Synthetic crudes produced from shales and coal are expected to be of little significance prior to about 1990. In that year synthetic crude production should be about 0.7 million B/D or 3% of the total U. S. liquid petroleum supply. Thereafter synthetic liquid production should increase rapidly to about 3.0 million B/D or 13% of the U. S. liquid supply by the year 2000. Beyond the year 2000 synthetic crude will increase significantly as crude oil reserves are depleted.

The difference between U. S. liquid petroleum demand and U. S. crude production will be provided by imported crude and products. These data are also shown in Table 1.04. By 1980 imported crude and products will be about 10.7 million B/D or 41.3% of the total supply. Imports will grow to 12.5 million B/D (49.9% of total) by 1990 and will then start to decline reaching 11.0 million B/D (50.3% of total) by the year 2000.

In recent years, the use of hydrogen has become increasingly more important in petroleum refining mainly because crude supplies have become heavier and of higher sulfur content, and the economic need to reduce resid fuel oil yields. In addition, stringent environmental restrictions requiring lower sulfur content products have accelerated the use of hydrogen processing.

Hydrogen is used principally for the hydrodesulfurization of petroleum streams and also for hydrocracking of heavy hydrocarbons, a process that produces high quality gasoline components by the cracking of heavy oils in the presence of hydrogen. Until recent years, most hydrogen consumption has been for the desulfurization of light distillate streams (650°F-). In general, these processes require little hydrogen ranging from about 10-20 SCF/B for light naphthas up to 100-200 SCF/B for the heavier distillates. Hydrogen demand for these processes has in the past, and will in the future, be provided by the hydrogen produced in catalytic reformers that are used to increase the octane number of motor gasoline. Hydrogen, a by-product from these reformers, is typically of 70-80% purity but is satisfactory for desulfurizing distillate stocks.

The development of hydrocracking processes, heavy gas oil desulfurization, and residuum desulfurization brought in refining processes requiring large volumes of high purity hydrogen (95%+). Hydrogen consumption for these processes ranges from approximately 300 SCF/B for light gas oil desulfurization to 3000 SCF/B for severe hydrocracking. Because of their high hydrogen consumption and their requirement for high purity hydrogen, hydrocrackers and heavy oil desulfurization processes are usually installed with their own hydrogen generation facilities. The hydrogen is produced by either steam reforming of natural gas or some other light hydrocarbon or partial oxidation of resid, although most of this hydrogen is produced in steam reformers.

Future hydrogen requirements were estimated assuming hydrogen required for hydrocracking, gas oil desulfurization, and residuum desulfurization would be specifically manufactured for these processes and that all hydrogen produced by catalytic reforming for octane improvement is consumed by distillate reforming and other miscellaneous consumers and would not be replaced by hydrogen generated from non-petroleum sources.

Projected crude runs, product slates, and processing requirements were estimated through the year 2000. These data are shown in Tables 1.04 and 1.05. Between 1977 and 2000 there is a marked increase in residuum processing requirements due to an overall increase in crude runs, a declining market for heavy fuel oils, and also from some "heavying up" of the crude slate.

Two alternative processing routes are available for processing residuum and the choice has significant effects on refinery hydrogen requirements. Residuum processes can be characterized as either carbon removal processes, e.g. coking, or hydrogen addition processes, i.e. hydrocracking. The hydrocracking alternative obviously requires much greater quantities of refinery hydrogen (Reference 21).

The choice between these two alternative processing methods depends on specific economic factors, and such an evaluation of the alternatives is beyond the scope of this study. The estimated processing requirements developed in this study assumed coking as the most economical residuum conversion process. The reasons for this choice are discussed in Reference 21. This will, of course, give lower hydrogen requirements than would be required if extensive hydrocracking were utilized. As a sensitivity, an additional case was estimated for the year 2000 in which hydrocracking was used instead of coking to provide the required product slate. This case is also shown on Table 1.05 and would result in the maximum anticipated hydrogen demand.

Future hydrogen requirements were estimated from the processing requirements shown on Table 1.05 by using typical hydrogen consumption figures for the various processes given in Table 1.06. The hydrogen consumption figures allow for theoretical hydrogen consumption and typically 20% additional for hydrogen purge required to maintain a high hydrogen purity in the process. If the hydrogen is produced by steam reforming, the purge can efficiently be used as part of the feed stream to the reformer. If hydrogen is provided from external sources, the purge would be burned as refinery fuel.

Table 1.07 lists the estimated refinery hydrogen requirements through the year 2000 and the crude oil equivalent of the natural gas feed required to produce this hydrogen by steam reforming. While liquid petroleum feed stock is usually not used as feed or fuel in hydrogen manufacture, reducing hydrogen production would release an equivalent amount of refinery fuel gas or naphtha for alternative use in the refinery and this would result in a reduction in crude requirements. The study shows refinery hydrogen consumption increasing from 0.17 Quad/year in 1977 to 0.56 Quad/year in 2000, if the coking processing sequence is utilized. If hydrocracking is utilized for residuum conversion, the hydrogen required by 2000 would be 1.5 Quad/year.

The hydrogen requirement of 0.17 Quad/year estimated for the year 1977 agrees well with published information on hydrogen producing capacity in U. S. refineries. As of January 1976, the U. S. capacity totaled 0.16 Quad/year with most of this being supplied by steam reforming of methane. Table 1.14 lists existing U. S. refinery hydrogen plants.

If all of the hydrogen required for processing heavy oils were supplied from non-petroleum sources, this would reduce crude imports in the year 2000 by 394,000 B/D assuming coking is employed for residuum processing. If hydrogen treating were employed, crude imports could be reduced by 1,161,000 B/D. These quantities of crude correspond to 4-11% of the projected crude imports in the year 2000. However, this does not suggest that substitution of non-petroleum hydrogen for petroleum produced hydrogen is economically attractive. The economics of hydrogen production are discussed in Section 3. Non-petroleum sources of hydrogen do, though, offer potential means of reducing imported crude if hydrogen can be produced economically.

The production cost of hydrogen by coal gasification is discussed in Section 3. Since the cost varies substantially from one geographical area to another, the refinery hydrogen requirements in various geographical areas are needed to determine the quantities of refinery hydrogen that possibly could be produced by coal gasification. The data in Table 1.08 show the projected crude runs in these four geographical areas: East Coast, Midcontinent, Gulf Coast and the West Coast and Mountain areas. This table also shows the hydrogen requirements per barrel of crude for each area based on the anticipated quality of crude for each area. The table then shows the hydrogen requirements for each of the four geographical areas. In the year 2000, about 12% of the refinery hydrogen will be needed at East Coast refineries, 24% at Midcontinent refineries, 42% at Gulf Coast refineries, and 22% at the refineries on the West Coast and in the Mountain area.

Ammonia Requirements

Table 1.09 presents estimates of U. S. ammonia requirements for the period 1970-2000. These data have been prepared by Chem Systems Inc. and are from Reference 11, page 101. The hydrogen requirements are the stoichiometric quantity of hydrogen (17.8 wt%) contained in ammonia.

Essentially all, if not all, of the current U. S. ammonia capacity employs catalytic steam reforming of natural gas as the hydrogen manufacturing process. The natural gas required for feed stock plus fuel for the manufacture of these quantities of ammonia are shown. These natural gas requirements have been converted to crude oil equivalent using the gross heat of combustion for both fuels.

These estimates of future ammonia requirements are similar to those made in unrelated, independent studies. Growth rates for the 1970-80 and 1980-2000 periods are also shown in Table 1.09 for each of the main ammonia consumption sectors.

About 75% of the total ammonia production was used for fertilizer in 1970. This sector is estimated to grow at 2.9%/year during the 1980-2000 period. The other sectors will have growth rates in the range of 5.4%/year (explosives) and 3.5%/year (all other uses). Overall, the growth rate will be 3.4%/year during the period.

U. S. ammonia plants are listed in Table 1.15 by owner, location, and 1976 capacity. The new plants which have been announced have been added to show capacity in 1980. However, the 1980 capacity has not been adjusted for the shut down of old, obsolete plants since such shutdowns are seldom announced prior to the date of actual shutdown.

Ammonia plants built outside the U. S. using coal gasification as the source of hydrogen are listed in Table 1.16.

Methanol Requirements

Table 1.10 shows current and future U. S. methanol requirements for the 1970-2000 period. These data have been prepared by Chem Systems, Inc. and are presented on page 102 of Reference 11. These estimates are similar to those made by other groups which are not published in the open literature. These data include only the methanol required for the manufacture of various chemicals. They do not include future new uses of methanol as a fuel which have been suggested by various groups.

Essentially all current U. S. methanol plants employ steam reforming of natural gas for synthesis gas manufacture. The "hydrogen equivalent" numbers shown in Table 1.10 are the stoichiometric hydrogen contained in the methanol molecule (12.6 wt%). The natural gas feed stock plus fuel requirements have been converted to crude oil equivalent using the gross heat of combustion for both fuels.

The growth rate for these chemical uses of methanol is expected to average overall about 7.7%/year during the 1970-80 period and 5.4%/year during the 1980-2000 period. Formaldehyde manufacture accounts for about 41% of the total methanol consumption and this segment is expected to grow at 5.9%/year during the 1980-2000 period. Dimethyl terephthalate, a monomer used in synthetic fiber manufacture, and methyl methacrylate, a monomer used in plastics manufacture, are also important methanol consumers.

U. S. methanol manufacturing plants are shown in Table 1.17 by owner, location, and 1976 capacity. Announced capacity additions are also shown. However, current plants that are likely to be shut down are not identified because such shutdowns are seldom announced.

Requirements for Small Uses

In addition to the three major industrial uses (refinery hydrogen, ammonia and methanol manufacture) hydrogen is used for dozens, possibly hundreds of small uses such as chemicals synthesis, metallurgical processing, reducing gas blanketing, semi-conductor and electronic component manufacturing, and vegetable oil hydrogenation (Reference 2). It is beyond the scope of this study to identify all these uses and to indicate the current quantity of hydrogen that is required for each. However, the sum of all these small uses constitutes a major hydrogen market, and the total quantity of hydrogen required for this category has been developed.

The uses for hydrogen in chemical processing other than for the manufacture of ammonia and methanol include the following:

cyclohexane production by benzene hydrogenation
benzene production by toluene hydrodialkylation
production of hexamethylenediamine
production of toluene diamine
production of oxo chemicals
processing of non-edible fats and oils
processing of edible fats and oils
production of aniline
production of hydrogen peroxide

production of tetrahydrofuran
production of soribitol
production of furfuryl alcohol
production of fatty alcohols
production of fatty amines

Non-chemical uses for hydrogen include the following:

pharmaceuticals manufacture
hydrogenation of fats and oils
liquid hydrogen for space vehicle engines and the testing of
  these engines
welding and cutting
direct reduction of ores (iron, tungsten, molybdenum)
production of sintered metal parts
cooling medium in electric generators, large electric motors,
  and frequency generators
reducing atmosphere for fabrication of electronic components
reducing gas atmosphere in float glass manufacture
liquid hydrogen in bubble chambers for nuclear research

Hydrogen used to supply these chemical and other small uses is now made mostly by the catalytic steam reforming of natural gas or some alternate light hydrocarbon feed stock although some of it is produced by electrolysis. Most of the hydrogen consumed for these uses is produced on site but some of it is purchased by the consumer from a producer or distributor and is obtained either by pipeline delivery or by truck delivery as cylinder hydrogen or as liquid hydrogen.

Many of these small uses require high purity hydrogen (99.9%+) and a few of them require ultra-high purity (99.999%+). The highest purity hydrogen is made by molecular sieve processing of reformer hydrogen. Hydrogen purity is of critical importance in vegetable oil processing and the manufacture of semi-conductors and other electronic components.

Data on the small uses of hydrogen are compiled by the Bureau of Census, U. S. Department of Commerce (Reference 12). Data used in these Bureau of Census reports covers well over 98% (possibly over 99%) of the total consumption of hydrogen for these small uses.

The Bureau of Census data for the years 1960 through 1970 are shown in Table 1.11. The total quantity of hydrogen consumed is broken down into that produced by electrolysis and that produced by all other procedures, mainly natural gas or light hydrocarbon steam reforming. The shipments (hydrogen other than that consumed on site) is also shown by the electrolytic and all other categories. Data for the 1960-70 period includes hydrogen of "lower purity," 70-75% of which was used for petroleum refining. These data include the dollar value of the shipments which permits the calculation of the value of shipments as $/MBtu.

In 1970 the Bureau of Census changed the format of the small use hydrogen report to provide the data shown in Table 1.12. The revised format does not include either the low purity hydrogen used for petroleum refining or the data to indicate the production method. However, the revised report includes data to show the method of delivery; e.g., consumed in production plant, shipped by pipeline, and shipped in cylinders or as a liquid. The value of the pipeline and cylinder plus liquid shipments is also shown.

Table 1.13 summarizes these Census Bureau Reports for the 16 year period, 1960-75. These data are plotted in Figure 1.01. The data in Table 1.13 and Figure 1.01 exclude the low purity hydrogen used for petroleum refining shown in the Bureau of Census reports for 1960-1970.

During the 1963-68 period a substantial amount of liquid hydrogen was used in testing liquid hydrogen powered engines for space vehicles. Hydrogen required for this program decreased substantially after 1968.

Table 1.13 also includes a forecast of future small uses requirements to the year 2000 assuming the annual growth rate of this category is 5%/year. These data are further summarized as follows:

<u>Hydrogen Required for All Small Uses</u>

Year	1975	1960	1985	1990	2000
Hydrogen, Quad/year	24	31	40	51	83
Hydrocarbon feed stock Stock required if all were produced by reforming kB/CD	14	21	28	35	56

Data shown in Table 1.11 indicate that the price of purchased "high purity" hydrogen during the 1960-1970 period increased from $3.49 to $5.46/MBtu. The price of purchased cylinder and liquid hydrogen (shown in Table 1.12) increased from $11.07/MBtu in 1970 to $20.09/MBtu in 1975.

Table 1.01

Summary of U. S. Industrial Hydrogen Requirements, 1975-2000 and Natural Gas Feed Stock Required to Produce this Hydrogen by Steam Reforming

Year	1975	1980	1985	1990	2000
Hydrogen Required Quads/Year					
For petroleum refining	0.15	0.21	0.28	0.38	0.56
For ammonia	0.35	0.46	0.55	0.66	0.90
For methanol	0.06	0.08	0.11	0.14	0.23
For all small uses	0.02	0.03	0.04	0.05	0.08
Total	0.58	0.78	0.98	1.23	1.77
Natural Gas Feed Stock Required to Produce, kB/D Crude Equivalent					
Hydrogen for petroleum refining	106	147	197	267	394
Ammonia	268	357	427	511	700
Methanol	63	87	118	155	251
Hydrogen for all small uses	14	21	28	35	56
Total	451	612	770	968	1401

Table 1.02

Comparison of Future Industrial Hydrogen Requirements Estimated in this Study with Those Prepared by Jet Propulsion Laboratory

Data are Quads/Year of Hydrogen

Year	1975	1985	2000
Estimates from this Study			
For petroleum refining	0.15	0.28	0.56
For ammonia	0.35	0.55	0.90
For methanol	0.06	0.11	0.23
For all miscellaneous other uses	0.02	0.04	0.08
Total	0.58	0.98	1.77
Estimates by Jet Propulsion Laboratory (Ref. 2)			
For petroleum refining	0.14	0.35	0.55
For ammonia	0.41	0.73	1.73
For methanol and all other uses	0.13	0.23	0.64
Total	0.68	1.31	2.92

TABLE 1.03

U.S. Energy Demand, 1974-2000

All data are Quads (10^{15} Btu) per year

Year	1974 Actual	1980	1985	1990	2000
Gas	23.5	19.2	19.4	19.6	18.1
Oil	34.0	41.3	44.4	49.9	50.3
Coal	14.8	18.2	20.9	23.6	32.1
Hydro, geothermal, solar	3.3	3.5	3.7	3.7	5.7
Nuclear	1.2	4.7	10.1	17.6	34.5
Total	76.8	86.9	98.5	114.4	140.7

These data were derived from References 9 and 10.

TABLE 1.04

U.S. Liquid Petroleum Supply, 1980-2000

All data are Million B/CD.

Year	1980	1985	1990	2000
Domestic crude oils	8.4	9.5	10.3	10.0
Imported crudes	7.4	6.6	8.8	8.0
Synthetic crudes	-	0.3	0.7	3.0
Total crude processed	15.8	16.4	19.8	21.0
Domestic natural gas liquids	1.2	1.0	0.9	0.8
Total refinery feed stocks	17.0	17.4	20.7	21.8
Imported refined products	3.3	4.4	3.7	3.0
Total liquid petroleum supply	20.3	21.8	24.4	24.8
Imported crude + imported products	10.7	11.0	12.5	11.0
Imported crude and products, % of total liquids	52.7	50.5	51.2	44.4
Total liquid petroleum supply, Quad/yr	41.3	44.4	49.9	50.3

These data were derived from Reference 9.

TABLE 1.05

U.S. Refining Processing Requirements, 1977-2000

All data are million B/CD for U.S. industry

Year	1977	1980	1985	1990	2000 Most Likely	2000* Alternate
Primary distillation	14.5	15.8	16.3	19.8	21.0	21.0
Catalytic cracking	5.3	5.4	5.5	5.8	5.6	5.6
Catalytic reforming	3.4	3.2	4.9	5.0	5.5	5.5
Coking	0.6	0.8	1.3	2.1	3.2	0.6
Gas oil desulfurization	0	1.2	1.9	3.2	5.5	4.6
Residuum hydrocracking	0.6	0.6	0.8	0.9	1.1	4.8
Resid desulfurization	0.1	0.1	0.1	0.3	0.4	1.9

*Based on maximum residuum hydroprocessing.

TABLE 1.06

Hydrogen Consumption in Refining Processes

Process	Hydrogen Consumption SCF/Bbl
Naphtha hydrotreating	10-50
Distillate hydrotreating	50-250
Heavy oil hydrotreating	300-750
Residuum hydrotreating	650-1600
Residuum hydrocracking	1500-3000
Catalytic reforming	(800-1200)*

*Hydrogen production

TABLE 1.07

U.S. Refinery Hydrogen Requirements, 1977-2000

Year	1977	1980	1985	1990	2000 Most Likely	2000 (1) Alternate
Hydrogen Consumed, Million SCF/CD for						
Gas oil desulfurization	--	424	672	1127	1925	1610
Resid desulfurization	120	210	210	385	600	2850
Resid hydrocracking	1265	1150	1522	1746	2200	9600
Total	1385	1784	2404	3258	4725	14060
Total, Quad/yr	0.17	0.21	0.28	0.38	0.56	1.65
Crude oil equivalent of feed stock required to produce this total quantity of hydrogen, kB/CD (2)	120	147	197	267	394	1161

(1) Based on maximum residuum hydroprocessing.
(2) Assuming 70% thermal efficiency for hydrogen manufacture

TABLE 1.08

U.S. Crude Runs and Hydrogen Requirements by Geographical Area

Year	1976	1980	1985	1990	2000
Crude Runs by Geographical Area, MB/CD					
East Coast	1.9	2.0	2.1	2.5	2.6
Midcontinent	4.0	4.3	4.3	5.2	5.4
Gulf Coast	6.8	7.3	7.5	8.9	9.4
West Coast + Mountain	3.2	3.4	3.5	4.1	4.4
Total U.S.	15.9	17.0	17.4	20.7	21.8
Hydrogen Required, SCF/Bbl					
East Coast	63	80	114	136	210
Midcontinent	40	63	109	135	210
Gulf Coast	48	71	112	137	210
West Coast + Mountain	243	244	243	243	243
Total U.S. (average)	87	105	138	157	217
Required Hydrogen, MSCF/CD					
East Coast	120	160	240	340	545
Midcontinent	160	270	470	700	1135
Gulf Coast	325	520	840	1220	1975
West Coast + Mountain	780	830	850	1000	1070
Total U.S.	1385	1780	2400	3260	4725

TABLE 1.09

U.S. Ammonia Requirements

Year	1970	1975	1980	1990	2000
Million ST/yr of NH_3 for					
Fertilizer	10.3	11.2	15.0	20.4	26.6
Synthetic fibers and plastics	0.9	1.8	2.6	4.1	6.4
Explosives	0.5	0.6	0.7	1.2	2.0
Livestock feed	0.4	0.7	1.1	2.0	3.0
All other uses	1.6	1.7	1.9	2.8	3.8
TOTAL	13.7	16.0	21.3	30.5	41.8
Hydrogen equivalent, Quad/yr	0.295	0.345	0.459	0.658	0.901
Natural gas feed required, Quad/yr	0.465	0.544	0.724	1.037	1.421
" " " " , MB/CD crude oil equivalent	0.229	0.268	0.357	0.511	0.700

Growth Rates, %/yr	1970-80	1980-2000
Fertilizer	3.8	2.9
Synthetic fibers & plastics	11.2	4.6
Explosives	3.4	5.4
Livestock feed	10.7	5.1
All other uses	1.7	3.5
TOTAL	4.5	3.4

Data from Reference 11, page 101. In this reference the data are erroneously reported as billion pounds per year. They should be labeled million ST/year.

TABLE 1.10

U.S. Methanol Requirements

Current Chemical Uses Only

Year	1970	1975	1980	1990	2000
Million Gallons Per Year for					
formaldehyde	313	440	640	1210	2020
dimethylterephthalate	95	170	260	640	1200
methyl amines	32	45	65	100	140
methyl halides	24	31	45	60	80
methyl methacrylate	25	35	50	100	170
solvents	42	50	60	80	110
acetic acid	32	80	130	210	280
miscellaneous	202	299	350	450	600
TOTAL	765	1150	1600	2850	4600
Total, million ST/yr	2.54	3.81	5.30	9.45	15.25
Hydrogen equivalent, Quad/yr	0.039	0.058	0.081	0.144	0.233
Natural gas feed required, Quad/yr	0.085	0.127	0.177	0.315	0.510
" " " " , MB/D oil equiv.	0.042	0.063	0.087	0.155	0.251

Growth Rates, %/yr	1970-80	1980-2000
formaldehyde	7.4	5.9
dimethylterephthalate	10.6	3.2
methyl amines	7.3	3.9
methyl halides	6.5	2.9
methyl methacrylate	7.2	6.3
solvents	3.6	3.1
acetic acid	15.0	3.9
miscellaneous	5.7	2.7
TOTAL	7.7	5.4

Data from Reference 11, page 102.

TABLE 1.11

U.S. Small Uses Hydrogen Market 1960-70 (Page 1 of 2)(1)

Year	1960	1961	1962	1963	1964	1965
Hydrogen Production, Million SCF/yr.(2)						
Electrolytic	10292	10535	11086	12553	12593	12813
Other high purity	2986	2932	4251	10114	13022	17301
Total high purity	13278	13467	15337	22667	25615	30114
Lower purity	51958	51768	57721	72941	82355	91521
Total hydrogen consumption	65236	65235	73058	95608	107970	121635
Shipments, Million SCF/yr.						
Electrolytic	7804	7814	*	*	*	8496
Other high purity	327	315	*	*	*	14364
Total high purity	8131	8129	9284	15656	18548	22860
Lower purity	3751	3472	3294	4292	4997	3112
Total hydrogen shipments	11882	11601	12578	19948	23545	25977
Value of Shipments, $/MBtu						
Electrolytic hydrogen	3.51	3.78	*	*	*	2.78
Other high purity	2.86	3.41	*	*	*	6.22
Total high purity	3.49	3.77	4.90	4.75	5.60	4.94
Lower purity	1.12	1.07	0.81	0.75	0.89	0.99
Total hydrogen shipments	2.74	2.96	3.83	3.89	4.60	4.48

* Not available

TABLE 1.11

U.S. Small User Hydrogen Market (1960-70) (Page 2 of 2)

Year	1966	1967	1968	1969	1970
Hydrogen Production, Million SCF/yr.(1)					
Electrolytic	13709	14374	13656	14444	11534
Other high purity	21785	19714	21043	17756	17357
Total high purity	35494	34088	34699	32180	28891
Lower purity	102225	124451	167053	32641	30763
Total hydrogen consumption	137719	158539	201752	64821	59654
Shipments, Million SCF/yr.					
Electrolytic	9446	9693	9359	10202	7265
Other high purity	18403	15914	16228	12876	11831
Total high purity	27849	25607	25587	23078	19096
Lower purity	2800	2059	2668	2378	1844
Total hydrogen shipments	30649	27666	28255	25456	20940
Value of Shipments, $/MBtu					
Electrolytic hydrogen	3.56	3.51	3.28	2.99	4.02
Other high purity	5.09	5.16	4.99	6.38	6.34
Total high purity	4.57	4.53	4.37	4.88	5.46
Lower purity	0.92	1.05	0.95	1.04	1.46
Total hydrogen shipments	4.24	4.27	4.04	4.52	5.10

Note 1 Data from Bureau of Census, U.S. Dept. of Commerce, Reference 12

Note 2 These data are for all hydrogen produced and consumed in the U.S., except that used for fuel, vented, used in the manufacture of ammonia and methanol, and for petroleum refining. Part (70 to 75%) of the lower purity hydrogen shown herein for years through 1969 was used in petroleum refining.

TABLE 1.12

U.S. Small Uses Hydrogen Market 1971-75(1)

Year	1971	1972	1973	1974	1975
Hydrogen Production, Million SCF/yr.(2)					
Consumed in production plant	38015	40596	46093	52221	45890
Shipped by pipeline	12312	13539	13416	21860	20780
Shipped in cylinders and as liquid	5311	4755	5659	7455	6882
Total	55639	58890	65168	81536	73552
Value of Shipments, $/MBtu					
Shipped by pipeline	3.05	2.51	2.41	2.99	3.42
Shipment in cylinders and as liquid	11.07	12.30	14.86	21.56	20.09
Total shipments	5.48	5.10	6.09	7.71	7.76

Note 1 Data from Bureau of Census, U.S. Dept. of Commerce, Reference 12

Note 2 These data are for all hydrogen produced and consumed in the U.S., except that used for fuel, vented, used in the manufacture of ammonia and methanol, and for petroleum refining.

TABLE 1.13

Summary of U.S. Small Uses Hydrogen Market, 1960-75(1)

data are MBtu/yr. x 10^6

Year	Produced by Electrolysis	Other High Purity	25% of Low Purity	Consumed on site	Shipped by Pipeline	Shipped as Liquid or Cylinders	Total Small User Market
1960	3.4	1.0	4.3	-	-	-	8.7
1961	3.5	1.0	4.3	-	-	-	8.8
1962	3.7	1.4	4.8	-	-	-	9.9
1963	4.2	3.3	6.0	-	-	-	13.5
1964	4.2	4.3	6.8	-	-	-	15.3
1965	4.2	5.7	7.6	-	-	-	17.5
1966	4.5	7.2	8.5	-	-	-	20.2
1967	4.8	6.5	10.3	-	-	-	21.6
1968	4.5	7.0	13.8	-	-	-	25.3
1969	4.8	5.9	10.8	-	-	-	21.5
1970	3.8	5.8	10.2	-	-	-	19.8
1971	-	-	-	12.6	4.1	1.8	18.5
1972	-	-	-	13.4	4.5	1.6	19.5
1973	-	-	-	15.3	4.4	1.9	21.6
1974	-	-	-	17.3	7.2	2.5	27.0
1975	-	-	-	15.2	6.9	2.3	24.4
1980		5%/yr. growth rate					31
1985		5%/yr. growth rate					40
1990		5%/yr. growth rate					51
1995		5%/yr. growth rate					65
2000		5%/yr. growth rate					83

(1) Data from Bureau of Census, U.S. Dept. of Commerce, Reference 12.

FIGURE 1.01

U.S. Small Uses Hydrogen Market

1960-75

Data from Bureau of Census,
U.S. Dept. of Commerce

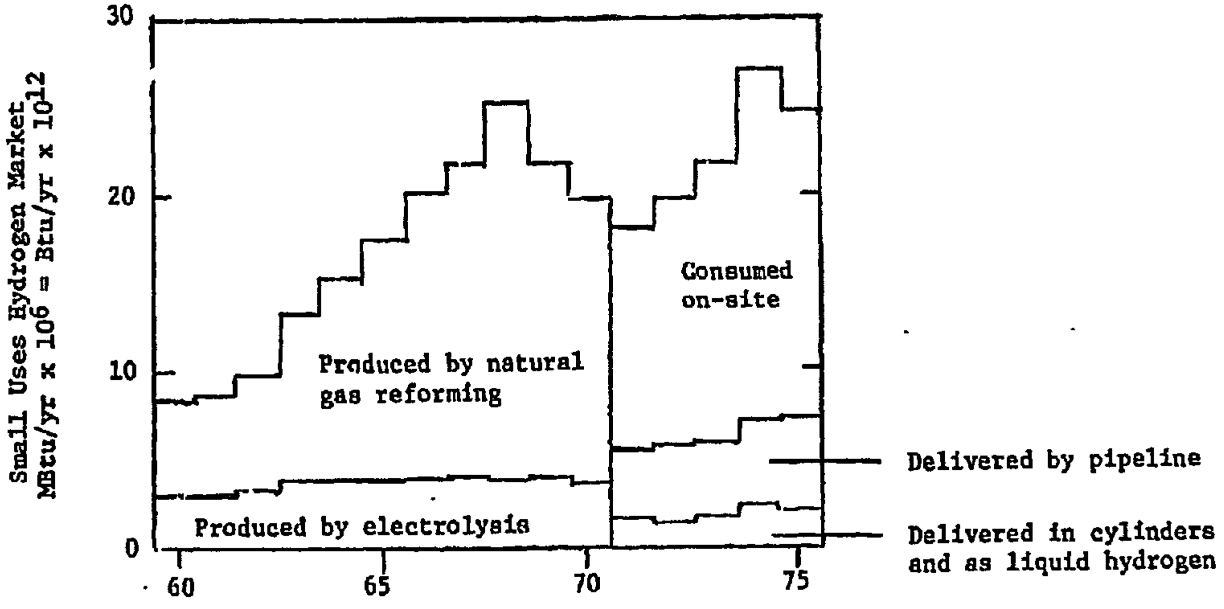

TABLE 1.14 (Page 1 of 2)

U.S. Refinery Hydrogen Plants as of January, 1976

Company	Location	Capacity, MSCF/SD	Process Type
Apco Oil Corp.	Arkansas City, Kan.	4.2	1
Atlantic Richfield	Carson, Cal.	50.0	1
	Philadelphia, Pa.	45.0	1
	Cherry Point, Wash.	60.0	1
Exxon	Benicia, Cal.	104.0	1
	Billings, Mont.	16.7	4
Cross Oil & Ref. Co.	Smackover, Ark.	2.9	1
Gary Western Co.	Fruita, Col.	1.0	1
Getty Oil	Delaware City, Del.	72.0	1
Gulf Oil	Sante Fe Springs, Cal.	12.0	4
	Port Arthur, Tex.	28.0	1
Kerr McGee	Wynnewood, Okla.	9.5	1
Marathon	Robinson, Ill.	25.0	1
Mobil	Torrence, Cal.	55.0	1
	Beaumont, Tex.	60.0	1
Quacker State	Newell, W. Vir.	1.2	1
Shell	Martinez, Cal.	65.0	1
	Wood River, Ill.	57.0	1
	Norco, La.	51.0	1
	Deer Park, Tex.	71.0	1
Standard Oil, Cal.	El Segundo, Cal.	67.5	2
	El Segundo, Cal.	57.5	3
	Richmond, Cal.	135.0	2
	Barkers Point, Ha.	2.5	1
Standard Oil, Kentucky	Pascagoula, Miss.	109.0	2
Standard Oil, Ohio	Toledo, Ohio	24.0	1
Sun Oil	Duncan, Okla.	50.0	1

TABLE 1.14 (Page 2 of 2)

Company	Location	Capacity, MSCF/SD	Process Type*
Tenneco	Chalmette, La.	22.0	1
Texaco	Wilmington, Cal.	48.0	3
Toscopetro Corp.	Bakersfield, Cal.	20.0	1
Union Oil	Los Angeles, Cal.	49.4	1
	Rode, Cal.	70.0	1
	Total Capacity. MSCF/D	1445.4	

*Process Type

1 - Methane Steam Reforming
2 - Naphtha Steam Reforming
3 - Partial Oxidation
4 - Other

(1) Reference: Oil & Gas Journal, Vol. 74, No. 13, 3-29-76.

TABLE 1.15 (Page 1 of 4)

U.S. Ammonia Capacity, 1976-80

Company	Location	Capacity K ST/yr of NH_3 1976	1980
Agrico Chemical Co.	Blytheville, Ark.	349	349
" " "	Donaldsonville, La.	349	772
" " "	Tulsa, Okla.	423	845
Air Products & Chemicals, Inc.	New Orleans, La.	230	313
" " " "	Pensacola, Fla.	90	90
Allied Chemical Corp.	Geismar, La.	329	329
" " "	Hopewell, Va.	329	329
" " "	La Platte, Neb.	203	203
" " "	South Point, Ohio	135	135
American Cyanamid Co.	Fortier, La.	348	348
Amoco International Oil Co.	Texas City, Tex.	769	769
Apache Powder Co.	Benson, Ari.	15	15
Atlas Powder Co.	Joplin, Mo.	134	134
Baker Industries Corp.	Carlsbad, N.M.	199	342
" " "	Conda, Idaho	99	99
Borden Chemical Co.	Geismar, La.	329	329
CF Industries, Inc.	Donaldsonville, La.	658	1051
" " "	Fremont, Neb.	40	40
" " "	Terre Haute, Ind.	115	115
Cherokee Nitrogen	Pryor, Okla.	52	52
Chevron Chemical Co.	Ft. Madison, Iowa	99	99
" " "	Pascagoula, Miss.	494	494
" " "	Richmond, Cal.	118	118
Collier Carbon & Chemical Co.	Kenai, Alaska	519	1013
" " " "	Wilmington, Cal.	259	259
Columbia Nitrogen Corp.	Augusta, Ga.	118	614
Cominco American Inc.	Borger, Tex.	399	399
Commercial Solvents Corp.	Sterlington, La.	342	342
Co-op Farm Chemical Association	Lawrence, Kan.	328	328

TABLE 1.15 (Page 2 of 4)

U.S. Ammonia Capacity, 1976-80

Company	Location	Capacity K ST/yr of NH_3	
		1976	1980
Diamond Shamrock Corp.	Sunray, Tex.	161	161
Dow Chemical Co.	Freeport, Tex.	115	115
E. I. Du Pont de Nemours	Beaumont, Tex.	329	329
" " " " " "	Belle, W. Va.	329	329
" " " " " "	Victoria, Tex.	99	99
El Paso Products Co.	Odessa, Tex.	108	108
Farmers Chemical Association, Inc.	Tunis, N.C.	198	198
" " " "	Tyner, Tenn.	149	149
Farmers National Chemical Inc.	Plainview, Tex.	60	60
Farmland Industries	Alexandria, La.	—	424
" "	Dodge City, Kan.	198	198
" "	Enid, Okla.	396	820
" "	Ft. Dodge, Iowa	198	198
" "	Hastings, Neb.	122	122
Fremont Oil Co.	Olean, N.Y.	79	79
FIRSTMISS INC.	Ft. Madison, Iowa	354	354
FMC Corp.	Charleston, W. Va.	20	20
Frontier Chemical Co.	Wichita, Kan.	23	33
Gardinier Inc.	Helena, Ark.	198	198
" "	Tampa, Fla.	130	130
Goodpasture Inc.	Dimmitt, Tex.	70	70
W. R. Grace, Inc.	Big Spring, Tex.	88	88
" " " "	Memphis, Tenn.	329	329
Grun Valley Chemical Corp.	Criston, Iowa	35	35
Hawkeye Chemical Co.	Clinton, Iowa	132	132
Hercules, Inc.	Hercules, Cal.	70	70
" "	Louisiana, Mo.	70	70
Hooker Chemical Corp.	Tacoma, Wash.	21	21

TABLE 1.15

(Page 3 of 4)

U.S. Ammonia Capacity, 1976-80

Company	Location	Capacity K ST/yr of NH_3 1976	Capacity K ST/yr of NH_3 1980
International Mineral & Chemical Corp., Inc.	Sterlington, La.	—	379
Kaiser Aluminum & Chemical Corp.	Savannah, Ga.	214	214
Mississippi Chemical Co.	Pascagoula, Miss.	181	181
" " "	not avail.	—	379
" " "	Yazoo City, Miss.	388	388
Mobil Chemical Co.	Beaumont, Tex.	290	290
Monsanto Co.	El Dorado, Ark.	230	230
" "	Luling, La.	437	839
New Jersey Zinc Co.	Palmerton, Pa.	32	32
Nipak Inc.	Kerens, Tex.	106	106
" "	Pryor, Okla.	99	99
Occidental Chemical Co.	Lathrop, Cal.	169	169
" " "	Plainview, Tex.	52	52
" " "	Taft, La.	110	110
Oklahoma Nitrogen Co.	Woodward, Okla.	—	396
Olin Corp.	Lake Charles, La.	460	460
Pennsalt Chemicals Inc.	Portland, Ore.	7	7
Pennzoil Chemicals Inc.	Hanford, Cal.	40	40
Phillips Pacific Chemical Co.	Kennewick, Wash.	150	150
Phillips Petroleum Co.	Pasadena, Tex.	227	227
" " "	Beatrice, Neb.	209	209
PPG Industries	Natrium, W. Va.	47	47
Reichold Chemicals Co.	St. Helens, Ore.	83	83
Rohm and Haas Co.	Deer Park, Tex.	91	91
J. R. Simplot and Co.	Pocatello, Idaho	104	104
St. Paul Ammonia Products Inc.	East Dubuque, Ill.	230	230

TABLE 1.15

(Page 4 of 4)

U.S. Ammonia Capacity, 1976-80

Company	Location	Capacity K ST/yr of NH_3 1976	1980
Tenneco Manufacturing Co.	Houston, Tex.	198	198
Terra Chemicals International Inc.	Port Neal, Iowa	206	206
Tipperary Corp.	Lovington, N.M.	35	102
Triad Chemicals Inc.	Donaldsonville, La.	388	388
Tennessee Valley Authority	Muscle Shoals, Ala.	74	74
USS Agri Chemicals Inc.	Cherokee, Ala.	165	165
" " " "	Clairton, Pa.	377	377
" " " "	Geneva, Utah	65	65
Valley Nitrogen Products Inc.	Chandler, Ariz.	40	40
" " " "	El Centro, Cal.	221	221
" " " "	Helm, Cal.	201	201
Vistron Corp.	Lima, Ohio	498	498
Wycon Chemical Co.	Cheyenne, Wyo.	131	131
	TOTAL	18,507	23,442

TABLE 1.16

Foreign Ammonia Plants Using Coal Gasification Technology

Company, Location	Capacity k ST NH_3/yr Winkler	Lurgi	Koppers-Totzek	Year Construction Started
Azot Gorazde, Yugoslavia	18	-	-	1950
Empreso Nacional Calvo, Spain	51	-	-	1950
Azot Sanayii, Turkey	44	-	-	1950
Typpi Oy, Finland	-	-	22	1950
Nippon Suiso, Onahama, Japan	-	-	37	1954
Empreso Nacional Calvo Sotelo, Spain	-	-	37	1954
Typpi Oy, Finland	-	-	22	1955
Daudhkel, Pakistan	-	22	-	1956
Nitrogenous Fertilizer, Greece	-	-	110	1959
Neyveli, South Ascot, India	110	-	-	1960
Naju Fertilizer, Korea	-	55	-	1962
Chemical Fertilizer, Mae Moh, Thailand	-	-	37	1963
Azot Sanayii, Kutahya, Turkey	-	-	92	1966
Industrial Development Corp., Zambia	-	-	37	1966
Nitrogenous Fertilizer, Greece	-	-	27	1969
Fertilizer Corp. of India, Ramagundam, India	-	-	329	1969
" " of " , Talcher Plant, India	-	-	329	1970
Nitrogenous Fertilizer, Greece	-	-	55	1970
Fertilizer Corp. of India, Korba Plant, India	-	-	329	1972
AE&Cl Ltd., Republic of South Africa	-	-	365	1972
Industrial Development Corp., Zambia	-	-	100	1974
TOTALS	223	77	1928	

From Reference 16.

TABLE 1.17

U.S. Methanol Manufacturing Plants

	Capacity, Million Gal/yr.		
	As of 1/1/76	Announced Additions	Total After Additions
Du Pont - Orange, Tex.	115	-	115
- Beaumont, Tex.	200	-	200
- Houston, Tex.	-	400	400
Celanese - Bishop, Tex.	60	100	160
- Clear Lake, Tex.	230	-	230
- Southeastern New Mex.	-	225	225
Borden - Geismar, La.	160	-	160
Georgia Pacific - Plaquemine, La.	100	-	100
Hercules - Iberville Parish, La.	100	-	100
Monsanto - Texas City, Tex.	100	-	100
Tenneco - Pasadena, Tex.	80	-	80
Air Products - Pace, Fla.	50	-	50
Commercial Solvents - Sterlington, La.	50	-	50
Rohm & Haas - Deer Park, Tex.	22	-	22
TOTALS	1267	725	1992

2. BASES FOR ECONOMIC STUDIES

The following paragraphs discuss the processes, assumptions, and procedures used in conducting these economic studies.

Processes Studied

Current state-of-the-art processes for hydrogen manufacture are natural gas or light hydrocarbon catalytic steam reforming (hereafter called steam reforming); resid partial oxidation; Koppers-Totzek coal gasification (hereafter called K-T); and water electrolysis using KOH electrolyte. Several other coal gasification processes are being developed for hydrogen manufacture. These include a high pressure oxidation process being developed by Texaco; a similar process being developed jointly by Shell and Koppers-Totzek; and the U-Gas and Steam-Iron processes being developed by the Institute of Gas Technology. These IGT processes are discussed in Chapter VII of Reference 2.

Steam reforming has been gradually improved during its many years of commercial use. In this process a light hydrocarbon feed stock such as methane is reacted with steam in the presence of nickel catalyst at about 1500°F and 250 psig to produce synthesis gas, a mixture of carbon monoxide and hydrogen:

$$CH_4 + H_2O \longrightarrow CO + 3H_2 \qquad (1)$$

The energy required for reaction (1) is transferred to the feed stock and steam across furnace tubes. Some of the hydrocarbon feed stock is used as fuel for the furnace to provide the required heat input. The products of reaction (1) are then cooled and reacted with additional steam in the shift reaction which is conducted at about 660°F in the presence of metallic iron catalyst:

$$CO + H_2O \longrightarrow CO_2 + H_2 \qquad (2)$$

The overall reaction is therefore:

$$CH_4 + 2H_2O \longrightarrow CO_2 + 4H_2 \qquad (3)$$

Half of the hydrogen product is provided by the methane feed stock and the other half is provided by the steam. Hydrogen can be produced from any light hydrocarbon feed stock that can be vaporized, but methane is the most desirable feed stock because it has the highest H/C ratio of any of the hydrocarbons.

Partial oxidation typically employs a heavy black oil residue feed stock that cannot be vaporized. The resid feed stock (H/C = 1.8) is reacted with steam and oxygen in a gasification (partial oxidation) reactor operated at about 2400°F. The resid conversion can be described by the reactions:

$$CH_{1.8} + H_2O \longrightarrow CO + 1.9\ H_2 \qquad (4)$$

$$CH_{1.8} + 1.45\ O_2 \longrightarrow CO_2 + 0.9\ H_2O \qquad (5),$$

and by the water gas shift, reaction (2). The heat required for the endothermic reaction (4) is supplied by the oxidation reaction (5). Oxygen is used instead of air to avoid diluting the synthesis gas with nitrogen. The products from the gasification reactor are cooled to about 700°F and the CO is shifted to H_2 as in reaction (2). The overall reaction for resid partial oxidation is therefore:

$$CH_{1.8} + 0.98\ H_2O + 0.51\ O_2 \longrightarrow CO_2 + 1.88\ H_2 \qquad (6)$$

Hydrogen production from coal is a partial oxidation process similar to resid partial oxidation but is substantially more difficult to conduct because coal, a solid, is difficult to handle, is relatively unreactive, and requires the removal of ash from the gasification reactor. These solid handling requirements involve substantially higher operating costs than with resid feed stock. Another difficulty with coal feed is that the H/C ratio of about 0.8 is much lower than in resid or methane.

For coal feed, as for resid partial oxidation, the hydrogen is produced by reforming, oxidation and shift reactions:

$$CH_{0.8} + H_2O \longrightarrow CO + 1.4\ H_2 \qquad (7)$$

$$CH_{0.8} + 1.2\ O_2 \longrightarrow CO_2 + 0.4\ H_2O \qquad (8)$$

$$CO + H_2O \longrightarrow CO_2 + H_2 \qquad (9)$$

The overall reaction for producing hydrogen from coal is therefore:

$$CH_{0.8} + 0.70\ O_2 + 0.60\ H_2O \longrightarrow CO_2 + H_2 \qquad (10)$$

For coal feed the gasification reactor is typically run at 2700°F. The heat required for the gasification reaction (7) is supplied by burning part of the coal with oxygen; reaction (8). When substitute natural gas (SNG) is the desired product, coal is gasified at a lower temperature compared to that required for hydrogen production. A higher overall thermal efficiency occurs in the SNG operation.

As in hydrogen manufacture, the first step in ammonia manufacture is the production of synthesis gas by either steam reforming, resid partial oxidation or coal gasification. When steam reforming is used, air is added to the synthesis gas to supply the required nitrogen. Oxygen in the air reacts with some of the synthesis gas to release additional heat needed to complete the reforming reaction. This gas is then cooled and the CO is shifted (Reaction 2) to provide additional hydrogen. The shifted gas is then further cooled; CO_2 is removed and residual CO and CO_2 are removed by methanation using a nickel catalyst at about 600°F:

$$CO + 3H_2 \longrightarrow CH_4 + H_2O \qquad (11)$$

$$CO_2 + 4H_2 \longrightarrow CH_4 + 2H_2O \qquad (12)$$

When resid partial oxidation or coal gasification are used to produce the synthesis gas, the gas from the gasifier is cooled and then shifted to convert CO to additional hydrogen. The CO_2 is then removed and high purity nitrogen from the air separation is then added.

The ammonia synthesis gas then is compressed to 2000 - 4500 psig and sent to the synthesis reactor where ammonia is formed at about 900°F over a promoted iron catalyst:

$$N_2 + 3H_2 \longrightarrow 2NH_3 \qquad (13)$$

Methanol is produced by the reaction of hydrogen with carbon monoxide or carbon dioxide at 750-1500 psi and at 400-600°F over a catalyst:

$$2H_2 + CO \longrightarrow CH_3OH \qquad (14)$$

$$3H_2 + CO \longrightarrow CH_3OH + H_2O \qquad (15)$$

The synthesis gas feed can be produced by either methane reforming, resid partial oxidation or coal gasification. With methane reforming the synthesis gas has a H_2/CO ratio of about 3.0 (Reaction 1). To utilize all of the H_2 in the synthesis gas, this ratio must be corrected by the addition of CO_2 from an outside source. Most existing methanol plants, however, designed based on relatively low cost natural gas, take a high hydrogen content purge stream from the methanol plant to maintain the correct gas ratio.

If the synthesis gas is obtained by resid partial oxidation or coal gasification, the H_2/CO ratio is below 2.0 and this is corrected by shifting only a portion of the raw synthesis gas and then combining the two streams. Some of the remaining CO_2 is usually removed by scrubbing. This gas stream is then compressed and sent to the methanol synthesis reactor.

The K-T process is used commercially to produce hydrogen from coal for use in ammonia manufacture at 15 plants located outside the U.S. (see Table 1.16). This process is discussed in References 4 and 16. In the K-T process, finely ground coal is gasified with oxygen and steam at about 2700°F and atmospheric pressure to produce synthesis gas, a mixture of H_2, CO, CO_2, H_2O, H_2S, COS, and SO_2. The gases are compressed to about 300 psig and then processed for CO shift conversion to H_2 and CO_2 and H_2S removal. This product gas is either produced as H_2 gas or is processed further for ammonia or methanol manufacture.

The investment and operating costs for the K-T gasification process could be reduced by operating the gasifier at say 450 psig. This would reduce the physical size of the gasifier vessels and would reduce the costs of gas compression. Pressurized operation of the gasifier would, however, require facilities for forcing the pulverized coal feed into the 450 psig gasifier vessel and removing the ash from this vessel. In this study the investment and operating costs for the pressurized gasification method have been estimated and these costs are referred to hereafter as the <u>new coal process</u>. To provide the economic advantages over K-T assumed in this study, the new coal process should have the following characteristics:

1. Gasification would be conducted at 400-500 psig;
2. A single gasifier would convert 2500 T/D of coal to high yields of synthesis gas with essentially zero methane content;
3. The gasifier would operate above 2000°F to minimize methane production;
4. The gasifier would provide 95%+ conversion of coal to synthesis gas.

Koppers and Shell are jointly developing a gasifier that will achieve these objectives. The Texaco gasifier has been proven on commercial scale for hydrocarbon feed stocks and extensive operations with coal have been conducted in a large pilot unit operated at 300 psig and 100 T/D coal feed rate. Another Texaco pilot plant has been operated with 15 T/D coal feed at pressures up [illegible] 2500 psig. Commercial scale operation of the Texaco gasifier with coal has not yet been conducted; however, this extensive development work is likely to result in the construction of a full scale gasifier in the 1977-79 period. It has been assumed, therefore, that the new coal gasification process will be available for commercial use in the 1980-81 period.

The light hydrocarbon reforming, resid partial oxidation, and coal gasification plants assumed in these economic studies are essentially self-contained plants complete with oxygen plants, and the utility systems are essentially in balance. Details concerning the utility systems are presented on pages 6-8 of Appendix A.

Current state-of-the-art water electrolysis plants require very large investments. Although electricity is the main component of the cost of electrolytic hydrogen, costs associated with the plant investment are very significant. Costs included in this study for current state-of-the-art electrolysis facilities are indicative of the equipment supplied by Lurgi or Teledyne but are not intended to relate to a specific process.

It is quite likely that electrolysis costs can be reduced significantly by making the electrolysis modules more compact, by operating the equipment under pressure (say 450-500 psig) and by improving the electrolysis mechanism to provide for higher thermal efficiency. In this study, such a "new" electrolysis process has been included to indicate the reduction in electrolysis costs that possibly could be achieved with further R&D work. The "new" electrolysis process involves costs similar to those that have been suggested for the GE Solid Polymer Electrolyte process (Reference 18) but it is possible that such an improvement in costs could be achieved by other groups conducting R&D on electrolysis.

Hydrogen storage using iron-titanium alloy has been studied extensively by Brookhaven National Laboratory (Reference 19). The investment and operating costs for hydrogen storage using this process are discussed in Reference 20. The costs of storage used in this study have been arrived at using this Brookhaven information.

Escalation Rates

Predictions in this study regarding the use of petroleum, coal, and electrolysis for the manufacture of hydrogen and its derivatives are based primarily on the estimated future costs for manufacturing these products during 1980-2000, the period of interest. Estimating future manufacturing costs involves making assumptions regarding future costs of natural gas, oil products, coal, electricity, construction costs, and other factors. Assumptions made concerning these economic factors are summarized in Table 2.01 and are discussed in the paragraphs that follow.

During the 1980-2000 period, the general or overall rate of inflation of all commodities including coal, electricity, and construction costs is assumed to average 5% per year.

Prices of natural gas and petroleum products delivered to large industrial customers are assumed to escalate at 6-1/2% per year during this period. This higher rate, compared to the general inflation rate, is probable because of:

- The decreasing domestic production of these products;
- Increasing demand for these products;
- Prices of imported gas, crude oil, and refined products will follow the inflation rate of the free world rather than that of the U.S.;
- The high cost of synthetic products manufactured from coal and/or oil shale.

Estimates of future costs for hydrogen, ammonia and methanol have been calculated for the period 1980-2000 using 1980 \$. The procedure involves comparing escalation rates during this period for each component of total cost with the general escalation rate of 5.0% per year for the general economy. Thus, if natural gas increases at 6.5% per year, the natural gas price for 1980 in 1980 \$ is increased by about 1.5% per year to obtain the natural gas price (in 1980 \$) for the year in question. For example, assume the natural gas price in 1980 (1980 \$) is \$3.15 per million Btu. The price in the year 2000 would then be:

$$\$3.15 \times (1.065)^{20} = \$11.10 \text{ in current (2000) } \$$$

$$\frac{11.10}{(1.05)^{20}} = \$4.18 \text{ in 1980 } \$.$$

Energy Prices

Table 2.02 and Figures 2.01, 2.02, and 2.03 show the prices of natural gas, resid fuel oil, electricity and coal used in this study. The prices are presented on the basis of the "most likely" price; the "minimum" price and the "maximum" price. Various other studies (References 1, 2, and 3) suggest prices that cover a rather broad range. In general, the most likely prices are those suggested by Chem Systems Inc. (Appendix A) and Exxon Co. USA; the minimum prices are those suggested by FEA (Reference 14) and the President's Council on Wage and Price Stability (Reference 15); the maximum prices are those suggested by A. D. Little (Reference 13).

The prices of natural gas or an alternate light hydrocarbon reformer feed, resid, and electricity are assumed to apply to all geographical locations in the U.S. However, delivered coal prices vary from one geographical location to another. Mine month coal prices are affected by mining requirements and the transportation cost for moving the coal to manufacturing sites is proportional to this distance.

Coal prices delivered to manufacturing sites on the East Coast, the Mid-Continent (Illinois), the Gulf Coast and the West Coast were estimated according to the data shown in Table 2.03. The estimated transportation cost using unit trains was added to the estimated mine month coal prices to provide estimated prices of coal delivered to the manufacturing sites.

High sulfur coal would be the optimum feed stock for coal gasification plants since the sulfur content of the feed stock has little effect on manufacturing costs and high sulfur coal will probably be priced substantially below low sulfur coals of equivalent heating value.

Cost Estimates by Chem Systems, Inc.

Chem Systems, Inc. of New York City provided as an input to this study investment and operating costs as of mid-year 1980 for the following processes:

Hydrogen Manufacture by

- methane reforming
- resid partial oxidation
- K-T coal gasification
- "new" coal gasification
- SPE electrolysis

Ammonia Manufacture by

- methane reforming
- resid partial oxidation
- K-T coal gasification
- "new" coal gasification

Methanol Manufacture by

- methane reforming
- resid partial oxidation
- K-T coal gasification
- "new" coal gasification

These data prepared by Chem Systems Inc. are consistent for the several products and processes thus permitting the cost of products to be compared using 1980 $ during the 1980-2000 period. The Chem Systems data are presented verbatim in Appendix A.

The investments presented in the Chem Systems report represent the "instantaneous" cost for a new grass roots plant starting up in mid-year 1980. These costs are arrived at by estimating materials costs, labor, etc., and assuming the plant is constructed "overnight" in the mid-1980 period. This procedure provides somewhat higher costs than would occur if construction occurred over a period of 24-30 months. However, this procedure does not require the addition of interest charges during construction. Thus, these two factors essentially off-set one another.

These Chem Systems investments include a contingency item which is normally added to the basic estimate to provide for startup and other unforeseen difficulties. Included in the Chem Systems data for hydrogen manufacture are contingencies of 10% for methane steam reforming, 15% for resid partial oxidation, 15% for K-T coal gasification, 20% for new coal gasification, and 30% for SPE electrolysis.

Financial Structure

All economics data prepared in this study assume 100% equity ownership of the manufacturing facility; the purchase of natural gas. oil, coal, and electricity feed stocks at their market price; and a before tax return of 20%/year on total plant investment. The working capital is assumed to be borrowed at an interest rate of 10%/year. Working capital requirements are approximately equal to the costs incurred over a period of two months (1/6 of annual charges) for feed stock, utilities, and labor and supervision.

Sensitivities

Costs for manufacturing hydrogen or ammonia or methanol by the several processes are affected by several variables of primary importance such as investment and feed stock cost which are included directly in the calculations. Several other factors which may also be important have been included in the calculations by showing their effect on manufacturing costs as sensitivities. Factors handled in this way are as follows:

1. The effects of variations in feed stock price from the low price level to the high price level;
2. The effect of a 10% higher investment than those assumed;
3. The effect of construction costs escalating 1%/yr above the general inflation rate, and 1%/yr below the general inflation rate;
4. The effect of coal prices escalating 1%/yr above and 1%/yr below the general inflation rate.

TABLE 2.01

Escalation Rates Assumed for 1980-2000 Period

	During 1980-2000 Period
Average annual rate of increase in costs and prices, %/yr.	
For general economy	5.0
Natural gas (delivered)	6.5
Crude oil and refined products	6.5
Electricity	5.0
Coal, delivered, most likely	5.0
" " , lower sensitivity	4.0
" " , higher "	6.0
Construction costs, most likely	5.0
" " , lower sensitivity	4.0
" " , higher "	6.0

TABLE 2.02

Assumed Prices of Natural Gas, High Sulfur Resid, Coal, and Electricity Delivered to Large Industrial Customers, 1980-2000

All data are 1980 $

	Pricing Unit	Minimum Price		Most Likely Price		Maximum Price	
		1980	2000	1980	2000	1980	2000
Intrastate natural gas	$/MBtu	2.50	3.37	3.15	4.24	3.40	4.58
High sulfur resid	$/bbl	10.00	13.47	15.00	20.20	17.50	23.57
" " "	$/MBtu	1.57	2.11	2.35	3.17	2.75	3.70
Electricity, continuous	$/kwhr	0.020	0.020	0.027	0.027	0.030	0.030
" "	$/MBtu	5.85	5.85	7.91	7.91	8.78	8.78
Electricity, off peak	$/kwhr	0.005	0.005	0.010	0.010	0.015	0.015
" " "	$/MBtu	1.46	1.46	2.93	2.93	4.39	4.39
Coal delivered to East Coast plants	$. con	19.01	19.01	27.00	27.00	34.00	34.00
" " to Mid Cont. "	"	14.82	14.82	21.80	21.80	30.80	30.80
" " to Gulf Coast "	"	20.52	20.52	25.40	25.40	27.35	27.35
" " to West Coast "	"	15.72	15.72	20.60	20.60	22.55	22.55
Coal delivered to East Coast plants	$/MBtu	0.73	0.73	1.04	1.04	1.31	1.31
" " to Mid Cont. "	"	0.65	0.65	0.96	0.96	1.35	1.35
" " to Gulf Coast "	"	1.24	1.24	1.54	1.54	1.66	1.66
" " to West Coast "	"	0.95	0.95	1.25	1.25	1.37	1.37

FIGURE 2.01

Assumed Prices of Energy Feed Stocks Delivered to Large Industrial Centers

1980 $

Minimum Prices

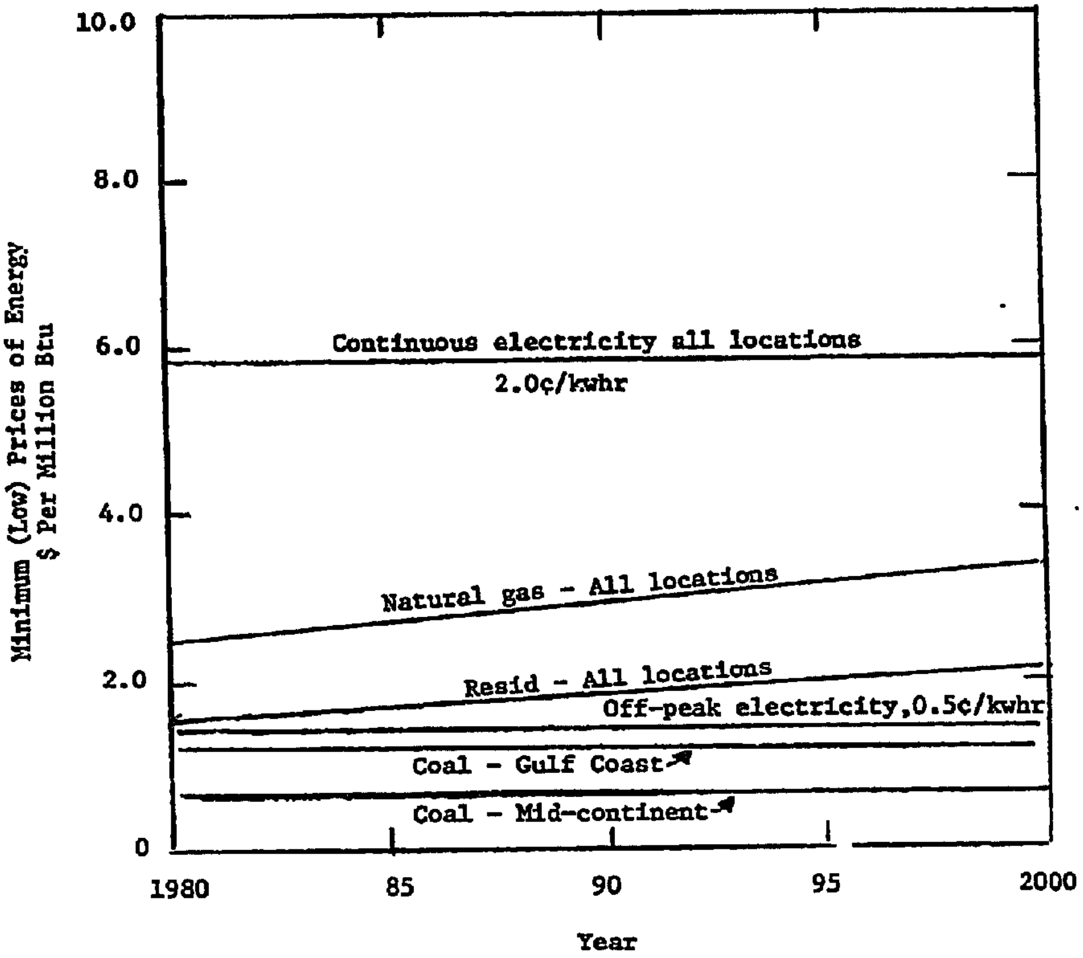

FIGURE 2.02

Assumed Prices of Energy Feed Stocks
Delivered to Large Industrial Centers

1980 $

Most Likely Prices

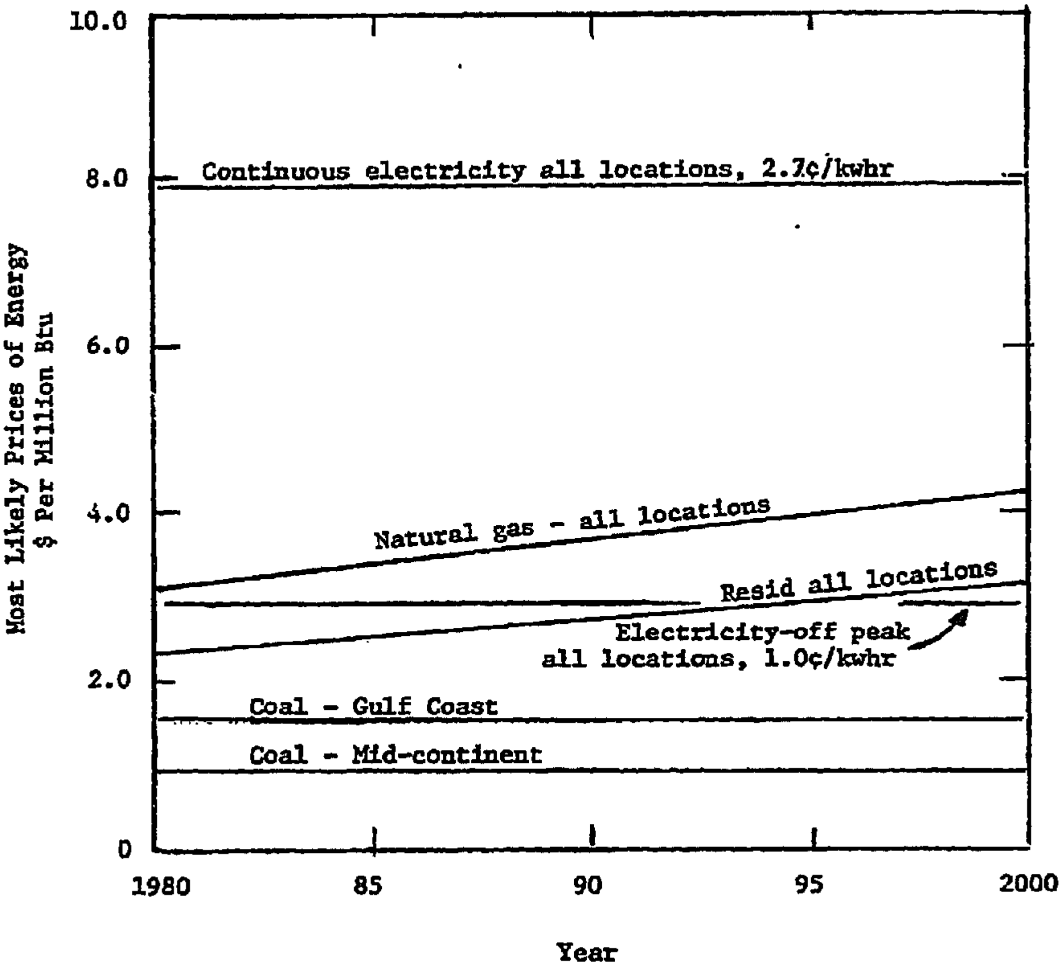

FIGURE 2.03

Assumed Prices of Energy Feed Stocks Delivered to Large Industrial Centers

1980 $

Maximum Prices

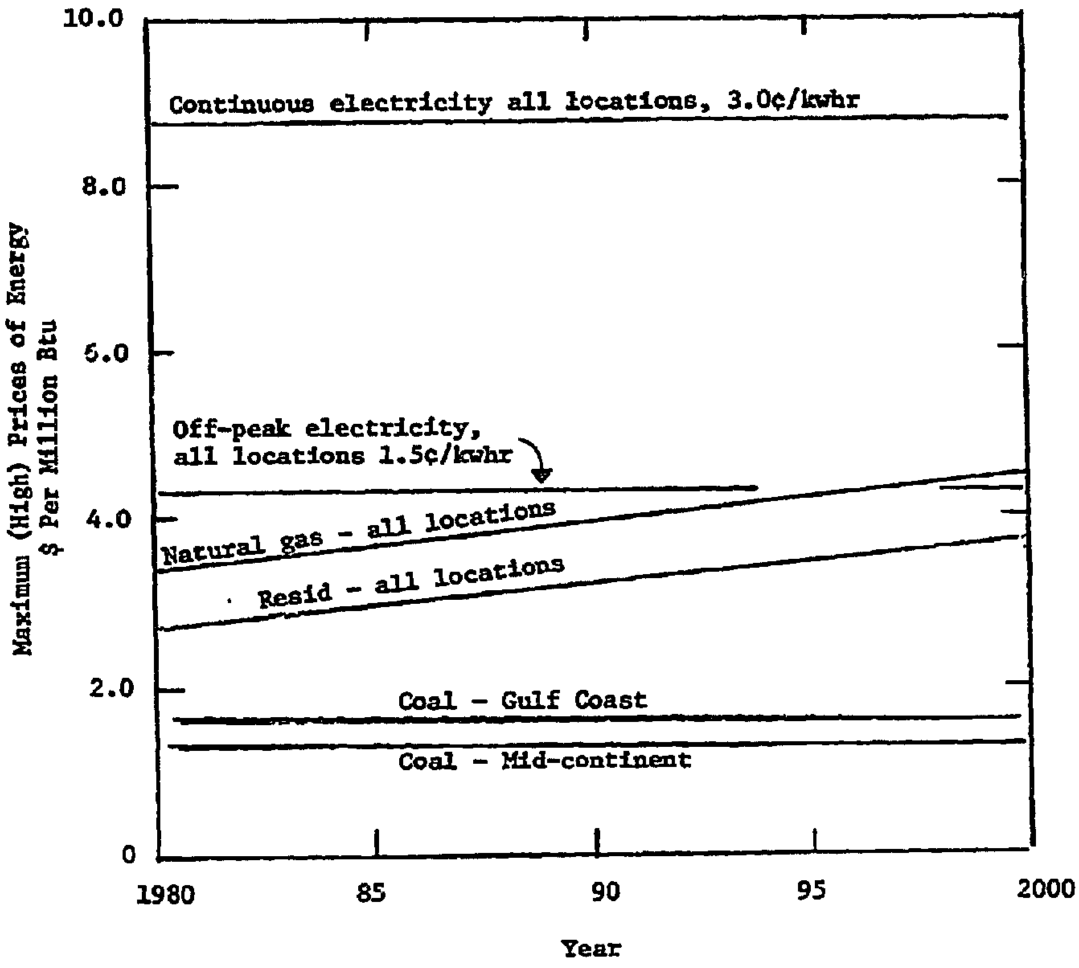

TABLE 2.03

Prices of Coal Delivered to Large Industrial Customers

All data are 1980-2000 prices, 1980 $

Mine location	Illinois	Wyoming	Wyoming	W.V.
Plant location	Mid. Cont.	Gulf Coast	West Coast	East Coast
Types of coal	High Sulfur	Sub-Bit.	Sub-Bit.	High Sulfur
Heating value, MBtu/ton	22.8	16.5	16.5	26.0
Distance, mine to plant, miles	100	1900	1300	500
Transportation cost by unit trains,				
$/ton mile	0.008	0.008	0.008	0.008
$/ton	0.80	15.20	10.40	4.00
Mim Month Price, $/ton				
Minimum	14.02	5.32	5.32	15.01
Most likely	21.00	10.20	10.20	23.00
Maximum	30.00	12.15	12.15	30.00
Delivered Price, $/ton				
Minimum	14.82	20.52	15.72	19.01
Most likely	21.80	25.40	20.60	27.00
Maximum	30.80	27.35	22.55	34.00
Delivered Price, $/MBtu				
Minimum	0.65	1.24	0.95	0.73
Most likely	0.96	1.54	1.25	1.04
Maximum	1.35	1.66	1.37	1.31

3. ECONOMICS OF HYDROGEN MANUFACTURE

The increasing cost and decreasing supplies of natural gas and light hydrocarbon feed stocks provide an incentive for developing new processes for hydrogen manufacture using coal gasification or electrolysis. Nearly all industrial hydrogen currently produced in the U.S. is manufactured by the catalytic steam reforming of natural gas or another light hydrocarbon feed stock. However, the partial oxidation of residuum is used to some extent in the U.S. and is more generally used in Europe. Coal gasification using Koppers-Totzek and Lurgi gasifiers is used in several plants outside the U.S. as has already been discussed. Improved coal gasification procedures have been studied in pilot plants and may soon be used commercially. Improved electrolysis processes requiring lower investments and electricity consumption are currently under development.

Future hydrogen manufacturing costs for the 1980-2000 period for large plants (100 MSCF/SD) have been developed by Chem Systems, Inc. and are presented in the Chem Systems report reproduced in Appendix A. Costs for ammonia and methanol are discussed in later sections.

Economics data for the several hydrogen manufacturing processes are summarized in Table 3.01 and Figure 3.01 for plants of 100 MSCF/SD capacity for the most likely feed stock and electricity prices expected for 1980. These data are further summarized as follows along with the anticipated hydrogen costs corresponding to feed stock costs predicted for the year 2000:

Investments and Operating Costs for Hydrogen
Plants of 100 MSCF/SD Capacity

1980 $

	Investment $ Millions	Production Cost. Inc. Return, $/MBtu	
	1980 or 2000	1980	2000
Steam reforming	62.6	6.12	7.54
Resid partial oxidation	159.3	8.14	9.19
K-T coal gasification *	246.4	9.81	9.81
New coal gasification *	200.1	8.17	8.17
Continuous SPE electrolysis	81.0	13.22	13.22

* For Midcontinent location

Steam reforming of natural gas or an alternative light hydrocarbon feed stock is currently the most attractive hydrogen manufacturing process and will apparently continue to be so during the 1980-2000 period. The investment for reforming is substantially lower than that for the other processes. The operating cost including return is substantially less for reforming throughout the 1980-2000 period than for the other processes. The investment cost for resid partial oxidation is nearly twice that for reforming. The investment for K-T coal gasification is nearly four times that of reforming and the new coal process is 3 fold that of reforming. The investment for the SPE electrolysis process is somewhat higher than that for reforming but the production cost is nearly twice that of reforming due to the electricity being a very expensive energy input. On the basis of these forecasts, there appears to be little chance that large volumes of refinery hydrogen will be made by any process other than reforming during the 1980-2000 period. Resid partial oxidation would be attractive in the U.S. if a long term supply of resid could be obtained at prices substantially less than the resid price structure assumed in these calculations.

Reforming, Resid Partial Oxidation and Coal Gasification

The 1980 economics data for methane reforming and resid partial oxidation are shown in Table 3.02. Although these data are indicated to be for the Gulf Coast location, they actually apply to all U.S. locations where the feed stock cost is $3.15/MBtu for natural gas or $15.00/bbl. for resid.

Coal gasification for both K-T and the new process are shown in Table 3.03 for four locations, East Coast, Midcontinent, Gulf Coast and West Coast corresponding to the four major petroleum refining centers of the U.S. Coal quality and prices are different in each of these areas. This results in differences in the manufacturing cost for hydrogen for each area because of differences in investment cost and coal price. The data for hydrogen manufacturing costs for each of the four areas shown in Table 3.03 are further summarized as follows:

Summary of Hydrogen Manufacturing Costs By Coal Gasification at Various Locations

100 SCF/SD Plants, 1980 Operation, 1980$

Locations Coal Source	East Coast W. Virginia	Midcontinent Illinois	Gulf Coast Wyoming	West Coast Wyoming
Cost of Coal feed, $/MBtu	1.04	0.96	1.54	1.25
Plant investment $Millions				
K-T	240	246	272	272
New	191	200	224	224
Cost of Hydrogen inc. return $/MBtu				
K-T	9.73	9.81	11.56	11.06
New	7.98	8.17	9.85	9.39

The production cost data for new coal gasification in the four geographical areas are compared to that for reforming in Figure 3.02. Costs are lower for the East Coast and Midcontinent areas than for the Gulf Coast and West Coast locations. However, hydrogen costs in the year 2000 by new coal gasification are somewhat higher than for reforming for all four locations.

Several economic factors that may have an important effect on total production costs have been studied as sensitivities. These factors were previously discussed (page 49). The calculated sensitivity data for methane reforming and resid partial oxidation are shown in Table 3.04; for K-T coal gasification in Table 3.05; and for new coal gasification in Table 3.06.

The important relationship shown by these sensitivity data is the comparison of manufacturing costs for reforming versus those for new coal gasification, the process that provides closely competitive production costs. This relationship is shown for the East Coast location in Table 3.07; for the Midcontinent location in Table 3.08; for the Gulf Coast location in Table 3.09; and for the West Coast location in Table 3.10. In each of these tables and for each of the sensitivities except one, reforming has a cost advantage over new coal gasification. The only exception is for the sensitivity of construction costs escalation of 1%/yr. below that of general inflation. In this case new coal gasification would provide slightly lower production costs in theyear 2000. However, in all the other sensitivities reforming has a competitive edge over new coal gasification. This advantage is much greater for the year 1980 when natural gas prices (1980$) are lower than for the year 2000. These data for the Gulf Coast location, where 42% of the total U.S. refinery hydrogen will be required in the year 2000 are further summarized as follows:

Sensitivities for Hydrogen Manufacture

Natural Gas Reforming vs New Coal Gasification
100 MSCF/D Plants, 1980 $
Gulf Coast Location

	Advantage for Natural Gas Reforming, $/MBtu	
	1980	2000
Most likely fuel prices	3.73	2.31
High fuel prices	3.82	2.28
Low fuel prices	4.22	3.09
10% additional investment	4.14	2.72
Construction costs escalate +1%/yr.	--	3.44
Construction costs escalate -1%/yr.	--	1.39
Coal prices escalate +1%/yr.	--	2.89
Coal prices escalate -1%/yr.	--	1.84

The use of the new coal process to produce refinery hydrogen would release natural gas or light hydrocarbon feed stock required if the hydrogen were produced by reforming. The cost of releasing the natural gas feed is shown in Table 3.11 for the new coal process and the Midcontinent (Illinois) location. The cost of the released natural gas is $4.56/MBtu for the most likely coal price, $4.16 for the low coal price, and $5.06 for the high coal price. These calculated natural gas "release" prices correspond to $25.35/bbl. of crude equivalent for the most likely coal price; $23.13/bbl. for the low coal price; and $28.13/bbl. for the high coal price. These release values are substantially higher than the anticipated prices of imported crude oil during the 1980-2000 period thus confirming that coal gasification will not be competitive with reforming for producing refinery hydrogen during the 1980-2000 period.

Electrolysis

Costs for producing electrolytic hydrogen are very high compared to those for reforming for plants of large capacity and when electricity is purchased at regular commercial rates. Today electrolysis is more expensive than reforming for plants of 10,000 SCF/Hr capacity or greater. Below this capacity, electrolysis may be more attractive than reforming; however, the exact break even point is affected by the prices of electricity and hydrocarbon feed. Capital costs per unit of electrolytic hydrogen product change only slightly with plant capacity, while reforming plants of small capacity have relatively high unit capital costs. The capital costs for current technology electrolysis, advanced (solid polymer electrolyte) electrolysis and reforming for plants of several capacities are as follows:

Capital Costs of Hydrogen Plants of Various Capacities

Capacity SCF/SH	4,000	20,000	100,000	4.17 M
Capacity, kw hydrogen product	380	1,903	9,517	0.397 M
Investment, $/kw (1980$)				
electrolysis, current technology	510	510	510	510
electrolysis, advanced	213	210	208	204
natural gas reforming	1,970	683	273	158

Electrolysis plants are currently manufactured by Luigi Apparate-Technik BmBH (Frankfort, West Germany); several other European manufacturers; The Electrolyzer Corp., Ltd. (Toronto, Canada); General Electric (U.S.); and Teledyne Isotopes (U.S.). Data from Reference 17 and other sources were used in this study to estimate costs for manufacturing electrolytic hydrogen using "current" electrolysis technology.

A new electrolysis process is being developed by General Electric. This process (discussed in References 17 and 18) employs a solid polymer electrolyte as a replacement for the traditional aqueous potassium hydroxide (KOH) solution. The solid polymer electrolyte has ion exchange properties and with the addition of liquid water, hydrogen ions flow through the electrolyte and are converted to hydrogen gas at the cathode. Chem Systems Inc. (Appendix A) have used data obtained from General Electric to estimate production costs for this advanced electrolysis process which is referred to as "SPE Electrolysis."

The investment and operating costs for current technology electrolysis and SPE electrolysis are compared in Table 3.12 for continuously operating plants of 100 M SCF/SD capacity using electricity priced at 2.7¢/kwhr. The cost of the hydrogen including 20%/yr before tax return is $20.99 and $13.22/MBtu respectively (1980 $).

In the future, electricity may be priced substantially less during off-peak periods than during on-peak periods. Table 3.13 shows the estimated costs for the SPE electrolysis process when electricity is available at 1.0¢/kwhr. Assuming the electrolysis plant could operate 3300 hours/year (10 hours per day or 0.38 Capacity Factor) the electrolytic hydrogen would cost $10.65/MBtu. This figure is somewhat less than the $13.22 figure for continuous operation with 2.7¢/kwhr electricity; however, most industrial hydrogen consuming plants require a steady constant rate of hydrogen addition and would not be able to use hydrogen produced only in off-peak periods.

Hydrogen produced intermittently could be supplied continuously to a hydrogen consuming operation if hydrogen storage were imposed between the production and consumption operations. Hydrogen storage using iron/titanium hydride as the storage medium has been extensively studied by Brookhaven National Laboratory; design and costs for the iron/titanium hydride storage system are discussed in References 19 and 20. The diagram shown in Figure 3.03 shows how the 4.167 SCF/hr electrolyzer (10 hours/day operation) could be coupled to iron/titanium hydride storage to provide a continuous flow of 1.736 MSCF/hr to the load. Investment data for the iron/titanium hydride storage facility are shown in Table 3.14. Costs for the electrolyzer and iron titanium hydride storage facility are combined in Table 3.15. The cost of the hydrogen product from the system for 1.0¢/kwhr electricity is $14.71/MBtu which is somewhat higher than the $13.22/MBtu figure for continuous electrolyzer operation using 2.7¢/kwhr electricity.

Hydrogen production costs including 20%/yr before tax return for these electrolysis systems are plotted in Figure 3.04; hydrogen costs by reforming are shown for comparison. As has been emphasized previously, electrolytic hydrogen costs are substantially above those for reforming for the large capacity plants (100 MSCF/hr) used in this comparison.

It is unlikely that a market for the oxygen by-product from electrolysis plants could be found, particularly for plants operating with intermittant off-peak electricity. However, if the oxygen could be sold at a price of $24/ton, the oxygen credit would correspond to $1.54/MBtu of hydrogen.

Sensitivity data for electrolytic hydrogen are shown in Table 3.16. The various factors considered in these sensitivity calculations provided some change in the hydrogen production costs, but these variations are small compared to the large differences between the costs for electrolysis and reforming.

TABLE 3.01

Summary of Investments and Operating Costs for Hydrogen Manufacturing Plants

All Plants are 100 MSCF/SD Capacity, Operation in 1980, 1980 $

Process	Methane Steam Reforming	Resid Partial Oxidation	Coal Gasification(1) K-T	Coal Gasification(1) New	SPE Electrolysis Continuous	SPE Electrolysis Intermittent + Storage
Investment, $ Millions						
Onsite	41.3	93.9	146.7	122.4	65.6	258.2
Offsite	21.3	65.4	99.7	77.7	15.4	47.0
Total	62.6	159.3	246.4	200.1	81.0	305.2
Cost of feed stock, $/MBtu	3.15	2.35	0.96	0.96	--	--
Cost of electricity, ¢/kwhr	--	--	--	--	2.7	1.0
Costs and Charges, $/MBtu Product						
Feed stock or electricity	4.09	2.84	1.61	1.50	10.19	3.78
Other operating costs	0.06	0.31	0.53	0.43	0.13	0.43
Capital charges(2)	1.97	4.99	7.67	6.24	2.90	10.50

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(1) Coal gasification plants are located in Illinois and use Illinois high sulfur coal.

(2) Capital charges include maintenance, overhead, insurance, property taxes, depreciation, interest on working capital and 20%/yr before tax return.

FIGURE 3.01

Hydrogen Manufacturing Costs - Midcontinent Location

$/MBtu - 100 MSCF/D Plants - 1980 $

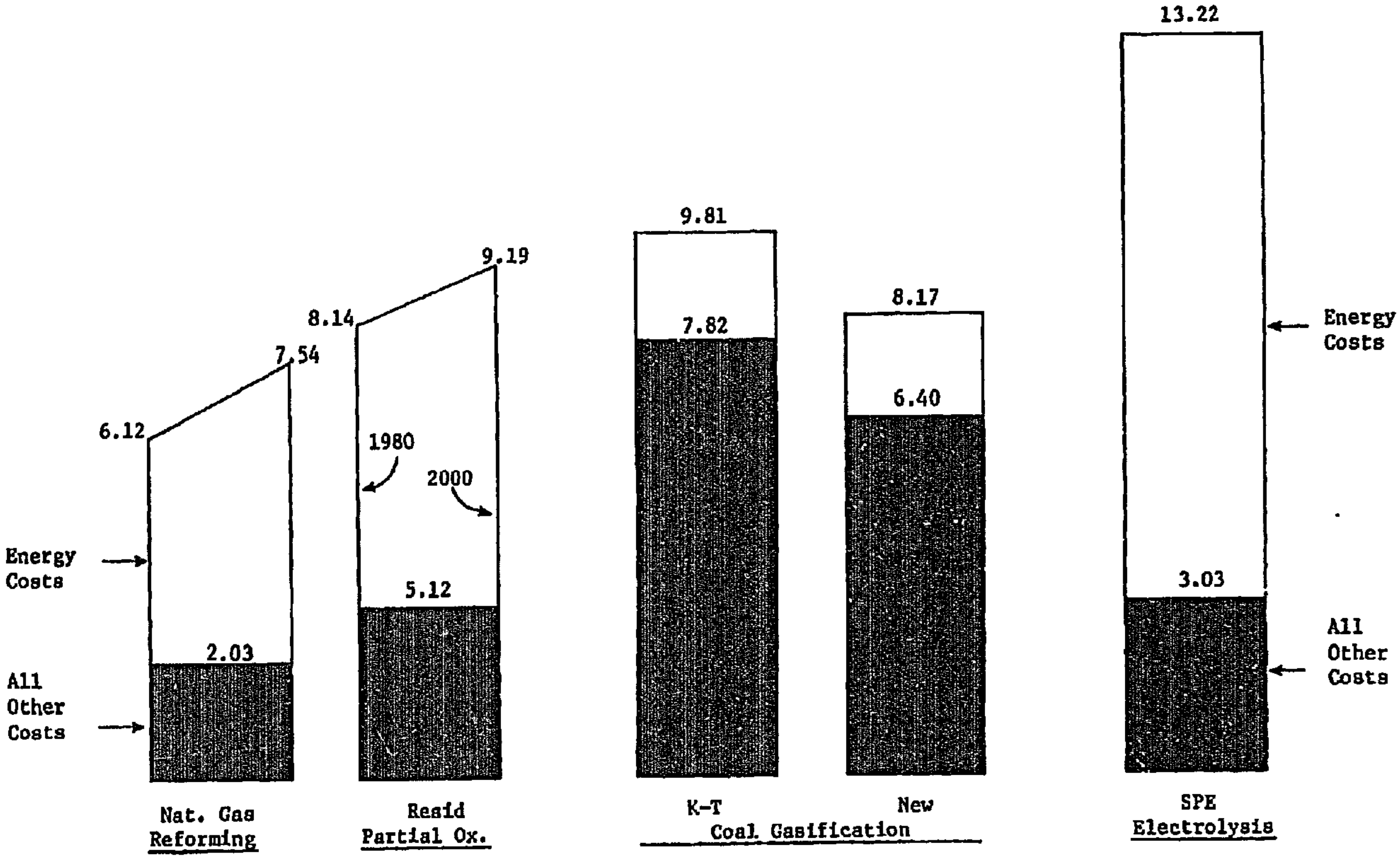


TABLE 3.02

Economics Data for Hydrogen Manufacture by Methane Reforming and Resid Partial Oxidation

1980 operation, 1980 $

Process	Methane Reforming		Resid Partial Oxidation	
Plant Location	Gulf Coast		Gulf Coast	
Design Capacity, Hydrogen product				
MSCF/Hour	4.167		4.167	
MSCF/Day	100		100	
MSCF/Year	35000		33000	
MBTU/Year x 10^6	11.27		10.63	
Feed stock cost at plant	--		$15.00/bbl	
Feed stock cost at plant, $/MBtu	3.15		2.35	
Btu product/Btu feed, %	70.2		82.7	
Investment, $Millions				
Onsite	41.3		93.9	
Offsite	21.3		65.4	
Total plant	62.6		159.3	
% contingency in these investments	10		15	
Working capital	7.8		5.6	
Costs and Charges	$M/yr	$/MBtu	$M/yr	$/MBtu
Feed stock or electricity	50.590	4.49	30.195	2.84
Utilities	(4.553)	(0.40)	1.902	0.18
Chemicals and catalyst	--		--	
Labor and supervision	0.682	0.06	1.364	0.13
Maintenance (4% onsite)	1.652	0.15	3.756	0.35
Plant overhead (2.6% onsite)	1.074	0.10	2.441	0.23
Insurance, property taxes (1.5%) total Plant	0.939	0.08	2.390	0.22
Depreciation (10% onsite + 5% offsites)	5.195	0.46	12.660	1.19
Interest on working capital (10%)	0.780	0.07	0.560	0.05
Return on investment (20% total plant)	12.520	1.11	31.860	3.00
Total cost including return	68.879	6.12	87.128	8.19
Sulfur credit ($50/ton)	--	--	(0.500)	(0.05)
Net cost including return	68.879	6.12	86.628	8.14

TABLE 3.03 (Page 1 of 2)

Economics Data for Hydrogen Manufacture by Coal Gasification

1980 operation, 1980 $

Coal Source	W. Virginia		W. Virginia		Illinois		Illinois	
Plant location	East Coast		East Coast		Midcontinent		Midcontinent	
Process	K-T		New		K-T		New	
Design Capacity, Hydrogen Product								
MSCF/Day	100		100		100		100	
MSCF/Year	33000		33000		33000		33000	
MBtu/Year x 10^6	10.63		10.63		10.63		10.63	
Coal heating value, MBtu/ton	26.0		26.0		22.8		22.8	
Coal cost at plant, $/ton	27.00		27.00		21.60		21.50	
Coal cost at plant, $/MBtu	1.04		1.04		0.96		0.96	
Btu product/Btu feed, %	59.7		64.1		59.4		64.1	
Investment, $ Millions*								
Onsite	142.7		116.5		146.7		122.4	
Offsite	97.0		74.0		99.7		77.7	
Total plant	239.7		190.5		246.4		200.1	
% Contingency in these investments	15		20		15		20	
Working capital	4.0		3.6		3.8		3.4	
Costs and Charges	$M/yr	$/MBtu	$M/yr	$/MBtu	$M/yr	$/MBtu	$M/yr	$/MBtu
Feed stock	18.496	1.74	17.221	1.62	17.114	1.61	15.839	1.49
Utilities	4.039	0.38	2.976	0.28	4.049	0.38	2.972	0.28
Chemicals and catalyst	--	--	--	--	--	--	--	--
Labor and supervision	1.591	0.15	1.591	0.15	1.591	0.15	1.591	0.15
Maintenance (4% onsite)	5.708	0.54	4.660	0.44	5.868	0.55	4.896	0.46
Plant overhead (2.6% onsite)	3.710	0.35	3.029	0.28	3.814	0.36	3.182	0.30
Insurance, property taxes 1.5% total plant	3.596	0.34	2.858	0.27	3.696	0.35	3.002	0.28
Depreciation (10% onsite + 5% offsites)	19.120	1.80	15.350	1.44	19.655	1.85	16.125	1.52
Interest on working capital (10%)	0.402	0.04	0.363	0.03	0.380	0.04	0.340	0.03
Return on investment (20% total plant)	47.940	4.51	38.100	3.58	49.280	4.64	40.020	3.76
Total cost including return	104.602	9.85	86.148	8.09	105.462	9.93	88.020	8.28
Sulfur credit ($50/ton)	(1.276)	(0.12)	(1.169)	(0.11)	(1.320)	(0.12)	(1.215)	(0.11)
Net cost including return	103.326	9.73	84.979	7.98	104.142	9.81	86.805	8.17

TABLE 3.03 (Page 2 of 2)

Economics Data for Hydrogen Manufacture by Coal Gasification

1980 operation, 1980 $

Coal Source	Wyoming		Wyoming		Wyoming		Wyoming	
Plant location	Gulf Coast		Gulf Coast		West Coast		West Coast	
Process	K-T		New		K-T		New	
Design Capacity, Hydrogen Product								
MSCF/Day	100		100		100		100	
MSCF/Year	33000		33000		33000		33000	
MBtu/Year x 10^6	10.63		10.63		10.63		10.63	
Coal heating value, MBtu/ton	16.5		16.5		16.5		16.5	
Coal cost at plant, $/ton	25.40		25.40		20.60		20.60	
Coal cost at plant, $/MBtu	1.54		1.54		1.25		1.25	
Btu product/Btu feed, %	59.4		63.7		59.4		63.7	
Investment, $ Millions								
Onsite	161.8		136.7		161.8		136.7	
Offsite	110.0		86.8		110.0		86.8	
Total plant	271.8		223.5		271.8		223.5	
% Contingency in these investments	15		20		15		20	
Working capital	5.3		4.9		4.4		4.1	
Costs and Charges	$M/yr	$/MBtu	$M/yr	$/MBtu	$M/yr	$/MBtu	$M/yr	$/MBtu
Feed stock	27.532	2.59	25.618	2.41	22.323	2.10	20.835	1.96
Utilities	2.764	0.26	2.232	0.21	2.764	0.26	2.232	0.21
Chemicals and catalyst	--	--	--	--	--	--	--	--
Labor and supervision	1.591	0.15	1.591	0.15	1.591	0.15	1.591	0.15
Maintenance (4% onsite)	6.472	0.61	5.468	0.51	6.472	0.61	5.468	0.51
Plant overhead (2.6% onsite)	4.207	0.40	3.554	0.33	4.207	0.40	3.554	0.33
Insurance, property taxes (1.5% total plant)	4.077	0.38	3.353	0.32	4.077	0.38	3.353	0.32
Depreciation (10% onsite + 5% offsites)	21.680	2.04	18.010	1.69	21.680	2.04	18.010	1.69
Interest on working capital (10%)	0.532	0.05	0.491	0.05	0.445	0.04	0.411	0.04
Return on investment (20% total plant)	54.360	5.11	44.700	4.21	54.360	5.11	44.700	4.21
Total cost including return	123.215	11.59	105.017	9.88	117.919	11.09	100.154	9.42
Sulfur credit	(0.319)	(0.03)	(0.319)	(0.03)	(0.319)	(0.03)	(0.319)	(0.03)
Net cost including return	122.896	11.56	104.698	9.85	117.600	11.06	99.835	9.39

NOT REPRODUCIBLE

FIGURE 3.02

Hydrogen Manufacturing Costs - New Coal Gasification

$/MBtu - 100 MSCF/D Plants - 1980 $

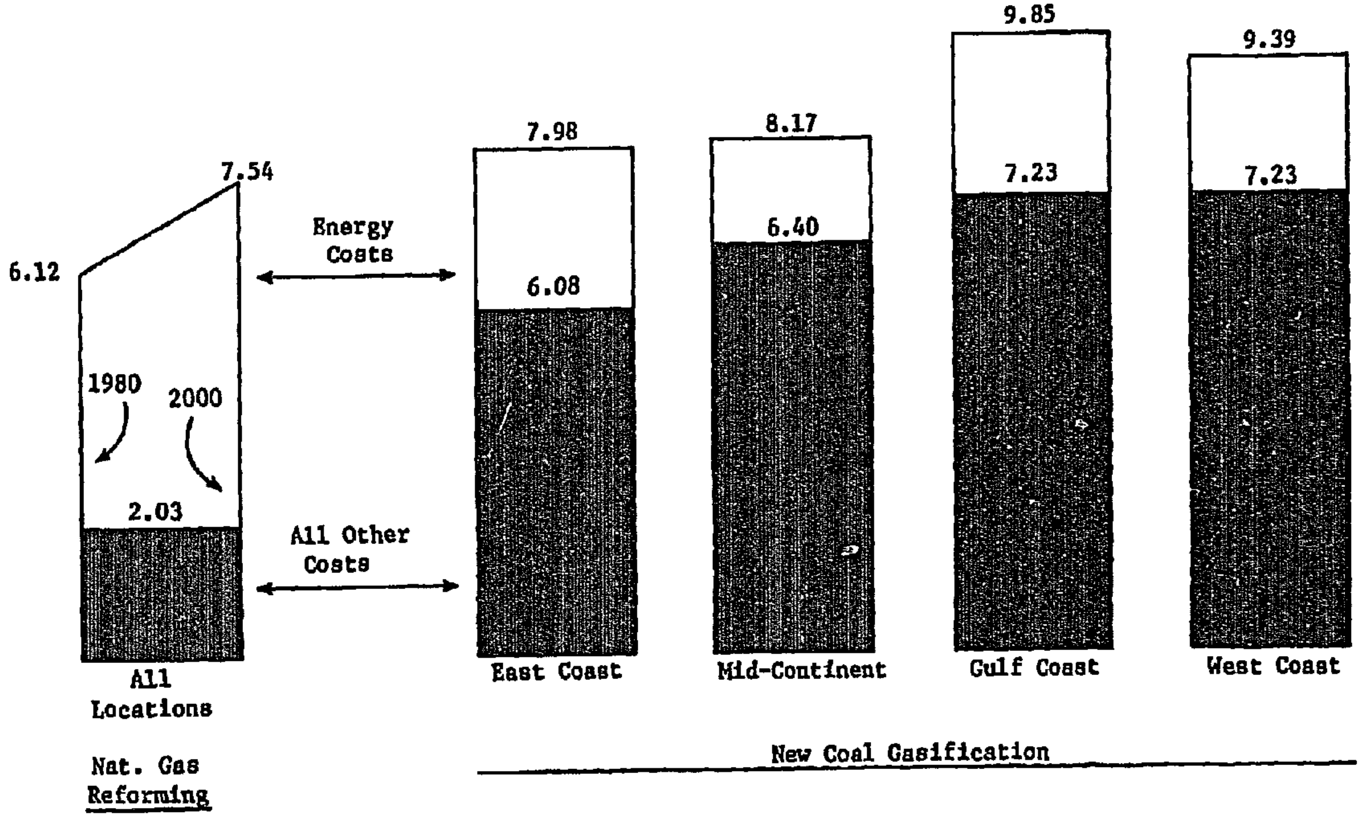
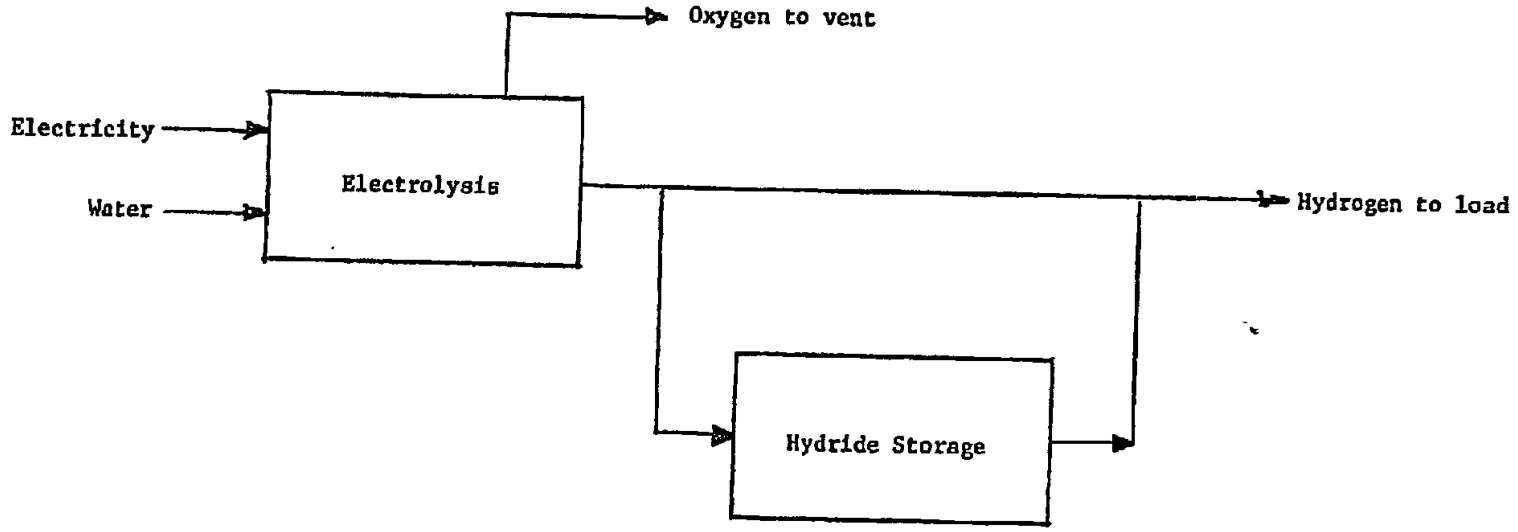


FIGURE 3.03

Hydrogen Manufacture and Storage Using Off-Peak Electricity



		Hours 1-10	Hours 11-24
Electricity to electrolyzer, mw		510	0
Hydrogen from electrolyzer, total	MSCF/Hr	4.167	0
" " " to storage	" "	2.431	0
" " " to load	" "	1.736	0
" " storage to load	" "	0	1.736

TABLE 3.04

Sensitivities for Hydrogen Manufacture, Reforming and Resid Partial Oxidation

Data are hydrogen production cost including 20% before
tax return, 100 MSCF/SD plants, $/MBtu, 1980 &

	Year	Methane Reforming	Resid Partial Ox.
Location		All U. S.	All U. S.
Base Case, most likely fuel price	1980	6.12	8.14
	2000	7.54	9.19
Base Case, high fuel price	1980	6.44	8.64
	2000	7.98	9.87
Base Case, low fuel price	1980	5.28	7.13
	2000	6.41	7.83
Additional 10% investment	1980	6.30	8.59
	2000	7.72	9.64
Construction costs escalate 1%/yr above gen. inflation	2000	7.97	10.29
Construction costs escalate 1%/yr below gen. inflation	2000	7.19	8.29
Coal prices escalate 1%/yr above gen. inflation	2000	7.54	8.14
Coal prices escalate 1%/yr below gen. inflation	2000	7.54	9.19

TABLE 3.05

Sensitivities for Hydrogen Manufacture by K-T Coal Gasification

Data are hydrogen production cost including 20% before tax return
for 100 MSCF/SD plants, $/MBtu, 1980 $

	Years	East Coast	Mid-Continent	Gulf Coast	West Coast
Base case - most likely fuel price	1980	9.73	9.81	11.56	11.06
	2000	9.73	9.81	11.56	11.06
Base case - high fuel price	1980	10.28	10.62	11.78	11.29
	2000	10.28	10.62	11.78	11.29
Base case - low fuel price	1980	9.10	9.17	11.00	10.49
	2000	9.10	9.17	11.00	10.49
Additional 10% investment	1980	10.38	10.48	12.30	11.80
	2000	10.38	10.48	12.30	11.80
Construction costs escalate 1%/yr above gen. inflation	2000	11.37	11.50	13.44	12.94
Construction costs escalate 1%/yr below gen. inflation	2000	8.39	8.43	10.02	9.52
Coal prices escalate 1%/yr above gen. inflation	2000	10.20	10.25	12.19	11.58
Coal prices escalate 1%/yr below gen. inflation	2000	9.35	9.45	11.05	10.64

TABLE 3.06

Sensitivities for Hydrogen Manufacture by New Coal Gasification

Data are hydrogen production cost including 20% before tax return
for 100 MSCF/SD plants, $/MBtu, 1980 $

	Years	East Coast	Mid-Continent	Gulf Coast	West Coast
Base case - most likely fuel price	1980	7.98	8.17	9.85	9.39
	2000	7.98	8.17	9.85	9.39
Base case - high fuel price	1980	8.47	8.87	10.26	9.72
	2000	8.47	8.87	10.26	9.72
Base case - low fuel price	1980	7.41	7.59	9.50	8.96
	2000	7.41	7.59	9.50	8.96
Additional 10% investment	1980	8.47	8.69	10.44	9.98
	2000	8.47	8.69	10.44	9.98
Construction costs escalate 1%/yr above gen. inflation	2000	9.28	9.55	11.41	10.95
Construction costs escalate 1%/yr below gen. inflation	2000	6.91	7.05	8.58	8.12
Coal prices escalate 1%/yr above gen. inflation	2000	8.40	8.56	10.43	9.87
Coal prices escalate 1%/yr below gen. inflation	2000	7.64	7.85	9.38	9.00

TABLE 3.07

Sensitivities for Hydrogen Manufacture in 100 MSCF/D Plants for Methane Reforming and New Coal Gasification

East Coast Location, 1980 $, $/MBtu

	1980			2000		
	Methane Reforming	New Coal Gasification	Advantage For MR	Methane Reforming	New Coal Gasification	Advantage For MR
Base Case - Most likely fuel prices	6.12	7.98	1.86	7.54	7.98	0.44
" " - High fuel prices	6.44	8.47	2.03	7.98	8.47	0.49
" " - Low fuel prices	5.28	7.41	2.13	6.41	7.41	1.00
10% Additional Investment	6.30	8.47	2.17	7.72	8.47	0.75
Construction costs escalate +1%/yr	-	-	-	7.97	9.28	1.31
" " " -1%/yr	-	-	-	7.19	6.91	-0.28
Coal prices escalate +1%/yr	-	-	-	7.54	8.40	0.86
" " " -1%/yr	-	-	-	7.54	7.64	0.10

TABLE 3.08

Sensitivities for Hydrogen Manufacture in 100 MSCF/D Plants for Methane Reforming and New Coal Gasification

Mid-Continent Location, 1980 $, $/MBtu

	1980			2000		
	Methane Reforming	New Coal Gasification	Advantage For MR	Methane Reforming	New Coal Gasification	Advantage For MR
Base Case - Most likely fuel prices	6.12	8.17	2.05	7.54	8.17	0.63
" " - High fuel prices	6.44	8.87	2.43	7.98	8.87	0.89
" " - Low fuel prices	5.28	7.59	2.31	6.41	7.59	1.18
10% Additional Investment	6.30	8.69	2.39	7.72	8.87	1.15
Construction costs escalate +1%/yr	-	-	-	7.97	9.55	1.58
" " " -1%/yr	-	-	-	7.19	7.05	-0.14
Coal prices escalate +1%/yr	-	-	-	7.54	8.56	1.02
" " " -1%/yr	-	-	-	7.54	7.85	0.31

TABLE 3.09

Sensitivities for Hydrogen Manufacture in 100 MSCF/D Plants for Methane Reforming and New Coal Gasification

Gulf Coast Location, 1980 $, $/MBtu

	1980			2000		
	Methane Reforming	New Coal Gasification	Advantage For MR	Methane Reforming	New Coal Gasification	Advantage For MR
Base Case - most likely fuel prices	6.12	9.85	3.73	7.54	9.85	2.31
Base Case - high fuel prices	6.44	10.26	3.82	7.98	10.26	2.28
Base Case - low fuel prices	5.28	9.50	4.22	6.41	9.50	3.09
10% additional investment	6.30	10.44	4.14	7.72	10.44	2.72
Construction costs escalate +1%/yr.	--	--	--	7.97	11.41	3.44
Construction costs escalate -1%/yr.	--	--	--	7.19	8.58	1.39
Coal prices escalate +1%/yr.	--	--	--	7.54	10.43	2.89
Coal prices escalate -1%/yr.	--	--	--	7.54	9.38	1.84

TABLE 3.10

Sensitivities for Hydrogen Manufacture in 100 MSCF/D Plants for Methane Reforming and New Coal Gasification

West Coast Location, 1980 $, $/MBtu

	1980			2000		
	Methane Reforming	New Coal Gasification	Advantage For MR	Methane Reforming	New Coal Gasification	Advantage For MR
Base Case, most likely fuel prices	6.12	9.39	3.27	7.54	9.39	1.85
Base Case, high fuel prices	6.44	9.72	3.28	7.98	9.72	1.74
Base Case, low fuel prices	5.28	8.96	3.68	6.41	8.96	2.55
10% additional investment	6.30	9.98	3.68	7.72	9.98	2.26
Construction costs escalate +1%/yr.	--	--	--	7.97	10.95	2.98
Construction costs escalate -1%/yr.	--	--	--	7.19	8.12	0.93
Coal prices escalate +1%/yr.	--	--	--	7.54	9.87	2.33
Coal prices escalate -1%/yr.	--	--	--	7.54	9.00	1.46

TABLE 3.11

Hydrogen Manufacture in 100 MSCF/D Plants - Cost of Hydrocarbon Feedstock Released When Using New Coal Gasification Process

Coal gasification plants located in Illinois, 1980-2000, 1980 $

Illinois high sulfur coal delivered to plant, \$/ton	14.82	21.80	30.80
Illinois high sulfur coal delivered to plant, \$/MBtu	0.65	0.96	1.35
<u>Costs for producing refinery hydrogen, \$/MBtu</u>			
Total cost from coal	7.60	8.17	8.89
Deduct methane reforming cost exclusive of feedstock	(1.63)	(1.63)	(1.63)
Cost of releasing 1.434 MBtu of natural gas feed required for reforming	5.97	6.54	7.26
Cost of natural gas released, \$/MBtu	4.16	4.56	5.06
Cost of natural gas released, \$/bbl crude equivalent	23.13	25.35	28.13

TABLE 3.12

Comparison of Current and SPE Electrolysis Systems
1980 Operation, 1980 $

Process	Current Technology KOH Electrolyte		New Technology SPE Electrolyte	
Plant capacity M SCF/Day	100		100	
Plant capacity M SCF/yr	33000		33000	
Plant capacity MBtu/yr x 10^6	10.63		10.63	
Hours per year operation	7920		7920	
MBtu Hydrogen product/MBtu electricity x 100	75.7		77.6	
Investment	$/kw	$M	$/kw	$M
Onsites	650	255	167	65.6
Offsites	100	40	39	15.4
Total	750	295	206	81.0
% contingency in investments	15	15	30	30
Working capital	--	18.9	--	18.3
Operating Costs	$M/yr	$/MBtu	$M/yr	$/MBtu
Electricity @ $0.027/kwhr	111.016	10.44	108.298	10.19
Water and chemicals	1.246	0.12	0.741	0.07
Labor and supervision	1.204	0.11	0.602	0.06
Maintenance (4% of onsites)	10.200	0.96	2.624	0.25
Plant overhead (2.6% of onsite)	6.630	0.62	1.706	0.16
Insurance, property taxes (1.5% of total plant)	4.425	0.42	1.215	0.11
Depreciation (10% of onsites, 4% of offsites)	27.500	2.59	7.330	0.69
Interest on working capital (10%)	1.890	0.18	1.830	0.17
Return on investment (20% of total)	59.000	5.55	16.200	1.52
Total cost inc. return	223.111	20.99	140.546	13.22
Oxygen credit ($24/ton)	(16.704)	(1.57)	(16.704)	(1.57)
Net cost including return	206.407	19.42	123.842	11.65

TABLE 3.13

Production Costs for Hydrogen--SPE Electrolysis Off-Peak Electricity Operation

1980 Operation, 1980 $

Capacity--4.167 MSCF/SH

Investment--M$		$/kw Hydrogen
Onsite	65.6	167
Offsite	15.4	39
Total	81.0	206

% contingency in investment--30

Operating hours/year	7920		3300	
MBtu/yr x 10^6	10.63		4.43	
	M$/yr	$/MBtu	M$/yr	$/MBtu
Operating Costs				
Electricity @ $0.01/kwhr	40.110	3.77	16.713	3.77
Water and chemicals	0.741	0.77	0.309	0.07
Labor and supervision	0.602	0.06	0.602	0.14
Maintenance (4% of onsites)	2.624	0.25	2.624	0.59
Plant overhead (2.6% of onsite)	1.706	0.16	1.706	0.39
Insurance, property tax (1.5% of T.P.)	1.215	0.11	1.215	0.27
Depreciation (10% of onsites + 4% OS)	7.330	0.69	7.330	1.69
Interest on working capital	0.691	0.07	0.294	0.07
Return on investment (20% of total)	16.200	1.52	16.200	3.66
	71.219	6.70	46.993	10.65

TABLE 3.14

Production Cost Analysis for Hydrogen Storage by Iron Titanium Hydride System(1)

1980 $

Location - U.S. Gulf Coast, 1980-2000 period
Pressure - input hydrogen - 450 psig
- hydrogen product - 290 psig

Storage capacity = 3.0M SCF/hr for 10 hours
= 30.0M SCF total for one storage cycle
= 159,580 lbs. total for one storage cycle

Product rate from plant = 1.736 MSCF/hr for 14 hours
= 24.310 MSCF total for one storage cycle
= 129,310 lbs. for one storage cycle
= 8022M SCF/yr
= 2.583×10^6 MSCF/yr

Investment, $ Millions	
Fe/Ti alloy - 13.8×10^6 lbs @ $1.50	20.7
Process equipment	11.6
Offsites	3.2
Contingency	10.7
Total plant	46.2
Onsites	42.0
Offsites	4.2
Total plant	46.2

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(1) Data from Reference 19

TABLE 3.15

Production Costs for Hydrogen Product - SPE Electrolysis Coupled to Iron Titanium Hydride Hydrogen Storage

1980 operation, 1980 $

This system involves operating the SPE electrolysis system with off-peak electricity for 10 hours per day with Fe/Ti hydride storage to provide for continuous delivery of hydrogen to load.

Capacity - Electrolysis - 4.167 MSCF/hr, 10 hrs/day, 330 days/yr
- Fe/Ti Hydride Stg. - 159,520 lbs/hr hydrogen storage per cycle to provide 1.736 MSCF/hr to load for 14 hours.

Capacity - Overall to Load - 1.736 MSCF/hr for 24 hrs/day
- " " " - 4.427 MBtu x 10^6 per year

	Electrolysis	Storage	Total	Total Cost $/MBtu
Investment, $M				
Onsites	65.6	42.0	107.6	
Offsites	15.4	4.2	19.6	
Total	81.0	46.2	127.2	
% Contingency in investment	30	30	30	
Working capital	2.937	0.166	3.103	
Operating Cost, $M/yr				
Electricity @ $0.01/kwhr	16.713	-	16.713	3.78
Chemicals, catalyst, utilities	0.309	0.995	1.304	0.29
Labor and supervision	0.602	-	0.602	0.14
Maintenance (4% onsite)	2.624	1.680	4.304	0.97
Plant overhead (2.6% onsite)	1.706	1.092	2.798	0.63
Ins. property taxes (1.5% total)	1.215	0.693	1.908	0.43
Depreciation (10% onsite + 5% off)	7.330	4.410	11.740	2.65
Interest on working capital (10%)	0.294	0.017	0.311	0.07
Return on investment (20%)	16.200	9.240	25.440	5.75
Total cost inc. return	46.993	18.127	65.120	14.71

FIGURE 3.04

Hydrogen Manufacturing Costs - Electrolysis

$/MBtu - 1980 $

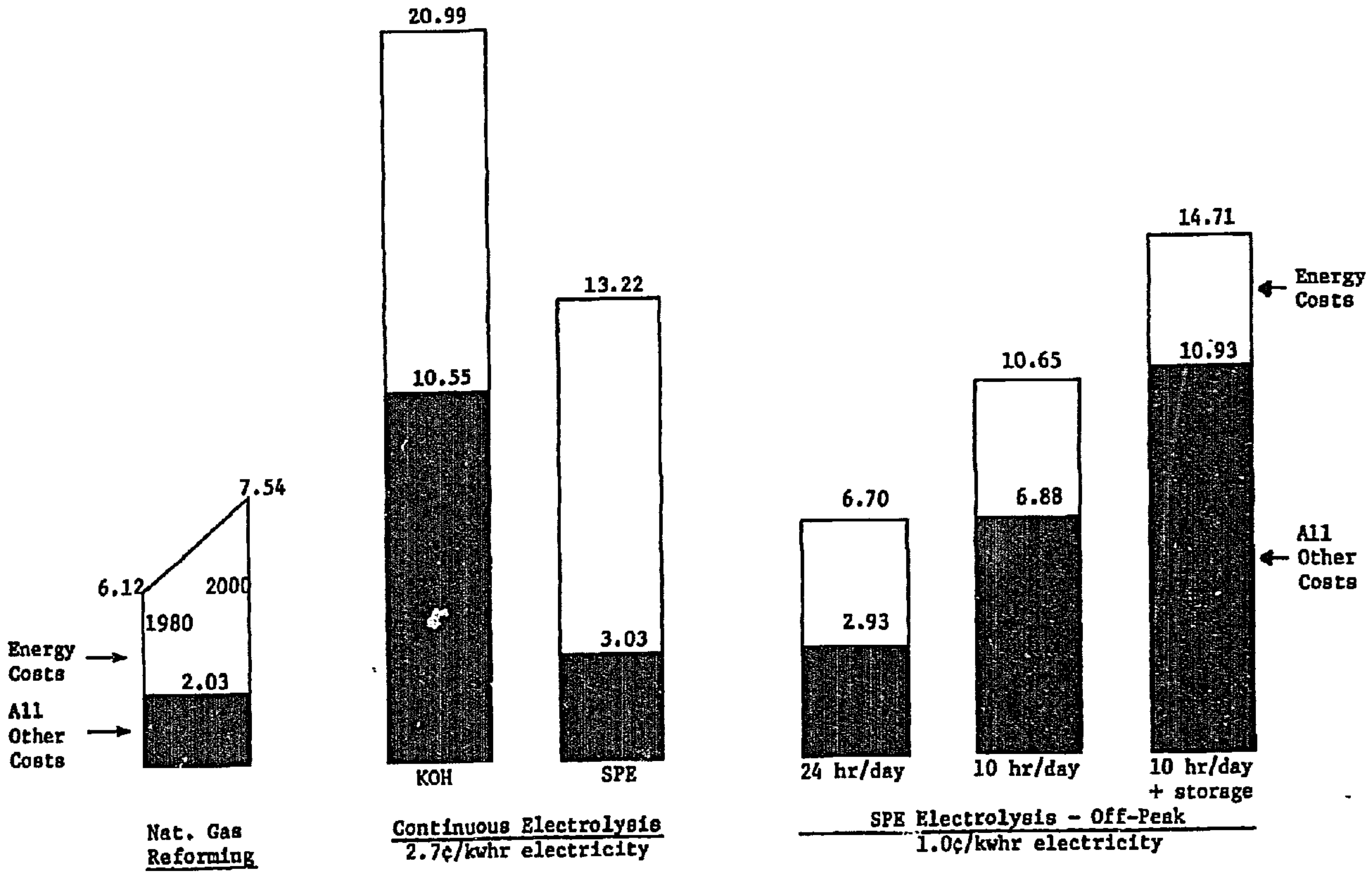

TABLE 3.16

Sensitivities for Hydrogen Manufacture by Electrolysis

All data are hydrogen production costs including
20% before tax return, $/MBtu, 1980 $

Process	Year	Current KOH Elect.	New Technology SPE Electrolyte		
Operating mode		Continuous	Continuous	Off-Peak	Off-Peak + Storage
Base case, most likely electricity prices	1980	20.99	13.22	10.65	14.71
	2000	20.99	13.22	10.65	14.71
Base case, high electricity prices	1980	22.15	14.35	12.51	16.60
	2000	22.15	14.35	12.51	16.60
Base case, low electricity prices	1980	18.28	10.58	8.73	12.82
	2000	18.28	10.58	8.73	12.82
Additional 10% investment contingency	1980	21.89	13.44	11.28	15.76
	2000	21.89	13.44	11.28	15.76
Construction costs escalate 1%/yr above inflation	2000	23.26	13.86	12.08	17.08
Construction costs escalate 1%/yr below inflation	2000	19.13	12.70	9.41	12.80