PROSPECTS FOR THE COMMERCIALIZATION OF HIGH-BTU COAL GASIFICATION

PREPARED FOR THE DEPARTMENT OF ENERGY

WILLIAM F. HEDERMAN, JR.

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PREFACE

This report examines some of the problems of and prospects for the commercialization of high-Btu coal gasification. It is part of a Rand study of constraints on the commercialization of energy processes for the production of substitutes for natural gas and imported petroleum. Commercialization here refers to the adoption of a technology for general use by the private sector--usually after most of the uncertainty about technical feasibility has been resolved. This analysis addresses the following questions:

- What is the current economic status of high-Btu coal gasification, and how sensitive are the economics to changes in the costs of factor inputs, competing fuels, and various assumptions?
- How do the current economic and institutional factors constrain the commercialization of high-Btu coal gasification?
- What are the prospects for overcoming the obstacles to commercialization through government action?

Constraints and uncertainties about the constraints on commercialization can be grouped into three categories: technological constraints relating to the performance characteristics of the process, economic constraints referring to the ability of investors to earn an acceptable rate of return through the use of the technology, and institutional constraints arising from the organizational and political context in which commercialization takes place. This study addresses technological issues only as they relate to the costs or institutional environment of the processes examined. It also considers the effect that such regulation has upon the economic attractiveness of these processes.

The significant cost escalation for high-Btu coal gasification has continued since 1976, the date of the cost estimates used in this report. Although these estimates are lower than those for early 1978, the comparisons remain valid in providing insights for energy policy planning.

This and a companion report by Edward W. Merrow, *Constraints on the Commercialization of Oil Shale*, R-2293-DOE, forthcoming, were prepared for the Energy Research and Development Administration, now incorporated in the Department of Energy.

SUMMARY

Because of the higher heating value demanded of gaseous fuels in present residential and commercial applications, new coal-gasification processes and modifications of existing ones are needed to produce high-Btu gas, also called synthetic or substitute natural gas (SNG), from coal.[1] Five processes are examined in this analysis: Bigas, Carbon Dioxide (CO_2) Acceptor, Hygas, Lurgi, and Synthane. The Lurgi process is available commercially, and the others are in various stages of development. These processes were selected for detailed analysis because they are among the most frequently mentioned candidates for high-Btu coal gasification projects and because detailed cost data are available from a recent (1976) comparative analysis.[2] Since cost estimates for the less mature technologies involve significant uncertainty, the Lurgi estimates for SNG produced by a 250-million-cubic-feet-per-day plant are used as the basis of comparison in this report.

ECONOMIC ISSUES

Plant Cost

Estimates of plant costs made between 1969 and 1972 for commercial scale plants producing 250 million cubic feet per day ranged from $95 million to $250 million. Estimates made in 1976 were five times the early estimates or even higher. Several factors have contributed to

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[1] Gas with an energy value exceeding 900 Btu per cubic foot (cf) is generally labeled high-Btu gas. The heating values associated with low-Btu gas are 100 to 200 Btu/cf and with intermediate-Btu, 300 to 650 Btu/cf.

[2] Roger Detman, *Factored Estimates for Western Coal Commercial Concepts, Interim Report*, prepared for the Energy Research and Development Administration (ERDA) and the American Gas Association (AGA), C. F. Braun and Co., Alhambra, Calif., October 1976.

these increases: general inflation, construction cost changes in excess of general inflation, process changes, and improved cost estimating capability. This analysis has found that the first three factors are important but explain only about 20 percent of the cost escalation observed for the Lurgi process, the most mature process examined. *Approximately 80 percent of the increase in plant cost estimates must be attributed to the fourth factor, an improved capability to make estimates based upon more complete experience in plant design and operation --or to other, unidentified causes.* Such serious underestimation of cost poses important difficulties for both potential investors and government planning. Moreover, similar capital cost underestimation has been observed for oil shale, coal liquefaction, and nuclear power plant projects.

Comparative Costs

SNG from coal cannot presently compete on a cost basis with the price of regulated natural gas; however, the supplies of natural gas at the current regulated price are limited. The $3.31 per thousand cubic feet (Mcf) cost estimated for SNG from Lurgi does appear to be at least potentially competitive with new sources of gaseous fuels, including Alaskan gas and imported liquefied natural gas. In addition, analyses using current SNG costs from Lurgi indicate that coal gasification could supply residential and commercial requirements for energy used as heat (e.g., space heating and cooking), rather than as mechanical energy, more economically than can base load electricity generation.

Sensitivity Analysis

This study includes an examination of the changes in cost estimates resulting from variations in several input parameters. This sensitivity analysis was performed to help determine opportunities for effective intervention and identify trouble spots requiring special attention. For the method of cost calculation used by gas utilities, the capital costs, operating and maintenance (O&M) costs, interest rate on debt,

and service factor[1] base case input values varied. The results indicated that

- For all processes, cost estimates show similar sensitivities to capital and O&M costs with the exception of the CO_2 Acceptor process; its cost estimate is approximately 35 percent more sensitive to changes in its O&M costs than to changes in its capital costs.
- The estimates are most sensitive to the service factor, an input likely to change in an unfavorable direction from the 90 percent value assumed in the cost studies reviewed, at least during initial operations.
- The insensitivity of the cost estimates for all processes to changes in the interest rate on debt indicate that government loan guarantees would not significantly lower the cost of SNG from coal.

In addition, some of the less mature coal gasification processes, Bigas, Synthane, and Hygas (steam-iron), not only are already estimated to produce SNG more costly than Lurgi-produced SNG, but they also exhibit behavior very similar to that of Lurgi in response to input parameter variations. Parallel funding of such processes might make sense if no processes were in-hand. However, given the status of the Lurgi process, there is no clear rationale for continued government support to commercialize the Bigas and Synthane processes for high-Btu coal gasification of western coals. If the other processes are judged unlikely to be able to process eastern coals at a competitive cost, continued development of all candidate second generation processes may be a useful strategy. However, such development would be unnecessarily expensive if it were undertaken on a commercial scale.

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[1]The service factor is the ratio of actual capacity of a plant utilized to the rated capacity of the plant run full time.

Economic Outlook

Increasing plant cost and resultant rising costs of SNG from coal may be reversed through learning effects and technological innovations once plants are brought on line. However, learning effects are applicable only to the share of plant cost linked to novel technology, which varies from 20 percent to 50 percent for the processes examined. Therefore, *even with an optimistic assumption of 10 percent learning effects for the novel share of plant, no major cost improvements are likely from learning.*

Technological innovations may also generate cost improvements. Experience suggests that as a process advances in development most such innovations have decreasing relative effects on total cost. Major breakthroughs are always possible and it is conceivable that a breakthrough could eliminate major portions of the plant required downstream of the gasifier. Although the potential for breakthroughs should be an important consideration in federal R&D support, *the cost and riskiness of basing a commercialization policy on the promise of technological breakthroughs must be appreciated.*

Technological innovations can also open up ways to use entirely new processes. For instance, research on the use of catalysts in coal gasification could lead to third generation processes capable of producing SNG from coal at significantly reduced costs. Nevertheless, there is no reason to expect the commercialization of currently developed processes to accelerate the development of third generation coal gasification technology. In fact, if resources available for coal gasification are limited, relatively expensive commercialization activities could be expected to decrease the funds available for R&D looking to new processes with potentially superior cost characteristics.

INSTITUTIONAL ISSUES

To fill the shortfall of natural gas supplies created by the current natural gas price ceiling, SNG from coal appears close to being economically competitive with alternatives. However, the magnitude of the necessary investment (approximately $1.3 billion), in combination with persisting technical uncertainty and uncertainties about the

financial strength of the gas companies and the future regulatory environment have prevented the initiation of any commercial scale high-Btu coal gasification project to date.

Industry Characteristics

The gas supply industry would change drastically if high-Btu coal gasification were commercialized. One commercial-size facility producing SNG from coal could almost double the value of the plant in service for a company with assets equal to the average of the ten largest natural gas pipeline companies. But the volume of available gas for this company would increase by only 10 percent. The difficulties associated with this "lumpiness" problem are likely to be exacerbated by the borrowing problems most pipeline companies face because of their high level of debt and weak financial condition. In the private sector, other potential adopters of coal gasification technology with stronger financial credentials, including oil companies and chemical companies, have not expressed any serious interest in purchasing SNG facilities. The marginal economics, the regulatory problems of the gaseous fuel industry, and concern about government action on horizontal divestiture all hinder the likelihood of entry by such firms.

Regulation

No economic regulatory treatment satisfactory to all parties has yet been developed for a project making SNG from coal. Both financing problems and technological uncertainty hinder the resolution of this problem. It has not been possible to devise a method of assigning the risks associated with this uncertainty acceptable to potential lenders, sponsor utilities, and regulators.

There are potential environmental problems; however, current data indicate that SNG from coal is less harmful than other large scale coal conversion technologies providing comparable energy outputs. In addition, our sensitivity analysis indicates that coal and water costs could increase substantially without having a major effect on SNG costs.

State and local regulation of potential SNG facilities to some degree overlaps federal regulation, but its primary goal at the supply

end is to ameliorate the adverse effects of energy development. These effects appear to be related to the timing of cash flows because the net revenues to a community from development are likely to be positive.

State and local regulation also poses the possibility of prohibitions on the construction of SNG facilities, either directly, or indirectly through prohibitions on water use. Prohibiting use of local water would cause major problems for the development of coal gasification facilities near coal beds. However, as mentioned above, high-cost solutions to such problems may not change the process economics significantly and therefore may permit negotiation opportunities even in the face of possible water use prohibitions. In any event, the water supply problem is important for all energy supply options. This study indicates that coal gasification is an energy conversion option that may provide a better chance to solve the problem of water supply than do conventional conversion systems such as electricity generation from coal.

The analysis of economic and institutional issues indicates that even the major economic constraints on the commercialization of high-Btu coal gasification are closely related to the economic regulation of the gas industry. One aspect of the basic problem of SNG commercialization within the gas supply system is that gas has been considered a depletable, irreplaceable natural resource. Although this assumption is valid for natural gas, it is less valid for SNG from coal because of the long time that coal resources will be available. Thus, *for the time frame relevant to government regulatory policy, to view gaseous fuels as a manufacturable product is more appropriate than the current approach.* This view would be much closer to that governing the generation of electricity. Gas companies now understand this distinction and they are seeking to add to base load capacity by producing gas from coal and by importing liquefied natural gas. However, the regulatory structure for gas is still set up to deal with a depletable resource, with potential gas users unable to obtain firm supplies of gas at any price because current regulatory policy allocates the limited gas supplies to users already connected to the gas supply system.

It is possible to envisage price levels of natural gas that could lead to an economically justified decision by a gas utility to initiate production of SNG from coal, directly based on the average cost estimate

for SNG from Lurgi.[1] Given an optimistic lead time requirement of five years, a project begun now could not begin commercial operation before the mid-1980s. However, given current economic and institutional conditions there is no chance that the private sector would make such a decision without government support.

POLICY IMPLICATIONS

The government has many policy instruments available to promote the commercial manufacture of SNG from coal processes, including capital grants, price supports, operating subsidies, price deregulation, and loan guarantees. These policy instruments could be used on a one-time or continuing basis. On a one-time basis, their use could stimulate demonstration activity that might overcome such obstacles to commercialization as technical uncertainties, including those arising from lack of hands-on experience with a process plant producing SNG from coal, and socioeconomic uncertainties associated with the boom-town effects of large energy projects. For obstacles of a more continuing nature, such as unfavorable economics, large capital requirements, or regulatory problems, these policy tools might have to be applied many times, in varying degrees. The illustrative cost estimates presented show that the economic disadvantage imposed by natural gas regulation is very significant and that large subsidies (about $1 billion per plant for capital grants) would be required to make the production of SNG from coal profitable in the short run compared to regulated natural gas.

SNG production would further two major U.S. energy policy goals: reducing energy imports and assisting the future transition away from oil and regulated natural gas. Government support of SNG can help achieve these policy goals only to the extent that it assists in overcoming the obstacles to commercialization:

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[1] If the cost of regulated natural gas became $2.25 per thousand cubic feet (Mcf) in 1978 and rose 12 percent annually, the cost in 1982 would be $3.54 per Mcf, which exceeds the current $3.31 per Mcf Lurgi average cost estimate but is lower than the current $4.34 per Mcf first year cost estimate.

- o The high estimated cost of SNG from coal.
- o The technical and cost uncertainties still associated with SNG from coal.
- o The large capital investment required.
- o The reluctance of the financial community to invest in SNG-from-coal projects.
- o The significant changes required in the financial and physical structure of the gas supply system.
- o The current economic regulatory approach to gaseous fuels.

As described earlier, some of these obstacles are short term, one-time problems; others are likely to be longer term, continuing problems. To deal with the short term barriers, policy tools--such as capital grants and loan guarantees--are available but expensive either to taxpayers or gas consumers. Moreover, this analysis indicates that the construction of even several demonstration projects would not advance high-Btu coal gasification to a self-sustaining status without regulatory changes. In the absence of such changes, continuing subsidies or R&D on new and more economical gasification concepts would be necessary.

Conflict among policy goals must also be considered. For instance, given budgetary constraints, expensive efforts to accelerate the commercial scale implementation of a technology to decrease energy imports could decrease the funds available for relatively inexpensive efforts to smooth a later transition with improved technologies. For gaseous fuels, the added costs of commercializing SNG before such a high cost gas source is necessary to replace natural sources must also be weighed against the possible costs of inadequate supplies of natural gas.

Federal policy must also address equity issues in the distributive effects of its decisions. Two issues associated with commercialization of SNG from coal involve questions about equitable distribution of the costs and benefits of government policy:

- o The allocation of the economic costs and risks of a commercialization program among specific gaseous fuel users, all gas users, taxpayers, or other segments of society; and

- The distribution of environmental and socioeconomic effects of commercial production of SNG from coal.

The cost and risk allocation problem has not yet been resolved, but some alternative formulas have been rejected. For instance, the Federal Power Commission rejected an all-events tariff that would have required the expected gas consumers for an SNG-from-coal facility to pay for the project even if technical failure prevented SNG production. This implies a judgment that it would be inappropriate to burden this particular set of gas users with all the costs and risks of a high-Btu coal gasification plant. Similarly, the defeat of loan guarantee proposals in Congress implicitly suggests that assignment of the risks to taxpayers in general has also been judged inappropriate.[1]

The environmental effects of energy development must be resolved in the context of national energy policy rather than specifically for high-Btu coal gasification policy and, therefore, are beyond the scope of this report. The known environmental effects of coal gasification, this analysis has found, appear less harmful than other uses of domestic coal. The socioeconomic effects of commercial scale coal gasification projects on isolated communities near energy resources are not known precisely, but they appear to be problems of local costs preceeding local benefits. The uncertainty associated with potential socioeconomic problems has been identified as one obstacle to commercialization, but one that should be resolvable with government assistance.

As the relationships among these competing policy goals are clarified and the areas of feasible government activities are identified, appropriate policies for addressing the commercialization of high-Btu coal gasification can be developed, with regulatory changes likely to play a key role in any effective commercialization program.

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[1] Although specific authorization of a synthetic fuels loan guarantee program has never been approved by both houses of Congress, the fiscal year 1978 authorization bill for the Energy Research and Development Administration passed the House and the Senate with generic loan guarantee authority. However, the bill would require specific Congressional authorization for any loan guarantee of more than $50 million.

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I. INTRODUCTION

Gas derived from coal is one of the oldest major synthetic fuels in the United States. As early as 1820, Baltimore's streets were lit by gas manufactured from coal. Although the introduction of the incandescent light bulb around 1900 sharply cut the use of gas for lighting, gas continued as a heating fuel. By 1920 the relatively low price of oil led to a switch from coal to fuel oil as feedstock for manufactured gas. Finally, with the development of satisfactory piping and gas storage facilities, natural gas took over the gas market, and by 1963 manufactured gas accounted for only .05 percent of the gas sold in the United States.[1]

IMPORTANCE OF GASEOUS FUELS

More recently, as concern about the decline in natural gas reserves and about dependence on foreign energy sources grows, the development of gas from coal is again being considered. The heating value of natural gas is much higher than that of the gas manufactured in the past.[2] Thus, new processes or major modifications of old processes are now required to produce a substitute for natural gas that can be used in today's appliances and the infrastructure that has developed in connection with natural gas.

This type of synthetic gas is called high-Btu[3] gas or SNG (synthetic or substitute natural gas). There are also low-Btu and medium-Btu forms of gas from coal. These other forms are of interest for applications (primarily as industrial fuels) significantly different from those of SNG, and they are not addressed in this analysis.

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[1] Ogden H. Hammond and Robert E. Baron, "Synthetic Fuels: Prices, Prospects, and Prior Art," *American Scientist*, July-August 1976, pp. 407, 408.

[2] Federal Power Commission, *National Gas Survey, Vol.* 2, 1973, p. 636.

[3] Gas with an energy value exceeding 900 Btu per cubic foot is generally labeled high-Btu gas. The heating values associated with low-Btu and intermediate-Btu gas are 100 to 200 Btu/cf and 300 to 650 Btu/cf, respectively.

The SNG technologies examined here involve the conversion of coal to SNG at surface process plants. That is, the technologies are based upon the chemical conversion of coal and other inputs into a gas, substitutable for natural gas, at a surface plant. Such a plant must be distinguished from the in situ conversion of coal to gas. In situ technology, still in an experimental stage, would burn coal in place underground to produce a gas. Process plants to convert coal to SNG should also be distinguished from process plants converting liquid hydrocarbons, such as naphtha, to SNG.

Natural gas provides an important share of the nation's energy supply. In 1970, about one-third of domestic energy production was natural gas. Natural gas provided a little over 45 percent of the energy consumed by the residential, commercial, and industrial sectors.[1] SNG from coal could replace natural gas as fuel in any of these uses, as well as electricity in such uses as space heating and cooking.[2] Thus, the effect of commercializing high-Btu coal gasification could be very significant, with a potential market share exceeding one half of residential and commercial energy consumption as the supply of less costly alternative sources of gaseous fuels declines.

U.S. GOVERNMENT SYNTHETIC FUELS POLICY

Policy interest in synthetic fuels has been high since the 1973 oil embargo. Synthetic fuels figured prominently in Project Independence.[3] In his 1975 State of the Union message, President Ford proposed the development of incentives to reach a level of daily synthetic fuel production equivalent to one million barrels of oil.[4] An interagency

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[1] A. L. Austin, "Energy Distribution Patterns in the U.S.A. for 1970 and 1985," UCID 16022, Lawrence Livermore Laboratory, April 20, 1972, Fig. 1.

[2] Low-Btu gasification would be more economical for most industrial applications.

[3] Federal Energy Administration, *Project Independence Report*, November 1974, pp. 129-141.

[4] Richard Corrigan, "Energy Report/Synthetic Fuels Sponsors Ready If Congress Backs Up Investments," *National Journal*, Vol. 7, No. 44, November 11, 1975, p. 1509.

federal task force established in response to the President's proposal recommended a program to develop a capacity equivalent to 350,000 barrels per day by 1985, with a decision on the million barrels per day capacity postponed until the late 1970s.[1]

The Ford administration's synthetic fuels proposal later became part of a proposed Energy Independence Authority. This authority would have provided a massive program of federal assistance for private sector efforts toward "energy independence." It would have had up to $25 billion in equity capital plus the authority to underwrite $75 billion of commercial loans. The authority's objective would have been to "create a new partnership between the private sector and the federal government to assure action on vital energy projects in the next decade."[2] The proposal made little progress in Congress.

Congress has, however, been interested in promoting the augmentation of usable domestic energy supplies through synthetic fuel development. On July 31, 1975, the Senate voted to add authorization for $6 billion in loan guarantees to the annual authorization bill (H.R. 3474) of the Energy Research and Development Administration (ERDA). However, the House was unwilling to approve the loan guarantee provisions. In 1976, a $2 billion loan guarantee and price support proposal favorably reported by three committees was narrowly defeated in the House (H.R. 12112).

Promotion of synthetic fuel supplies is still under serious consideration, with support of demonstration plants receiving the most attention. Loan guarantees remain a politically attractive policy option because of the anticipated low net cost and the specific exemption of loan guarantees from the budgetary limits imposed by the Congressional Budget and Impoundment Control Act of 1974.[3]

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[1] Synfuels Interagency Task Force, *Recommendations for a Synthetic Fuels Commercialization Program*, Vol. 1, *Overview Report*, November 1975, p. vi.

[2] From President Ford's letter of transmittal to Congressional leaders, cited in Richard Corrigan's "Energy Report/Rockefeller Presses His Plan for $100 billion Bank for Fuels," *National Journal*, Vol. 7, No. 43, October 25, 1975, p. 1470.

[3] Section 3(a) of the Act excludes the "authority to insure or guarantee the repayment of indebtedness incurred by another person or government" from the definition of "budget authority."

With respect to high-Btu coal gasification processes, the technology examined in this report, President Carter has expressed the desire to "pursue an active RD&D program for advanced high-Btu coal gasification," and to avoid subsidizing "existing technologies."[1]

The policy goals of reducing energy imports and smoothing the transition to new energy sources are discussed in the final section of this analysis.

HIGH-BTU COAL GASIFICATION PROCESSES AND ALTERNATIVES

Before further examining high-Btu coal gasification, a brief discussion of SNG-from-coal processes and of alternative sources of gaseous fuels is helpful. Additional data are included in the economic analyses and references in Section II.

Coal consists of about 5 percent (by weight) hydrogen and 75 percent carbon. Pipeline quality gaseous fuel is about 25 percent hydrogen. To convert coal to a suitable substitute for natural gas requires the chemical addition of hydrogen, combining it with the coal's carbon and removing compounds containing sulfur, oxygen, and nitrogen.[2] The five processes described below employ different techniques to accomplish the necessary chemical reactions.

Bigas

The Bigas process prepares a coal-water slurry input to a two-stage pressurized coal-fired gasifier where the temperature exceeds 2500°F. The raw product gas passes through a water wash column, a shift reactor, and an acid gas removal stage before methanation. The methanator is a fluidized bed with embedded water-cooled tubes. This oxygen-addition process was developed by Bituminous Coal Research, Inc., an affiliate of the National Coal Association.

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[1] White House Fact Sheet, "National Energy Policy Principles, Strategies, and Goals," April 20, 1977, reprinted in *Energy Daily*, April 22, 1977, pp. 2-10.

[2] G. E. Klingman and R. P. Schaaf, "Make SNG from Coal?" *Hydrocarbon Processing*, April 1972, p. 97.

Carbon Dioxide Acceptor

In this process, crushed preheated lignite or sub-bituminous coal is fed into a pressurized fluidized-bed gasifier operating at 1500°F. Solids circulating in the gasifier and regenerator evolve carbon dioxide, absorbing energy in the regenerator, and accept carbon dioxide in the gasifier, releasing energy. The gasifier product gas flows through a steam-generating heat exchanger to a quench tower and a scrubber, to a shift converter, to an acid gas removal step, and finally to a packed bed methanator. This heat-carrier process was developed by the Consolidated Coal Company.

Hygas

This process slurries pretreated coal with a process-derived oil. The slurry is pressurized and pumped into a four-section hydrogasifier. After effluent quenching, purification, and residual recycling, methanation is carried out in two packed-bed downflow reactors. Hygas requires a hydrogen source, and steam-oxygen and steam-iron processes have been developed to supply it. This hydrogen-addition process was developed by the Institute of Gas Technology with partial support from the American Gas Association.

Lurgi

In this process, coal enters a pressurized gasifier through a coal lock and is distributed over a bed of coal resting on a rotating grate. Oxygen and steam flow countercurrently to the descending bed of coal. Product gases then flow through crude-gas shift conversion, Rectisol gas purification, cleaning, and methanation. This first generation oxygen-addition process is available commercially through the American Lurgi Corporation.

Synthane

In this process, coal is pulverized and pretreated in a pressurized environment to destroy its caking properties. The coal then enters a pressurized fluidized-bed gasifier operated between 1400°F and 1800°F.

After the gas produced is water-scrubbed to remove tar, it flows through the shift reactor, acid gas absorber, and sulfur removal steps. Methanation is accomplished by a tube wall reactor or hot gas recycle methanator. This oxygen-addition process was developed by ERDA's Pittsburgh Energy Research Center.

Other Gaseous Fuel Sources

Potential competitors to provide new gaseous fuel supplies are of two kinds: new sources of natural gas or other sources of SNG. New sources of natural gas include natural gas from Alaska, which would require a dedicated transportation system; imported liquid natural gas, which requires specialized vessels, plants, and ports, and increases imported energy levels; natural gas from Devonian shale and other tight formations, which requires the development of techniques to increase the flows of gas out of the formations; natural gas from geopressurized zones, which would involve great environmental problems; and natural gas from coal beds, which also requires improved techniques for economic collection. Other sources of SNG include production from naphtha, crude oil refining, or propane and butane, all of which would cause greater imports of energy.

COMMERCIALIZATION

In this study, commercialization refers to adoption by the private sector of a technology for general use after most uncertainties surrounding technical feasibility have been resolved. Commercialization may take many years or only a few depending on the degree of economic advantage and the constraints on the use of the technology. In the United States most commercialization of new technology is undertaken by the private sector without direct government involvement, although government activity to aid commercialization has expanded greatly in the past ten years, especially through the use of demonstration projects. A major interest of this study is the initial period of commercialization --roughly from when the results of development activities are known, to the time when expanding use of a technology by the private sector

is self-sustaining. This study is also concerned with how the government might facilitate or accelerate the initial phases of commercialization.

For high-Btu coal gasification, the scenario for accelerated commercialization is based upon data from unpublished ERDA planning documents. The maximum feasible accelerated scenario considered would involve commitments for seven commercial-scale plants by 1985, 40 by 1995, and 60 by 2000. The corresponding contributions to domestic energy production would be about 0.6 Quads[1] in 1985, 3.3 Quads in 1990, and 4.9 Quads in 2000. A less ambitious schedule, still requiring government promotion, might contribute about 0.2 Quads by 1985, 0.7 Quads by 1995, and 1.1 Quads by 2000.

It is helpful to distinguish commercialization from two related but distinct processes, development and deployment. Development activities are directed at the reduction of technological and related cost uncertainties; most pilot plant operations, for example, are developmental. A government deployment effort involves direct federal intervention to assure that a technology is applied. For instance, the government subsidized the construction of synthetic rubber plants as part of its World War II efforts.

To increase domestic supplies of usable energy forms, both deployment and commercialization programs for energy process plants have been suggested. The differences in the relationship between the private sector and the government for these alternative approaches are significant. If a decision to deploy the technologies were made, the pace of the implementation would depend upon government plants. For commercialization, the pace may be less predictable, and progress would depend more upon governmental understanding of the concerns of potential adopters in the private sector. Commercialization under regulation might be viewed as an intermediate case, sharing the characteristics of deployment and unregulated commercialization. To a large extent,

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[1] 1 Quad = 10^{15} Btu. United States energy consumption in 1976 was approximately 73 Quads (Executive Office of the President, *The National Energy Plan*, Government Printing Office, Washington, D.C., April 29, 1976, p. 10).

regulatory policy can pace the initial commercial application of technological innovations by shifting risks from private firms and investors to consumers.

In the case of SNG from coal, the private sector elements most likely to be involved are gas industry and other energy firms. The present gas industry performs three functions and the firms involved generally specialize in a function. These functions are exploration and collection, pipeline transmission, and distribution. The pipeline companies are the central figures in the supply of gaseous fuels. They contract with other firms, frequently oil companies, to provide natural gas, and they also develop their own natural gas resources. Local gas utilities distribute natural gas that they obtain through contracts with pipeline companies. The gas industry and the government interact throughout the process of supplying natural gas: Many gas resources are obtained through federal leases; natural gas transported interstate is regulated by the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission (FERC); and local gas utilities are regulated by state public utility commissions.

This study approaches the commercialization of high-Btu coal gasification in the following manner. It examines the current state of the technology and the economics of its status relative to potential alternatives in order to determine whether the technology might be commercially attractive. It reviews the expected performance of coal gasification technologies to obtain insights regarding prospects for a non-subsidized coal gasification industry. And it explores the institutional environment in which the technology would be implemented to identify any structural barriers to a potential market.

Section II addresses the economic issues associated with the commercialization of SNG-from-coal technology. It reviews the funding of the early federal coal gasification program and the changes over time in estimates of process cost. It compares the economics of high-Btu coal gasification with that of its competitors, analyzes the sensitivity of SNG cost estimates to the cost of several input variables, and reviews the economic outlook for the technology.

Section III examines the institutional issues important to commercialization. The issues covered include federal, state, and local regulation, other potentially important components, and product characteristics.

Section IV concludes with a review of the important barriers to high-Btu coal gasification and a discussion of selected policy options for addressing the barriers and the policy goals with which to evaluate the options.

We conclude from the assessment of commercialization prospects that there is no chance of the private sector's adopting any process for producing SNG from coal, either currently available or in development, without significant direct government support or changes in the regulatory environment. This is a result of the costs of producing SNG from coal and the regulatory environment for any gas fuels commingled with interstate natural gas.

Cost estimates for SNG from coal have risen rapidly. Plant cost estimates in 1976 were five or more times higher than estimates at the beginning of the decade. We find, moreover, that general inflation, construction-cost rises in excess of general inflation, and process changes explain only about 20 percent of the cost escalation observed for the Lurgi process, the most mature process examined.

- The rest of the increase in estimated plant cost, approximately 80 percent, must be attributed to an improved capability to make estimates, based upon more complete experience in plant design and operation--or to other, unidentified causes.

Not only are current cost estimates high, but we find that current estimates are not based on conservative assumptions. The sensitivity analysis presented in this study indicates the importance of some of the assumptions.

- The SNG cost is sensitive to changes in the load factor, which is assumed to be 90 percent in the cost estimates examined.

Decreases in the actual load factor experience could cause significant increases in SNG costs.

- Important SNG cost increases would result from continued plant cost escalation.

The sensitivity analysis also suggests at least one bright spot for high-Btu coal gasification.

- Since SNG costs are found not to be very sensitive to water and coal costs, there may be greater opportunity for negotiation of environmental issues associated with high-Btu coal gasification than has been envisioned.

The cost outlook has worsened as knowledge has been gained about the first and second generation high-Btu coal gasification processes, and the prospects for steady future improvement in gas cost once commercial scale operation has begun are not bright.

- Even with an optimistic assumption of 10 percent learning effects, we find that no major cost reductions can be anticipated--because the plant costs associated with novel technology (20 to 50 percent) for the processes examined are such a relatively small share of total costs.

Furthermore, we find the economic regulations with which high-Btu coal gasification must interact a formidable obstacle to commercialization of this technology. Although SNG from coal is much more expensive than regulated interstate natural gas, it appears comparable in price to most of the candidate unconventional sources of gaseous fuels. In addition, the favorable cost of SNG from coal compared to energy from electricity generation for home heating also suggests that the current regulatory structure is strongly influencing the reluctance of the private sector to undertake coal gasification. The institutional analysis indicates that the gas industry and its regulators must proceed towards a new perspective.

- Given the technical feasibility of coal gasification, the supply of gaseous fuels should be viewed more as the manufacturing of a product and less as distribution of a depletable natural resource.

II. ECONOMIC ISSUES

INTRODUCTION

Especially for innovations that provide close substitutes for available goods, the relative economic advantage of a new technology is an important determinant of commercial adoption. After briefly describing the coal gasification processes examined and reviewing the early coal gasification R&D program, this section examines the economics of SNG from coal processes. Capital, operating and maintenance, feedstock, and transportation costs are discussed and analyses made of product SNG cost sensitivity to the costs of these components. The economics of coal gasification is compared to that of other gas fuel sources, and the economic outlook for SNG from coal is examined. Finally, the implications of the economic issues are discussed.

SNG from Coal Processes

The several processes available for producing SNG from coal can be described as either first or second generation. The first generation processes are based upon technology that has been used commercially. Although no commercial high-Btu coal gasification plants have been built, the technologies have been used for ammonia and medium-Btu gas production.[1]

The processes described as first generation include Lurgi, Koppers-Totzek, Winkler, Wellman-Galusha, Riley-Morgan, Woodall-Duckham, Wilputtee, and Ignifluid. They produce medium and low-Btu gas. Only Lurgi has operated with a methanation step to produce high-Btu gas, and proposed American projects have been based upon Lurgi or second generation processes. Therefore, the Lurgi process is the only first generation process examined in detail in this work.

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[1]The Lurgi process has been used commercially in Europe and Africa, but most of the experience has been with projects less than one quarter the size most frequently proposed for American projects, i.e., 250 million cubic feet per day (cfd). High-Btu gas production has been demonstrated at a plant in Scotland, but the system distributed medium-Btu gas.

Second generation processes are still at a developmental stage. They include Hygas, Synthane, CO_2 Acceptor, Bigas, and other processes. The processes mentioned were examined recently in a comparative analysis by C. F. Braun and Co.,[1] from which data were published in the fall of 1976. Because these detailed data were available for examination, Hygas, Synthane, CO_2 Acceptor, and Bigas are the second generation technologies included in this analysis.[2] They are also among the most advanced and have received the most attention.

None of the data available for the second generation processes are based upon detailed design of commercial-scale facilities. Hygas and CO_2 Acceptor estimates are projected from preliminary pilot plant data, and Bigas and Synthane estimates are projected from bench scale and process development unit data. The level of confidence that is justified for such projections--to anticipate some of this study's findings --is not high. On the other hand, detailed engineering designs of commercial plants are completed for the Lurgi process, and data based upon such designs are available. As discussed later, greater confidence can be placed in detailed design data than in projected data from preliminary designs. Therefore, this analysis uses Lurgi cost figures as the base case for the discussion of economics.

Early Program

ERDA's present program for the conversion of coal to synthetic natural gas was initiated by two agencies within the Department of the Interior, the Office of Coal Research (OCR) and the Bureau of Mines. Related activity was funded by the Environmental Protection Agency, the National Science Foundation, and the Tennessee Valley Authority.[3] Most

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[1]Roger Detman, *Factored Estimates for Western Coal Commercial Concepts, Interim Report*, prepared for ERDA and AGA, C. F. Braun and Co., Alhambra, Calif., October 1976.

[2]The data were available because they were developed with support of federal funds and thus were not proprietary.

[3]General Accounting Office, *Status and Obstacles to Commercialization of Coal Liquefaction and Gasification*, RED-76-81, May 5, 1976, p. 5.

of the currently promoted processes received support from the OCR, which was established in 1961 by the Coal Research Act.

OCR's early budget was very small compared to recent coal conversion efforts, with OCR annual appropriations under $50 million until 1974, when they jumped to over $120 million. OCR used its scarce funds privately. Such technologies receiving partial support from OCR included the Institute of Gas Technology's Hygas process, the Consolidated Coal Company's CO_2 Acceptor process, Bituminous Coal Research's Bigas process, and Union Carbide's Agglomerating Burner process.[1]

Early capital cost estimates for coal gasification plants based on the Lurgi, Hygas (steam-iron and steam-oxygen), CO_2 Acceptor, and Bigas processes are presented in Table 1. These early plant cost estimates indicated potential product gas prices in the range of $0.75 to $1.25 per million Btu.[2] Such prices would have compared favorably in the unregulated intrastate natural gas markets as early as 1975, when the price was approximately $1.25 per million Btu;[3] however, these early estimates have not proved accurate.

Cost Calculation Method

Before proceeding to examine the comparative economics of high-Btu coal gasification and its alternatives, an explanation of the method used to calculate the cost figures is helpful. In studies explaining their methodologies, two methods of calculation have been encountered in cost analyses of high-Btu coal gasification. The methods differ significantly and yield substantially different cost estimates. One is the utility financing method and the other the discounted cash flow (DCF) method.

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[1] John Wirt, "Synthetic Fuels Demonstration Program," in Walter S. Baer, Leland L. Johnson, and Edward W. Merrow, *Analysis of Federally Funded Demonstration Projects: Supporting Case Studies*, The Rand Corporation, R-1927-DOC, April 1976, pp. K31-K33.

[2] Sidney A. Bresler and John D. Ireland, "Substitute Natural Gas: Processes, Equipment, Costs," *Chemical Engineering*, October 16, 1972, pp. 105-107.

[3] John Wirt, "Synthetic Fuels," p. K14.

Table 1

ILLUSTRATIVE EARLY ESTIMATES FOR PLANT CAPITAL COSTS BY PROCESS

Process	Date of Estimate	Plant Capacity (million cfd)	Cost ($ millions)[a]
Bigas	1970	250	170[b]
CO_2 Acceptor	1969	250	95[b]
Hygas	1971	250	170[b]
Lurgi	1971	288	250[c]
Synthane	1972	250	195[b]

[a]Current dollars.

[b]Cited in Bresler and Ireland, "Substitute Natural Gas."

[c]Cited in Henry Linden, "Is the Synthetic Fuels Option Still Credible?," *Energy Systems and Policy*, Vol. 1, No. 4., Crane, Russak and Company, Inc., 1976.

The actual decisionmaking with respect to SNG from coal is likely to be made in a regulated environment--if not at the federal level, at the state and local level--for the foreseeable future. Therefore, the utility financing method is used in this section.[1] For the steady state in which many SNG from coal plants are operating, the average gas cost figure would be the appropriate measure for comparisons among the candidate processes.[2]

The utility financing method is based upon a procedure developed by the AGA General Accounting Committee in 1961[3] and modified in 1971

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[1]Data for the discounted cash flow method are presented in Appendixes B and C.

[2]Consider the case where 20 plants are on line (one built in each of 20 years) and depreciation allowances are reinvested to open a new plant every year (as the oldest plant closes). Then, if gas costs are based on the 20 plant system, the appropriate cost would be the average gas cost.

[3]J. K. Kavanaugh, "General Accounting Procedures To Be Used for Large Scale Production of Gas from Coal and Oil Shale," memorandum, AGA General Accounting Committee, May 1, 1961, cited in U.S. Federal Power Commission, *National Gas Survey, Vol. II: Supply Task Force Reports*, Washington, D.C., 1973, p. 507.

by Panhandle Eastern Pipeline Company in connection with the National Gas Survey's Synthetic Gas-Coal Task Force.[1] This method assumes an N-year project life[2] and 100/N percent per year straight line depreciation on the total capital requirement (excluding working capital). The gas cost in year N is calculated by dividing the required revenues by the annual gas production, and the required revenue figure is calculated as the sum of the return on the rate base, federal income taxes, depreciation, and net operating costs. The cost figure would decrease every year, primarily because of the decreasing rate base.

To compare gasification processes, a 20-year average gas cost is generally used. This average has been calculated by averaging the 20 values of the gas costs calculated for each year.[3] Because the relative changes in the revenue stream are assumed to be the same for the various gasification plants, this average gas cost figure provides a convenient benchmark for interprocess comparison. However, this average understates the gas cost figure for the early years of plant operation, because the rate base for an individual plant decreases over time through depreciation.

COMPARATIVE COSTS

The costs of a new product--as compared with the costs of its competition--figure prominently in its commercialization. For high-Btu coal gasification, the question "Compared with what?" is still being debated. This subsection presents the potentially relevant comparisons on a per million Btu basis, discusses their relative importance for the commercialization of SNG from coal, and analyzes the comparative data available.

SNG from coal will be compared with the following:

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[1] Letter from J. F. Schomaker, Panhandle Eastern Pipeline Company to J. R. Garvey, Chairman, Synthetic Gas-Coal Task Force, November 1, 1971, cited in FPC, *National Gas Survey, II*, p. 507.

[2] For this report, N is assumed to be 20 years.

[3] FPC, *National Gas Survey, II*, pp. 510-512; and Detman, *Factored Estimates*.

- o Domestic natural gas.
- o Other domestic natural gas substitutes.
- o Imported substitutes for domestic natural gas.
- o Unconventional natural gas sources.

Because of the relative confidence possible for the Lurgi process estimates, Lurgi technology is used as the basis for comparison in this analysis.[1]

Lurgi versus Domestic Natural Gas

Natural gas prices are not established in the marketplace; they are subject to regulation by FERC when the gas is sold interstate. The President has recommended that natural gas regulation be extended to intrastate sales as well, but there is strong Congressional interest in deregulating the cost of natural gas. At this time, the outcome of the debate is uncertain. If the President's recommendations for natural gas were implemented, then SNG from coal could be competing with an equivalent fuel selling for $1.75 per thousand cubic feet, roughly equivalent to one million Btu.[2] Since the minimum cost estimate for SNG from the Lurgi process is $3.22 per million Btu (utility financing),[3] a consumer would always choose regulated natural gas rather than Lurgi-produced SNG when given a choice. However, the regulatory price ceiling on natural gas has led to a demand-supply imbalance, and the resulting excess demand means that there may not be enough $1.75 natural gas for all interested consumers.

Higher price ceilings have also been suggested, ranging from $2.00 to $2.50 per Mcf, and the question of how much natural gas would be available at various price levels above the price ceiling recommended

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[1] The importance of estimate uncertainty is discussed in a later section.

[2] In the studies referenced throughout this section, the costs of gas are expressed in terms of either the cost per unit of volume or the cost per heating unit. A rule of thumb for conversion is that at standard temperature and pressure a cubic foot of natural gas or SNG is equivalent to 1,000 Btus.

[3] Detman, *Factored Estimates*, p. 77.

by the President has been the subject of intense debate.[1] The American Gas Association recently analyzed a scenario in which a balance of supply and demand would result in a natural gas cost of approximately $3.25 per Mcf.[2] In this case, coal gasification might become economically competitive in an unregulated environment. Some analysts come to similar conclusions; others familiar with the natural gas issue assert that sufficient natural gas simply does not exist;[3] still others estimate that a $2.00 per Mcf price would eliminate any natural gas shortage by balancing the quantity of gas demanded and supplied.[4]

It should be noted that the price of natural gas sold on the interstate market has been uniform in the past, but a tiered market may develop. Efforts to deregulate or raise the ceiling for "new" natural gas have been especially strong recently. Because of the finite supplies of "old," cheap natural gas, the appropriate comparison would be SNG costs versus new gas costs. Other special conventional sources of natural gas may also be available at rates higher than general. Natural gas from Alaska and from the Outer Continental Shelf (OCS) would be the primary examples of such cases. The cost of Alaskan gas has been estimated at $2.50 to $3.00 per Mcf (at the lower-48 border),[5] with most of the cost uncertainty associated with the transportation system used. A major economic uncertainty associated with OCS gas costs is the size of the fields discovered.[6] The Federal Energy Administration (FEA) has

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[1] See Richard Myers, "Natural Gas: The Numbers Game Goes On," *Energy Daily*, June 2, 1977, pp. 1-2, for a brief review of part of this controversy.

[2] William T. McCormick, Jr. and L. Tucker, "The Cost Impact of Deregulation of New Natural Gas Prices," *AGA Gas Supply Review*, Vol. 5, No. 7, April 1977, pp. 1-5.

[3] "FPC Official: Little Natural Gas Left, Whatever the Price," *Energy Daily*, March 25, 1977, p. 3.

[4] R. S. Pindyck, of the Massachusetts Institute of Technology (MIT) Energy Laboratory, cited in "When Gas Goes Up," *Technology Review*, March/April 1977, p. 68.

[5] Federal Energy Administration (FEA), *National Energy Outlook, 1976*, FEA-N-75/713, Washington, February 1976, p. 150.

[6] The minimum field size that can be developed economically is also related to the price that can be charged (which is true onshore as well as on the OCS).

stated that "the OCS leasing schedule is the prime determinant of frontier OCS gas production . . . at prices above about 80¢ per Mcf."[1] Thus, natural gas from OCS fields will be a joint product of OCS oil production, and its production will not be closely related to the regulated price of natural gas.

Lurgi versus Other Domestic Natural Gas Substitutes

The economic comparison of interest could be the relative prices of substitutes for natural gas, if continued regulation or resource depletion were to maintain an imbalance between gas demanded and available. In this subsection, the domestic substitutes are discussed; these are the second generation coal gasification processes.[2]

The C. F. Braun and Co. comparative analysis already cited includes estimates of product gas costs. Table 2 presents the costs for several of the cases evaluated. In view of the uncertainty associated with all these estimates, Lurgi appears to be quite competitive with any of the advanced technologies presented, given a common set of design assumptions. In fact, given the actual existence of definitive plant designs for the Lurgi process, incorporating bids on equipment and materials as well as detailed manpower estimates and construction schedules, this set of costs is less likely to continue high escalation rates, and thus, Lurgi may be even more competitive with other processes than the table indicates.[3] In any case, only the Hygas steam-oxygen process shows lower cost estimates.[4]

SNG from oil shale has been mentioned as a possibility in the past. However, when the FPC's Synthetic Gas-Coal Task Force was asked to evaluate the potential of SNG production from oil shale in 1973, they found

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[1] FEA, *National Energy Outlook*, 1976, p. 135.

[2] Other natural gas substitutes using domestic resources would indirectly increase energy imports, and therefore, are discussed in the next comparison.

[3] This is discussed further in a following section on the economic outlook for coal gasification.

[4] The CO_2 Acceptor process has a lower cost estimate than Lurgi when calculated by the DCF method.

Table 2

COMPARISON OF COSTS OF GAS PRODUCED BY VARIOUS COAL GASIFICATION PROCESSES[a]

Process	Technical Status	Utility Average Cost[b] ($/million Btu)	Utility Cost Ratio to Lurgi
Lurgi	Commercial plant designed	3.30[c]	1.0
Hygas			
Steam-oxygen	Pilot plant operating	2.71[d]	0.82
Steam-iron	Pilot plant operating	4.10	1.24
CO_2 Acceptor	Pilot plant operation completed	3.38	1.02
Bigas	Pilot plant operation beginning	3.50	1.06
Synthane	Pilot plant operation beginning	3.70[e]	1.42

SOURCE: Detman, *Factored Estimates*, p. 77.

[a]Unless otherwise specified, 1976 dollars are used throughout this report.

[b]Detman notes that modifications to reduce costs have been proposed for some of the processes. Unfortunately, information on these modifications was not available at the level of detail necessary to incorporate them into this comparison. The average costs using these modified processes are given in the footnotes below.

[c]Dual feed cost is shown; single feed case = $3.22.

[d]Export power cost is shown; no export power case = $3.22.

[e]Slurry feed, export char case is shown; slurry feed, export power case = $4.11; dry feed, export power = $4.69.

that interest in the technology had not remained active. They based their report on work prepared by the Institute of Gas Technology in 1966.[1]

Lurgi versus Imported Substitutes for Domestic Natural Gas

Other substitutes for domestic natural gas are also available, but they involve the importation of foreign energy. Because of the importance of the energy dependence issue to the energy policy debate, these supply alternatives are considered separately from substitutes based upon domestically available energy resources.

[1]FPC, *National Gas Survey*, Section VIII, pp. 480-485.

SNG can be produced by the gasification of naphtha, crude oil, or LPG (propane and butane). These techniques require much smaller, simpler plants and lower capital investments than coal gasification. The feedstock costs of SNG by naphtha gasification and by the refining of liquid fuels were estimated in 1972 to represent 80 percent and 60 percent, respectively, of the cost of the gas produced.[1] Because of the lower capital intensity, the SNG-from-naphtha process has been used for several years by natural gas distribution companies as a peak supply source. Recent cost estimates for this product range from $3.50 to $5.20 per Mcf.[2] These processes may either use imported fuels directly or raise imports indirectly by increasing consumption of petroleum products.

Another supply option presently used on a limited basis is the importation of liquefied natural gas (LNG).[3] In a comparative analysis by Harral et al., a brief discussion of LNG delivered to the Pacific Basin versus SNG from coal estimated that the supply of LNG required almost 30 percent less capital per unit of capacity and that LNG's cost at the service area would be 15 percent lower than the cost of SNG from coal.[4] However, major safety questions are associated with the use of LNG--i.e., the possibility of large explosions.[5]

Recent LNG developments include the signing of a contract between the Algerian government and U.S. gas companies to import LNG produced in Algeria. The final impediment to this agreement had been FPC insistence that incremental pricing (i.e., marginal cost) be used for the sale of the gas, but the FPC finally accepted rolled-in (i.e., average

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[1]James A. Finnerman, "SNF--Where Will It Come From, and How Much Will It Cost?" *Oil and Gas Journal*, July 17, 1972, p. 84.

[2]Don Kash et al., *Our Energy Future*, University of Oklahoma Press, Norman, Okla., 1976, p. 161.

[3]Liquefied natural gas has been delivered to Boston since 1971.

[4]J. K. Harral, M. Jones, and D. Hall, "A Comparison of Energy Options: Gas or Electricity," Pacific Gas and Electric Co., San Francisco, California, April 1977, p. 18. It should be noted that the LNG cost estimate is based on a combination of Alaskan and Indonesian LNG.

[5]For instance, see F. W. Murray, D. L. Jaquette, and W. S. King, *Hazards Associated with the Importation of Liquefied Natural Gas*, The Rand Corporation, R-1845-RC, June 1976.

cost) pricing. The FPC has approved a price of $3.37 per Mcf on the gas sold interstate.[1]

Unconventional Natural-Gas Sources

Several technologies are also under development to supply natural gas from sources other than the geological structures from which natural gas has usually been taken in the past. These technologies would produce natural gas from sources collectively called "unconventional." These sources include coal seams, Devonian shale and other formations, geopressurized zones, and gas hydrates.[2]

Coal beds are a potential source of gas directly as well as through chemical conversion to SNG. Methane has always constituted a hazard to coal mining, but in general methane concentrations are not great enough for economic recovery. R&D utilizing fractioning and directional drilling techniques is under way to develop commercially feasible gas collection methods. In some favorable areas, limited production has been accomplished and pilot efforts involving the Bureau of Mines, ERDA, and gas companies are under way. As much as 300 to 800 Quads are potentially available, but the supplies available at various costs are not yet known.

Gas can be produced from Devonian shales and other tight formations. Relatively permeable Devonian shales in the Appalachian basin have already been exploited commercially. Attempts to loosen these formations through explosive or hydraulic fracturing have been partially successful, but only minor supplies are expected to be available by 1985 even at prices exceeding $3.50 per Mcf.[3] Thus, commercial development appears far in the future.

Natural gas is also present in geopressurized zones, areas of sedimentary deposits containing trapped pressurized water in which significant quantities of methane may be dissolved. One of the largest zones

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[1]"Energy Highlights--LNG Imports Approved," *Energy*, Summer 1977, p. 15.

[2]Alaskan gas, sometimes considered as an unconventional source, is discussed above.

[3]FEA, *National Energy Outlook, 1976*, p. 159.

lies off the Gulf Coast of Texas and Louisiana. Questions about technological feasibility and the extent of the resource remain unanswered, with saline water disposal and potential land subsidence as potentially major problems. One expert has suggested $2 per Mcf as a possible cost, but commercial development is still questionable and the technology is currently at the research stage.[1]

Gas hydrates are a more exotic unconventional source of natural gas. The Soviet Union has been studying the use of these frozen methane-water compounds found in the colder regions of the oceans. No estimate of the American resource base is available and no research is in progress.

Because of the uncertain technical and economic status of all the technologies for using unconventional sources of natural gas, it would not be useful to attempt any cost comparisons between SNG and this set of natural gas options.[2]

Lurgi versus Electricity

The above comparisons assess the attractiveness of SNG from coal in terms of similar fuels. Another possible approach is to consider the potential for substitution in terms of end use. Comparisons could be made with several alternatives, including solar energy, insulation, fuel oil, and electricity. Recent analyses have asserted that the conversion of coal to SNG is economically superior to conversion to electricity for many residential and commercial applications, and this is the comparison presented here. Burning coal in coal-fired electric power plants is how most residential and commercial consumers use coal today. Naturally, as the nation seeks to use more of its most abundant natural energy resource, coal, there is interest in expanding the conversion of coal to electricity.

The relative costs to the ultimate consumer of coal "by wire" versus coal "by pipeline" have been debated for at least two years. A

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[1] Myron H. Dorfman, "Natural Gas from Geopressurized Zones in the U.S. Gulf Coast Basin," *Gas Supply Review*, Vol. 5, No. 6, March 1977, p. 3.

[2] In developing national energy policy, other unconventional substitutes for gaseous fuels, such as insulation, storm windows, and automatic thermostats, should also be compared to SNG.

brief review of some of the analyses associated with the debate is presented as Appendix D. The more recent analyses of coal gasification versus electrification strongly indicate that, for a set of commercial and residential end uses, gasification is a potentially cost-competitive use of domestic coal reserves.[1] Tables 3 and 4 illustrate the potential economic attractiveness of an energy system providing SNG from coal, given the goal of using more domestic coal. There may be reasons to debate the methodology of these analyses; for instance, average costs were used rather than marginal costs. However, this average cost estimate is based on the costs of single plants supplying base load power and the necessary support components (transmission, appliances, etc.). Therefore, average costs do appear to be an appropriate basis for a cost comparison. The superior economics of coal gasification reported in these comparisons indicate that the relative advantage of SNG versus electricity production from coal is an issue requiring additional analysis.

Table 3

COMPARATIVE PRICES OF ELECTRICAL AND SNG USEFUL ENERGY FOR SELECTED AREAS

Area	Cost of Useful Energy Consumed ($/million Btu) SNG (from coal)	Electricity (from coal)
Atlanta, Ga.	4.94	7.45
Concord, Mass.	4.52	10.61
Houston, Texas	5.43	6.96
Philadelphia, Pa.	4.35	8.41
Seattle, Wash.	4.05	8.73
Tulsa, Okla.	4.49	7.75

SOURCE: American Gas Association (AGA), *A Comparison of Coal Use for Gasification Versus Electrification*, April 4, 1977.

[1]This is the set of end uses requiring heat rather than physical work. The most important end uses are space heating, hot water heating, cooking, and clothes drying. Almost all of Pacific Gas and Electric's residential gas sales are for these end uses, as are one-third of its residential electricity sales.

Table 4

COMPARATIVE TOTAL ANNUAL COSTS[a] OF APPLICANCE OPERATION ON ELECTRICITY AND SNG IN NORTHERN CALIFORNIA

Appliance	SNG from Coal[b]	Electricity from Coal
Cooking range	130	137
Clothes dryer	88	125
Water heater	166	340
Space heating	530	918
Space heating and cooling	804	1124

SOURCE: Harral, *A Comparison of Energy Options*.

[a]Includes amortized purchase and installation costs and annual maintenance costs.

[b]Assuming gas appliances have no pilot lights.

Appendix D presents a brief history of this issue, a summary of the results of studies by the American Gas Association and the Pacific Gas and Electric Company, and a brief discussion of the appropriate basis for comparing SNG and electricity costs.

Comparative Economics Summary

Table 5 summarizes the current cost and status data presented for SNG-from-coal technologies and their competitors in supplying gaseous fuels. It appears that high-Btu coal gasification could possibly become competitive with deregulated natural gas. For Lurgi, Hygas, CO_2 Acceptor, and Bigas processes, costs computed by the utility method all appear at least potentially competitive with those of unconventional forms of gas supplies currently available (i.e., SNG from naphtha and LNG). Other options may also become competitive, but their cost estimates are more uncertain than are estimates for Lurgi.

GASIFICATION COST COMPONENTS

In addition to capital costs and operating and maintenance (O&M) costs, a potentially important component of the ultimate cost of

Table 5

ESTIMATED COSTS AND STATUS OF SNG FROM COAL AND ALTERNATIVES

Gas Source	Estimated Cost ($/million Btu)	Status
Lurgi process	3.31 (utility)	Definitive commercial designs prepared
Hygas (steam-oxygen) process	2.71 (utility)	Pilot plant operating
CO_2 Acceptor process	3.38 (utility)	Pilot plant operation completed
Bigas process	3.50 (utility)	Pilot plant operation beginning
Hygas (steam-iron) process	4.10 (utility)	Pilot plant operating
Synthane process	4.69 (utility)[a]	Pilot plant operation beginning
Regulated natural gas	1.42	Supplies uncertain
Deregulated natural gas (including OCS)	1.42 and up	Price to clear market uncertain ($2.00 to $3.25 suggested)
Alaskan gas	2.50 to 3.00	Preliminary estimate (without data on pipeline route)
SNG from naphtha	3.50 to 5.20	Commercially available
LNG	3.00 to 4.00	Commercial available, large variation possible for each contract
Geopressurized gas	2.00	Speculation
Devonian shales and other tight formations	3.50 and up	Rough estimates for limited amounts
Gas hydrates	?	No American data base

[a]The proposed modifications discussed in Table 2 are also relevant here.

producing SNG from coal is transportation. The following subsections examine each of these components. Because of the importance of the cost of coal feedstock and water, these items are examined in greater detail in connection with operating and maintenance costs.

For most processes, capital costs are now the major part of the cost. Table 6 illustrates the relative importance of capital costs to the costs of SNG produced from coal, and the next subsection addresses the issues of capital costs.

Table 6

SHARE OF COST ESTIMATES FOR PRODUCING SNG ATTRIBUTABLE TO CAPITAL AND O&M FOR SELECTED PROCESSES (utility financing method)

Process	Share	
	Capital	O&M
Bigas	58%	42%
CO_2 Acceptor	52	48
Hygas		
Steam-iron	47	53
Steam-oxygen	52	48
Lurgi	58	42
Synthane (dry feed, export char)	57	43

SOURCE: Detman, *Factored Estimates*.

CAPITAL COSTS

The capital cost of an SNG-from-coal project includes the following: total plant investment,[1] initial charge for catalysts and chemicals, paid-up royalties, allowance for funds used during construction,[2] start-up costs, and working capital.[3] In the cases examined, total plant investment is by far the largest of these factors. Increases in estimates of required plant investment are discussed next. Then the sensitivity of SNG costs to capital-oriented factors is examined.

In the last five to seven years, the estimated costs for coal gasification plants have increased dramatically. Table 7 presents the history of estimates for Lurgi process plants to illustrate the magnitude of the escalation. The Lurgi estimates are the most significant;

[1]Total plant investment includes installed plant cost, contractor's home office costs and fees, and project contingency (about 15 percent of the first two items).

[2]This equals the total plant investment times the average weighted spending period (in years) times the interest rate on debt.

[3]The working capital estimate includes a 14-day inventory of raw materials, materials and supplies, and net receivables. Since net receivables are related to revenues, they differ for the private and utility financing cases.

Table 7

SOME LURGI PLANT COST ESTIMATES OVER TIME[a]
(Current dollars)

Estimate Date	Plant Size (million cfd)	Plant Cost ($ millions)	Cost per tcf Daily Output	Index to 8/71 Estimate
August 1971[b]	288	250	868	100
June 1972[c]	250	350[d]	1640	189
February 1973[b]	250	406	1624	187
October 1973[b]	288	491	1705	196
March 1974[b]	250	450	1800	207
June 1974[b]	250	447	1788	206
January 1975[b]	250	853	3412	393
April 1975[b]	250	778[e]	3112	359
March 1976[f]	250	1060	4240	488
1977[g]	250	1200	4800	553

[a]It has not been possible to determine all of the assumptions upon which these estimates were based. The estimates are presented to illustrate the order of magnitude of the escalation.

[b]Linden, "Synthetic Fuels Option."

[c]Bresler and Ireland, "Substitute Natural Gas."

[d]Without coal mine.

[e]Does not include capitalized interest during construction which is provided for on a current basis through a surcharge on Michigan-Wisconsin Pipe Line Company sales.

[f]Detman, *Factored Estimates*.

[g]Architect-constructor's latest informal estimate, private communication, April 1977.

this technology is closest to commercialization and there has been foreign commercial exprience with medium-Btu Lurgi plants. Nevertheless, Table 7 and Fig. 1 show cost estimates increasing almost fivefold from 1971 to 1977. These changes are even more impressive when one realizes that the estimates are all based upon designs for plants of approximately the same size, 250 million cubic feet per day.

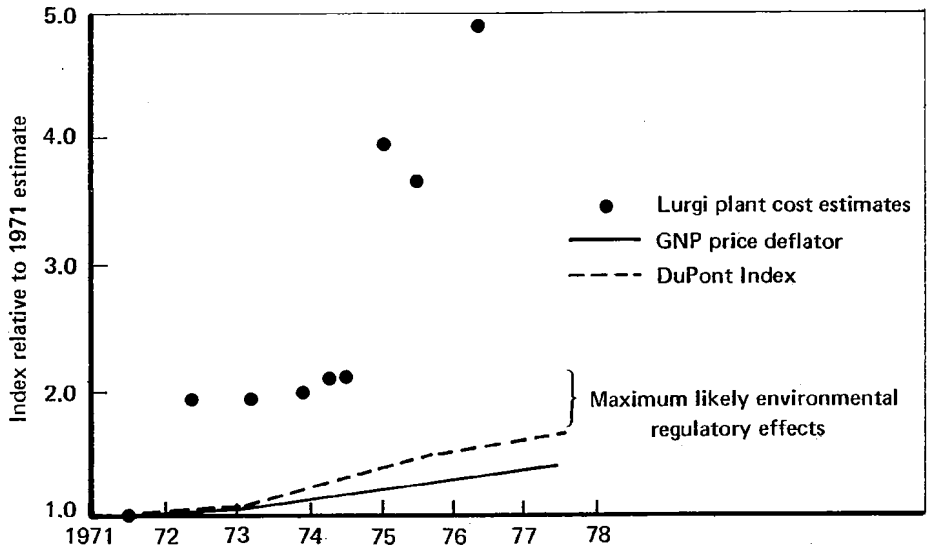

Fig. 1--Escalation of capital cost estimates since 1971

Reasons for Plant Cost Escalation

Because Lurgi is the coal gasification technology most likely to be commercialized first in the United States, it is useful to investigate the reasons for the significant cost escalation this process has experienced. Changes in the cost estimates of several second generation technologies significantly less developed than Lurgi are reviewed later in this report.

Four factors may be important in explaining the increases in plant cost, the variable traced over time in Fig. 1: general inflation, construction-cost changes above general inflation, improved bases for estimation, and mandatory process changes. General inflation is represented by changes in the GNP price index. Construction cost changes are those variations in plant costs above general inflationary increases in the purchase price of the labor, equipment, and raw materials that are inputs for constructing the process plant. Improved estimation

capability is based on increased knowledge obtained as additional data from R&D, pilot and commercial design experience, and operational experience are generated. Mandatory process changes could result from new product gas specifications, new feedstock specifications, or other changed constraints, such as new environmental regulations for plant operation.

Mandatory process changes appear to be the least important of the four factors identified. All the Lurgi plant cost estimates discussed have been based upon the assumed use of noncaking, Western sub-bituminous coal as the feedstock. Product gas specifications have not changed. And environmental regulations play a minor part in rising cost estimates. The full share of plant costs for sulfur recovery, solids disposal, and plant water systems is low, between 7 and 16 percent.[1] For Lurgi, the full cost of these components is 7.5 percent of plant costs. Even if the full cost of these components were attributed to changes in environmental regulations, they would account for less than 8 percent of the plant cost escalation. Therefore, whether or not some treatment was included in the original design, environmental protection measures could only account for a minor share of the escalation that has occurred.[2] Some share of the steam and utility systems cost (1 to 23 percent for the processes examined) may have increased because of air quality regulations, but the requirements are estimated to be minor.

Construction cost changes have been an important cause of plant cost estimate increases. These increases are the result of both general inflation and real cost increases (in excess of general inflation) for process plant construction. Fig. 1 traces the DuPont Chemical Process Plant Index[3] and the GNP price index during the period of cost escalation

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[1] Based on Table 16, p. 50.

[2] Water treatment and recycling measures are considered detailed engineering rather than environmental cost factors because, as large net consumers of water in water-short sites, the plants must use completely any water made available as a site-specific constraint.

[3] A forthcoming report by Edward Merrow, *Constraints on the Commercialization of Oil Shale*, The Rand Corporation, R-2293-DOE, discusses in detail the choice of this index.

examined. It shows that most construction-cost increases were owing to general inflation but that in addition real costs increased about 2 percent per year during the period.

Using an 8 percent upper limit on plant cost escalation assigned to environmental regulation, the escalation not attributable to general inflation, construction cost increases, or environmental regulation must be due to improvements in detailed engineering knowledge or other, unidentified factors. Approximately 80 percent of the cost escalation observed is in this residual category.

The most significant cost estimate increases have occurred as serious commercial interest led to detailed engineering designs of coal gasification facilities, and we have similar evidence for other technologies.[1] Hence there is reason to attribute most of this residual cost escalation to the enhanced engineering knowledge developed through successively more sophisticated plant designs and hands-on experience with processes.

Better knowledge of costs is possible as engineering designs become more complete. Because more detailed designs are expensive, early estimates are unlikely to be based upon designs past a block diagram level until there are potential plant purchasers. Merrow labels the stages of estimates as initial estimates, preliminary design estimates, detailed design (control) estimates, and definitive design estimates.[2]

The basis for the figures used in the detailed estimate is also very important in determining how much confidence the estimate merits. Before a process is applied commercially, it must advance through a development process. Work on a new technology usually begins at bench scale in a laboratory. When the basic elements of the process are understood, the process can advance from the laboratory bench to a process development unit (PDU), generally a small unit incorporating the complete process. Successful operation at this level would clear the way for a pilot plant operation, preferably about an order of magnitude smaller than the smallest feasible commercial scale. As the size of

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[1] See Merrow, *Constraints*.

[2] Ibid., for an expanded discussion.

the application increases, so does confidence that the problems always encountered as a process advances towards real-world application have been identified and solved.

Merrow illustrates conventional wisdom about the combined effects of development stage and engineering design detail in a matrix--shown in Table 8. It can be seen that confidence in the cost estimates is expected to increase as details are worked out and actual data are developed. The cost figures presented for coal gasification, however, indicate that this matrix does not accurately represent what has occurred with respect to this process. Confidence in estimates has risen as the technology has proceeded through the stages presented, but increases in the estimates have been significantly beyond the upper range of uncertainty described in the table. Merrow has observed similar behavior for oil shale technology.

Table 8

CONVENTIONAL WISDOM ON THE EFFECT OF DESIGN DETAIL AND DEVELOPMENT STAGE ON COST UNCERTAINTY

Data Base for Design (Development Stage)	Type of Engineering Design			
	Initial	Preliminary	Detailed	Definitive
Bench scale	?	?	?	?
Process development unit	?	±30%	±30%	±20%
Pilot plant	?	±30%	±20%	x
Commercial scale or demonstration	?	±20%	x	x

NOTE: ? denotes little confidence; x denotes ±10 percent, or +20% to -10 percent, depending on the process.

For Lurgi the most important identified factor underlying the increased plant cost estimates appears to be the improved engineering knowledge developing through the successively more sophisticated plant designs.[1] Although less detailed data are available for the advanced

[1] Linden estimates detailed engineering knowledge to be important but only about half as important. See Appendix A for a brief comparison.

SNG from coal processes, it is already possible to observe similar plant cost increases.

Cost Histories of Second Generation Process Plants

Table 9 presents plant cost estimates for selected second generation coal gasification processes, the advanced processes examined in the recent comparative analysis by C. F. Braun and Co.[1]

The nature of these estimates differs significantly from that of Lurgi estimates. There has been European commercial experience with Lurgi gasifiers, and there are detailed commercial designs for high-Btu Lurgi plants. Therefore, Lurgi plant cost estimates can now be based upon detailed specifications; the C. F. Braun and Co. estimate for the Lurgi plant (Table 7, p. 28) is based upon computerized modifications of present Lurgi designs. On the other hand, the second generation coal gasification technologies are in a much less developed state. Even the 1976 estimates for these second generation processes are extrapolations from experimental and developmental experience.[2]

These processes are in various stages of pilot plant operation. Final reports are in preparation for the Chicago, Ill., Hygas pilot plant and the Rapid City, S. Dak., CO_2 Acceptor facility. The Bruceton, Pa., Synthane pilot plant and the Homer City, Pa., pilot plant became operational during fiscal year 1977.[3]

The C. F. Braun and Co. estimates for the Hygas and CO_2 Acceptor processes are based upon computerized projections of bench-scale and process development unit data supplemented with preliminary pilot plant data, and their Synthane and Bigas estimates are based solely upon computerized extrapolations from bench-scale and PDU data.[4] If experience with oil shale and Lurgi processes is any guide, one might reasonably expect additional plant cost escalation as the sophistication of the engineering designs and experience increases for these processes.

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[1]Detman, *Factored Estimates*.

[2]Ibid., p. 1.

[3]ERDA, *Budget Estimates, Fiscal Year 1978*, Book I, *Fossil Energy Section*, January 19, 1977, p. 25.

[4]Detman, *Factored Estimates*, p. 1.

Table 9

ILLUSTRATIVE PLANT-COST CASE HISTORIES: SECOND GENERATION PROCESSES
(Current dollars)

Process	Estimate Date	Cost per Unit of Capacity ($/1000 cfd)	Increment[a] (%)	Corresponding DuPont Index Increment[b] (%)
CO_2 Acceptor	1969[c]	380		
	1971[d]	412		
	1976[e]	3560	837	90
Hygas				
Steam-iron	1971[d]	688		
	1976[e]	5120[f]	644	61
Steam-oxygen	1971[c]	680[g]		
	1971[c]	610[h]		
	1971[d]	709[i]		
	1976[e]	3480[g]	412	61
Bigas	1970[c]	680		
	1971[d]	716		
	1976[e]	4120	506	75
Synthane	1972[c]	780		
	1972[d]	804		
	1976[e]	4600[j]	590	52

[a]Increment provided only for earliest to latest estimate. When multiple estimates are cited for a year, the estimate for the same size plant is used. When there are multiple estimates for same size plant, the most optimistic estimate is used.

[b]Based on private communication from DuPont.

[c]Bresler and Ireland, "Substitute Natural Gas."

[d]L. K. Mudge et al., "The Gasification of Coal," Battelle Pacific Northwest Laboratories, July 1974 (base year is assumed to be estimate date).

[e]Detman, *Factored Estimates*.

[f]Export power case.

[g]250 million cfd base.

[h]500 million cfd base.

[i]265 million cfd base.

[j]Slurry feed, export char case.

SNG Cost Sensitivity to Capital Parameters

Given the major uncertainties about plant costs already encountered, it is important to develop some understanding of the sensitivity of the costs of the SNG produced to changes in the costs of selected input parameters. The sensitivity of SNG cost to O&M (operation and maintenance) and other input costs is examined in later sections of this report. Such exercises help in identifying trouble spots requiring special attention and opportunities for effective intervention, and in planning an overall federal strategy for promoting production of SNG from coal. The sensitivity analysis is presented in Appendix B. Here the implications of the results of that work are discussed.

Input parameters associated with the capital cost contributions to SNG cost include--in addition to the project's cost--the interest rate on debt and the service factor. As mentioned earlier, project cost includes total plant investment, initial charge of catalysts and chemicals, paid-up royalties, and working capital. The interest rate on debt is self-explanatory. The service factor is the ratio of actual capacity of a plant utilized to the rated daily capacity of the plant run full time.

The responses of SNG cost to parameter variations differ under different financing method assumptions. The results for the utility financing method are discussed here. The discounted cash flow results are discussed in Appendix C.

As indicated in the discussion of comparative economics, the Hygas (steam-oxygen) and the CO_2 Acceptor processes are the only second generation processes estimated to provide SNG less expensively than the Lurgi process. For this reason, and because an examination of these three processes provides results that apply to all the processes in C. F. Braun and Co.'s comparative study, the sensitivity discussion is limited here to three processes, the Lurgi, Hygas (steam-oxygen), and CO_2 Acceptor.[1]

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[1]Even though the Hygas and CO_2 Acceptor estimates are based on preliminary data, these estimates are firmer than those for the other second generation processes.

Capital Cost. Table 10 illustrates the effect of changes in capital requirements on SNG cost calculated by the utility financing method. The table shows that capital subsidies would be more effective for capital intensive processes such as Lurgi and Hygas than for the less capital intensive CO_2 Acceptor process.

Table 10

RELATIVE SNG COSTS FOR VARIATIONS IN CAPITAL COST BY PROCESS[a]

(Utility method, Base Case Index = 1.00)

Capital Cost Multiplier	Process		
	Lurgi[b]	Steam-Oxygen Hygas[c]	CO_2 Acceptor[d]
0.50	0.75	0.75	0.80
0.75	0.88	0.88	0.90
1.00[e]	1.00	1.00	1.00
1.25	1.12	1.12	1.10
1.50	1.24	1.24	1.20
2.00	1.49	1.49	1.40
3.00	1.98	1.97	1.80
4.00	2.47	2.46	2.20
5.00	2.97	2.94	2.60
10.00	5.42	5.38	4.60

[a] Based on data in Appendix B.

[b] Base case cost: $3.31/million Btu.

[c] Base case cost: $2.72/million Btu.

[d] Base case cost: $3.39/million Btu.

[e] Base case assumption.

Interest Rate on Debt. Table 11 presents the relative effects of changes in the interest rate paid on utility debt. The results indicate that no large decrease in SNG cost would result from a low interest rate on debt, even for the 75/25 debt/equity ratio assumed for calculations done using the utility financing method.

Such data should be considered in evaluating loan guarantees and related programs. There may be reasons to support loan guarantees or

Table 11

RELATIVE SNG COSTS AS A FUNCTION OF INTEREST ON DEBT[a]
(Utility method, Base Case Index = 1.00)

Interest Rate on Debt	Process: Lurgi[b]	Process: Steam-Oxygen Hygas[c]	Process: CO_2 Acceptor[d]
0.04	0.87	0.87	0.90
0.05	0.90	0.90	0.92
0.07	0.95	0.94	0.96
0.09[e]	1.00	1.00	1.00
0.11	1.05	1.05	1.04
0.13	1.11	1.11	1.09

[a]Based on data in Appendix B.

[b]Base case cost: $3.31/million Btu.

[c]Base case cost: $2.72/million Btu.

[d]Base case cost: $3.39/million Btu.

[e]Base case assumption.

other subsidies to lower the interest rate on debt, but such action should not be expected to improve significantly the economic attractiveness of SNG from coal.

A related point deals with increased rates of interest on debt. The SNG cost need not increase significantly even if investors must be sought who would accept greater risks only in exchange for greater returns.

Service Factor. The effect of the service factor could be reviewed as an aspect of operating an SNG facility. However, since it expresses a measure of the efficiency with which a capital expenditure is utilized, it is examined as a capital input parameter. Because of the high service factor used in the base case assumption (90 percent), changes in the service factor significantly affect SNG costs only in an unfavorable direction, as follows:[1]

[1]Since these figures are based on no change in input costs accompanying given changes in the service factor, they should be considered as a first approximation of the SNG cost behavior. The figures are

Service Factor	Base Case Index
1.0	0.90
0.9	1.00
0.8	1.12
0.7	1.29
0.6	1.50
0.5	1.80
0.4	2.25

The government could insure a high service factor by encouraging or requiring redundant systems, but this could involve large additional capital expenditures. Because possibilities for improving process economics through the service factor are limited, the important implication for SNG cost is that the government should ensure that any subsidy arranged does not discourage full utilization of the SNG plant.

Other Capital Cost Factors

At least two other factors related to capital costs could affect product SNG costs. They are the length of construction time and the debt-to-equity ratio.

Increased construction time can vary in effects on SNG costs, according to circumstances. To extend construction time increases SNG costs to the extent that it increases interest during construction. Thus, if delays occur prior to any capital expenditures, little cost effect is likely. If construction in general takes longer than anticipated, then capital expenditures are also likely to be delayed. In this case, the cost effects are likely to be greater than for the first case, because as purchases are spread out the average time that investments are idle increases--although these effects would not necessarily be large. The worst case would be delays in the completion of construction, or in the commencement of operations, after most of the capital expenditures have been made. For example, if the effective period for

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taken from data in Appendix B; the Base Case Index is the same for all processes.

paying interest on the plant doubled for a Lurgi facility, the SNG cost would increase 7 percent (utility method).[1]

The cost of debt is generally assumed to be less than the return required on equity; in the method used here, annual interest on debt is assumed to be 9 percent and the annual return on equity is assumed to be 15 percent. It might appear that project costs could be reduced by more debt financing, but savings would be illusory. The amount of capital a firm can borrow is based upon its equity.[2] Therefore the apparent savings to the coal gasification project from increased borrowing would be made available through higher costs for other projects, shifting their debt-to-equity ratio in the opposite direction.

OPERATING AND MAINTENANCE COSTS

The operating and maintenance costs for a high-Btu coal gasification project include purchases of raw materials, water, catalysts, chemicals, and other supplies; labor, administration, and overhead; and local taxes and insurance. It is assumed that several by-products of the coal gasification processes[3] would be sold and credit for these sales is netted from the gross O&M cost figure to provide the net operating cost.

The O&M cost is important to that of SNG from coal for the processes examined. As shown in Table 6 (p. 27), the O&M share of the cost of SNG produced could go as high as 53 percent (estimated for the CO_2 Acceptor process, utility financing method). This subsection reviews the results of the O&M costs sensitivity analysis and then considers the special cases of charges for coal and water.

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[1] The base case assumptions used in the C. F. Braun and Co. analysis differ by slightly less than two months in their utility and DCF cases (utility: 1.75 years, DCF: 1.875 years). The reason for this difference is not clear, but it has been retained so that readers interested in the development of the figures used throughout this work can relate them to the engineering analyses made by C. F. Braun and Co.

[2] That is, additional financing would not be available at the same interest rates as the debt/equity ratio grows and might not be available at all when some debt/equity ratio is reached.

[3] These by-products include sulphur, ammonia, light oil, char, coal fines, tar, phenols, naphtha, and, in some design assumptions, surplus electric power.

SNG Cost Sensitivity to O&M Costs

Since the early estimates of SNG-from-coal costs, O&M cost estimates (in which the major item is the purchase of coal) have increased, but not as drastically as capital cost estimates. Just as SNG cost responds differently according to the financing method assumed, so do operating costs vary as well.

Table 12 presents the response of SNG costs to O&M cost changes, assuming the utility case. Comparison with Table 10 indicates that Lurgi and Hygas (steam-oxygen) SNG costs vary similarly for equivalent changes both in capital and operating costs. CO_2 Acceptor SNG cost variations are greater for O&M cost changes.

Table 12

RELATIVE SNG COSTS FOR VARIATIONS IN OPERATING COSTS BY PROCESS[a]

(Utility method)

Capital Cost Multiplier	Process		
	Lurgi[b]	Steam-Oxygen Hygas[c]	CO_2 Acceptor[d]
0.50	0.78	0.78	0.73
0.75	0.89	0.89	0.86
1.00[e]	1.00	1.00	1.00
1.25	1.11	1.11	1.14
1.50	1.21	1.22	1.27
2.00	1.43	1.44	1.54
3.00	1.87	1.88	2.08
4.00	2.30	2.31	2.62
5.00	2.73	2.75	3.16
10.00	4.90	4.94	5.85

[a] Based on data in Appendix B.

[b] Base case cost: $3.31/million Btu.

[c] Base case cost: $2.72/million Btu.

[d] Base case cost: $3.39/million Btu.

[e] Base case assumption.

Coal and Water Costs

Because coal purchases are a major share of operating costs and because water supplies have such importance for coal gasification facilities, the effects of changes in the costs of these two inputs are examined separately.

The most straightforward method of assessing the effects of feedstock price increases is to utilize the available data on thermal efficiency of conversion. For instance, if a process has a thermal efficiency of 70 percent, then an increase in the cost of the input coal of $.10 per million Btu implies an increase in the cost of the gas produced of

$$\frac{\$0.10}{\text{million Btu}} \times \frac{1}{.70} = \frac{\$0.14}{\text{million Btu}} .$$

Converting this data into units more common for coal and gas, an increase of $1 per ton of coal is approximately equal to an increase of 4½ cents per Mcf of gas produced. Because sensitivity is related to the size of the base as well as the size of a change, feedstock price variations would affect the earlier estimated gas cost of $1.25 per million Btu more than the current $3.30 per million Btu estimate.

It should be noted that feedstock prices have also risen. A 1972 analysis[1] assumes that a price of approximately $4.00 per ton is appropriate, but a 1976 study[2] assumes $7.50 as the appropriate cost.

Table 13 shows the share of operating costs attributable to coal and water purchases in the C. F. Braun and Co. base case. These O&M cost-share data and the O&M cost-sensitivity data indicate that even if the cost of coal doubled (base assumption: $7.50/ton for western sub-bituminous) because of very strict stripmining regulation or other restrictions, the SNG cost would not increase by so much as a third, even for the most sensitive case of any process. They also indicate that even a tenfold increase in the price paid for water (base assumption: $.40/1000 gallons) would have a negligible effect on SNG cost.

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[1] Bresler and Ireland, "Substitute Natural Gas," p. 107.

[2] Detman, *Factored Estimates*, Appendix, p. 23.

Table 13

RELATIVE NET OPERATING COSTS ASSOCIATED WITH COAL AND WATER IN BASE CASES, BY PROCESS[a]

(In percentages)

Process	Coal Cost Share	Water Cost Share
Lurgi	64.6	0.4
Hygas		
Steam-Oxygen	53.3	0.4
Steam-Iron	37.8	0.4
CO_2 Acceptor	48.6	0.3
Bigas	40.9	0.3
Synthane (slurry feed, export char)	50.7	0.3

[a]Calculated from data in Detman, *Factored Estimates*.

OFFSITE COSTS

Costs of transportation and distribution also affect the cost of gas to the ultimate consumer; however, most of these costs would be identical to the costs for natural gas if existing pipeline facilities are used. The cost of transporting energy in the form of gas is relatively low. Linden estimates the costs per million Btu-100 miles[1] as 2 cents for gas, 2 to 5 cents for coal, and 10 to 15 cents for electricity.[2] Therefore, very large changes in the cost of gas transportation would be necessary before the cost of moving the product gas to the national gas-pipeline network would be important to the economics of coal gasification. So marginal a transportation cost figure may not be valid if new pipeline must be constructed solely for an SNG facility. In such a case, the capital investment for the pipeline would have to be included. The FPC points out, however, that in many instances domestic coal resources are situated near existing pipeline rights-of-way

[1]"Million Btu-100 miles" is the unit of energy required to move an amount of fuel containing 1 million Btus of energy 100 miles.

[2]Linden, "Synthetic Fuels Option," p. 333.

or centers of population.[1] If the early coal gasification plants use this advantage, then the construction of new pipeline should not be significant.

Another transportation issue could become important to the economics of SNG from coal. If a coal gasification plant were not located at the mine site, then the costs of additional coal handling equipment at the mine, plant, and railroad terminals, plus the higher transportation costs for the coal leg of the trip, might significantly increase the costs of producing gas from coal.[2] There have been suggestions that some coal-rich western states would allow coal mining for SNG plants located elsewhere but would not accept minemouth coal gasification facilities. Concern about water consumption could lead to such a state policy. No analysis of the economic implication of such a situation has been found; exploration of this topic would provide helpful data for government decisions.

OVERVIEW OF SENSITIVITY ANALYSIS RESULTS

The results of the sensitivity analysis for the processes and input parameters examined above are illustrated in Fig. 2. The sensitivities of the six high-Btu coal gasification processes analyzed in Appendix B are summarized in Table 14. From these overviews we can make the following observations:

- The cost estimates are about equally sensitive to capital and to operating cost parameters, except that the CO_2 Acceptor process is about 35 percent more sensitive to changes in its operating costs than in its capital costs.
- The estimates are most sensitive to the service factor, an input likely to change in an unfavorable direction at least for early operations.

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[1] FPC, *National Gas Survey*, pp. 441-442.

[2] The effective transport cost would be even higher than the 2 to 5 cents per million Btu-100 miles because this leg of the trip would be pre-conversion. Assuming a 70 percent conversion efficiency, the rail transport cost per effective million Btu-100 miles would be 3 to 7 cents.

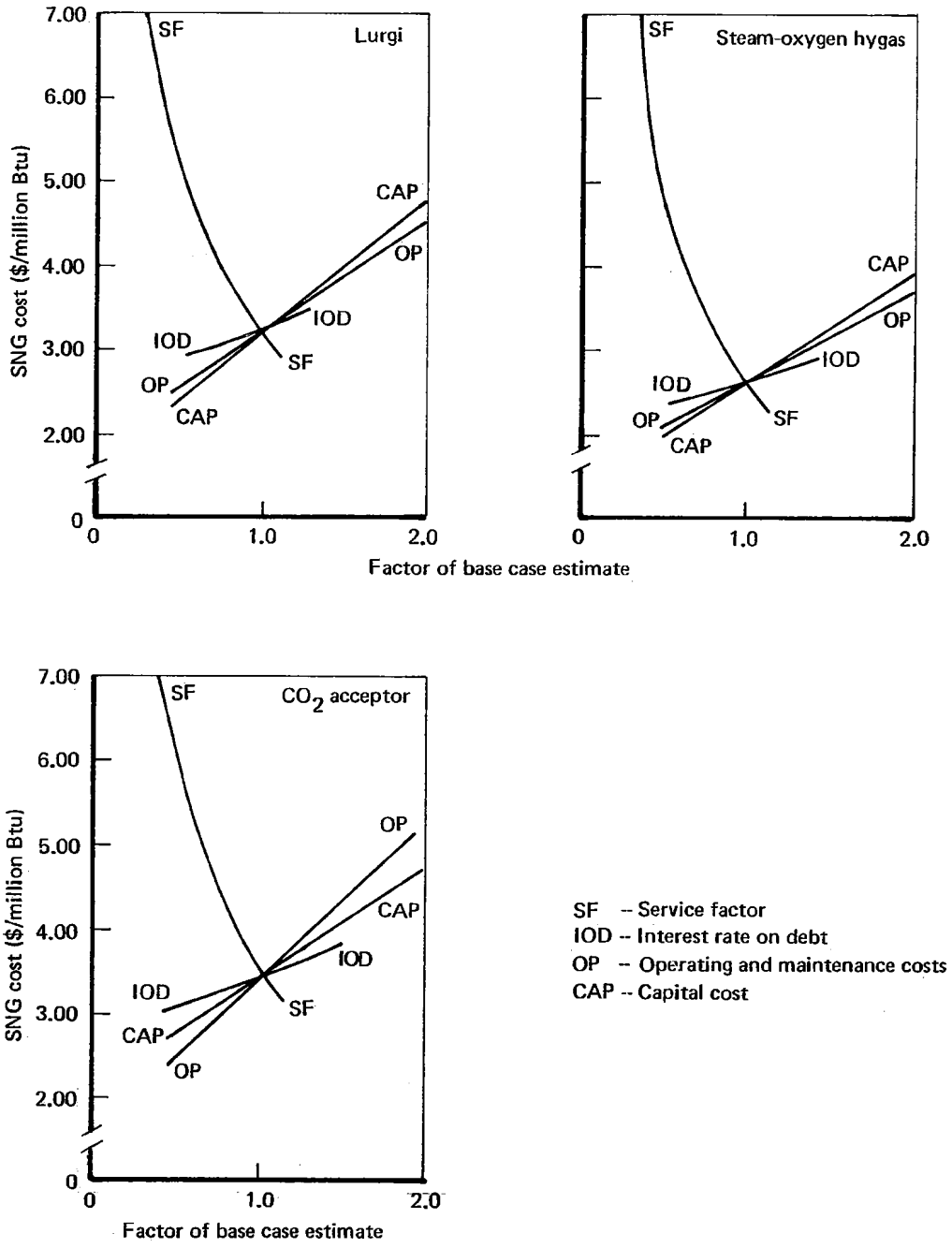

Fig. 2 — Summary sensitivity analysis results (in 1976 dollars)

Table 14

SNG COST SENSITIVITY TO INPUT ESTIMATES
(From base case, by process)

Input	Bigas	CO_2 Acceptor	Steam-Iron Hygas	Steam-Oxygen Hygas	Lurgi	Synthane[a]
Capital cost[b]	+0.44	+0.40	+0.48	+0.49	+0.48	+0.46
Operating cost[b]	+0.49	+0.54	+0.46	+0.43	+0.44	+0.45
Service factor[c]	-1.125	-1.125	-1.125	-1.125	-1.125	-1.125
Interest on debt[d]	+0.21	+0.20	+0.22	+0.25	+0.24	+0.23

[a]Slurry feed, export char.

[b]Using a +25 percent change from the base case assumption.

[c]Using a -11 percent change from the base case assumption.

[d]Using a -22 percent change from the base case assumption.

- For all processes, the insensitivity of the cost estimates to changes in the interest rate on debt indicates that government loan guarantees would not lower the cost of SNG from coal significantly.

The sensitivity of the SNG cost estimates to the assumptions used is especially evident for cases where the value of several different input assumptions are changed simultaneously. In the analyses reviewed above, only one input parameter is varied at a time. The impression may be given that important changes are possible but require major variations in the inputs. This is not necessarily the case. Even using identical methodologies for cost estimation, reasonable analysts could develop significantly different estimates because of differences in assumptions within a range which all parties might consider reasonable. Table 15 illustrates the major differences in SNG costs for two reasonable base cases with different input assumptions (see Table 14 footnotes). The reader will note that the order of the costs among the coal gasification processes does not change for the alternative assumptions, because of similarity in sensitivities. The real significance

Table 15

SNG COST ESTIMATES FOR COMPARATIVE BASE CASES[a] BY PROCESS

Process	Utility Method: Braun Base Case	Utility Method: Alternative Base Case
Lurgi	$3.30	$4.34
Hygas		
Steam-oxygen	2.71	3.56
Steam-iron	4.10	5.39
CO_2 Acceptor	3.38	4.45
Bigas	3.50	4.61
Synthane (slurry feed, export char)	3.70	4.86

SOURCES: Detman, *Factored Estimates*, and data from Appendix B.

[a]C. F. Braun and Co. and Appendix B alternative base cases. The Appendix B base case assumes an increase in capital and operating costs of 10 percent over the Braun case assumptions, a 75 percent service factor (Braun, 90 percent), a 9 percent interest on debt (Braun, the same), and a 15 percent return on equity (Braun, 12 percent).

of the alternative assumptions appears when alternative cost estimates are compared with the costs of competitive gaseous fuel sources listed in Table 5, p. 26. Clearly, consensus on the input assumptions is important to consensus on the SNG cost estimates.

A final point here is based upon the cost sensitivity data and current cost estimates. Some of the less mature processes, Bigas, Synthane, and Hygas (steam-iron), not only are already estimated to produce SNG costing more than SNG from the Lurgi process but also to exhibit very similar sensitivities to the input parameters examined. Parallel funding of such processes might make sense if no process were in hand. However, given the status of the Lurgi process, the rationale for the continued government support of development is less than clear.

This in no way suggests that government support of R&D for new processes should be lessened. The conversion of Lurgi to handle

eastern coal may be required. Nevertheless, such development would be unnecessarily expensive if it were carried on at the commercial scale.

ECONOMIC OUTLOOK

After this review of the current economic status of SNG-from-coal technology and our analysis of the sensitivity of SNG cost to input costs, it is useful to examine the outlook for future costs and consider the factors that tend to make SNG from coal more--or less--competitive economically.

In addition to the uncertainty associated with current estimates, several other factors can be expected to influence the relative economic attractiveness of the SNG-from-coal processes. They include trends in capital and operating costs, effects of learning and other technological improvements, and the potential for bottleneck problems.

Cost Trends

As has been discussed earlier, the product costs of the various SNG processes vary in their sensitivity to the costs of operation and of capital. Merrow points out that capital costs have been experiencing a real increase (i.e., above the rate of general inflation) of about 2 percent annually.[1] If real capital costs continue to increase, then the comparative cost relationship of various alternatives to SNG from coal would shift. Thus, if capital costs were to continue increasing at a rate above inflation for other factors related to natural gas and substitutes, then SNG from coal could improve its comparative advantage over electricity as a more capital intensive alternative but could lose ground compared to other gaseous fuels.[2]

Among the SNG-from-coal processes, a more capital intensive process would lose ground to a less capital intensive process. Fig. 3 illustrates the behavior of SNG costs for the Lurgi and CO_2 Acceptor processes. If real capital costs were to increase by about one-third,

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[1] Merrow, *Constraints*, Chapter II.

[2] Appendix D discusses the comparative capital requirements of SNG from coal and electricity.

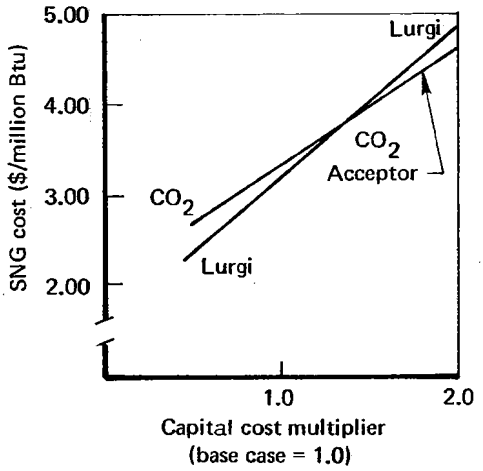

Fig. 3--Changes in the comparative costs of SNG from Lurgi and CO_2 Acceptor for changes in capital costs

the estimated cost for SNG from a CO_2 Acceptor plant would become lower than for a Lurgi plant. With similar cost sensitivity information on alternative coal gasification processes or alternatives to SNG from coal, similar illustrations could be developed to identify the cross-over points for other technologies compared to the high-Btu coal gasification processes considered here.

Contrary behavior would be observed for operating costs. That is, if operating costs were to increase faster than other input factors, then SNG from coal could improve its position relative to the other gaseous fuels. Similarly, within the SNG technologies, the Lurgi process could improve its position relative to the Hygas and CO_2 Acceptor processes in the face of higher than normal operating cost increases, especially if utility financing is used.

Learning and Innovation Effects

Both future learning and technological innovation could improve the cost picture for the SNG from coal processes.

"Learning" refers to an inverse relationship between the cumulative number of units of an item produced and the unit cost of production. Learning is most commonly discussed in terms of a log-linear

learning curve. This curve represents a constant percent decline in the unit cost for each doubling of production capacity completed. For instance, if 10 percent learning were assumed, the unit cost for the fourth plant would be 91 (.90 x .90) percent of that for the first unit. In related work on shale oil, Merrow provides a thorough discussion of the application of learning curve theory to energy process plants.[1] He concludes that learning is less pronounced for capital-intensive than for labor-intensive technologies and that a 10 percent learning factor represents the most optimistic figure that might be used "if other aspects of the technology's deployment are favorable to learning."

This 10 percent learning factor would be valid only in the case of new technology. Several components of coal gasification processes use well-established, mature technologies. Table 16 gives a breakdown by component of plant cost for the coal gasification plants. Major capital components, such as the "steam and utility steam" or "general facilities," involve little or no novel technology and no learning effects would be anticipated. The approximate share of plant costs[2] associated with novel technology for each process is as follows (based on data in Table 16):

Bigas	20%
CO_2 Acceptor	42%
Hygas (steam-iron)	48%
Hygas (steam-oxygen)	20%
Lurgi	26%
Synthane (slurry feed, export char)	21%

Since the learning effects are applicable only to the novel share of plant, it is clear that a learning factor much lower than 10 percent is actually an optimistic learning assumption for coal gasification plants. The differences in relative cost for various learning factors are illustrated in Fig. 4.

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[1] Merrow, *Constraints*, Section III.

[2] Includes coal preparation, Lurgi proprietary, coal feed, gasification and power recovery, raw gas quench, shift conversion, and methanation components.

Table 16

PLANT INVESTMENT SHARES, BY PLANT COMPONENT

(In percentages)

Component	Steam-Oxygen Hygas	Steam-Iron Hygas[a]	CO_2 Acceptor	Bigas	Synthane[b]	Lurgi[c]
Cold storage and reclaiming	1.5	1.0	1.5	1.3	0.9	1.3
Coal preparation	2.0	2.0	6.6	3.3	4.2	2.5
Lurgi proprietary	---	---	---	---	---	18.0
Coal feed	3.0	2.2	3.0	1.6	5.4	(d)
Gasification and power recovery	5.2	35.9	21.7	4.3	3.2	(d)
Raw gas quench	2.2	6.3	7.2	4.9	2.7	(d)
Shift conversion	3.6	---	---	3.1	3.5	(d)
Acid gas removal	12.4	5.9	4.0	11.1	8.5	11.0
Methanation	3.3	2.0	4.0	2.8	2.2	5.5
Sour water stripping, ammonia recovery, and bio-oxidation	6.7	5.3	2.0	3.6	2.8	1.8
Sulfur recovery	6.9	5.9	5.8	5.7	5.1	5.1
Solid disposal	7.0	0.6	1.0	0.9	0.6	0.3
Product gas drying	0.1	(e)	0.1	0.1	0.1	0.1
Steam and utility systems	15.6	0.9	11.2	17.9	23.3	16.8
Plant water systems	2.0	2.7	2.0	2.4	1.3	2.1
Oxygen plant	5.2	---	---	7.8	6.5	6.1
General facilities	7.8	7.8	7.8	7.8	7.8	7.8
Contractor's home office cost	8.5	8.7	8.6	8.8	8.7	8.8
Contingency	13.0	12.8	13.4	12.6	13.2	12.8
Total plant investment ($ million)	$870	$1,280	$890	$1,030	$1,500	$1,060

SOURCE: Detman, *Factored Estimates*.

[a]Export power case.

[b]Slurry feed, export char.

[c]Dual feed case.

[d]Included in Lurgi proprietary.

[e]Less than 0.05 percent.

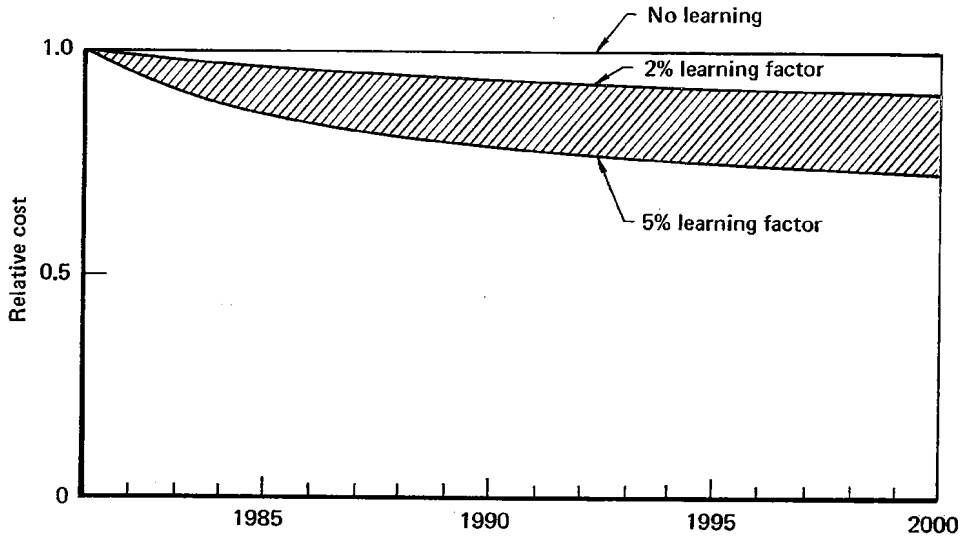

Fig. 4--Likely range of plant cost improvements as a function of learning factor and experience (general case, accelerated scenario as described in Section I, with all capacity built for the same process)

Related to learning effects is the issue of technological innovation. Technological breakthroughs are unpredictable and cannot reasonably be included in a projection of process economics. It may be difficult to distinguish incremental technological improvements from learning effects. Some evolutionary changes already suggested for the processes are good examples of incremental changes that can be anticipated for these processes. For instance, upon review of a Lurgi design requiring two sets of gasifiers, each with a different size range for the pieces of coal feed, Lurgi determined that a single feed configuration would be possible and would save on coal preparation and handling equipment.[1] In another case, slurry feed instead of dry feed and the export of char instead of power were found to be superior economically for the Synthane process. The resultant savings are summarized in Table 17.

[1]Detman, *Factored Estimates*, pp. 27-28.

Table 17

ILLUSTRATIVE INCREMENTAL SAVING THROUGH TECHNOLOGICAL IMPROVEMENTS

Process	Gas Cost — Average (Utility)	Gas Cost — Constant (Private)
Lurgi		
Dual feed	$3.30/MMBtu	$4.71/MMBtu
Single feed	$3.22/MMBtu	$4.62/MMBtu
Saving	2%	2%
Synthane		
Dry feed, export power	$4.69/MMBtu	$6.72/MMBtu
Slurry feed, export char	$3.70/MMBtu	$5.25/MMBtu
Saving	21%	22%

SOURCE: Detman, *Factored Estimates*, pp. 27-28.

Thus, improvements in the cost of SNG from coal can be expected from learning and technological improvements. However, these improvements are unlikely to be large; an optimistic estimate of learning would be in the 2 to 5 percent range. Government policy should take a close look at any forecasts of major decreases in real costs of high-Btu coal gasification facilities (such as suggestions that learning could cancel the effects of inflation).

It should be noted again that technological breakthroughs are not included in learning effects and have not been addressed here. There is always a chance that an unforeseen technological breakthrough will reduce costs significantly. However, the approach taken here assumes that although government support of research should anticipate such breakthroughs, justifying government support of commercialization efforts on the basis of such breakthroughs makes less sense.

Technological innovations may also open up ways to use entirely new processes. For instance, research on the use of catalysts in coal gasification could lead to third generation processes capable of producing SNG from coal at significantly reduced costs. Nevertheless, there is no reason to expect the commercialization of currently developed processes to accelerate the development of third generation coal gasification technology. In fact, if resources available for coal

gasification are limited, relatively expensive commercialization activities could be expected to decrease the funds available for R&D on new processes with potentially superior cost characteristics.

IMPLICATIONS

This analysis finds that high-Btu coal gasification plants could be economically operated in the private sector only at prices at least 90 percent higher than the current price of interstate natural gas. Moreover, with the possible exception of the Lurgi process, significant uncertainty remains concerning the cost of SNG produced by coal gasification. As the process modifications discussed earlier indicate, cost decreases are certainly possible. However, experience suggests that cost estimate increases should be expected, especially for the less mature, i.e., non-Lurgi, processes. Therefore, given the current status of the gaseous fuel market and of high-Btu coal gasification economics, commercialization is not likely without large government subsidies.

A comparison with one non-gas form of energy at the point of consumption has been included in this analysis because at present the major use of domestic coal is to produce electricity, and federal policy has sought to increase coal consumption. Recent economic analyses indicate that high-Btu coal gasification is at least potentially attractive compared to the generation of electricity from coal for such residential and commercial end uses as space heating, cooking, water heating, and clothes drying.

Even if coal gasification were an economically superior source of gaseous fuel to supplement the interstate supplies of natural gas available under regulation, additional conventionally supplied natural gas could be made available as a result of regulatory changes as long as the regulated price were below the cost of SNG produced from coal. Regulatory issues and other institutional problems are examined in the next chapter.

III. INSTITUTIONAL ISSUES

Major technological innovations such as SNG production from coal affect and are affected by an environment broader than the R&D community developing the technology. Others whose cooperation is often required before an innovation can be commercialized include the producers; financiers for the producers' facilities; economic, health, safety, and environmental regulators; product distributors; and ultimate users. This section examines the issues associated with implementing high-Btu coal gasification technology within an institutional environment. These issues would become important only if ways were found to overcome the economic problems addressed in the previous section or if energy prices were to increase rapidly.

High-Btu coal gasification must integrate in some way with the natural gas delivery and use system. This system is characterized by significant economic regulation at the state and federal levels. The Federal Energy Regulatory Commission regulates the interstate activities of the natural gas pipeline companies and state public utility commissions regulate the local gas utilities (distributors). The natural gas industry has required little plant investment to date (less than $15 billion for the ten largest interstate pipeline companies--see Table 18), and thus, capital financing and the resulting links to sources of significant capital have not been important. Other important components of this system are the consumers, the manufacturers of gas appliances, and the servicers of those appliances. The integration of coal gasification into this system will generate major changes, and these are discussed in the following subsections.

A large set of environmental issues concerned with the land, air, water, and social infrastructure is also associated with the creation of a coal gasification industry. These environmental issues are addressed as well.

Table 18

COMPARISON OF SNG PLANT AND TEN LARGEST[a] INTERSTATE NATURAL GAS PIPELINE COMPANIES

	Volume Sold[a] (billion cf)	Total Gas Utility Plant in Service[b] ($ millions)	Percentage of 1975 Base Represented by SNG Plant of Plant in Service[b]	Percentage of 1975 Base Represented by SNG Plant of Volume Sold[c]
	(1)	(2)	(3)	(4)
El Paso Natural Gas Co.	1,232	1,915	63	6.7
Tenneco, Inc.	1,097	2,135	56	7.5
Natural Gas Pipeline Co. of America	1,038	1,460	82	7.9
Columbia Gas Transmission Co.	1,026	1,199	100	8.0
United Gas Pipeline Co.	873	628	191	9.4
Northern Natural Gas Co.	854	1,431	84	9.6
Michigan-Wisconsin Pipeline Co.	785	1,317	91	10.5
Texas Eastern Transmission Corp.	731	1,695	71	11.2
Transcontinental Gas Pipeline Corp.	689	1,716	70	11.9
Southern Natural Gas Co.	658	736	163	12.5
Unweighted Average	898	1,423	97	9.5

[a]FPC, *Statistics of Interstate Natural Gas Pipeline Companies, 1975*, FPC-S-257, Washington, D.C.

[b]Assumes a plant cost of $1.2 billion.

[c]Assumes a 250 million cfd plant operating at a 90 percent service factor.

GAS SUPPLY INDUSTRY CHANGES

The commercialization of coal gasification would bring a major change in the nature of the inudstry presently supplying natural gas. Coal gasification on a large scale would shift this industry from an exploration, transportation, and distribution system based on relatively low capital investments towards a major capital intensive process industry.

Table 18 lists the ten largest interstate natural gas pipeline companies by total volume of sales to all sources. Colume (2) shows the values of their total gas utility plant in service for 1975. The largest value was $2.1 billion, and the average for these ten largest

companies was about $1.4 billion. These relatively low figures for the value of plant in service are especially striking when compared with a recent estimate of $1.2 billion for a 250 million cf per day Lurgi coal gasification plant.[1] Column (3) shows this Lurgi plant cost as a percentage of the 1975 plant in service. Even for these ten largest companies, the minimum plant fraction for the SNG facility exceeds one half.[2] Another important factor is the relatively modest increase in supply capacity that one of these commercial scale SNG plants represents. Column (4) presents the percentage of the 1975 sales volume that would be produced by a 250 million cfd Lurgi plant operating at 90 percent service factor. The average (unweighted) effect would be an increase of less than one-tenth, and the increase for the tenth largest company would be only one-eighth.

Thus the investment required would be large, both absolutely and relatively, and long construction periods would be required. Moreover, the existing interstate gas-pipeline companies would find it difficult to arrange financing for such plants within their present debt structure. The debt-to-capitalization ratio of major Class A and B pipeline companies for 1971-1975, the most recent five years for which statistics were available, is as follows:[3]

	Debt-to-Capitalization Ratio
1971	0.68
1972	0.67
1973	0.61
1974	0.59
1975	0.59

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[1] See Table 7, p. 28.

[2] The plant investment is large in almost any relative sense. For instance, with a single $1.2 billion SNG-from-coal facility, a company would rank No. 153 in terms of assets on the Fortune 500 list of industrial corporations. See "The Fortune Directory of the 500 Largest U.S. Industrial Corporations," *Fortune*, May 1977, pp. 364-389.

[3] FPC, *Statistics of Interstate Natural Gas Pipeline Companies, 1975.*

These data show an industry heavily dependent upon borrowing. The extent of borrowing has led to lower bond ratings for some transmission companies, beginning as early as 1972.[1] Declining natural gas reserves have also helped weaken the financial status of gas companies.

In addition to changes in the financial structure of the gas industry, the commercialization of gas-from-coal technologies would lead to major changes in its physical structure. The gas industry began as a decentralized set of local plants converting coal into a low-heating-value gas. As natural gas became exploitable through improvements in pipe and storage technology and as demand for natural gas exceeded the supplies available as a joint product of petroleum extraction, natural gas companies added exploration and production efforts to their gathering, storage, and transmission activity. This led to a national network of natural gas pipelines and to the end of locally manufactured gas.[2]

Commercialization of coal gasification processes would require another important change in the nature of the gas supply industry. As shown, one commercial size (250 million cfd) coal gasification plant can supply about 10 percent of the present gas requirements of the largest natural gas pipeline companies. Yet, such a plant is a very large facility, requiring as much as 29,000 tons of coal per day.[3] Hence the pipeline companies would have to become handlers of great masses of solid bulk material in addition to being handlers of gaseous fluids.

These plants would also add another major function to the present logistics functions of the pipeline industry. Large scale implementation of coal gasification would transform the industry into a major processing industry. The operation and maintenance of process plants would require new types of personnel with new skills.

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[1] Rex T. Ellington, "Problems in Financing Synthetic Fuel Plants Will be Complex," *Coal Age*, September 1972, p. 107.

[2] There are some local SNG-from-naphtha plants to help with peak loads, but these are not the same as the old (lower Btu) gas plants.

[3] Detman, *Factored Estimates*, p. 75.

It should be noted that although these transition barriers are far from trivial, there is no reason to view them as insurmountable. There has already been movement of the pipeline companies into the ownership and operation of coal mines and into the capital-intensive supply alternative of liquefied natural gas (LNG). The Panhandle Eastern Pipeline Company is an example of a company successfully diversifying into these other areas of the energy supply business.[1] In addition, firms more familiar with process industries might seek entry to the coal gasification industry if its prospects for profits were attractive.

Other potential candidates for supplying SNG through coal gasification could include oil companies, other energy firms, or chemical companies. To date, however, only pipeline companies and local gas utilities have expressed a serious interest in SNG-from-coal projects. Most firms plan moves into significantly different markets only when greater-than-average returns can be anticipated. The current economic status of coal gasification, reviewed in the previous chapter, makes such returns unlikely at present. Even if the cost of SNG from coal became competitive enough to attract the interest of other industries, concerns about pressures for horizontal divestiture and the regulatory nature of the gas supply industry would also be likely to cause additional hesitation.

FEDERAL REGULATION

The commercialization of coal gasification must take place within an energy production system subject to significant federal regulation. This regulation is both economic and environmental.

Economic Regulation

The federal government has imposed economic regulation on the natural gas industry since the Natural Gas Act of 1938. On the other hand, the "manufacture of gas from coal has a long and extensive history

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[1]Deborah Waroff, "Changing Face of the Gas Pipelines," *Energy Daily*, July 13, 1977, pp. 2-3.

of non-regulation by the FPC."[1] Thus, the Federal Power Commission has ruled that it has no jurisdiction over SNG production facilities.[2]

There have been efforts on the part of gas companies to obtain FPC authorization in the form of certificates of public convenience and necessity.[3] The federal jurisdiction that would be established by the issuance of these certificates has been desired by the gas companies. One reason for filings with the FPC was a desire on the part of parent companies for FPC assurance that regulated rates would reflect synthetic gas cost-of-service rates. Another reason was local distributors' interest in rulings about allocation of the high per unit cost of SNG among distribution companies. These issues have already been resolved for a case involving SNG from naphtha.[4] There the Administrative Law Judge decided to issue a certificate of public convenience and necessity to the pipeline-company parent of the SNG subsidiary to transport and sell a mixture of SNG and natural gas and attach conditions allocating the costs of SNG among distributor customers of the transmission company.[5]

The FPC authorization that has resulted from these regulatory decisions is required for (1) building a connection to an existing natural gas pipeline, (2) transporting and selling SNG commingled with natural gas, and (3) setting rates that companies would be permitted to charge for the gas.[6] The basis for the SNG tariffs must also be determined. Because there is an element of technological uncertainty associated with SNG from coal, those promoting high-Btu coal gasification have

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[1] FPC, *National Gas Survey*, p. 639.

[2] The proposed National Energy Act would extend FPC (now the Federal Energy Regulatory Commission) jurisdiction to SNG plants.

[3] For instance, Wesco, a consortium trying to build a coal gasification plant, wanted the FPC to have authority over gasification plants and contested the FPC's decision that it did not have jurisdiction over SNG plants, but the District of Columbia Circuit Court sustained the decision in July 1975.

[4] *Algonquin SNG, Inc., et al.*, FPC, Dockets CP72-35 et al., March 28, 1972.

[5] FPC, *National Gas Survey*, pp. 638-639.

[6] GAO, *Status and Obstacles*, p. 25.

sought "all events tariffs" under which consumers would pay for plants even if no SNG were ever produced. The FPC has been unwilling to approve such a tariff.

There are also rate design issues, e.g., whether incremental rates or "rolled-in" rates would be approved for SNG. Incremental pricing would set the price of supplemental units of the gas at the incremental cost of supply for customers who would otherwise receive no gas. Rolled-in rates would set the price for all units of gas at the average cost of gas production. No potential operator of an SNG-from-coal plant has yet obtained a satisfactory tariff or other governmental support arrangement.

Environmental Regulation

The federal regulatory structure also involves environmental protection. Current federal environmental regulations do not appear to pose a serious problem for SNG production because the pollutants emitted are low in an absolute sense and the environmental effects of an SNG plant are significantly lower than for other energy conversion processes, such as the conversion of coal to electricity.

Plant Environmental Issues. The potential damage to the environment by an SNG facility can be discussed in terms of (1) solid wastes, (2) water, or (3) air. The following paragraphs describe the design standards used in the development of the base case SNG cost figures used in the C. F. Braun and Co. analysis.

Little degradation of water quality should result from the operation of an SNG-from-coal plant. All effluent water would be treated and either returned to the process for reuse, discarded with solid waste, or used to control dust.[1] The more important environmental issue associated with SNG production is the volume of water consumed. SNG production does consume a great deal of water. The daily net consumption figures for 250 million cfd Lurgi, Hygas, and CO_2 Acceptor SNG plants are estimated at 10.7 acre-feet, 8.3 acre-feet, and 10.1 acre-feet, respectively. Nevertheless, if some form of energy development is

[1]Detman, *Factored Estimates*, Appendix, p. 6.

undertaken, SNG production would use significantly less water than likely alternatives. For instance, it has been estimated that SNG would require about one-quarter to one-half the water consumed for various options of electricity generation to produce equivalent amounts of useful energy.[1] Other studies have come to similar or more dramatic conclusions about comparative water use. In addition, the results of the sensitivity analysis indicate that even a very high priced solution to the water supply problem should not have a major effect on the cost of the SNG produced. Nevertheless, there is the possibility of prohibitions on the use of water for energy development, a topic that will be discussed in the subsection on state and local regulation.

In the basic plant design assumptions, non-toxic solid waste would be returned to the mine at western sites and used for land fill at eastern sites. Toxic solids would have to be treated to "an acceptable limit" prior to disposal.[2] These toxic coal wastes do represent a serious environmental problem for which regulations are being developed.

Other environmental effects that might result from SNG plant operation relate to air quality. Three kinds of emission can be considered: (1) boiler emissions, (2) process sulphur emissions, and (3) fugitive emissions. The design assumptions used for boiler emissions are based upon a federal regulation for fossil-fuel-fired steam generators having a heat input in excess of 250 million Btu per hour.[3] The recovery of sulphur from the process stream would be accomplished by the Stretford or other sulphur recovery processes.[4] The design assumptions are aimed at sulphur recovery "equivalent to a Claus plant plus a tail gas treating plant," with 99.8 percent of the input sulphur recovered.[5] The fugitive emissions are dust emissions and miscellaneous gas emissions.

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[1] Harral, "A Comparison of Energy Options," p. 21.

[2] Detman, *Factored Estimates*, Appendix, p. 6.

[3] Part 60, Chapter 1, Title 40, Code of Federal Regulations. The maximum emissions in pounds per million Btu heat input are 1.2 of SO_2, 0.7 of NO_2, and 0.1 of particulates.

[4] K. C. Vyas and W. W. Bodle, *Costs of Synthetic Fuels from Coal and Oil Shale*, Institute of Gas Technology, August 1974, p. 40.

[5] Detman, *Factored Estimates*, p. 7.

Coal dust results from coal crushing equipment, conveyor belts, lock hoppers, and other solids-handling equipment and is controlled by such treatments as cyclone separators, bag filters, and scrubbing.[1] For miscellaneous gas emissions, the basic design assumes the inclusion of scrubbing devices on all gas streams containing particulates. Emission levels of other gas stream sources, such as gas-fired turbines, heaters, or incinerators, are below pollution standards.[2]

The air pollutant emissions from SNG-from-coal plants are significantly lower than for coal-fired electric generating plants. The American Gas Association cites a study prepared for the President's Council on Environmental Quality (CEQ) which stated that, among equivalent-size plants, coal gasification produced only one-tenth as much pollution as other processes.[3] Another study, for the Federal Energy Administration, concluded that none of the proposed SNG facilities would be required to change sites by the 1977 amendments to the Clean Air Act. In fact, this study estimated that for plants meeting new source performance standards (NSPS), several could be located in the same area in flat or moderate terrain without exceeding Class II (standard class) pollution standards. There would be some constraints in hilly terrain or near Class I (pristine quality) areas.[4] Although emissions from the pollutants for which standards are set would be lower than required, little scientific information has been developed about the effects of some plant emissions, which include organic and heavy metal pollutants. If levels of such pollutants were found to be harmful, new environmental obstacles could develop.

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[1] Vyas and Bodle, *Costs of Synthetic Fuels*, p. 40.

[2] Environmental Research and Technology, Inc., *Impact Assessment of Significant Deterioration Amendments to the Clean Air Act on Siting of Synthetic Fuel Plants*, prepared for the Federal Energy Administration, P-2125-300.

[3] Radian Corp., *A Western Regional Development Study: Primary Impacts*, prepared for CEQ, August 1975, cited in American Gas Association, *A Comparison of Coal Use for Gasification Versus Electrification*, Planning and Analysis Group, April 4, 1977, p. 6.

[4] Environmental Research and Technology, Inc., *Impact Assessment*, Attachment C, pp. 7-11.

Mining Environmental Issues. SNG production would require large amounts of coal. For instance, one estimate of the mine capacity required to supply a 250-million-cfd plant with western sub-bituminous coal is 8 million tons per year.[1] All the general issues about the mining of coal are relevant to SNG commercialization; however, it would not be productive to restate these issues here. If a commitment is made to develop U.S. coal resources, then the following points are important to mining in support of SNG production.

The production of SNG, for the residential and commercial end purposes described earlier, uses the energy embodied in coal more efficiently than does the production of electricity; for this reason, equivalent useful fuel could be supplied through SNG production with less coal mined. Pacific Gas and Electric's comparative analysis estimated that about 22 percent less surface area would be strip-mined if, for a set of typical residential end uses, energy needs were met with SNG from coal (even with pilot-light appliances) than with electricity from coal.[2] Thus, even though SNG would involve large absolute environmental disruption from associated mining operations, there does appear to be an advantage over electricity production.

A related issue is the cost of coal mined for SNG production. When earlier cost estimates were made for SNG production, the feedstock cost was a dominent item and SNG cost estimates were very sensitive to the cost of coal.[3] However, capital costs have become increasingly important to the cost of SNG; therefore, while any added costs of mining coal to meet environmental requirements would still be important, they would be relatively less so for current than for earlier estimates.

Other Federal Regulation

Other federal regulations may also apply to an SNG industry. The Interstate Commerce Commission (ICC) has jurisdiction over any interstate transportation of liquids, which would include natural gas liquids

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[1] FPC, *National Gas Survey*, p. 498.

[2] Harral et al., "Comparison of Energy Options," p. 21.

[3] FPC, *National Gas Survey*, p. 639.

or water. Any transported coal would be moved by ICC-regulated common carriers, either barges or railroads. Mining operations are covered by federal health and safety regulations. There are also federal regulations for the use, storage, and (in many cases) manufacture of explosives in connection with mining operations.[1] These regulatory systems are not expected to be important obstacles to the commercialization of high-Btu coal gasification prior to the resolution of the economic obstacles.

STATE AND LOCAL REGULATION

State and local regulation of SNG activities would occur at both the point of production and the point of consumption.

At the site of the SNG plant and associated mine, the regulatory tools used by state and local authorities could be classified as health, safety, environmental, or economic, but because any of these types of regulations might be used for related goals, they are discussed together here. An example should clarify what is meant by the use of one type of regulation to attain another type of goal. Thus, an effort is being made in Dunn County, N. Dak., to have the county designated as a Class I air quality region. If this were accomplished, the air quality would have to be maintained in a pristine state, and this would disrupt plans for a coal gasification plant planned for the county. A leader in the fight for redesignation made it clear that general concern about energy development rather than about air quality in particular led to the request for redesignation.[2]

State and local concerns with SNG production include worker safety, reclamation of the land, environmental protection issues, and the socio-economic disruption resulting from energy development. Although there is concern about all these issues, the potential effects of large-scale energy development activities on an isolated area appear to dominate. The potential for massive disruption is illustrated by an FPC estimate that one 250 million cfd SNG plant using western sub-bituminous coal could disrupt up to 1,600 acres of land at a time (including land in

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[1] Ibid., p. 640-642.

[2] Dan Whipple, "Locals Take up Clean Air Act to Stop North Dakota Coal Gasification," *Energy Daily*, March 29, 1977, p. 2.

various stages of reclamation), increase population by about 16,000, and increase annual income by more than $12 million.[1] State and local governments have a major stake in controlling such massive development, and it is not surprising that any regulatory tools available might be used to control energy development affecting their areas.

The large site-specific effects of energy development include new demands for roads, sewers, schools, public safety, and other community services. To cover the costs of such social infrastructure and other requirements, states are moving to impose development restrictions and significant severance taxes on the mining of minerals exported from their boundaries. Restrictions suggested by western states include prohibiting process plant construction at the mine site and restricting exported converted energy, although coal mining would be allowed. Severance taxes as high as one-third of value have been mentioned;[2] Montana's severance tax rate is 30 percent.

In addition to severance taxes, state coal mining regulations address health, safety, and reclamation standards, and for the most part, overlap federal regulations.[3] As of 1975, New Mexico's air pollution regulations, passed in anticipation of two Lurgi SNG plants scheduled for construction in that state, were the most comprehensive regulations in effect for such facilities.[4] The extent to which state and local governments may impose environmental protection requirements exceeding federal standards is an unresolved issue.[5]

The regulation of water rights is another area where states may impose constraints tighter than those of the federal government. For instance, if willingness to pay were the criterion used to judge the best uses of water, energy development would probably be able to obtain the water necessary for operation. In fact, energy developers have

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[1]FPC, *National Gas Survey*, pp. 498-499.

[2]"Coal Taxes Up in North Dakota," *Energy Daily*, May 11, 1977, p. 4.

[3]Ibid., p. 642.

[4]E. S. Rubin and F. C. McMichael, "Impact of Regulations on Coal Conversion Plants," *Environment Science and Technology*, February 1975, pp. 114-115.

[5]FPC, *National Gas Survey*, p. 653.

already paid far more for water rights than have farmers in at least one western state.[1] Yet Colorado has indicated that it will not allow water to be diverted to energy uses from federal water projects.[2] This particular action would affect oil shale more than coal gasification, but it does illustrate how state-level prohibitions might pose a problem not subject to economic solutions.

The availability of water supplies is an important problem for all energy supply options. Although the prohibition of water use for coal conversion could prevent commercialization of coal gasification in any area under such prohibitions, the sensitivity analysis presented earlier indicates that there is opportunity for negotiating relatively high cost solutions to the water problem because of the low sensitivity of SNG costs to water prices.

Local governments have also used zoning to influence energy development. The validity of zoning regulations for federally controlled lands is unlikely to be upheld, but the Department of the Interior has chosen to avoid the issue so far by acquiescing.

In summary, state and local regulatory efforts aimed at SNG production appear to pose potential problems for SNG development, but these are likely to delay, rather than prevent, development. If the economics of SNG were favorable, such delays might be less formidable problems.

At the consumption end of the pipeline, state and local regulation of pure SNG, or natural gas/SNG mixtures, would cover all aspects of retail sales. The local gas distribution companies are public utilities, and local regulation has been in effect since the period when only manufactured gas was available. The aspects of the retail gas business that are regulated include price, pressure, heating value, purity, odor, construction and placement of pipelines and other equipment, consumption measurement, service requirements, and promotional activities.[3]

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[1] $50 per acre-foot versus $20 per acre-foot; see Charles E. Calef, *Water Availability for Energy in the Western U.S.: An Overview of Issues*, Brookhaven National Laboratory, 1977, p. 8.

[2] Merrow, *Constraints*, Section IV.

[3] FPC, *National Gas Survey*, p. 642.

A potential area for minor problems arising from local regulation is the definition of acceptable quality for the SNG product. The discussion of the substitutability of SNG for natural gas later in this paper points out that tradeoffs are possible among the important characteristics of the SNG. Thus, if a local authority were to emphasize maintenance of exactly the same heating value per volume and ignore some other performance parameters, the SNG supplied might meet the heating value requirement, but the flame produced might have a tendency to lift, i.e., the flame could rise above the gas fixture. Again, this is only a potential problem area, and should be easily averted through communication among the appropriate parties of the necessary information.

So far, no major problems have been identified that would prevent an economically attractive SNG product from being distributed in regulated localities.

EFFECTS OF FRAGMENTATION

The state public utility commissions (PUCs) operate independently of the FPC. This autonomy could stimulate SNG production problems. For instance, the California PUC, in promoting federal assistance for coal gasification facilities, has discussed the imposition of a guaranteed price ceiling on SNG to protect consumers from high prices. The reaction of a firm considering construction of an SNG project aimed at the California market was that they would probably not proceed with the project if there were not a good indication that full costs could be passed on to the California consumers.[1]

SNG-from-coal projects must also obtain numerous permits and licenses to comply with all the regulations discussed above, and the time required to comply with these procedures can be a problem in and of itself. However, these problems are present for all energy projects.

OTHER POTENTIALLY IMPORTANT COMPONENTS

In addition to the firms directly involved in the production, transportation, and distribution of SNG, and the agencies that impose

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[1]GAO, *Status and Obstacles*, p. 26.

economic regulation, other components can play important parts in the economics of commercialization. In particular, financing institutions are likely to influence the evolution of the SNG industry in important ways.

The cooperation of financial institutions is required to provide the funds for the construction of coal gasification plants and other supporting facilities. Financing is a critical step in the commercialization process, and it has not yet been completed for any project because lenders are not seeking the type of risky investment that SNG-from-coal projects currently represent. Lack of financing is frequently mentioned as the one major barrier remaining to commercial production of SNG from coal.

PRODUCT CHARACTERISTICS

In the discussions above, it has been assumed that gas produced from coal can be substituted for natural gas. However, the requirements for making this synthetic fuel completely interchangeable with natural gas are not trivial, and without substitutability significant changes in the gas appliance manufacture and maintenance industries, and in consumer behavior, could be necessary. Interchangeability requirements may differ according to how the gas is used (i.e., as a fuel or a feedstock). In 1970, more than 99 percent of American gas customers used natural gas as a fuel.[1] Therefore, the interchangeability requirements of importance here are those for consumption of the gas as a fuel.[2]

The properties of SNG sought are those that will least change the performance of gas appliances using the substitutes. To be substitutable, it is important that SNG provide similar heat inputs, good flame stability, and complete combustion, without requiring appliance adjustments. Substitutability is assessed by evaluating the physical

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[1] AGA statistics cited in George Long, "Quality Requirements for Substitute Gas," *AGA Monthly*, June 1972, p. 32.

[2] Long points out that other cases can be handled individually when necessary.

characteristics of gas.[1] In testing gas formed to duplicate the expected composition of SNG from the Hygas process (93 percent methane, 6.5 percent hydrogen, with a heating value of 968 Btu/cf), all the indices other than the lifting index were well within the preferred range for substitution. The flame from SNG had a slight tendency to lift, and this was confirmed in combustion tests. However, the lifting was very slight, and the gas was considered interchangeable.[2]

Complications might arise if certain heating value regulations are imposed by PUCs or other regulatory bodies. For instance, in one test of SNG from naphtha gasification, the product gas was enriched with ethane to raise the heating value from the produced level of 869 Btu/cf to an assumed regulated minimum value (here, 1030 Btu/cf). This enrichment caused the SNG to burn inefficiently; however, this tendency was not considered severe enough to be objectionable.[3] Nevertheless, this phenomenon illustrates the potential for problems if regulations to protect consumers from "inferior" products do not take all the important gas characteristics into account.

INDUSTRIAL CONSUMERS

The characteristics of the institutional environment described above are generally viewed as potential obstacles to the commercialization of SNG-from-coal processes. However, at least one institutional characteristic is favorable: the high value placed on the availability of gaseous fuels by some industrial consumers. Industrial consumers are much more likely to develop medium or low-Btu sources of gas from coal, but it is worth making the point here that premium prices can be obtained for assured supplies of clean gaseous fuels.

A quotation from the director of General Motors' energy management section illustrates this point well, ". . . we'll pay, if we have to,

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[1] The AGA uses the following indices to describe the physical characteristics of the gas: the Wobbe Number (heating value divided by the square root of specific gravity), the lifting index (I_L), the flashback index (I_F), and the yellow-tip index (I_Y).

[2] Long, "Quality Requirements," p. 33.

[3] Ibid., p. 33.

twice the intrastate price. We must have the gas. The old yardstick of return on investment doesn't always apply with regard to energy." General Motors has in fact secured a gas supply by operating its own 35,000-acre natural gas field. Other automobile manufacturers are similarly concerned about gas supplies.[1] If such industrial consumers can assure gas supplies by purchases of SNG from coal, commercialization of high-Btu coal gasification will be promoted.[2]

IMPLICATIONS

Coal gasification technologies would have to be commercialized in a highly regulated environment. Therefore, even if the economics of SNG from coal were superior to alternatives, the government should not expect widespread adoption to occur solely on the basis of market forces.[3]

The industry primarily responsible for gas development and transmission would change drastically if high-Btu coal gasification were commercialized. These natural gas pipeline companies would be required to become much more capital-intensive, and the local distributor utilities would also be required to join in this effort. One commercial-size SNG-from-coal facility would almost double the size of assets, on the average, of the ten largest natural gas pipeline companies but would increase the volume of available gas by only 10 percent--an extreme "lumpiness" that can be expected to provide an important problem for diffusion of high-Btu coal gasification technology. The difficulties associated with this problem are likely to be exacerbated by the borrowing problems most pipeline companies face because of the large relative debt they already have and their already weak financial positions. Government promotion of SNG-from-coal commercialization would have to give attention to this transition.

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[1] Janet Kreilling, "Painful Lesson in Self-Reliance for U.S. Automakers," *Technology Review*, March/April 1977, pp. 12-13.

[2] With dedicated lines containing no natural gas, SNG from coal projects could operate on a nonregulated basis.

[3] It is difficult to estimate the relative importance of market versus non-market forces in cases such as SNG from coal where both sets of forces operate against implementation.

No economic regulatory position satisfactory to all the interested parties has yet been developed. Both the financing problems just mentioned and the technological uncertainty discussed earlier hinder the resolution of problems in this area. Other economic regulation issues, such as assignment of risk, cost allocation, and rate design, have already been resolved with regard to LNG and SNG from naphtha; the results are likely to be transferrable. The need for additional special government intervention to overcome the remaining regulatory problems has not been conclusively demonstrated, and a decision on this matter should await further resolution of the technological (and consequently, cost) uncertainty.

Problems may arise from federal environmental regulations; however, SNG-from-coal is less harmful than other large-scale energy conversion technologies. Feedstock cost increases caused by environmental regulations are not likely to cause major SNG cost increases. Such potential problems will be resolved on the basis of a national evaluation of energy versus environmental requirements rather than as a coal gasification issue.

State and local regulation overlaps federal regulation to some degree, but its primary goal at the supply end is to ameliorate the adverse effects of energy development on local economies. These effects appear to concern the timing of cash flows, since the net revenues to a community from development should be positive. That is, the costs to the local community to develop the infrastructure (schools, public safety, sewer systems, etc.) to support large energy projects would precede receipt of the taxes anticipated from the projects. If satisfactory borrowing cannot be arranged through the bond market, federal intervention may be necessary to prevent the shortage of pre- and early-development funds common to most energy development.

Federal intervention might also be necessary if state and local regulation were to prohibit SNG-from-coal facilities. There may be a need to coordinate federal and state regulation, especially at the level of state public utility commissions and the FERC. In the past, private interests have been able to develop workable arrangements for processes involving less technical and economic uncertainties. Other downstream

institutional problems that might be anticipated for a new type of fuel would not be relevant for high-Btu gas from coal because it is a near-perfect substitute for natural gas.

IV. CONCLUSION

OBSTACLES TO COMMERCIALIZATION

This analysis has examined the reasons why the private sector has been reluctant to undertake high-Btu coal gasification commercially. Technical, economic, and institutional barriers have been identified.

- o The estimated cost of SNG from coal is currently higher than the price of regulated natural gas.
- o Although the estimated cost of SNG from coal is within competitive range of other gaseous fuel substitutes, the technical and cost uncertainty is greater for coal gasification.
- o A large capital investment would be required for an SNG-from-coal project.
- o There is reluctance in the financial community to back SNG-from-coal projects.
- o Significant changes in the gas supply system would be required to commercialize high-Btu coal gasification.
- o The current regulatory approach to natural gas and SNG is not conducive to production expansion.

These obstacles have prevented existing private sector interest in coal gasification from proceeding to commercialization. The future, however, could bring more favorable conditions.

Current Economics

An analysis of comparative economic projections is beyond the scope of this work. In Section II, however, we concluded that with currently envisioned coal gasification technologies improvements in the costs of producing SNG are unlikely to be significant. Nevertheless, natural gas is likely to experience real cost increases in the future because of rising exploration and extraction costs, as well as regulatory changes. The likely cost of natural gas in an unregulated market has been the

subject of intense debate.[1] If the real price of natural gas grows, high-Btu coal gasification could eventually become economically competitive. If there were a 10 percent real annual rise in natural gas prices, the crossover could occur in the mid-1980s. Since lead times to develop mines and construct plants are on the order of five years, affirmative decisions to pursue commercial projects would have to be made soon in order to have SNG projects operating by 1985. However, private firms are not likely to take positive action given the uncertainties surrounding future economics of both natural gas and SNG.

Technical and Cost Uncertainty in a Regulated Environment

In considering the comparative economics of SNG, the importance of remaining uncertainties in the production of SNG from coal must be kept clearly in mind. Significant uncertainty is still associated with recent cost estimates, especially for the non-Lurgi processes, and the evidence presented in Section II strongly suggests that the probability distribution of this cost uncertainty is skewed in an upward direction.

Closely associated with this cost uncertainty is technological uncertainty about the production of SNG from coal. This study has shown that the cost implications of technological uncertainty are important and that cost estimates for SNG-from-coal have increased significantly as technological expertise has developed. The Lurgi process has been used commercially in Europe and Africa for over 20 years, but there are major differences between these and planned American commercial operations. Foreign experience has been on a smaller scale and has involved gas products of significantly lower heating values. The daily coal input to the South African Sasol coal gasification facility was reported in 1976 as about 3,500 tons,[2] with more recent estimates of about 6,600 tons; the daily coal requirements for the Lurgi plant design

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[1]Richard Myers, "Natural Gas," pp. 1-2.

[2]Neal P. Cochran, "Oil and Gas from Coal," *Scientific American*, Vol. 234, No. 5, May 1976, p. 24.

used throughout this report exceeds 29,000 tons.[1] High-Btu gas production has been demonstrated at the Westfield coal gasification facility in Scotland, but this demonstration was never operated on a continuing commercial basis. In addition, the properties of coal vary significantly among regions and even among seams in the same region. A Lurgi publication suggests the problems with coal to be the following: "Coal is a raw material of unique and variable nature and its properties have a major influence on the design of the gasifier, its operating method and the downstream units for gas conditioning and gas purification."[2] Finally, the lack of actual hands-on experience with a high-Btu coal gasification plant means that unforeseen technical problems may still surface.

Applications to the Federal Power Commission for all-events tariffs for SNG-from-coal projects, by which plant customers would be required to cover project costs even in the event of a technical failure, must be viewed as a sign that the gas companies involved, or the potential financiers, perceive technological uncertainty. The FPC, however, has ruled against all-events tariffs for proposed coal gasification facilities.[3] The progress of LNG projects, which require less domestic capital but produce gas fuels more expensive than presently estimated for SNG from coal, also suggests that risks for LNG technology--already used commercially, primarily abroad--are expected to be lower than for high-Btu coal gasification technology.[4]

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[1] Detman, *Factored Estimates*, p. 75.

[2] Paul F. Rudolph, "The Lurgi Process: The Route to SNG from Coal," presented at the Fourth Synthetic Pipeline Gas Symposium, Chicago, October 1972, p. 3.

[3] Gas companies have not been able to arrange project financing without such a tariff, and loan guarantees have been recommended by the industry. For example, see U.S. House of Representatives, Committee on Science and Technology, *Synthetic Fuel Loan Guarantees*, 94th Congress, Second Session, hearings on H.R. 12112, March 31, April 1, 6, 7, 8, 13, 1976, Volume I.

[4] It should be noted that there are other basic differences between an SNG project and an LNG project. For instance, recent Algerian LNG projects involve financial backing from the Export-Import Bank and the U.S. Maritime Administration. Also, the U.S. LNG facility was under FPC jurisdiction (as of October 1977 the Secretary of Energy was given jurisdiction over imports).

There are also institutional obstacles to commercialization. The FERC is willing to allow the recovery of costs for operable facilities producing new supplies of gaseous fuels, but unwilling to place the technical risk (i.e., the cost burden of a plant failure) on the gas consumers. The more important economic issue controlled by the FERC is the ceiling price for interstate natural gas. However, without data on the price elasticity of the supply and demand curves, it is difficult to determine whether the natural gas price harms or helps coal gasification. A simplistic illustration of two possible alternative outcomes from deregulation is presented in Fig. 5, in which S_{ng}, S_{sng}, and D_g represent the supply and demand curves. The left figure indicates that the free market price, P_{fm}, is below the price for SNG produced from coal, P_{sng}, and that deregulation would not aid the commercialization of high-Btu caol gasification. For the situation described in the right figure, the SNG price is below the free market price of natural gas, and deregulation would improve the prospects for commercialization of SNG from coal.

Environmental regulation may also affect coal gasification, but the analysis in Section II indicates that regulations, other than a ban on such activity, are not likely to have a major effect on SNG prospects.

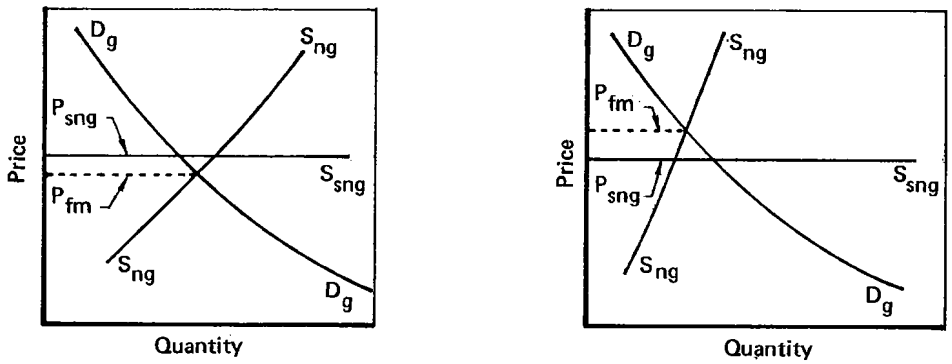

Fig. 5--Alternative deregulation scenarios

Capital Aggregation

Most of the obstacles discussed above can be related to technical and cost uncertainty; however, even if all these problems were solved, an important institutional obstacle would remain. The low levels of capitalization and the debt-to-equity ratios described in Section III, combined with the magnitude of the investment required, would still hinder satisfactory financing agreements between gas companies and potential investors.

Regulatory Philosophies

All these factors appear to be contributing to the inability of the gas industry to compete with the electric industry for new residential and commercial customers. Analyses comparing the present economics of base load sources of SNG from coal with electricity from coal indicate that for certain residential and commercial end uses,[1] the SNG alternative could provide base load energy at a lower cost per effective Btu than could electricity.[2]

However, the patterns of economic regulation for natural gas and for electricity appear to be fundamentally different. Electricity has been viewed as a producible good for which prices have been raised to cover the increasing costs of production. Natural gas has been viewed as a depletable and irreplaceable natural resource--which it is; but this perspective has wrongly been applied generally to gaseous fuels--although some can be produced. The effect of these different perspectives is especially interesting at the local regulation level. Local gas utilities have been treated, and appeared to have viewed themselves, as distributors with limited supplies. Therefore, the regulatory emphasis has been to prevent shortages by limiting expansion of gas service to new customers and to protect existing customers from excessive prices for the limited supplies. In contrast, local electric utilities

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[1]These are end uses requiring heat rather than physical work, e.g., the heat to dry clothes rather than the power to run the clothes dryer's motor.

[2]Harral, "Comparison of Energy Options," AGA, *Comparison of Coal Use*.

have been expanding at greater rates than might have been possible if gas utilities could have competed for new customers in the residential and commercial fuels market for space and water heating, cooking, and other end uses. The comparative analyses completed to date indicate that this regulatory structure has led to economic and energy inefficiency since high-Btu coal gas (and natural gas exceeding the price ceilings) could provide base load power for selected end uses more cheaply than electricity can.

One result of these differences has been that local electric utilities can build local *base load* power plants, transport coal to fuel these power plants, and sell the energy produced at prices higher than equivalent gas costs, but that local gas utilities have been limited in their search for additional gas supplies to *peak load* SNG or LNG facilities. No evidence was uncovered that local gas utilities have ever expanded their markets through SNG or LNG supplies of base load capacity. LNG facilities for which plans have recently been completed will be geared towards base load supplies, and some mention of offering new service because of conservation and these new supplies has appeared recently. Massive capital requirements and technological uncertainty appear to have kept local gas utilities from considering construction of SNG-from-coal facilities locally to provide base load expansion.

When the economic obstacles to the commercialization of coal gasification are viewed in this way, they appear to be primarily institutional problems, resulting in the main from government-imposed regulation of the electricity and gas industries. A regulatory approach toward high-Btu coal gasification based on a recognition of its production of a gaseous fuel rather than on its relation to depleted natural gas would be appropriate for current policymaking.

POLICY OPTIONS

Several policy instruments could be used to promote the commercial adoption of various SNG-from-coal processes. They include capital grants, price supports, operating subsidies, price deregulation, and loan guarantees.

These policy instruments could be used on a one-time or a continuing basis. On a one-time basis, they could stimulate demonstration activity that could overcome such obstacles to commercialization as the lack of hands-on experience with a process plant producing SNG from coal, other technological uncertainties, and the socioeconomic uncertainty associated with large energy project development in isolated areas. For obstacles such as poor economics, large capital requirements, or regulatory problems, intervention would presumably be on a continuing basis. A 250 million cfd plant is used in the following analysis to illustrate the magnitude of the economic disadvantages imposed upon coal gasification by current natural gas regulation.[1]

Capital Grants

Given current coal prices, the cost of producing SNG by the Lurgi process, without including any cost of capital, is estimated to be $1.38 per MBtu, very close to the current ceiling price for interstate natural gas of about $1.50. Consequently, the capital subsidy required per plant to reduce the product gas cost to the current price of regulated natural gas would be almost all (96 percent) for plant investment and other capital requirements, or about $1.3 billion per Lurgi plant.[2] For a Hygas (steam-oxygen) facility, the subsidy required would be approximately $0.9 billion per plant, based upon current estimates.[3] With the CO_2 Acceptor process, complete subsidy of capital costs (about $1.1 billion)[4] would only lower the cost of the SNG produced to $1.78 per MBtu, still higher than the regulated price of natural gas. If President Carter's recommended ceiling of $1.75 per MBtu were used instead of the current ceiling, the subsidies required for Lurgi, Hygas

[1] Another option for reducing the large costs described below is to reduce the size of the SNG plant that would be subsidized. This could decrease the absolute cost of the subsidy for a project, but it could increase the costs per unit of SNG produced because of lost economies of scale. Although this approach could cut costs, it could also decrease the useful information developed.

[2] Detman, *Factored Estimates*, p. 74.

[3] Ibid., p. 46.

[4] Ibid., p. 54.

(steam-oxygen), and CO_2 Acceptor plants would be about one billion dollars.

This discussion is in no way meant to suggest that subsidies to lower SNG costs to regulated interstate natural gas prices would be desirable or even necessary. The point of these subsidy figures is that present regulatory policy provides an economic environment that is very unfavorable to the capital intensive novel sources of gaseous fuels represented by high-Btu coal gasification.

Price Supports

Price supports represent a continuing source of subsidy rather than a one-time payment. The government could agree to purchase SNG produced at the currently estimated costs for the three processes discussed above and re-sell it at the currently regulated ceiling price. For Lurgi this would mean a subsidy of $1.89 per million Btu. A plant operating with a 90 percent service factor and producing 250 million cubic feet per day would receive a subsidy of approximately $155 million per year. The subsidy for a similar Hygas (steam-oxygen) plant would be $107 million per year and for a CO_2 Acceptor facility, $162 million per year. If gas were sold at the $1.75 ceiling price recommended by President Carter, the annual price support subsidies for Lurgi, Hygas (steam-oxygen), and CO_2 Acceptor plants would be approximately $128 million, $80 million, and $134 million, respectively.

Of course, a constant real price for interstate gas is unlikely in the future. Exploration and extraction costs are likely to continue increasing as natural gas supplies dwindle.[1] Table 19 illustrates how the annual price support subsidies would decline if the interstate natural gas price ceiling rose 5 percent per year through the 20-year life of the first SNG-from-coal plants. This table assumes that SNG costs remain constant over that period.

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[1] *Energy Daily* recently reported that applying the FPC ratemaking methodology to the 1975 drilling cost data compiled by the Joint Association Survey, the data relied upon by the FPC, would yield a national rate for new gas of $2.44 per Mcf. *Energy Daily*, June 17, 1977, p. 1.

Table 19

ILLUSTRATIVE SNG PRICE SUPPORT SUBSIDIES OVER A 20-YEAR PLANT LIFE ASSUMING CONSTANT SNG COSTS AND 5% ANNUAL RESALE PRICE GROWTH (1976 dollars)

	Resale Price ($/MBtu)	Annual Subsidy per Plant ($ millions)		
		Lurgi	Hygas	CO_2 Acceptor
1982	1.90	116	67	122
1983	2.00	107	59	114
1984	2.10	99	51	106
1985	2.20	91	43	98
1986	2.31	82	34	89
1987	2.43	72	24	79
1988	2.55	62	14	69
1989	2.68	52	3	58
1990	2.81	41	--	47
1991	2.95	30	--	36
1992	3.10	17	--	24
1993	3.25	5	--	11
1994	3.42	--	--	--
1995	3.59	--	--	--
1996	3.77	--	--	--
1997	3.96	--	--	--
1998	4.15	--	--	--
1999	4.36	--	--	--
2000	4.58	--	--	--
2001	4.81	--	--	--
2002	5.05	--	--	--

Again, price supports are presented to illustrate the current economic disadvantage of SNG compared with regulated natural gas, rather than as policies recommended to further the commercial adoption of coal gasification.

Loan Guarantees

Loan guarantees cannot be evaluated independently of the regulatory environment in which a guarantee policy would be implemented. Involved, for example, are such questions as whether the price of SNG would be rolled in with other gas sources or set at marginal cost. The sensitivity analysis reviewed in Section II makes clear the fact that the lower interest rates obtained with loan guarantees cannot

make SNG from coal competitive with the regulated price of natural gas.

Government guarantee of loans to build SNG-from-coal plants is the policy tool that has figured most prominently in recent debate concerning synthetic fuels policy. Implicit in a loan guarantee strategy is a judgment that the major barrier to commercialization is the ability to arrange financing because of the risks perceived by private financiers, risks that the government judges to be sufficiently low that the project should proceed.

Loan guarantees could be arranged with many different provisions, according to government and industry assessments of the technical and economic risks involved in a particular project. These might include various risk-pooling arrangements between SNG suppliers and consumers, private sector and government, or SNG suppliers and all gaseous fuel suppliers. The low capitalization of the major gas companies strongly suggests that, in any case, some form of recourse assurance (not necessarily loan guarantees) may be required for financing the first SNG-from-coal plants.

Regulatory Changes

Because of the influence that natural gas regulation exerts on prospects for commercializing coal gasification, changes in this area could clearly enhance those prospects. For example, approval of an all-events tariff might not only remove investor hesitancy but also remove the issue of remaining technological uncertainty as far as gas companies would be concerned. Similarly, regulatory approval to roll-in SNG costs with the costs of other gas supplies would enhance SNG's marketability.

A detailed examination of the effects of major changes in the regulatory environment is beyond the scope of this analysis. But it seems apparent that a higher regulated ceiling, full natural-gas price deregulation, or deregulation of new gas sources (including SNG from coal), with a tiered market similar to that used now for oil, would improve the chances for commercial use of coal gasification. For instance, if new natural gas cost $2.25 per million Btu in 1978 and it

were known the cost would grow at an annual rate of 10 percent, then SNG from Lurgi could be competitive in the early 1980s and a commercial decision to proceed with a Lurgi project might be made now.[1] However, if the price elasticity of supply of natural gas were great enough to provide sufficient natural gas to meet demand at the new, higher prices, the commercialization of high-Btu coal gasification might be further delayed. There is no consensus on the value of this elasticity.

POLICY IMPLICATIONS

In summary, many policy instruments are available for government promotion of the commercial use of SNG from coal processes. These policy instruments could be used on a one-time or continuing basis. On a one-time basis, the use of these tools could stimulate demonstration activity that might overcome such obstacles to commercialization as uncertainty due to the lack of hands-on experience with a process plant producing SNG from coal, other technological uncertainties, and socioeconomic uncertainties associated with the boom-town effects of large energy projects. For obstacles of a more continuing nature, such as poor economics, large capital requirements, or regulatory problems, these policy tools might have to be applied many times in varying degrees. The illustrative cost estimates presented show that the economic disadvantage imposed by natural gas regulation is very significant, and that large subsidies (about $1 billion per plant for capital grants) would be required to make the production of SNG from coal profitable in the short run compared to regulated natural gas.

SNG production would further two major U.S. energy policy goals: reducing energy imports and assisting a future transition from oil and regulated natural gas. Government support of SNG can help achieve these policy goals only to the extent that they assist in overcoming the obstacles to commercialization:

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[1] Assuming that the Lurgi SNG cost estimate of $3.31 per million Btu is correct and that the time required to get the plant on line is five years.

- o The high estimated cost of SNG from coal.
- o The technical and cost uncertainties still associated with SNG from coal.
- o The large capital investment required.
- o The reluctance of the financial community to invest in SNG-from-coal projects.
- o The significant changes required in the financial and physical structure of the gas supply system.
- o The current economic regulatory approach to gaseous fuels.

As shown earlier, some of these obstacles are short term, one time problems; others are likely to be longer term, continuing problems. The policy tools to deal with the short term barriers--such as capital grants and loan guarantees--are available but expensive either to the federal government or gas consumers. Moreover, this analysis indicates that the construction of even several demonstrations would not advance high-Btu coal gasification to a self-sustaining status without regulatory changes. In the absence of such changes, continuing subsidies or R&D on new and economical gasification concepts would be necessary.

Conflict among policy goals must also be considered. For instance, given budgetary constraints, expensive efforts to accelerate the commercial-scale implementation of a technology aimed at lowering energy imports could decrease the funds available for efforts to improve technologies. For gaseous fuels, the added costs of commercializing SNG too early must also be weighed against the possible costs of inadequate supplies of natural gas.

Federal policy must also address equity issues posed by the distributive effects of its decisions. Commercialization of SNG from coal raises two issues that need to be considered and resolved with a view to equitable distribution of the costs and benefits of government policy:

- o The allocation of the economic costs and risks of a commercialization program among specific gaseous fuel users, all gas users, taxpayers, or other segments of society; and

- The distribution of environmental and socioeconomic effects of SNG-from-coal commercialization.

The cost and risk allocation problem has not yet been resolved, but some possible choices have been rejected. For instance, the refusal of the Federal Power Commission to implement an all-events tariff implies a judgment that it would be inappropriate to burden gas users with all the costs and risks of a high-Btu coal gasification plant. Similarly, the defeat of loan guarantee proposals in Congress implicitly suggests that the assignment of the risks to taxpayers in general has also been judged inappropriate.[1]

The environmental effects of energy development must be resolved in the context of national energy policy rather than with specific regard to high-Btu coal gasification policy, and therefore this issue is beyond the scope of this report. Our analysis has found, however, that the known environmental effects of coal gasification appear less harmful than other uses of domestic coal. The socioeconomic effects of commercial-scale coal gasification projects on isolated communities near energy resources are not known precisely, but they appear to be problems of local costs preceeding local benefits. The uncertainty associated with potential socioeconomic problems has been identified as one obstacle to commercialization, but one that should be resolvable with government assistance.

In considering whether or not to promote high-Btu coal gasification, the government must judge (1) the relative importance of the long and short term barriers; (2) the importance of reduced energy imports and a smooth transition from conventional sources of gas; (3) the equity of the distribution of the costs of a commercialization program among specific gaseous fuel users, all gas users, all energy users, and all taxpayers; (4) the likely responses of the sources of alternatives to

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[1]Although specific authorization of a synthetic-fuels loan guarantee program has never been approved by both houses of Congress, the fiscal year 1978 authorization bill for the Energy Research and Development Administration passed the House and the Senate with generic loan guarantee authority. However, the bill would require specific Congressional authorization for any loan guarantee of more than $50 million.

SNG from coal; and (5) the effect of SNG from coal commercialization on the environment and the effects on isolated communities near coal resources.

As the relationships among these sometimes competing policy goals are clarified and the areas of feasible government activities are identified, appropriate policies for addressing the commercialization of high-Btu coal gasification can be developed, with regulatory changes likely to play a key role in any effective commercialization program.

Appendix A

COMPARATIVE ESTIMATES OF THE ROLE OF DETAILED ENGINEERING KNOWLEDGE IN PLANT COST ESCALATION

This appendix presents alternative explanations of the escalation in estimates of coal gasification plant cost. It is based on a particular project, the Western Gasification Company (Wesco) coal gasification plant, for the period from mid-1973 to January 1975. This project and this period were selected because there are two alternative explanations for the cost escalation that was experienced. Both explanations find increases due to construction cost escalation and to definitive engineering analysis significant; however, their relative significance varies substantially.

One of the two estimates is based upon the data presented in this report, the other on data presented by Linden in 1976.[1] Linden estimated the effects of escalation and definitive engineering for the period examined to be +62 percent and +31 percent, respectively.[2]

For the same period, the escalation of the DuPont Chemical Process Plants Construction Index is estimated at +28 percent. Because of the general recognition of this index's utility among engineering firms associated with the construction of large process plants, such as the Wesco facility, the DuPont Index is used here as a surrogate measure of how coal gasification process plant costs would have changed if a more standard design were available. (This index is presented graphically in Fig. 1.) If no major process changes are assumed to occur during this period--and Linden mentions no such changes--the residual increase in the cost estimates, +65 percent, would be attributed to improved engineering knowledge, or other, unidentified causes.

It is possible to argue about the relative merits of these two sets of estimates; however, both make a similar point, and one applicable to the economic analysis of SNG from coal: These estimates indicate that

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[1] Linden, "Synthetic Fuels Option," p. 350.

[2] The basis of these estimates is not clear.

even during a period of rapid escalation in the cost for the construction of process plants, the cost reestimates resulting from more technical information about the requirements for building such a plant have still been of major importance. In fact, between one-third and two-thirds of the cost increases is attributable to such definitive engineering analysis. This finding is especially significant when the relative maturity of the Lurgi process is considered.

Appendix B
SENSITIVITY ANALYSIS DATA

The gas cost equations used in this analysis are based upon the work of the synthetic gas-coal task force of the Federal Power Commission National Gas Survey. Two basic approaches are used, a public utility method and a private investor method. The public utility method calculations were based upon a procedure developed by the American Gas Association's General Accounting Committee in 1961 and modified slightly in 1971 as a result of the task force's activity. The private investor method is based on the principles of discounted cash flow. These formulas were also used by C. F. Braun and Co. for their cost analyses.[1]

Because the two financing methods used have not been designed with comparability in mind, it is not recommended that the two sets of figures be compared with one another. Since high-Btu coal gasification must be commercialized within an institutional environment regulated at the federal and state levels, the public utility financing method is more appropriate for assessing commercialization prospects.

In the sensitivity analysis for the two methods presented here, the base case figures used in the C. F. Braun and Co. analysis are varied one parameter at a time, to determine the sensitivity of the cost estimate for the SNG produced to the value of the parameter varied.

An appreciation of the sensitivity of the cost of the product gas to the input estimates used is important for several reasons. Because the estimates are based upon computer projections of bench scale, PDU,[2] and pilot plant data, there is significant uncertainty associated with the estimates for the second generation (i.e., non-Lurgi) processes. Such an analysis also makes it possible to compare the behavior of various processes if given identical changes in inputs. This exercise also helps identify any leverage points at which relatively small changes in values cause major changes in costs. Such insights serve to reveal

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[1] Detman, *Factored Estimates*, Appendix A.

[2] Process development unit.

opportunities for effective intervention and trouble spots requiring special attention, as well as helping to plan an effective overall strategy to promote production of SNG from coal.

Parameters

The parameters varied in this analysis are capital cost, operating cost, service factor, interest rate on debt, and discount rate. These inputs have been selected because of their suspected major influence on product costs or their policy relevance.

Capital Cost. The capital investment required for an SNG-from-coal plant is an interesting parameter to vary for several reasons.

- o Capital investment, especially the cost of the plant, has been shown to be a variable subject to large changes in the recent past.
- o The capital investment is a major cost factor for the product of any process plant.
- o The capital investment is a variable subject to government intervention, either to decrease the requirement (e.g., by direct subsidy) or to increase it (e.g., by requiring additional equipment to meet environmental regulations).

Four factors are varied simultaneously to demonstrate the effect of changes in capital costs. These factors are the total plant investment,[1] initial charge of catalysts and chemicals, paid-up royalties, and working capital.[2] A capital cost multiplier is then applied to each of these four terms to yield an estimate of the resultant cost estimate for the SNG produced. Table B.1 presents the results of this analysis for six processes.

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[1] Total plant investment includes installed plant cost, contractor's home office costs and fees, and project contingency (about 15 percent of the first two items). This is by far the largest factor.

[2] The working capital estimate includes a 14-day inventory of raw materials, materials and supplies, and net receivables. Since net receivables is related to revenues, it differs for the private and utility financing cases.

Table B.1

GAS COST AS A FUNCTION OF CAPITAL COST, BY PROCESS[a]

Capital Cost Multiplier	Process					
	Lurgi	Steam-Oxygen Hygas	CO_2 Acceptor	Bigas	Steam-Iron Hygas	Synthane[a]
DCF method						
0.50	$3.12	$2.56	$3.23	$3.33	$3.88	$3.50
0.75	3.95	3.24	3.93	4.13	4.88	4.40
1.00[b]	4.79	3.92	4.63	4.94	5.88	5.29
1.25	5.63	4.68	5.32	5.75	6.89	6.19
1.50	6.47	5.28	6.02	6.55	7.89	7.09
2.00	8.14	6.64	7.42	8.16	9.89	8.88
3.00	11.49	9.37	10.21	11.39	13.89	12.47
4.00	14.84	12.09	13.00	14.61	17.90	16.06
5.00	18.19	14.82	15.80	17.83	21.90	19.65
10.00	34.95	28.44	20.76	33.95	41.92	37.59
Utility method						
0.50	2.49	2.05	2.71	2.73	3.14	2.84
0.75	2.90	2.38	3.05	3.12	3.63	3.27
1.00[b]	3.31	2.72	3.39	3.51	4.11	3.71
1.25	3.71	3.05	3.73	3.90	4.60	4.14
1.50	4.12	3.38	4.07	4.30	5.08	4.58
2.00	4.93	4.04	4.75	5.08	6.06	5.45
3.00	6.56	5.36	6.10	6.64	8.00	7.19
4.00	8.19	6.68	7.46	8.21	9.94	8.93
5.00	9.82	8.01	8.82	9.77	11.89	10.68
10.00	17.95	14.62	15.60	17.60	21.60	19.39

[a]Only the lowest cost Synthane results (slurry feed, export char) are listed. Insufficient data were available from the C. F. Braun and Co. summary data for a Lurgi case (single feed) and a Hygas, steam-iron case (no export power) to be analyzed.

[b]Base case.

Although there are no real surprises, there are some interesting responses. For every process, the gas cost is significantly less sensitive to capital cost variations if the utility financing rather than the private financing method is used. This might be expected because the capital cost is spread over 20 years of operation to determine the

average gas cost by the utility method.[1] Second, although the processes behave similarly given the same financing method, in each case the Lurgi process is the most sensitive and the CO_2 Acceptor process the least sensitive to changes in capital costs.

Operating Cost. The effects of changes in operating costs on SNG costs are of interest for at least two reasons.

- o The cost of major components of operating costs (such as coal or water) may change significantly.
- o Operating costs are subject to government intervention, not only positively or negatively, but also directly and indirectly.[2]

Two factors are varied together to observe the effects of changes in operating costs, total net annual operating cost,[3] and start-up costs.[4] As in the case of capital costs, the response of the SNG costs to variations in operating costs is not surprising but is useful to understand.

Table B.2 presents some of the results of this analysis. For every process, the SNG cost is more sensitive to operating cost changes when the utility rather than the private financing method is used. This is to be expected because the effect of a given (constant dollar) change in annual operating costs is discounted for the later years in calculating the gas cost by the discounted cash flow method, but is of equal importance for every year when the utility method is used. Given the financing method, the cost estimate of the processes responded to

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[1]It should be noted that the gas cost actually changes every year with the utility method because the rate base is changing.

[2]Increases in the cost of coal due to new strip mining regulations might be viewed as an indirect effect of government intervention and increased costs to recover plant emissions would be a direct effect.

[3]The total net annual operating cost is estimated by adding estimates for the cost of materials, supplies, labor, administration and other business expenses and subtracting estimated credits from the sale of by-products, such as sulphur, ammonia, phenols, naphtha, tar, light oil, car and coal fines, from the gross operating expenses.

[4]The start-up costs are varied with the operating costs because they are estimated as a function of the gross operating costs.

Table B.2

GAS COST AS A FUNCTION OF OPERATING COST, BY PROCESS

Capital Cost Multiplier	Process					
	Lurgi	Steam-Oxygen Hygas	CO_2 Acceptor	Bigas	Steam-Iron Hygas	Synthane[a]
DCF method						
0.50	$4.07	$3.32	$3.71	$4.08	$4.94	$4.44
0.75	4.43	3.62	4.17	4.51	5.41	4.87
1.00[b]	4.79	3.92	4.63	4.94	5.88	5.29
1.25	5.15	4.22	5.08	5.37	6.35	5.72
1.50	5.51	4.52	5.54	5.80	6.82	6.15
2.00	6.23	5.12	6.46	6.65	7.76	7.00
3.00	7.67	6.31	8.29	8.37	9.64	8.71
4.00	9.12	7.51	10.13	10.09	11.53	10.41
5.00	10.56	8.71	11.96	11.80	13.41	12.12
10.00	17.76	14.69	21.13	20.30	22.81	20.65
Utility method						
0.50	2.59	2.12	2.48	2.66	3.18	2.86
0.75	2.95	2.42	2.93	3.09	3.64	3.28
1.00[b]	3.31	2.72	3.39	3.51	4.11	3.71
1.25	3.67	3.01	3.85	3.94	4.58	4.13
1.50	4.02	3.33	4.30	4.37	5.05	4.56
2.00	4.74	3.91	5.22	5.22	5.99	5.41
3.00	6.18	5.10	7.05	6.93	7.86	7.11
4.00	7.61	6.29	8.87	8.64	9.74	8.81
5.00	9.05	7.48	10.70	10.35	11.61	10.51
10.00	16.23	13.45	19.84	18.91	20.98	19.01

[a]Slurry feed, export char.

[b]Base case.

variations in operating costs very similarly, with most of the variation within the margin of uncertainty of the base estimates. Table B.2 indicates that for both financing methods, however, the CO_2 Acceptor process is the most sensitive to variations in operating costs and the Lurgi process is the least sensitive.[1]

[1]These results are opposite to those for capital costs and follow our expectations from the capital cost analysis.

Another interesting observation results from a comparison of the SNG price responses to both capital and operating costs. Using the base cases of the C. F. Braun and Co. comparative analysis, there are important differences in the relative sensitivity of the processes as a function of the financing method used. With utility financing, the percent changes in SNG costs are similar when the same percent changes in operating or capital costs are applied, with sensitivity to operating costs slightly greater. For the discounted cash flow method of financing, the SNG cost is significantly more sensitive to variations in capital costs than to operating costs.

Service Factor. The service factor is the ratio of actual capacity of a plant utilized to the theoretical capacity of the plant run at design capacity full time. The C. F. Braun and Co. analysis uses 90 percent as the assumed service factor value.[1] The change in SNG cost resulting from variations in the service factor is the next response analyzed because

- Service factors have been identified as important to product costs for other energy conversion systems, especially central electric power generation stations.[2]
- The 90 percent service factor assumed for the base cases appears optimistic.

Recent studies of central power generation stations have found capacity factor (a measure similar to service factor) decreasing noticeably with plant size for both nuclear and coal plants, and the large units are, on the average, operating at less than 60 percent capacity factor.[3] SNG plants are less likely than power stations to have capacity factor problems due to load variations, because SNG is easily stored.[4] Nevertheless,

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[1] Detman, *Factored Estimates*, p. A8.

[2] FEA, *A Report on Improving the Productivity of Electric Power Plants*, Washington, D.C., March 1975.

[3] Ibid., p. 1.

[4] This might make availability factors rather than capacity factors a more useful comparison.

the variation between anticipated and actual capacity factors makes important an examination of the sensitivity of SNG cost to changes in the service factor assumptions.

From the base case assumption of 90 percent, the cost of product SNG is more sensitive to decreases in the service factor than to changes in any other variable examined. Fig. B.1 illustrates the relative costs of SNG for variations from a 90 percent base case. The relative behavior is the same for both accounting methods and for all processes. The absolute figures are presented in Table B.3.

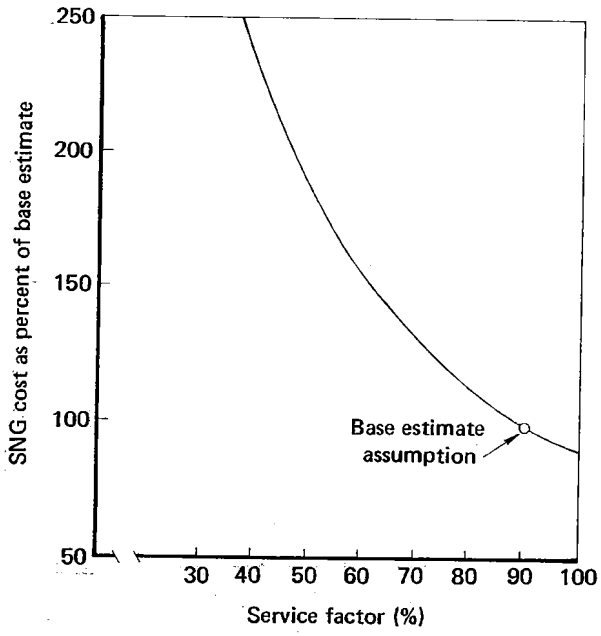

Fig. B.1--Effect of service factor on SNG cost (Utility or private financing, 90% service factor base)

Table B.3

GAS COST AS A FUNCTION SERVICE FACTOR, BY PROCESS

Service Factor	Process: Lurgi	Steam-Oxygen Hygas	CO_2 Acceptor	Bigas	Steam-Iron Hygas	Synthane[a]
DCF method						
1.0[b]	$4.31	$3.53	$4.16	$4.45	$5.30	$4.76
0.9	4.79	3.92	4.63	4.94	5.88	5.29
0.8	5.39	4.41	5.20	5.56	6.62	5.96
0.7	6.16	5.04	5.95	6.35	7.57	6.81
0.6	7.19	5.88	6.94	7.41	8.83	7.94
0.5	8.63	7.06	8.33	8.89	10.59	9.53
0.4	10.78	8.82	10.41	11.11	13.24	11.91
Utility method						
1.0[b]	2.98	2.44	3.05	3.16	3.70	3.34
0.9	3.31	2.72	3.39	3.51	4.11	3.71
0.8	3.72	3.05	3.81	3.95	4.63	4.17
0.7	4.25	3.49	4.36	4.52	5.29	4.77
0.6	4.96	4.07	5.08	5.27	6.17	5.56
0.5	5.95	4.89	6.10	6.32	7.40	6.67
0.4	7.44	6.11	7.63	7.90	9.25	8.34

[a]Slurry feed, export char.

[b]Base case.

Interest Rate on Debt. The variation of the interest rate on debt is relevant only for the utility financing method. It was not suspected that this variable would have a major effect on SNG cost, but it has been examined because of its policy relevance. *If loan guarantees for synthetic fuel projects are available, the interest rate on debt is likely to vary significantly.*

Table B.4 indicates the effects of variations in this interest rate on SNG cost. The product gas cost is relatively insensitive to variations in this input, and changes exceeding 50 percent of the base case value of 9 percent would be required to change the SNG cost by even 10 percent.

Table B.4

GAS COST (UTILITY FINANCING) AS A FUNCTION OF INTEREST RATE ON DEBT, BY PROCESS

Interest Rate	Process					
	Lurgi	Steam-Oxygen Hygas	CO_2 Acceptor	Bigas	Steam-Iron Hygas	Synthane[a]
0.04	$2.89	$2.37	$3.04	$3.11	$3.61	$3.26
0.05	2.97	2.44	3.11	3.19	3.71	3.34
0.07[b]	3.13	2.57	3.24	3.35	3.91	3.52
0.09	3.31	2.72	3.39	3.51	4.11	3.71
0.11	3.49	2.86	3.54	3.69	4.33	3.90
0.13	3.67	3.01	3.70	3.87	4.55	4.10

[a]Slurry feed, export char.

[b]Base case.

Rate of Return. Changes in the rate of return are only relevant to the private financing of SNG projects.[1]

- For capital-intensive projects such as SNG plants, the rate of return selected could make an important difference in the results.
- The rate of return assumed for the base case may be optimistically low given the nature of the projects examined.

Table B.5 illustrates the response of SNG cost to changes in the rate of return. As anticipated, the cost of product gas is relatively sensitive to changes in the input rate assumption. The relative sensitivities are similar to the capital cost results, and relative responses for all the processes are generally similar, but Lurgi appears the most sensitive and CO_2 Acceptor the least sensitive.

[1]There is also a return-on-equity figure relevant to the equity financing within the utility financing method, but different values are used. Since the rate of return on equity is regulated for a utility, it was not considered necessary to vary this input.

Table B.5

GAS COST (DCF METHOD) AS A FUNCTION OF RATE OF RETURN, BY PROCESS

Rate of Return	Process					
	Lurgi	Steam-Oxygen Hygas	CO_2 Acceptor	Bigas	Steam-Iron Hygas	Synthane[a]
0.05	$2.94	$2.42	$3.08	$3.16	$3.68	$3.32
0.10	4.19	3.43	4.12	4.36	5.17	4.65
0.11[b]	4.48	3.67	4.37	4.64	5.52	4.96
0.12	4.79	3.92	4.63	4.94	5.88	5.29
0.13	5.11	4.18	4.90	5.25	6.27	5.64
0.15	5.80	4.74	5.47	5.91	7.09	6.37
0.20	7.75	6.33	7.09	7.33	9.47	8.46
0.25	10.01	8.16	8.98	9.96	12.11	10.88
0.30	12.55	10.23	11.10	12.40	15.15	13.60

[a]Slurry feed, export char.

[b]Base case.

Construction Time. Changes in the length of construction time can vary in terms of effects on SNG costs according to the circumstances surrounding any delay.[1] Additional construction time increases SNG costs to the extent that it increases interest costs during construction. Thus, if delays occur prior to any capital expenditures, little cost effect is likely. If construction in general takes longer than anticipated, then capital expenditures are also likely to be delayed. In this case, the cost effects are likely to be greater, but they would not necessarily be large. The worst case would be delays in the completion of construction, or in the commencement of operations, after most of the capital expenditures have been made. For example, if the effective period for paying interest on the plant doubled for a Lurgi facility, the SNG cost would increase 16 percent (DCF) and 7 percent (utility).[2]

[1]The discussion of changes in construction time has subjectively been limited to longer periods of time.

[2]The base case assumptions used in the C. F. Braun and Co. analysis differ by slightly less than two months in their utility and DCF

Compounded Effects. Even though some of the changes in SNG cost presented in the tables above are already impressive, the effect of compounded changes in the input variables are even more significant.

Consider another base case in which environmental restrictions and site problems increase capital and operating costs by a modest 10 percent each. Assume a 75 percent service factor for the plant. Retain the 9 percent interest on debt figure, but assume a 15 percent discount rate.

Table B.6 presents a comparison of the SNG costs for the two base cases. Clearly, different assumptions within a range that could be considered reasonable by all interested parties can produce significantly different base figures to be debated.

Table B.6

SNG COST ESTIMATES FOR COMPARATIVE BASE CASES, BY METHOD AND PROCESS

	DCF Method		Utility Method	
Process	Braun Base Case	Alternative Base Case	Braun Base Case	Alternative Base Case
Lurgi	$4.78	$7.66	$3.30	$4.34
Hygas				
Steam-oxygen	3.91	6.26	2.71	3.56
Steam-iron	5.87	9.36	4.10	5.39
CO_2 Acceptor	4.61	7.22	3.38	4.45
Bigas	4.93	7.80	3.50	4.61
Synthane (slurry feed, export char)	5.28	8.41	3.70	4.86

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cases (utility: 1.75 years, DCF: 1.875 years). The reason for this difference is apparently a minor oversight, but it has been retained so that readers interested in the development of the figures used throughout this work can relate them to C. F. Braun and Co.'s engineering analyses.

Appendix C
SENSITIVITY ANALYSIS RESULTS FOR DISCOUNTED CASH FLOW METHOD

This appendix presents the implications of the sensitivity analysis in Appendix B for the case of 100 percent equity financing with the discounted cash flow (DCF) method. The cost figures discussed here would not necessarily be actual costs because, even with private financing, debt financing is likely to be used.

Capital Cost

When estimates are based on the DCF method, the sensitivity of the cost of gas produced to capital cost is significant enough that the government could lower the SNG price to commercially competitive levels through direct capital subsidies. However, because of the cost of SNG plants, such subsidies would have to be massive, in the hundreds of millions of dollars. For example, a $1.3 billion capital grant would be required to lower the cost of Lurgi SNG to $1.42 per million Btu, the cost of regulated natural gas. Moreover, any additional capital requirements to meet new environmental standards could also be expected to affect product gas costs.

Another important implication of the sensitivity of SNG cost to capital cost is that there must be confidence in the capital cost estimate. If a project were to experience plant cost growth of the order of magnitude noted in Section II, after a decision to proceed had been made, then the economic attractiveness of the project would be very likely to decrease significantly. Therefore, confidence in the estimate is essential.

The results, normalized to the base case estimates of each process, are summarized in Table C.1. Note that the CO_2 Acceptor process is less sensitive to the changes in capital requirements. This is because the process, as presently anticipated, is less capital intensive.

Table C.1

RELATIVE SNG COSTS FOR VARIATIONS IN CAPITAL COSTS, BY PROCESS[a]
(DCF case, Base Case Index = 1.00)

Capital Cost Multiplier	Process		
	Lurgi[b]	Steam-Oxygen Hygas[c]	CO_2 Acceptor[d]
0.50	0.65	0.65	0.70
0.75	0.85	0.83	0.85
1.00[e]	1.00	1.00	1.00
1.25	1.18	1.19	1.15
1.50	1.35	1.35	1.30
2.00	1.70	1.69	1.60
3.00	2.40	2.39	2.21
4.00	3.10	3.08	2.81
5.00	3.80	3.78	3.41
10.00	7.30	7.26	4.48

[a]Based on data in Appendix B.

[b]Base case cost: $4.79/million Btu.

[c]Base case cost: $3.92/million Btu.

[d]Base case cost: $4.63/million Btu.

[e]Base case assumption.

Rate of Return

The sensitivity of the SNG cost to the rate-of-return assumption makes its choice especially important. The 12 percent rate used in the base case analysis could probably be viewed as a minimum acceptable rate for any privately financed venture. A new venture such as SNG might be expected to attract capital only through a higher return. (On the other hand, 10 percent has been widely used as an appropriate social discount rate, and the government might want to use that rate in deciding whether or not to proceed with SNG development.)[1]

The sensitivity of the cost of gas produced to the rate of return also suggests that important decreases in cost may be possible as risks

[1]Under normal circumstances, commercialization would not be possible with a 10 percent rate of return without subsidies to increase the return to private investors.

are decreased. These changes would be from a higher initial case, however, with the discount possibly decreasing to the 12 percent used in the base case. The results are summarized in Table C.2.

Table C.2

RELATIVE SNG COSTS FOR VARIATIONS IN RATES OF RETURN BY PROCESS, 100 PERCENT EQUITY[a]

(DCF case, Base Case Index = 1.00)

	Process		
Rate of Return	Lurgi[b]	Steam-Oxygen Hygas[c]	CO_2 Acceptor[d]
0.50	0.65	0.62	0.67
0.10	0.87	0.88	0.89
0.11	0.94	0.94	0.94
0.12[e]	1.00	1.00	1.00
0.13	1.07	1.07	1.06
0.15	1.21	1.21	1.18
0.20	1.62	1.61	1.53
0.25	2.09	2.08	1.93
0.30	2.62	2.61	2.40

[a]Based on data in Appendix B.

[b]Base case cost: $4.79/million Btu.

[c]Base case cost: $3.92/million Btu.

[d]Base case cost: $4.63/million Btu.

[e]Base case assumption.

Service Factor

Relative SNG cost changes as a function of the service factor are identical to those discussed in Section II for the utility financing method of cost calculation.

O&M Costs

Table C.3 presents the relative variations in SNG cost estimates as a function of changes in operating costs. Comparions with Table 1 show the relative insensitivity of SNG cost to O&M cost changes. (Note that the CO_2 Acceptor process is more sensitive to O&M than to capital

Table C.3

RELATIVE SNG COSTS FOR VARIATIONS IN OPERATING COSTS, BY PROCESS[a]
(DCF case)

Operating Cost Multiplier	Process		
	Lurgi[b]	Steam-Oxygen Hygas[c]	CO_2 Acceptor[d]
0.50	0.85	0.85	0.80
0.75	0.92	0.92	0.90
1.00[e]	1.00	1.00	1.00
1.25	1.08	1.08	1.10
1.50	1.15	1.15	1.20
2.00	1.30	1.31	1.40
3.00	1.60	1.61	1.80
4.00	1.90	1.92	2.19
5.00	2.20	2.22	2.58
10.00	3.71	3.75	4.56

[a]Based on data in Appendix B.

[b]Base case cost: $4.79/million Btu.

[c]Base case cost: $3.92/million Btu.

[d]Base case cost: $4.63/million Btu.

[e]Base case assumption.

cost variations, but both sensitivities are less than the Lurgi and Hygas sensitivity to capital cost).

Appendix D
ANALYSES OF COAL GASIFICATION VERSUS ELECTRIFICATION

In an article published in the summer of 1975, Hammond and Zimmerman of the MIT Energy Laboratory estimated that for space heating, a major consumer of gas, the use of electricity from coal (through heat pumps) would be cheaper than the use of SNG from coal. They then concluded that if the conventional coal-fired production of electricity could provide this major gas market with a substitutable good at a cost that was lower when the full system's economics were considered, then "careful thought is in order before further investment is made in the type of coal-based synthetic plant currently at the pilot plant stage."[1] It is apparent that the authors sought to be conservative and keep their estimates of SNG's cost low and electricity's high. But according to Foster's view of their work, they did not succeed in doing this.[2] They apparently had difficulty keeping up with the most current performance characteristics and cost estimates, a problem for anyone attempting comparative analyses that involve changing technologies. They may also have mixed theoretical and field data (e.g., on heat pump coefficients of performance).[3]

These articles sparked an interest in further work on the relative advantages of these two ways of providing energy that is convenient and clean at the point of final consumption. Two recent analyses provide additional data for this comparison, and both conclude that SNG from coal appears to be superior to electricity for several major residential and commercial end uses.[4]

One of these, a comparison by J. K. Harral, M. Jones, and D. Hall of electricity and gas options for the service area of Pacific Gas and

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[1] Ogden Hammond and Martin Zimmerman, "The Economics of Coal-Based Synthetic Gas," *Technology Review*, July/August 1975, p. 43.

[2] R. B. Foster, "Rebuttal of: 'The Economics of Coal-Based Synthetic Gas,'" Institute of Gas Technology, September 2, 1975.

[3] Ibid., p. 2.

[4] AGA, "A Comparison of Coal Use"; and Harral et al., *A Comparison of Energy Options*.

Electric Company (PG&E), concludes that "gas, manufactured or natural, generally is or can be [a] more efficient, less costly and less capital intensive form of energy than electricity for comparable uses when the total production through utilization system is considered."[1] Similarly, an American Gas Association (AGA) study of using coal for gas as against using it for electricity in six metropolitan areas around the continental United States[2] concludes that "with respect to the cost of the energy to the end-use, coal gasification has substantial advantage over coal electrification, even when advanced end-use technologies are employed."[3] Other advantages, relating to energy efficiency, capital requirements, and environmental issues, are also asserted for SNG from coal.

These two analyses differ in their assumptions, and their results therefore are not easily comparable. Among the differences are those in sites for end use, appliance efficiencies, and gasification plant capital costs. The differences in sites have already been mentioned. The PG&E appliance efficiency estimates were developed for several major appliances[4] using data from government agencies, the AGA, and in-house PG&E tests.[5] The AGA analysis used an average residential consumption efficiency based on 1968 consumption patterns for four appliances.[6] The capital cost estimate used by AGA, $1.3 billion for a 250 million cfd plant,[7] is compatible with other 1977 estimates for such a Lurgi plant (although it appears AGA is using a Hygas estimate), but the PG&E 1977 estimate for a Lurgi plant of $1.15 billion[8] is 11.5 percent lower than the AGA figure. Nevertheless, these analyses are important, *not for what they prove*, for in that case the differences in assumptions

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[1] Ibid., p. i.

[2] Atlanta, Ga.; Concord, Mass.; Houston, Texas; Philadelphia, Pa.; Seattle, Wash.; Tulsa, Okla.

[3] AGA, *A Comparison of Coal Use*, p. 3.

[4] Cooking range, clothes dryer, water heater, space heater, and space conditioning (various combinations).

[5] Harral et al., *A Comparison of Energy Options*, p. 6.

[6] Space heating, water heating, cooking, clothes drying.

[7] AGA, *A Comparison of Coal Use*, pp. 3-4.

[8] Harral et al., *A Comparison of Energy Options*, p. 13.

would be significant, but *for what they indicate*: They indicate that *coal gasification is a potentially cost competitive use of domestic coal reserves*. The implications of this finding are discussed elsewhere, but the results supporting this finding also need to be reviewed.

These studies are based upon the cost of performing certain end uses (e.g., space heating) rather than the unit purchase price of energy types (e.g., gas or electricity). This perspective on cost is superior to one that compares the cost of converted energy production or even of delivered energy, because raw energy transportation, conversion, converted energy transportation and distribution, and end use efficiencies are all taken into account. The results of these analyses are summarized in tables 3 and 4 (pp. 24, 25). As is made clear by these tables, the AGA analysis has still left out an important set of costs in its comparative analysis, the costs of purchase, installation, and maintenance of the appliances.

These tables indicate the potential economic attractiveness of an energy system providing SNG from coal, *given a goal of using more domestic coal.*

Comparing SNG costs with the marginal costs of electricity production during periods of off-peak demand has also been suggested as the appropriate comparison. This would probably be a correct approach when electricity generation capacity required to cover an outage of the alternative energy source, as is true for some solar energy applications, because only fuel--not production capacity--would be conserved. However, SNG supply capacity would replace electricity supply capacity. An off-peak marginal cost comparison for both energy sources might be correct, but for the long run a comparison on the basis of costs per unit produced by base load capacity appears most appropriate.

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