9950-395

A STUDY OF INDUSTRIAL HYDROGEN AND SYNGAS SUPPLY SYSTEMS

FINAL REPORT

W. J. AMOS, J. SOLOMON, K. F. ELIEZER, G. V. RUX, AND G. M. DRISSEL

AIR PRODUCTS AND CHEMICALS, INC.
P.O. BOX 538
ALLENTOWN, PA 18105

RESEARCH AND DEVELOPMENT CONTRACT NO. 955421
SUBCONTRACT UNDER NASA CONTRACT NAS7-100
TASK ORDER NO. RD-152

OCTOBER 1979

This work was performed for the Jet Propulsion Laboratory, California Institute of Technology sponsored by the National Aeronautics and Space Administration under Contract NAS7-100

(NASA-CR-163523) A STUDY OF INDUSTRIAL HYDROGEN AND SYNGAS SUPPLY SYSTEMS Final Report (Air Products and Chemicals, Inc.) 159 p HC A08/MF A01 CSCL 21D
N80-31624
Unclas
G3/28 28570

ABSTRACT

This summary outlines the work performed and conclusions reached under JPL Contract No. 955421.

This study evaluates the potential and incentives required for supplying hydrogen and syngas ($2H_2/1CO$) feedstocks to the U.S. chemical industry from coal gasification systems. Future hydrogen and syngas demand for chemical manufacture is estimated by geographic area. Projected economics for hydrogen and syngas manufacture are estimated with geographic area of manufacture and plant size as parameters. These estimates are made for natural gas, oil and coal feedstocks. The economic estimates for coal technology involve different coal type, lignite and bituminous, and also atmospheric and elevated pressure gasification.

Several problem areas presently affecting the commercial feasibility of coal gasification are considered in this study. The impact of potential process improvements are considered via the impact of hypothetical capital and operating cost improvements on hydrogen and syngas economics. Unique factors involved in financing coal gasification plants are discussed. Regulatory barriers are evaluated as they affect coal gasification. Coal mining/transportation, air quality regulations, and competitive feedstock pricing barriers are evaluated in summary fashion.

Finally, the study discusses the potential for making coal gasification the least costly H_2 and syngas supply option. Options to stimulate coal gasification system development are discussed.

NOTE: It must be emphasized that the results and conclusions in this report are based on energy escalation scenarios provided by JPL. Because of the continuing upward volatility of world oil prices, it is particularly important that the results and conclusions herein be viewed in the context of the energy escalation scenarios on which they are based.

TABLE OF CONTENTS

Page

1.0 Summary 1

2.0 Introduction 11

  2.1 Objective 11

  2.2 JPL Energy Scenario 11

  2.3 Basic Assumptions 12

3.0 Task I Economic Assessment 14

  3.1 Future Chemical Industry H_2/CO/Syngas Capacity Requirements 1978-1987 14

    3.1.1 Major Requirements Plants 18

      3.1.1.1 Ammonia 18

      3.1.1.2 Methanol 19

      3.1.1.3 Benzene 22

      3.1.1.4 Ethanol 25

    3.1.2 Oxo Alcohols 27

      3.1.2.1 Solvent Alcohols 27

      3.1.2.2 Plasticizer Alcohols 28

      3.1.2.3 Detergent Alcohols 28

    3.1.3 Polyurethanes and Aniline 34

      3.1.3.1 MDI 34

      3.1.3.2 TDI 35

      3.1.3.3 Aniline 38

      3.1.3.4 Supply/Demand Balances and H_2/CO Requirements 39

    3.1.4 Fibers 41

      3.1.4.1 General Overview of U.S. Fibers Markets 41

        3.1.4.1.1 U.S. Fiber Consumption 43

        3.1.4.1.2 Summary of Statistical Data 46

      3.1.4.2 Ethylene Glycol 47

      3.1.4.3 DMT/TPA 51

        3.1.4.3.1 Markets 51

        3.1.4.3.2 Polyethylene Terephthalate (PET) Film 51

        3.1.4.3.3 Polybutylene Terephthalate (PBT) Resins 52

TABLE OF CONTENTS
(continued)

Page

3.1.4.3.4 Polyethylene Terephthalate (PET) Barrier Resins 52

3.1.4.3.5 Supply/Demand Balances 53

3.1.4.4 Acetic Anhydride 55

3.1.4.4.1 Markets and Supply/Demand Balance 55

3.1.4.5 Hexamethylenediamine, Adipic Acid and Cyclohexane 55

3.1.4.5.1 HMDA 55

3.1.4.5.2 Adipic Acid/Caprolactam 57

3.1.5 Other Chemicals 59

3.1.5.1 Acetic Acid 59

3.1.5.2 Pesticides 61

3.1.5.2.1 Insecticides 61

3.1.5.2.2 Herbicides 61

3.1.5.2.3 Fungicides and Fumigants 64

3.1.5.2.4 Projected CO Requirements 64

3.1.5.3 Polycarbonates 64

3.1.5.4 Hydrogen Peroxide 67

3.1.5.5 Butanediol 69

3.1.5.6 Specialty Chemicals 69

3.1.5.6.1 Specific Chemicals 71

3.1.5.6.2 H_2/CO Requirements 74

3.1.6 Electrolytic Hydrogen Potential 74

3.2 Future Chemical Industry H_2/CO/Syngas Capacity Requirements, 1988-2000 75

3.2.1 Major Requirements Plants 77

3.2.2 Oxo Alcohols 78

3.2.3 Polyurethanes 78

3.2.4 Fibers 78

3.2.5 Other Chemicals 79

3.3 Economic Comparison of H_2 and Syngas Production Costs using Coal Gasification Technology vs. Existing Production Methods 80

TABLE OF CONTENTS
(continued)

Page

3.3.1 Methodology 81

3.3.1.1 Capital Cost Estimates 81

3.3.1.2 Major Operating Cost Estimates 84

3.3.2 Discussion of Results 85

3.3.2.1 Results for H_2 and Syngas Production 86

3.3.2.2 Pressurized vs. Atmospheric Gasification 97

3.3.2.3 Evaluation of Co-Producing Fuel and Syngas 97

3.3.3 Discussion of Revised Energy Scenario Sensitivity Cases 97

3.3.3.1 Results for H_2 and Syngas Production Using Revised Energy Scenario 102

3.3.3.2 Revised Scenario Results for Pressurized vs. Atmospheric Gasification 113

3.3.3.3 Revised Scenario Results for Co-Producing Fuel and Syngas 113

4.0 Task II Analysis of Technical/Non-Technical Problem Areas 116

4.1 Analysis of Potential R&D Impact 116

4.1.1 Analysis of Potential R&D Impact Under Original Energy Scenario 116

4.1.2 Analysis of Potential R&D Impact Under Revised Energy Scenario 121

4.2 Analysis of Institutional Barriers 126

4.2.1 Financing Considerations 126

4.2.2 Technology and Cost Risk Factors In Coal Gasification 127

4.2.3 Financing Techniques 128

4.3 Analysis of Regulatory Barriers Affecting Coal Gasification 133

4.3.1 Impact of State Implementation Plan Delays on Commercial Potential 133

4.3.2 Regulatory Barriers Affecting Coal Directly: Transportation/Mining 134

4.3.3 Impact of Future Oil and Gas Regulatory Pricing Uncertainty 136

4.4 Estimate of Government Incentives to Make Coal Gasification Competitive and Recommended Actions to Stimulate Coal Gasification System Development 138

TABLE OF CONTENTS
(continued)

Page

4.4.1 Financial Incentives 138

4.4.2 Recommended Options to Stimulate Coal Gasification System Development 141

4.4.3 Regulatory Actions 143

Appendix A: Description of Financial Analysis Computer Program

TABLE OF CONTENTS
(continued)

LIST OF TABLES

Table Number	Title	Page
3.1	Estimate of 1978-1987 H_2/CO/Syngas Requirements for Chemical Production	17
3.2	Projected Methanol Demand (MM Gallons)	24
3.3	Synthetic Ethanol Markets (MM Gallons)	26
3.4	Demand for Solvent Alcohols (MM lbs.)	29
3.5	Capacities for Butanols and Propanol (MM lbs.)	30
3.6	Syngas Additions for Oxo Alcohols (MM SCFD)	31
3.7	Plasticizer Markets for Oxo Alcohols	32
3.8	Projected Capacities for Plasticizer Oxo Alcohols	33
3.9	Demand and Supply for Detergent Range Alcohols	33
3.10	Summary Market Information for MDI (MM lbs.)	36
3.11	Summary Market Information for TDI (MM lbs.)	36
3.12	Summary Market Information for Aniline (MM lbs.)	40
3.13	Projected U.S. Consumption of Fibers, 1977-1987	46
3.14	Projected U.S. Fiber Consumption for Years 1977, 1982 and 1987 (Millions of Pounds)	48
3.15	Ethylene Glycol Supply/Demand Projections	49
3.16	Comparison of Existing and New Technology Product Prices (1978 Dollars)	50
3.17	U.S. Terephthalate Polyester Resin and Film Markets	54
3.18	DMT/TPA Supply-Demand Balances (MM lbs.)	54
3.19	Acetic Anhydride Markets (MM lbs.)	56
3.20	Acetic Acid Supply/Demand Projections (MM lbs.)	60
3.21	Phosgene Derivative Usage in U.S. Pesticides, 1977	62
3.22	U.S. Production of Monoisocyanates	62
3.23	Phosgene - Consuming Carbamate Insecticides	63
3.24	Phosgene - Consuming Herbicides	65
3.25	Projected CO Use in Phosgene Production	65
3.26	U.S. Demand for Polycarbonates (MM lbs.)	66
3.27	U.S. Demand for Hydrogen Peroxide (MM lbs.)	68
3.28	U.S. Demand for 1,4-Butanediol (MM lbs.)	70
3.29	Estimate of 1988-2000 H_2/CO/Syngas Requirements for Chemical Production	76

TABLE OF CONTENTS

LIST OF TABLES
(continued)

Table Number	Title	Page
3.30	Economic Comparisons for 150 MM SCFD Syngas (\$/MSCF)	88
3.31	Economic Comparisons for 150 MM SCFD H_2 (\$/MSCF)	91
3.32	Economic Comparisons for 40 MM SCFD Syngas (\$/MSCF)	94
3.33	Comparison for Atmospheric and Pressurized Coal Gasification for Syngas Production	98
3.34	Evaluation of Fuel Gas Prices Co-Produced With Syngas	98
3.35	Economic Comparisons for 150 MM SCFD Syngas (Revised Energy Scenario)	104
3.36	Economic Comparisons for 150 MM SCFD H_2 (Revised Energy Scenario)	107
3.37	Economic Comparisons for 40 MM SCFD Syngas (Revised Energy Scenario)	110
3.38	Comparison of Atmospheric and Pressurized Coal Gasification for Syngas Production	114
3.39	Evaluation of Fuel Gas Prices Co-Produced With Syngas	115
4.1	Projected Impact of Potential R&D Improvement on Product Price at 40 MM SCFD Syngas	118
4.2	Year of Production in Which 40 MM SCFD Syngas via Coal Gasification is Less Costly than Alternatives	118
4.3	Projected Impact of Potential R&D Improvement on Product Price at 150 MM SCFD Syngas	120
4.4	Year of Production in Which 150 MM SCFD Syngas via Coal Gasification is Less Costly than Alternatives	120
4.5	Projected Impact of Potential R&D Improvement on Product Price at 40 MM SCFD Syngas (Revised Energy Scenario)	124
4.6	Year of Production in Which 40 MM SCFD Syngas Via Coal Gasification is Less Costly than Alternatives	124
4.7	Projected Impact of Potential R&D Improvement on Product Price at 150 MM SCFD Syngas (Revised Energy Scenario)	125
4.8	Year of Production in Which 150 MM SCFD Syngas via Coal Gasification is Less Costly than Alternatives	125
4.9	Effect of Capital Structure on Product Price at 40 MM SCFD Syngas	130
4.10	Effect of Capital Structure on Product Price at 150 MM SCFD Syngas	131

TABLE OF CONTENTS

LIST OF TABLES
(continued)

Table Number	Title	Page
4.11	Effect of Debt Leverage on Total Investment DCF Return	132
4.12	Impact of Potential Financial Incentives 150 MM SCFD Syngas	140
4.13	Impact of Potential Financial Incentives 40 MM SCFD Syngas	140

TABLE OF CONTENTS
(continued)

LIST OF FIGURES

Figure Number	Title	Page
3.1	Potential Impact of New Syngas Technology on Methanol Demand	23
3.2	Overview of Existing and Potential H_2, CO Use in Fibers Manufacture (pounds H_2, CO per pound intermediate)	42
3.3	Fiber Productions in U.S., 1950-1976	44
3.4	Projected Product Prices 150 MM SCFD Syngas (Original Energy Scenario)	89
3.5	Projected Product Prices 150 MM SCFD Syngas, Coal/Lignite Comparison (Original Energy Scenario)	90
3.6	Projected Product Prices 150 MM SCFD H_2 (Original Energy Scenario)	92
3.7	Projected Product Prices 150 MM SCFD H_2, Coal/Lignite Comparison (Original Energy Scenario)	93
3.8	Projected Product Prices 40 MM SCFD Syngas (Original Energy Scenario)	95
3.9	Projected Product Prices 40 MM SCFD Syngas, Coal/Lignite (Original Energy Scenario)	96
3.10	Energy Price Projections, With Functional Representations	101
3.11	Projected Product Prices 150 MM SCFD Syngas (Revised Energy Scenario)	105
3.12	Projected Product Prices 150 MM SCFD Syngas, Coal/Lignite Comparison (Revised Energy Scenario)	106
3.13	Projected Product Prices 150 MM SCFD H_2 (Revised Energy Scenario)	108
3.14	Projected Product Prices 150 MM SCFD H_2, Coal/Lignite Comparison (Revised Energy Scenario)	109
3.15	Projected Product Prices 40 MM SCFD Syngas (Revised Energy Scenario)	111
3.16	Projected Product Prices 40 MM SCFD Syngas, Coal/Lignite (Revised Energy Scenario)	112

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 ye 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)

	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 IlaD Cyclo	HAc	Pest.	Polyc	H_2O_2	1,4B0	Spec
	1978-1982																			
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																			
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.

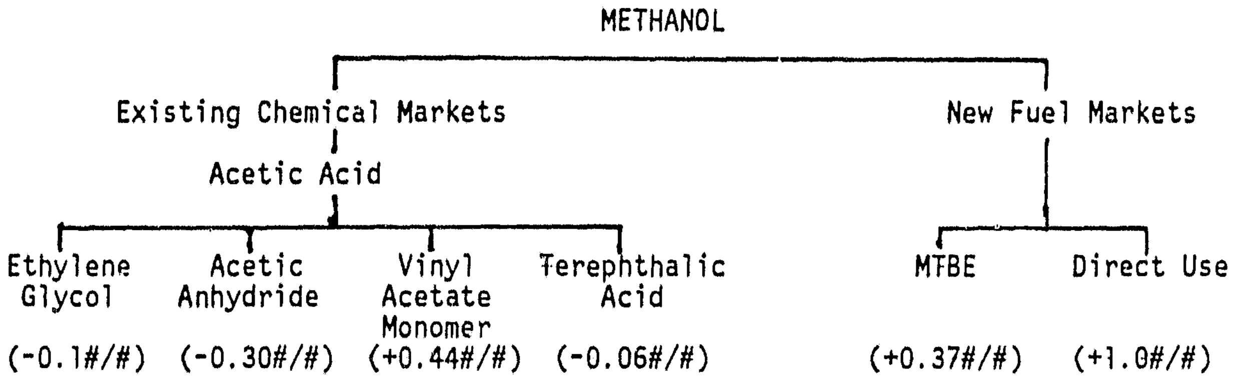
3.1.1.3 BENZENE VIA TOLUENE HYDRODEALKYLATION

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

3.1.2 OXO ALCOHOLS

Oxo alcohols are produced by reacting olefins with either a) syngas (1 H_2/1 CO) to form aldehydes which are hydrogenated to alcohols, or b) (2 H_2/1 CO) syngas to produce alcohols. These alcohols are used in solvent, plasticizer, and detergent range markets.

Technological change has recently affected oxo alcohol production. New and larger olefin plants have resulted in sharply increased quantities of olefins available. This supply situation has provided relatively low cost olefin feedstock for oxo producers. During this same period, substitution of a rhodium catalyst for the normal cobalt catalyst in the oxonation reaction has further improved the competitiveness of the oxo process.

Projected syngas requirements for oxo-alcohols are shown in Table 3.6.

3.1.2.1 SOLVENT ALCOHOLS

Solvent alcohols include n-propanol produced by oxo-processing of ethylene and normal and iso-butanol produced by oxo-processing of propylene. Most n-butanol is used in surface coatings, either directly as a solvent or via derivatives such as n-butyl acetate or glycol ethers. Ethylene is also oxo-processed to propionaldehyde for oxidation to propionic acid.

Growth prospects for solvent alcohols will be strongly influenced by legislation as well as displacement of existing solvent systems. Aromatic solvents have been restricted in solvent coating systems. The same legislation has exempted n-butanol and as a result its direct solvent use is expected to increase. The key growth performer in the solvent area is expected to be n-butyl acetates due to superior wear properties and production costs of interior and exterior latex coatings.

Table 3.4 summarizes projected n-butanol, i-butanol and propanol demand. Over the period 1978-1987, demand growth is projected at between 5% and 6% for each of these solvent alcohols. Capacity for propionic acid exceeds demand and is expected to throughout the ten year period.

Capacities for butanols and propanol are shown in Table 3.5. The information provided includes projection of specific plant expansions. Syngas requirements to meet solvent alcohol capacity expansions are shown in Table 3.6.

3.1.2.2 PLASTICIZER ALCOHOLS

Oxo alcohols in the C_6 to C_{13} range are used to produce plasticizers, primarily phthalates. The primary product, di-octyl phthalate (DOP), is produced from the major plasticizer alcohol, 2-ethyl hexanol (2-EH). Over the years DOP has been the general purpose plasticizer for both vinyl and rubber application. Since the early 1970's linear plasticizers have successfully displaced DOP due to superior low temperature flexibility and low volatility. Among the higher alcohols used in plasticizers, iso-nonanol is also expected to take market share from DOP. Iso-nonanol is used to produce di-isononyl phthalate (DINP) which is expected to grow faster than the total plasticizer market.

Table 3.7 summarizes plasticizer markets for oxo alcohols. Future capacity vs. demand balances are shown in Table 3.8. Two capacity additions are projected for the period 1978-1987.

3.1.2.3 DETERGENT ALCOHOLS

Oxo alcohols in the C_{10}-C_{20} range are referred to as detergent alcohols. Oxo technology competes in the detergent range with linear alcohols made by Ziegler technology and with natural alcohols produced by hydrogenation of fatty acids. Detergent-range alcohols are used in production of detergents and cosmetics. The major alcohol products, ether sulfates and ethoxylates, will become increasingly dependent on oxo technology. Ether sulfates perform better than the corresponding tallow alcohol sulfates in low and non-phosphate products. Alcohol ethoxylates are likewise replacing alkylphenol products. Table 3.9 summarizes expected demand for detergent range alcohols in the U.S. A 300 MM lb expansion is expected in the 1983-1987 period.

Table 3.4

DEMAND FOR SOLVENT ALCOHOLS
(MM lbs.)

	1977	1982	1987
n-Butanol:			
Solvent	140	206	300
N-Butyl Acrylates	206	271	314
Glycol Ethers	112	134	291
Plasticizers	89	106	105
n-Butyl Acetate	66	94	115
n-Butyl Amine	9	9	12
Miscellaneous	33	49	55
U.S. Domestic	655	870	1192
Exports	90	90	90
Total	745	960	1282
i-Butanol:			
Isobutyl Acetate	28	38	55
Isobutyl Acrylate	14	17	19
Lube Oil Additives	23	35	44
Amines	43	62	75
Others	33	38	42
Exports	9	13	25
Total	150	203	260
n-Propanol (or equivalent):			
Solvent	142	157	220
Aldehyde for acid	73	83	120
Total	215	240	340

Table 3.5
CAPACITIES FOR BUTANOLS AND PROPANOL
(MM lbs.)

	1977	1982	1987
n-Butanol:			
Gulf Coast	573	814	1084
Other	338	371	491
Total	911	1185	1575
Less NBA for 2-EH and other	60	60	60
Available (@90%)	766	1012	1364
Surplus/(Shortfall)	21	52	82
	(Below - Listed for maximum Iso Conditions)		
i-Butanol:			
Gulf Coast	223	147	163
Other	133	126	144
Total	256	273	307
Available (@90%)	230	246	276
Surplus/(Shortfall)	80	43	16
n-Propanol capacity:			
East Texas	250	300	450
Available (@90%)	225	270	405
Surplus/(Shortfall)	10	30	65

Table 3.6

SYNGAS ADDITIONS FOR OXO ALCOHOLS
(MM SCFD)

	1978-1982			1983-1987		
	H_2	$1H_2/1CO$ Syngas	$2H_2/1CO$ Syngas	H_2	$1H_2/1CO$ Syngas	$2H_2/1CO$ Syngas
Butanols						
Gulf Coast	4.1	9.1	--	4.1	9.1	8.5
Other	--	--	--	4.1	9.1	--
Propanol						
Gulf Coast	1.1	2.6	--	3.2	7.8	--
Other	--	--	--	--	--	--
C_7-C_9 Plasticizer						
Gulf Coast	--	--	4.5	--	--	4.5
Detergent						
Gulf Coast	--	--	--	3.1	7.1	--

Table 3.7
PLASTICIZER MARKETS FOR OXO ALCOHOLS

	1977	1982	1987
2-EH			
Dioctyl Phthalate	276	301	332
Dioctyl Adipate	31	36	41
2-EH Acrylate	39	44	48
Others	31	35	40
U.S. Domestic	377	416	461
Export	15	18	18
	392	434	479
Linear Alcohols	222	282	360
Isodecyl Alcohol	105	129	157
Isononyl Alcohol	92	131	184
Other	68	79	91
Total	879	1055	1271

Table 3.8

PROJECTED CAPACITIES FOR PLASTICIZER OXO ALCOHOLS

	1977	1982	1987
2-EH			
Gulf Coast	240	240	240
Other	380	380	380
Total	620	620	620
Available (@90%)	558	558	558
Surplus/(Shortfall)	166	124	79
Other Plasticizers			
Gulf Coast	525	675	825
Other	90	90	90
Total	615	765	915
Available (@90%)	553	688	823
Surplus/(Shortfall)	66	67	31

Table 3.9

DEMAND AND SUPPLY FOR DETERGENT RANGE ALCOHOLS
(MM lbs.)

	1977	1982	1987
Alcohol Sulfates	140	175	225
Ethoxylates	115	180	220
Ether Sulfates	130	145	165
Viscosity Improvers	60	55	55
Other	100	140	200
Total	545	695	865
Available	850	850	850
Surplus/(Shortfall)	305	155	(15)

3.1.3 POLYURETHANES AND ANILINE

Polyurethanes are the newest, fastest growing and most versatile member of the plastics family.

The use of diisocyanates as a means of making polymers was begun in the U.S. in the mid-1950's for the manufacture of flexible foam. Urethane foam began its highly successful market replacement of latex foam cushioning in the late 1950's when polyether based polyols were reacted with toluene diisocyanate resulting in much more resilient foams.

Isocyanates are produced in existing plants by reduction of nitrocompounds to amines followed by phosgenation. There are three key isocyanate products:

- Toluene Diisocyanate (TDI)
- Polymethylene Polyphenylene Diisocyanate (Polymeric MDI)
- 4,4-Methylenediphenyl Diisocyanate (Refined MDI)

3.1.3.1 MARKETS FOR MDI (PURE AND POLYMERIC)

MDI depends heavily on the insulation market for rigid foams. The insulation market accounts for over half of domestic shipments. Insulation applications for rigid polyurethane foam fall in four categories: roofs, walls, tank and pipe, and walk-in coolers. Roof insulation is used in board stock form (75%) and spray-in-place form (25%). Wall insulation applications are about half the size of the roof market. All other categories of rigid foam insulation are significantly smaller than roof and wall markets. Polyurethane manufacturers have established a strong market position in insulation. The rapid rise of energy costs plus likely energy conservation financial incentives are expected to push the rigid foam insulation market at a near term growth rate of about 15%.

The refrigeration, transportation and other rigid foam markets collectively amount to about 80% of the insulation market. Foam has penetrated about 50% of the residential refrigeration market. Continued displacement of fiberglass in this market is expected.

In the transportation markets, polyurethane foam is used to insulate railroad cars, truck trailers, truck bodies, containers, tank trucks, etc. Truck, trailer and container applications account for about 70% of the rigid foam consumption in transportation. Growth in refrigeration, transportation and other markets is expected to be over 10%.

The major isocyanates application in the adhesives area is in foundry binders based on alkyds and phenolics. Textile bonding also consumes isocyanates. A growth rate of nearly 15% is expected in the adhesives area on a relatively small base of 20 million pounds in 1977.

The most dramatic growth area for MDI is expected to be microcellular elastomers. This growth will be due almost entirely to application in automotive fascia. By 1982, penetration in fascia could be as high as 30% of U.S. passenger cars.

Exports are expected to be a declining market as U.S. energy prices rise to parity with world prices, eliminating the present U.S. feedstock cost advantage. However, the substantial foreign position in U.S. isocyanates production is expected to moderate any trend to a rapid build-up of offshore isocyanate plants.

Projected MDI markets are shown in Table 3.10.

3.1.3.2 MARKETS FOR TDI

TDI markets are shown in Table 3.11.

Flexible foam applications account for about 70% of total 1977 TDI markets. Four key flexible foam markets exist -- transportation, furniture, bedding, and carpet cushioning.

Table 3.10

SUMMARY MARKET INFORMATION FOR MDI
(MM lbs.)

	1977	1982	1987
Rigid Foams			
Insulation	120	250	450
Refrigeration	40	80	125
Transportation	30	50	75
Other	30	45	90
Adhesives	20	45	80
Elastomers	17	40	80
Flexible Foams	18	30	50
Exports	125	100	100
Total	400	640	1050

Table 3.11

SUMMARY MARKET INFORMATION FOR TDI
(MM lbs.)

	1977	1982	1987
Flexible Foam			
Transportation	120	130	140
Furniture	150	175	200
Bedding	45	70	100
Carpeting	85	120	170
Other	50	60	70
Rigid Foam	25	45	70
Other	20	50	75
Export	130	125	125
Total	625	775	950

Passenger cars account for about 80% of the transportation market. Seat bottoms and seat backs account for the large volume use in passenger cars. Downsizing of cars to meet federal gasoline mileage requirements is expected to virtually eliminate the growth in the transportation market for flexible foams.

Household furniture dominates the flexible foam applications in the furniture market. The furniture market is expected to grow at less than 3% annually as the rate of new housing starts moderates.

The bedding market for flexible foam should grow at about 8% over the next ten years. The solid foam core mattress, which accounted for less than 20% of all mattresses sold in 1977, is expected to continue to replace innersprings to an ever-increasing extent.

The carpet cushioning market utilizes flexible foam for carpet underlay and integral carpet backing. Rubber latex is presently cheaper than urethane foam, however foam has significant abrasion resistance, compression resistance, and tear resistance advantages. The price differential of foam vs. latex is expected to decline resulting in further penetration of the carpet cushioning market. An overall growth rate of over 7% is projected for the period 1978-1987.

Exports are the second largest general market for TDI. This TDI end-use is expected to be stagnant as large TDI plants are built outside the U.S. No serious deterioration of this market is expected.

Rigid foam and other TDI applications such as lamination uses in textiles, and general packaging should grow from less than 10% of the TDI market to about 15% by 1987.

3.1.3.3 ANILINE

Aniline is currently made by the catalytic hydrogenation of vaporized nitrobenzene. Aniline capacity also exists as a by-product in the production of iron oxide.

Over half of 1977 aniline production was used for production of pure and polymeric MDI, a polyurethane intermediate. Currently all MDI production technology requires aniline. New technology has recently been announced, however, which uses nitrobenzene as a raw material rather than aniline. MDI has accounted for a high proportion of aniline growth over recent years. Therefore, the future direction of MDI technology will be the major factor in future aniline requirements. The aniline market information presented in Table 3.12 projects a split of approximately 2:1 between existing MDI technology and new technology in future MDI capacity expansion.

Aniline and some of its first-generation derivatives are the basic raw materials for many cyclic rubber-processing chemicals. Aniline is used in two key classes of rubber chemicals: accelerators/activators/and vulcanizing agents, and antioxidants/antiozonants/and stabilizers. The complex interaction of high energy costs affecting rubber for transportation uses and changing demographics is expected to result in a 4% annual growth of rubber chemicals/aniline use during the 1977-1987 period.

Dyestuffs were one of the earliest commercial applications for aniline. The general trend expected for aniline use in dyestuffs is a reduction in finished dyestuffs use and an increase in intermediate use for dimethylaniline. Overall, very little growth is expected in the dyes market.

Part of U.S. hydroquinone production is based on aniline. Most of the aniline-based hydroquinone capacity is used for photographic chemicals. Monomer inhibitors and rubbers chemicals are also important. Environmental problems with the conventional curing agent for castable urethane elastomers could open up a new market for hydroquinone.

Multiple uses for aniline exist in the drugs, pesticides and other category. A major herbicide used for corn and soybeans has developed into a key market for aniline in the past ten years. The projections in Table 3.12 assume continued expansion of acres planted in corn and soybeans and also an increase in the number of acres treated. Cyclohexylamine is a small but rapidly growing market for aniline. Applications include rubber chemicals and water treatment. Pharmaceuticals and fine chemicals represent only a modest market for aniline in the production of sulfur drugs, analgesics, antipyretics, and fungicides.

3.1.3.4 SUPPLY/DEMAND BALANCES AND H_2/CO REQUIREMENTS

Effective capacity for MDI production was about 425 million pounds in 1977. Effective production capacity is expected to increase to 650 million pounds by 1982. Further effective production capacity of 400 million pounds is expected by 1987.

Effective capacity for U.S. TDI production was about 750 million pounds in 1977 with production for domestic and export uses at about 625 million pounds. During the period 1978-1982, some small, inefficient capacity will be shutdown and, therefore, capacity additions will be required. Approximately 200 million pounds of production capability will be required in the 1983-1987 period.

Incremental CO requirements for TDI and MDI are projected as follows (MMSCFD):

	1978-1982	1983-1987
TDI	2.2	3.3
MDI	5.8	9.9

Table 3.12

SUMMARY MARKET INFORMATION FOR ANILINE
(MM lbs.)

	1977	1982	1987
MDI	310	445	730
Rubber Chemicals	155	185	235
Dyes	45	49	53
Hydroquinone	29	36	47
Drugs, Pesticides, Other	60	85	110
Demand	599	800	1180
Effective Capacity	605	1090	1090
Excess Capacity	6	290	(90)

Incremental H_2 requirements for reduction of dinitrotoluene to toluenediamine (TDA) in TDI production and for aniline in MDI production are projected as follows (MMSCFD):

	1978-1982	1982-1987
TDA	8.8	13.3
Aniline	3.5	10.5

Effective capacity for aniline production was about 605 million pounds in 1977. Production capability is expected to increase to 1090 million pounds by 1982. Further effective capacity of about 125 million pounds will be required by 1987.

Incremental hydrogen requirements for aniline are expected to be about 19.4 MMSCFD in the 1978-1982 period and 4.7 MMSCFD in the 1983-1987 period. Excluding the isocyanate requirements, the net hydrogen requirements for aniline are expected to be 12.1 MMSCFD for the 1978-1987 period.

3.1.4 FIBERS

3.1.4.1 GENERAL OVERVIEW OF U.S. FIBERS MARKETS

A complex competitive situation exists between the segments of the U.S. fibers industry. Competition involves those fiber intermediates presently consuming H_2 and those that could become future H_2, CO, syngas users in the event that new technology develops.

Because of the large quantities of intermediates involved in the production of synthetic fibers for U.S. markets, a detailed overview of the competitive fiber situation is required. Figure 3.2 summarizes the potential role of new chemical intermediates in fibers manufacture. Also, the latter period covered by Section 3.2 on future chemical industries H_2/CO/syngas capacity requirements, 1988-2000, is heavily dependent on the outlook for fiber intermediates developed in this section. The basis for market projections over that time period is covered in a general overview of U.S. fiber consumption in the next section.

Individual markets analyses on key fiber intermediates - ethylene glycol, terephthalic acid, hexamethylenediamine, acetic anhydride, and adipic acid are provided.

Figure 3.2

OVERVIEW OF EXISTING AND POTENTIAL H_2, CO USE IN FIBERS MANUFACTURE
(pounds H_2, CO per pound intermediate)

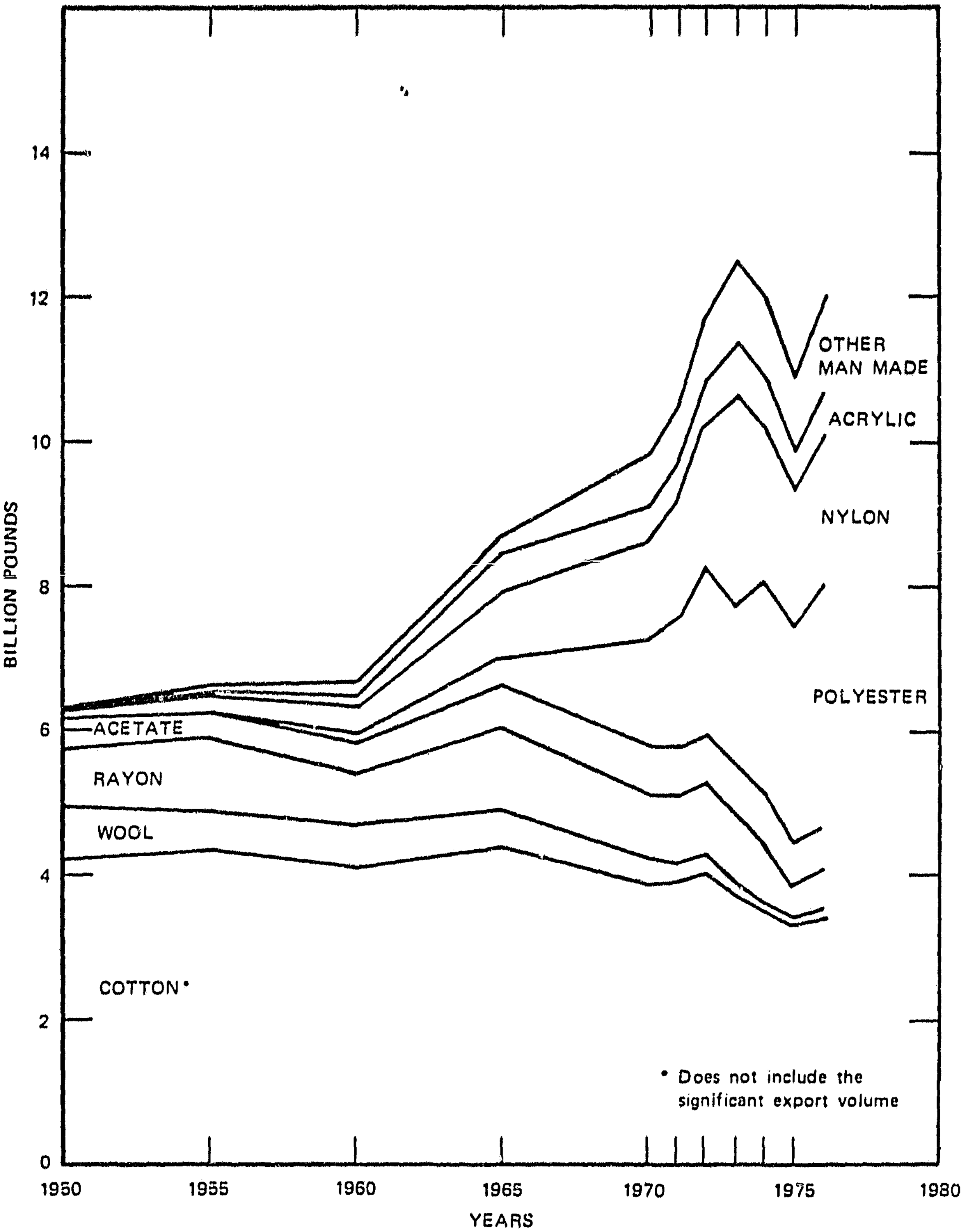
Fiber		Polyester		Cellulose Acetate	Nylon		
Intermediate		Ethylene Glycol	Terephthalic Acid	Acetic Anhydride	Adipic Acid	Hexamethylene-Diamine	Caprolactam
New	H_2	+0.18#/#	--	--	--	--	--
Technology	CO	+1.7#/#	+0.25#/#	+0.34#/#		--	--
Existing	H_2	--	--	--	0.57#/#	0.07#/#	0.08#/#
Technology	CO	--	--	--	--	--	--

3.1.4.1.1 U.S. FIBER CONSUMPTION

Consumption of fibers in the United States began to increase at an accelerated pace after 1960, coincident with the development and rapid acceptance of synthetic fibers. Most of the early part of this growth was spearheaded by nylon followed by the emergence of polyester, which became the leading man-made fiber in the 1970's.

In 1950, the natural fibers, cotton and wool, represented 78% of the total U.S. consumption; by 1976, the natural fibers accounted for less than 30% of the total. In 1950, the important man-made fibers were based on cellulose, i.e , rayon and acetates, which essentially accounted for the rest of the fibers consumed. By 1976, the demand for cellulosic fibers had experienced several years of steady decline and now represents less than 10% of the total; while the synthetic fibers--led by polyester and nylon, with acrylics and polyolefins also occupying sizeable niches--have become the major class of fibers consumed. Within this time period, the overall consumption of fibers had doubled by 1973; however, during the recessionary years of 1974-75, overall fiber consumption experienced a setback, which was followed by a partial recovery in 1976.

These historical trends are illustrated in Figure 3.3. This figure is based on production data because reliable historical data on consumption of specific fibers are not available. With the exclusion of the significant volume of cotton fibers that is export , the figure is considered to be a reasonably accurate description of fiber consumption in the United States.



* Does not include the significant export volume

FIGURE 3.3 FIBER PRODUCTIONS IN U.S. 1950-1976

The general reasons that account for the trends shown in Figure 3.3 are as follows:

- The advent of synthetic fibers was accompanied by the development of a host of new fabrics and other textile products having advantages over traditional textiles ranging from superior performance to heretofore unattainable properties. This led to new markets as well as to the expansion of established markets, which were enhanced by an increasingly style- and fashion-conscious public.
- The evolving technology of synthetic fibers resulted in a continuing flow of new products concurrent with decreasing unit cost.
- Unlike synthetic fibers, which can respond to increasing demand by the construction of new plants, the availability of natural fibers is fixed by available land, for which they must compete with other uses. Natural fibers therefore are a rather inelastic resource.

Figure 3.3 also shows that the economic disruption associated with the oil crises has led to reduced levels of fiber consumption since 1973. Future consumption will be affected by a set of factors and conditions that did not exist before the oil crises, and forecasts of future demand must contend with the uncertainties associated with these changes. The projections in this section take into account the increasing cost of synthetic fibers (reversing the pre-1973 trend) <u>and</u> the different impacts of these increasing costs on the various fibers. The projections are constructed primarily by microeconomic analysis of each major market; in markets where different fibers compete, the effect of the changes in manufacturing economics on the degree of fiber substitution is considered. The linkages of fiber demand to macroeconomic parameters are beyond the scope of this section; therefore, for example, the way in which the projected personal consumption expenditure might be related to fiber consumption will not be discussed.

3.1.4.1.2 SUMMARY OF STATISTICAL DATA

In this section, the data compiled are summarized in a number of ways to facilitate review and reference. Discussion and analysis are provided in later sections.

The total fiber demand from 1977-1987 by market and by fiber is shown in Table 3.13.

Table 3.13

PROJECTED U.S. CONSUMPTION OF FIBERS, 1977-1987

	Consumption (millions of pounds)			1977-87 Average Growth Rate (percent/year)
	1977	1982	1987	
Market				
Apparel	4,930	5,816	6,391	2.4%
Home furnishings	1,609	1,883	1,958	1.8
Carpet	2,130	2,654	3,202	3.8
Tire cord	545	565	580	0.6
Other industrial use	341	436	487	3.3
Other uses	2,065	2,314	2,544	1.9
Total	10,810	13,668	15,162	3.1
Fiber				
Cotton	3,040	2,860	2,620	(1.3)
Wool	141	132	132	(0.6)
Rayon	603	722	695	1.3
Acetates	564	539	542	(0.4)
Acrylics	652	742	877	2.7
Nylon	2,395	2,700	3,210	2.7
Polyester	3,620	5,050	6,050	4.8
Polypropylene	605	923	1,036	5.0
Total	10,810	13,668	15,162	3.4

Although the actual projections were not based on uniform linear growth rates for the entire period of study, the average growth rates by market and by fiber were calculated over the period 1977-1987 for the purpose of comparing the relative change between the various uses and fibers.

The estimated consumption of fibers in each of the markets for 1977, 1982, and 1987 are given in Table 3.14.

3.1.4.2 ETHYLENE GLYCOL

Ethylene glycol is produced commercially in the U.S. by successive oxidation and hydration of ethylene. Technology for production of ethylene glycol from synthesis gas has been under development for a number of years. This section defines potential syngas requirements for glycol production.

Ethylene glycol production was approximately 3,600 million pounds in 1977. Exports accounted for about 200 million pounds of that production.

Market requirements in 1977 amounted to an effective capacity utilization of about 73%. This utilization figure is based on a nameplate capacity of 5,775 million pounds and an effective capacity figure of 85% of nameplate. Capacity utilization will rise over the period 1978-1982 to a 1982 figure of about 83% assuming one new grass roots plant, one expansion and one offshore shutdown due to olefin feedstock problems. This information is shown in Table 3.15. Without further plant expansion in the 1983-1987 period, 1987 demand would amount to a 95% effective capacity utilization figure. Therefore, new capacity is expected late in the period 1983-1987.

Table 3.16 compares projected economics for syngas vs. conventional ethylene oxide routes to ethylene glycol. As the table shows, conventional technology is expected to be the least cost route for plant start-up in 1982 and 1987. No syngas market is projected for ethylene glycol. The table also contains other technology comparisons which are discussed in later sections.

Table 3.14

PROJECTED U.S. FIBER CONSUMPTION FOR YEARS, 1977, 1982 AND 1987
(Millions of Pounds)

	Cotton	Wool	Rayon	Acetate	Acrylics	Nylon	Polyester	Polypropylene	Total
1977									
Apparel	1,500	92	123	205	470	405	2,130	5	4,930
Home furnishings	778	15	150	43	66	75	432	50	1,609
Carpet	12	15	--	--	100	1,465	238	300	2,130
Tire cord	--	--	39	--	--	236	270	--	545
Other industrial uses	35	--	26	1	1	108	80	90	341
Other uses	715	19	265	315*	15	470	470	160	2,065
Total	3,040	141	603	564	652	2,395	3,620	605	11,620
1982									
Apparel	1,400	90	164	177	535	445	3,000	5	5,816
Home furnishings	760	11	198	32	85	82	653	61	1,883
Carpet	8	12	--	--	100	1,790	345	490	2,654
Tire cord	--	--	40	--	--	235	290	--	565
Other industrial uses	27	--	21	--	2	118	114	154	436
Other uses	665	19	299	330**	20	120	648	213	2,314
Total	2,860	132	722	539	743	2,700	5,050	923	13,668
1987									
Apparel	1,250	90	165	160	640	480	3,600	6	6,391
Home furnishings	700	11	185	22	110	90	775	65	1,958
Carpet	5	12	--	--	100	2,150	400	535	3,202
Tire cord	--	--	30	--	--	225	325	--	580
Other industrial uses	25	--	15	--	2	135	140	170	487
Other uses	640	19	300	360***	25	130	810	260	2,544
Total	2,620	132	695	542	877	3,210	6,050	1,036	15,162

Notes: Acetate split between fibers and cigarette tow as follows (MM lb)
* 11 fibers, 304 cigarette tow
** 10 fibers, 320 cigarette tow
*** 10 fibers, 350 cigarette tow

Table 3.15
ETHYLENE GLYCOL SUPPLY/DEMAND PROJECTIONS

	1977	1982	1987
Antifreeze	1650	1800	1970
Polyester Fiber	1413	1950	2190
Polyester Film	115	175	275
PET Bottles	10	185	300
Industrial Uses	222	285	365
Exports: Net	210	250	300
Total	3620	4645	5400
Effective Capacity	4910	5760	5760
Capacity Required	(1290)	(1115)	(360)

Table 3.16

COMPARISON OF EXISTING AND NEW TECHNOLOGY PRODUCT PRICES*
(1978 Dollars)

	Per Pound Start-Up Price	
	1982	1987
Acetic Anhydride		
(New) Carbonylation	32¢	35¢
Ketene	36¢	41¢
Ethylene Glycol		
(New) Syngas	40¢	42¢
Ethylene	34¢	37¢
Terephthalic Acid		
(New) Carbonylation	29¢	32¢
Direct Air Oxidation	37¢	38¢
Ethanol		
(New) Syngas	22¢	25¢
Ethylene Hydration	18¢	20¢
Adipic Acid		
(New) CO/Butadiene	32¢	32¢
Cyclohexane	36¢	38¢

*Note: All olefin and aromatics price projections used in the comparison of existing and new technology are based on the original JPL (1978) price projections. No revisions were made in the Task IV revised energy scenario work.

3.1.4.3 DMT/TPA

Dimethyl terephthalate (DMT) and purified terephthalic acid (TPA) are used in terephthalate polyester resins and films. Specific uses evaluated here are polyethylene terephthalate (PET) film, polybutylene terephthalate (PBT) resins, and polyethylene terephthalate (PET) barrier resins.

3.1.4.3.1 MARKETS

The estimated 1977 and future markets for terephthalate polyester resins and films is shown in Table 3.17.

3.1.4.3.2 POLYETHYLENE TEREPHTHALATE (PET) FILM

PET film is presently the largest of the resin and film markets. Photographic film is the largest market in PET film and it will continue to be. Most of the readily displaceable markets where cellulose acetate was previously used have been captured by PET film. The key application in this area has been x-ray film. Continued PET penetration is expected in other photographic film markets. Cellulose acetate is expected to remain the preferred motion picture film.

The magnetic tape market has matured in the key initial growth area, computer tape. Auto tape and video tape markets will be the growth areas for PET magnetic tape led by cassette tapes and home video markets, respectively.

PET film has competed successfully against cellophane and will continue to do so. Metallic film used in packaging is also expected to grow well.

The smaller markets for PET film shown in Table 3.17 will grow faster than total PET film but the smaller market sizes lessen the importance of these markets.

PET film is produced from both DMT and TPA as shown in Table 3.18. Unlike the fiber market where TPA has displaced DMT, DMT is expected to continue as the dominant material for PET film.

3.1.4.3.3 POLYBUTYLENE TEREPHTHALATE (PBT) RESINS

Since their introduction in 1970 PBT-based plastics have grown to over 40 million pounds of useage in 1977. Excellent growth is expected to continue.

Automotive and truck components and parts, which is the largest market presently for PBT resins, will face stiff competition from reaction injection-molded polyurethanes. Under-the-hood applications are expected to be the largest growth area in automotive due to warpage problems with large exterior PBT parts.

Electrical and electronic components and parts will be the major growth market for PBT resins. PBT resins have better dimensional stability and flame-retardant properties than thermosets and will continue to displace thermosets in this market.

PBT engineering thermoplastic resins are produced by polycondensation of DMT with 1,4-butanediol. TPA is not used because it catalyzes the cyclization of 1,4-butanediol to tetrahydrofuran during the polycondensation.

3.1.4.3.4 POLYETHYLENE TEREPHTHALATE (PET) BARRIER RESINS

PET barrier resins are used for the production of carbonated beverage bottles. Nitrile barrier resins initially were competitive with PET until late 1977 when the FDA banned acrolynitrile resins for bottle use. Subsequently, the use of PET resins in this market has exploded.

Legislation will also affect growth projections for PET barrier resins. PET beverage bottles will not continue to be used in any states that enact deposit laws specifying refilling bottles (such as now in effect in Vermont). The future of PET beverage bottles in states that enact deposit laws not requiring refillability is less clear.

To date, market penetration for PET soft drink bottles has been in the 2-liter "family" sizes. One liter sizes are also produced. The projections shown in Table 3.17 assume continued rapid penetration of the bottle market by PET barrier resins.

Nearly all of the PET barrier resin produced in the U.S. is based on TPA. This is expected to continue.

3.1.4.3.5 SUPPLY/DEMAND BALANCES

Table 3.18 shows projected supply/demand balances for DMT/TPA use in PET fiber, PET film, PET barrier resin, and PBT resin uses. As the table indicates, new TPA capacity is required by 1987.

Table 3.16 compared the conventional p-xylene and CO routes to TPA for various plant start-up years. Conventional technology is expected to be the cheaper route in 1987. No CO market is projected for new TPA technology.

Table 3.17

U.S. TEREPHTHALATE POLYESTER RESIN AND FILM MARKETS
(MM Pounds)

	1977	1982	1987
PET Film			
Photographic Film	135	200	300
Magnetic Tape	50	75	115
Packaging	30	50	85
Electrical	23	30	40
Metallized Film	20	40	70
Other	52	85	125
	310	480	735
PBT Resins			
Auto and Truck	18	40	70
Electrical and Electronic	14	45	110
Other	11	30	50
	43	115	230
PET Barrier Resins			
Beverage Bottles	30	500	800
Total	383	1095	1765
TPA	90	640	1025
DMT	293	455	740

Table 3.18

DMT/TPA SUPPLY-DEMAND BALANCES
(MM lbs.)

	1977		1982		1987	
	DMT	TPA	DMT	TPA	DMT	TPA
PET Fiber	2000	1270	2000	2520	2000	3070
PET Film	250	60	370	110	545	190
PBT Resins	43	0	115	0	230	0
PET Barrier Resins	0	30	40	460	50	750
Exports	150	75	150	100	150	150
Effective Capacity	4250	3200	3000	3200	3000	3200
Capacity Required	(1817)	(1768)	(325)	(10)	(25)	1160

3.1.4.4 ACETIC ANHYDRIDE

Acetic anhydride is used primarily for production of cellulose acetate and other esters.

3.1.4.4.1 MARKETS AND SUPPLY/DEMAND BALANCE

Markets for cellulose acetate are dominated by production of textile fiber and flake and also cigarette tow. Specific market projections are shown in Table 3.19.

Present capacity for production of acetic anhydride will be adequate until the mid-1980's. That capacity is based heavily on ketene technology involving the "dehydration" of acetic acid. In the early 1980's existing anhydride producers must decide between continuing to run existing ethylene/acetaldehyde/acetic acid/acetic anhydride technology and construction of new anhydride capacity, possibly involving new technology.

Economic evaluations comparing CO/methanol technology and conventional ketene technology were shown in Table 3.16. New syngas technology appears to be the technology of choice for a plant to be constructed early in the 1983-1987 period. In addition to the 15 million gallons per year of methanol for a 250 million pound per year anhydride plant, approximately 3.5 MMSCFD CO would be required as plant feedstock.

3.1.4.5 HEXAMETHYLENEDIAMINE (HMDA) ADIPIC ACID, AND CAPROLACTAM

3.1.4.5.1 HMDA

HMDA is currently produced using five different processes. Four of the five require hydrogen for reduction of adiponitrile to HMDA. All plant expansions and new plant commitments are expected to use one of two routes, both of which require reduction of adiponitrile with H_2. Cyclohexane is not expected to be used as a raw material for production of HMDA in any future plant expansions or new capacity.

Table 3.19

ACETIC ANHYDRIDE MARKETS
(MM lbs.)

	1977	1982	1987
Textile Fiber	414	377	344
Textile Flake	176	196	218
Cigarette Tow	530	615	712
Acetate Plastics	91	98	109
Photo Film	108	131	165
Ester-Ethers	119	138	155
Mixed Ester	20	21	22
Coatings	9	9	9
Triacetin	22	25	30
Aspirin	19	20	25
Other	36	40	43
Net Exports	(18)	(20)	(20)
Total Production	1526	1650	1812
Effective Capacity	1600	1600	1900
Capacity Required	(74)	50	(88)

HMDA is used almost entirely for nylon fiber and resin production. HMDA is used for nylon 6/6, 6/10, and 6/12. It is not used for production of nylon 6. Miscellaneous end uses for HMDA include polyurethane coatings, polyamide adhesives, ink resins, and specialty surface-active agents. Total HMDA output for these miscellaneous end uses amounts to less than 1% of HMDA production.

The outlook for HMDA is reflected in the summary table for U.S. fiber consumption - 1977, 1982, and 1987, adjusted for the nylon 6/nylon 6,6 split. The one-third nylon 6, two-thirds nylon 6,6 ratio is expected to continue.

Consumption of nylon is expected to increase to about 2,700 million pounds by 1982 and to about 3,200 million pounds by 1987.

The 1987 production level for nylon 6,6 will require about 1200 million pounds of HMDA. Present capacity is above that figure and therefore no H_2 capacity is expected for HMDA in the 1978-1987 period.

3.1.4.5.2 ADIPIC ACID/CAPROLACTAM

Adipic acid is presently produced by oxidation of cyclohexane. Potential new technology would involve carbonylation of butadiene.

Approximately 90% of adipic acid production is used for manufacture of nylon 6,6 products. This ratio is expected to continue over the 1978-1987 period.

The 1977 adipic acid production capacity was about 1,900 million pounds. This capacity is expected to be sufficient for nylon 6,6 and other requirements through the 1978-1987 period assuming no plant shutdowns.

Hydrogen is required indirectly for the production of adipic acid due to the use of cyclohexane. Cyclohexane is manufactured from benzene and hydrogen. Although cyclohexane is produced at U.S. refineries, not chemical companies, nearly all cyclohexane is consumed for chemicals production. Cyclohexane can also be used in the production of caprolactam. Approximately 50% of caprolactam capacity is based on cyclohexane.

The 1977 production rate of 1,100 million pounds for adipic acid and 800 million pounds for caprolactam were about 58% and 71% of nameplate capacity, respectively. As mentioned above, adipic capacity will be sufficient through 1987, barring shutdowns due to new technology. By 1982 caprolactam is expected to be at 80% of capacity. At the projected 1987 production rate for nylon 6, a 95% operating rate on nameplate would be required. A previously announced but cancelled caprolactam plant was sized at 250 million pounds. That is the assumed size for the plant required in the 1983-1987 period.

The present U.S. cyclohexane capacity of 3,100 million pounds will be adequate to cover the 1,800 million pounds required for adipic acid and caprolactam production in 1982. This capacity will also be adequate for the 2,575 million pounds of cyclohexane required for 1987 production of nylon 6 and nylon 6,6 assuming:

1. No technology changes.
2. A new caprolactam plant at 250 million pounds requiring 265 million pounds of cyclohexane with start-up in 1987.
3. Nylon 6 and 6,6 uses of cyclohexane continue at 90% of total cyclohexane use.

3.1.5 OTHER CHEMICALS

3.1.5.1 ACETIC ACID

Acetic acid is produced commercially in the U.S. using three different technologies. The technology chosen in recent capacity additions requires carbon monoxide and methanol as feedstocks. Methanol syngas requirements were covered in the methanol section of this study. This section defines future carbon monoxide requirements for acetic acid production.

Domestic and imported acetic acid production totaled about 2,600 million pounds in 1977. Imports amounted to about 1% of that figure. Acetic acid is co-produced in some chemical intermediate processes. These supply sources accounted for about 250 million pounds in 1977 for a total supply capability of 2,850 million pounds.

Market requirements in 1977 amounted to a sold out position. Over the period 1978-1982, two additional carbon monoxide-methanol based plants will come on stream. This will raise nameplate on-purpose capacity to over 4,000 million pounds and effective on-purpose capacity to over 3,800 million pounds. Market requirements are expected to grow at about 4.5% annually for the 1978-1987 period. By 1987 demand will require additional capacity. A continuation of the trend toward methanol carbonylation technology is assumed. This will require 12.5 MMSCF of carbon monoxide at the end of the 1983-1987 period.

Table 3.20 summarizes demand requirements, effective capacity, by-product acetic production, and requirements for additional on-purpose capacity.

Table 3.20

ACETIC ACID SUPPLY/DEMAND PROJECTIONS
(MM lbs.)

	1977	1982	1987
Acetic Anhydride	868	936	1020
Vinyl Acetate	1172	1464	2048
Terephthalic Acid	157	350	457
Alcohol Acetates	217	242	267
Textiles	69	62	55
m-Chloroacetic acid	66	32	36
Diketene	38	46	55
Acetate Sales	19	21	21
Organic Dyes	12	14	15
Pharmaceutical	14	17	19
Ethylene Glycol	3	33	34
Other	134	172	204
Total	2769	3889	4231
Effective Capacity	2566	3850	3850
By-Product	245	273	354
Capacity Required	0	0	525

3.1.5.2 PESTICIDES

Phosgene, produced from carbon monoxide and chlorine, is an important feedstock in the production of pesticides. It is estimated that approximately 10-11% of phosgene produced in the United States is used in pesticide production. The volume of phosgene produced for pesticide consumption for a recent year is shown below.

CONSUMPTION OF PHOSGENE IN PESTICIDES, 1977
(MM lbs.)

	Quantity
Insecticides	65
Herbicides	40
Fungicides	11
Total	116

Methyl isocyanate (MIC) produced from phosgene and methylamine, is the most utilized phosgene intermediate, accounting for 56% of the pesticide market for phosgene. Commercial success of carbamate pesticides based on MIC and other phosgene derivatives is mainly due to their environmental acceptance. The use of phosgene derivatives in pesticides is shown in Table 3.21.

3.1.5.2.1 INSECTICIDES

Carbamate insecticides are characterized by short to moderate activity with acute toxicity. Such insecticides work within the nervous system of the insect, causing eventual respiratory system failure. Carbamate insecticides find their greatest use in corn, soybean, alfalfa and cotton applications. Major products are listed in Table 3.23 with approximate capacities.

3.1.5.2.2 HERBICIDES

Phosgene is used in the production of both carbamate (and thiocarbamate) and urea herbicides which are produced from phosgene and anilines. Carbamate herbicides are most effective for corn applications, while ureas find uses predominantly on soybeans and cotton. Consumption growth of carbamate herbicides is projected at 2.6-4.4%/year, and urea at 3.3%/year. Major herbicide products are summarized in Table 3.24.

Table 3.21

PHOSGENE DERIVATIVE USAGE IN U.S. PESTICIDES, 1977

Million Pounds Phosgene

Intermediate	Quantity
MIC	65
Carbamyl chlorides, thiochloroformates	21
'In Situ' Isocyanates	12
Chloroformates	3
Isocyanates (phenyl and C_2-C_6 aliphatic)	10
Total	116

Monomethyl carbamate insecticides and pesticides, are produced by reacting methyl isocyanate with hydroxyl groups of phenol, oxime or hydroxy-substituted hetero cyclic compounds. The three most important mono-isocyanates are methyl, n-butyl and cyclohexyl. Methyl isocyanate accounts for about 90% of this production, as shown below.

Table 3.22

U.S. PRODUCTION OF MONOISOCYANATES

Million Pounds

	1976	1982	AAG 1976-82
Methyl Isocyanate	30.3	54.6	10.3%
n-Butyl Isocyanate	3.0	3.9	4.6
Cyclohexyl Isocyanate	1.1	3.8	23.0
Total	34.4	62.3	10.4%

Table 3.23

PHOSGENE - CONSUMING CARBAMATE INSECTICIDES

Location	Product Generic Name/ Trade Name	Capacity (MM lbs) 1977	1982
Gulf Coast			
	methonyl/Lamate	5	5
	oxamyl/Vydate	n.a.	n.a.
	BPMC/MIPC	n.a.	n.a.
Ohio Valley			
	thiofanox/Dacancox	--	n.a.
	oxamyl/Vydate(1)	1	--
	aldicarb/Temik(1)	4	6-10
	carbaryl/Sevin	72	100
Mid-Atlantic			
	carbofuran/Fudaran(1)	15	30
	BPMC, CPMC, MIPC	n.a.	n.a.
Other			
	bendrocarb/Fican, Garvox	1	1
	formetanate/Caryol	1	n.a.
	methonyl/Nudrin	2	2
	BPMC, CPMC, MIPC	2	5

(1) also used as fungicide and fumigant

3.1.5.2.3 FUNGICIDES AND FUMIGANTS

Dithiocarbamate fungicides and fumigants are also used as pesticides and are included in Table 3.24.

3.1.5.2.4 PROJECTED CO REQUIREMENTS

Table 3.25 summarizes projected CO use for phosgene manufacture in the insecticide, herbicide and fungicide markets.

3.1.5.3 POLYCARBONATES

Originally, polycarbonates were produced by a solution polymerization process in which the phosgenation reaction is carried out in a homogeneous solvent such as pryridine/methylene chloride. However, recent evidence suggests that all domestic producers are currently using interfacial polymerization of bisphenol A and phosgene to produce polycarbonates. Phosgene is produced on site from chlorine and carbon monoxide.

Polycarbonates are high performance thermoplastics with high optical clarity and impact strength. These thermoplastics have found application in glazing, lighting and equipment housings.

The high demand growth rates for polycarbonates experienced in the 1970's (13-15%) are expected to moderate somewhat in the future due to increasing competition from other plastics as well as approaching saturation in some markets. Demand growth can still be expected to grow at near ten percent per year. Growth at this level may attract new producers to the polycarbonate market.

Table 3.26 summarizes projected demand through 1987 for polycarbonates by end product. Throughout the period, demand growth is projected at 10%.

Capacities for polycarbonate production are shown in Table 3.26. Given these supplies, additional capacity is needed during each of the 1978-82, 1983-87 periods. One 150 million pound per year plant is projected for each of these periods. Additional CO requirements of about 900 MSCFD are projected for each five year period with one addition each in the Gulf Coast and Ohio Valley regions.

Table 3.24

PHOSGENE - CONSUMING HERBICIDES

Product and Location	Product Common Name/ Trade Name	Capacity (MM lbs) 1977	1982
Carbamate			
Gulf Coast	Butylate/Sutan EPTC/Eptam	50	60
Ohio Valley	chlorpropham/Furloe	7	7
	propham/Chemhoe	3	3
Mid-Atlantic	karbutilate/Tandex	n.a.	n.a.
Other	barban/Carbyne	n.a.	n.a.
Urea			
Gulf Coast	linuron/Lorox monuron/Telran siduron/Tupersan	30	30
	duiron	4	4
Mid-Atlantic	chloroxuron/Temoran	n.a.	n.a.
Other	chlorobromuron/Maloran	n.a.	n.a.

Table 3.25

PROJECTED CO USE IN PHOSGENE PRODUCTION
(MM SCFD)

	1977	1982	1987
Insecticide	2.5	4.1	5.5
Herbicide	1.7	2.2	2.8
Fungicide	0.4	0.6	0.8
	4.6	6.9	9.1

Table 3.26

U.S. DEMAND FOR POLYCARBONATES
(MM lbs.)

	1977	1982	1987
Glazing	35	65	90
Lighting and Signs	7	11	20
Business Machines	22	40	55
Appliances	28	40	65
Transportation	21	30	55
Tools	14	20	30
Electric/Electronic	26	40	65
Sporting Goods and Helmets	8	10	15
Other	9	0	35
Total Consumption	170	266	430
Exports	11	17	30
Total U.S. Production	181	283	460
Effective Capacity	245	245	245
Capacity Required	(64)	38	215

3.1.5.4 HYDROGEN PEROXIDE

Hydrogen peroxide is currently produced by the successive hydrogenation and oxidation of ethylanthraquinone or other organic diketone.

Hydrogen peroxide has a wide market base but is used mostly as a bleaching agent. Its greatest market is in textile bleaching. It is also used in the paper industry to bleach wood pulp. Hydrogen peroxide is used in other paper making applications to de-ink recycled newsprint, a market which is expected to grow during the next decade. The chemical industry provides a market for hydrogen peroxide in the production of plasticizers, peroxides, and glycerol. Waste water treatment is expected to become a major market for hydrogen peroxide within the next few years. It can effectively remove hydrogen sulfide from sewer systems, as well as replace chlorine in prechlorination treatment of wastewater. Current uses for hydrogen peroxide are shown in Table 3.27.

During the 1970's, growth for hydrogen peroxide has averaged 6.5% per year. New uses in wastewater and paper bleaching applications are expected to assure steady, consistent growth over the next decade at a 5-6% rate.

There are currently four domestic manufacturers of hydrogen peroxide, with a fifth expected to enter the market before 1980. The price of hydrogen peroxide over the past ten years has been depressed due to the building of new plants utilizing more efficient and less costly product which resulted in overcapacity. Not until 1978 did the price reapproach the 1969 level. Two expansions are expected in the 1978-1982 period. A total hydrogen requirement of 5.4 MMSCFD is expected.

Table 3.27

U.S. DEMAND FOR HYDROGEN PEROXIDE
(MM lbs.)

	1977	1982	1987
Textile Bleaching	59	82	95
Plasticizers and Epoxidation	51	72	90
Glycerine Production	18	20	22
Pulp and Paper Bleaching	16	26	39
Water Treatment	13	26	40
Miscellaneous	18	23	29
Exports	19	26	35
Total	200	275	350
Effective Capacity	275	425	425
Capacity Required	0	150	0

3.1.5.5 1,4 BUTANEDIOL

1,4-butanediol is produced domestically by reacting acetylene with formaldehyde to produce 1,4-butynediol which is subsequently hydrogenated to 1,4-butanediol. The final product is used to produce tetrahydrofuran (a specialty solvent) and several acetylinic chemicals and polymers. The major acetylinic chemicals produced from the diol are used in a number of adhesives, pharmaceuticals and solvents. The recent development of markets for 1,4-butanediol in the production of polybutylene terepthalate (PBT) and polyurethanes will provide much of the demand growth in future years. PBT is a polymer substitute for metals and thermoset resins. Both PBT and polyurethanes (especially reaction injection molded polyurethanes) are expected to find a significant market in automobile applications. Current and projected demand for 1,4-butanediol is shown in Table 3.28.

The domestic demand for 1,4-butanediol is expected to grow at greater than 9% per year through 1981 and nearly 8% from 1981 to 1986. The resulting total demand is shown on Table 3.28 along with domestic production capacity and supply.

3.1.5.6 SPECIALTY CHEMICALS

A number of chemical synthesis technologies require relatively small quantities of H_2, CO, or syngas. The small requirements for H_2 and/or CO may be due to either a small market for the chemical produced or small proportions of H_2 and CO in the chemical product. These small H_2 and CO consumers are grouped in this section on specialty chemicals.

Some technologies which require H_2 or CO are obsolete as far as new capacity expansions are concerned even though existing plants may continue to operate. These situations are discussed briefly.

Brief product application descriptions are given and where significant, market and plant capacity statistics are discussed in the following paragraphs.

Table 3.28
U.S. DEMAND FOR 1,4-BUTANEDIOL
(MM lbs.)

	1977	1982	1987
Tetrahydrofuran (THF)	107	133	167
Acetylinic Chemicals	50	79	126
Polyurethanes			
Thermoplastic Polyurethane	11	14	18
Castable Polyurethane	5	5	6
Rim Injection Molded (RIM) Polyurethane	4	14	26
Polybutylene Terephthalate (PBT)	19	44	65
Miscellaneous	4	11	22
Total	200	300	430
Effective Capacity	338	338	414
Surplus/(Deficit)	128	38	(16)

3.1.5.6.1 SPECIFIC SPECIALTY CHEMICALS

The fatty acid industry developed around the process of upgrading tallow and lard into soap manufacturing. Splitting and distillation techniques were rapidly introduced during World War II for the purpose of recovering glycerin to be used in explosives. The markets for fatty acids today are dependent on cosmetics and toiletries (including bar soap), other cleaning products and synthetic lubricants. The other major branch of alkali refining of oils, the edible products markets, are not considered chemicals and are not discussed in this section.

Fatty acids are generally considered to be those monocarboxylic acids higher than the straight-chain (C_1-C_4) carboxylic acids (formic, acetic, propionic, butyric).

Beginning in 1980, hydroformylation technology will be first used in the U.S. to produce the first synthetic acids in the C_5-C_{10} medium length range. The C_{11}-C_{15} coconut range acids are expected to continue to involve the sequence of operations involved in processing coconut oil, the most common feedstock: 1) fat splitting, 2) distillation, and 3) hydrogenation.

During the period 1978-1987, the demand for medium length fatty acids is expected to increase from somewhat over 100 million pounds to about 175 million pounds. The new synthetic acid plant should be the only expansion required in the 1978-1987 period and will require about 4.5 MMSCFD syngas. Existing production capacity for coconut-range acids is expected to be sufficient through 1987.

MMT, a tricarbonyl, was introduced in 1974 as an economical octane source for unleaded gasolines. Discussions concerning the impact of MMT on air quality followed and today only minor amounts of MMT are used in the U.S. gasoline pool. Some MMT is exported. No future capacity expansion is expected.

Dimethylformamide is an industrial solvent used in butadiene and isoprene manufacture as is acetate-fiber spinning. Demand is expected to increase by more than 50% during the 1978-1987 period. Existing U.S. capacity to produce DMF, including carbon monoxide generating capacity, is expected to be sufficient to meet increased demand throughout the 1978-1987 period.

Methyl formate is a chemical intermediate used in the manufacture of dimethyl formides (acrylic fibers), esters, aldehydes, and other intermediates. It is produced from carbon monoxide and methanol. Future methyl formate capacity expansions are not expected to require carbon monoxide capacity expansions at existing methyl formate production locations.

Oxalic acid is formed from sodium hydroxide and carbon monoxide via sodium formate. The acid is used primarily in textile and metal cleaning but is also sold as a chemical intermediate. The market outlook for oxalic acid is stagnant, with consumption holding steady at 20 MM lb/yr. The sole domestic producer operates two plants for the production of oxalic acid, but has sufficient capacity at one location to supply the United States. Both plants are located in the Northeast U.S.

Glycolic acid is used in the leather industry and in preparing chelating formulations of iron. The sole domestic producer, located in the Ohio Valley region, manufactures this acid via the reaction of formaldehyde and carbon monoxide. Excess carbon monoxide production capacity at that location is expected to be sufficient for any glycolic acid expansions during the period 1978-1987.

Sorbitol is a sweetening agent which has been used extensively in recent years, especially in the sugarless candy and chewing gum markets. It is also widely used as an intermediate in the production of vitamin C. Sorbitol is naturally occurring in many foods, but is prepared commercially through the catalytic hydrogenation of sugars. The sweetener is usually sold in liquid form, as a 70% solution in water.

The market for sorbitol has been increasing at about 5% annually for the past several decades, with several years showing growth at greater than 9% p.a. during the 1970's. However, with growth expected to moderate in the early 1980's, expansions by leading producers over the past few years assure an adequate supply throughout the next ten years. No further expansions are planned nor expected.

Furfuryl alcohol is produced by moderate to high pressure hydrogenation of furfural over a copper chromate catalyst. The alcohol can be further hydrogenated to tetrahydrofurfuryl alcohol. Furfuryl alcohol is the major derivative of furfural. It is used in producing furan resins for foundry binders and metal castings and cores. There is only one U.S. manufacturer currently producing furfuryl alcohol. Since the feedstock for the alcohol is furfural which is produced from agricultural feedstocks, plants are located in agricultural regions. Estimated capacity is nearly 100 million pounds. Production in 1977 was about 50 million pounds and no capacity expansions are expected during the 1978-1987 period.

Tetrahydrofuran is usually produced from butanediol, however, one manufacturer in the United States currently produces THF through the catalytic hydrogenation of furfural. No expansions are expected via this technology during the 1978-1987 period.

Cyclohexylamine is produced by the hydrogenation of aniline. It is used as an intermediate in the production of several rubber chemicals and as a carbon dioxide scavenger in boiler systems. Small amounts are used in the production of cyclamate sweeteners. Production capacity is located in the mid-Atlantic region and also in the Western U.S. A 1978-1982 expansion is expected at the Western U.S. location and another is expected on the Gulf Coast in the 1983-1987 period.

3.1.5.6.2 H_2/CO REQUIREMENTS

The estimated H_2 and CO capacity additions required for production of specialty chemicals is as follows (MMSCFD):

	1978-82	1982-87
H_2	2.5	0.3
CO	2.2	--

3.1.6 ELECTROLYTIC HYDROGEN POTENTIAL IN CHEMICAL MANUFACTURE

As proposed, one element of this study concerns the potential for production of hydrogen for chemical manufacture in the mid-Atlantic region using electrolytic cells.

This evaluation assumes that cell hydrogen is economically competitive when produced in volumes of from 200,000 SCFD to 500,000 SCFD. As defined in Table 3.1, Section 3.1 of this study, no potential hydrogen markets were identified for the mid-Atlantic region in this size range during the 1978-1987 period. This conclusion is no doubt due to the fact that hydrogen uses in this volume range are concentrated in non-chemical applications such as metal treating, edible oil processing, float glass plants, and electronics manufacture.

Because market conditions in the mid-Atlantic area do not warrant further study, no electrolytic hydrogen economics will be considered in this study.

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

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

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

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

Table 3.29

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

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

*780/390 as syngas
**as syngas

3.2.1 MAJOR REQUIREMENTS PLANTS

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

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

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

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

3.2.2 OXO ALCOHOLS

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

3.2.3 POLYURETHANES

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

3.2.4 FIBERS

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

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

3.2.5 OTHER CHEMICALS

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

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

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

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

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

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

3.3.1 METHODOLOGY

3.3.1.1 CAPITAL COST ESTIMATES

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

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

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

where C_1 = known cost to produce Q_1 quantity
C_2 = desired unknown cost
N = cost exponent
Q_1 = quantity produced for C_1 cost
Q_2 = desired quantity of production

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

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

The process block components of the computer data base necessarily have varying degrees of certainty with regard to their accuracy. At one extreme are the O_2-blown high pressure coal gasification units of which no commercial scale plant has been built -- at least at the time this study was done. Hence, all the costs associated with these plants must come from design studies. On the other hand, a great deal is known about the costs associated with some process blocks such as air separation units. Cost information was based upon contractor-owner confidential data that has been developed over several years of experience as an owner/operating company.
Air Separation Units - ASU's are required for partial oxidation of oil and both high and low pressure coal gasification. The program is designed to differentiate between high and low pressure supply of oxygen and to adjust the capital and operating costs appropriately.
Reformers - H_2 and CO are produced by the steam reforming of natural gas. The desired reaction is $CH_4 + (2\text{-}n)\ H_2O \longleftrightarrow n\ CO + (1\text{-}n)\ CO_2 + (4\text{-}n)\ H_2$. When H_2 is the final product, the effluent from the reformer is sent to a shift unit to convert CO and H_2O to H_2 and CO_2. Then the CO_2 is removed leaving H_2 product. In the cases where 2:1 H_2 to CO is desired, reformer effluent is first sent to a CO_2 removal unit to recover CO_2 for recycle to the reformer inlet. The CO_2 free gas then goes to a cryogenic separation unit which produces the 2:1 product stream and a waste H_2/CH_4 stream which is used as part of the fuel to the reformer.
Partial Oxidation - In this case, a H_2-CO stream is produced by the reaction of oil with steam and oxygen at high temperature and pressure. The raw effluent contains H_2S and CO_2 which is removed and sent to a sulfur recovery system. The lean gas has an excess

of CO whether syngas or hydrogen is the required product. Hence, the appropriate quantity of gas must be sent to shift and CO_2 removal to produce the final product slate.

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

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

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

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

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

Regional Costs

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

3.3.1.2 MAJOR OPERATING COST ESTIMATES

Major operating costs consist of the following:

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

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

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

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

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

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

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

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

3.3.2 DISCUSSION OF RESULTS COMPARING H_2 AND SYNGAS PRODUCTION COSTS

The key production cost issues addressed in this study are:

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

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

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

3.3.2.1 RESULTS FOR H_2 AND SYNGAS PRODUCTION - ORIGINAL ENERGY SCENARIO

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

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

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

Table 3.30

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

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

*In year 1 of plant operation.

FIGURE 3.4

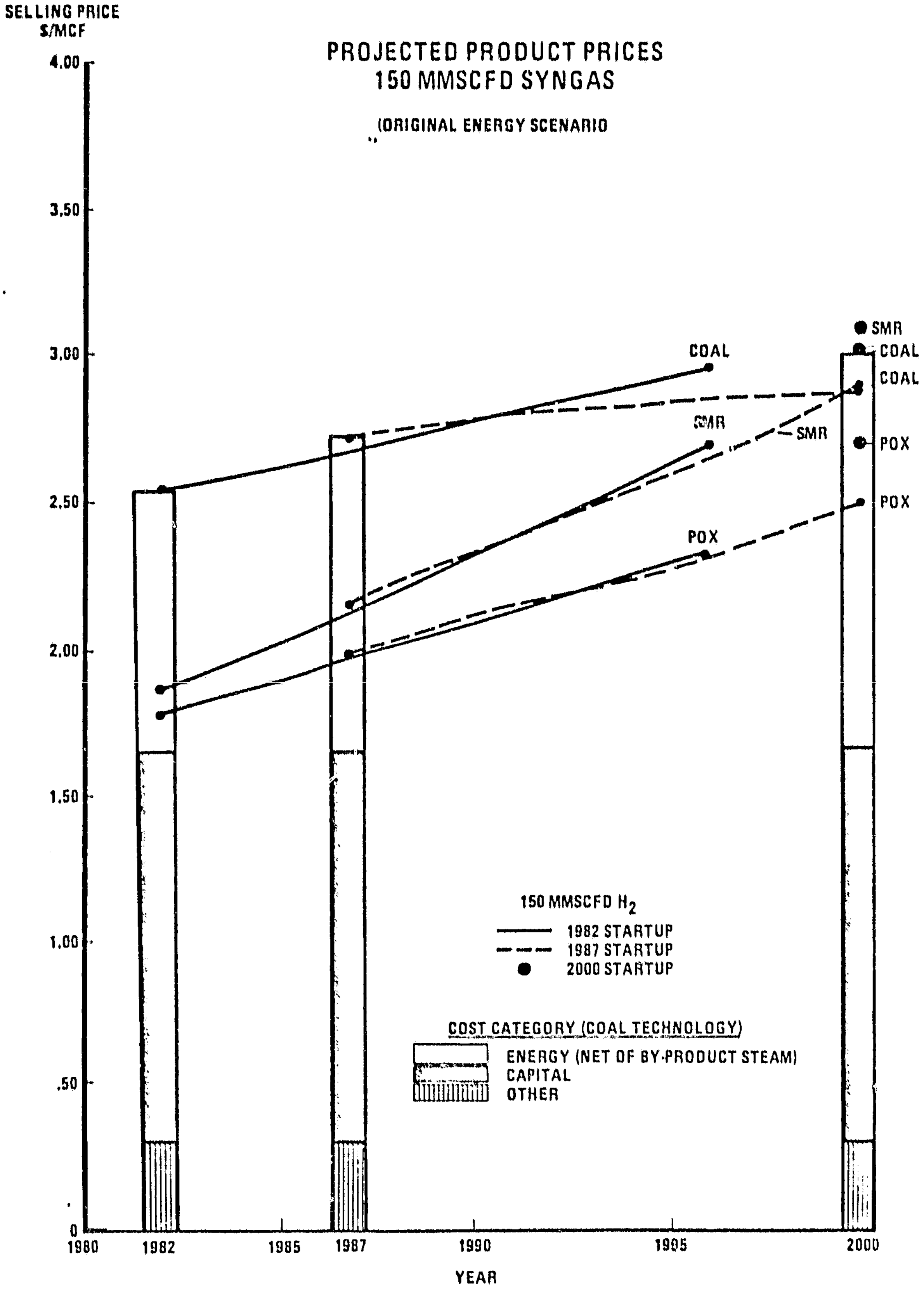

SELLING PRICE
$/MCF
PROJECTED PRODUCT PRICES
150 MMSCFD SYNGAS
(ORIGINAL ENERGY SCENARIO
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
COAL
SMR
POX
SMR
COAL
COAL
SMR
POX
POX
150 MMSCFD H_2
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY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

FIGURE 3.5

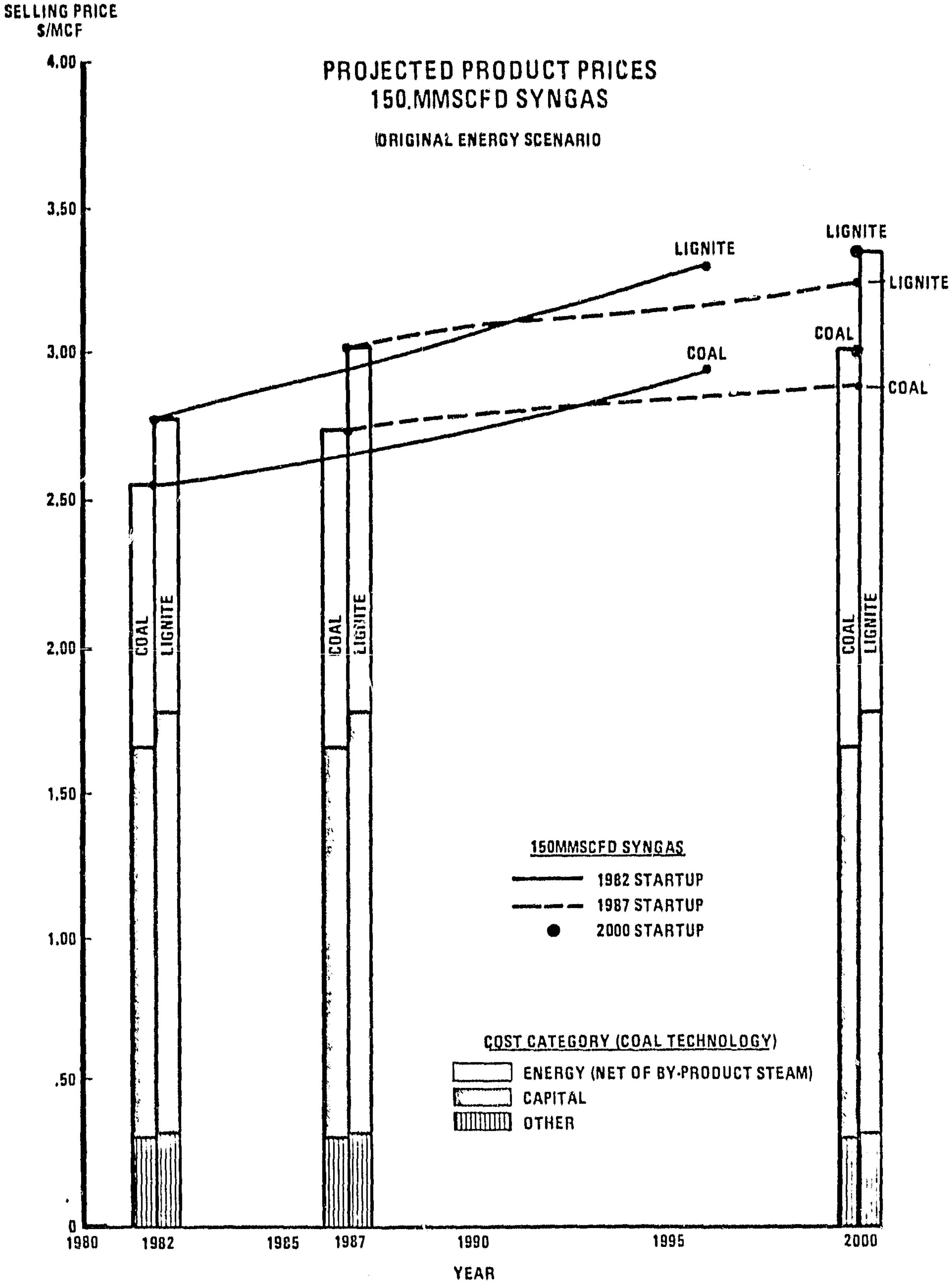

SELLING PRICE
$/MCF
PROJECTED PRODUCT PRICES
150 MMSCFD SYNGAS
(ORIGINAL ENERGY SCENARIO
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
LIGNITE
COAL
LIGNITE
LIGNITE
COAL
COAL
COAL
LIGNITE
COAL
LIGNITE
COAL
LIGNITE
150MMSCFD SYNGAS
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY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

Table 3.31

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

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

*In year 1 of plant operation.

FIGURE 3.6

PROJECTED PRODUCT PRICES
150 MMSCFD H_2
ORIGINAL ENERGY SCENARIO

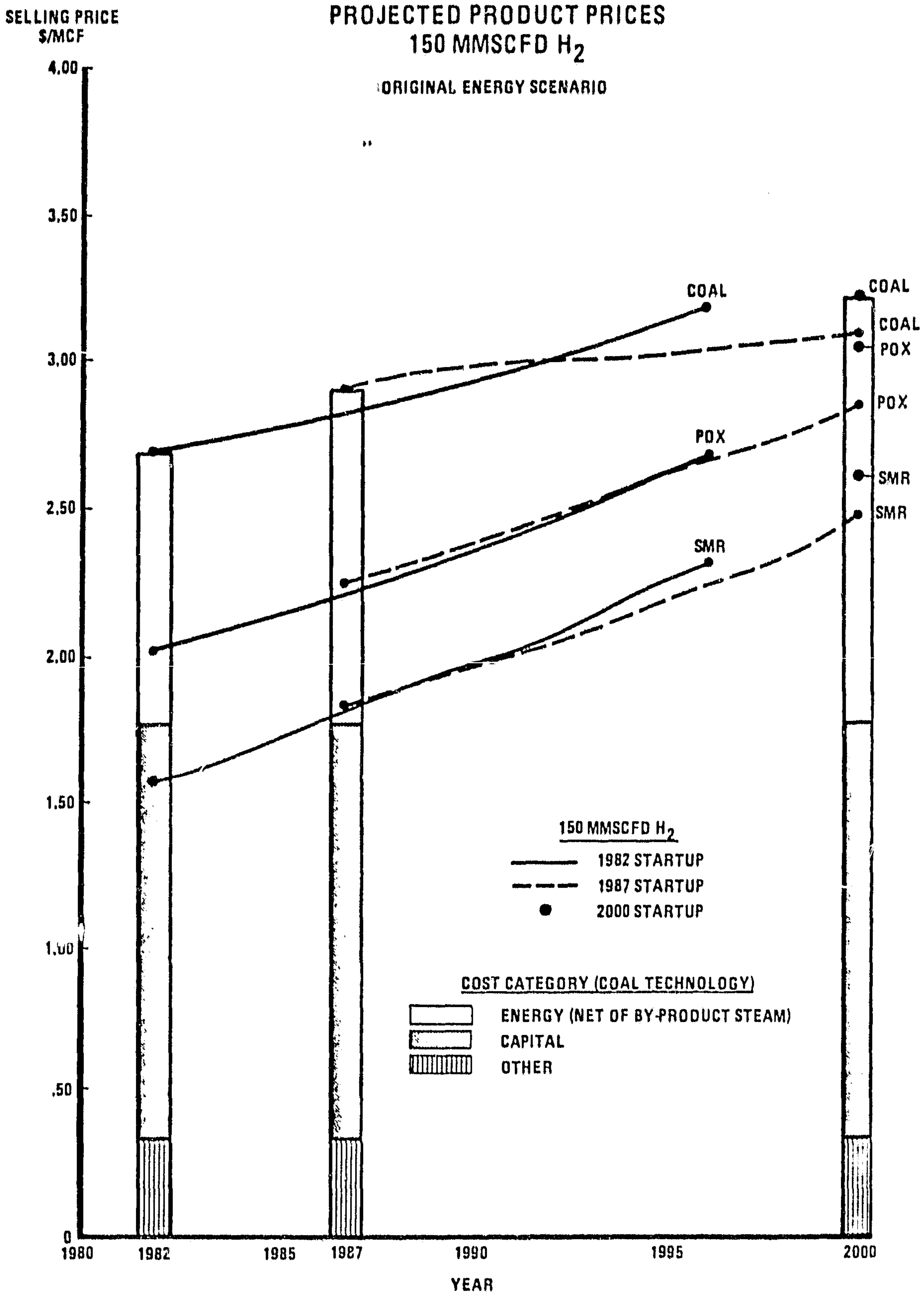


FIGURE 3.7

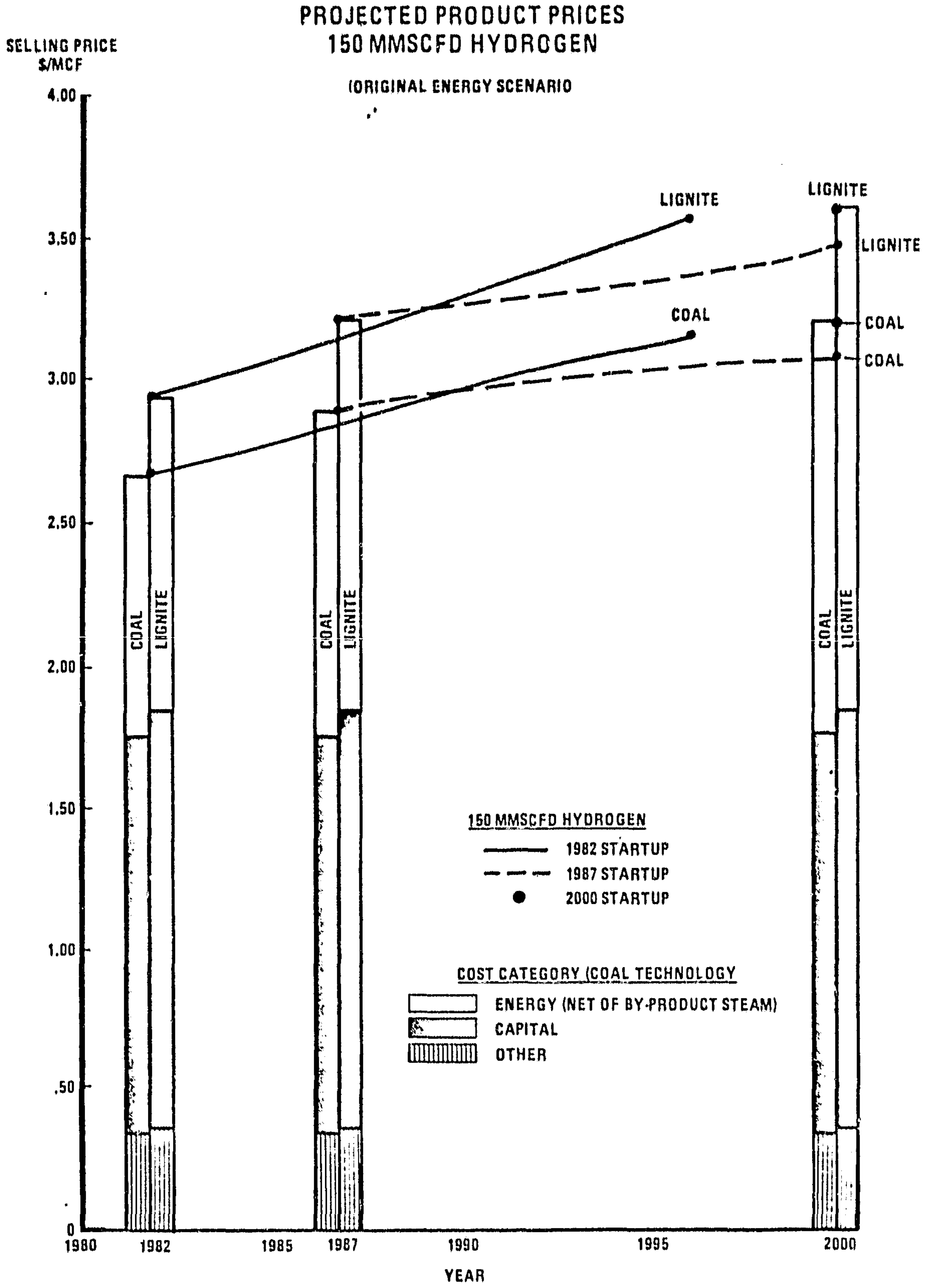

PROJECTED PRODUCT PRICES
150 MMSCFD HYDROGEN
(ORIGINAL ENERGY SCENARIO
SELLING PRICE $/MCF
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
COAL
LIGNITE
150 MMSCFD HYDROGEN
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY
ENERGY (NET OF BY-PRODUCT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

Table 3.32

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

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

*In year 1 of plant operation.

FIGURE 3.8

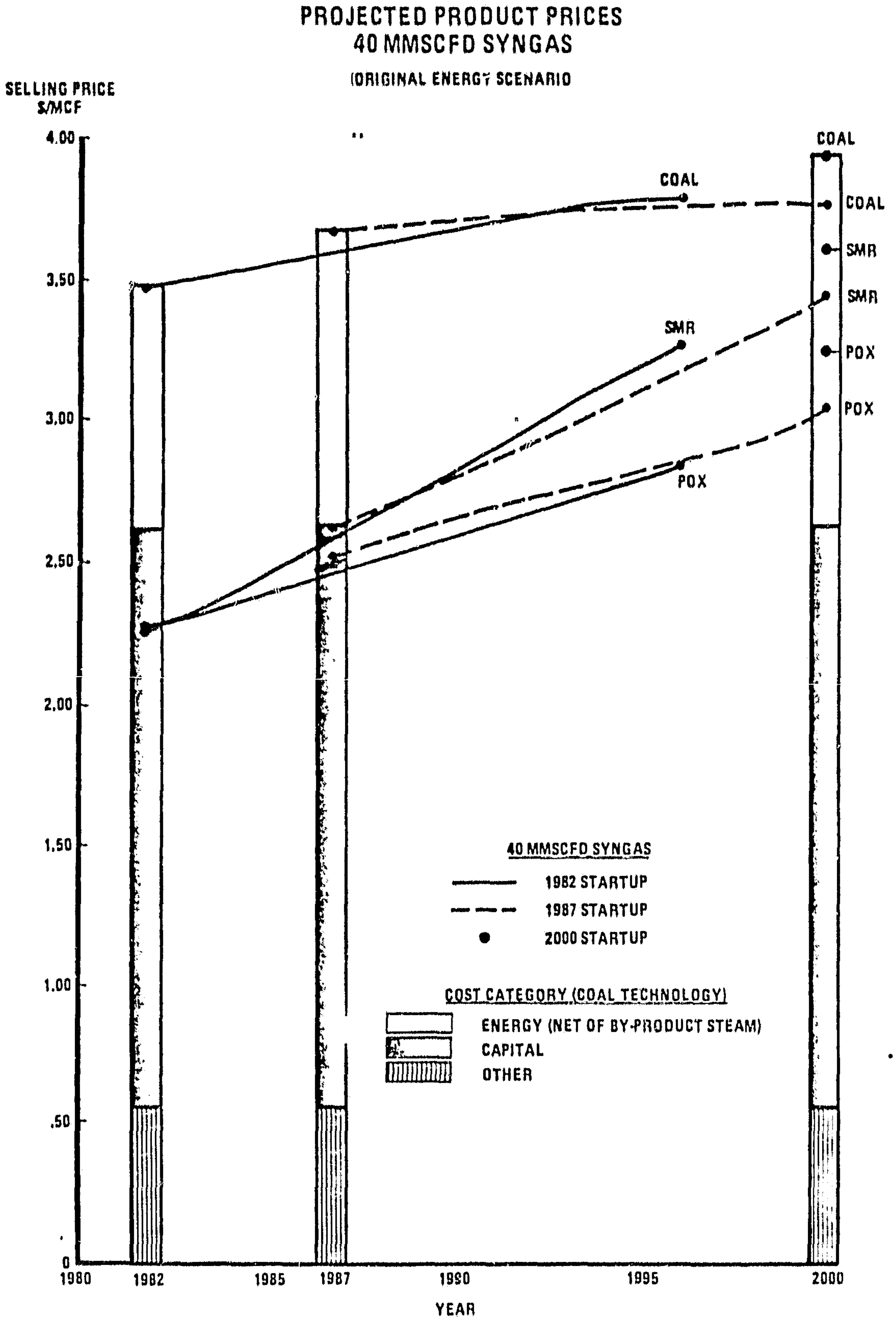
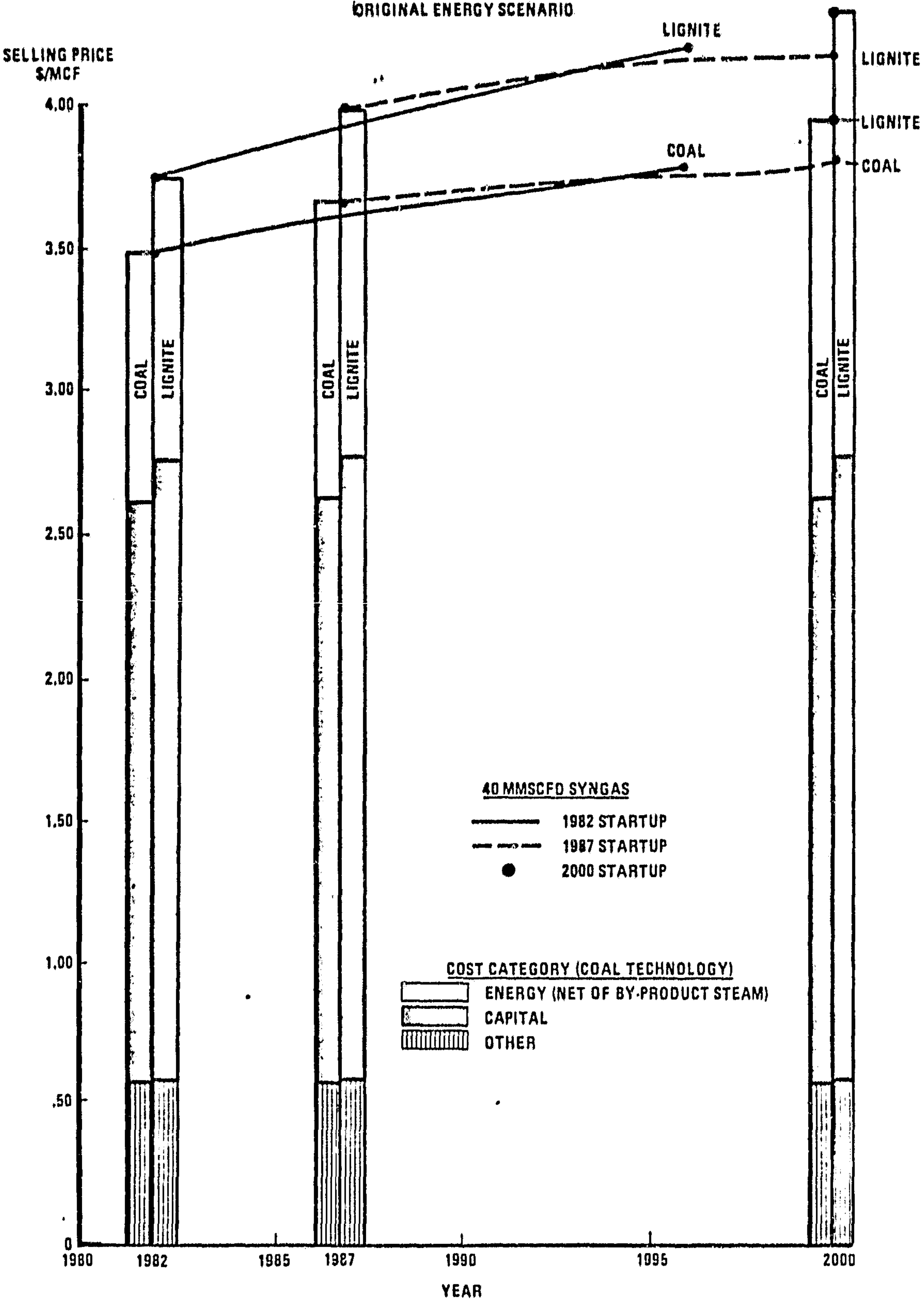

PROJECTED PRODUCT PRICES
40 MMSCFD SYNGAS
(ORIGINAL ENERGY SCENARIO
SELLING PRICE
$/MCF
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
COAL
COAL
COAL
SMR
SMR
SMR
POX
POX
POX
40 MMSCFD SYNGAS
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY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

FIGURE 3.9

PROJECTED PRODUCT PRICES
40 MMSCFD SYNGAS
ORIGINAL ENERGY SCENARIO



3.3.2.2 PRESSURIZED VS. ATMOSPHERIC COAL GASIFICATION

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

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

3.3.2.3 EVALUATION OF CO-PRODUCING FUEL AND SYNGAS

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

3.3.3 DISCUSSION OF REVISED ENERGY SCENARIO SENSITIVITY CASES

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

Table 3.33

COMPARISON OF ATMOSPHERIC AND PRESSURIZED COAL GASIFICATION FOR SYNGAS PRODUCTION

40 MM SCFD SYNGAS
(Gulf Coast Location)

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

150 MM SCFD SYNGAS
(Gulf Coast Location)

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

Table 3.34

EVALUATION OF FUEL GAS PRICES CO-PRODUCED WITH SYNGAS

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

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

*In year 1 of plant operation.

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

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

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

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

d) For purposes of deriving functional relationships, let:

y = price

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

The results of this analysis are shown below:

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

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

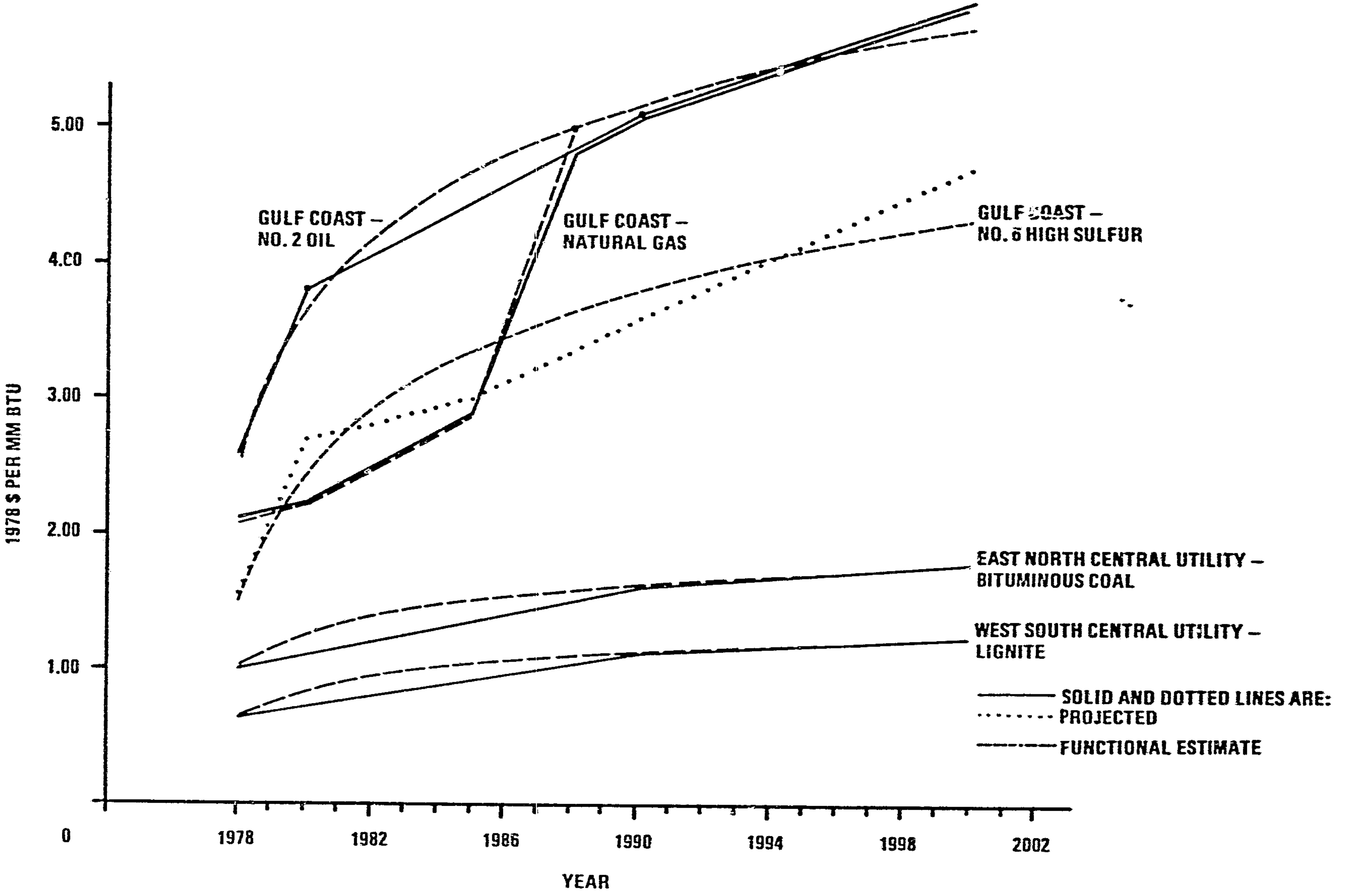
Functional Form: $y = ae^{bx}$

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

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

FIGURE 3.10

ENERGY PRICE PROJECTIONS,
WITH FUNCTIONAL REPRESENTATIONS



3.3.3.1 RESULTS FOR H_2 AND SYNGAS PRODUCTION USING REVISED ENERGY SCENARIO

The results of H_2 and syngas price comparisons for product slate/ plant sizes for the revised energy scenario are shown in Tables 3.35 through 3.39. Figures 3.11 through 3.16 illustrate the results for a Gulf Coast location. The revised scenario shows coal to be more competitive than the results of the original scenario.

1. With only one exception, coal is not competitive in year 1 of operation for any future plant start-up date regardless of plant size/slate and geographic region. The only exception is the production of 150 MM SCFD hydrogen in the Ohio Valley with start-up in year 2000.
2. The competitive position of coal depends more on product slate than plant size in 1982, but is more dependent on plant size for start-up years 1987 and 2000.
    a. Coal is least competitive with the H_2 slate for start-up in 1982, but is most competitive with the H_2 slate for 2000 start-up. The slate for which coal is most competitive for start-up in 1987 is region dependent.
    b. Coal is less competitive at 40 MM SCFD syngas than at 150 MM SCFD H_2 for plants with start-up in 1987 or 2000. In 1982, coal is more competitive at 40 MM SCFD syngas than at 150 MM SCFD H_2.
    c. The 1982 price premium for syngas from coal is about 50% averaged over regions at 40 MM SCFD and about 35% averaged over regions at 150 MM SCFD versus 70% for the hydrogen slate.
3. The high escalation rates of oil and natural gas as opposed to coal result in a steadily declining premium for coal based product (versus the least cost alternative). The average "year one" premium for coal for all product slates and plant sizes declines from 53% in 1982 to 9% in 2000.
4. Real annual escalation rates are significantly higher for natural gas and oil as compared to coal. The impact of the different escalation rates becomes significant in 1987

when the initial year prices difference coal and the least cost alternative is only about 20%. For example, for production of 150 MM SCFD H_2 in the Ohio Valley region, product from coal is the least cost alternative for the last half of the project life.

5. Lignite and bituminous coal types were compared for both product slates and plant sizes in the Gulf Coast region. Lignite results in about a 10% premium in product price compared with bituminous.
6. Year of start-up determines the least costly feedstock option, natural gas vs. oil. For all 1982 start-up, natural gas results in the lowest cost product. For 1987 start-up, oil is the least cost option with the exception of Gulf Coast and Ohio Valley location production of 150 MM SCFD hydrogen. For 2000 start-up, oil is the least cost alternative, again with the exception of Gulf Coast and Ohio Valley hydrogen production. The least cost option in the Gulf Coast for H_2 production is still natural gas, while that in the Ohio Valley is bituminous coal.

Table 3.35

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

Start-Up Year	1982			1987			2000		
Region	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*
Gulf Coast									
Natural Gas	$1.84	5.8%	--	$2.70	3.2%	--	$3.41	--	--
Oil	$2.06	1.9%	--	$2.30	1.1%	--	$2.62	--	--
Coal - Lignite	$2.71	0.8%	--	$2.90	0.1%	--	$3.07	--	--
Coal - Bituminous	$2.49	0.7%	35.3%	$2.64	0.1%	14.8%	$2.78	--	6.1%
Ohio Valley									
Natural Gas	$1.90	6.6%	--	$2.94	3.3%	--	$3.77	--	--
Oil	$2.11	2.1%	--	$2.41	1.1%	--	$2.75	--	--
Coal	$2.62	0.3%	37.9%	$2.70	0.1%	12.0%	$2.82	--	2.5%
Mid-Atlantic									
Natural Gas	$2.12	8.1%	--	$3.48	4.9%	--	$4.92	--	--
Oil	$2.16	1.9%	--	$2.43	1.1%	--	$2.78	--	--
Coal	$2.77	0.5%	30.7%	$2.88	0.1%	18.5%	$3.04	--	9.4%

*In year 1 of plant operation.

FIGURE 3.11

PROJECTED PRODUCT PRICES
150 MMSCFD SYNGAS

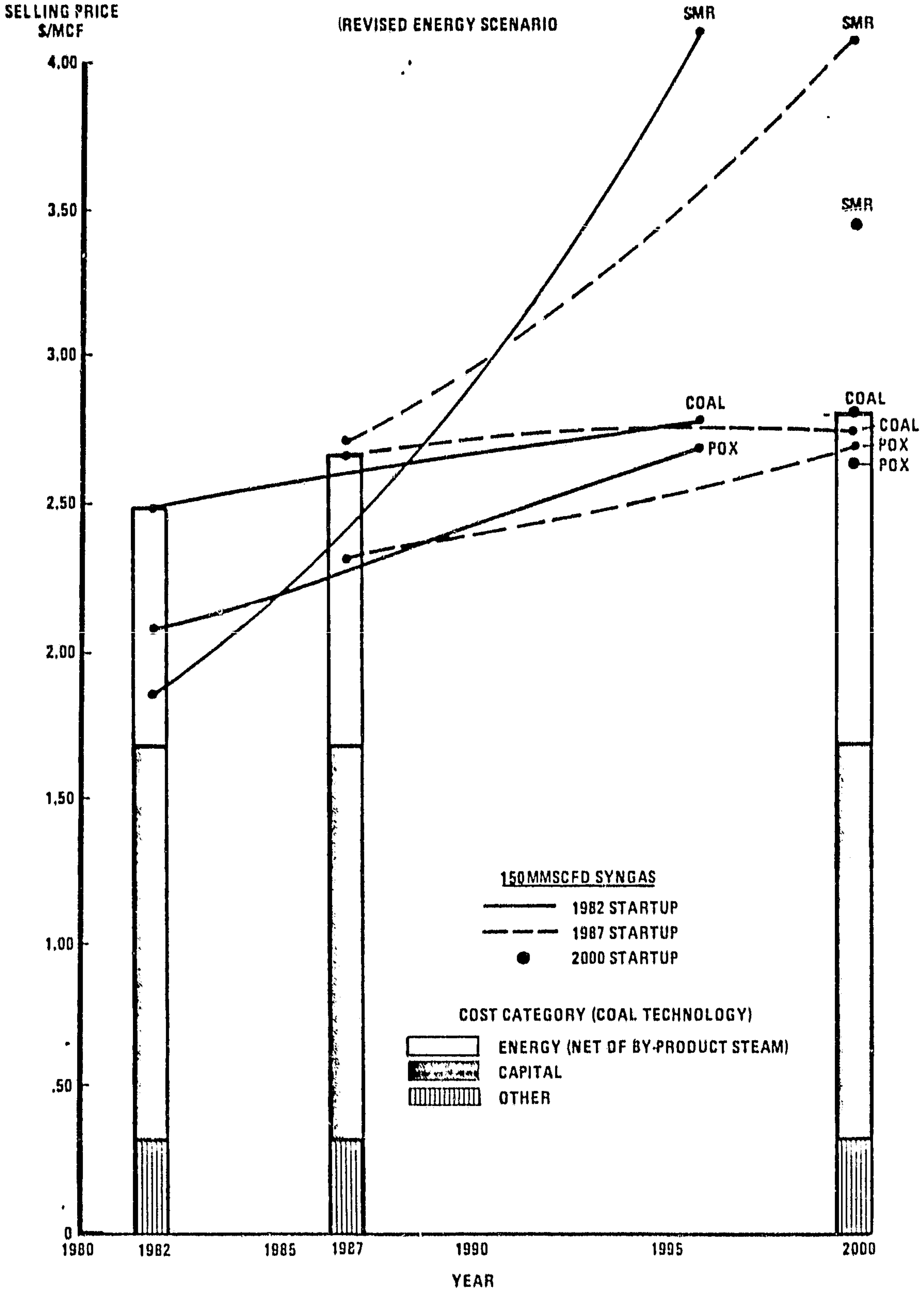


FIGURE 3.12

PROJECTED PRODUCT PRICES
150 MMSCFD SYNGAS

(REVISED ENERGY SCENARIO

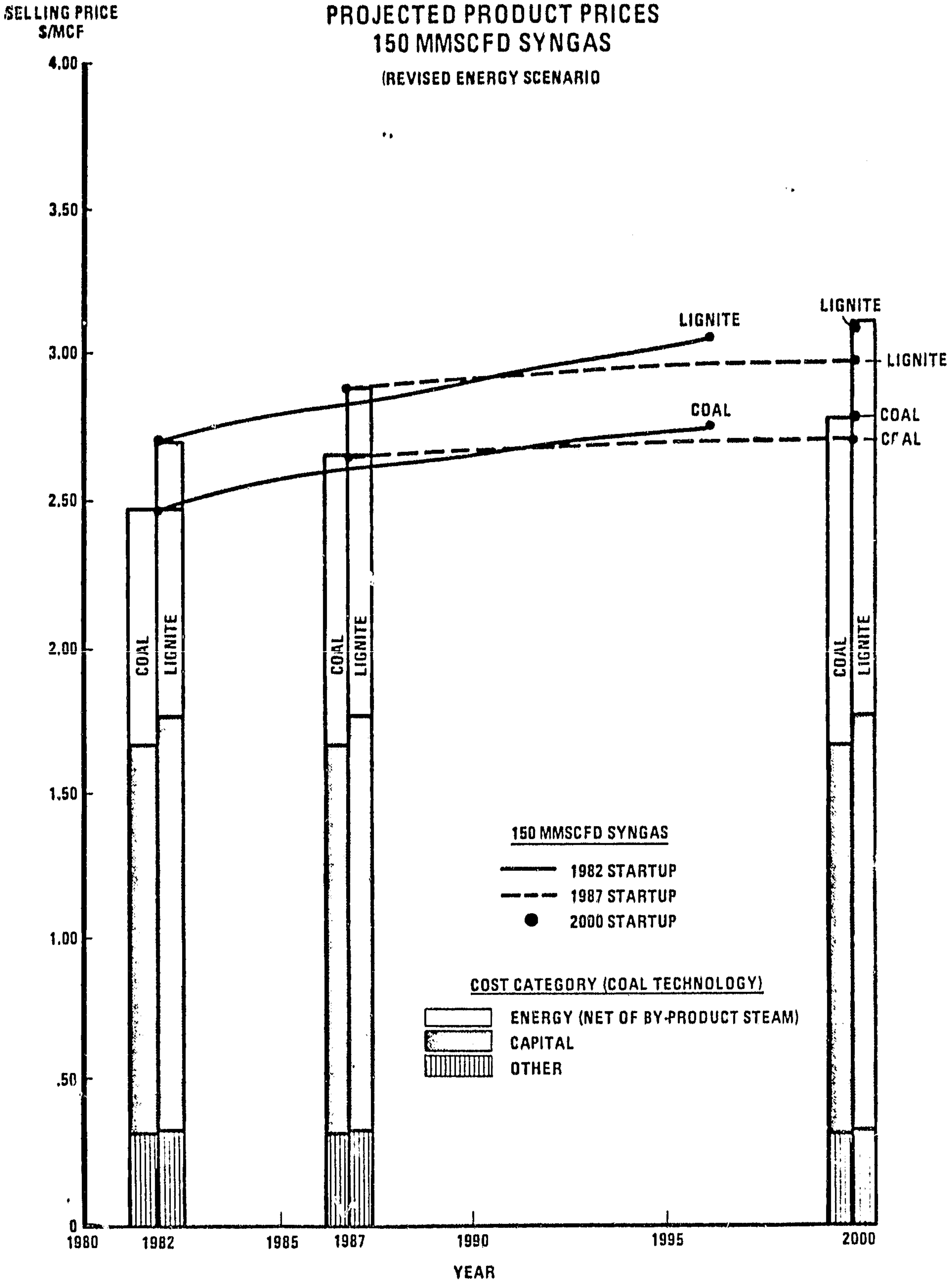


Table 3.36

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

Start-Up Year	1982			1987			2000		
Region	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*
Gulf Coast									
Natural Gas	$1.50	6.2%	--	$2.22	3.4%	--	$2.80	--	--
Oil	$2.30	2.0%	--	$2.57	1.1%	--	$2.92	--	--
Coal - Lignite	$2.92	0.9%	--	$3.14	0.2%	--	$3.33	--	--
Coal - Bituminous	$2.64	0.8%	76.0%	$2.81	0.2%	26.6%	$2.97	--	6.1%
Ohio Valley									
Natural Gas	$1.61	6.3%	--	$2.44	3.3%	--	$3.13	--	--
Oil	$2.39	2.1%	--	$2.70	1.0%	--	$3.07	--	--
Coal	$2.79	0.4%	73.3%	$2.89	0.0%	18.4%	$3.02	--	(1.7%)
Mid-Atlantic									
Natural Gas	$1.80	7.8%	--	$2.90	4.8%	--	$4.07	--	--
Oil	$2.45	1.9%	--	$2.74	1.0%	--	$3.12	--	--
Coal	$2.96	0.5%	64.4%	$3.08	0.1%	12.4%	$3.25	--	4.2%

*In year 1 of plant operation.

FIGURE 3.13

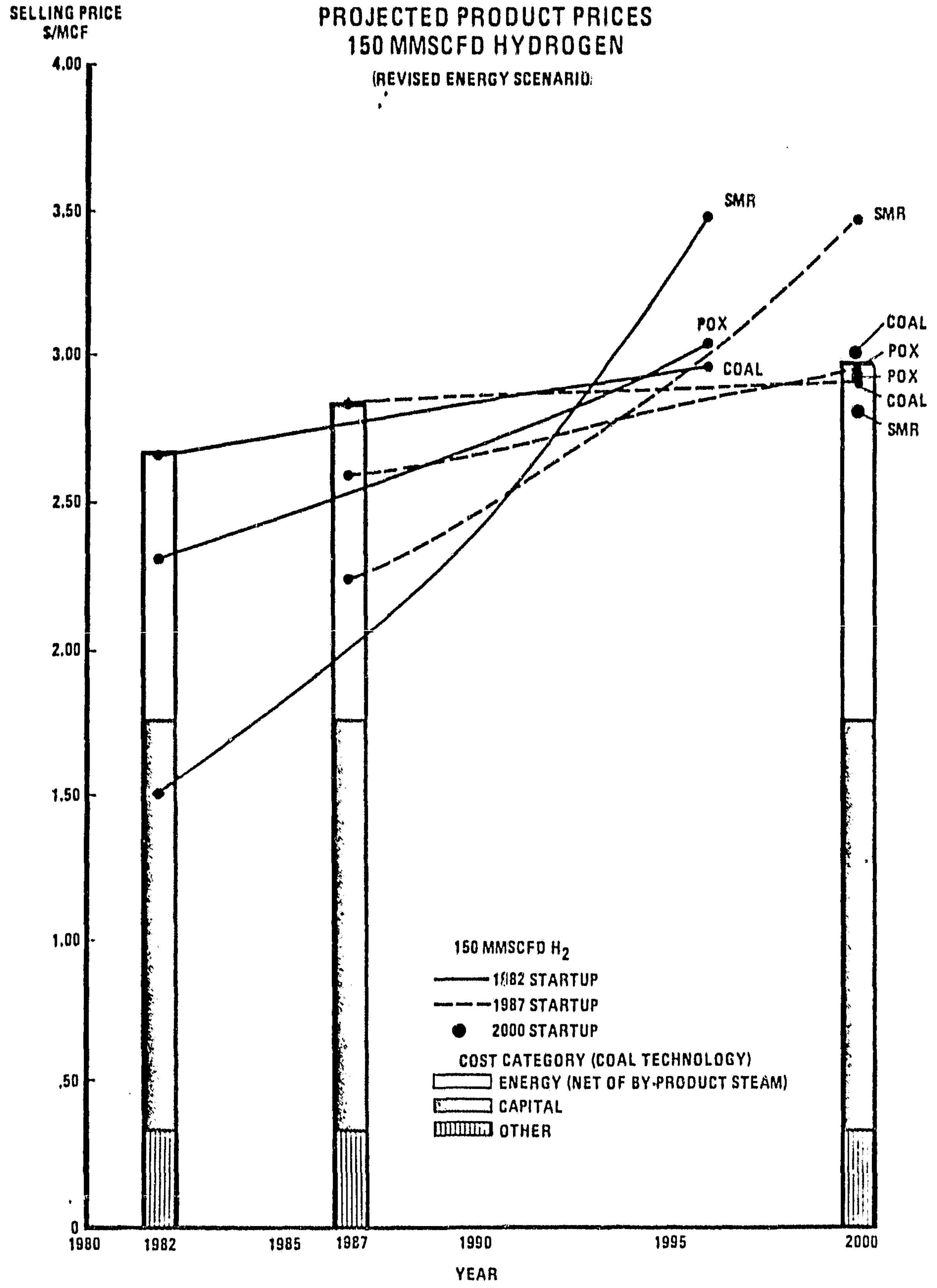

SELLING PRICE
$/MCF
PROJECTED PRODUCT PRICES
150 MMSCFD HYDROGEN
(REVISED ENERGY SCENARIO)
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
SMR
SMR
POX
COAL
COAL
POX
POX
COAL
SMR
150 MMSCFD H_2
1982 STARTUP
1987 STARTUP
● 2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY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

FIGURE 3.14

PROJECTED PRODUCT PRICES
150 MMSCFD HYDROGEN
REVISED ENERGY SCENARIO

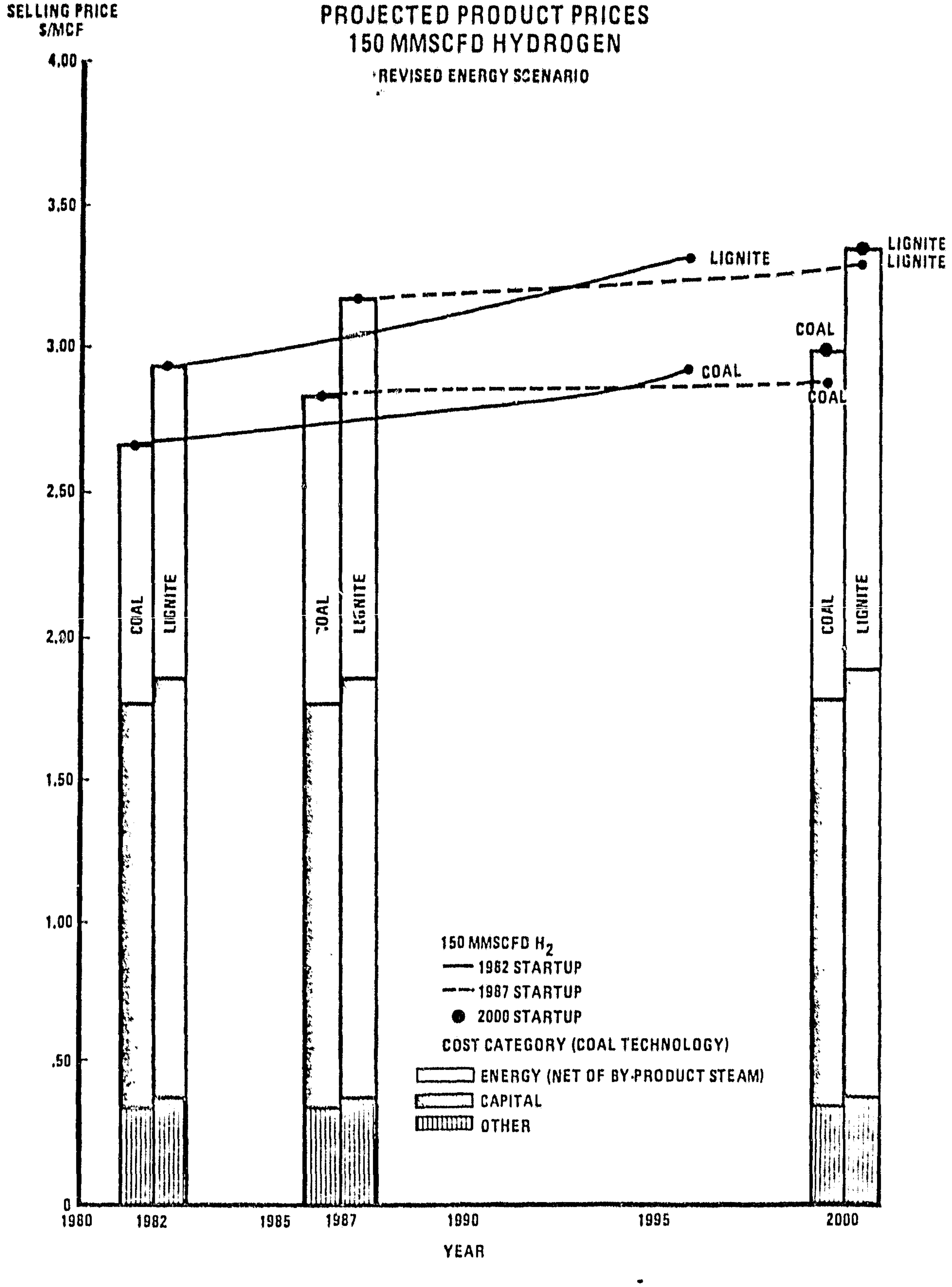


Table 3.37

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

Start-Up Year	1982			1987			2000		
Region	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*	Initial Price	Annual Escal.	Coal Premium*
Gulf Coast									
Natural Gas	$2.20	5.6%	--	$3.12	3.3%	--	$3.87	--	--
Oil	$2.51	2.1%	--	$2.76	1.4%	--	$3.09	--	--
Coal - Lignite	$3.75	0.5%	--	$3.94	0.0%	--	$4.11	--	--
Coal - Bituminous	$3.45	0.4%	56.8%	$3.59	0.0%	30.1%	$3.74	--	21.0%
Ohio Valley									
Natural Gas	$2.29	6.2%	--	$3.37	3.4%	--	$4.23	--	--
Oil	$2.67	1.7%	--	$2.97	0.9%	--	$3.32	--	--
Coal	$3.61	0.1%	57.6%	$3.70	0.0%	24.6%	$3.82	--	15.1%
Mid-Atlantic									
Natural Gas	$2.56	7.3%	--	$3.97	4.7%	--	$5.46	--	--
Oil	$2.69	1.7%	--	$2.97	0.9%	--	$3.33	--	--
Coal	$3.73	0.2%	45.7%	$3.83	0.0%	29.0%	$3.99	--	19.8%

*In year 1 of plant operation.

FIGURE 3.15

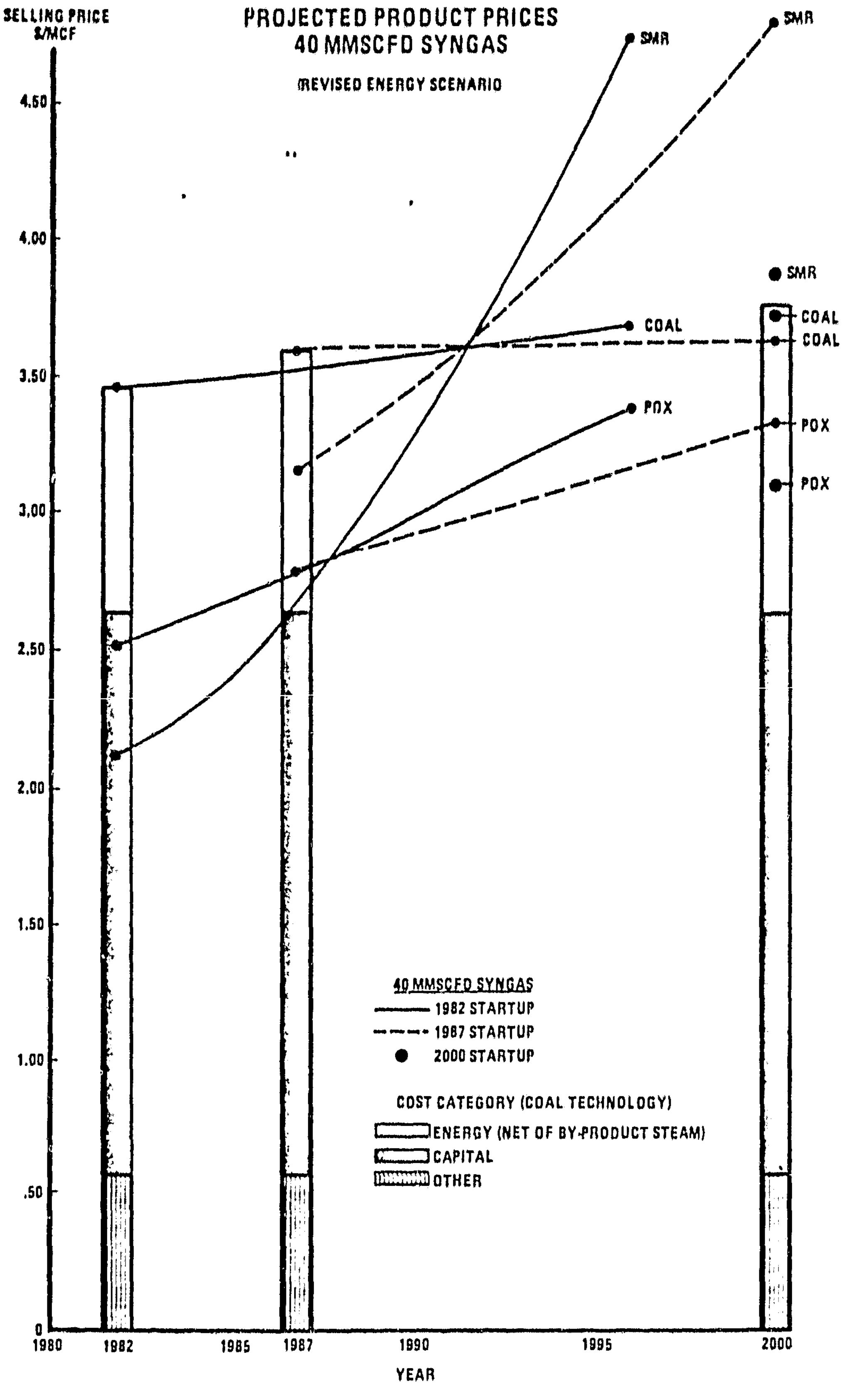
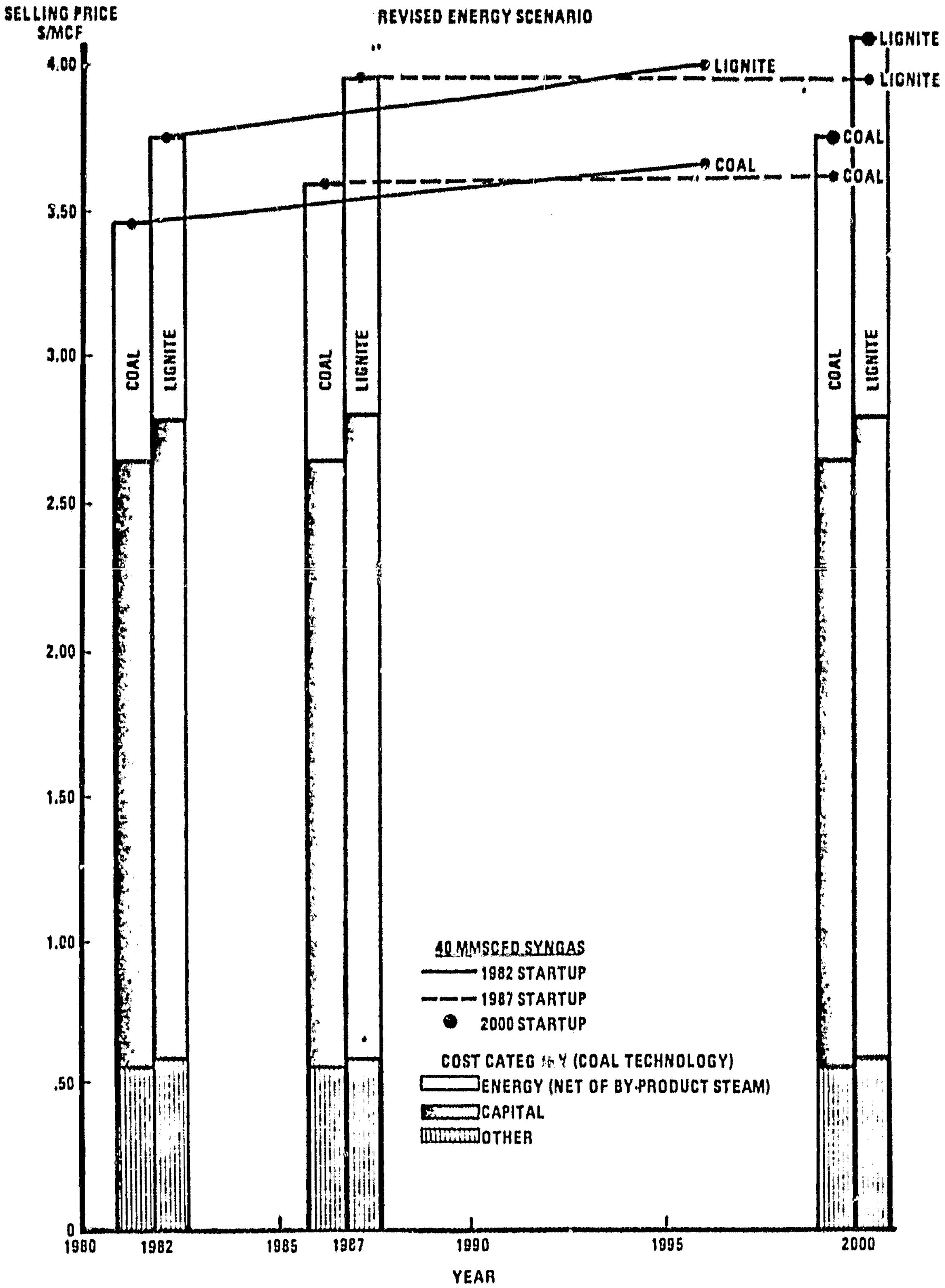

PROJECTED PRODUCT PRICES
40 MMSCFD SYNGAS
(REVISED ENERGY SCENARIO
SELLING PRICE $/MCF
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
.50
0
1980
1982
1985
1987
1990
1995
2000
YEAR
SMR
SMR
SMR
COAL
COAL
COAL
POX
POX
POX
40 MMSCFD SYNGAS
1982 STARTUP
1987 STARTUP
2000 STARTUP
COST CATEGORY (COAL TECHNOLOGY)
ENERGY (NET OF BY-PRODUCT STEAM)
CAPITAL
OTHER

FIGURE 3.16

PROJECTED PRODUCT PRICES
40 MMSCFD SYNGAS
REVISED ENERGY SCENARIO



3.3.3.2 PRESSURIZED VS. ATMOSPHERIC COAL GASIFICATION

The advantage of pressurized versus atmospheric gasification for the production of syngas was found to be practically identical under the revised energy scenario as compared to the original scenario. Results are shown in Table 3.38. The price advantages of the 40 MM SCFD size is 13.9% for both 1982 and 1987 start-ups. At 150 MM SCFD, the price advantage is 14.5% for 1982 start-up and 14.8% for 1987 start-up.

3.3.3.3 EVALUATION OF CO-PRODUCING FUEL AND SYNGAS

Under the revised energy scenario, the disadvantage of fuel gas from coal has been greatly reduced as shown in Table 3.39. However, medium Btu fuel gas from coal still requires a 25% premium over the least cost clean fuel in 1987.

Table 3.38

COMPARISON OF ATMOSPHERIC AND PRESSURIZED COAL GASIFICATION FOR SYNGAS PRODUCTION

40 MM SCFD Syngas
(Gulf Coast Location)

	1982			1987		
	Initial Price	Annual Escalation	Pressurized Advantage*	Initial Price	Annual Escalation	Pressurized Advantage*
Atmospheric	$3.45	0.4%	--	$3.59	0.0%	--
Pressurized	$2.97	0.4%	13.9%	$3.09	0.1%	13.9%

150 MM SCFD Syngas
(Gulf Coast Location)

	1982			1987		
	Initial Price	Annual Escalation	Pressurized Advantage*	Initial Price	Annual Escalation	Pressurized Advantage*
Atmospheric	$2.49	0.7%	--	$2.64	0.1%	--
Pressurized	$2.13	0.7%	14.5%	$2.25	0.1%	14.8%

---

*In year 1 of plant operation.

Table 3.39

EVALUATION OF FUEL GAS PRICES CO-PRODUCED WITH SYNGAS

150 MM SCFD "Medium Btu" Fuel Gas
(50 MM SCFD Natural Gas Equivalent)
Dollars per MM Btu

	1982		1987	
	Price	Disadvantage of Medium Btu Fuel Gas*	Price	Disadvantage of Medium Btu Fuel Gas*
Medium Btu Fuel Gas	$5.01	--	$5.37	--
Natural Gas	$2.50	$2.51	$4.30	$1.07
Fuel Oil	$4.21	$0.80	$4.92	$0.45

*In year 1 of plant operation.

4.0 TASK II ANALYSIS OF TECHNICAL/NON-TECHNICAL PROBLEM AREAS

4.1 ANALYSIS OF POTENTIAL R & D IMPACT

4.1.1 ANALYSIS OF POTENTIAL R & D IMPACT UNDER ORIGINAL ENERGY SCENARIO

The potential impact of research and development on the competitive position of coal gasification has been analyzed. The objective of this task is to assess the degree of cost improvement required in these areas in order to make gasification of coal viable without legislative incentives. For this analysis, it has been assumed that the results of research and development can take two forms: improvements in capital cost or improvements in operating cost. For this analysis, operating cost improvements were assumed to entail a reduction in energy-based inputs only, i.e., an improvement in the overall efficiency of the process. Results of R&D effort were estimated by performing product cost sensitivity calculations for capital cost improvements of 10%, 20% and 30%, and operating cost improvements of 10% and 20%. Also, the potential of combined improvement in capital and operating costs was assessed. The calculations were done for a syngas product slate of 40 MM SCFD and 150 MM SCFD using atmospheric gasification of bituminous coal at a Gulf Coast location. Results are shown in Tables 4.1 through 4.4.

Table 4.1 and Table 4.2 illustrate the results for production of 40 MM SCFD of syngas. Given no captial or operating cost improvements, the most economic alternative for a plant with start-up in 1982, 1987 or 2000 is partial oxidation of oil (POX), followed by steam-methane reforming (SMR). A capital cost improvement of 10% does little to enhance the year 1 competitive position of coal gasification. With a capital cost improvement of 20%, coal gasification is more economical than SMR for a plant starting up in year 2000, but is still not competitive with POX. With a 20% capital cost improvement, a coal gasification plant starting up in 1987 would not produce a lower cost product than a similar SMR plant until 1991. If a 30% capital cost improvement were achieved, a coal gasification plant starting up in 1987 would produce less costly product after 1994 than a SMR plant with 1987 start-up. Product cost in year 15 would be $3.44 from reforming as opposed to $3.14 from coal. Even with this improvement, gasification would still not be competitive in the year of start-up with SMR in 1982 or POX in 1982 or 1987. However, coal gasification would be the least cost alternative for a plant starting up in year 2000 given this assumption.

As shown in Table 4.2, operating cost improvements of up to 20% do not change the competitive ranking of coal gasification for any year of start-up.

Table 4.1

PROJECTED IMPACT OF POTENTIAL R&D IMPROVEMENT ON PRODUCT PRICE AT 40 MM SCFD SYNGAS
Gulf Coast

Year of Start-Up	1982		1987		2000	
	Price	Esc.	Price	Esc.	Price	Esc.
Steam-Methane Reforming	$2.28	2.4%	$2.61	2.0%	$3.61	--
Partial Oxidation of Oil	$2.29	1.5%	$2.50	1.4%	$3.33	--
Coal Gasification						
Base Case	$3.48	0.6%	$3.67	0.2%	$3.94	--
Capital Cost Improvement						
- 10%	$3.24	0.7%	$3.43	0.3%	$3.71	--
- 20%	$3.01	0.7%	$3.20	0.3%	$3.47	--
- 30%	$2.77	0.9%	$2.96	0.4%	$3.24	--
Operating Cost Improvement						
- 10%	$3.39	0.5%	$3.56	0.2%	$3.81	--
- 20%	$3.30	0.5%	$3.46	0.1%	$3.68	--
"Best" Case (-30%/-20%)	$2.59	0.7%	$2.75	0.2%	$2.97	--

Table 4.2

YEAR OF PRODUCTION IN WHICH 40 MM SCFD SYNGAS VIA COAL GASIFICATION IS LESS COSTLY THAN ALTERNATIVES*

Year of Start-Up	1982		1987		2000	
	SMR	POX	SMR	POX	SMR	POX
Base Case	--	--	--	--	--	--
Capital Cost Improvement						
- 10%	--	--	--	--	--	--
- 20%	--	--	14	--	1	--
- 30%	15	--	8	--	1	1
Operating Cost Improvement						
- 10%	--	--	--	--	--	--
- 20%	--	--	--	--	--	--
"Best Case" (-30%/-20%)	8	--	4	10	1	1

*Given 15 year production life.

A 30% improvement in capital cost and a 20% operating cost improvement were selected for product cost comparisons resulting from coal gasification R & D. For a 40 MM SCFD plant, this resulted in a less costly product than either SMR or POX for a plant starting up in 2000. For a 1987 start-up, syngas from coal was less costly than SMR beginning in 1990 and less costly than POX beginning 1996. For start-up in 1982, coal gasification produces less costly product than SMR beginning in 1990, but cannot produce syngas competitive with POX throughout the 15 year production life of the plant.

Potential R & D impact on the larger scale plant (150 MM SCFD) is shown in Tables 4.3 and 4.4. As can be seen, large improvements are necessary for coal gasification to achieve a competitive position in year 1 product pricing. With no capital or operating cost improvements, a coal plant starting up in 2000 is more economical than SMR, but more expensive than POX.

A 10% capital cost improvement makes coal gasification somewhat more competitive with SMR, but provides for little improvement with relation to POX. A coal plant starting up in 2000 is more economic than a SMR plant in the year of start-up, and a 1987 start-up coal plant produces less costly product than SMR beginning in 1998.

With a capital cost improvement of 20%, a coal plant starting up in 1987 produces less costly syngas than SMR beginning 1994, but still is significantly more costly than the least cost alternative, POX.

Table 4.3

PROJECTED IMPACT OF POTENTIAL R&D IMPROVEMENT ON PRODUCT PRICE AT 150 MM SCFD SYNGAS

Gulf Coast

Year of Start-Up	1982		1987		2000	
	Price	Esc.	Price	Esc.	Price	Esc.
Steam-Methane Reforming	$1.86	2.5%	$2.15	2.1%	$3.06	--
Partial Oxidation of Oil	$1.77	1.8%	$1.96	1.7%	$2.68	--
Coal Gasification						
Base Case	$2.53	1.0%	$2.72	0.4%	$2.99	--
Capital Cost Improvement						
- 10%	$2.37	1.1%	$2.57	0.4%	$2.84	--
- 20%	$2.22	1.2%	$2.41	0.5%	$2.69	--
- 30%	$2.06	1.4%	$2.26	0.6%	$2.53	--
Operating Cost Improvement						
- 10%	$2.44	0.9%	$2.61	0.4%	$2.86	--
- 20%	$2.35	0.8%	$2.51	0.3%	$2.72	--
"Best" Case (-30%/-20%)	$1.89	1.1%	$2.04	0.5%	$2.26	--

Table 4.4

YEAR OF PRODUCTION IN WHICH 150 MM SCFD SYNGAS VIA COAL GASIFICATION IS LESS COSTLY THAN ALTERNATIVES

Year of Start-Up	1982		1987		2000	
	SMR	POX	SMR	POX	SMR	POX
Base Case	--	--	--	--	1	--
Capital Cost Improvement						
- 10%	--	--	12	--	1	--
- 20%	--	--	8	--	1	--
- 30%	9	--	5	15	1	1
Operating Cost Improvement						
- 10%	--	--	13	--	1	--
- 20%	15	--	10	--	1	--
"Best Case"	8	11	1	5	1	1

A 30% capital cost improvement, however, shows coal gasification to be the least cost alternative for 2000 start-up. In addition, syngas from a 1987 start-up plant will be less costly than that from SMR beginning in year 1991, and less costly than POX in the final year of the 15 year production life. Syngas from a coal plant with 30% capital cost improvement starting up in 1982 will be less costly than SMR beginning in year 1990.

As with the smaller scale plant, operating cost improvements do little to enhance the competitive position of coal gasification with respect to POX. For a plant starting up in 1987, coal gasification produces less costly product than SMR beginning in 1999 given a 10% operating cost improvement, and beginning in 1996 given a 20% operating cost improvement.

Assumed R & D effort resulting in 30% capital and 20% operating cost improvements results in coal gasification being the least cost alternative for production of 150 MM SCFD syngas for a plant with year 2000 start-up. For 1987 start-up, coal gasification is clearly the choice over SMR, and produces less costly syngas than POX beginning in year 1991. For a plant starting up in 1982, syngas from coal gasification is competitive with SMR with 1989, and less than POX in 1992.

From the results discussed above based on the initial JPL Energy Scenario, it appears a massive and very successful R & D program would be required to make coal gasification competitive with the least cost alternative before 2000 without external incentives.

4.1.2 ANALYSIS OF POTENTIAL R&D IMPACT UNDER REVISED ENERGY SCENARIO

Under the revised energy scenario, the effect of potential R&D on the competitive position of coal gasification was examined. As expected, results show coal gasification to be more competitive in year 1 under the revised scenario than the original energy scenario. The cost of syngas from both a 40 MM SCFD and a 150 MM SCFD atmospheric gasification facility as compared to alternatives are shown in Tables 4.5 through 4.8.

The effects of R&D effort through decreases in capital and operating costs on production of 40 MM SCFD syngas via coal are shown in Table 4.5. Given no cost improvements in coal gasification, the most economic alternative is steam-methane reforming (SMR) for start-up in 1982, and partial oxidation of oil (POX) for 1987 and 2000 start-up. With a capital cost improvement of 10%, coal gasification is less costly than SMR for 2000 and produces less costly product than SMR in years 10 and 6 for plants starting up in years 1982 and 1987, respectively, but is not competitive with the least cost alternative, POX.

A 20% capital cost improvement results in coal gasification being competitive with SMR for 1987 start-up and years 8-15 of a plant starting up in 1982. With this level of capital cost improvement, coal gasification produces less expensive syngas than POX beginning in year 10 for a 1982 start-up, and 12 for 1987 start-up. An improvement of 30% results in coal gasification being the lowest cost alternative for 2000 start-up, and better than SMR in 1987. However, POX is still the lower cost method of production for the first four years of production for a plant starting up in 1987. For a 1982 start-up, coal gasification is more economical than SMR beginning in year 6, and POX beginning in year 7.

As shown in Table 4.6, an operating cost improvement of up to 20% does little to enhance the competitive position of coal gasification over POX. However, such an improvement results in coal gasification product costs in the year of start-up being lower than SMR in 2000, and producing less costly product in years 9 and 3 for plants with 1982 and 1987 start-up, respectively.

To generate competitive product prices, a "best case" (30% capital cost improvement and 20% operating cost improvement) was examined. The results show coal gasification to have the lowest cost in the year of start-up for 1987 and 2000, and to produce competitively priced product in 1982.

Similar results were obtained for the larger scale plant (150 MM SCFD syngas), with improvement in the competitive position of coal gasification manifesting itself with less capital and operating cost improvement. The base case shows SMR as having the lowest cost in year of start-up for 1982 and POX as least expensive for 1987 and 2000 start-up. A 20% capital cost improvement results in coal gasification having the lowest cost for start-up in 2000, and becoming very competitive for 1987, producing least costly syngas by the third project year. A 30% capital cost improvement results in coal gasification producing least costly syngas in the fourth year of a project with 1982 start-up, and overall least cost product for 1987 and 2000 start-up. An operating cost improvement of 20% results in coal gasification producing syngas at lowest cost in year 7 of 1987 start-up plants, and lowest cost for 2000 start-up.

The achievement of "best case" cost improvements would result in coal gasification as the most economic alternative for any start-up year; 1982, 1987, and 2000. In summary, and assuming no new incentives, results for the large scale plant reveal that for coal gasification to be most economic in year 2000, a 20% capital cost improvement, 20% operating cost improvement or combination of 10% capital and 10% operating cost improvement must be achieved. For coal gasification to be most economic in 1987, a 30% capital cost improvement or 20% capital and 10% operating cost improvement must be attained. Finally, for coal gasification to result in least costly product in 1982, the best case of 30% capital and 20% operating cost improvement is required. Clearly, a significant capital and operating cost improvements will be needed to permit coal gasification to become a more competitive alternative, under the revised energy scenario and assuming no other new incentives.

Table 4.5

PROJECTED IMPACT OF POTENTIAL R&D IMPROVEMENT ON PRODUCT PRICE AT 40 MM SCFD Syngas

(Revised Energy Scenario)

Year of Start-up	1982		1987		2000	
	Price	Esc.	Price	Esc.	Price	Esc.
Steam-Methane Reforming	$2.20	4.5%	$3.12	3.3%	$3.87	--
Partial Oxidation of Oil	$2.51	2.1%	$2.76	1.4%	$3.09	--
Coal Gasification Base Case	$3.45	0.4%	$3.59	0.0%	$3.74	--
Capital Cost Improvement						
-10%	$3.21	0.4%	$3.36	0.0%	$3.50	--
-20%	$2.97	0.6%	$3.12	0.0%	$3.26	--
-30%	$2.74	0.6%	$2.88	0.0%	$3.03	--
Operating Cost Improvement						
-10%	$3.36	0.3%	$3.49	0.0%	$3.62	--
-20%	$3.28	0.3%	$3.39	0.0%	$3.51	--
"Best" Case (-30%/-20%)	$2.57	0.5%	$2.69	0.1%	$2.80	--

Table 4.6

YEAR OF PRODUCTION IN WHICH 40 MM SCFD SYNGAS VIA COAL GASIFICATION IS LESS COSTLY THAN ALTERNATIVES*

Year of Start-up	1982		1987		2000	
	SMR	POX	SMR	POX	SMR	POX
Base Case	10	--	6	--	1	--
Capital Cost Improvement						
-10%	9	--	4	15	1	--
-20%	8	12	1	10	1	--
-30%	6	7	1	5	1	1
Operating Cost Improvement						
-10%	10	--	5	--	1	--
-20%	9	--	3	15	1	--
Best "Case" (-30%/-20%)	5	3	1	1	1	1

*Given 15 year Project Life

Table 4.7

PROJECTED IMPACT OF POTENTIAL R&D IMPROVEMENT ON PRODUCT PRICE AT 150 MM SCFD Syngas

Gulf Coast

Year of Start-Up	1982		1987		2000	
	Price	Esc.	Price	Esc.	Price	Esc.
Steam-Methane Reforming	$1.84	5.8%	$2.70	3.2%	$3.41	--
Partial Oxidation of Oil	$2.06	1.9%	$2.30	1.1%	$2.62	--
Coal Gasification Base Case	$2.49	0.7%	$2.64	0.1%	$2.78	--
Capital Cost Improvement						
-10%	$2.34	0.8%	$2.49	0.2%	$2.63	--
-20%	$2.19	0.9%	$2.33	0.2%	$2.48	--
-30%	$2.03	0.9%	$2.18	0.2%	$2.32	--
Operating Cost Improvement						
-10%	$2.41	0.6%	$2.54	0.0%	$2.67	--
-20%	$2.32	0.6%	$2.44	0.0%	$2.56	--
"Best" Case (-30%/-20%)	$1.86	0.8%	$1.98	0.1%	$2.09	--

Table 4.8

YEAR OF PRODUCTION IN WHICH 150 MM SCFD SYNGAS VIA COAL GASIFICATION IS LESS COSTLY THAN ALTERNATIVES*

Year of Start-Up	1982		1987		2000	
	SMR	POX	SMR	POX	SMR	POX
Base Case	8	--	1	15	1	--
Capital Cost Improvement						
-10%	6	14	1	9	1	--
-20%	5	7	1	3	1	1
-30%	4	1	1	1	1	1
Operating Cost Improvement						
-10%	7	14	1	11	1	--
-20%	6	11	1	7	1	1
"Best Cast" (-30%/-20%)	2	1	1	1	1	1

*Given 15 year Project Life

4.2 ANALYSIS OF INSTITUTIONAL BARRIERS AFFECTING COAL GASIFICATION

Key considerations regarding the financing of potential coal gasification facilities are discussed in this section.

4.2.1 DISCUSSION OF FINANCING CONSIDERATIONS

This section deals with the key considerations in financing a coal gasification facility. A variety of business arrangements are possible, including (1) the user of the syngas or H_2 also being the producer, (2) the user of the syngas or H_2 purchasing the gas from a separate producer or (3) combinations and variations of these two approaches. Because the separate buyer/seller arrangement effectively highlights the key considerations which are common to various business arrangements, the following discussion and analysis are in terms of this approach. The discussion covers the business objectives of the buyer and seller, the allocation of rewards and business exposure factors between the buyer and seller, investment evaluation techniques, and financing techniques. The resolution of the basic business factors will determine the appropriate business structure and method of financing for a given gasification plant. It is essential that the allocation of risks and rewards be understood when product prices based on alternative feedstocks or technologies are compared, in order to make meaningful comparisons.

Since the scope of this study deals with feedstocks, hydrogen (H_2), carbon monoxide (CO) and syngas, the perceived business objectives of the parties can be summarized as follows:

1. The buyer is interested in receiving a long term commitment of feedstock for further processing at predictable prices. Generally, the buyer will accept the marketing risks of the final product and is most interested in obtaining secure raw material supplies for that business.

2. The seller is generally interested in making a capital investment in a technology for the purpose of converting a basic energy source into a intermediate chemical building block. In addition, he generally desires to avoid price risks resulting from possible future cost changes in alternative means of production of the same intermediate chemical product (e.g., via a different feedstock and/or technology).
3. The seller, in his role as an investor, is interested in furnishing capital, engineering and operating expertise and in receiving an appropriate rate of return, based on the expertise he brings to the project and the business exposure which he accepts.

The business structure and the financing decision ultimately are determined by the manner in which the buyer and seller satisfy their business objectives and determine relative risk positions. To the extent that the buyer accepts risk, such risk will be reflected in higher potential variability of the actual price. At the same time, the apparent price will decrease. The lowest apparent price will result from a situation where the equity investor and the lendor are renting money to the project and the buyer bears all of the risks. In essence, a leveraged lease approaches this situation.

4.2.2 TECHNOLOGY AND COST RISK FACTORS IN COAL GASIFICATION

The gasification of coal for the production of chemical feedstock in the United States, even though previously practiced in a few plants overseas, would be in a general sense a new technical development for the 1980's. As such, coal gasification involves many of the risk factors inherent in new or developing technologies, among them:

- less certainty of capital and operating cost estimates.
- uncertainty in predicting future costs of competing basic oil and natural gas feedstocks, particularly with the combination of O.P.E.C. unpredictability and U.S. government regulations.
- changes in regulations affecting the design, environmental aspects, etc., of a coal gasification facility.

The business deal between buyer and seller will deal with the allocation of these exposure factors, with a higher rate of return to the seller indicating a larger assumption of risk and/or the ability to offer a particularly strong position with regard to management, engineering and operating expertise.

4.2.3 FINANCING TECHNIQUES

There are generally two means of financing plant facilities. These are, general corporate funds which are obtained on the general credit of the seller without a direct relationship to the specific facility financed by such funds, and project financing, where financing is obtained specifically for a given project and the project forms the basis of the credit support.

The project financing technique has been discussed at great length as a means of providing funds for synthetic fuel projects in part because of the size of the projects and because of the nature of the fundamental business objectives discussed above. The same issues are addressed in the contractual documents for a project financing. Sources of funds and relevant characteristics of such sources are discussed below:

1. Equity funds which are available from existing companies. Such companies may be industrials or utilities. In either case the funds represent stockholders' investments and are intended as risk capital.
2. The seller or a group of sellers can obtain borrowed funds where the lender is interested in renting money and in looking only to the project assets and their earning potential as the ultimate credit for the loan. Lenders can provide funds in the following basic forms:
    a. Instruments where the holder is subject to income tax.
    b. Tax exempt securities.
    c. A tax motivated lease where the object of renting money is supplemented by a tax payment transfer mechanism.

In conclusion, the ultimate financial structure for a coal gasification deal will depend primarily upon the risk/reward allocation process, and the manner in which specific financing is utilized to reflect and support the business arrangement. A range of the different appropriate prices depending upon capital structure is shown in the following tables.

Given a debt rate of 10% and a required DCF return on equity of 15%, the ability to leverage a project to 50%-75% debt results in a reduction in the apparent product price equal to a 33%-50% reduction in the cost of capital. A lower debt rate, indicating a tax-exempt debt instrument, results in a further reduction in apparent product price. Financing via a leveraged lease would result in a further decrease in apparent product price; however, the use of leveraged leases on major capital projects requires a very specific, and not very common, type of business arrangement between buyer and seller.

Table 4.9

EFFECT OF CAPITAL STRUCTURE ON PRODUCT PRICE AT 40 MM SCFD SYNGAS

(Gulf Coast)

Debt/Equity	Debt Interest Rate	DCF on Equity	1982 Start-Up Price	1982 Start-Up Esc.	1987 Start-Up Price	1987 Start-Up Esc.	2000 Start-Up Price
0/100	N/A	15%	$3.45	0.4%	$3.59	0.0%	$3.74
50/50	10%	15%	$3.16	0.9%	$3.30	0.4%	$3.45
65/35	10%	15%	$3.07	1.0%	$3.22	0.5%	$3.36
75/25	10%	15%	$3.01	1.2%	$3.16	0.8%	$3.30
50/50	8%	15%	$3.08	1.0%	$3.22	0.4%	$3.37
65/35	8%	15%	$2.97	1.1%	$3.11	0.7%	$3.26
75/25	8%	15%	$2.89	1.3%	$3.04	0.8%	$3.18
50/50	10%	20%	$3.16	2.9%	$3.30	2.4%	$3.45
65/35	10%	20%	$3.07	2.5%	$3.22	1.9%	$3.36
75/25	10%	20%	$3.01	2.4%	$3.16	1.9%	$3.30
0/100	N/A	10%	$3.45	-2.7%	$3.59	-3.2%	$3.74
75/25	10%	10%	$3.01	0.5%	$3.16	0.0%	$3.30

Table 4.10

EFFECT OF CAPITAL STRUCTURE ON PRODUCT PRICE AT 150 MM SCFD SYNGAS

(Gulf Coast)

Debt/Equity	Debt Interest Rate	DCF on Equity	1982 Start-Up		1987 Start-Up		2000 Start-Up
			Price	Esc.	Price	Esc.	Price
0/100	N/A	15%	$2.49	0.7%	$2.64	0.1%	$2.78
50/50	10%	15%	$2.30	1.2%	$2.45	0.5%	$2.59
65/35	10%	15%	$2.25	1.3%	$2.39	0.7%	$2.54
75/25	10%	15%	$2.21	1.5%	$2.36	0.7%	$2.50
50/50	8%	15%	$2.25	1.2%	$2.40	0.5%	$2.54
65/35	8%	15%	$2.18	1.2%	$2.23	0.6%	$2.47
75/25	8%	15%	$2.13	1.5%	$2.28	0.8%	$2.42
50/50	10%	20%	$2.30	3.0%	$2.45	2.2%	$2.59
65/35	10%	20%	$2.25	2.5%	$2.39	1.9%	$2.54
75/25	10%	20%	$2.21	2.5%	$2.36	1.8%	$2.50
0/100	N/A	10%	$2.49	-2.1%	$2.64	-2.6%	$2.78
75/25	10%	10%	$2.21	0.8%	$2.36	0.2%	$2.50

Table 4.11

EFFECT OF DEBT LEVERAGE ON TOTAL INVESTMENT DCF RETURN

Debt/Equity Ratio	Return on Capital (Debt Interest Rate)	DCF Return on Equity	DCF Return on Total Investment
0/100	N/A	15%	15.0%
50/50	10%	15%	12.7%
65/35	10%	15%	11.8%
75/25	10%	15%	11.5%
0/100	N/A	20%	20.0%
50/50	10%	20%	15.8%
65/35	10%	20%	14.5%
75/25	10%	20%	13.2%
	TAX EXEMPT BONDS		
50/50	8%	15%	11.8%
65/35	8%	15%	10.7%
75/25	8%	15%	10.4%
	LEVERAGED LEASE		
75/25	10%	10%	10.6%

4.3 ANALYSIS OF REGULATORY BARRIERS AFFECTING COAL GASIFICATION

4.3.1 IMPACT OF STATE IMPLEMENTATION PLAN DELAYS ON COAL GASIFICATION COMMERCIAL POTENTIAL

The largest potential market for coal conversion, including gasification, appears to be the legislated clean up of major utility and industrial fuel burning installations. Responsibility for implementing this legislation exists at the state level. To date, the ambitious federal programs begun in the late 60's to affect air quality have not been translated to a finalized set of requirements at the plant level. The following paragraphs discuss the history and impact of those delays on coal gasification potential.

The Clean Air Act Amendments of 1970 required that EPA establish primary national ambient air quality standards (NAAQS) and point source emission standards. The 1970 amendments establishing the basic concept that states decide how to achieve the federal air quality standards.

Since 1970 it has become increasingly necessary to re-legislate at the federal level as successive milestones of air quality improvement were not achieved. This has continually delayed state implementation plan (SIP) preparation.

By 1971 it was apparent that NAAQS were not going to be met. As a stopgap measure EPA established the emission offset ruling that permitted construction in areas where NAAQS were not met. In 1977 Congress amended the Clean Air Act requiring new state implementation plans by 1 July 1979. The new offset ruling was to apply to new construction before July 1, 1979. After that date the SIP's were to apply. In order to assume timely completion of new SIP's, penalties were included to be imposed on states that failed to have completed and approved plans by 1 July 1979. The penalties included construction moratorium and withholding of federal grants for highways, air pollution control, and waste water treatment facilities.

As of 1 July 1979 only 35 states had submitted revised SIP's and only one state had an approved plan. EPA then established an extension to the 1 July date. During the extension period none of the required sanctions dealing with construction permits and federal funds were imposed.

Delays of SIP approvals have coincided with the recent shortage of liquid fuels. The shortage of crude supply presently threatens to compromise not only the timing but also the content of SIP's. DOE has favored allowing states to ease sulfur dioxide emission rules so that high sulfur fuels can be burned. Energy legislation has included provisions to allow easing of emission standards so plants can switch from oil to coal. Legislation requiring that coal-capable boilers fire only coal, has been softened in the case of new plants and delayed in the case of existing plants.

In summary, a key initial market potential for coal gasification will be in conversion of major fuel burning installations either due to unavailability of fuel (natural gas) or outright legislated requirement. The bases for legislative requirement were laid out in the original Clean Air Act Amendments. During the past ten years those requirements were defined and then successively softened. This softening reduced the potential technical advantage of coal gasification vs. other synthetic fuel approaches, i.e., with coal gasification the cost to remove essentially all sulfur compounds is about the same cost of removing most sulfur in the coal. Coal gasification's potential role as a utility and industrial synthetic fuel source has been substantially reduced as other less technically developed approaches to synthetic fuels have become compatible with financial incentives and clean air regulations to remove most rather than essentially all sulfur compounds.

4.3.2 REGULATORY BARRIERS AFFECTING COAL DIRECTLY: TRANSPORTATION/MINING

During most of the 1970's the regulatory barriers of mining and transporting coal increased. At the present time those barriers are being substantially reduced as a result of new and modified legislation. The Clean Air Act Amendment's of 1977 (CAAA) and the Surface Mine Control and Reclamation Act tend to reduce transportation and mining barriers respectively.

The key future tonnage market for coal is new electric utility plant construction. Prior to the CAAA of 1977, new source performance standards encouraged hauling "low" sulfur coal long distances to meet the point source emission standard for SO_2. The new standards have largely eliminated the incentive of long distance low sulfur coal hauling.

The CAAA of 1977 will also reduce transportation barriers via Section 125 of the legislation. The EPA can prohibit the use of those fuels "derived other than locally" in order to prevent or minimize "significant local or regional economic disruption or unemployment". The original intent of the section was to preserve mine and mine-related jobs in states producing high sulfur coals by keeping out western low sulfur coals that could be blended with high sulfur coals resulting in compliance fuel.

The recent trend toward legislation supporting synthetic fuels plants will also reduce transportation barriers. The legislation encourages large plants with readily transportable liquid and gaseous products. This will reduce coal transportation problems.

In the second area of regulation directly affecting coal, mining, it appears likely that regulatory barriers will be reduced.

The 1977 Surface Mining and Reclamation Act is presently being implemented. The original implementation schedule required that state plans be submitted to the Department of Interior by August 1979. During the 1978 debate of proposed regulations, the Office of Surface Management (OSM), Department of Interior made changes providing substantially more flexibility to states in interpreting the act. In mid-1979 the act was opened to amendment to allow extension of the filing date for state programs to mid-1980. It is expected that further softening of the legislation will be attempted. In particular, modification may allow the use of state programs that are simply "consistent with the act" rather than requiring them to conform to OSM regulations as well (as is now the case).

In balance regulation barriers to coal gasification in the areas of transportation and mining are weakening as a result of recent legislation.

4.3.3 THE IMPACT OF FUTURE OIL AND GAS REGULATORY PRICING UNCERTAINTY

Pricing uncertainty has been a major regulatory barrier affecting commercial potential for coal gasification. The impact of the uncertainty has been commercial inaction. The two key areas of uncertainty are (1) the future of regulated energy pricing in the U.S. and (2) the future direction of U.S. government initiatives in the syn fuels area that affect pricing by subsidy.

The 1979 experience with world oil pricing has amplified the uncertainty of future pricing in the feedstock areas competitive to coal gasification. In the case of oil, 1979 price increases were much higher than generally expected. Natural gas, the historical feedstock for H_2 and syngas production, will have a limit on price expansion until 1985 due to ceilings in new natural gas pricing. After that time, new gas is expected to move closer to parity with Number 2 oil, as the large fraction of natural gas production currently being sold to industrial users in competition with #6 oil gradually shifts by legislation and price to "higher value" (and high price) markets. Many sources then expect the rate of natural gas price increases to moderate. Under this type of scenario absolute real price increases could decrease over time.

Typically, future energy pricing is presented in terms of annual compound real price increases. Under these scenarios absolute real price increases are successively larger.

Figure 3.10 compared alternate bases for projecting prices between fixed end points, years 1978 and 2000. The alternatives of successively larger and successively smaller real price increases are shown by power curves. The large differences between these approaches is due to valid uncertainty in the timing and extent of deregulation of U.S. energy prices.

The future direction of U.S. government initiatives in the syn fuels area has been very unclear during the past five years. Repeated attempts have been made to begin programs that would reduce future U.S. dependence on imported oil. In the early 70's massive government programs were discussed along the lines of the so-called "Rockefeller Program". An attempt was made in the mid-1970's to shift the burden of energy independence to the private sector via oil and natural gas use taxes. Now, at the end of the decade, initiatives have shifted back to the government sector with funding to be derived from excise taxation of deregulated petroleum. Throughout this series of initiatives the private sector has made only a minimal attempt to develop coal gasification technology. The future succession of government initiatives has significantly increased the risk of private coal gasification ventures due to the possibility of a massive federal program which would significantly improve the prospects of coal gasification vs. oil or natural oil at a later date due to direct or indirect federal subsidy. Thus, the potential for future subsidies has been superimposed on the existing lack of incentive, for most project developers, of "being the first" amongst one's competitors to develop a major coal gasification project. This lack of clear government initiatives in the synfuels areas has created a significant barrier in the form of pricing uncertainty between oil/natural gas based feedstocks and gasified coal feedstocks.

4.4 ESTIMATE OF GOVERNMENT INCENTIVES TO MAKE COAL GASIFICATION COMPETITIVE AND RECOMMENDED ACTIONS TO STIMULATE COAL GASIFICATION SYSTEM DEVELOPMENT

4.4.1 FINANCIAL INCENTIVES/ACTIONS

Industrial producers of hydrogen and syngas will begin to build coal-based plants when the price is competitive and when the uncertainties associated with the projected price are part of the normal business risk process. The usual approach to measuring business risk in major projects involves comparison of alternative cash flows associated with alternative approaches to the project. The most readily available and effective approaches to affecting project cash flows are those which are tied to the capital investment itself. In terms of selectively affecting cash flow and providing financial incentives to technologies such as coal gasification, the investment tax credit and accelerated plant write-off approaches appear to have the most potential. However, this potential will not be easy to realize.

For the purposes of this study, an "appropriate" financial incentive for coal gasification has been arbitrarily defined as an incentive which results in a five-year lead time until coal gasification product costs equal the lowest competitive product cost (oil or natural gas based), i.e., "appropriate" incentive defined as incentive that results in:

Cost of product from coal gasifier built in year X using coal in year (X + 5) = Cost of product from least costly option plant (oil or gas) built in year (X + 5) using oil or gas feedstocks priced in year (X + 5)

Two choices for year X, 1982 and 1987, were used for plants located in the Gulf Coast producing syngas at 40 and 150 MM SCFD. Results are shown in Tables 4.12 and 4.13.

As results in the table indicate, neither investment tax credit nor plant write-off provide "appropriate" incentive, using the financial analysis criteria adopted for this study. If more liberal criteria had been employed, start-up year product prices for gasified coal could be driven significantly lower with a 40% ITC taken in the first year vs. a 20% ITC amortized over project life. However, it is very possible that in generating an attractive discounted cash flow by this approach, the first year book income would become extremely low, perhaps negative. This would result in qualifying a project for acceptance on a DCF basis and at the same time disqualifying it on the ROI basis. Therefore, for the purposes of this study, tax shields were restricted to the project being evaluated. In the case of providing incentive through accelerated depreciation methods, similar considerations preclude the project from receiving the full potential benefit of the incentive. Since the project requires a given book return on investment at start-up in order to qualify under the general rules used in this study, the first year selling price is by definition unaffected by the depreciation method allowed. As stated previously, the amount of depreciation which can be absorbed is constrained by the project's income. Thus, accelerated depreciation methods have the result of only reducing the product price escalation rate required in order to achieve the necessary DCF return.

Table 4.12

IMPACT OF POTENTIAL FINANCIAL INCENTIVES
150 MM SCFD SYNGAS
(Gulf Coast)

Year of Start-Up	1982		1987		2000	
	Price	Esc.	Price	Esc.	Price	Esc.
SMR	$1.84	5.8%	$2.70	3.2%	$3.41	--
POX	$2.06	1.9%	$2.30	1.1%	$2.62	--
Coal Gasification						
Base Case	$2.49	0.7%	$2.64	0.1%	$2.78	--
Depreciation						
11 years	$2.49	0.6%	$2.64	-0.2%	$2.78	--
7 years	$2.49	0.3%	$2.64	-0.4%	$2.78	--
5 years	$2.49	0.4%	$2.64	-0.2%	$2.78	--
ITC						
30%	$2.44	1.1%	$2.59	0.5%	$2.73	--
40%	$2.38	1.7%	$2.53	1.1%	$2.67	--

Table 4.13

IMPACT OF POTENTIAL FINANCIAL INCENTIVES
40 MM SCFD SYNGAS
(Gulf Coast)

Year of Start-Up	1982		1987		2000	
	Price	Esc.	Price	Esc.	Price	Esc.
SMR	$2.20	5.6%	$3.12	3.3%	$3.07	--
POX	$2.51	2.1%	$2.76	1.4%	$3.09	--
Coal Gasification						
Base Case	$3.45	0.4%	$3.59	0.0%	$3.74	--
Depreciation						
11 years	$3.45	0.2%	$3.59	-0.3%	$3.74	--
7 years	$3.45	-0.2%	$3.59	-0.6%	$3.74	--
5 years	$3.45	0.0%	$3.59	-0.4%	$3.74	--
ITC						
30%	$3.36	0.9%	$3.51	0.4%	$3.65	--
40%	$3.27	1.5%	$3.42	1.1%	$3.56	--

4.4.2 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 in 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, 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. This assumption was made in order to address the broadest range of business situation, 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 coal gasification system development 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.

4.4.3 REGULATORY ACTIONS

Oil and natural gas pricing uncertainty appears to be the single most important area where reducing regulatory barriers would stimulate coal gasification development in the production of hydrogen and syngas feedstocks.

The impact of a revised energy scenario on future syngas and hydrogen economics was discussed in Section 4.3. Results for coal gasification as a hydrogen and syngas energy source were much more positive than the results based on the draft JPL Energy Scenario. The revised energy scenario is based on decontrol of U.S. oil and natural gas prices. Assuming the revised scenario accurately reflects decontrol, coal gasification could become an economically competitive route to syngas production in the mid-1980's. Unfortunately, the issue of higher U.S. energy prices is subject to the actions of the U.S. political system. The result is often a mixture of energy policy and social policy, or energy policy and farm policy, etc. Even after legislation is enacted, the political process continues to influence interpretation of the law.

Incremental pricing of natural gas is a good example of the uncertainties which face an industrial company in choosing future energy sources. The incremental pricing provision of the Natural Gas Policy Act is applicable to boiler fuels rather than hydrogen and syngas feedstocks. However, the issue of resistance to, and therefore, uncertainty concerning higher energy prices is the same. To date, the Federal Energy Regulatory Commission has experienced considerable difficulty in defining in a way both consistent with basic energy policy and satisfactory to the various groups affected by the definition.

The private company evaluating use of coal gasification as a future U.S. feedstock supply faces the same set of ambiguous and conflicting state and federal energy pricing jurisdictions. As long as coal gasification system development depends on increasing oil and natural gas prices relative to coal, the realistic potential for reducing regulatory barriers will be minimal. The alternative approach to encouraging coal gasification system development involves avoiding, in least at the near term, the regulatory barriers associated with oil and gas pricing. An approach which encourages coal-based energy technologies both by modifying tax laws and providing cash grants to affect cash flow was discussed in Section 4.4.2 above. In general, this approach appears to have more potential for stimulating coal gasification system development than does any approach toward reducing long-run uncertainty on pricing of oil and natural gas.

APPENDIX A

DESCRIPTION OF FINANCIAL ANALYSIS COMPUTER PROGRAM

The financial analysis program used in this study was written to enable comparison of alternative technologies for production of hydrogen and synthesis gas. The program uses:

- Feedstock prices over the period 1978-2000 for coal, oil, and natural gas. These price projections were supplied by JPL.
- Capital and operating costs including labor, fixed costs, power, raw materials excluding feedstocks. These cost estimates were developed by Air Products.

A detailed description of the financial analysis computer program is outlined later in this Appendix.

The financial analysis program uses two criteria for comparison of alternative technologies for hydrogen and syngas manufacture:

- Initial year hydrogen/syngas selling price.
- Hydrogen/syngas selling price over the project life.

These criteria were chosen to reflect two realities of financial analyses that concern synfuels manufacture, assurance of a satisfactory return on initial invested capital and a selection of minimum cost technology. There are numerous ways to evaluate return on invested capital. In the approach used here the after tax return on investment in the project start-up year is an input variable. A nine percent return was selected for the analyses done in this study. Selection of minimum cost technology is made by comparing required cash flows associated with each technology option over the projected life. These cash flows are discounted to reflect the time value of money. A fifteen percent discounted cash flow return was selected for the technology comparisons made in this study.

The result of this analysis is a stream of product prices which, over the life of the project, escalate at a rate which reflects both the feedstock escalation rate and project capital structure. These product prices represent required prices which would enable the firm to earn the minimum return on equity necessary to make investment in the technology attractive. Actual prices will be specified through long term contractual agreements, and will depend on the production technology employed. As a result, these required prices are expected to approximate the actual selling prices that will be established through the contract bargaining process. While it is true that various escalation rates of feedstock prices may cause a given technology which has a high product price in year 1, to be competitive in later years, we believe this is an accurate representation of how industrial investment and financing decisions are made.

It should be pointed out that while this approach may be adequate for many industrial investment and financial decisions, it does introduce the possibility of a bias against the technologies requiring large initial capital investments. The initial year price, as estimated in this report, depends primarily on the initial capital costs and ignores future savings in feedstock costs. Future savings in feedstock costs are included in the calculation of the price escalation rates. The methodology, however, does not provide an explicit means for trading off the higher initial capital costs with the future energy savings in a single parameter. Thus, the analysis focuses primarily on a comparison of initial year prices to determine the preferred technology. In the case of companies expecting relatively high feedstock escalation rates, or for companies with sufficient internal investment capital, emphasis on initial year price does introduce the possibility of a bias against technologies requiring large initial capital investments, such as coal gasification.

There are alternative methods available which provide the means for trading off explicitly the higher initial capital costs of coal gasification systems with the lower subsequent feedstock costs, considering the timing of the returns in the trade-off as well. For example, the Net Present Value approach involves summing the costs and returns occurring in each year of the project to arrive at a figure for the investment's total return, with discounting of future returns to account for the timing as well as the size of the future returns. (For a detailed review of an alternative methodology see Gates, Bill and Terasawa, Katsuaki "A Study of Industrial Hydrogen and Syngas Supply Systems: Methodology Comment" JPL IOM 311.5-539, Jet Propulsion Laboratory, Pasadena, California, May 27, 1980.)

The following outline describes the capability of the computer program used in "A Study of Hydrogen and Syngas Supply Systems". An X denotes where the program will accept input. Values in parentheses are the assumptions for the analysis. In addition to what is described below, the program will handle various mixes of debt and equity and any prescribed bond interest rate.

A. Capital Cost Assumptions

1. Plant Facilities - Are constructed over X (3) years. Progress of construction may be specified in yearly spending as follows:

Year	Spending
1	Y (16% of Total Spending)
2	Z (42% of Total)
3	W (42% of Total)
Etc.	

2. Land - Land investment in dollars is specified (no land investment assumed).

3. Interest During Construction - Calculated based on spending progress at an interest rate of X% (10%) per year.

4. Royalty - Specified in dollars (for purposes here, any paid-up royalties included in Plant Facilities).

5. Organization and Start-Up Expense - Calculated as a percentage of plant facility investment.

6. Working Capital - Estimated based on X (30) days of feedstock inventory, 3 months of labor and one month of other operating expenses.

7. Initial Catalysts and Chemicals - Specified in dollars.

8. Depreciable Investment - Total depreciable investment is made up of all of the above except land and working capital, which are reclaimed at the end of the project life.

9. Additional Assumptions -

   a. Investment Tax Credit (ITC) - X% (20%) of plant facility investment for coal gasification.
      (10%) of plant facility for other.

   b. Income Tax Rate - Federal at X% (46%)
      State at Y% (2%)

B. Operating Cost Assumptions

1. Raw Materials

   a. Primary Feedstock - Coal, natural gas or oil. Price is based on a given JPL Energy Scenario.

   b. Cooling Water - Price in 197X$ (1978$) of X¢/MGal. (60¢/MGal.).

   c. Other Feedstocks - Other energy feedstocks (e.g., distillate fuel) priced based on the same energy scenario.

   d. Catalysts and Chemicals

   e. Maintenance Materials - Estimated at X% of plant facility investment.

2. Labor

   a. Operating Labor - Four shifts. Base pay of $X/Hr.

   b. Operating Labor Supervision - 15% of total operating labor.

   c. Maintenance Labor - Estimated at X% of plant facility investment.

d. Administrative and Support Labor - 10% of Operating Labor, Operating Labor Supervision and Maintenance Labor.

e. Payroll Burden - 35% of Operating, Supervision, Maintenance and Administrative and Support.

3. Power - Purchased electric power, priced based on the given energy scenario.

4. Fixed Costs

a. General and Administrative Expense - Estimated at X% (4%) Plant Facility Investment.

b. Property Taxes and Insurance - Estimated at X% (1.2%) Plant Facility Investment.

c. Depreciation - Book depreciation is X year straight line; tax is X year sum-of-year's-digits; X is the project life (15 years).

C. Program Analysis

1. Objectives - The program calculates the selling price of primary product (H_2 or syngas) for each plant operating year given the year of start-up and required returns. Required input is the first year's Return on Equity (9%) and required discounted cash flow return (15%)

2. Assumptions - All costs (capital plus operating) are in constant 197X (1978) dollars. That is, all costs other than energy are assumed to increase at the GNP deflator. Energy-related costs are escalated according to the given JPL scenario in constant 1978 dollars. Energy costs are projected by JPL to increase faster than the GNP deflator. Energy-related costs which will escalate according to the reference scenario are coal, petroleum products, natural gas and purchased electric power.

3. Calculations - The program will calculate the revenue of the primary product for the first plant operating year, which will yield an X% (9%) return. The X% return is after tax; the revenue is calculated as below:

$$\text{Return on Equity} = \%\text{ROE} = \frac{X}{100} \times \text{Total Equity Investment}$$

$$\text{Year 1 Total Revenue} = \frac{\$\text{ROE} - \text{Avg ITC}}{1 - \text{Total Tax Rate}} + \text{Book Depreciation} +$$

(First Year's Operating Costs Excluding Depreciation)

First year selling price is equal to revenue divided by first year production. The first year selling price is assumed to escalate at a constant rate throughout the life of the plant. The required escalation rate is that which is calculated to yield the X% (15%) DCF return. By-product selling prices also escalate at this escalation rate. The first year selling price of by-products is assumed to be based on the cost of the feedstock for the plant. Subsequent years of operation of the plant result in escalation of by-product prices equal to primary product selling price. Thus, a selling price for each year in constant 197X (1978) dollars is determined.

4. Output - Results are produced on a histogram which displays the first year selling price of primary product divided into energy, capital and other costs.

   Energy - Is the portion of selling price attributable to cost of energy-related feedstocks and purchased power.

   "Other Costs" - Are operating costs which do not classify into either of the other areas, i.e., labor and non-energy feedstocks and materials.

   Capital Costs - Are general and administrative expenses, property taxes and insurance, pre-tax return on investment as calculated above and straight line depreciation.

   The selling price is the sum of these three components.

   Possible by-product credits per unit of primary product is shown indirectly as reductions to the energy component.