1.0 SUMMARY

Task 1. Evaluation of Chemical Industry Capacity Requirements and Projected Economics

Projected Chemical Industry Capacity Requirements

Chemical industry hydrogen (H_2), carbon monoxide (CO) and syngas (H_2/CO) capacity addition requirements during the 1978-1982 period are expected to amount to about 800 MM SCFD. The total will be dominated by chemical plant capacity additions in ammonia and methanol. About 80% of the expected 1978-1982 new H_2/CO syngas requirements are expected to be used for ammonia and methanol. This figure is somewhat misleading since the hydrogen requirements for ammonia, over 50% of the 1978-1982 total, resulted from plants planned in the mid-1970's when ammonia prices peaked.

The other major H_2/CO/syngas market categories will be about equally important during the 1978-1982 period. These general market categories are oxo alcohols, polyurethanes, fibers, and other chemicals. Requirements over the five year period will be in the range of 20 MM SCFD to 40 MM SCFD for each category. Polyurethanes are expected to be the largest market of the four, with the largest single factor in polyurethanes use being hydrogen for aniline.

The other chemicals category uses of hydrogen and carbon monoxide will be dominated by use of carbon monoxide for acetic acid production. Oxo alcohols, primarily solvent alcohols, will require about 20 MM SCFD syngas during the 1978-1982 period.

Projected H_2/CO/syngas net additional markets will amount to about 450 MM SCFD during the 1983-1987 period. This is only about 60% of the projection for the previous five year period. No ammonia capacity additions are expected. Projected syngas requirements for methanol amount to about 75% of the total H_2/CO/syngas requirements for 1983-1987. The oxo alcohols market is also projected to be strong during that period amounting to about

60 MM SCFD of syngas. Polyurethanes H_2 and CO requirements will decline to about 30 MM SCFD. New technology for chemical manufacture using H_2/CO/syngas is not expected to be an important factor in terms of new capacity brought on line between now and 1987.

Comparison of H_2 and Syngas Costs From Alternate Feedstocks

The costs of H_2 and syngas product via gasification of coal were compared with partial oxidation of residual oil and steam reforming of natural gas. All product cost calculations are in terms of 1978 dollars, with only energy costs assumed to escalate over a 15 year project life.

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

These comparisons were based initially on the draft JPL Energy Scenario. The world petroleum market underwent severe upward price disruptions during the early months of 1979. This situation required a revision of the Energy Scenario projections used in economic comparisons. Because much of the study was complete when the Revised Energy Scenario was defined, the results of calculations on both scenarios are included in this report for comparative purposes.

The economic comparisons of alternate H_2 and syngas production costs which were used in this study are based on a combination of two criteria - return on equity invested in the project and discounted cash flow return. Both criteria were used assuming the equity owner of the project was an independent single project company. In the case of return on equity, a value was selected which resulted in both an acceptable initial year return and approximately level after tax book returns over the project life. This assumption follows from the usual preference among lenders for a level or increasing income stream from individual projects. Discounted cash flow return calculations assumed only income streams and tax payments from the project itself with regard to the utilization of investment tax credits and capital depreciation. This approach was used in order to put the basic feedstock/technology comparisons on the basis of the project itself, and therefore independent of the effects on the economic comparisons of income streams and tax payments associated with the other businesses in which the equity principal might be involved. In the case of a project specific situation, the evaluation of various feedstocks would, of course, include such effects consistent with the ability of the owner to utilize the available tax credits in early years of the project and consistent with the owner's actual investment analysis philosophy. Detailed methodology is further described in the study; however, the approach employed results in a "year one" price and projected escalation curve for each feedstock/technology case considered, incorporating (1) the two above mentioned financial criteria, (2) the revised energy scenario, and (3) the relevant capital and operating costs. Hence, the competing feedstock/technology comparisons in this summary are described in the terms of the "year one" component and the escalation curve component of the overall economic comparison.

The methodology adopted in this study places primary emphasis on the "initial year price" in the economic comparison of alternative technologies. The initial year price, as estimated in this report, depends primarily on the initial year costs rather than future savings in feedstock costs. While future savings in feedstock costs are included in the calculation of the price escalation rates, the methodology does not provide an explicit means for trading off the higher initial capital costs with the future energy savings in order to determine the preferred technology. The views of various companies on the importance of initial year price vs. escalation of that price will vary widely. This divergence of viewpoints reflects the uncertainty in future feedstock costs, and the constraints on investment capital facing the majority of the firms operating in this industry. Since no specific trade-off was assumed in this analysis, cost competitiveness, in the conclusions, refers to a comparison of initial year prices, and does not necessarily indicate that a specific technology is preferred overall. In the case of companies expecting relatively high feedstock escalation, or for companies with sufficient internal investment capital, and the philosophy of evaluating investment decisions without specific regard to initial year price, emphasis on initial year price does introduce the possibility of a bias against technologies requiring large initial capital investments, such as coal gasification.

The economic comparison of H_2 and syngas costs on coal, oil and natural gas feedstocks were computed for several parameters: (1) year of plant start-up, (2) geographic location of plant, (3) plant size and, (4) coal type. Conclusions based on the Revised Energy Scenario and the above study bases for plants starting up in years 1982, 1987 and 2000 were as follows:

1. With one exception, coal-based H_2 and syngas were not estimated to be price competitive in year 1 of plant operation for any of the plant start-up years, plant size/slate and geographic regions studied. The only exception was the production of 150 MM SCFD hydrogen in the Ohio Valley with start-up in year 2000.
2. Conclusions on hydrogen and syngas product cost escalation for 1982 and 1987 plant start-up were as follows:
   a. In the Ohio Valley and Mid-Atlantic regions, oil feedstock was projected to result in average product price escalations at least twice as high as escalations for coal. Natural gas feedstock was projected to result in product price escalations about five times greater than for coal.

b. In the Gulf Coast region, oil was projected to result in product escalations about 50% higher than coal. Product price escalations based on natural gas were projected to be at least twice as high as escalations for coal.

3. The "year one" competitive position of coal was projected to improve sharply for start-up years 1982 and 1987 in the major market identified, syngas. The average 1982 price premium for syngas from coal was about 50% at 40 MM SCFD and about 35% at 150 MM SCFD. By 1987 the premiums dropped to approximately 30% and 15%, respectively.
4. For the major chemical feedstock market identified in this study, syngas, natural gas was evaluated to have the lowest cost in initial year of plant operation for plants starting up in 1982. Oil was evaluated to have the lowest cost in initial year of plant operation for plants starting up in 1987 and 2000.
5. For the hydrogen product slate natural gas was evaluated to have the lowest cost in initial year of plant operation for plant start-up years 1982 and 1987.
6. For both syngas and hydrogen and for plant start-up years 1982, 1987 and 2000, the Gulf Coast region had the lowest evaluated product cost followed by the Ohio Valley region. The Mid-Atlantic region was evaluated to be the highest product cost region.
7. Lignite and bituminous coal types were compared for both product slates and plant sizes in the Gulf Coast region. Lignite resulted in about a 10% premium in product price compared with bituminous. The higher capital and lower efficiency of lignite gasification more than offset the lower cost of lignite feedstock.

Task 2. Analysis of Problem Areas and Options to Stimulate Coal Gasification System Development

Analysis of Gasification Improvement Incentives

The effect of potential research and development impact on coal gasification economics was estimated by calculating product prices for capital cost improvements of 10%, 20% and 30%, and operating cost improvements of 10% and 20%.

Based on the above, capital cost and operating cost improvements resulted in no 1982 R&D cost reduction result which would make coal gasification competitive with reforming, the most economic option at 150 MM SCFD syngas. A 30% capital improvement made coal competitive with oil at 150 MM SCFD syngas in 1987 when oil is the most economic alternative.

Cost comparisons of pressurized vs. atmospheric coal gasification were made for a Gulf Coast location producing syngas. Results at both 40 MM SCFD and 150 MM SCFD indicated an economic advantage of approximately 14% for pressurized gasification for design conditions of 350 psig product gas. While pressurized gasification economics were thus projected as more favorable than atmospheric pressure gasification, the difference was not large in relation to the accuracy of the estimates.

An economic evaluation was also made of co-producing fuel gas and syngas. The comparison assumed incremental medium Btu fuel gas production on a previously justified 150 MM SCFD syngas plant. The incremental fuel gas production was assumed to be 150 MM SCFD of medium Btu gas. Based on the revised Energy Scenario, incremental fuel gas was not competitive for 1982 or 1987 plant start up with either natural gas or fuel oil. Incremental medium Btu fuel gas is projected to be more than twice as expensive as natural gas in 1982 and 25% more expensive in 1987. The premium above fuel oil was calculated at about 20% in 1982 and 10% in 1987.

Analysis of Non-Technical Problem Areas and Options to Stimulate Coal Gasification System Development

Non-technical factors present major barriers to construction of coal gasification plants. Two of the most important non-technical factors which can significantly affect coal gasification system development are discussed below.

While financing approaches can significantly affect projected product price, alternative project financing methods generally reflect the allocation of business exposure factors between the product buyer and product seller. The allocation process has been analyzed in this study according to two key effects of financing approach: the effect of capital structure in initial price and the effect of debt leverage on the project return on total investment. Variation of debt/equity ratio from 0/100 to 75/25 affects initial year product price in the range of 10-15%. Increasing the debt interest rate from 8% to 10% increases initial year product price less than 5% for debt/equity and DCF return on equity criteria. The effect of debt leverage on project return on investment was calculated. Alternative debt/equity ratios and debt interest rates were considered for specific discounted cash flow returns on seller's equity and, as expected, the effect of leverage was significant. For example, a change from 0/100 debt/equity to 75/25 debt/equity had the impact of decreasing required return on total investment from 15% to 11.5% assuming the DCF return on equity is 15%. With a 20% DCF return on total investment, the ability to leverage the project from 0% debt to 75% debt results in an even greater decline in return on total investment, from 20% to about 13%. Other financing approaches with potentially even lower apparent capital costs can be considered, such as leveraged leases; however, these and any highly leveraged approaches cannot be considered in the abstract, as is often done. The business arrangement between buyer and seller must first be defined before any financing approach or cost of capital can be meaningfully considered.

Among the various regulatory barriers affecting coal gasification, oil and natural gas pricing uncertainty are the most significant. Given the nature of the political process which determines U.S. oil and natural gas prices, the indirect regulatory barriers to coal gasification which result from historical price controls present a very difficult commercialization problem. Over the 1982-1987 period, this study projects that rapidly escalating oil and gas prices will reduce the "year one" premium of coal-based syngas to about 15%. However, the actual gap could be significantly different depending on the extent to which, directly and indirectly, the government affects the prices of oil and natural gas. Fortunately a reduction of government influence in the pricing of conventional energy appears to be underway. As this trend continues, government efforts to stimulate coal gasification system development will have a higher probability of success, as the current "subsidy gap" between the cost of gasified coal and the cost of H_2 and syngas from conventional feedstocks decreases through the effects of market forces.

Recommended Options to Stimulate Coal Gasification System Development

The economic analyses completed in this study indicate a requirement for significant additional financial incentives in order to place coal gasification in a competitive position for hydrogen and syngas production. The financial incentives which are most likely to succeed are those of a "front end" type which provide direct or indirect cash flow impact definable prior to start-up of a plant. Cash grant, cost share, and legislatively implemented investment tax credit and rapid write off are possible front end options.

There are three distinct areas considered in this study for the stimulation of coal gasification system development. Those areas are: (1) Government R&D expenditures that would significantly reduce coal gasification product costs, (2) significant reduction of government participation in pricing of oil and natural gas and (3) Government encouragement of pioneer coal gasification plants through appropriate financial incentives. These areas are discussed in the following paragraphs.

For syngas, the major chemical feedstock market identified in this study, a coal gasification R&D effort resulting in a 30% capital cost reduction and a 20% operating cost reduction was evaluated. Syngas from a 1982 commercialization of these R&D results was projected to cost more than syngas from natural gas. By 1987, when oil was projected to be the least cost syngas option, a 30% reduction in coal gasification plant capital cost would be required to produce product competitively priced in the year of start-up. These R&D results would be difficult goals and do not appear to justify a massive Government R&D program.

The most important variable in coal gasification system development is expected to be competitive feedstock costs. Government involvement in U.S. energy pricing has clouded potential coal gasification plant investor's views of future competitive economics. For example, the premium in initial year of operation for syngas from coal was projected to be about 15% in the mid-1980's over the projected least cost feedstock, oil. An initial 15% premium might be acceptable to some plant investors today if other institutional barriers could be successfully dealt with and if the continuing potential of reimposed price controls on domestic oil and gas could be eliminated.

Under the financial analysis assumptions developed for this study, conventional ITC and accelerated depreciation are not sufficient incentives to make coal gasification competitive in the year of plant start-up, until 2000. Accelerated depreciation directly affects only the timing of cash flows and not the amounts. ITC affects both, providing taxes would otherwise be payable. As previously noted, and in accordance with the contract scope of work, the syngas producer on which this study is based is assumed to be a separate company and, thus, the amount of ITC and depreciation which benefits the company is constrained by pre-tax profit from the coal gasification project. This assumption was made in order to address the broadest range of business situations, including those which are constrained in the use of ITC and depreciation. In those specific situations where such constraints do not exist, accelerated depreciation and increased ITC can of course be effective incentives.

In summary, the most effective methods for stimulating the initial development of the coal gasification industry for the broadest range of business situations appear to be cash grant and cost share approaches as supplements to ITC and accelerated depreciation. These approaches can be implemented most effectively when a return on investment criterion for private capital is set and implemented as the project develops. While this approach may require additional government involvement in the project, its use helps avoid (1) discouraging all but very large companies or consortia from participation due to the magnitude of the projects, particularly in light of the many other project risks which have not been discussed in this summary - government design/construction/operation approvals, environmental law changes, etc. - which must be evaluated and provided for, and in light of the above, (2) requests for Government grants or cost share which may appear unrealistically high in order to provide for those business risks which are inherently difficult to quantify.

These same basic shortcomings of "fixed amount" incentives also apply to production credits or subsidies unless specifically eliminated by the enabling legislation which would implement this type of incentive.

2.0 INTRODUCTION

2.1 OBJECTIVE AND APPROACH

The basic objective of this study is evaluation of the potential for coal gasification in reducing future oil and natural gas requirements for H_2, CO, and syngas feedstocks in the production of chemicals.

The approach used basically involves estimation of the future requirements for H_2, CO, and syngas needed as feedstocks in the production of chemicals; and estimation of the least cost alternative for H_2/syngas production at different plant sizes. Since coal gasification is the technology of primary interest, sensitivity cases are considered for different gasifier pressures, coal types, and geographic location of H_2/syngas producing facility.

Critical barriers to coal gasification commercialization are considered including financing barriers and regulatory barriers such as: coal transportation and mining, delays in finalizing air pollution regulations, and oil/natural gas pricing uncertainty. Financial and regulatory actions to stimulate coal gasification system development are recommended.

2.2 JPL ENERGY SCENARIO

Most projections of future U.S. oil, natural gas and coal prices are based on these general assumptions:

1. "World" crude oil prices are based on politics, not economics of oil production.
2. At some future time U.S. natural gas and oil prices will be "decontrolled" and will rise to world prices after accounting for form value, sulfur content, etc.
3. The U.S. coal industry is sufficiently competitive that future prices will be related to cost of production, i.e., no monopoly price setting situation will develop.

Under the general assumptions listed above, the price escalation rates of coal and oil/natural gas should be different over the long run. If they are, technologies which are comparatively expensive now (coal gasification) relative to other approaches to syngas production (oil, natural gas) will close the gap and, eventually, the least cost syngas production technology will change. In order to evaluate the impact of these assumptions in this study, all costs are evaluated in 1978 dollars. Only energy costs are assumed to escalate in real terms.

The energy price escalations used in the Task I economic assessments in this study are based on an energy scenario provided by the Jet Propulsion Laboratory (JPL). This set of energy price projections is referred to as the Draft JPL Energy Scenario. The scenario was constructed prior to the series of major OPEC petroleum price increases which occurred in early 1979. Therefore, an alternate scenario was constructed after this contract was begun and sensitivity cases for H_2, syngas production were developed. Results of the sensitivity projections are shown in Section 3.3.3.

2.3 ASSUMPTIONS

This study is intended to answer the following questions:

1. What are the chemical markets for H_2, CO, and syngas?
2. Can H_2 and syngas produced from coal compete with conventional feedstocks, i.e., natural gas and oil?
3. What types of financial incentives will be required to make gasified coal competitive as a chemical feedstock during the 1980's?

In order to provide answers to these questions, key assumptions have been made.

In the area of coal gasification technology, questions of technical and cost estimate uncertainty are not addressed in detail in making capital and operating cost estimates. However, appropriate contingencies are included to make coal gasification technologies comparable to oil and natural gas technologies.

Financial analyses are carried out using a discounted cash flow approach. In order to set initial year prices, a target return on equity investment is set for the first year of plant start-up. It is assumed that any national policy which intends to accelerate the rate of coal use for chemical feedstock production can best be implemented by increasing cash flow available to the coal gasification plant owner. The options for doing this are assumed to be investment tax credit (higher ITC) and depreciation (faster plant write-off).

Finally, in the estimation of H_2/CO/syngas market potential resulting from new chemical synthesis technology, CO and syngas prices are assumed to be those prices applicable to the least expensive production alternative at that scale. That is to say, if a small quantity of CO is to be sold from a large coal gasification plant, it is assumed that the CO would be priced at the cost of production (including profit) applicable to producing that CO from the least cost -- oil or natural gas plant sized for that CO volume. It is also worth noting that this study evaluates only a few of the potential H_2/CO/syngas based new chemical synthesis technologies. Therefore, potential synthesis gas uses could exceed those estimated.

3.0 TASK I ECONOMIC ASSESSMENT

The approach used in this study to evaluate the potential and incentives required for supplying hydrogen and syngas ($2H_2/1CO$) feedstocks to the U.S. chemical industry via coal gasification included these three steps:

1. Estimation of future capacity expansions for chemicals production and the H_2/CO/syngas capacities required as feedstock.
2. Economic comparisons of future H_2 and syngas capital and operating production costs over a range of parameters (plant scale, gasification technology, coal type).
3. Conversion of capital and operating cost estimates (1978 dollars) into product prices in future years of plant start-up using a) a financial analysis computer program and b) a JPL energy scenario.

Sections 3.1 and 3.2 define estimated future H_2/CO/syngas capacity requirements. The economic comparisons and results are defined in Section 3.3.

3.1 FUTURE CHEMICAL INDUSTRY H_2/CO/SYNGAS CAPACITY REQUIREMENTS, 1978-1987

The following sections define the projected hydrogen (H_2), carbon monoxide (CO), and syngas (H_2 plus CO) capacity requirements for chemical manufacture.

The historical markets for H_2 and syngas have been due almost entirely to ammonia and methanol plants. While future prospects for these commodity chemicals do not appear as bright as they have been in the past, careful evaluation of these markets is important for these reasons:

1. As mentioned, these are the major markets today.
2. If coal gasification becomes a commercial reality in the chemical industry, it is more likely to occur at the scale of ammonia and methanol plants rather than at smaller scale.

3. Ammonia and methanol plants have become an increasingly attractive means of realizing the fundamental valuation difference between unutilized offshore natural gas and natural gas in Western Europe and the U.S. Any trade barriers erected sufficiently high to keep out imports and make new plants economic in the U.S. would encourage coal gasification technology. The question then becomes competitive hydrogen and syngas costs. These are evaluated in Section 3.3 of this study.

In this study, evaluation of H_2/CO/syngas feedstocks for future chemical production included analysis of a few new routes to existing chemicals using these feedstocks. The potential impact of this type of new chemical synthesis technology for production of chemicals may have important consequences for the fibers markets and for products produced from methanol. These new H_2/CO/syngas markets are discussed in Section 3.1.4.

Table 3.1 summarizes the estimated H_2/CO/syngas requirements for chemical production during the 1978-1987 period. As the table shows, during the 1978-1982 period, ammonia and methanol production will be important in the major requirements plants category. However, the figures shown are somewhat misleading. In the case of ammonia, all the capacity additions shown represent the last few expansion commitments made in the 1974-1975 period when ammonia prices were high. Most of the syngas capacity shown for methanol represents a single Gulf Coast plant. No ammonia capacity additions have been projected for the 1983-1987 period. Methanol demand is expected to require one major plant in the 1978-1982 period and two additional plants in the 1983-1987 period. A qualification is necessary here also since the projected use of an entirely new methanol consuming product, MTBE, accounts for one-third of the 1978-1987 capacity additions projected.

Oxo-alcohol and polyurethane intermediates expansions represent average growth with the exception of aniline. Aniline capacity is expected to become substantially overbuilt during the 1978-1979 period. No further aniline capacity addition has been projected until the end of the 1983-1987 period.

Hydrogen consuming fibers intermediates plants were substantially overbuilt in 1977 and no expansions are projected through 1987. Only one of the four potentially CO/syngas based fibers intermediates plants based on new technology is expected to develop during the ten year forecast period. This conclusion must be qualified, however, since projected olefin and aromatics pricing has been based on the original energy scenario used in this study and not the revised scenario described in Section 3.3.3.

Acetic acid is the only product in the other chemicals category which is expected to be a major requirement, in this case for CO. This is due to commitments made in the mid-70's and coming on-line in the 1978-1979 period. An additional world scale acetic acid plant completion is expected at the end of the 1983-1987 period. This assumes continuation of existing technology in key markets for acetic such as vinyl acetate. New technology for vinyl acetate production was not evaluated in this study, and the impact of new vinyl acetate technology on acetic demand has not been evaluated.

Table 3.1

ESTIMATE OF 1978-1987 H_2/CO/SYNGAS REQUIREMENTS FOR CHEMICAL PRODUCTION
(MM SCFD)

1978-1982

	Major Requirements Plants				Oxo Alcohols			Polyurethanes			Fibers				Other Chemicals					
	NH_3	MeOH	C_6	Ethanol	Solv	Plas	Det	MDI	TDI	Aniline*	EG	TPA	AcH	HMDA HaD Cyclo	HAc	Pest.	Polyc	H_2O_2	1,4BD	Spec
Gulf Coast	200/0	160/80	25/0	--	11/6	3.0/1.5	--	0/5.8	8.8/2.2	14.8/0	--	--	--	--	0/25	0/1.3	0/0.9	5.4/0	--	2.2/2.2
Mid-Atlantic	--	--	--	--	--	--	--	--	--	2.3/0	--	--	--	--	--	0/1.0	--	--	--	--
Ohio Valley	--	--	5/0	--	--	--	--	--	--	2.3/0	--	--	--	--	--	--	--	--	--	--
Other	200/0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0.3/0
Totals	400/0	160/80**	30/0	--		14.0/7.5**			28.2/8.0			0/0					2.9/30.4			

1983-1987

	NH_3	MeOH	C_6	Ethanol	Solv	Plas	Det	MDI	TDI	Aniline*	EG	TPA	AcH	HMDA HaD Cyclo	HAc	Pest.	Polyc	H_2O_2	1,4BD	Spec
Gulf Coast	--	220/110	10/0	--	21.4/11.3	3.0/1.5	6.6/3.5	0/9.9	13.3/3.3	4.7/0	--	--	0/3.5	--	0/12.5	0.1.2	--	--	1.8/0	0.3/0
Mid-Atlantic	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0/1.0	--	--	--	--
Ohio Valley	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0/0.9	--	--	--
Other	--	--	--	--	8.6/4.6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Totals	--	220/110**	10/0	--		39.6/20.9**			18.0/13.2			0/3.5					2.1/15.6			

* Includes aniline for non-urethane uses
**H_2/CO used as syngas

KEY: Hydrogen figure upper left, carbon monoxide figure lower right

3.1.1 MAJOR REQUIREMENTS PLANTS

3.1.1.1 AMMONIA

If fully utilized, anhydrous ammonia capacity in the U.S. would require over three billion cubic feet per day of hydrogen. This is by far the largest market for hydogen in the U.S. Nearly all of U.S. capacity is based on plants with integrated methane reforming and ammonia synthesis.

As of 1977 substantial excess ammonia production capacity existed in the U.S. U.S. ammonia prices roughly quadrupled between the early and mid-1970's. Capacity was increased about 25% during the 1974-1978 period in response to higher prices and profits. About 6000 tons per day of the total expansion was brought on-line during 1978 and is therefore included in this study. Unfortunately, demand for ammonia increased about 7% during the 1974-1978 period. By 1977 ammonia prices were back to 1974 levels. Since natural gas prices increased substantially between 1974 and 1977, 1977 ammonia prices were in some cases insufficient to cover variable costs and a substantial number of plants were shut down.

The possibility of major future ammonia imports to the U.S. began to take shape in 1977. The fundamental valuation difference between shut-in offshore natural gas and domestic natural gas prices has encouraged exportation of energy values in commodity forms such as ammonia. Various sources have projected that up to 25% of U.S. consumption of ammonia equivalents will be imported by the early 1980's. The Soviet Union, Trinidad, and Mexico are expected to be major sources of U.S. imports.

The outlook for capacity additions, and therefore hydrogen capacity requirements for U.S. ammonia production, depends on when existing shutdown capacity is restarted and the level of future imports.

With 1978 ammonia requirements at 16.5 million tons and effective capacity at 19.5 million tons, no incremental capacity (above the mid-70's commitments) will be required through 1982. Even with the assumption of no imports (which will not be true) the 3 million tons of excess capacity will accommodate the expected U.S. annual ammonia market growth of 3.7%.

Domestic capacity increases for ammonia production during the 1983-1987 period appear to depend on future ammonia import levels. A range of 2-4 million tons of imports has been projected by 1982. Even if the upper end of that import range is not reached until 1987, no domestic capacity additions will be required during the 1983-87 period. Recently, some domestic ammonia producers have attempted to limit the level of imported ammonia by requesting import duty "that would enable domestic producers to operate at reasonable levels of profit and at appropriate rates of capacity..." The outcome of the duty request will eventually reach Congress and will be resolved by the political process. At this time it does not appear likely that ammonia import duties will be imposed at a level sufficiently high to permit new U.S. capacity expansion based on conventional natural gas technology during the 1983-1987 period.

3.1.1.2 METHANOL

The analysis presented below defines expected changes in methanol demand due to changes in specific methanol-consuming product areas. The analysis is concerned with three key areas -- existing chemical markets for methanol, existing chemical markets for methanol involving new technology, and new markets for methanol.

Methanol Markets

Methanol is the most important syngas-consuming product evaluated in this study. Next to ammonia it is the largest market for either hydrogen or syngas.

Throughout the 1960's and early 70's, demand for methanol increased substantially faster than overall U.S. economic growth. This was due to the above average growth of the housing and construction markets which required increasing amounts of formaldehyde. Also, key methanol derivatives were introduced and participated in very high growth markets as the following examples illustrate. During the 1960's, dimethyl terephthalate expanded in parallel with polyester fiber use. Technology for conversion of methanol to acetic acid was introduced in 1970 and opened up major indirect growth areas for methanol in vinyl acetate and terephthalic acid. Methanol demand peaked in 1973 at over 1 billion gallons, a level somewhat above the 1977 U.S. domestic and net export requirements.

The major methanol markets based on existing and new technology are discussed in the following paragraphs. Market projections are shown in Table 3.2.

Formaldehyde is the largest single market for methanol. Through the late 1960's and early 70's production increased from just over 4 billion pounds to about 6.5 billion pounds. The mid-70's recession reduced consumption to about 4.5 billion pounds. Methanol consumption for formaldehyde is estimated at 425 million gallons in 1977. A growth rate of 4% is expected through 1987.

Methyl Halides, primarily methyl chloride, required about 70 million gallons of methanol in 1977. Methyl chloride consumes nearly all of the methanol used in methyl halides. Silicones and tetramethyl lead (TML) are the major methyl chloride markets. Silicones are expected to grow at a 15% annual rate. TML useage is expected to phase out due to the incompatibility with catalytic converters. Methylene chloride and chloroform are used in aerosol and fluorocarbon applications, respectively. Modest growth is expected for both. A 3.5% growth rate is expected for methyl halides.

Methyl Methacrylate (MMA) production was about 750 million pounds in 1977 requiring about 45 million gallons of methanol. MMA is used in acrylic sheet, surface coating resins, and molding/extrusion powders. New technologies have recently been discussed for MMA production. However, all require approximately the same methanol use. MMA growth is expected to continue at above 5% per year through 1987.

Methylamines, (mono-, di- and trimethylamines), are produced by the catalytic reaction of ammonia and methanol. Monomethylamines are used in insecticides, surfactants, and explosives. Dimethylamines are used in spinning solvents, rubber chemicals, and pesticides. Trimethylamine is used in animal food supplements. Methylamine use of methanol is expected to increase from about 60 million gallons in 1977 to about 100 million gallons in 1987.

Solvent, antifreeze, and other applications for methanol amounted to over 200 million gallons of total 1977 methanol use. As a solvent, methanol is used in extracting, washing, drying, and crystallizing. Solvent uses of methanol involve numerous products. As an antifreeze, methanol is still used in farm equipment engines and windshield washing solutions. Methanol is also used with formaldehyde to inhibit polymerization. Solvent and miscellaneous uses of methanol are expected to grow at a rate of about 4.5% through 1987.

Figure 3.1 shows the potential impact of technological changes in existing and new methanol markets. Products where the impact of new syngas technology on methanol demand is expected to be greatest, are discussed in the following paragraphs.

Acetic Anhydride use of methanol is based on a requirement for new capacity early in the 1983-1987 period. New technology is expected to be used and the methanol requirement is included in methanol market projections.

Dimethyl Terephthalate (DMT) use of methanol depends primarily on the future market split between DMT as a fiber intermediate and terephthalic acid (TPA) use. The DMT/TPA split used in this study appears in the fibers section, Table 3.18. DMT use of methanol also depends on what proportion of the operating plants recycle methanol. The figure used in this study is 85%.

Methyl Tertiary Butyl Ether (MTBE) is a new market in U.S. methanol consumption. MTBE is presently a front running candidate for blending in unleaded gasoline as an octane improver. The conclusion on MTBE's economic viability has resulted from a number of petroleum refiners' independent analyses of their various octane supply sources. Basically, refiners appear to have concluded that the complex relationship between gasoline demand, octane requirements, butylene supply for alkylation and other factors favor MTBE. The projected methanol demand shown in Table 3.2 results from synthesis of a number of MTBE market projections.

Imports of methanol are projected to increase moderately. No flood of imported methanol on U.S. markets is expected.

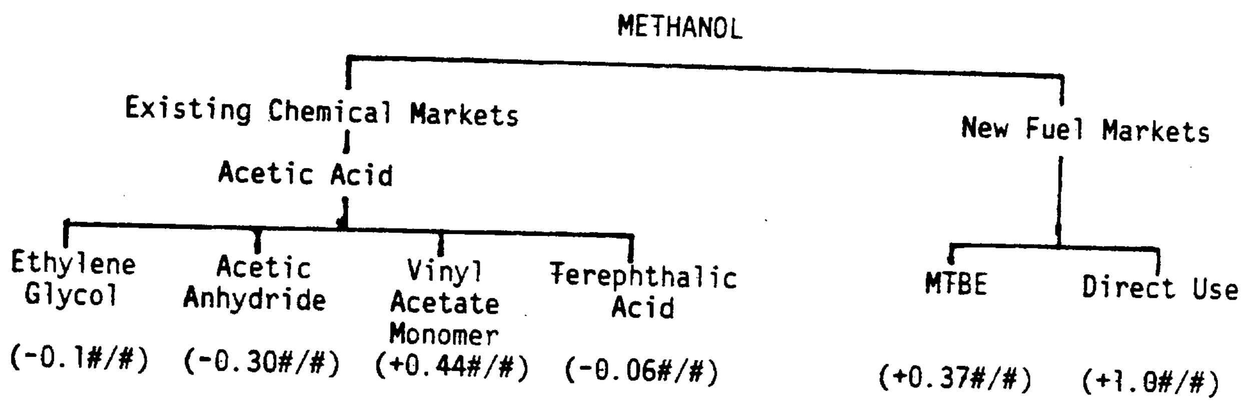
3.1.1.3 BENZENE VIA TOLUENE HYDRODEALKYLATION

Refiners typically hydrodealkylate substantial quantities of toluene to produce benzene. When combined with disproportionation, production of both xylene and benzene from toluene without using hydrogen, between 25% and 30% of U.S. benzene supply is produced from toluene. This amounts to about 450 MM gallons of annual toluene demand.

The primary factor holding back increased use of H_2 for benzene production from toluene is the lack of strong demand in the benzene markets. Demand for benzene in cyclohexane, cumene/phenol and styrene is expected to increase in the vicinity of 3-4% annually. A somewhat lower growth rate in the production of benzene from toluene has been projected in this study.

Figure 3.1

POTENTIAL IMPACT OF NEW SYNGAS TECHNOLOGY
ON METHANOL DEMAND



Notes:

1. Numbers in parenthesis indicate net change in methanol (pounds) required per pound of ethylene glycol, acetic anhydride, vinyl acetate monomer, terephthalic acid, MTBE and direct use, respectively.

2. Net change data assume the following existing technology routes:

   - Ethylene glycol via ethylene oxide
   - Acetic anhydride via ketene technology
   - Vinyl acetate via acetic acid
   - Terephthalic acid via p-xylene

3. No direct fuel markets were analyzed in this study since these are not within the definition of chemical markets which this study covers.

Table 3.2

PROJECTED METHANOL DEMAND
(MM Gallons)

	1977	1982	1987
Formaldehyde	425	550	725
Methyl Halides	70	85	100
Methylamines	60	75	100
Methyl Methacrylate	45	60	75
Solvent/Other	210	260	330
Acetic Anhydride	--	--	15
Acetic Acid	42	146	160
Dimethyl Terephthalate	53	58	65
MTBE	--	125	175
Net Export	(10)	(40)	(60)
Total U.S. Demand	895	1319	1685
Effective Capacity	1135	1375	1375
Capacity Needed	--	(56)	310

	1978	1982	1987
Benzene, MM Gallons	375	440	460
H_2, MM SCFD	175	205	215

The approximate geographic breakdown of this increased H_2 demand is expected to be as follows (MMSCFD):

	1978-1982	1983-1987
Gulf Coast	25	10
Mid-Atlantic	--	--
Ohio Valley	5	--
Other	--	--
	30	10

3.1.1.4 ETHANOL

Ethanol (ethyl alcohol) is produced from ethylene and by fermentation. U.S. ethanol production is split roughly 25/75 between fermentation and ethylene hydration. Ethanol is of interest in this study due to the potential introduction of new syngas technology that would result in production of ethanol from methanol and syngas.

Ethanol Markets

Fermentation ethanol produced in 1977 was used almost exclusively for production of alcoholic beverages. By law, "spirits" manufactured for liquor must be produced by fermentation. Since fermentation alcohol was substantially higher in price than synthetic ethanol in 1977, only small quantities were used outside of alcoholic beverages.

Chemical markets for ethanol are summarized in Table 3.3. With an overall growth rate of less than 2% and with existing capacity mothballed, no ethanol capacity additions for the chemical markets shown in Table 3.3 will be necessary through 1987.

The interesting future market for ethanol began to develop when the national energy bill passed in 1978 exempted alcohol/ gasoline blends from the 4 cent per gallon federal excise tax on gasoline. This alcohol subsidy, applicable to blends containing at least 10% alcohol, amounts to an effective 40 cent per gallon subsidy in 90/10 blends of gasoline/alcohol.

In order for a chemical market to develop for ethanol as a gasoline extender in the U.S., ethanol must compete -- roughly on a cents-per gallon basis -- with the leading octane improver, MTBE. MTBE was analyzed in the methanol section of this study. The projections in that section assumed a 1978 cost for MTBE of about 60 cents per gallon. With a 90/10 gasoline/ethanol blend, the 1978 price for producing ethanol using syngas would have to be less than $1.00 per gallon to compete with MTBE. This is not expected to be the case in 1978 or even in the late 1980's. No syngas market is projected for ethanol production through 1987.

Table 3.3

SYNTHETIC ETHANOL MARKETS
(MM Gallons)

	1977	1982	1987
Intermediates	65	75	87
Cosmetics	45	52	60
Cleaning Preparations	30	40	53
Coatings	32	32	32
Vinegar	20	27	35
Pharmaceuticals	20	23	26
Acetaldehyde	17	17	17
Solvents	4	4	4
Exports	10	--	--
	243	270	314
Effecive Capacity*	320	320	320

*Includes mothballed plant