ALTERNATE COAL
CONVERSION TECHNOLOGIES

prepared by

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for

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FOREWORD

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Douglas N. Jones
Director

EXECUTIVE SUMMARY

This study was initiated in response to a need for guidelines in evaluating proposals for new uses of coal in the regulated industries. The source of the problem is that coal can be used for power generation in a number of different ways and can be converted to other products, notably SNF,[1] in a number of different ways. There are many constraints on the use of coal and of coal products, however, that make some uses acceptable and others not acceptable. Nevertheless, all processes tend to have one thing in common: they are expensive. This means that there is little or no room for error in choice of a system since implementation of a choice generally will close out other options.

In the regulated industries, the cost of developing new processes can either be carried by the companies, with the costs to be recovered later when the new process is in operation, or the development costs can be passed through to the consumer during development. This presents regulators with two dilemmas. First, if the lead time is very long, and costs are passed through immediately, present customers are paying today for future benefits that they may never see. Second, the wrong choice of system, with alternative choices preempted, would mean that future customers would be paying higher costs for their energy than should have been necessary.

Proposals for new coal uses are difficult to evaluate; nevertheless, some basis for evaluation is necessary. The purpose of this report is to develop some guidelines to assist evaluation of proposals for new uses for coal in the regulated industries.

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[1] Synthetic Fuel or Substitute Natural Fuel

This report discusses the magnitude of effective coal conversion programs and the corresponding magnitude of coal production needs. The basic chemistry of the various coal conversion processes and the equipment requirements for production, as well as the equipment needed for compliance with established environmental standards, represent constraints on conversion programs. Using coal liquefaction as an example, the report points out the advantages and disadvantages of initial small scale and later larger scale, commercially acceptable production units and the effect of the corresponding time requirements for small units versus larger units to come on stream.

Development costs of smaller production units and larger production units are compared. The smaller initial programs have the advantages of lower capital investment, less time required to come on stream and potentially greater reliability, but the unit cost of production is exhorbitant compared with conventionally produced fuels. The larger scaled initial programs with the attendant larger capital investment requires a much longer time span to come on stream. During this extended time, new coal conversion approaches or other energy source developments could make the proposed development obsolete.

A slow, cautious approach and smaller capacity production units at the start of a coal conversion project are recommended. Although unit costs would be high, the lesser cost of the smaller unit could be rolled into total final costs without an excessive impact. Another method of covering costs mentioned but not necessarily recommended is a small "fuel development" surcharge in the approximate range of 5%.

It is suggested that regulatory agencies, faced with a request for consideration of an approval for a coal conversion project, attempt to gain as much factual information as might be available related to answers to the following questions:

a) Is the proposed process the best available today with respect to costs, reliability and future success?

b) What is the time requirement for the facility to come on stream?

c) What are the possibilities for more rapid technical development of other energy sources?

d) Has a "failure analysis" been made to assess the consequences of a breakdown or of maintenance down time?

e) What percentage of the overall production load of the utility will the facility support?

f) What is the projected cost of the fuel at the time it is expected to come on stream?

ABOUT THE AUTHOR

Dr. Robert H. Essenhigh received his formal education in England at Repton School, the University of Cambridge (Clare College), and at the University of Sheffield. He received a Ph.D. as a staff candidate from the latter institution in 1959 in the fields of Fuel Technology and Chemical Engineering. He was involved in extensive research in factory and coal mine dust explosion prevention and in pulverized coal firing. Dr. Essenhigh was awarded the Bone-Wheeler Medal by the Institute of Fuel (London) in 1959 for his work as director of a research program on the combustion of pulverized coal.

From 1961 until 1978, Dr. Essenhigh was a faculty member at The Pennsylvania State University as Professor of Fuel Science where he continued his work in the areas of technology of fuel combustion, furnace analysis, combustion chamber and reactor design, incineration and solid waste disposal and air pollution problems.

In mid-1978, Dr. Essenhigh accepted the E.G. Bailey Chair of Energy Conversion in the Department of Mechanical Engineering at The Ohio State University. In this position, he is continuing his teaching and research in combustion technology and fuel efficiency.

Dr. Essenhigh has written or co-authored about 110 publications in the fields of combustion and fuel usage, including nine book chapters and monographs; he has also been extensively involved as a speaker on energy and related matters at workshops and conferences.

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CHAPTER I

INTRODUCTION

The revival of interest in coal as a major source, or the future major source of energy in the United States as a consequence of dwindling sources of oil and natural gas, would seem to have precipitated a problem without precedence in the history of the regulated industries. There is a vast literature on the potential and problems of using coal, but the real costs, particularly of converting coal to alternative liquids or gases on the scale required to have any impact, are little more than informed guesswork. The point was made most succinctly by the report to the U.S. Senate Committee on Energy and Natural Resources (in publication No. 96-17) of June 1979: "[due to] uncertainty engendered by the inexperience of designers, contractors, and others... [and as]...no commercial plants have yet been built...no one actually knows what the cost will be. It may be postulated, however, that the actual costs may be as high as twice the estimates."

The problem facing regulators, therefore, is to know how to evaluate requests for rate increases to cover costs of development of coal-based supplementary or alternative energy supplies. The critical questions that regulators need answers to are:

- What is the evidence that the proposed conversion method is the best?
- How long will it take for the coal-derived fuel to come on stream: at the start; and in quantity?
- What will the fuel cost be at the time of use: absolutely; and relative to conventional supplies?
- Is coal conversion the only or the cheapest answer, or has the contribution of increased supplies of conventional fuels, contributions of further conservation, and a move to alternatives such as solar, been underrated, which can affect the intended market and thus the justification for the conversion process?

Even these questions, however, do not fully define the problem; it is necessary to consider its context.

1. Context of the Problem

The regulated industries that are supplying energy are the electrical and the gas distribution utilities. Coal can be used directly only in electrical generation; alternatively, all conversion products of coal can be used as boiler fuels, including low, medium, or high Btu gas, oils or high reactivity chars. Only SNG[1] is suitable for the present gas pipeline system, although a case can be made for gas grids carrying 500 or 300 Btu in specified restricted areas.

The choice of conversion product, or in the case of electricity generation, whether to stay with direct firing, depends on what will satisfy a number of different constraints. These are:

- the cost of the delivered fuel
- the quantity available
- the ability to meet emission constraints

Emission Constraints affect direct firing of boilers directly and manufacture of coal derived fuels indirectly. There is very little doubt that if particulate and sulfur oxide emissions (and NO_x) could be cheaply controlled, direct firing of utility boilers would be the preferred solution in electricity generation; these are the prime concerns in this instance and provide the incentive for the fluid bed combustion (FBC) developments. In the production of manufactured or substitute natural fuels (SNF), emmission constraints are mainly a factor during manufacture, though noting that high temperature combustion of SNG can, like natural gas, produce substantial NO_x if the firing system is not properly designed or operated. There is also concern over high levels of nitrogen in the oils so far produced from coal by direct hydrogenation, which, likewise, can lead to high NO_x production.

The problem of this constraint, however, is not so much that it exists, but that it is essentially a legal constraint that can be altered by

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[1] Substitute Natural Gas or Synthetic Gas

administrative decision; and the uncertainty imposed thereby for a plant that might take five years to build with an expected lifetime of 25 years can be decisive in generating negative decisions, and thus holding up development of coal use.

Availability of the SNF is a function notably of time and maturity of the process chosen, or physical scale. The two are related, of course, since the longer the elapsed time, the more mature the process, given continued work on its development. Once a mature commercial design has been developed, however, further time is required for the construction of sufficient other plants so that the SNF is available in significant quantity. The time scales being considered here are 5 to 15 years for a first, mature commercial plant and similar lengths of time to build sufficient others for them to make a significant contribution to the fuel supply of the State and the Country.

An additional uncertainty, therefore, is the possibility of different processes moving at different speeds to maturity, so that the most economic process in 15 years' time may be one that is rated very low today; and, more significantly, this could lead to investment today in development of a process that would be relatively less economic than some other in 10 or 15 years' time. This means trying to establish today that a given process of coal conversion will be the best in a decade's time. There is nothing inherently at fault with this, but for one thing: the physical scale of the processes being proposed. If the scale was so small that the capital investment was minor and could be written off as development costs if a given process turned out to be not the best, then practically all reasonable ideas would be tested in small scale plant, built and operated by the potential user. What is being proposed for the first generation "commercial" plant, however, is so large that the capital investment is too great for the developing company to stand the loss. It is then either imperative to back a winner, or to be assured that the costs are insured in the case of failure; in addition, as the smaller, nominally "pilot" plants are too expensive also to be developed without some return, the cost of all the smaller development requirements are also being regarded as the responsibility of the Federal government. There can, however, be a considerable difference in attitude between those operating a pilot plant just to find out how it works, and those whose objective is to produce fuel for sale, even on a very small scale, while obtaining engineering data for further scale up.

Cost and availability are clearly so closely linked that part of the cost problem has already been indicated. There are three components of cost, however.

- The first is the one outlined above, which is the cost of fuel from one process compared with another. If all processes were developed today, with all costs known, these would provide the basis for choosing one conversion process over another.

- Second, there is the relative cost of SNG or SNF compared with the cost of (presumed) shrinking supplies of natural fuels. The relative costs will only be important if there are two markets, such as the inter- and intra-state gas markets; for in one market, all costs will be rolled in together, and the price will be paid by consumers if the fuel is essential, or they will go without. If there are two markets, or if the SNF costs cannot be rolled into other fuel costs in some way, then a difference -- and particularly a large difference -- in price can have a drastic influence on decisions to develop or not to develop an SNF plant. This problem of cost could, indeed, become the dominant constraint.

- Third, the costs of SNF, whether rolled into an existing price structure or not, will have further effect on the size of the market to be satisfied. Although natural gas, in particular, is the premium fuel generally preferred above all others in most of industry, if extra fuel supplies are available only as high-priced SNG, or large quantities of SNG were available with the price rolled in with SNG prices to increase the overall cost considerably, then at some point it will have a significant effect on the size of the market, with customers turning even more to conservation and other energy sources in response to the high prices. This is a constraint that makes forecasting the future size of the market to be met particularly difficult, thus affecting also estimates of the SNF plants required to satisfy the projected market.

2. The Structure of the Problem: The Influence of Physical Scale and Time Scale

The influence of constraints does not tell the whole story, however. The heart of the problem is that the relevant industries are in a dilemma that centers on the effect of physical scale and cost, and the lead time involved on account of the required scale. This has already been indicated above, but can justify restatement in the different context.

The essence of the dilemma is that a "commercial" scale plant that is large enough to produce SNF at "competitive" prices, relying on the efficiencies of scale, is also so large that the time taken to construct it may be unacceptable, and the financial penalty for failure is certainly unacceptable. Because of the time required to develop and construct the plant, the process may already be considered out of date and uneconomic by comparison with some newer process that is maturing more rapidly. If smaller plants are constructed first as "commercially" producing plant, to reduce the financial exposure and development time and to obtain operating and performance data, the product will be hopelessly uncompetitive in price. The point has been made above; what needs emphasis is that this would appear to be the most critical constraint in SNF development.

The reason for this situation compared with the past is that alternate fuel supply systems have to enter a highly developed, large scale system, and to enter it at the same scale and with the same reliability as the existing equipment. This is considered impossible to achieve with the first generation "commercial" plant, as the existing procedures are already so far along the "learning curve." The development of large utility boilers fired by pulverized coal has taken 80 or 90 years, and was accomplished by relatively small incremental changes almost year by year. By comparison, the development of the fluid bed combustor (FBC) for utility purposes is being attempted in 5 or 10 years, and this is a relatively simple development compared with development of SNF technology. The development needs to start small and to scale up has led to the concept of a sequence of non-commercial development units of different sizes, such as: the bench-scale unit, laboratory scale unit, product development unit (PDU), pilot plant, demonstration units, first sub-commercial scale, and first commercial scale -- with full commercial competitiveness not reached until the size is at the mature commercial scale. The problem is compounded by the very large scale involved in utility operations where utility boilers of 1000 MW(e) are two or three orders of magnitude (factor of 10) larger than industrial process furnaces, for example; and proposed SNF mature commercial plant are to be up to half an order of magnitude larger again. By comparison with plant development in the past, the scale-up of the past took up to ten times longer than is projected today, and all stages beyond the initial bench scale operations, or perhaps the lab scale, were income-producing operations at the forefront of the prevailing technology. The proportional impetus, incentives, and returns were all quite different from what prevails today in SNF and FBC development. It would appear that the effects of scale on commercial competitiveness have been quite critical in hindering alternative fuel developments.

3. Scope of this Report

In summary, the development of alternate coal conversion technologies is a complex of interacting factors whose influence on each other is often only guessed at. What is clear, however, is that evaluations of alternative technologies must pay attention to certain specific problems that have determined the focus and scope of this Report, as follows:

- Chapter II reviews the Fundamental Magnitudes involved; it asks the question: What is the magnitude of the fuel market and what are the coal requirements to satisfy that market by coal conversion products?
- Chapter III is concerned with the Chemical Aspects of Coal Conversion and asks the question: What are the possibilities for converting coal into other fuels, and what trade-offs may be involved in that?
- Chapter IV addresses the interaction of Time and Physical Scale on Costs, using Liquefaction for which sufficient data are available as the test example.
- Chapter V examines the Elements of Costing Problems with an approximate determination of the relative contributions of: Capital, O & M, and fuel costs, to the final SNF cost.
- Chapter VI-The Discussion, Conclusions, and Recommendations complete the report.

CHAPTER II

FUNDAMENTAL MAGNITUDES

1. Introduction

In the evaluation of the use of coal and/or coal conversion products, there are certain time scales and physical scales that must be satisfied, in addition to cost requirements. Notably, a proposed coal conversion process must come on stream at a physical scale that will have more than a few percent impact on the total fuel supply picture and within a time scale that does not exceed one or two decades at the outside if major sums of development and investment capital are to be provided for the purpose today.

Specification of even one decade for return on investment capital alone, of course, is five or seven times the conventional periods of 18 months to 2 years. The longer periods of time, of one or two decades, represent the time required for the additional research and development needs.

The basic research requirements are largely complete when scientific proof of a conversion concept has been established, generally by bench scale experiments. Development is primarily the process of scale-up from bench scale to the first-generation commercial plant.

The overall development time, therefore, has three phases of varying length, with physical scale closely associated with the different phases. The phases are defined as follows:

Phase I: Scientific proof of concept by bench scale experiments.

Phase II: Scale-up and development (each subphase represents increase of one to two orders of magnitude in physical quantities processed).

- Phase IIA: R & D in process development units (PDU's).
- Phase IIB: Engineering confirmation in pilot plant.
- Phase IIC: Test of integrated operation and of economic evaluations in Demonstration or Pioneer plant.

Phase III: Commercial operation

- Phase IIIA: Single first-generation plant (at approx. scale of pioneer plant).
- Phase IIIB: Construction of further first-generation plant, and/or construction of a second-generation plant (at 1 to 5 times scale of first-generation plant).
- Phase IIIC: Development of mature industry for generation and delivery of substitute natural fuels (SNF) or of alternate direct coal use.

2. Objectives of this Chapter

The objectives of this chapter are as follows:

(1) To identify processes of conversion or alternate use.

(2) To identify the development phase each process has reached, thus identifying the physical scale and time scale of that development.

(3) To evaluate or provide bases for evaluation by PUCO of the various processes for their prospects of success.

3. Scope of this Report

The emphasis of the overall study is being placed on three interrelated magnitudes: physical scale; development time scale; and cost. The required scales are largely determined or dictated by the overall fuel needs of the State and/or the country.

In this chapter the essential magnitudes for the fuel requirements for the State are summarized to provide a set of targets or a framework in which to discuss the different SNF or alternate coal-use systems.

4. Coal and Fuel Consumption in Ohio

Table 1 summarizes coal and other fuel consumption in Ohio for 1975 in rounded-off values. The fuels are compared on their equivalent Btu basis for both Btu per year and Btu per hour. This last figure is used on account of the ease of plant size evaluations, as summarized below.

It will be noted that,

(1) About 2/3 of the coal is used in electricity generation.

(2) On a Btu basis, the oil, gas, and coal use for electricity generation are roughly equal.

(3) There are some discrepancies in the values obtained from different sources, but the rough division of 1/3 between the three markets is good enough for the purposes following.

(4) The division between coal, oil, and gas is changing under market and other pressures; but again, the rough division of the three fuels provides an adequate framework for what follows.

5. Coal Requirements in Use/Conversion

5.1 Commerical plant sizes. Commonly accepted magnitudes for SNF production are:

SNG Production delivering 250 million scfd ($\sim 10^{10}$ Btu/hr)

SNO Production delivering 50,000 bbl/day ($\sim 10^{10}$ Btu/hr)

as the minimum sizes for commercial viability. Targets for later (second generation) plant on further scale-up would be: 1 billion scfd for SNG production and 100,000 bbl/day for oil production.

It may be noted that:

(1) The Btu equivalent of the first-generation plant is approximately equal at about 10^{10} Btu/hr equivalent value in the output streams (1.3×10^{10} for SNO).

(2) The output of 10^{10} Btu/hr is approximately the input fuel demand for one 1000 MW(e) generating plant.

5.2 Coal feed rate for conversion. Coal requirements for a given size of SNG and SNO plants depend on the coal rank and quality, and on the assumed efficiency of conversion. For bituminous coal of good quality at 25 million Btu/ton (12,500 Btu/lb), fuel requirements are estimated as follows:

SNG with conversion at 40% efficiency delivering 250 million scfd -- coal demand = 1000 tph
= 8.8×10^6 tpy

SNO with conversion at 67% efficiency delivering 50,000 bbl/day -- coal demand = 100 tph
= 8.8×10^6 tpy

It may be noted that,

(1) Coal requirements increase as coal quality diminishes and decrease as conversion efficiency increases.
(2) Coal required for 1000 MW(e) electricity generation is about 400 tph at 33% conversion efficiency.
(3) At 1000 tph for each SNF plant, each delivering approx. 10^{10} Btu/hr, matching thermal input for 1000 MW(e) generation, use of SNF by such plant to provide clean boiler fuel would increase coal requirements by about 2 1/2, or 250%. For SNO, using more accurate figures, coal requirements would be increased by only 150%.

6. Coal Requirements for Gas and Oil Replacement

6.1 Gas. Table 1 shows natural gas supply at 12×10^{10} Btu/hr. Total replacement by SNG would require about 12 plants, each delivering 250 million scfd and with a coal demand of 12,000 tph, or 105 million tpy. This is about 1.5 times the present total coal use in Ohio and 2.3 times present production from Ohio mines.

6.2 Oil. Comparable figures for SNO production yield about 10 SNO plants (at 1.3×10^{10} Btu/hr delivery), with a coal demand of

88 million tpy which is 1.25 times present total coal use and about twice present Ohio production.

6.3 Combined requirements. Oil and gas replacement by SNF would require nearly 200 million tpy, which is approximately 1/3 of present national production and over four times present Ohio production.

7. Mine Requirements for Coal Demand

Coal demand per SNF plant at 8 to 9 million tons per year corresponds to the coal demand for generation of 2,500 MW(e). Meeting this demand is obviously not an insuperable problem, noting that some existing power stations draw on as many as 30 different mines for similar or smaller quantities.

For SNF production where coal type and rank may have significantly greater impact on gas or oil composition and properties, there may be reason to confine supply to a few mines. It may be noted that:

(1) Production at 2 million tpy from a single mine is a large production, yet 4 to 5 such mines would be necessary.

(2) Only three counties in Ohio have total production in excess of 5 million tpy (Muskingum, Belmont, and Harrison).

(3) Nine million tpy is 20% of total current Ohio production.

8. Comments

(1) Coal requirements for minimum size commercial plant for SNF production are clearly feasible as a logistic stream. Questions of plant viability arise from other sources.

(i) Comparable coal rates are to be found in electricity generation, but there could be questions of acceptability of long term contracts for SNF plant. Twenty-year contracts would probably be essential, but these would be an impossible financial load if the plant failed to operate as designed. It has to be remembered that coal-fired generating stations were built up to their present size over a period of 50 or 60 years, not 5 or 6 (or less than 10), as some protagonists of SNF plant hope will be the case. Expectations of reliability for large generating stations were that much more certain. This suggests need for study of coal handling logistics and contracts.

(ii) Reliability of power stations and SNF plant may also be two very different things in view of the far greater complexity of a set of (generally pressurized) chemical reactors as compared with a combustion boiler. This suggests need for detailed failure mode analysis of the most promising reactors, although the data base for such analysis is appallingly small in the majority of cases. (Some of this may be available.)

(iii) If second generation SNF plant are increased in size by a factor of two to four, the percentage of Ohio mined coal at current rates required for one SNF plant would increase to the range 40% to 60%. This would be in addition to the 20% already in use (presumably) for a first-generation plant. One wonders at the possibility of any one single plant being able to handle such quantities of material, if only because of the space requirements. Taking a median figure of 25 million tons per year for a second-generation plant, a 30-day stockpile alone would require 2 million tons or the annual output from a single large mine.

(iv) At this point, the rate of expansion of present mining capacity becomes a question. If present coal-fired utility boilers were changed overnight from coal to SNF, the coal requirement of 50 million tpy for this purpose would have to be increased by 25 million tpy to 75 million tpy if SNO was used, and by 75 million tpy to 125 million tpy if SNG was used. If the increases came from Ohio mined coal, the production rates would require increases of roughly 50% and 170% respectively. If the increases came from out-of-state, it would presumably be a matter of importing coal, not SNF or electricity generated from SNF out-of-state.

(v) Something of the time scales enters here: how long it would take to build a first generation and then a second generation SNF plant, how long to multiply the plant (and how many first or second-generation plant would be necessary), how long to increase coal production to meet the expected demand, and whether the various time periods would be compatible or incompatible with each other.

(vi) The above figures would be modified somewhat, but only to the extent of a factor of 2 or 1/2 at the outside if the adopted efficiencies (40% for SNG production and 67% for SNO) were appreciably higher. Some sources cite expected efficiencies of 67% for SNG production, but this seems to be optimistic.

(2) It is not clear what market or markets SNF should be produced for: power production, or natural gas replacement in the industrial market, or oil replacement in the domestic, commercial, and industrial market. One thing that would seem to be clear is the gross inefficiency of using SNG rather than SNO in all cases but the domestic market and possibly the commercial market.

The principal question about SNG is: Who would use it: If produced through the Syngas ($CO + H_2$) route, or any similar route, it makes no sense to clean, shift, methanate, and then burn it in an industrial furnace (or boiler). Industry, in particular, would be able to use the (300 Btu/ft^3) Syngas itself at a much higher conversion efficiency in production (possibly about 67%). Questions then to be answered include the fraction of the industrial market that could use 300 Btu gas with little changeover problems, the economic distance to pipe such gas (250 miles has been suggested), and the distribution requirements or changes that would be involved, such as the possibility of two superimposed gasline grids of 300 and 1000 Btu gas for the industrial and domestic markets respectively and the extra pipeline requirements to deliver the Btu's required at 300 Btu/cu. ft. Part of such a study might have to consider also the advisability or desirability of further fragmenting the gas market by encouraging individual companies to generate gas themselves (as Syngas or Producer gas) which would take a fraction of the gas market out of the realm of regulation.

(3) An overall question is, indeed, whether monolithic supply systems are either necessary or desirable for the future. Nationally, there seems to be good reason to expect that the three "national" markets of coal, oil, and gas will give way, to a lesser or greater extent, to more regional markets, with emphasis in different regions on different mixes of natural fuels and SNF, including use of solid waste and biomass. In addition, the combination of central plant scale and time scale to develop and test such central plant could encourage reversion to individual SNF plant on a one-to-one scale with the industrial plant they serve. This could have significant implications for the regulated utilities.

(4) The figures would also seem to be against the probability of total replacement of gas and/or oil by SNF (SNG or SNO) in the

near future. Construction of one or two each of first-generation plant would be major constructional and financial undertakings that would only replace 10 to 20% of present supplies, or extend present supplies by 10 or 20% in the time period of 10 to 20 years required to develop and construct such plant.

Table 1

Coal and Other Fuel Consumption in Ohio (1975)

Fuel	Primary	Btu Equivalents	
Coal	Quantities	(Btu/yr) x 10^{12}	(Btu/hr) x 10^{10}
Net mined	35 million tpy	1750	20
Net imported	35 million tpy		
[Ohio mined coal exported]	[10 million tpy]		
Natural Gas	10^{12} cu. ft./yr.	1025	12
Oil	200 million bbl/yr	1150	13
Electrical Use -- Fuel Demand			
Ohio Mined Coal:	31.5 million tpy		
Imported Coal:	18.5 million tpy		
Total	50 million tpy	1110	13

Btu Conversions: 25 million Btu/ton for coal; 1,000 Btu/cu. ft. for natural gas; 6 million Btu per barrel for oil.

Table 2

Coal Requirements for SNF or Electricity Production

A coal rate of 1000 tph equivalent to 2.5×10^{10} Btu/hr will produce or generate:

Electricity 2,500 MW(e) at 2.5 MW(e)/ton, equivalent to 33% efficiency conversion

SNG 250 million scfd at 40% conversion efficiency,
equivalent to 10^{10} Btu/hr in the product output stream;
also equivalent to thermal input for 1000 MW(e) power station.

SNO 50,000 bbl/day at 67% conversion efficiency
equivalent to 1.3×10^{10} Btu/hr in the product output stream.

Note 1000 tph of coal at 25 million Btu/ton (12,500 Btu/lb)

$\equiv$ 24,000 tpd $\equiv$ 8.76 million tpy $\equiv$ 20% of Ohio coal production.

This exceeds the county production rate of all
but three counties in Ohio.

CHAPTER III

CHEMICAL ASPECTS OF COAL CONVERSION

1. Introduction

This chapter is concerned with summarizing the objectives of coal conversion and the routes that are possible in going from coal to a liquid or a gas. It is not concerned with the details of the complex chemistry involved, some of which is still unknown.

The objective is to identify targets, conversion routes, and constraints in conversion as well as sources of inefficiency which strongly affect costs; it also provides a basis for estimating relative quantities of other materials, notably oxygen, hydrogen, and water, required in conversion.

Most of what is summarized here is well known and even self-evident; it is needed as background and context for later chapters. The fuels involved are the natural fossil fuels or the manufactured (substitute) fuels (SNF) obtained from the natural fuels. Coal is the prime source of SNF, but oils and naphtha are other sources, for example.

2. Chemical Summary

2.1 The principal properties of the fuels of importance are their:

- phase (solid, liquid, or gaseous)
- heat of combustion
- adiabatic flame temperature
- diluents and impurities (nitrogen, sulfur, mineral matter).

2.2 The first three properties are governed mainly by the relative proportions of only three elements: carbon, hydrogen, and oxygen. These aspects are illustrated in Figures 1 - 3. In Figures 1 and 2 the ratios of the number of atoms of hydrogen and oxygen to carbon have been used as the axes (H/C and O/C).

Figure 3 shows the relationship between Adiabatic Flame Temperature and Heat of Combustion.

The problem of conversion centers on increasing the hydrogen content. With reference to Figure 1:

<u>The hydrocarbon fuels</u> are strictly those containing only carbon and hydrogen, with no oxygen. These are the fuels lying only on the x-axis (H/C axis), with carbon (coke) at the one extreme of no hydrogen, and hydrogen at the other extreme of no carbon. Coals do contain some oxygen, but this is only appreciable in the sub-bituminous coals and lignites. The anthracites and higher rank bituminous may reasonably be classed as hydrocarbons.

<u>The coals</u> lie on a band that starts at nearly 100% carbon in the anthracites. The band then shows increasing hydrogen with little oxygen (see above) and lies almost, but not quite, horizontal on the H/C axis (see above). This is for coals down to about 85 - 90% carbon weight in the coal or a hydrogen to carbon ratio of about 0.9. Below 85% carbon, the hydrogen to carbon ratio remains almost constant; the oxygen to carbon ratio increases, up to a value in the region of 0.3 or 0.4.

<u>The oils</u> generally have little oxygen. High quality crude oils have a hydrogen to carbon ratio in the region of 1.7 to 1.8, and

distillation will cut such crudes into distillates of about 2 in H/C ratio and residuals of about 1.5 in H/C ratio. Some heavy crudes such as the 20 billion bbl deposit in Alberta have H/C ratios of closer to 1.5, and distillation yields a low fraction (20%) of distillate of H/C ratio = 2, with a residual with an H/C ratio of 1.2 to 1.3. At those low values, the crude and residual fraction are very viscous with very low flowability. This is an important factor in oil recovery that has, for example, militated against the exploitation of the Alberta heavy crude deposits.

The gases occur in two groups: with little or no oxygen and with O/C ratios of about 1.

- Low (zero) oxygen: This includes the natural gases (H/C about 4) and the associated low molecular weight hydrocarbon gases associated with or recovered from natural gas (ethane, propane). It also includes: oil gas, obtained by pyrolysis (cracking) of oil; and coal gas, obtained by pyrolysis of coal which contains roughly one-half hydrogen, one-third methane, one-tenth carbon monoxide, and assorted other constituents.

- High oxygen: This is a range of manufactured mixtures of hydrogen and carbon monoxide, with ratios of H_2/CO varying from zero to about three.

The low ratios (H_2/CO below 1/2, H/C below 1) are known as the Producer Gases, and are obtained by gasification of coal or coke in dry or moist air (as the air moisture increases, the hydrogen percentage increases). The fuel value of the gases from the air-blown Producer is greatly reduced by dilution by the nitrogen in the air.

The first step in production of the higher ratios (H_2/CO greater than 1; H/C greater than 2) is gasification of coal or coke in steam or steam and oxygen. The product is known as either Water Gas on account of its origin, Blue Gas on account of the flame color, or Synthesis Gas (SynGas) since the (theoretical) 50/50 ratio of hydrogen and carbon monoxide is widely used as the starting point in chemical syntheses. The higher H_2/CO ratios are obtained by reaction between CO and additional water (steam) accelerated over a catalyst utilizing the Water Gas Shift Reaction. The ratio 2:1 is the (theoretical) mixture required for Methyl Fuel production, and the ratio 3:1 is the mixture required for methanation to produce SNG.

2.3 Phase (solid, liquid, gas). The phase or state of the fuel (solid, liquid, or gas) dominates handling properties - storage, transportation, and metering. It also affects very strongly the ease of cleaning or removal of impurities.

The more important of the principal handling and cleanability properties are summarized in Table 3. It may be noted that:

(1) The phase or state of the fuel depends mainly on the size of the molecule (molecular weight) and this generally falls as the H/C ratio increases so that as the hydrogen content increases, the fuels go from solid to liquid to gas.

(2) Impurities in the natural fuels fall as the H/C ratio increases.

(3) Handling and cleanability properties (with minor caveats) show the following general trends:

- the solids (coal) generally have the highest level of impurities, are the most difficult to clean, and most difficult to handle
- handling and cleanability of oils and gases are much easier than solids

(4) Improvements in cleanability and handling properties are a major incentive for conversion of coal to oil or gas.

2.4 Heat of Combustion. Figure 2 shows that heat of combustion in Btu/lb. increases with increase in hydrogen percentage and decreases with increase in oxygen percentage. On that account, the heating value of coal peaks in the bituminous. The anthracites contain less hydrogen, and the lignites contain more oxygen.

It may be noted that:

(1) Any conversion, or conversion path that involves addition of oxygen to the fuel molecule represents a loss of chemical energy that appears as an inefficiency in the conversion process unless the heat of reaction can be recovered. Thus, Producer Gas delivered hot represents a thermal efficiency in its generation of 90 to 95%. If the gas is cooled for cleaning, the loss of sensible heat represents a loss of 5 to 20 percentage points in thermal efficiency. The thermal efficiency is reduced to 70 to 75%. (Producer gas is also loaded with nitrogen, but this only reduces the Btu/lb. or Btu/cu. ft. It does not, by itself, represent a loss of thermal efficiency in conversion. Instead, there can be a reduction of flame temperature which may reduce the thermal efficiency of the utilization stage of the fuel gas.)

(2) Hydrogen addition represents an upgrading of the fuel; oxygen addition represents a downgrading of the fuel.

(3) All conversions that add either hydrogen or oxygen involve an energy loss due to processing, but oxygen addition involves an

increased efficiency penalty on account of the downgrading of the fuel.

2.5 Adiabatic Flame Temperature. When the fuel is used in a furnace or boiler, the thermal efficiency of the furnace or boiler is partly determined by the flame temperature. The maximum possible flame temperature, that is never achieved in industrial practice, is the adiabatic flame temperature. Temperatures actually found in operation are typically 100 to 500 degrees below the maximum. The adiabatic flame temperature is, nevertheless, a good relative guide to the practical flame temperature that may be possible. Surprisingly, the adiabatic flame temperature is very *in*sensitive to fuel type, except at the very low heating values, on a Btu/lb. basis. This is illustrated in Figure 3.

For fuels of heating value greater than 5,000 Btu/lb., adiabatic flame temperatures mostly lie in the range 3,600 ± 200°F. The flame temperature then drops off very rapidly as the heating value drops below 5,000 Btu/lb. The curves showing the falling off are for Producer Gases, and for different mixture proportions of coke oven gas (COG - or coal gas) and blast furnace gas (BFG). In the Producer gases, a small increase in hydrogen, which is controlled by the level of moisture in the blast air, has a very strong influence on the flame temperature.

It may be noted that:

(1) The oils and good quality coals have about the same adiabatic flame temperature.

(2) The adiabatic flame temperatures of oils and coals exceed that of methane.

(3) The adiabatic flame temperatures of hydrogen and carbon monoxide (highest and a low Btu/lb.) are about the same. (Heating values on Btu/ft^3 basis are almost identical.)

(4) From the fuels utilization or processing point of view, fluctuations in fuel analysis are not important as a factor influencing flame temperature if the heating value exceeds 5,000 Btu/lb. Conversely, processing by Producer Gas may have to be watched quite carefully on that account. (However, composition may affect flame speed, and this is important in some applications. This introduces the "Interchangeability" problem.)

3. Reaction Paths

Figure 1 shows that there are only two general reaction paths for SNF production by upgrading coal; they are drawn out more explicitly in Figure 4. The other alternatives to SNF production are Producer Gas Generation and Pyrolysis.

The four options for conversion are:

(1) Direct hydrogenation that increases the H/C ratio in the product fuel.

(II) Indirect hydrogenation by first forming Syngas followed by a shift reaction to adjust the H_2/CO ratio to the proportions required for either methanol (ethanol) or methane production, followed by methanolation or methanation.

(III) Producer gas generation using moist air in which the reactions are essentially those of syngas production, but with lower H_2O in the blast gas and major nitrogen dilution in the product gas. On account of the nitrogen, this gas would never be processed further.

(IV) Pyrolysis, manufacturing coke or char and coal gas or a variant thereof (by such methods as coke oven processing; FMC - COED; or Garret Flash Pyrolysis).

3.1 Description of Paths.

(I) The direct paths to either liquids or gases are nominally one-step reactions requiring, nominally, a simple reactor. For reaction enhancement, two reactors are sometimes used. With the exception of Producer Gas, the paths parallel the H/C axis. In principle, no oxidation is involved. Liquefaction (Path IL) takes solid coal at an H/C ratio of about 0.9 or less, to an H/C ratio between 0.9 and 2, depending on the process and depending on the level of hydrogenation required for a particular purpose. A minimum of hydrogen addition leaves the coal as a clean solid (Solvent Refined Coal: SRC I). This is less attractive than SRC II, which is liquid.

The minimum H/C ratio required for the solvent refined coal or converted coal to be liquid appears to be about 1.1.

The maximum hydrogen addition yields methane with an H/C ratio of 4.

(II) The indirect paths to either liquids (alcohols) or methane (SNG) involves, nominally, three reactions, involving three reactors. The three steps are indicated on Figure 4 as G_1, G_2, and G_3 or L_3 as follows:

- G_1: Syngas production by Gasification with partial oxidation. Product is approx. 50/50 H_2 and CO, with some methane from coal pyrolysis, CO_2, tars, and sulfur compounds.
- G_2: Shift reaction is catalytic oxidation of CO by additional water (steam) to adjust the H_2/CO ratio to 2 : 1 (nominal) for alcohols production and 3 : 1 (nominal) for SNG production.

either - G_3: Methanation of $3H_2$ - CO mixture by catalytic reaction yielding methane (SNG).

or - L_3: Methylation of $2H_2$ - CO mixture by catalytic reaction, yielding methanol or higher alcohols.

The Consol CO_2-Acceptor process essentially combines Steps 1 and 2 in a single stage, though still using 2 interchanging reactors, to yield a first-product gas with $3H_2/CO$ (and with 14% methane).

(III) Producer gas generation is reaction of coal or coke with moist air by blowing up through a fixed bed. The technology is more than 100 years old. Fifty years ago, it is estimated that upwards of 10,000 such units were in operation, operated at atmospheric pressure. A few are in operation today. With upwards of half a dozen new units recently constructed, some writers believe the Producer Gas generators are due for a revival. It is certainly the only commercial technology available today as an alternate source of clean gas. The largest units use 3 to 4 tons of coal per hour, delivering up to 75 million Btu/hr. The drawbacks of the gas are as noted:

- the adiabatic flame temperature is very sensitive to the hydrogen percentage in the product gas, and this normally depends on the degree of air preheat and level of saturation of the air, unless the charge is steamed
- the gas is heavily diluted with nitrogen, which makes it uneconomical either to store or to transport any appreciable distance (anything more than a few thousand yards)
- the coals must be non-caking or weakly caking unless significant precautions against hang-up are taken; this limits the range of coals, but it does open the way to redevelopment of a coke market
- use of bituminous coals results in tar deposits in the delivery lines that have to be burned out periodically; again, this is eliminated by use of anthracite or coke
- the size in terms of fuel delivery capacity is unsuitable for electricity production except, conceivably, on a very small

scale. A General Electric/EPRI program is investigating the potential for increasing the scale by using a pressurized air-blown gasifier, with the gas cleaned and fed to a gas turbine, but this is still in the experimental stage.

Redeployment of Producer Gas generators raises the question of the impact of small scale gas generators on regulatory guidelines. Is there a physical scale, a function, or distribution limitation that will place a set of gas generators outside control by regulatory bodies? If so, what are the sizes, functions or other limitations?

(IV) Pyrolysis is thermal degradation of coal, first used commercially in the late 1790's to produce coal gas (also known as town gas or city gas, and essentially the same as coke oven gas, or COG); pyrolysis also produces coke and tars with other liquids. With 50% hydrogen in the coal gas mixture, the H/C ratio is high at about 4.5 (see Fig. 1), with a high flame speed that allows high gas throughput with stable flames in utilization. The heating value is 500 to 600/Btu/ft^3.

(i) Conventional pyrolysis used coking ovens and this is not generally a commercially attractive proposition today except in the special case of metallurgical coke production with coke oven gas (COG) co-product or by-product used in the steel plant. The reasons are that conventional coking ovens are notoriously dirty in their emissions, and only about 1/3 of the coal by weight is converted to gas with the balance (2/3) going to coke. Also, the coke is relatively unreactive compared with coal, and if finely ground, is generally considered to be worse than anthracite as a fuel for pulverized coal boilers, or impossible to use in p.c. boilers.

Conventional coking ovens could become attractive, in principle, however, under the following circumstances:

- using continuous vertical retorts in place of intermittent slot retorts to control emissions
- development of a market for coke such as redeployment of Producer Gas (or Water Gas) generators
- a local market for the 500 Btu gas: this could be easily accomodated by industry
- a market for the tars and liquids, noting that coal chemicals were the forerunners of petrochemicals, and coal tars could possibly replace some of the petrochemical feedstock at the right price

(ii) There are two recent approaches to pyrolysis that attempt to meet the conventional objections in other ways. Both use fluid bed pyrolysers. These can handle crushed or ground coal on a continuous basis, and they reduce the (generally unwanted) tar component as a consequence of the rapid heating that occurs in fluid beds. The fraction of lighter liquids, for use as boiler fuels, chemicals, or other feedstock, in enhanced and potentially controllable.

- The FMC - COED process uses a sequence of four fluid beds of increasing temperature, with hot gas in counterflow to provide heat for pyrolysis. The end products are char, oil, and gas. A principal disadvantage is that the char is of low reactivity, though better than anthracite, and use in most boilers is likely to be difficult or impossible.

- The Garret (Occidental Oil) Flash Pyrolysis process also produces char, liquids, and gases; but the char is reported to have sufficiently high reactivity to be useable as a boiler fuel. The char is also said to be quite easily desulfurized with tests showing 3% S in uncleaned char from 3.8% S in the parent coal (W. Ky #9) and 0.3% in the cleaned char.

3.2 Comparison of Paths. The different routes to production of manufactured fuels differ mainly in the following characteristics:

(1) Directness of Path

- Direct: includes Producer Gas; direct hydrogenation in (nominally) one-step to liquids or gases; Pyrolysis (though upgrading the liquids by further hydrogenation by conventional means may be necessary). Direct or one-step manufacture is always to be preferred, if possible, on account of intrinsically lower losses in conversion and simplicity, which generally means lower maintenance costs and likelihood of greater reliability.
- Indirect: includes alcohols production and SNG production via the Syngas route (Path II). With the exception of the CO_2-Acceptor process, in general, three reactors are needed for: Syngas generation, shift to the correct H_2/CO ratio, and alcohol production or methanation. This is the only manufacturing route for alcohols, and it has been in commercial use on a small scale for decades. As a route to SNG, it is inherently unsatisfactory on account of the high level of oxidation required that can lead to high losses or low efficiency (40% was used in Chapter II).

(2) Temperature

Elevated temperature is necessary for one or both of two prime reasons:

- (i) For the necessary reactions to take place fast enough
- (ii) For the reaction products to be as close to the desired ratio as possible at temperature equilibrium

Temperatures vary in the different reactors with, for example in SNG production, relatively high temperatures in the Syngas reactor and relatively low in the reactors following. Taking the highest temperature reactors as a guide, however, they may be divided roughly into two groups: high temperature, above

1,000 °C (about 2,000 °F), and low temperature, below 1,000 °C. The reactors then divide up as follows:

- High Temperature ($> 1,000$ °C): Producer Gas and Syngas, Coking ovens, FMC - COED
- Low Temperature ($< 1,000$ °C): Direct hydrogenation, Water gas shift reactors, Methanolation, Methanation.

The significance of temperature derives from 3 facets of behavior:

- First, temperature requires a source of heat and thus a potential for energy consumption that is unrecoverable or not easily recovered, such as the sensible heat in Producer Gas that is lost on cooling for cleaning. This contributes to thermal inefficiency of conversion. Low temperatures can be maintained by external sources so that waste heat from other processes can be recovered. High temperatures must be produced, in general, by *in situ* combustion of part of the feed stock (there are exceptions).
- Second, high temperatures lead to slagging of the ash. This can: (i) block the reactor, (ii) attack the containing refractory. This last is a major materials problem in many cases.
- Third, high temperatures lead to general thermal stresses on other components: reactor tubes; catalysts and catalyst supports, if used; containment shells; pumps and other auxiliary equipment.

(3) Pressure. High pressure is used or needed on three accounts:

- (i) For the required reaction to proceed at all. This is particularly the case for direct hydrogenation; for example, in the early 1940's, Germany used the Bergius process of direct hydrogenation to produce liquids, operating at 10,000 psi. Pressurized operation in direct hydrogenation for either liquid or gas production is typically in the range 1,000 to 10,000 psi.
- (ii) The second prime reason for operating at pressure is to increase the reaction density, i.e., to increase the mass conversion per cubic foot of reactor volume. This leads to

a small reactor for a given throughput or a greater throughput for a given reactor: this is aimed at reducing costs.

- (iii) The third reason for pressurization is the need for pressure in downstream operation, such as in the GE/EPRI pressurized air-blown fixed-bed gasification feeding a gas turbine.

Three pressure regimes may be identified:

- Atmospheric: Producer Gas generation, flash pyrolysis, and coke oven pyrolysis, low pressure water-gas/Syngas.
- Medium Pressure (1 to 1,000 psi): Pressurized Syngas production, water gas shift reactors, and methyl/methanation.
- High Pressure (1,000 to 10,000 psi): Direct hydrogenation for production of either liquids or gas.

Pressure affects SNF production in several different ways, most of which are adverse. Principally,

- First, high pressure stresses any reactor. This by itself can be a major problem, particularly if the fluid being carried is in any way reactive or corrosive and also hot.
- Second, to carry the high pressure, thick diameter tubing is necessary, and this reduces ease of heat transfer in those cases where the reactor tubing must be heated externally to maintain reaction temperature.
- Third, the need for thick reaction tube diameters at high pressure limits the acceptable internal diameter, and this can present a problem of providing necessary reactor cubic capacity for high throughputs.
- Fourth, feeding and valving of particulate matter carried in liquids or gases is severely aggravated by working at pressure. Particles can be trapped on seats of lock hopper valves or pipeline valves that can lead to frequent failure, high maintenance costs, and low reliability or on-line duty.
- Fifth, pressurization of the feeds uses energy. This is easiest with liquids. It is most costly with gases.

That high pressure can be accommodated in commercial operation is evidenced by the German experience from 1930 to 1945, operating up to 10,000 psi. The lower the pressure, the better, however.

(4) Hydrogen and/or Oxygen requirements. Some of the processes require either free hydrogen or free oxygen in the reactions (or in some cases, steam). The processes divide up as follows.

- Hydrogen as gas, is required for the SNO or SNF direct hydrogenation (path I). This is generally represented as being obtained from a separate or auxiliary water-gas reactor in which steam is reacted with hot char. This complicates the apparent simplicity of the one-step process and increases the reactor requirements by one. The quantity required depends on the degree of hydrogenation involved, being minimal for SRCI, and maximum for SNG. Adopting the majority view that hydrogen production and pressurization are expensive, the smaller the quantities, the better. This would favor production of fuels with just sufficient hydrogen addition that they are liquid (SRC II or an equivalent).
- Oxygen as gas is required in Syngas production (path II G_1) by reaction with steam and oxygen. This objective is to eliminate nitrogen which is present when blowing with air (Producer Gas). Use of oxygen again requires an additional reactor, but production tonnage oxygen is a well-established commercial process. It is the one process that is not expected to create significant development problems.
- No Special Requirements are called for by way of additional reactor gas, other than steam, for: Producer Gasification, the Shift reactors (steam required), methyl/methanation, and Pyrolysis (steam may be required).

These alternative requirements would favor reactor schemes in the following order of preference: first, requiring no special gases (O_2 or H_2); second, requiring oxygen; third, requiring hydrogen.

(5) Other Aspects. Three other aspects of significance include:

- Possible need for coal pretreatment, including crushing, grinding, decaking
- Catalysts requirements
- Clean-up

These are complex operations, not easily generalized, but they generate additional complexity to the overall SNF manufacture that varies with the different processes.

It may be noted that:

- (i) Indirect gasification would appear to present the greatest complexities in clean-up. Figure 5 illustrates a generalized process scheme for SNG production with clean-up. By contrast, in direct liquefaction, mineral matter or ash removal is a matter of filtering. This has caused problems in the past, but they appear to be largely solved.
- (ii) The level of clean-up required in the indirect gasification sequence is high at each stage. This is on account of poisoning of the conversion catalysts by gaseous sulfur compounds, particularly H_2S. This means that the delivered gas is clear of sulfur. By contrast, substantial sulfur may remain in the first stage product in liquefaction. However, if this is treated as "Syn Crude" to be fed to a refinery, the sulfur can be reduced to necessary levels, but by processing an ash-free liquid, not a solid.
- (iii) Pretreatment for decaking (usually by light preoxidation) is required in those cases where caking may block the reactor. The reactors most prone to this are the fixed bed Producer Gas or Syngas generators. Such pretreatment represents a potential loss due to reduction of the heating value of the coal fed to the reactor.
- (iv) Catalysts are required in some of the direct liquefaction processes, and in the shift, methyl/methanation reactors. Problems here are varied but include: maintenance of activity, poisoning, and collapse of the catylist support (where used).

Catalyst poisoning is evidently less likely in liquefaction than in gasification.

3.3 Comparison of Fuels. Essential comparisons have been made periodically through this report. Summarizing key points, utilizing Table 3 for comparison with natural fuels:

- (1) Light to medium oils represent the optimum flexibility in storage, transportation, and utilization. It is for that reason that oil has really become the "swing fuel" in the world energy delivery system.
- (2) Gas represents possibly the most desirable fuel from the point of view of ease of utilization, but it is hampered by need for a pipeline and then being tied into a single supplier once installed. (Propane stand-by or alternative only partly mitigates that situation, but it is usually regarded as an expensive option.)
- (3) Reversion to coal or coal-derived fuels is clearly dominated by emission considerations at the larger scale and convenience and operability at the smaller scale.
- (4) If available in quantity at the right price, no problems of SNF utilization are foreseen in general: both SNO and SNG should be as clean or cleaner than natural oils and gas.
- (5) There may be some specific problems of utilization if the SNF fuel composition varies too much, even for a controlled calorific value, particularly with gases (the interchangeability problem).

4. A Preliminary Evaluation

The choice of conversion method from coal to a manufactured fuel must depend on application and cost. Clearly, oil cannot be used to fill a gasoline delivering fuel to gas burners. In this preliminary evaluation, costs are not yet included. It is still possible, nevertheless, to review some of the major pros and cons between different systems. In the first case, this can be a general evaluation assuming total flexibility in end use; in the second case, the evaluation is limited to electricity and gas utilities.

What follows is tentative, requiring more definitive expression, in due course, on the basis of costs. It may be noted, at this time, that costs are still speculative to a degree in most cases as the full-scale plants, for the most part, have not been built. Some of the more qualitative factors discussed below should, therefore, be given considerable weight.

4.1 General Evaluation. The principal factors discussed in Section 3.2 (Comparison of Paths) are summarized in Table 4.

The least attractive route to SNF would appear to be indirect production of SNG. This conclusion is based, in particular, on:

- The large number of processes (Figure 5) required that must all operate simultaneously for long periods of time. A failure in any one step will shut the whole line down. This might be due to slagging in the reactor due to a change in coal and/or mineral matter or poisoning of one of the catylists due to a small drop in gas cleaning efficiency, as examples.
- The process route that involves substantial losses on oxidation with a low overall thermal efficiency of conversion.
- The first reactor stage requires high temperature of potentially highly corrosive reactants (slags) at medium pressure. In reactors that will have to handle up to 1,000 tons per hour of coal for a commercially viable plant, this potential for erosion/corrosion failure is formidable.

The most attractive route to SNF so far developed on an appreciable scale is direct hydrogenation to produce oil with relatively small hydrogen addition. This conclusion is based on the availability of test results of SRC II coupled with the comparative evaluations of Table 4. A one-step process using a relatively small quantity of hydrogen is inherently attractive.

Of the other processes, Producer Gas is otherwise the only other immediately commercial possibility, but it is restrictive in physical scale to less than 100 million Btu/hr delivery, except for the pressurized, air-blown unit which is intended only for gas turbines.

A relatively unknown factor in this is the potential of the flash pyrolysis process. If this can provide fuels at lower cost than SRC II, it could be the most attractive route of all. It is direct, at atmospheric pressure, using no hydrogen, oxygen, or catalysts; and it operates at fairly high but relatively modest temperatures compared with other pyrolysis processes.

4.2 Selected Evaluations. For the regulated utilities, certain processes - notably Producer Gas obtained at atmospheric pressure - are of no direct interest. There could be some indirect interest, however.

The two areas of concern are: electricity generation and gas distribution.

- (1) Electricity Generation. The use of clean fuels from coal for electricity generation limits choices today essentially to SNG, Syngas, and an oil product such as SRC II. Of these three, SRC II is the most attractive. As remarked in Chapter II, there is no point in manufacturing SNG from Snygas to burn it in a boiler or furnace. The same is essentially true of direct manufactured SNG; SNO (such as SRC II) uses much less hydrogen and it is also years or decades closer to commercial-scale production than SNG.

  Between SNO and Syngas, SNO is probably preferable, even if there proved to be a small price superiority in Syngas manufacture at the requisite physical scale. The reason is that the Syngas generator would have to be close to the boiler if retrofit is involved on essentially a one-to-one basis. The reliability of the system would then depend as much on the

Syngas generator as on the boiler-generator system. With oil, the manufacture and utilization can be decoupled. A single SNO generator may be dedicated primarily to a single utility plant, but there is flexibility for switching if either unit goes off-line.

A decision to manufacture SNO, however, should not be based only on comparisons between different SNF processes. There are other possible options beyond this. A full range of all options for converting coal to energy is given in Table 5. For electricity generation, we may list, incorporating some elements of Table 5:

- (i) Direct pulverized coal firing with cleaned coal
- (ii) Fuel from pyrolysis (gas, oil, or char)
- (iii) Low Btu gas for gas turbines from pressurized, air-blown gasifiers. This still requires substantial development, however.
- (iv) Syngas (not favored by the argument above)
- (v) SNG (not favored by the argument above)
- (vi) SNO (specifically SRC II as the most advanced)
- (vii) Direct firing of gas turbines using ultra-fine coal to reduce turbine erosion (not attractive as it still requires low S coal)
- (viii) Coal-Oil Mixtures (COM) (Very attractive as an interim measure if low-S oil is already in use and coal is used as an oil extender; not relevent, however, to Ohio electricity generation except as a possible addition to SNO.)
- (ix) Two-stream operation: coal is deep cleaned to yield one clean stream of coal that meets current emission standards, and the other stream is sent to conversion plant or to utilities with maximum FGD equipment. The value of this approach is to concentrate the FGD equipment and operators at a few selected stations instead of spreading them out over all stations in a system.

Of the above list, the closest to implementation could be (in a probable order of most likely feasible):

- SNO (SRC II) as discussed above, requiring construction of necessary plant at necessary scale.
- Pyrolysis Fuel, from flash pyrolysis, using either the gas, oil, or high reactivity char, requiring construction of necessary plant at necessary scale. In the long run, this may be the best option.
- Direct firing of cleaned coal, in a boiler or fine-ground in a gas turbine, with or without the two-stream option, requiring construction of necessary cleaning plant. This, in turn, depends on the coal, whether necessary S reduction is possible by current commercial methods (floatation, etc.) or whether it would require development of new solution or other chemical cleaning methods. Table 6 lists general options for S control. If new methods must be developed, this would delay use of deep cleaned coal by one or two decades.

- (2) Gas Production. From the regulatory point of view, the only gas production of nominal interest is SNG. The situation here would appear to be that:
  - (i) Regulations to reduce natural gas use by utilities and by industry (ignoring the current temporary [?] reversion) has relieved pressure of demand over supply in the domestic market. How long this state of affairs will continue is not clear; a decade or so is not unreasonable, but figures should be available for better estimates.
  - (ii) The cost of SNG from coal is currently estimated at \$4 to \$5 per million Btu (sources can be found giving about any value one would like to have).
  - (iii) The cost of SNG from coal would seem to be completely out of line with other coal conversion methods. If the domestic market can be supplied from natural sources for one or two decades, it makes much better sense nationally to produce SNO, or other mixtures of fuels by pyrolysis, to serve the industrial and part of the commercial market.

- (iv) This, however, would limit the role of the gas companies to purely static or contracting operations.
- (v) From the point of view of the continued efficiency of the gas companies, it would seem unwise, psychologically, to condemn them to become a declining industry that high quality managers and others would leave as soon as possible.
- (vi) While it is by no means certain that this will be the future role for the gas companies, it might be appropriate, nonetheless, to start to explore what other functions they could fulfill, either under continued regulation or with part of their operations outside regulatory control. Such other functions might include development of an industrial pipeline system of 300 Btu gas, with much more localized groupings, or providing expertise for deployment of Producer Gas units or some other. Expenditures on SNG do not appear to be warranted at this time, barring some major catalytic breakthrough or other development. In that case, it would appear to be appropriate to encourage the gas companies to be more flexible in their thinking and future operations.

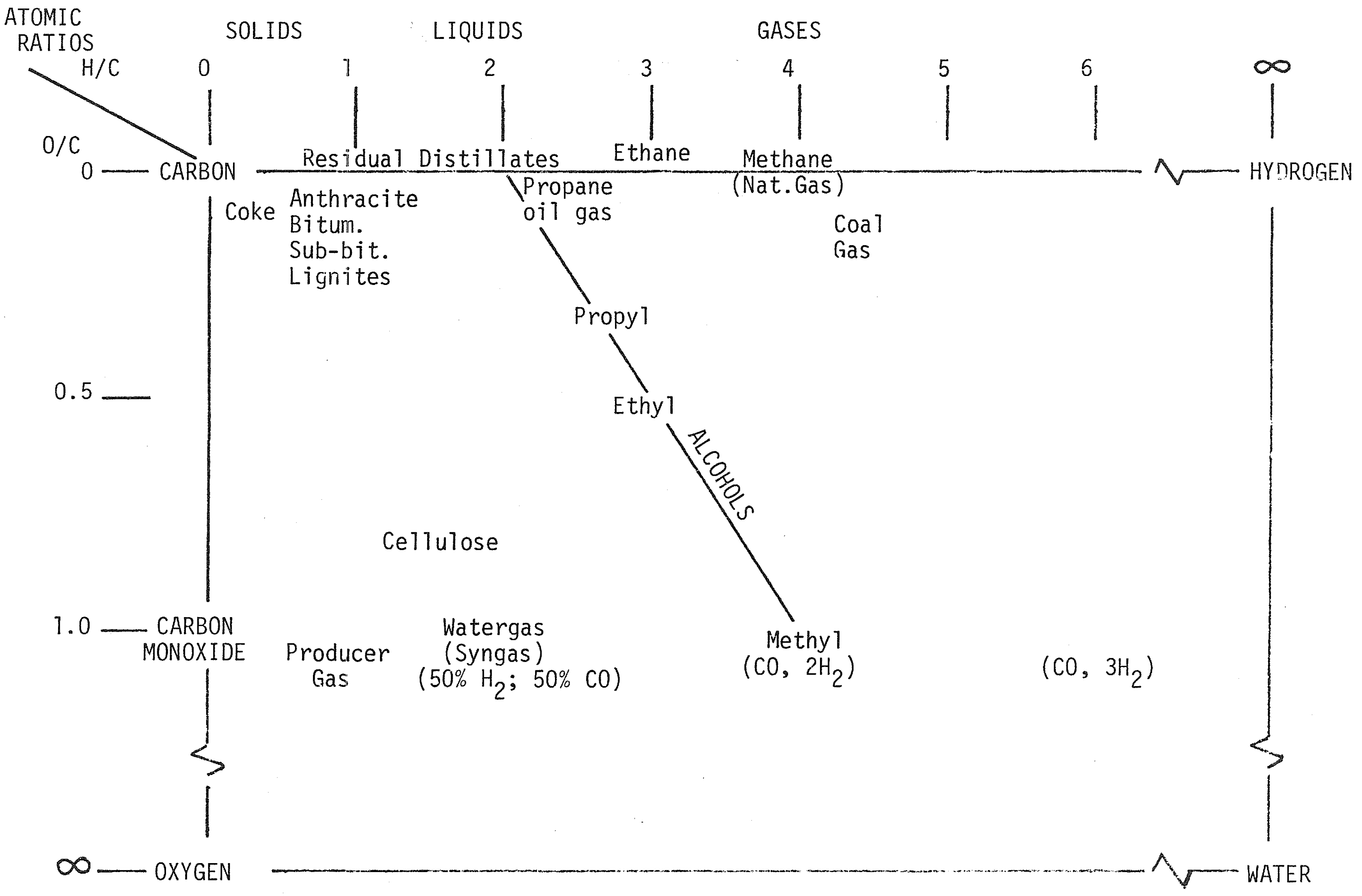

Figure 1 - C-H-O DIAGRAM FOR FOSSIL FUELS AND RELATED MATERIALS

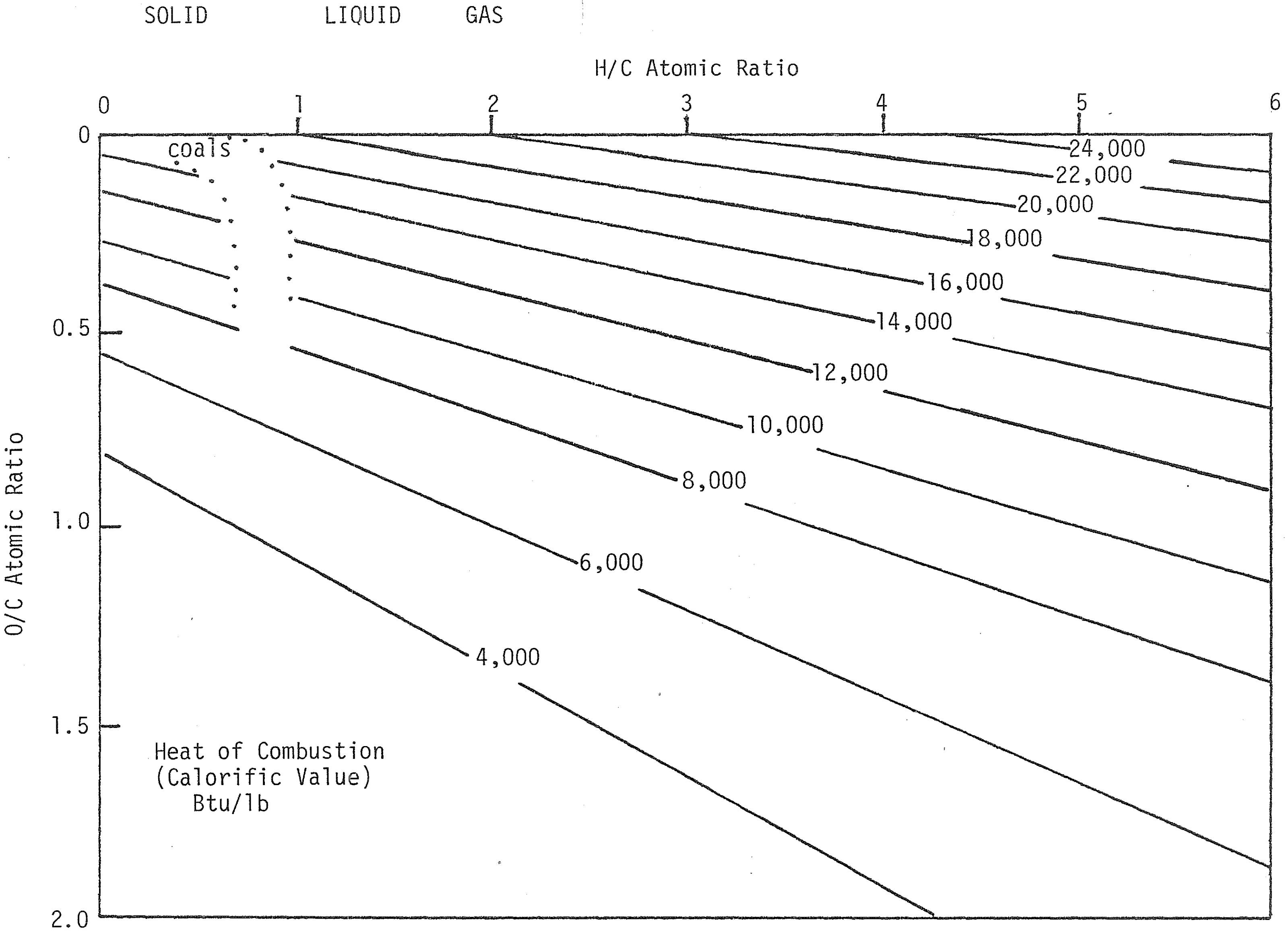

Figure 2 - Heat of Combustion (Calorific Value) of Pure C-H-O Materials. Illustrates lines of constant Heat of Combustion (Btu/lb) on axes of H/C against O/C. Note: Lines are for pure C-H-O materials. Values for coals must be corrected for dilution by N, S, moisture, and ash. Good quality coals range from 12,000 to 14,000 Btu/lb. Lignites go down to 10,000 Btu/lb.

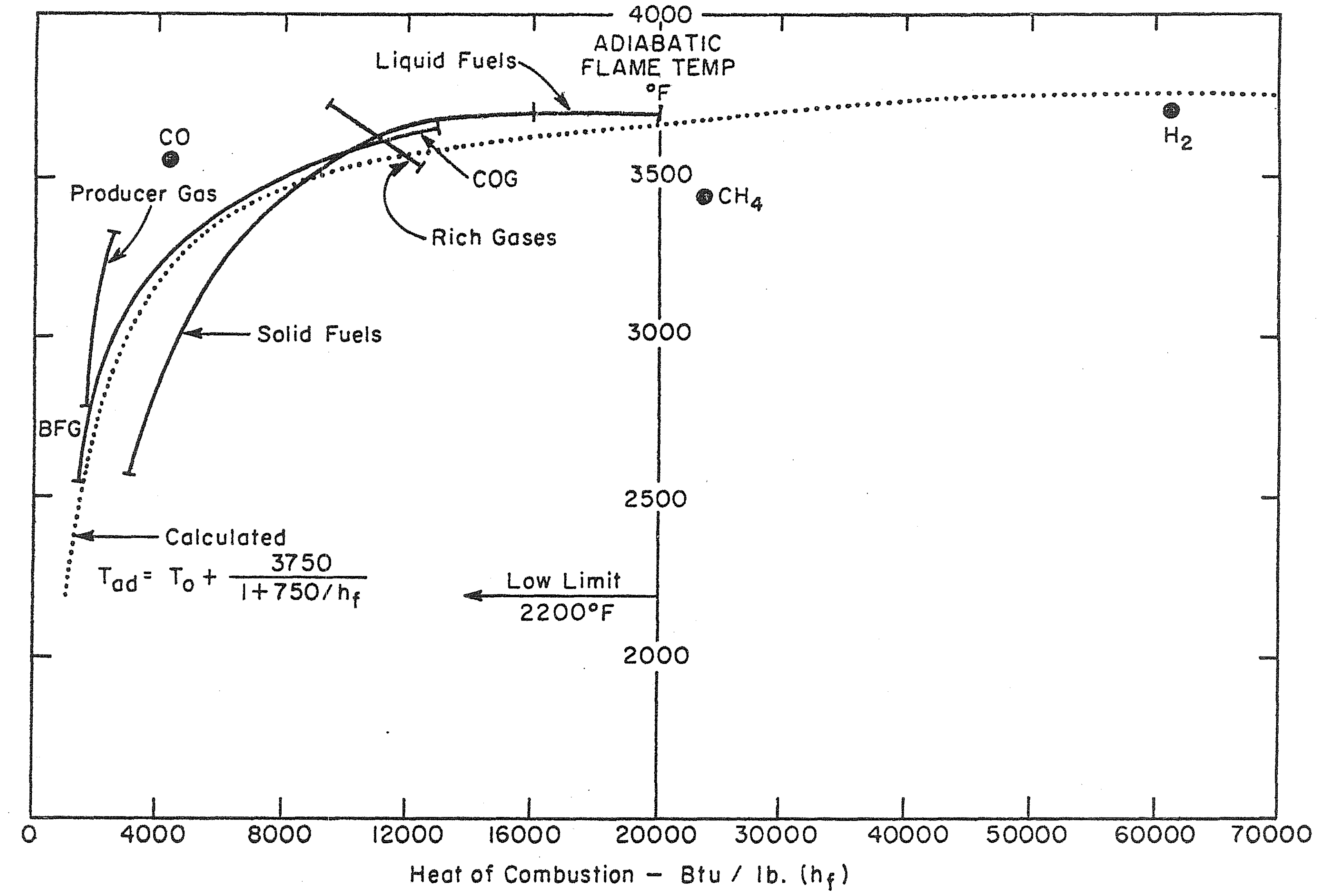

Figure 3 - Variation of adiabatic flame temperature with heat of combustion. (Note: change of scale at 20,000 Btu/lb.)

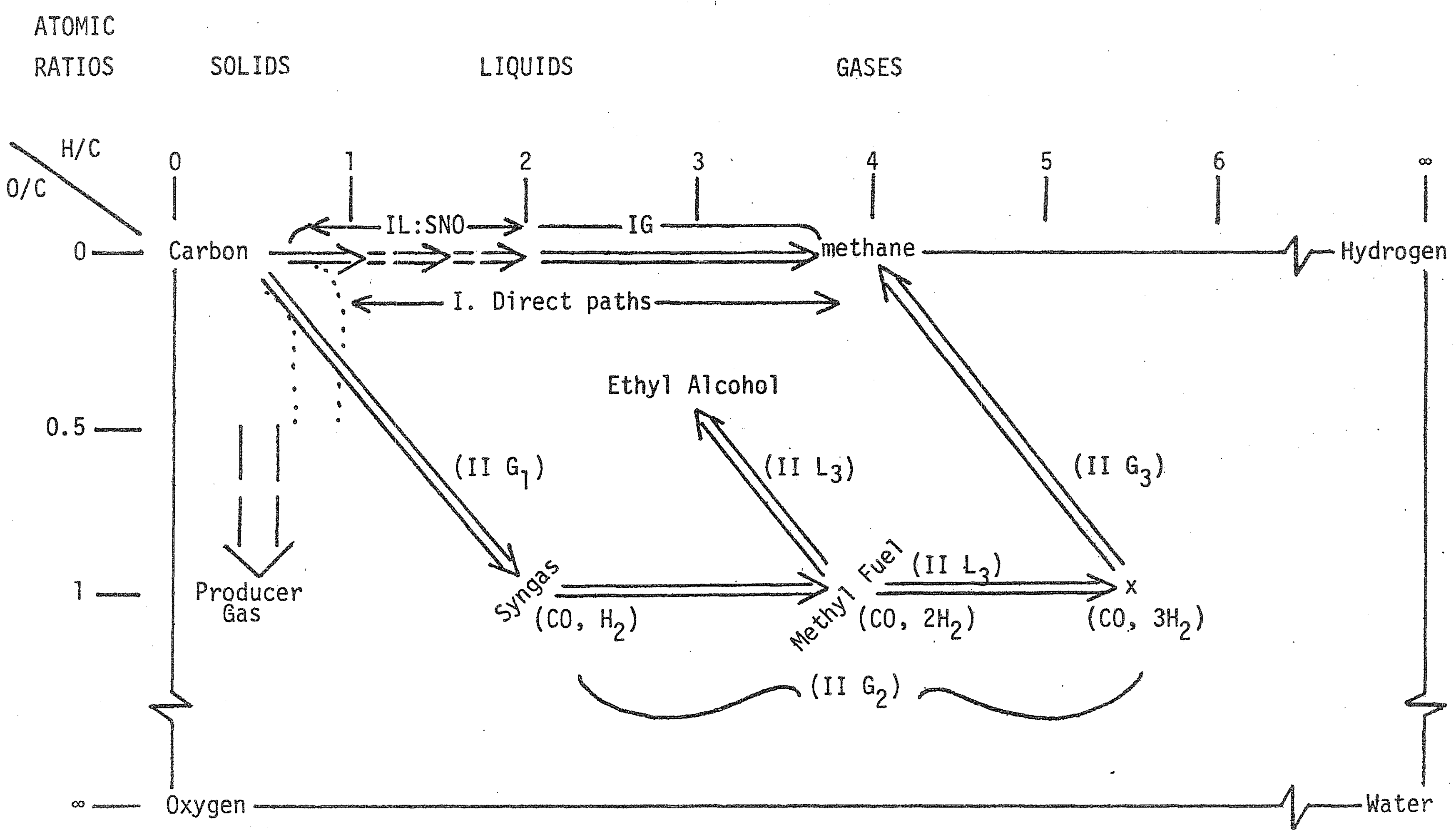

Figure 4 - CHO Diagram for Fossil Fuels and SNF Production from Coal by Hydrogenation, Illustrating: (I) Direct paths to liquids and gases; (II) Indirect paths to liquids and gases.

Legend. ⟹ SNF path
...... Coal band

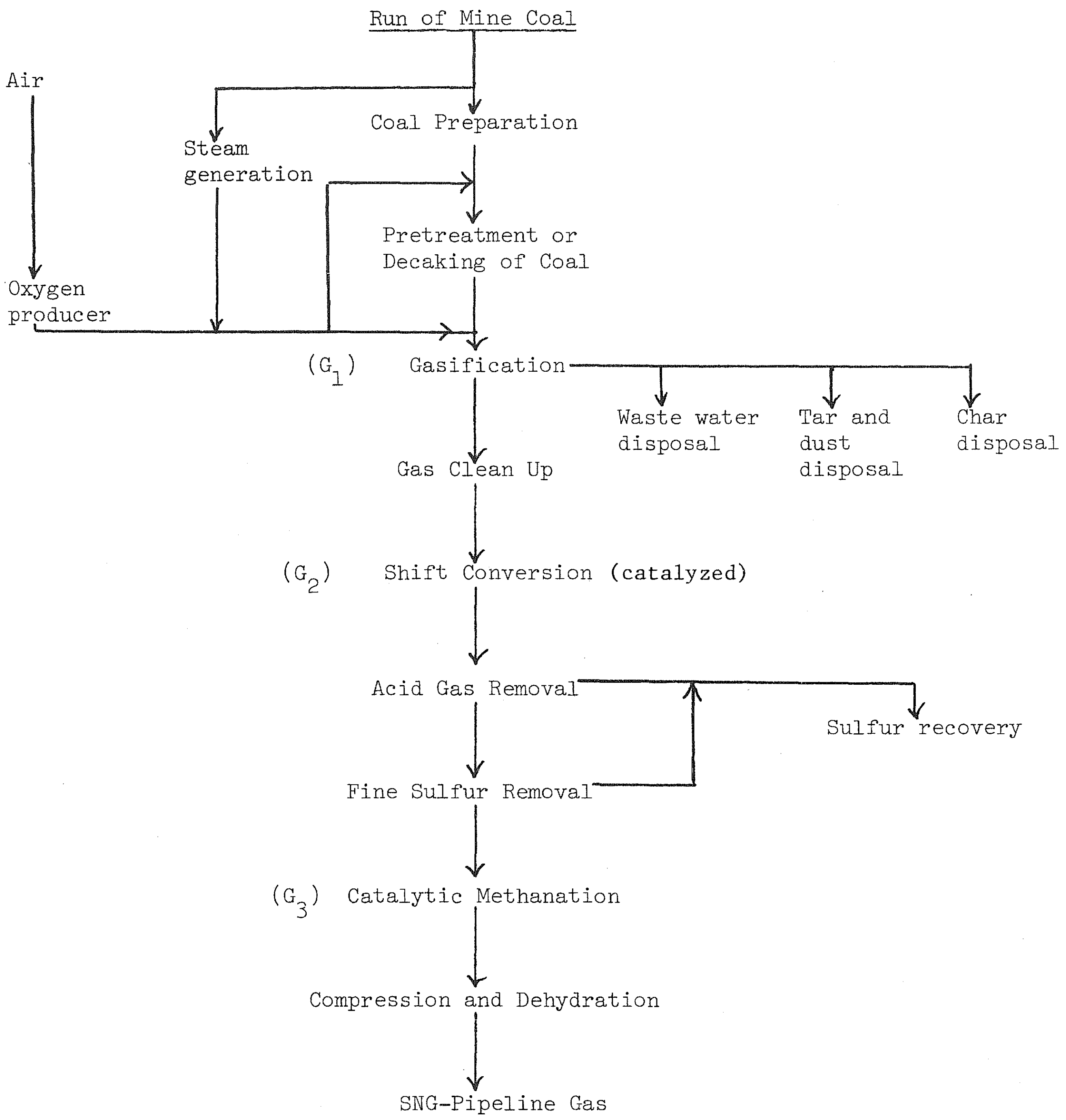

Figure 5- A Generalized Process Scheme for Making SNG from Coal.

Table 3

Handling and Cleanability Properties

Property	Coal	Oil		Gas
		resid.	distill.	
Storage	requires precautions	easy	easy	relatively easy
Transportation				
road/rail/water	easy when loaded	easy	easy	----
pipeline	water/oil slurry difficult	easy	easy	easy
Feeding	v. difficult	some difficulty (steam eracing)	easy	easy
Metering	v. difficult	some difficulty	easy	easy
Impurities				
inorganics	high	med/low	low	(none)
org-Sulfur	low to high	low to high	low	(gaseous sulfides: H_2S)
Cleanability				
inorganics	v. difficult	relatively - - - easy		(none)
org-Sulfur	v. difficult	relatively - - - easy		easy

Table 4 - Principal Comparative Factors in Coal Conversion to SNF

	I Direct Hydrogenation	II Indirect Hydrogenation	III Producer Gas	IV Pyrolysis
1. Directness of Paths (direct preferred)	Direct	Indirect	Direct	Direct
2. Temperature (low preferred)	L	Syngas H	H	L
3. Pressure (low preferred)	H	M	At	At
4. H_2 required (none preferred)	yes	---	---	---
5. O_2 required (none preferred)	---	yes	---	---
6. Catalysts (none preferred)	yes	yes	---	---
7. Auxiliary Reactors (none preferred)	yes (H_2 gen)	yes (O_2 gen)	no	no

Table 5

Methods for Converting Coal to Energy

	Commercial
I. Direct Firing: requires clean coal or clean-up methods for compliance.	
1. Lump (grate) firing	
(i) hand fired	yes
(ii) stoker fired	yes
2. Crushed firing - Fluid bed	
(i) ballasted	no
(ii) unballasted (Ignifluid)	yes
(iii) fast fluid bed (Szikla-Rozinek)	no
3. Pulverized (fine ground) firing	
(i) standard pulverized coal combustion (<100 microns)	yes
(ii) ultra-fine ground (<10 microns)	no
II. LOgas: Producer-gas/water (syn) gas (CO, H_2, N_2, [CH_4]) (100 to 300 Btu/cu.ft.)	
1. Fixed bed, vertical shaft (Wellman, Lurgi) - counter flow	yes
2. Fluid or fast fluid bed	no
3. Entrained (fine grind: Koppers Totzek)	yes
Notes: (1) Units in principle can be atmospheric or pressurized.	
(2) Most units are continuous; small water gas may be intermittent.	
(3) Sulfur is removed as H_2S by standard methods for the cold gas; hot gas cleaning is a problem.	
(4) Gas can be delivered and used hot, with ash and S, or cold cleaned.	
(5) Efficiencies are 85 to 90% used hot, 70 to 75% used cold and clean.	
III. Pyrolysis: Coking ovens - yields are	yes
(1) tars (can be used for some chemical feedstock)	
(2) coal gas (500 Btu per cu.ft. of H_2, CO, CH_4)	
(3) coke (feed for gas producers)	
Note: Emissions are under control using continuous vertical retorts.	
IV. HIgas: SNG from coal (1000 Btu/cu.ft.)	
1. Direct production	no
2. Indirect (syngas to shift to methanation)	no
V. Liquefaction: SNO from coal	
1. Solvation (solvent refining)	no
2. Direct catalytic (Synthoil: $CH_{0.9}$ to $CH_{1.1}$	no
3. Methanol: from syngas ($CO + 2H_2$) to CH_3OH	yes

Table 5 Cont'd

	Commerical
4. Fischer-Tropsch	yes
5. Bergius	yes

Note: The last three are commercial on a proportionately small scale.

VI. Combination Fuels	
1. Coal dispersion in oil	no
2. Coal dispersion in methyl fuel	no
VII. Direct Power	
1. Diesel (ultra fine grind)	no
2. MHD	no
3. Gas turbine	
(i) Low-Btu gas	yes
(ii) Direct fired clean coal	no
VIII. Mixed Methods	
1. Two steam cleaning options by deep cleaning: clean stream (50 to 80% of total) to conventional equipment with no FGD necessary; dirty stream to specially equipped boilers or gasifiers.	no
2. Partial pre-cleaning (low efficiency) with partial (low efficiency) cleaning of inter stage gas with (low efficiency) FGD. Overall high control efficiency.	no
IX. Underground gasification	no

Table 6

Sulfur Control Strategies

I. Pre-Combustion Cleaning

(1) Mechanical (physical) (inorganic sulfur only)	(i) dry methods (ii) wet methods (floatation etc.: Trent process etc.)
(2) Chemical (total sulfur)	(i) hydrodesulfurization (ii) oxydesulfurization (iii) solvation or other removal of mineral matter

II. Inter-Cleaning

(1) Gasification strategy: sulfur removed as H_2S in an inter stage of the processing	(i) Producer/water (synthesis) gas -- including combines cycle operation (ii) Pyrolysis (destructive distillation in coke ovens) (iii) Indirect methane production (HIgas)
(2) Liquefaction strategy	(i) Solvation (SRC) (ii) Synthoil production

III. Post Cleaning

(1) Stack gas cleaning (FGD)

[2 Tall stack dispersion (dilution*)]

*Dispersion is not advocated as a strategy for control of sulfur emissions, but it is advanced as an interim strategy for control of ambient air levels.

*Source: Ref. 4

CHAPTER IV

ASPECTS OF COAL LIQUEFACTION: INFLUENCE OF TIME SCALE AND PHYSICAL SCALE ON ESTIMATED COSTS

1. Introduction

This chapter illustrates some of the scale problems described in Chapter II with a focus on the DOE Coal Liquefaction program, and with emphasis on the three most promising liquefaction processes. The time scale for development is compared with the development of the coal liquefaction program in Germany between 1925 and 1945.

2. Liquefaction Processes Considered

2.1 The most promising liquefaction processes today, according to a reasonable consensus, are the (Gulf) SRC II, the EXXON Donor Solvent process (EDS), and the Hydrocarbon Research "H-coal" process. An essentially similar process is the Consol (Consolidation Coal) Donor Solvent Process, which had reached a pilot plant stage in 1963 before work was suspended.

2.2 Liquefaction Process Elements. All four processes can be regarded as essentially variants or extensions of the German coal liquefaction processes commercialized in 1940 and used in World War II. By 1944, 12 plants were operating, producing about 4,000 bbl/day per plant, or nearly 50,000 bbl/day from the 12 plant. The original process, dating from 1915, is known as the "Bergius" hydrogenation process. This is a process that involves "liquid-phase" hydrogenation.

Liquid-phase hydrogenation is simple in principle. Ground coal is slurried in an oil, and the slurry mixture is forced with hydrogen gas through a heated reactor, which can be a heated tube, a tank, or some type of fluid bed. A catalyst may or may not be added to the slurry to be carried through the reactor with the slurry. An alternative is to use a fixed catalyst in the reactor; this may be catalyst pellets inside the tube or tank, or attached to the tube or tank wall, or forming the material of the fluid bed. The function of the catalyst is to aid hydrogen transfer to the coal. Catalysts may be special metals or metal sulfides or oxides of Cobalt, Molybdenum, Nickel, or Tungsten; however, coal ash may also be an effective catalyst.

The oil used in the slurry is primarily required as a carrier for the coal, to take the coal through the reactor. The best source of oil is the liquefaction product itself so that a fraction of the oil produced by hydrogenation of the coal is recycled.

The oil may also serve an additional purpose, acting as a "donor" solvent. Some of the hydrogen in the donor solvent is easily detached and transferred to the coal particles. The donor solvent molecules are then short of hydrogen that can be obtained from the hydrogen gas. The donor solvent molecules act as shuttles, carrying hydrogen from the hydrogen gas bubbles, or hydrogen dissolved in the oil to the coal. This is found to be a more efficient method of adding hydrogen to coal than by direct addition. This, in turn, reduces the pressures and temperatures at which hydrogenation is possible. A good donor is tetralin. The oil produced by the coal liquefaction may contain such donors.

If a catalyst is present with a hydrogen donor solvent, its function can be to aid the recharging of the donor. Hydrogen is adsorbed on the catalyst surface and is available to the donor solvent when its molecules also adsorb on the catalyst surface. The donor solvent molecules then shuttle between the coal particles and the catalysts.

2.3 Summary Comparison of Processes. Table 7 compares the essential features of the five processes principally being considered. The following differences may be noted:

(1) The use of donor solvents since the 1940's or improved catalysts have so improved the efficiency of the process that pressures have been drastically reduced from the 1940 operations, by half to one order of magnitude.

(2) At the same time, reaction times have also been substantially or drastically reduced, being down to 2 to 20 minutes from a period of 1 hour in 1940.

(3) The Gulf oil SRC II is nominally a non-donor solvent process; however, the process uses recycle oil which has been found to be a natural donor solvent. At the same time, the recycling also supplies coal ash that acts as a catalyst.

(4) SRC I is a process that is essentially the same as SRC II except for the use of recycle oil. Lacking the donor solvent effect, the hydrogenation is less efficient, and the product is a low-melting-point solid. SRC II does use more hydrogen.

(5) The two processes named as "donor-solvent" nominally use no catalyst, but naturally occurring coal ash may provide some catalytic action.

(6) The final product in all the processes is essentially a mixture of product oil, mineral matter or ash, and solvent or slurry carrier where this is different from the product oil. These constituents must be separated from each other. This adds at least one further reactor to the process.

Distillation is the preferred method of product/solvent regeneration.

(7) The processes use different numbers of stages. The EXXON Donor Solvent (EDS) has two, which provides some apparent flexibility in use, but may lead to greater coke formation than if all reactions occur together.

2.4 Some Problems. The conversion processes and their liquid products do not have total acceptability for a number of reasons.

(1) The hydrocarbon products of the hydrogenation may react with additional (expensive) hydrogen over the available catalysts to produce an unwanted wider range of hydrocarbons with increased hydrogen use. This unnecessarily increases hydrogen consumption.

(2) The processes are reasonably and acceptably efficient in sulfur removal. SRC is the least efficient, but the most advanced technically. Improved S-removal would increase acceptability.

(3) There is a progressive loss of catalyst activity by accumulation of mineral deposits on the catalyst pore structure. This is more critical in the case of a fixed catalyst that cannot be continually removed and replenished.

(4) The liquid products have several potential disadvantages:
- all tend to have high nitrogen; this reduces acceptability for immediate use as a Syncrude or in combustion. Combustion can lead to NO_x unless this can be controlled by combustion modification (e.g. staging). For use as Syncrude, denitrogenation is necessary.

(5) Low hydrogen consumption leads to heavy grade oils of low H/C ratios with high pour points, particularly from the SRC process; and this leads to potentially poor atomization, combustion stability, and emission characteristics.

(6) The same H/C characteristics may also present handling and storage problems; the fuels may be heavy enough to require heated storage tanks and steam tracing of feed lines.

(7) The oils contain residual ash that may contain trace elements that could damage superheater tubes or gas turbine blades and the like.

(8) Coal is a widely variable feedstock, and it may take many years before there is complete information on the influence of coal type and mineral matter composition on the product oil characteristics and ash content. Upgrading of most product oils may be necessary which may reduce output and increase costs.

Note: The original Bergius process was re-investigated after World War II by the Bureau of Mines. It was found to be uneconomical for reasons listed in Table 8. The SRC, EDS, and H-coal Developments were designed to improve the economics.

3. Development Status and Cost Estimates

3.1 Development Status. Table 9 lists the present status (1979) for the processes listed. Figure 6 shows this in a more general perspective, on the basis of plant scale-up with time. Figure 6 also compares the development time with the development of the German program from 1920 to 1945. It may be noted that:

(1) The rate of development from bench scale development of the concept is apparently non-linear, but with something of the same overall time scale to reach a given commercial size for both the German and the DOE programs.

(2) A scale of 4,000 bbl/day was regarded as commercial scale in Germany; this is regarded as pilot plant scale in the DOE program.

In either case, the scale-up time to that point was 10 to 15 years. Scale-up from bench scale to 50,000 bbl/day produced by 12 plant required 20 to 25 years in Germany, and is estimated at about the same period for a single full-scale pioneer plant in the DOE program.

(3) In the DOE program, the demo plant will use reactors that are an order of magnitude larger than those used in the German program. This is to achieve cost efficiencies of scale that are necessary if a number of commerical plant are to be able to have any significant impact on the oil use in the country. The stated DOE program is the production by 1990 of less than half a million bbl/day from 9 plant. This is only about 2.5% of today's use, or about 9 or 10 day's supply. A major contribution would require more like 50 to 100 plant.

3.2 Cost Estimates. Figure 7 illustrates the projected reduction in capital costs per bbl/day. The reduction in cost is approximately a negative two-thirds empirical power law with some indication of flattening at the large-size end. It demonstrates most convincingly the effect of scale on cost. It ignores the probable problem of decreasing reliability above a particular size: in electricity generation, for example, some sources indicate that with today's experience, peak reliability is to be found at about 650 MW(e), although this can be expected to increase with time.

These figures can be used to illustrate the approximate cost estimates that can be made of the price of SNO produced.

For a 60,000 bbl/day plant, the capital cost is about $1.4 billion. At 10% as the cost of money, amortization is estimated at:

$$\$1.4 \times 10^{9} \times (10\%/100)/60{,}000 \times 365$$

$$= 6.4 \quad \$/\text{bbl}$$

At 2 bbl/ton of coal, the fuel cost is $10/bbl for coal at $20/ton. A first requirement in cost is therefore:

Fuel cost (2bbl/ton at $20/ton) =	10 $/bbl
Amortization	6.4
Total	16.4

Adding in the cost of labor, maintenance, and all other costs makes it clear that oil from other sources has to be above or substantially above 20 $/bbl for SNO to be competitive, so long as all costs are not too sensitive to increases in natural oil costs. This has not been the case in the past.

4. Conclusions

The disconcerting conclusion from this simple evaluation is that it may be necessary to wait one or two decades before the price of natural oil is so high, due to scarcity, that it ceases to have the leverage effect it has had in the past on general price levels.

This is taking the view that, for reasons given in the earlier chapters, oil is the swing fuel that is not only the preferred fuel for many purposes but for some (e.g.,transportation) is the only fuel. As this significantly affects the cost of living, it means that increased imported oil costs will be reflected in increased costs of coal (mining and transportation), SNO plant operation, and plant maintenance. This means that there is a differential or "wedge" between natural oil and SNO that is partly maintained by the feedback effect of rising oil costs. The wedge must be diminishing in size, but at what rate is evidently unknown at present. If world oil supplies are effectively depleted in 30 years, the wedge might go to zero in about 20 years. If that guess is correct, SNO plant will not be economically justifiable in less than about 15 years.

One of the additional factors that makes oil the swing fuel is the large fraction of the energy market that it supplies. The feedback effect of oil prices is progressively reduced as circumstances force or encourage moves to other fuels, notably coal. The most effective means of doing this would be to remove price controls. This will almost certainly happen de facto, even if price controls are continued de jure because of the almost certain development of a gray or black market, where true market prices (demand matching supply) would prevail. Since energy accounts for 5 to 7% of industrial production costs on average (compared with 3 or 4% ten years ago) there is still relatively low elasticity between price and consumption at the average level and below. The substantial energy savings already achieved by industry are in those industries with generally above average fuel costs in production (energy intensive) where price and conservation are more sensitive. Proportionate savings have mostly not been achieved at the less sensitive end, which is largely why the average energy costs in industry have been rising. This means that the very large number of small energy consumers would be best able to pay prices above the controlled value, and would at the same time be most difficult to police. The problem is politically sensitive.

At the same time, the situation is inherently illogical where there is a threat of shortages leading to rationing, but price controls delay the day when SNO could be competitive.* The source of the problem would appear to be the regulation of natural gas prices from the 1950's which created an artificial fuel price structure and fuel-type mix that now has to be resolved by artificial means. The answer may have to be the provision of subsidies or loan guarantees that would sufficiently reduce costs to a competitive point (i.e., reduce the wedge artificially). This may be the only means of changing the fuel-type mix to the point that the price leverage of natural oil is reduced to a tolerable level.

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*The idea that expensive SNO or SNG plant would be hostage to Arabian oil prices would seem to be absurd. The Arabs themselves would now seem to be hostage to their own high prices.

Thus, from a strict economic point of view, it may not be possible to justify pass-through of costs of SNF plant to present customers for at least a decade.

From a broader policy point of view, however, the need to reduce the price leverage of imported oil may require justification of passing through SNF plant costs to present customers to protect future customers in 10 to 20 years' time, many of whom are also today's customers.

Table 7

Features of Hydroliquefaction Processes

	1940 Bergius	Consol Donor-Solvent	Gulf/ PAMCO SRC II	EXXON Donor-Solvent	Hydrocarbon Research H-Coal
Number of Stages	Single, batch	Single	Single	Two	One or multiple
Reactor type	Sump/tank	Tank	Tank/ Tubular	Tubular	Ebullating CSTR
Pressure, psig	10,000	500	1500	2000	3000
Temperature, °F	800-900				
Reaction time	1 hr.	2 to 20 mins.			
Catalyst	Red mud	None	Recycled Coal Ash	None	Co-Mo Ni-W
Solids Separation Technique	Centrifuges Filteration Coking	Hydroclones Centrifuges Filteration	Critical Solvent Deashing	Fluid Coking	Hydroclones Filteration Coking
Solvent Regeneration	Distillation	Fluidized Coking of Hydroclone Underflow	Distillation	Catalytic Hydrogenation	Distillation

Source: Duraiswamy, Occidental Research Corp.

Table 8

Problems of Bergius Process

1. Operation required pressures ranging from 3000 to 10,000 psi
2. Reaction (reactor retention) time was very long: 1 to 2 hours
3. Product oil that had to be recycled was heavy; it displaced so much coal that the quantity of coal that could be hydrogenated was reduced by nearly 50%
4. Heavy oil, ash, and unreacted coal had to be separated (a continuing problem)
5. The cost of generating and compressing hydrogen was high, a reason for reducing the hydrogen addition to a minimum
6. Finished product had to be produced by a final vapor phase hydrogenation

Table 9

Major DOE Funded Coal Liquefaction Projects

NAME	PROCESS	DEVELOPER	STATUS
SRC-II	Coal Hydrogenation	Gulf Oil	30 TPD Plant at Tacoma, Washington 6 TPD Plant at Wilsonville, Alabama Demo Plant Design Begun
H-Coal	"	Ashland Oil	600 TPD Demo Plant Under Construction
EXXON Donor Solvent	"	EXXON	250 TPD Demo Plant Under Construction
Consol Donor Solvent	"	CONOCO	Past 1963 Pilot Plant Restarted Currently by DOE at Cresap, W. Va.
		Past Technology	
Bergius	Coal Hydrogenation		Commercialized in 1940 By Germans - 12 Plants (None Operates Currently)

All of these processes are based on essentially the same chemistry - Coal Hydrogenation

Source: Duraiswamy, Occidental Research Corp.

Figure 6

U.S. COAL LIQUIFACTION PROGRAM

Data sources: Brame and King,"Fuel" (pre-1960); others misc.

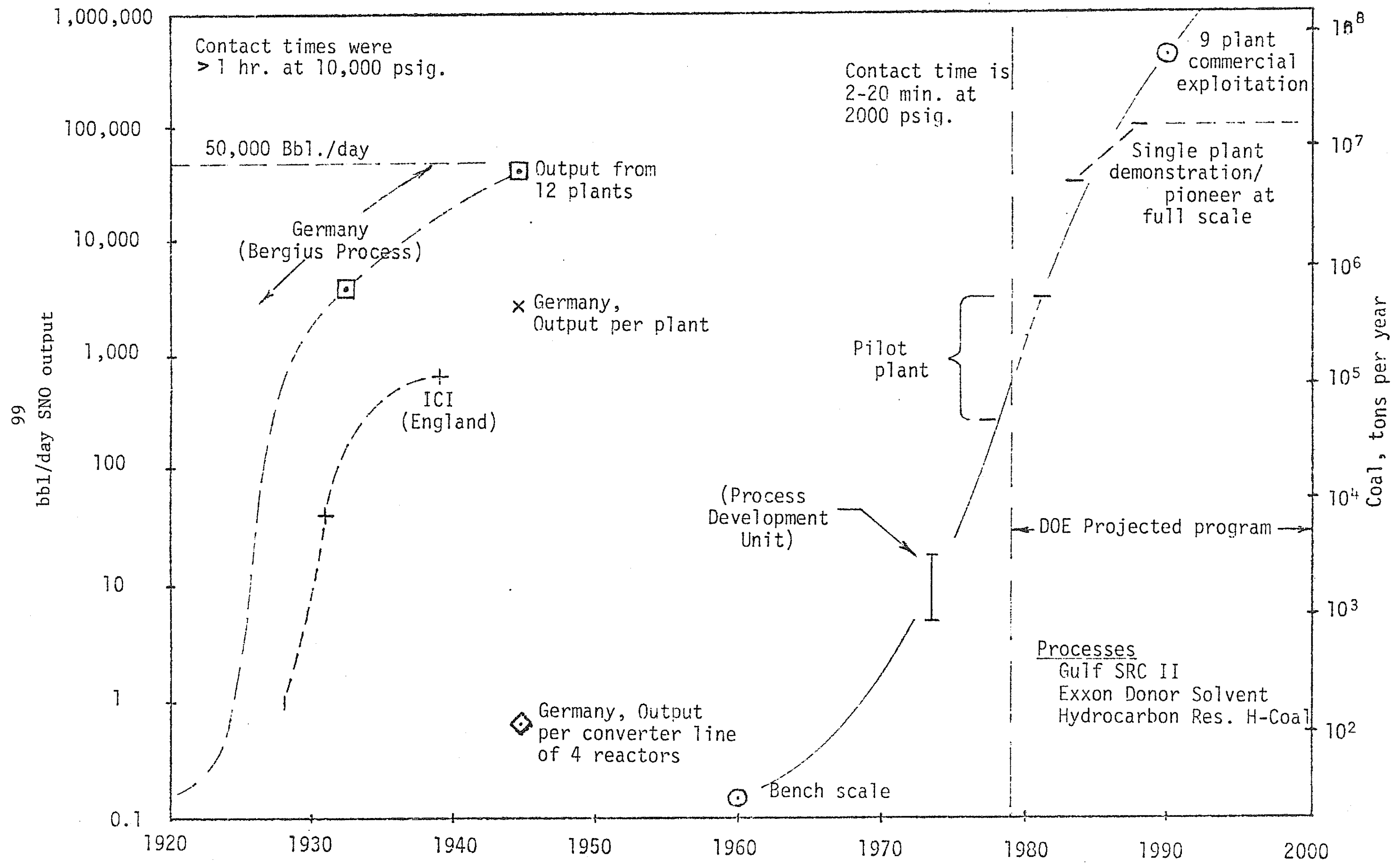
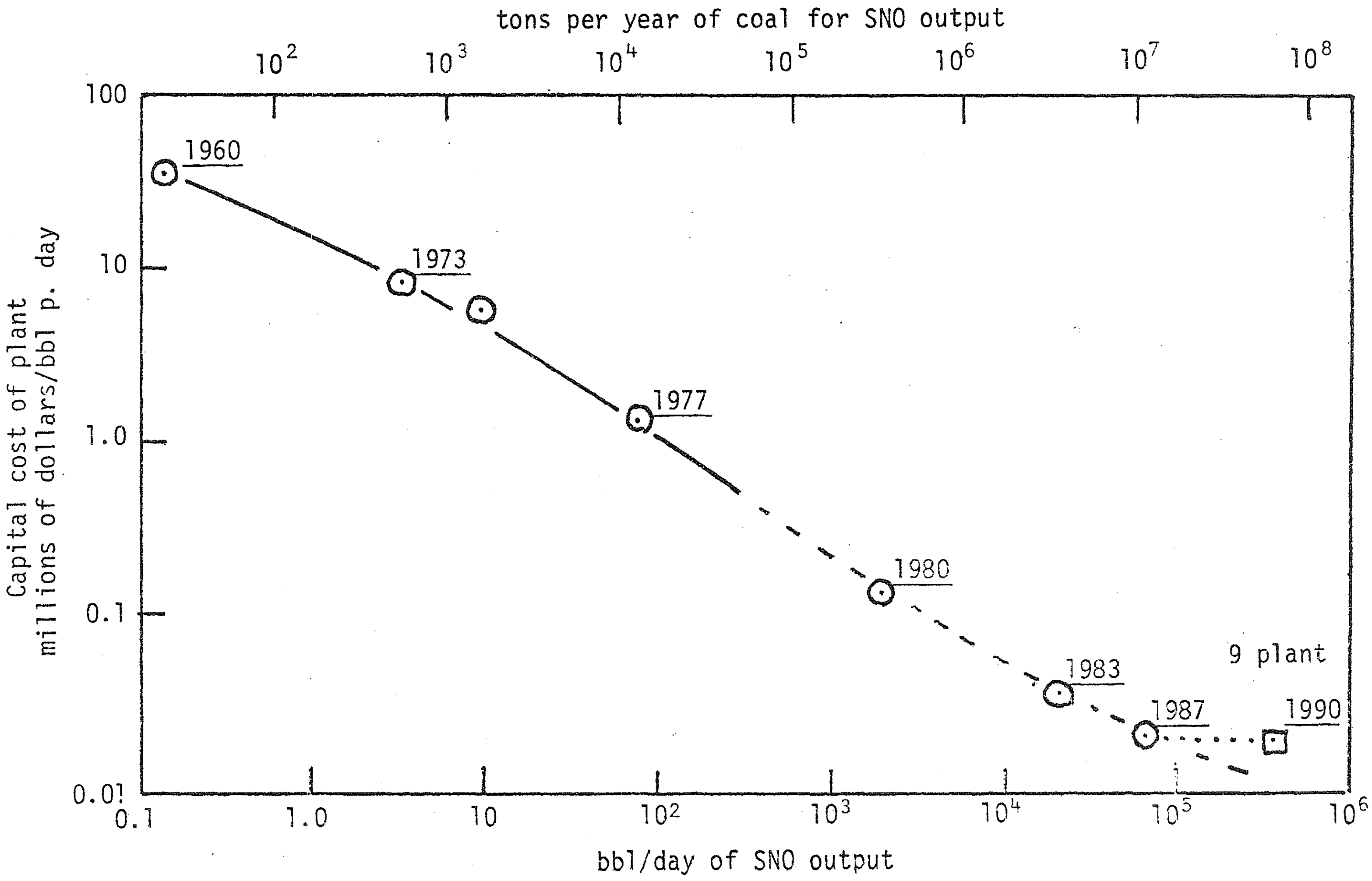


Figure 7 - Effect of scale on cost. Reduction of capital cost of plant ($MM/bbl-day) with increased plant size for donor-solvent SNO production (SRC-II, EDS, & H-coal). (Source: Gates, B.C., ChemTech Feb., 1979)



CHAPTER V

ELEMENTS OF COSTING PROBLEMS

1. Introduction

This chapter is concerned with summarizing some central aspects of costing of synthetic fuels production from coal. The matter was touched on briefly in Chapter IV in which it was shown that coal was a significant-to-major fraction of the cost of SNO production. In this chapter the point is elaborated, with extension to gases, the objective being to show the extent to which the cost of synfuels is dependent on coal costs; and since these are themselves tied to overall living costs, both will rise together as the result of inflation. The break-even point at which synfuels are cost-competitive with natural fuels may, therefore, be further away than is often represented.

2. Some Background

Any discussion of the cost of synthetic fuels is bound to be a little unreal to the extent that the costs are based on many arguable assumptions, with some costs speculative or guesswork. The point was made most succinctly in a recent Report (June 1979) of the U.S. Senate Committee on Energy and Natural Resources (publication No. 96-17: "Synthetic Fuels from Coal: Status and Outlook of Coal Gasification and Liquefaction"). In commenting on estimates to be quoted later in this Report, the authors of the Senate Report noted, "Because of the lack of production experience, assumptions behind the(se) numbers (cited) are hazy at best." In the accompanying text they note further, "... no U.S. commercial plants have yet been built, so no one knows what the cost will be. It can be postulated, however, that the actual costs may be as high as twice the estimates."

It is also most evident that cost estimates have been changing rapidly in the last 5 to 10 years. Thus, estimates of present costs for SNG quoted in the Senate Report range from $2.7 to $4.7 per million Btu (respectively for Hygas and Synthane gas), i.e. $3.7 ± $1 per million Btu. These can be compared with estimates of $0.8 ± $0.4 per million Btu only in 1974, essentially reflecting estimates for 1970 to 1973. Earlier than that, in the late 1960's, when some natural gas was still being sold at $0.2 per million Btu, SNG was estimated at $0.4 to $0.5 per million Btu.

The rise in estimates reflects, in part, improved knowledge of behavior on a larger scale and improved process designs; but it also reflects real cost increases due to higher oil costs and inflation. This indicates one of the key factors: the extent to which coal prices, specifically, and thus synfuel prices, are tied in to oil prices, so that both rise together. The same is true of Operation and Maintenance costs (O & M). The point is further elaborated briefly below.

In spite of the changing estimates, a pattern of cost relationships would appear to be emerging that would appear to be substantially less variable with time, and this can be used as a guide to possible future costs. It would be particularly valuable if these can be related to coal costs as these reflect general raw energy costs which, in turn, correlate well with general price levels.

What follows is still essentially tentative. It has been the focus of the current phase of the project, but it has not yet been possible to develop firmly definitive numbers. The tentative estimates of relative costs are informative, nevertheless.

3. Some Current and Relative Costs

3.1 General Cost Structure. Detailed cost analyses are needed to obtain an initial pattern of costs; but such detailed analyses are out of place in a report such as this. What is of greater value is the end result of such analyses with costs in appropriately lumped categories. The prime categories in synfuels production are: (1) Coal cost, (2) Capital cost, and (3) Operations and Maintenance costs. These each have sub-categories as discussed below.

3.2 Coal Cost in Synfuel Production. The contribution of coal cost towards the final SNO or SNG cost depends on three primary factors: the cost of the coal supplied, the quality of the coal (Btu/lb. or ton); and the efficiency of conversion. As these are all somewhat or highly variable, their effects in SNO and SNG production have been evaluated graphically.

- SNO: Figure 1 is a graph of oil quantity obtainable (bbl/ton) from different quality coals (Btu/lb. or ton), at different assumed conversion efficiencies. This is based solely on Btu contents of the input coal and delivered oil. It says nothing about the quality of the delivered oil. If the oil is of such quality that it needs further refining, then inclusion of such an additional refinery step would be represented by an appropriate reduction in conversion efficiency.

  If most commercial coals on an "As Received" basis lie between 10,000 and 12,500 Btu/lb. (20 to 25 million Btu/ton), the graph shows that, at 60 to 65% conversion efficiency, oil production would typically range from 2 to 2.5 bbl/ton. Some sources suggest that 3 bbl/ton is realistic, but this is impossible to assess with any confidence while full-scale commercial-plant data are still lacking. The Senate Report cited above quotes figures of 2.5 to 3 bbl/ton at 65 to 70% conversion efficiency; but with some possible need for further S and/or N removal, and possibly lower initial efficiencies as large scale plant are developed, a median figure of 2.5 bbl/ton is probably a good planning value. (The German plant of 1940 operated at about 2 bbl/ton of brown coal.)

Figure 9 shows the contribution of fuel cost to SNO as a function of coal cost, at 2, 2.5, and 3 bbl/ton conversion efficiency. It shows that, with coal in the $20/ton range, the fuel cost can contribute from $6 to $10/bbl, depending on conversion efficiency. If oil is in the range $18 to $20/bbl and SNO is to be competitive, it shows that the coal cost would have to be 1/3 to 1/2 of the SNO cost. For estimating future prices, the extent to which coal costs are tied to natural oil costs then becomes a critical factor.

It may be noted that this method of presentation can be used to account for any pretreatment. If pretreatment is necessary, the cost can be incorporated as part of the initial coal cost.

- SNG: Comparable graphs for SNG production are provided in Figures 10 and 11. In Figure 10, the common range of coal quality from 10,000 to 12,500 Btu/lb. (20 to 25 million Btu/ton) at 40 to 50% conversion efficiency yields 7.5 to 12.5 million Btu/ton) at 40 to 50% conversion efficiency cost fraction is roughly $2 ± $0.5/million Btu (Figure 11). Natural gas prices will still have to rise substantially to match even that figure at source.

3.3 Capital Costs. This category lumps several factors together: debt service or amortization, taxes, depreciation, and profits. These can be estimated as appropriate percentages of the actual physical plant costs; here again, past history has shown some interesting increases.

- SNO: Current estimates (1979) from two separate sources of plant costs are typically $1 billion for 16 or 17 million bbl/year (40,000 bbl/day) or $1.4 billion for 60,000 bbl/day. These are increases of factors of 4 or 5 from 1970 to 1973 figures of $200 to $250 million for 50,000 bbl/day. Capital charges then run at $5 to $6/bbl at a 10% return.
- SNG: SNG plant costs have escalated by about the same factor. In 1970, plant costs were being cited at about $1/scfd of production capacity. This has now increased to $4 to $5/scfd so that a "small" commercial plant of 250 million scfd is now estimated at $1 to $1.25 billion, up from a quarter billion in 1970. Annual capital charges can run from $100 million to $150 million depending on the return and debt structure. This would add at least $1 to $1.5 per million Btu to the gas cost.
- kW Basis Comparison: An alternative basis for comparing plant costs is on the basis of Btu or kW delivered. Both a 50,000 bbl/day SNO plant and a 250 million scfd SNG plant deliver approximately 10^{10} Btu/hr, which is about 3,000 mW(t). These figures yield about $300 to $400/kW(t). This provides an interesting comparison with electricity generation.

3.4 O and M Costs. Operation and Maintenance costs are particularly difficult to estimate in the absence of actual operating plant data. Typically, O&M costs are generally estimated as 25 to 30% of final cost.

4. Some Comparative Costs

Table 10 is expanded from the U.S. Senate Committee Report cited above. It compares Capital, O&M, Coal, and total costs of production of low, medium, and high Btu gas, liquid boiler fuel, and gasoline. Figures are in $/million Btu with costs additionally in $/bbl for the liquid boiler fuel and $/gal. for gasoline. In parentheses, the cost percentages are given. As these represent 1978 estimates, it may be assumed 1979 re-evaluations would show up to 10% increases.

The values given are generally in line with data from other sources, with the greatest questions probably focussing on the fuel costs. With the exception of the fuel costs, the present impression is that the percentages should generally be given a range of about ± 10 percentage points.

The Table 10 data are derived from Commercialization Strategy Reports of pertinent DOE Task Forces, so they should be open to view as some of the best available data. Nevertheless, there are several questionable and other points to consider:

- The conversion efficiencies listed (calculated from the cited data) are acceptable for the low and medium Btu gas, but the figure for the high Btu gas is a high value that was current about 10 years ago. Values quoted in the 1970-73 period were down to the 60-70% range. Since then, the values have dropped to the 40-55% range, with this writer of the opinion that the lower end of the range is more probable when plant are finally built and actual numbers become available. The efficiency can be increased by 10 percentage points if coal can be used untreated (for caking) as compared with use after decaking treatment.
- The low Btu gas efficiency can be increased by 10 to 15 percentage points, and the cost drops about $1/million Btu, if the gas can be used hot and uncleaned. At that value, it can be competitive with NG delivered costs in some areas. It must be used on-site, however. It is totally uneconomic to pipeline it.
- The final cost data are somewhat misleading as no range is given in the Table. Some range does exist, as indicated above. The cost can be written as $3.5 ± $1/million Btu. The medium Btu and low Btu data are more accurate as they represent commercial plant costs. The liquefaction data, however, should probably be considered to be subject to about the same range (about ± 30%).
- The coal costs for the high Btu gas appear to be questionable. For the low and medium Btu gasification, the coal cost was taken as

$1.5/million Btu, which is in the range of $30 to $40/ton. For the high Btu gas it was taken as $0.5/million Btu, which is in the range $10 to $15 per ton. (The costs used in liquefaction are not given.) This would seem to explain the unexpectedly low fuel cost fraction, particularly with conversion taken at 71%. The real figure could be $1 to $2 higher, giving a production cost of $4.5 to $5.5/million Btu.

- It is also noted that the high Btu gas calculations are averaged over the 20 year life of the plant and, assuming falling gas costs with increasing experience, the initial production costs, according to the Senate Report, would initially be higher again.
- The breakdown and total costs for SNG and SNO production are somewhat comparable. They are within about 30%, which is comparable to the probable spread in total costs and substantially less than the suggested factor of 2 under estimate. They would be closer again with SNG fuel costs closer to $2/million Btu (and the oil costs may likewise be in that region).
- The approximate estimates of this present report (Sec 3) are roughly in agreement on the SNO unless the capital costs have been significantly underestimated, which may be the case; the figure may be low by $2 or $3/bbl. If the coal is in the $20 to $30/ton range, the cost would increase another $5/bbl or so to give a final figure in the mid $20's/bbl, which is in line with most recent estimates. It does show the sensitivity of the SNO production cost to coal cost.
- The approximate SNG cost estimates of this present report (Sec. 3) are higher by about $1/million Btu. Again, the capital costs are low, compared with the Senate Report costs, by about $0.5. The principal cost increase is in the coal cost. Here again, the final cost could easily rise by $1/million Btu as coal costs go from $20/ton to $30/ton.
- The O&M costs at about $75 million/yr. are then in the region of 7.5% of the plant capital cost (at $1 billion). This is a little low, but generally in line with figures given 5 to 10 years ago (of closer to 10%). At O&M costs of about 10% of capital plant costs, the O&M costs would be closer to 30% of the total SNF production cost.

- With fuel costs higher than given in the Senate Report, and capital costs higher than estimated (roughly) in Sec. 3, it would appear that present capital and fuel costs may be taken as roughly equal, at say 35 ± 5% of total cost. This would allow 30 ± 5% for O&M costs.
- If the cost proportions remain roughly the same as coal costs rise, it would seem that we can say very approximately that Capital to Coal costs are about 1:1; and O&M to Coal costs are about 0.85:1, for both SNO and SNG. This would give us a very rough yardstick, on a Btu basis, for the cost of SNO and SNG as approximately 2.85 ± 0.45 times the fuel cost. This means that synfuels should be roughly cost competitive with natural oil if the cost of coal per Btu is between 30 and 40% of the cost of natural oil.

5. Conclusions

The first clear conclusion from the above evaluations is that the estimated SNO cost is still above natural oil cost, and SNG cost is substantially above natural gas cost.

The second clear conclusion is that SNO and SNG cost are closely tied to coal costs. To the extent that coal costs are also influenced by oil costs, to that extent SNO and SNG costs will continue to rise as oil prices rise. It is to be expected that the differential between SNO and natural oil prices will be diminishing with time, but it has not yet proved possible to determine the rate at which this differential, or "wedge," is diminishing. As this determines the point in future time at which SNO is cost competitive with natural oil, it is a critically important parameter to evaluate if at all possible.

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Table 10

BASED ON U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES PUBLICATION NO. 96-17 (JUNE 1979) AND OTHER SOURCES

Estimated Costs of Synthetic Gas and Liquids from Coal

Units: $/million Btu
(% of total)

Type of Plant	Capital	O&M	Coal	Total	Conv. Effic.
Gasification					
- Low Btu	0.9 (24)	0.7 (19)	2.1 (57)	3.6	73%
- Med. Btu	1.4 (34)	0.7 (17)	2.0 (49)	4.1	75%
- High Btu (SNG)	1.8 (52)	1.0 (27)	0.7 (21)	3.5	71%
- SNG estimate of this Report	1.25 ± 0.25 (29)	1.1 ± 0.25 (25)	2 ± 0.5 (46)	4.3 ± 1	45-50%
Liquefaction					
- Boiler fuel (SNO)	1.3 (40) [($7.6/bbl)]	0.8 (25) [($4.7/bbl)]	1.1 (35) [($6.6/bbl)]	3.2 [($19/bbl)]	----
- SNO estimate of this report	1.0 (30) [($5.5 ± 0.5/bbl)]	0.7 (25) [($4.5 ± 1/bbl)]	1.3 (45) [($8 ± 2/bbl)]	3.0 [($18 ± 3.5/bbl)]	65%
- Gasoline	2.9 (48) [($0.46/gal.)]	1.6 (27) [($0.24/gal.)]	1.5 (25) [($0.23/gal.)]	6.0 [($0.9/gal.)]	----

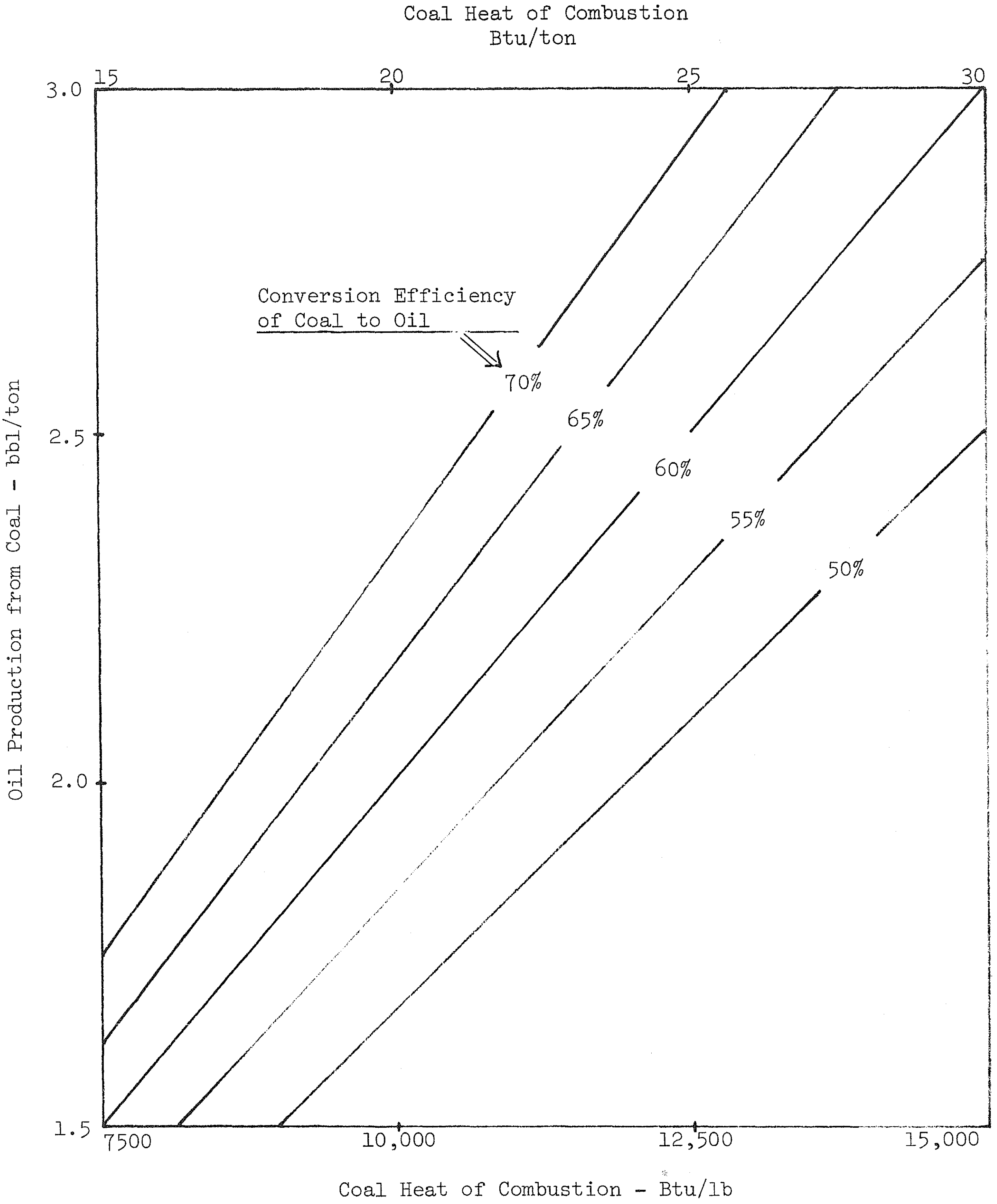

Figure 8 - Conversion of Coal to Oil; Oil Production (bbl/ton) as a function of coal quality and rank rated as heat of combustion (Btu/lb or ton) at 5 levels of conversion efficiency.

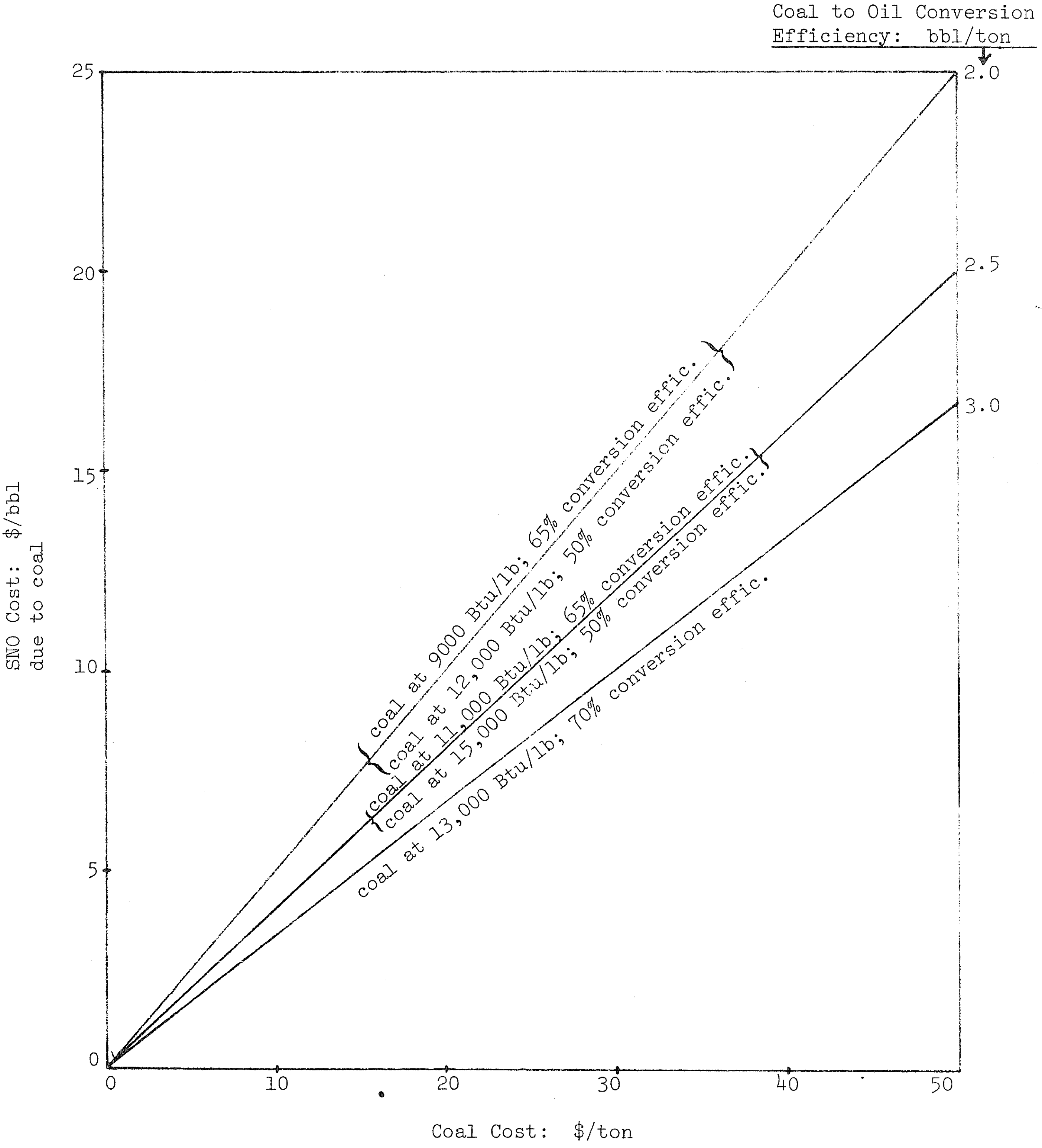

Figure 9 - Conversion of Coal to Oil; Cost of Synthetic Oil (SNO): contribution of coal cost to SNO cost as a function of coal cost at three conversion levels (bbl oil/ton coal).

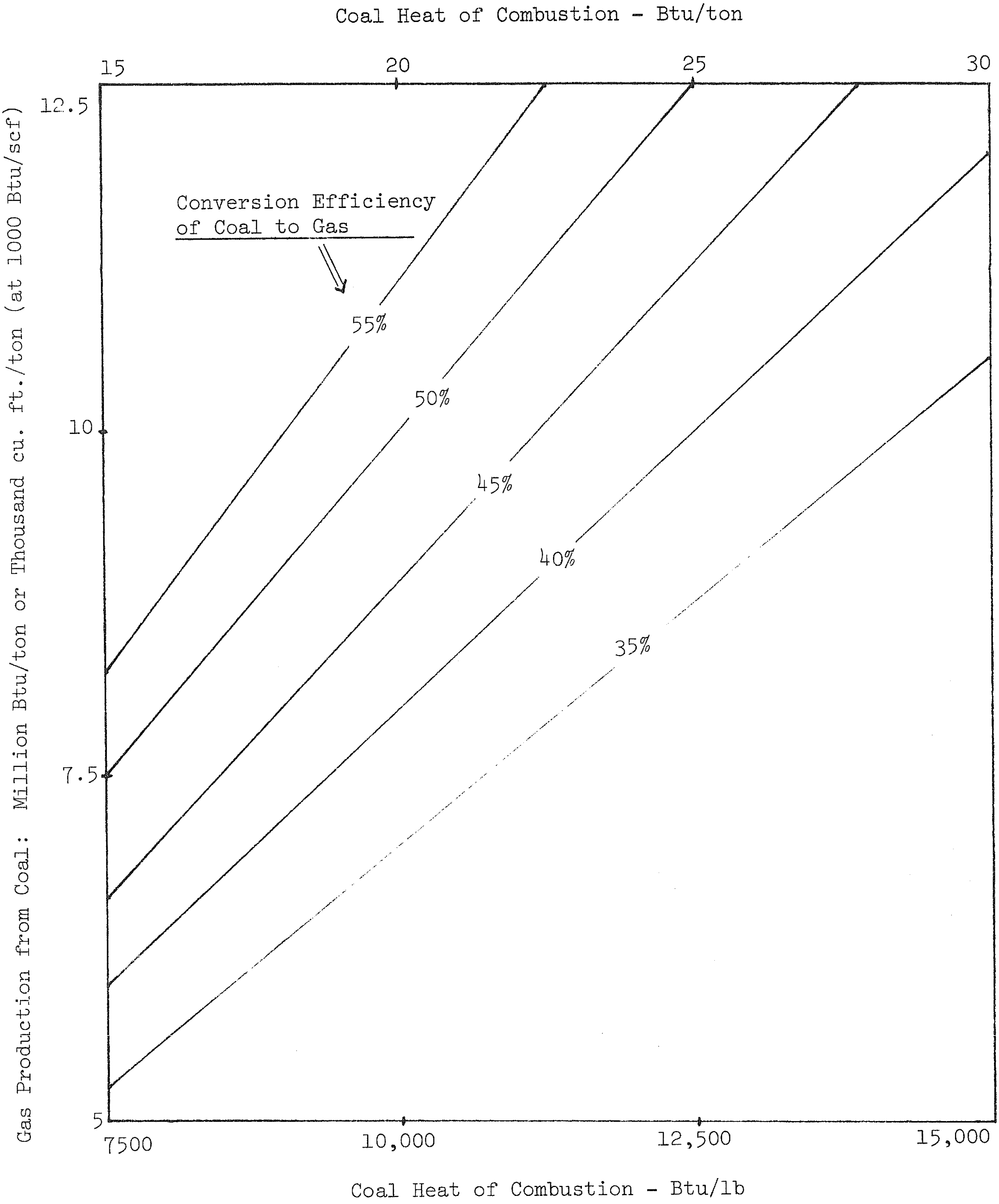

Figure 10 - Conversion of Coal to Gas; Gas Production (MM Btu/ton or thousand cu. ft. of 1000 Btu gas/ton) as a function of coal quality and rank rated as heat of combustion (Btu/lb or ton) at 5 levels of conversion efficiency.

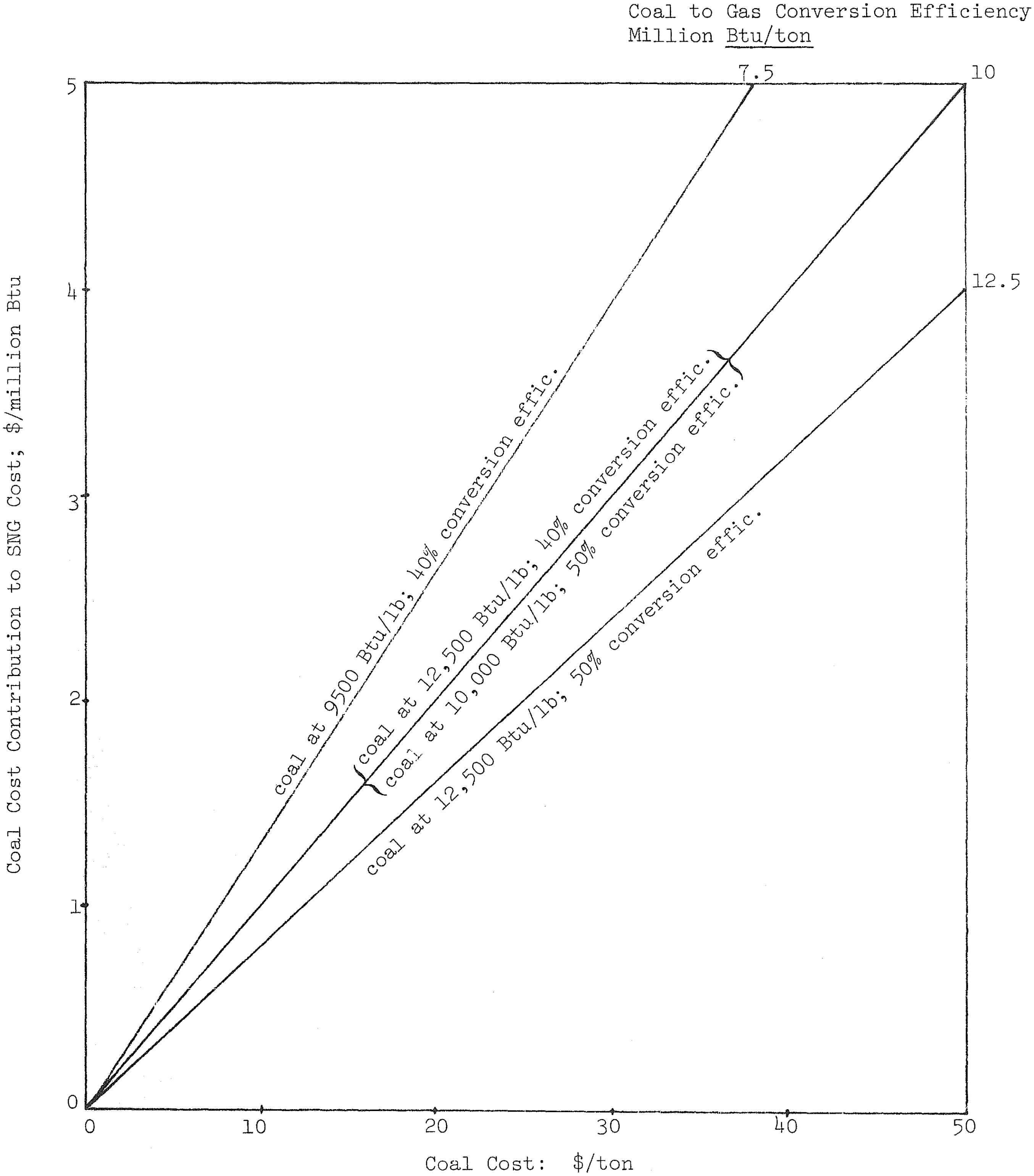

Figure 11- Conversion of Coal to Gas; Cost of Synthetic Gas (SNG): Contribution of Coal Cost to SNG cost as a function of coal cost at three conversion levels (million Btu in gas/ton coal).

CHAPTER VI

DISCUSSION, CONCLUSIONS, AND RECOMMENDATIONS

1. Discussion

Coal conversion in the regulated industries covers: high Btu gasification for pipelining; low and medium Btu gasification, and liquefaction to boiler fuels for electricity generation. Also pertinent is modified direct combustion, such as Fluid Bed Combustion for electricity generation. Medium Btu gas for supplementary pipelining must also be considered; although it may not necessarily be a regulated product, it can have considerable effect on the size of the regulated high-Btu gas market. For more detailed background, Appendix I lists the present status of major liquefaction and gasification programs. In addition to the processes listed in the Appendix, there is also other important experience and planning.

- The SASOL I liquefaction plant in South Africa has used the Fischer-Tropsch process since 1955 to generate oil, gas, and petrochemicals from coal via the Syngas route; and the present plant is to be supplemented by SASOL II, which is under construction, and SASOL III, which is authorized, to provide 50 percent of South Africa's needs by 1985.
- In high Btu gasification, the first commercial plant to be built in the United States may be the one proposed for Mercer County, N.D., costing about $1 billion, to produce 125 million scfd; however, the FERC administrative law judge ruling would not appear to be favorable at this time.
- There is also a low Btu gas proposal for development in the State of Illinois that would use the Kilngas reactor (a tumbling bed device) for an electrical generating plant; the start-up date could be 1980 or 1981.

Reviewing the status of different conversion or utilization proposals and demand requirements, one is struck by the predictions of disaster of five years ago that have not come to pass. To be sure, the development of an effective conversion program in the last five years would have begun inroads into reducing the outflow of payments for imported oil and would have shown a determination to reduce dependence on oil in general and imported oil in particular. The fact that such an effective conversion program has not been developed, however, is probably best regarded as clear indication that no "best" policy could be constructed then; and likewise, a review of the material in this report would suggest that the same is true today -- that there are still so many major uncertainties in all proposed conversion proposals and energy plans that rapid development of large scale SNF facilities is probably as premature today as it most probably was five years ago.

What is still missing is the small and intermediate scale "full operation" plant that would actually produce SNF products for the commercial market even if they were very highly priced. Existing PDU, pilot, and demonstration plant that operate for only 100 or 1000 hours do not test either the concepts or the processes in the same way that continued market production would do. It is an attitude of mind that considers any plant that is not commercially (cost) competitive as being not commercial so that it must be operated under special circumstances for limited periods of time. The barrier is always seen as the uncompetitive cost of the product. However, if the quantity produced is very small, the cost is rolled into the quantity supply from conventional sources, it is possible that the cost can be as easily met as in joint programs with DOE; both represent a subsidy, but the intention, planning, scope for more original ideas, scope for a wider range of ideas, and the mental attitude toward the plant would be very different. As estimates of magnitudes of costs, if production cost of SNG is ten times the conventional source cost, then supply by SNG of 1 percent of the distribution requirements would increase the delivered price by less than 1 percent, and a supply of 0.1 percent would increase the delivered price by less than 0.1 percent. Surcharges to allow a pass-through of such experimental costs to establish a growing base of continuous production experience would seem to be worthwhile, even if the SNG cost was not cost competitive in its own right. The objective would be to establish the necessary commercial production experience at initially small, but progressively increasing scale, with the smallest capital investment per plant or per process. This would permit a faster field evaluation of a wider range of processes, and produce the necessary engineering data for scale-up at the same time.

Small scale development of a range of different processes would have other advantages. It would be an earnest display of intention to develop alternative energy sources without having to select an unknown process today that would preempt alternatives and be economically disasterous in the event of failure; in short, it maintains flexibility and open options, particularly for implementing new concepts not yet thought of. Such flexibility is particularly important in view of the shifting position of conventional fuel supplies and other alternatives. The background to this is the appreciation that many projected disasters of the last five years did not come about, with projections of massive energy shortages by 1980 and corresponding unemployment. Energy use was, in fact, below demand, in part because of the economic slow-down or recession caused by higher oil prices, but only in part. The projections did not take into account the flexibility of the industrial/economic system that was able to conserve beyond expectation (in spite of claims to the contrary), eliminate specific energy uses beyond expectation, and shift to alternate power and energy sources beyond expectation. This was brought about largely by higher prices which also resulted in increased conventional fuel supplies, particularly of natural gas. There would seem to be scope for continued improvements and shifts of demand with further increase in prices. One of the most notable indications of this is the recent declaration by General Motors that the incentive to produce more fuel efficient automobiles is no longer being set by the Federal Government, but by consumer demand, or the marketplace, in response to higher gasoline prices. Removal of the federally mandated fuel efficiency targets would not now make any difference to the GM fuel efficiency development programs and targets. The lesson would seem to be that the whole energy field is still in such a state of flux that maximum flexibility in options for alternatives must be maintained for some time to come.

There are now also other factors that are being given greater weight than they were five years ago. There would seem to be greater optimism about further supplies of natural gas, even excluding the problematic Geopressurized deposits, from such sources as coal-seam methane drainage and production from tight formations. There is increasing concern about the possibility of uncontrollable toxic emissions from SNF plant, and even more serious in many ways, toxic components in the liquid products. There is also strong feeling that liquid hydrocarbons are better obtained by hydrogenation of tar sands, oil shales, and very heavy crudes that are not currently in production. Also gaining ground is the opinion, with some well argued support in the Report of the Energy Project at the Harvard Business School (Stobaugh and Yergin), that the energy pattern of the future must depend increasingly on renewable resources. The conclusions lie somewhat parallel to those implied by this Report that the possible contribution by coal may be somewhat or substantially overrated -- the development time scales are too long, the costs too great, and the possible quantities too small for coal to provide anything but a significant, but not dominant, contribution to the energy requirements of the future.

2. Conclusions

- It may be said at the outset that there is no evidently unique path of action that is clearly superior in providing supplementary energy by coal technology.

- All estimates show that the costs of conversion to either liquids or gases are high, with the proviso that the costs are more likely to have been underestimated than overestimated.

- A major component of SNF cost is the cost of the coal with estimates of 1/3 to 1/2 of the SNF cost due to this; and the capital cost is of similar magnitude. If both inflation (and thus interest rates) and coal mining cost are tied fairly closely to the price of imported oil, the SNF cost will continue to rise with the oil prices, thus holding the break-even point away.

- There are major technical and environmental uncertainties in coal conversion operations, notably on-line reliability of conversion plant, particularly when dealing with a continually changing range of coals where properties can change along the seam; there are also serious emission and toxicity questions to be resolved.

- There is increasing evidence that the existing energy delivery and use system is more flexible and more able to respond to necessary signals such as higher prices than had been thought a few years ago; likewise, there is more scope possibly for the expected energy load or size of the market to be reduced, and more particularly for the mix of energy supply methods to adjust to changing supplies.

- It would be wise, therefore, to err on the side of caution in developing an SNF industry until there is at least more operating experience on a continuous commercial basis of much smaller plant than would normally be considered economic.

- A further consequence is that the overall expectations of major expansion of coal production are probably overrated; if this is the case, it may very well be of vital importance in view of the problematical ability of the mining industry to expand production to the levels required for development of a major SNF industry in the next two decades.

- With less dependence on the traditional fuel supplies of gas and oil, with coal (mostly direct fired) for some purposes and mainly utility use, a wider range of energy supplies can be expected, with increasing use of heat pumps, solar heating, and the like; in spite of the less than optimistic expectations for major expansion of coal use, significant expansion is nevertheless expected, with probably a wider range of uses to produce a range of different gases in particular. The mix of different energy sources is likely to become much more varied in different locations --that is to say that there is expectation of development of essentially regional markets.

3. Recommendations

From the regulatory point of view, decisions about new coal conversion technologies can be examined in two contexts: in terms of PUC strategies -- whether the regulatory agencies ought to be passive or active with respect to energy supply problems, and in terms of tactics regarding responses to specific proposals to use or develop specific conversion processes and how to evaluate those proposals.

4. Passive and Active Strategies

In the context of declining conventional fuel supplies and shifting demand mix for different energy sources, Public Utility Commissions can decide to operate passively, responding only to submitted requests for permission to develop particular alternate fuel supplies coupled with whatever rate increase request that may be necessary; or they can react actively, formulating policies that will encourage particular energy developments -- for example, the possibility of constructing a substitute grid carrying a medium gas for particular purposes, industries, and regions can be a PUC-designated strategy, actively encouraged by PUC policies.

This is itself a larger question that requires a separate study, but in the interests of giving the regulated industries the maximum flexibility for them to determine the best possible courses of action, it would seem desirable only to develop active policies by agreement with all concerned parties. With the present uncertainties in fuel conversion developments, however, it would seem desirable for the policies to be conservative rather than too active to avoid premature preemption of potentially effective conversion techniques.

5. Evaluation Procedures

The objective of any evaluation procedure is to establish the acceptability of some proposal for developing a specified coal conversion technology and to approve any associated rate increase requests necessary to permit implementation. In essence, it is necessary to establish answers to the four questions posed in the Report Introduction (Chapter I) repeated here:

- What is the evidence that the proposed conversion method is the best?
- How long will it take for the coal-derived fuel to come on stream: at the start, and in quantity?
- What will the fuel cost be at the time of use: absolutely, and relative to conventional supplies?
- Is coal conversion the only or the cheapest answer, or has the contribution of increased supplies of conventional fuels, contributions of further conservation, and a move to alternatives such as solar been underrated, as this will affect the intended market and thus the justification for the conversion proposal?

It may be said at the outset that it is unlikely or even impossible that answers to all these questions can be given with sufficient accuracy at this time; the questions remain as the ultimate objective of an evaluation procedure, nevertheless. Lacking the possibility of fully acceptable answers at this time, there are some answers that can be instructive and informative. An evaluation procedure ought to consider the following points.

- Description of the proposed system with emphasis on its physical scale, the time required to construct and to bring it on stream, and the quantity of fuel it will supply in absolute terms and as a percentage of the system requirements. This is an elaboration of the second question listed above. Also to be considered is the number of such plant required to provide significant contributions to the systems requirements, the time required to build them, and the total cost. The use of such data in evaluation is to determine whether the financial, physical, and time resources will match the system requirements. If the plant takes too long to build, costs too much, and provides too little contribution to the system demand, the benefit is clearly too marginal to justify any support. The emphasis is on the scale of the proposal, particularly in relation to the proposer's resources.

- There should be an evaluation of the proposed conversion process itself that should include evidence that it is the best of alternatives and include an estimate of its complexity: how many stages, ancillary reactors, and the like, and the probable percentage of time that the plant would be expected to remain on line without unscheduled outages due to component breakdowns.

- There should be a reasonably detailed failure analysis of the plant in start-up and during operation. This should include an estimate of the increased costs that could be incurred on account of delayed start-up or of failure to operate for any significant continuous period -- that is to say, the consequences of non-availability.

- An evaluation of alternative strategies would also be useful, including an assessment of the impact on the market of significantly higher prices that could lead consumers to consider other ways of meeting their energy requirements.

6. Closing Comments

The above recommendations are sufficiently general and obvious as to be somewhat bland in statement. Their value lies more in the subsequent evaluation of the answers with particular objectives in mind.

- The most important factor would seem to be the scale of the proposal and other associated consequences of scale. The most important associated consequence is reliability. If there has been no integrated test of all components at a sub-scale and test of individual components at the proposed scale, the expected reliability is likely to be low. This places emphasis on the suggested Failure Analysis. Bringing the plant on line could take many times longer than predicted and likewise delay construction of other plants, if planned. If the proposed unit is important to the system, such delays can be costly, with continued expenses and no revenue. It would seem reasonable to allow a pass-through of construction and development costs if there was a reasonable expectation of a return by revenue generation from the SNF sale within, say, five years; but it would not seem reasonable if the revenue return was delayed to, say, 15 years. It is then a matter of plant evaluation, judgement, and Commission decision whether some other period of time, say 10 years, is a reasonable delay of return on pass-through costs.
- In reviewing plans and proposals, it would seem reasonable to make the assumption that both costs and time to start-up are most likely to be up to twice what is estimated.

- An alternative approach might be to have an approved "fuel development surcharge," on a similar basis to the pass-through costs of existing fuel price adjustment charges, with a maximum of, say, 1% or 5% or 10% of existing charges. This would be automatically allowed to cover the costs of SNF or other approved fuel production from unusual sources, and could represent the rolled-in cost of either a relatively small quantity of very high-priced fuel or a larger quantity of more moderately priced fuel. If the charges started with delivery of fuel or energy to the delivery system, this would initially encourage construction of "small" plant with relatively low capital costs and reduced construction time, even if it produced SNF at nominally uncompetitive prices. This would also encourage a wider range of approaches that would not have to rely on DOE and DOE evaluations for approval. It would also build up the small, diverse plant data base that is missing at present and whose absence makes evaluation of alternatives so difficult.

APPENDIX

Status
of
Liquefaction and Gasification
Principal Programs

Sources: Report to the U.S. Senate Committee on Energy and Natural Resources (Publication No.: 96 - 17) June 1979 and others.

Table - A1

STATUS OF DOE ACTIVE COAL CONVERSION PROJECTS ON SOLVENT REFINING AND LIQUEFACTION

Process	Status	Demo Start Year
CLEAN SOLID		
SRC-I - Solvent Refined Coal	Demo Plant Design Started	1983
LIQUEFACTION		
Fischer-Tropsch	Proven Demonstration Plant	1983
Methanol	" " "	1982
SRC-II - Solvent Refined Coal	Demo Plant Design Started	1983
Cresap (LC-Fining)	Successful Series of Pilot Runs	1985
M-Gasoline	" " " " "	1985
EDS - Exxon's Donor Solvent	Pilot Plant Designed	1985
H-Coal	" " "	1984
ZnCl	Successful Process Demonstration Unit Operation	1988
CO-Steam	Successful Process Demonstration Unit Operation	1988
Synthoil	Successful Process Demonstration Unit Operation	1995

Table - A2

FUNDING STATUS OF MOST PROMISING DOE COAL LIQUEFACTION EFFORTS

Research Area/Major Projects	FY 1980 Status	FY 1980 Request
H-Coal Pilot Plant Catlettsburg, Kentucky	Initiate operation	$35,000,000
Solvent-Refined Pilot Plant Tacoma, Washington	Operational	$15,000,000
Exxon's Donor Solvent Pilot Plant Baytown, Texas	Initiate operation	$30,000,000
Solvent Refined Coal Demonstration Plant	Continue Phase Cne	$ 7,000,000

Table - A3

COMMERCIAL AND DEMONSTRATION HIGH BTU COAL GASIFICATION PROJECTS
(as of June 1979)

Controlling Company	Site	Process	Coal Feed, Tons/day	Peak Output MMcf/day	Status
COMMERCIAL PROJECTS					
American Natural Resources Co., Tenneco, Peoples Natural Gas Co. Columbia Transmission Corp. & Transcontinental Gas Pipline Corp.	Beulah-Hazen Area, Mercer County, N.D.	Lurgi gasification with methanation	12,328	137.5	The plant will be built in two phases. The first phase is scheduled to be operational by the end of 1982 and will be half the size of a full commercial plant. Plant costs are estimated at $890 million (1978 dollars) with another $88 million for transmission facilities. Output from the plant is projected to cost $5.60 per Mcf not including transmission and distribution costs.
WESCO; Texas Eastern Transmission Corp. and Pacific Lighting Corp.	Four Corners Area, N.M.	Lurgi gasification with methanation	24,820	275	The plan is for a plant on the Navajo Indian Reservation near Farmington, N.M. Negotiations for site lease have not yet been completed. Utah International Corp. will supply the coal and water for the plant. Water and coal are also available for an additional plant. Estimated project cost for the first plant is $1.4 billion (1978 dollars). (Now Cancelled)
El Paso Natural Gas Co.	Four Corners Area, N.M.	Lurgi gasification with methanation	14,175	144	El Paso Natural Gas Co. plans to construct and operate a half or quarter size plant on the Navajo Indian Reservation. A joint partnership with Rhurgas .G. of West Germany is under consideration. A new application is expected to be filed in early 1979.
Pahhandle Eastern Pipe Line Co. (Peabody Coal Co.)	Eastern Wyoming	Lurgi gasification with methanation	27,700	275	Plans for a plant remain in a holding stage. Investment costs are estimated at $1.3 billion (early 1976 dollars). No filing has yet been made to the Federal Energy Regulatory Commission.
Natural Gas Pipeline Co. of America	Dunn County, N.D.	Lurgi gasification with methanation	30,000	270	Phase 1 engineering design has been completed. No filing has been made with the FERC. Further action on the project is currently under review.
Northern Natural Gas Co. of America	Powder River Basin, Mont.	Lurgi gasification with methanation	30,000	275 Expansion 275	Project suspended.

Table - A3 cont'd

Controlling Company	Site	Process	Coal Feed, Tons/day	Peak Output MMcf/day	Status
The Columbia Gas System, Inc.	Illinois	-	-	300	Columbia Gas exchanged a 50 percent interest in 43,400 acres of its 300,000 acres of West Virginia coal lands for a 50 percent interest in 35,000 acres of Illinois coal lands held by Exxon's Carter Oil Co. The Illinois coal is being held by Columbia for coal gasification pending development of an economic and technically sound process.
Exxon Corp. (Carter Oil)	Northern Wyoming	-	-	-	Feasibility studies have been completed. Project deferred.
Consolidated Natural Gas Co.	Southwest Pennsylvania	-	-	-	The company has purchased about 600 million tons of recoverable coal for gasification, but no specific project plans have been announced.
DEMONSTRATION PROJECTS					
Conoco Coal Development Co. & DOE	Noble County, OH	Slagging Lurgi with methanation	3,800	60	DOE has awarded the company a $24 million contract to design the demonstration facility. The commercial conceptual design phase is completed. The demonstration plant is still being designed. Plant operations are expected to last for three and a half years. Total project cost is estimated at $324 million. The cost for construction and operations will be shared equally by DOE and the company.
Illinois Coal Gasification Group & DOE	Perry County, IL	COGAS Process	2,200	18 Plus 2400 bbl/d synthetic crude oil	DOE has awarded this group of companies a $22.5 million contract to design the demonstration plants. Presently the conceptual design is finished and the design for the demonstration facility is being completed. Construction and operation phases are expected to last 34 and 42 months respectively, with costs shared equally between DOE and the group. Total costs are estimated at $334 million.
Procon, Inc. & DOE	-	HYGAS	-	-	Doe has awarded Procon Inc. a two-year $7.5 million contract for a conceptual design of a commercial plant and a process design and economic evaluation of a demonstration plant. The conceptual design is completed and the process design economic evaluation will be finished in April, 1979. The Institute of Gas Technology has a separate contract under the joint A.G.A.-DOE pilot plant program to supply data from the HYGAS pilot plant for the Procon, Inc. design.

Table - A3 cont'd

Controlling Company	Site	Process	Coal Feed, Tons/day	Peak Output MMcf/day	Status
Coalcon Dept. Union Carbide Corp. & DOE	New Athens, IL	Union Carbide	2,600	22 (plus 2900 bbl of Syncrude per day)	The process design stage was completed in June 1977. DOE has not announced any further plans.

Table - A4

FUNDING STATUS OF SELECTED DOE SURFACE GASIFICATION PROJECTS

Research Area/Major Projects	FY 1980 Status	FY 1980 Request
Synthane Pilot Plant Bruceton, Pa.	Mothballed	0
Hydrogasification, PDU Site Undetermined	Design and Construction	$11,000,000
Catalytic Gasification Pilot Plant Site Undetermined	Design and Modification of existing pilot plant	$12,000,000
Fixed-Bed Gasification Pilot Plants - W.Va., N.D.	Operational	$ 6,000,000
Fluid-Bed Gasification Pilot Plants - Pa. (2)	Operational	$ 8,000,000
Gasifiers-in-Industry Five locations: Pa., Minn. (2), Ky., Tenn.	Operational	$ 500,000
Gasification System Test Facility - Site undetermined	Design and Construction	$15,000,000
High-Btu Demonstration Plant Site Undetermined	Detailed Design and Construction	$85,000,000
Fuel Gas, Small Industrial Demonstration Plant - Hoyt Lakes, Minnesota	Construction Planned	$15,000,000

Table - A5

COMMERCIALLY AVAILABLE GASIFIERS

GASIFIER	MANUFACTURER/LICENSEE	PRODUCT
Fixed Bed Type		
1. Wellman-Galusha	McDowell-Wellman, Inc. Cleveland, Ohio	Producer gas (low Btu)
2. Riley-Morgan	Riley-Stokes Corp. Cleveland, OH	"
3. Wilputtes	Wilputtes-Wilburn Murray Hill, New Jersey	"
4. Woodall-Duckham	Woodall-Duckham, Inc. Pittsburgh, Pennsylvania	"
5. Wellman-Incandescent	Applied Technology Corp. Houston, Texas	"
6. STOIC	Foster Wheeler Energy Corp. Livingston, New Jersey	"
7. Lurgi	American Lurgi Corp. Hasbrouck, New Jersey	Producer gas/ Synthesis gas (300 Btu)
Entrained-Bed		
1. Koppers-Totzek	Koppers Co., Inc. Pittsburgh, Pennsylvania	Synthesis gas
Fluidized-Bed		
1. Winkler	Davy Powergas Lakeland, Florida	"

Table - A6

STATUS OF ACTIVE COAL CONVERSION PROJECTS

	Process Status	Year of Demonstration Plant
GASIFICATION, PIPELINE QUALITY GAS		
Lurgi/Methanation	Proven Demonstration Plant	1983
Conoco (Slagging Lurgi)	Demo Plant Design Begun	1983
Cogas	" " " "	1983
Hygas	Successful Series of Pilot Runs	1986
Bigas	Pilot Plant Operating	
GASIFICATION, INDUSTRIAL SECTOR		
Texaco Gasifier	Pilot Plant Operating	1984
Exxon Catalytic Gasification	Competitive Cost Established	1987
Rockgas	Economic Studies Done	1988
COMBINED CYCLE: TO PROVIDE ELECTRICITY		
Westinghouse	Pilot Plant Designed	1986
Combustion Engineering	" " "	1986

Table - A7

OPPORTUNITIES FOR COAL CONVERSION APPLICATIONS IN THE ELECTRIC UTILITY SECTOR

1. Normal Pressure Use of Low and Medium Btu Gas
   - Retrofit existing combines-cycle plants in base load and intermediate service; gasification plant could be build on-site, or medium-Btu gas could be purchased from a nearby plant;

   - New combined-cycle plants in base load and intermediate service gasifier systems could be built on-site, and integrated with this power cycle for improved efficiency; and

   - As a fuel for existing and new peaking turbines, in this case, medium-Btu gas would be purchased from a large central plant furnishing medium-Btu gas to a number of energy users.

2. Pressurized Use of Medium Btu Gas
   - Boiler fuel for existing oil or natural gas fired utility boilers, i.e., retrofitting of existing steam boilers;

   - Boiler fuel for new base load service electric generating station boilers; and

   - Gas turbine fuel for combined cycle power plants in base load and intermediate service.