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 Price	1982 Start-Up Esc.	1987 Start-Up Price	1987 Start-Up Esc.	2000 Start-Up 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 <u>reducing</u> regulatory barriers will be minimal. The alternative approach to encouraging coal gasification system development involves <u>avoiding</u>, 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:

- o Feedstock prices over the period 1978-2000 for coal, oil, and natural gas. These price projections were supplied by JPL.
- o 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:

- o Initial year hydrogen/syngas selling price.
- o 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 <u>explicitly</u> 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 IØM 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. <u>Plant Facilities</u> - 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. <u>Land</u> - 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.