SYNTHETIC FUELS: A PERSPECTIVE ON COMMERCIALIZATION

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Introduction

The commercial production of liquid and gaseous fuels derived from coal and oil shale is currently hindered by a variety of complex and interacting factors. Conversion processes are highly capital-intensive, and their products are at best estimated to be only marginally competitive with landed world crude oil and imported LNG at current prices. Added to this is a multitude of constraining factors, such as resource availability, protection of the environment, sociopolitical considerations, marketplace logistics, financing, the potential effects of competing new technology, and the possibility of wider availability of international supplies of lower-cost crude oil and natural gas.

Strongly countering this situation is a growing realization of the long-term need for supplemental supplies of gaseous and liquid hydrocarbons as we enter an era in which depletion of conventional resources is a worldwide concern. Although recovery and conversion will be costly, the United States has substantial reserves of coal and oil shale that can provide supplemental fuels. This situation, together with a national goal of reducing dependence on oil and gas imports, will lead to increasing pressure for the commercialization of synthetic fuels.

This paper presents summary comparative economics estimated for synthetic fuels from coal and oil shale and focuses on some of the important financial considerations associated with the commercialization of synthetic fuels. Some of the pertinent conclusions are:

- Upgraded shale oil liquids are estimated to be less expensive than coal-derived liquids and can be marginally competitive with imported crude oil.
- Based on recent field pilot work, speculative economics look attractive for low-Btu gas by underground gasification of coal. Large-scale demonstration appears desirable.
- A financing mechanism sheltered from excessive risk will probably be necessary to encourage commercial synthetic fuels ventures.

The summary economics presented are derived from a variety of studies recently performed at SRI involving the comparative evaluation of synthetic fuels from coal and oil shale.

Status of Technology

Considerable research and development activity in the United States has recently been devoted to the conversion of solid fossil fuels into the more desirable energy forms--clean gases and liquids. This is far from a new concept. Coal has been gasified to produce town gas, synthesis gas, or reducing gas on a worldwide scale since early in the 19th century. Underground coal gasification (UCG) has been commercially practiced in the USSR since around 1940. Coal liquids have been recovered from the pyrolytic coking operations associated with steel manufacturing since early in the industrial revolution. More recently, during World War II, conversion of coal to liquid fuels reached a production level of approximately 100,000 barrels per day in Germany; and coal liquefaction is currently practiced commercially on large

scale in South Africa. However, most of this recent production of liquids was, and continues to be, by Fischer-Tropsch synthesis from coal-derived gases ($CO + H_2$). In Estonia, recovery of liquids from oil shale began commercially in the mid-1930s. Since that time, developmental scale oil shale retorts have been operated in several countries including the United States, Brazil, and China.

Two notable coal gasification systems that are actively marketed throughout the world and commercialized in several countries are the familiar Lurgi fixed-bed gasifier and the Koppers-Totzek entrained gasifier. Other gasification systems marketed commercially are: Winkler, McDowell-Wellman, Woodhall-Duckham, Riley-Morgan, and Wilputte.

Coal conversion systems at or nearing large-scale development in the United States or with direct U.S. involvement are listed in Table 1. Also shown are oil shale retorting systems that have been developed on a large scale in the United States and have been indicated for use in potential commercial ventures. Of the coal conversion systems listed, the Lurgi gasifier, as previously mentioned, has already been widely commercialized for synthesis gas and town gas. It is mentioned here as a developing system because of its potential extension to production of SNG or fuel gas, in modified form to permit gasification of caking coals, and for close coupling with electric power generating systems.

In addition to the developmental oil shale retorting systems listed in Table 1, large-scale projects are also currently active in Brazil (Petrosix process) and in Estonia (the Soviet-developed Galoter process). Plans have been announced (1), (2) in those countries to build commercial-scale plants using the two processes.

Three of the developmental coal conversion processes mentioned--BG-Lurgi slagging, COGAS, and Coalcon--have been chosen by the U.S. Energy Research and Development Administration (ERDA) at this time for more detailed study to determine suitability for ERDA/industry jointly sponsored large commercial-scale demonstration. Evaluation of the first two systems for SNG continues while the future of the Coalcon "Clean Boiler Fuel" demonstration program is now in considerable doubt. In addition, ERDA and a variety of industrial organizations are supporting the thrust toward demonstration of low- or intermediate-BTU gas (LBG/IBG) systems with the "Combined Cycle Test Facility" and ERDA's "Gasifiers in Industry Program," which is aimed at the small and medium sized user, and their "Hydrogen from Coal Program."

Economic Analysis

Cost is normally the overriding consideration in bringing a new technology into the marketplace. In this regard, the most visible competition in the United States for gaseous and liquid fuels from coal and oil shale (unless there are significant new finds of oil and gas in North America) is imported world crude oil which is currently landed at $13 to $15 per barrel ($2.20 to $2.50 per million Btu) and imported LNG which will be somewhat more expensive. Additional competition for the use of synthetic fuels includes direct firing of coal for power generation or industrial heat (with or without flue gas desulfurization), and eventually natural gas transported from northern Alaska or the Canadian frontier.

Most of the conversion processes listed in Table 1 have been technically and economically evaluated by SRI in the course of a variety of recent project work. Summary process cost ranges are presented in Table 2. Capital costs are presented in terms of dollars of plant investment per daily production output in barrels of oil equivalent. Product costs are compared both on the basis of U.S. regulated utility economics (cost of service/rate base) and the discounted cash flow (DCF) rate of return analysis commonly used for commercial ventures. Resulting annual capital charge rates are 29 to 32 percent for the 15 percent DCF rate of return cases and 15 to 17 percent for the regulated utility analysis. All costs are in terms of mid-1977 constant dollars.

With the highly debt-leveraged and relatively financially sheltered regulated utility analysis, estimated process costs vary from $1.50 per million Btu for the speculative economics associated with low-Btu gas from underground coal gasification to $5.00 per million Btu for methanol from coal by near-term commercial technology. These costs increase to $2.00 and $7.25 per million, respectively, for a 100 percent equity DCF analysis yielding a 15 percent rate of return. On the same DCF basis, costs for synthetic crude oil from oil shale are in the range of $2.75 to $3.50 per million Btu ($16 to $21/barrel) for developing retorting and upgrading systems. The regulated utility analysis results in costs 25 to 30 percent lower than those for the DCF analysis. Product costs shown in Table 2 are compared and discussed in more detail later in the paper.

A few caveats concerning the development of these costs are clearly in order. The coal costs specified are intended to represent a mine-mouth conversion plant location and therefore do not include coal transportation charges. Furthermore, the costs presented in Table 2 are battery limits process costs and do not include specific site-related charges that can be significant, depending on the remoteness of location. Some of these potentially important site-related factors are: water development projects (including pipeline and storage); mine to conversion-plant railroads; power transmission lines; access roads; product pipelines; extensive environmental analysis; and townsite development activities.

These, together with other potential site-specific requirements, could easily increase capital investment by 10 to 20 percent and could add $2.00 to $3.00 per barrel ($0.35 to $0.50 per million Btu) or more to product cost for a synthetic fuels venture in a remote location. Product cost ranges, based on Table 2, but including provision for such site-specific costs, are compared in Figure 1. Excessive delay in attaining design capacity and plant modifications during start-up of new technology are other factors that will add significantly to costs for first-of-a-kind plants. Over the life of the project, these items could easily contribute additional product costs in the range of $1.00 to $3.00 per barrel ($0.20 to $0.50 per million Btu). The costs summarized in Figure 1 do not include contingency for pioneer plants.

There is some hope of process "learning curve" cost reduction over near-term technology with the evolutionary development of advanced technologies. Development of processes that eliminate or combine process steps could potentially lead to significantly lower product costs. An example in the case of SNG could be a system successfully combining process steps such as gasification, shift conversion, and perhaps reducing the gas cleanup and methanation requirements, or eliminating the need for an oxygen plant. Such processes will undoubtedly contribute additional costs of their own, but significant potential exists for lower overall costs. In the case of LBG/IBG, lower costs could potentially result from successful development of a gasifier using a sulfur acceptor or combined with some other type of hot gas cleanup system. The lower cost ranges in Table 2 and Figure 1 represent such advanced or innovative processes. Without such development, it is doubtful that cost reductions of greater than about 10 percent will be possible with foreseeable conversion technology, since such systems will probably be composed primarily of plant sections based on already commercial or near-commercial technology.

Outlook for Commercialization

Clearly, the considerations concerning commercialization will vary somewhat for SNG from coal, LBG/IBG from coal, coal liquids, and oil shale. In view of the status of technology, the economics of production, and other factors, what are the prospects for commercialization? The following prognosis is offered.

SNG from Coal: The estimated cost of SNG from western U.S. subbituminous coal using conventional Lurgi gasification technology in a coalfield location is estimated to be $3.75 to $4.25 per million Btu (coal at $7 per ton), which is clearly not competitive directly with natural gas marketed either on an interstate or intrastate basis. However, a massive and intricate distribution system exists for transmitting energy in the form of high-Btu gas directly to the consumer. Therefore, while interfuel competition at the marketplace will be a prime consideration, there will be strong incentive to use these existing distribution systems for SNG. Potential direct alternative competitors for SNG from coal in the United States are imported LNG and natural gas transmitted from the northern frontier areas of North America. However, these alternatives will also involve extremely large front-end investment, and some will have the additional disadvantages associated with security of supply. Of course, energy conversion, transmission, and distribution via electrification is a competitor, but again the costs for that alternative are also significant (3), and comparative costs are highly dependent on location.

Some SNG technology is now near commercial and additional systems are ready for commercial-scale demonstration. However, the cost of conversion plants will often be large in relation to the capitalization of companies planning to build such plants, thus making financing difficult without some type of guarantee for the lending institution. If regulatory approval necessary for the gas pricing structure permits rolling-in of the higher cost of SNG, then commercialization would probably follow, although it is likely that some type of debt guarantee will also be required.

Because of necessary regulatory approvals, the probable need for federal financial sheltering, and the lead-time necessary for plant construction, it is doubtful that any plants based on Lurgi technology could be on stream before 1985. However, with regulatory and financial approaches now under discussion, some commercial operation appears likely in the period 1985-1990.

LBG/IBG from Coal: LBG/IBG from bituminous coal in an eastern U.S. location without site-related factors included is estimated to cost about $3.25 per million Btu for commercial technology and ranging to about $2.50 per million Btu for some developmental processes.

High conversion plant investment and production costs will limit markets for LBG/IBG in the near term; however, some markets may develop in the 1980s due to the curtailment of natural gas, or where the direct use of coal or heavy oil is excluded. Potential markets for LBG/IBG technology include utility power generation (4), industrial fuel (5), synthesis gas as a chemical feedstock, and reducing gases for the primary metal industries. The production of synthesis gas from coal may be most attractive in areas of the United States where chemical manufacturing is heavily concentrated, therefore permitting construction of large central conversion facilities.

The logistics of coal and gas are important when comparing competitive markets for SNG from coal with LBG/IBG from coal. For example, coal supply, distribution, and handling considerations may add significantly to the cost for the small LBG/IBG producer. Therefore, an SNG-from-coal facility feeding existing natural gas distribution networks may deliver high-Btu gas to local markets competitively with small-scale systems producing LBG or IBG for those markets. Moreover, even when large centralized production facilities are used, both LBG and IBG will require limited but expensive gas distribution systems which may make delivered SNG less expensive. This type of comparison is highly site-specific, and generalization is difficult.

Recent experimental field pilot work (6) conducted by ERDA's Laramie Energy Research Center (LERC) in the Hanna Basin in Wyoming indicates progress toward development of an operable underground coal gasification system in

the United States. Speculative economic estimates indicate process costs for low-Btu gas of about $1.50 per million Btu on the basis of regulated utility economics. Remote site-related costs could increase this to about $2.00 per million Btu. Coalfield gas-fired power generation will be the primary market for this gas. Recent cost estimates (7) indicate that this may be competitive with mine-mouth power generation by direct firing of coal with flue gas desulfurization. Based on recent LERC experience, it appears that developmental costs for UCG are in some cases probably the lowest of any of the synthetic fuel types. UCG will eliminate most of the objections of stripmining of coal and can permit utilization of thick deep or otherwise difficult to mine coal seams, although surface subsidence and disruption and contamination of aquifers are potentially serious problems. Underground gasification control problems will have to be identified and overcome before low-Btu gas from UCG can be used in its most logical market--coalfield-located power generation. UCG technology is in the early stages of development in the United States; however, based on current field test results, large-scale demonstration now appears desirable to verify speculative economics, prove necessary operability, and assess environmental effects. Future commercialization will, of course, be dependent on demonstration results. Development is not far enough advanced at this time to predict when commercial application might occur.

Coal Liquefaction: Coal-derived liquids appear to face a more difficult competitive situation than coal-derived gases, since they will compete directly with imported oil in petroleum liquids markets. Liquids from oil shale will also compete directly in these markets.

Costs for low-sulfur liquids and boiler fuel with developmental systems are estimated here to be in the range of $3.50 to $4.50 per million Btu ($21 to $26 per barrel) for a 15 percent DCF rate of return. The regulated utility financing analysis does lower this to the $15 to $19 per barrel range. However, site-specific factors could easily add $2 to $3 per barrel to the costs.

Production of methanol from coal by gasification and catalytic methanol synthesis is somewhat more expensive than direct liquefaction of coal because of lower conversion efficiencies (40 to 50 percent versus 65 to 70 percent) and significantly higher capital costs. Based on a DCF rate of return analysis, the cost of methanol from coal is estimated at a little over $7.00 per million Btu using near term commercial technology before providing for remote site costs. Even assuming cost reductions due to evolutionary improvements in technology, and when using a highly debt-leveraged regulated utility economic analysis, the estimated cost of methanol from coal exceeds $4.00 per million Btu or $22.00 per oil-equivalent barrel on the process basis used. DCF costs on the same basis are approximately $6.00 per million Btu or about $35 per oil-equivalent barrel.

Large pilot plants for the direct production of liquids from coal are now in varying stages of design, construction, and operation. However, because of the high estimated costs, it is doubtful that there will be any significant commercial production of liquids from coal, other than from potential government-sponsored commercial scale demonstration programs, before the mid-1990s, at the earliest. Furthermore, there appears to be little prospect of methanol being produced from coal in the United States in the foreseeable future.

Oil Shale: Even though this paper is part of a session addressing the comparative economics of coal conversion processes, it is appropriate that production of liquids from oil shale be considered.

Based on a variety of SRI studies, the costs of an upgraded synthetic crude oil using developmental retorting systems are estimated (Table 2) to be in the range of $2.75 to $3.50 per million Btu ($16 to $21 per barrel) for a

discounted cash flow rate of return of 15 percent. The equivalent costs for regulated utility financing are in the $12 to $15 per barrel range. If it is feasible to produce and ship raw shale oil or a lightly upgraded high nitrogen content product, the cost would be $3 to $5 per barrel less at the plant than for a highly hydrotreated, low-nitrogen synthetic crude. Even though site-specific factors could easily add $2 to $3 per barrel to the above costs, shale syncrude with a sheltered financial basis appears to be marginally competitive with imported oil (Figure 1).

Shale oil product costs are estimated to be significantly lower than costs for coal-derived liquids. However, it should be emphasized that the greatest technical and economic risks in oil shale production are in shale mining and disposal of spent shale. In the case of coal liquefaction, uncertainties associated with the mining of coal and disposal of ash are considerably less. Large-scale pilot testing of several retorting technologies has been carried out. Some of this technology is now ready for commercial-scale demonstration. Such a demonstration in addition to proving retorting technology reliability would provide answers to serious questions concerning mining technology, overall economics, and environmental effects.

The lead-time necessary for construction of a commercial-scale plant would now probably preclude oil shale operation prior to about 1985, even with an early decision to construct a plant. In general, with access to world oil prices and a sheltered financial position, together with resolution of environmental constraints, some commercial production should develop in the period 1985-1990.

Any discussion at this time of the commercialization of synthetic fuels is not complete without addressing the issue of potential federal government incentives. During the 1973-1976 period, at least three industrial groups were willing to initiate commercial SNG-from-coal projects, assuming their SNG pricing structure was approved by the Federal Power Commission. No additional federal incentives or financial sheltering were apparently felt to be necessary to assist commercialization at that time. Moreover, at least four industrial-sponsored oil shale projects were set to move forward without federal assistance; indeed, the oil shale groups in most cases paid large front-end federal lease bonuses for the "opportunity" to do so.

Cost escalation has since magnified the risk of these ventures to a level where the sponsors have indicated that some type of financial incentive and/or risk reduction mechanism is now necessary. Four potential incentives often discussed to assist the commercialization of synthetic fuels processes are:

- Federally guaranteed construction loans
- Product price supports
- Tax credits
- Construction grants.

These incentives are discussed in detail in the report summarizing results of the Synfuels Interagency Task Force Study in 1975 (8). Since 1975, Congress has focused legislative attention on the use of loan guarantees. While this technique is now being sought by regulated producers for construction of SNG plants, there is no such consensus about loan guarantees among nonregulated producers for ventures involving synthetic liquids plants.

An alternative to the incentive approach is a modification of the so-called government-owned, company operated (GOCO) approach. During World War II, processes for the production of high octane gasoline and synthetic rubber were developed with federal assistance. The federal government provided the risk capital for initial construction and operation of pioneer commercial-scale demonstration plants and

when the plants were commercially proven, they were sold on a bid basis to the industrial developer, or to some other company. This type of approach may now be necessary to assist construction of pioneer plants, particularly for coal liquefaction, oil shale, and second-generation SNG systems now under development.

Summary and Overview

Commercial viability of synthetic fuels operation in the near term is clearly questionable because of the competition with natural gas and imported oil. Based on the economic analyses discussed in this paper, LBG/IBG from coal and liquids from oil shale appear to have the best chances for near-term commercial application. However, financial success appears to be contingent on economics based on a sheltered financial position to permit rates of return characteristic of a regulated utility producer. SNG from coal, while estimated to be more costly than LBG/IBG and shale liquids, may see earlier commercialization because of an existing sheltered regulatory position and because existing transmission, distribution, and utilization systems are available for the product.

Estimated costs for developmental conversion processes may be reduced by perhaps 20 percent or a little more with evolutionary technology, but greater cost reductions are difficult to foresee. A notable exception is underground coal gasification which, while being extremely site-specific and at an early stage of development in the United States, can have attractive economics.

Incentives currently discussed may be sufficient to commercialize first-generation coal gasification systems; however, an alternative such as government-financed plant construction and operation prior to successful commercial demonstration with sale to the developer/operator may be necessary for commercialization of pioneer technologies. Even when analyzed using the most attractive financial situation, the costs of synthetic fuels (UCG is a potential exception) will be at best marginal with to well above the current and near-term projected prices of natural gas and imported oil.

It becomes increasingly apparent that it is desirable for the United States to expand its ability to develop additional indigenous supplies of hydrocarbons, both to increase the base of a secure supply and to reduce the potentially adverse effect that excessive imports will have on the U.S. trade balance. However, the free market driving force for near-term large-scale commercialization of solid fossil fuel conversion processes is tenuous. Some specific marketing situations will develop; but in the near- to intermediate-term these will be caused more by shortages of conventional fuels rather than by price competition. In the meantime, large-scale research and development of a variety of systems has reached a significant level of sophistication and accomplishment. Commercial-scale demonstration of selected technologies because of the long lead-time necessary to commercialize such technology is now desirable to assist in the selection of the best near- to intermediate-term processes and for the benefit of long-term ongoing research and development.

Acknowledgment: SRI's Energy Center and Chemical Engineering Laboratory have been involved in comparative technical and economic evaluations of synthetic fuels processes since the mid-1960s. Acknowledgment is made of the many staff members from these two groups who participated in the development of background material for this paper.

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Table 1

MAJOR COAL CONVERSION AND OIL SHALE RETORTING SYSTEMS NOW UNDER DEVELOPMENT

Name	Type
COAL GASIFICATION	
• SNG	
- Lurgi	Fixed-bed, dry-ash
- BG-Lurgi	Fixed-bed, slagging
- HYGAS	Fluid-bed
- CO_2 Acceptor	Fluid-bed
- BIGAS	Entrained
- Synthane	Fluid-bed
• LBG/IBG[1]	
- Lurgi	Fixed-bed, dry-ash
- BG-Lurgi	Fixed-bed, slagging
- Texaco (Partial Oxidation)[2]	Entrained
- Combustion Engineering	Entrained
- Battelle (Agglomerating Ash)	Fluid-bed
- Westinghouse	Fluid-bed
- GEGAS	Fixed-bed
- Underground gasification	Laramie ERC technique
COAL LIQUEFACTION	
• Solid Boiler Fuel	
- Solvent Refined Coal	Noncatalytic
• Low-Sulfur Oil	
- H-Coal	Direct catalytic
- Exxon Donor Solvent	Indirect catalytic
- Synthoil	Direct catalytic
- Coalcon	Noncatalytic
OIL SHALE RETORTING	
• Liquids Production	
- TOSCO II	Circulating Heat Carrier
- Paraho	Internal Combustion
- Occidental	In situ

[1] Low or intermediate Btu gas

[2] This general type of technology is also under development jointly by the Royal Dutch Shell Group and Krupp/Koppers

Table 2: ESTIMATED CAPITAL AND PRODUCT COST FOR SOLID FUEL CONVERSION SYSTEMS

(Battery Limit Basis)[1]

Coal Gasification	Coal Type	Battery Limit Process Capital Investment M$/Daily O.E.Bbl[2]	Product Cost[7] Regulated Utility Analysis $/MMBtu	Regulated Utility Analysis $/O.E.Bbl	Discounted Cash Flow Analysis $/MMBtu	Discounted Cash Flow Analysis $/O.E.Bbl
SNG						
· Lurgi	Sub. Bit.[3]	24	3.75	22.00	5.25	30.75
· Developmental Processes	Sub. Bit.	18-24	2.75-3.75	16.00-22.00	4.00-5.25	23.50-30.75
LBG/IBG						
· Lurgi	Bit.[4]	19	3.25	19.00	4.75	26.25
· Developmental Processes	Bit.	15-21	2.50-3.50	14.50-20.50	3.50-5.00	20.50-29.25
· Underground Coal Gasification	Sub. Bit.	8	1.50	8.75	2.00	11.75
Coal Liquefaction[6]						
· Low-Sulfur Liquids and Boiler Fuel	Bit.	13-15	2.50-3.25	15.00-19.00	3.50-4.50	21.00-26.25
· Methanol	Bit.	21-25	3.75-5.00	22.00-29.25	5.50-7.25	32.25-42.50
Oil Shale[6]						
· Synthetic Crude Oil[5]	--------	12-15	2.00-2.50	11.50-14.50	2.75-3.50	16.50-20.50

NOTES:

(1) Battery limits costs, site-specific factors are excluded

(2) Oil equivalent barrel (O.E. Bbl): 5.85 million Btu

(3) Powder River Basin

(4) Illinois No. 6

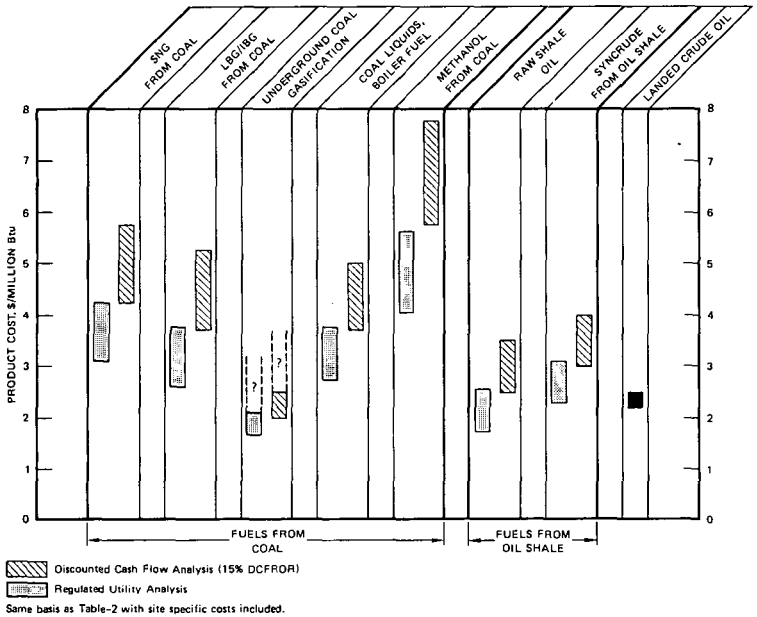
(5) Piceance Basin

(6) Developmental Processes, low-sulfur/nitrogen products

(7) Plant gate product costs

BASIS:

- Mid-1977 constant dollar analysis
- Regulated Utility Analysis: 65% debt, 15% return on equity, 10% interest on debt
- Discounted Cash Flow Analysis: 15% DCF rate of return, 100% equity financing
- Plant size: SNG : 250×10^6 scf/day (1,000 MW equivalent)
  LBG/IBG : 5×10^9 Btu/hour (500 MW equivalent)
  Liquids : 100,000 O.E.Bbl/day (2,500 MW equivalent)
- Mine Mouth Coal Prices: Powder River Basin Subbituminous = $7/ton
  Illinois No. 6 Bituminous = $18/ton
- Site-specific costs for a remote location may add $2 to $3 per O.E.Bbl ($0.35 to $0.50 per million Btu).



Same basis as Table-2 with site specific costs included.

FIGURE 1 ESTIMATED PLANT GATE COST FOR SYNTHETIC FUELS FROM COAL AND OIL SHALE
(Mid-1977 Constant Dollar Analysis)