Chapter 6

Synthetic Fuels

Contents

TABLES

FIGURES

BOX

Chapter 6

Synthetic Fuels

INTRODUCTION

Synthetic fuels, or "synfuels," in the broadest sense can include any fuels made by breaking complex compounds into simpler forms or by building simple compounds into others more complex. Both of these types of processes are carried out extensively in many existing oil refineries. Current technical usage, however, tends to restrict the term to liquid and gaseous fuels produced from coal, oil shale, or biomass. This usage will be followed in this report.

Synfuels production is a logical extension of current trends in oil refining. As sources of the most easily refined crude oils are being depleted, refiners are turning to heavier oils and tar sands. Oil shale and coal, as starting materials for liquid hydrocarbon production, are extreme cases of this trend to heavier feedstocks.

Although synfuels production involves several processes not used in crude oil refining, many current oil refining techniques will be applied at various stages of synfuels processing. In order to indicate the range of currently used hydrocarbon processing techniques and to provide definitions of certain terms used later in describing some synfuels processes, a brief description of commonly used oil refining processes is given below. Following this are descriptions of coal, oil shale, and biomass synfuels processes; an evaluation of synfuel economics; and a presentation of two plausible development scenarios for a U.S. synfuels production capacity.

Petroleum Refining

A petroleum refinery is normally designed to process a specific crude oil (or a limited selection of crudes) and to produce a "slate" of products appropriate to the markets being supplied. Refineries vary greatly in size and complexity. At one extreme are small "topping" plants with product outputs essentially limited to the components of the crude being processed. At the other extreme are very large, complex refineries with extensive conversion and treating facilities and a corresponding ability to produce a range of products specifically tailored to changing market needs.

Refining processes include:

- Atmospheric Distillation. –The "crude unit" is the start of the refining process. Oil under slight pressure is heated in a furnace and boiled into a column containing trays or packing which serve to separate the various components of the crude oil according to their boiling temperatures. Distillation ("fractionation") is carried out continuously over the height of the column. At several points along the column hydrocarbon streams of specific boiling ranges are withdrawn for further processing.
- Vacuum Distillation. –Some crude oil components have boiling points that are too high, or they are too heat-sensitive, to permit distillation at atmospheric pressure. In such cases the so-called "topped crude" (bottoms from the atmospheric column) is further distilled in a column operating under a vacuum. This lowers the boiling temperature of the material and thereby allows distillation without excessive decomposition.
- Desulfurization. –Sulfur occurs in crude oil in various amounts, and in forms ranging from the simple compound hydrogen sulfide and mercaptans to complex ring compounds. The sulfur content of crude oil fractions increases with boiling point. Thus, although sulfur compounds in fractions with low boiling points can readily be removed or rendered unobjectionable, removal becomes progressively more difficult and expensive with fractions of higher boiling points. With these materials, sulfur is removed by processing with hydrogen in the presence of special catalysts at elevated temperatures and pressures. The "hydrofining," "hydrodesulfurization," "residuum hydrotreating, " and "hydrodemetallation" processes are examples. Nitrogen compounds

and other undesirable components are also removed in many of these hydrotreating processes.

- Therma/ Cracking Processes, –Prior to the development of fluid catalytic cracking (see below), the products of distillation that were heavier than gasoline were commonly "cracked" under high temperature and pressure to break down these large, heavy molecules into smaller, more volatile ones and thereby improve gasoline yields. Although the original process is no longer applied for this purpose, two other thermal cracking processes are being increasingly used. In visbreaking, highly viscous residues from crude oils are mildly cracked to produce fuel oils of lower viscosity. In delayed coking, crude unit residues are heated to high temperatures in large drums and severely cracked to drive off the remaining high-boiling materials for recovery and further processing; the porous mass of coke left in the drums is used as a solid fuel or to produce electric furnace electrodes.
- Fluid Catalytic Cracking.—This process in its various forms is one of the most widely used of all refinery conversion techniques. It is also undergoing constant development. Charge stocks (which can be a range of distillates and heavier petroleum fractions) are entrained in a hot, moving catalyst and converted to lighter products, including high-octane gasoline. The catalyst is separated and regenerated, while the reaction products are separated into their various components by distillation.
- Hydrocracking. —This process converts a wide range of hydrocarbons to lighter, cleaner, and more valuable products. By catalytically adding hydrogen under very high pressure, the process increases the ratio of hydrogen to carbon in the feed and produces low-boiling material. Under some conditions hydrocracking maybe competitive with fluid catalytic cracking.
- Catalytic Reforming. –Reforming is a catalytic process that takes low-octane "straight-run" materials and raises the octane number to approximately 100. Although several chemical reactions take place, the predominant reaction is the removal of hydrogen from naphthenes (hydrogen-saturated ring-like compounds) and their conversion to aromatics (benzene-ring compounds). In addition to markedly increasing octane number, the process produces hydrogen that can be used in desulfurization units.
- Isomerization, Catalytic Polymerization, and Alkylation. -These are specialized processes that increase refinery yields of high-octane gasoline blending components from selected straight-chain liquids and certain refinery gases.

Historically, the U.S. refining industry has dealt primarily with light, low-sulfur crudes. Using processes described above, the industry achieved a balance between refinery output and markets. Adjustments have been made to meet the increasing demand for lead-free gasolines and to the mandated reduction of lead in other gasolines. The heavy residual fuels, considerably higher in sulfur content than treated distillate fuels, have continued to find a market as ships' boilers and as fuels for utility plants that have not converted to coal. (In the latter market, it has sometimes been necessary to blend in desulfurized fuel oils to meet maximum fuel sulfur specifications.) In addition, large volumes of residual fuel oils have continued to be imported, largely from Venezuela and the Caribbean.

Now, however, the picture is changing. Due to the limited availability of light crude oils, refineries are being forced to run increasing volumes of heavy crudes that are higher in sulfur and other contaminants. With traditional processing methods, these crudes produce fewer light products and more heavy fuel oils of high sulfur content. On the other hand, fuel switching and conservation in stationary uses will shift market demand increasingly toward transportation fuels—gasoline, diesel, and jet–plus petrochemical feedstock.

Refiners are responding to this situation by making major additions to processing facilities. Although they differ in detail, the additions are intended to reduce greatly the production of heavy fuel oil and to maximize the conversion and recovery of light liquids. For a typical major refinery, the additions could include: 1) vacuum distillation facilities, 2) high-severity hydroprocessing, such as residuum desulfurization, together with hydrogen manufacturing capacity, 3) delayed coking, along with processes to recover and treat the high-boiling vapor fractions driven off, and 4) perhaps visbreaking, catalytic cracker expansions, and other modifications to accommodate the changed product slate. It should also be noted that none of these additions increases the crude-processing capacity of a refinery; they merely adapt it to changed supply and marketing conditions.

Purvin and Gurtz[1] have estimated the costs of upgrading domestic refining capacity to make such changes. Their results are shown in table 40. Although, as indicated in note d of the table, the investments shown do not include all applicable costs, upgrading existing refineries is, in most cases, less expensive than building synfuels plants to produce the same products; and there are regular reports that investments are being made in oil refineries to upgrade residual oil and change the product slate. *2

For a discussion of other issues related to oil refineries, the reader is referred to a Congressional Research Service report on "U.S. Refineries: A Background Study. "[3]

---

[1] Purvin & Gertz, Inc., "An Analysis of Potential for Upgrading Domestic Refining Capacity, " prepared for American Gas Association, Arlington, Va., undated.

*Another issue related to refining and oil consumption is the low yield of lubrication and specialty oils from certain types of crude oils (paraffinic crudes) and the redefining or reuse of these oils. There appears to be no technical problem with increasing the yield of lubrication and specialty oils from the paraffinic crudes (*Oil and Gas Journal,* "Gulf's Port Arthur Refinery Due More Upgrading," Sept. 8, 1980, p. 36.) or the redefining of lubrication oils. However, heat transfer, hydraulic, capacitor, and transformer fluids often become contaminated with PCBs (polychlorinated biphenyls) leached from certain plastics such as electrical insulating materials. Because of the health hazard, EPA regulations limit the allowable level of PCBs in enclosed systems to 50 ppm (parts per million). The contaminated oils pose a waste disposal problem and could damage refinery equipment (through the formation of corrosive hydrogen chloride and possible catalyst poisoning) if rerefined without treatment. Recently, however, two processes (*Chemical* and Engineering News, "Goodyear Develops PCB Removal Method, " Sept. 1, 1980, p. 9; Chemical and Engineering News, "More PCB Destruction Methods Developed, " Sept. 22, 1980, p. 6.) have been announced that enable the removal of most of the PCBs, thereby enabling reuse directly or redefining if necessary; and one of these processes has been demonstrated with a prototype commercial unit. Consequently, there do not appear to be significant technical problems with decontamination and reuse of PC B-contaminated oils. Due to the limits of this study, however, OTA was unable to perform an economic analysis of oil production from paraffinic crudes, redefining of lubrication oils, or decontamination of specialty oils.

[2] For example, *Oil* and Gas *Journal,* Aug. 25, 1980, p. 69; *Oil and Gas Journal,* Sept. 8, 1980, p. 36; *Oil* and Gas *Journal,* Nov. 10, 1980, p. 150; *Oil* and Gas *Journal,* Jan. 19, 1981, p. 85.

[3] Congressional Research Service, "U.S. Refineries: A Background Study, "prepared at the request of the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, U.S. House of Representatives, July 1980.

Table 40.—Analysis of Potential for Upgrading Domestic Refining Capacity

	Topping refineries		Total U.S. refineries
	Case 1a[a]	Case 1b[b]	Case 2[c]
Total investment[d]	$2.3 billion	$4.7 billion	$18.0 billion
Reduction in total U.S. residual fuel production, bbl/d	217,000-301,000	418,000-501,000	1,587,000-1,670,000
Percent total pool	13-18	25-30	95-1oo
Increase in motor gasoline production, bbl/d	134,000-200,000	167,000-234,000	467,000-534,000
Percent total pool	2-3	2.5-3.5	7-8
Increase in diesel/No. 2 fuel production, bbl/d	105,000-135,000	150,000-180,000	540,000-600,000
Percent total pool	3.5-4.5	5-6	18-20
Increase in low-Btu gas, MM Btu/D	—	233	1,320
Implementation period, years			4-1o
Investment per unit capacity	$6,800-9,600 per bbl/d	$11,300-14,000 per bbl/d	$15,800-17,900 per bbl/d

[a] Vacuum distillation, catalytic cracking, visbreaking.
[b] Vacuum distillation, catalytic cracking, coking plus gasification.
[c] Case 1 b plus coking and gasification and downstream upgrading at remaining U.S. refineries.
[d] First-quarter 19&3 investment, No provision for escalation, contingency or interest during construction.

SOURCE: Purvin & Gertz, Inc., "An Analysis of Potential for Upgrading Domestic Refining Capacity," prepared for American Gas Association, 19S0.

PROCESS DESCRIPTIONS

A variety of synthetic fuels processes are currently being planned or are under development. Those considered here involve the chemical synthesis of liquid or gaseous fuels from solid materials. As mentioned above, the impetus for synthesizing fluid fuels is to provide fuels that can easily be transported, stored, and handled so as to facilitate their substitution for imported oil and, to a lesser extent, imported natural gas.

The major products of various synfuels processes are summarized in table 41. Depending on the processes chosen, the products of synfuels from coal include methanol (a high-octane gasoline substitute) and most of the fuels derived from oil* and natural gas. The principal products from upgrading and refining shale oil are similar to those obtained from conventional crude-oil refining. The principal biomass synfuels are either methanol or a low- to medium-energy fuel gas. Smaller amounts of ethanol (an octane-boosting additive to gasoline or a high-octane substitute for gasoline) and biogas can also be produced. Each of these fuels can be synthesized further into any of the other products, but these are the most easily produced from each source and thus probably the most economic.

In the following section, the technologies for producing synfuels from coal, oil shale, and biomass are briefly described. Indirect and direct coal liquefaction and coal gasification are presented first. Shale oil processes are described second, followed by various biomass synfuels. Hydrogen and acetylene production are not included because a preliminary analysis indicated they are likely to be more expensive and less convenient transportation fuels than are the synthetic liquids.[4]

Table 41 .—Principal Synfuels Products

Process	Fuel production	Comments
Oil shale	Gasoline, diesel and jet fuel, fuel oil, liquefied petroleum gases (LPG)	Shale oil is the synfuel most nearly like natural crude.
Fischer-Tropsch	Gasoline, synthetic natural gas (SNG), diesel fuel, and LPG	Process details can be modified to produce principally gasoline, but at lower efficiency.
Coal to methanol, Mobil methanol to gasoline (MTG)	Gasoline and LPG	LPG can be further processed to gasoline. Some processes would also produced considerable SNG.
Coal to methanol	Methanol	Depending on gasifier, SNG may be a byproduct. Methanol most useful as high-octane gasoline substitute or gas turbine fuel, but can also be used as gasoline octane booster (with cosolvents), boiler fuel, process heat fuel, and diesel fuel supplement. Methanol can also be converted to gasoline via the Mobil MTG process.
Wood or plant herbage to methanol	Methanol	Product same as above.
Direct coal liquefaction	Gasoline blending stock, fuel oil or jet fuel, and LPG	Depending on extent of refining, product can be 90 volume percent gasoline.
Grain or sugar to ethanol	Ethanol	Product most useful as octane-boosting additive to gasoline, but can serve same uses as methanol.
SNG	SNG	Product is essentially indistinguishable from natural gas.
Coal to medium- or low-energy gas	Medium- or low-energy fuel gas	Most common product likely to be close to synthesis gas.
Wood or plant herbate gasification	Medium- or low-energy fuel gas	Fuel gas likely to be synthesized at place where it is used.
Anaerobic digestion	Biogas (carbon dioxide and methane] and SNG	Most products likely to be used onsite where produced.

SOURCE: Off Ice of Technology Assessment.

---

*As with natural crude oil, however, refining to produce large gasoline fractions usually requires more refining energy and expense than producing less refined products such as fuel oil.

[4] For a more detailed description of various processes, see: Engineering Societies Commission on Energy, Inc., "Coal Conversion Comparison, " July 1979, Washington, D. C.; An Assessment *of Oil Shale* Technologies (Washington, D, C.: U.S. Congress, Office of Technology Assessment, June 1980), OTA-M-118; Energy From *Biological* Processes (Washington, D, C.: U.S. Congress, Office of Technology Assessment, July 1980), vol. 1, OTA-E-124; and Energy From Biological Processes, Volume I/–Technical and *Environmental Analyses* (Washington, D. C.: U.S. Congress, Office of Technology Assessment, September 1980), OTA-E-128.

Synfuels From Coal

Liquid and gaseous fuels can be synthesized by chemically combining coal with varying amounts of hydrogen and oxygen, * as described below. The coal liquefaction processes are generally categorized according to whether liquids are produced from the products of coal gasification (indirect processes) or by reacting hydrogen with solid coal (direct processes). The fuel gases from coal considered here are medium-Btu gas and a synthetic natural gas (SNG or high-Btu gas). Each of these three categories is considered below and shown schematically in figure 13.

Indirect Liquefaction

The first step in the indirect liquefaction processes is to produce a synthesis gas consisting of carbon monoxide and hydrogen and smaller quantities of various other compounds by reacting coal with oxygen and steam in a reaction vessel called a gasifier. The liquid fuels are produced

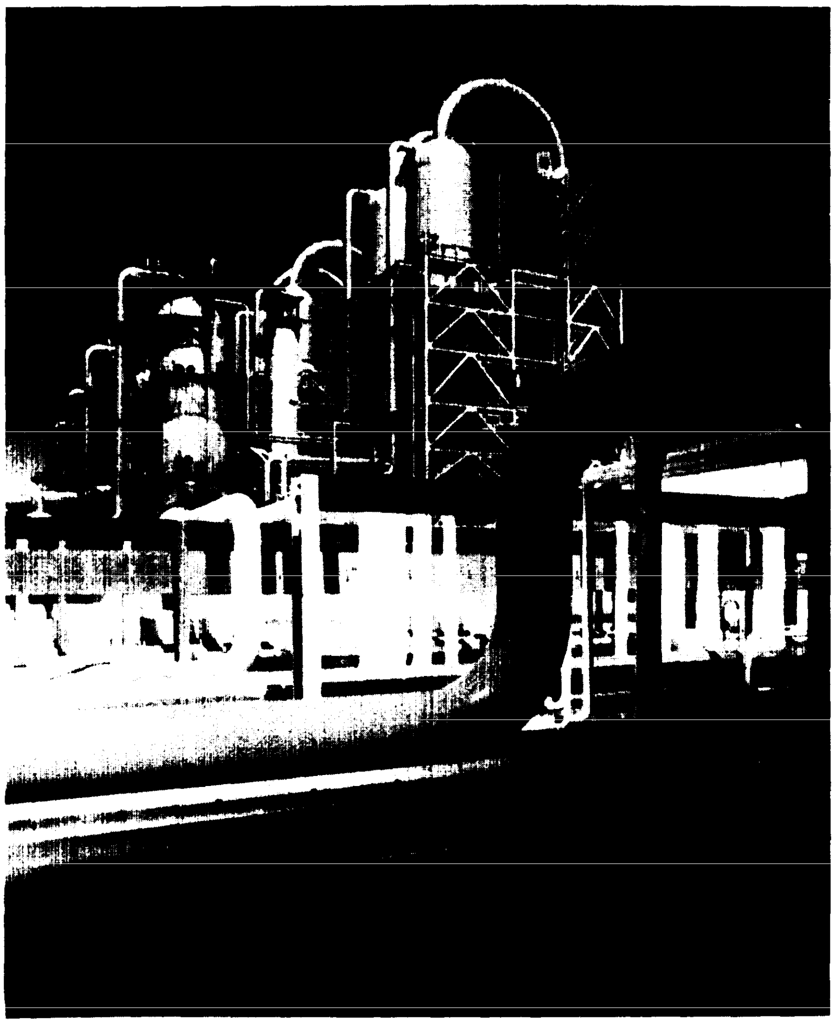


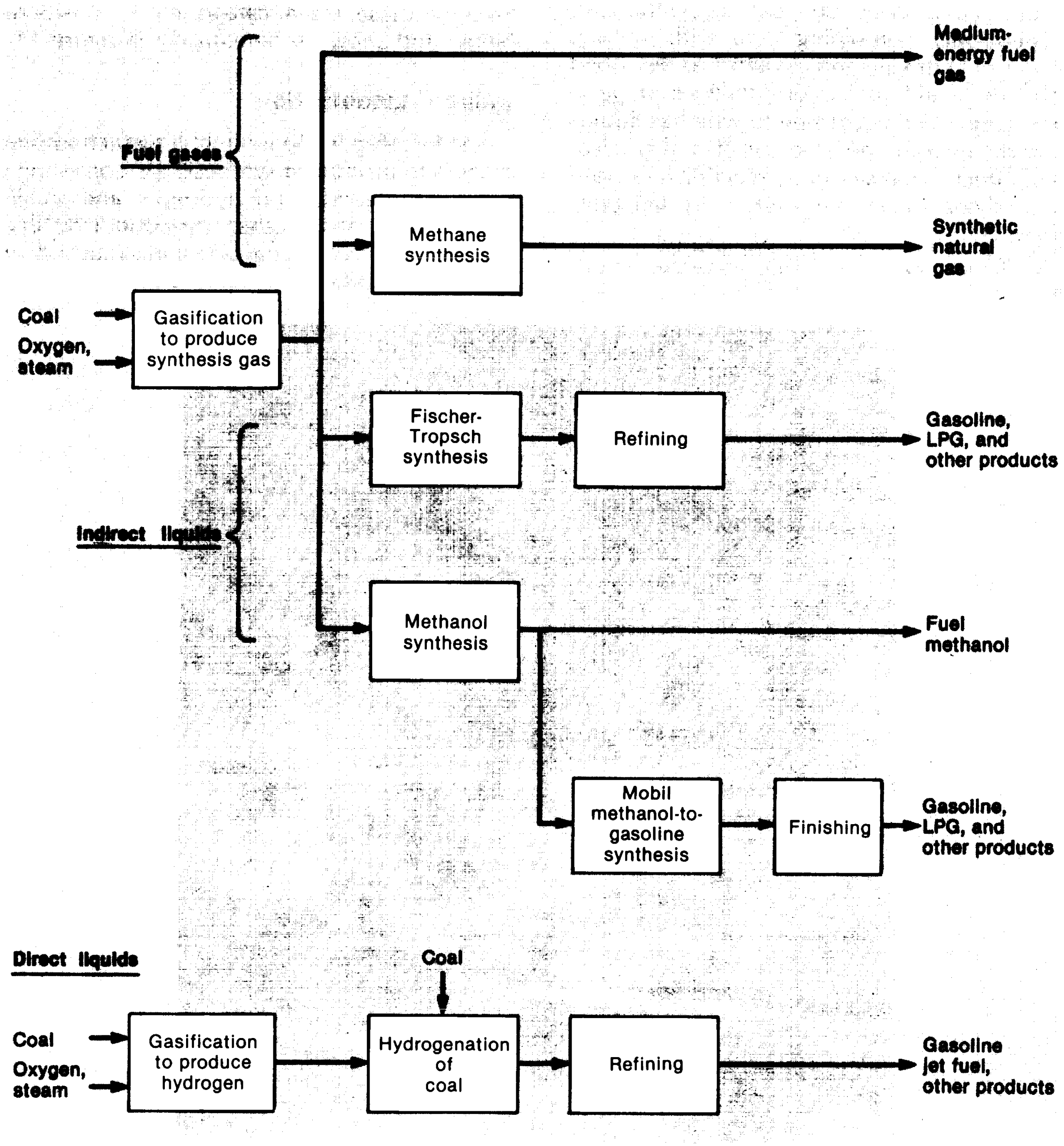
Photo credit: *Fluor Corp*

Synthesis gas is converted to liquid hydrocarbons in **Fischer-Tropsch** type reactors

---

*Some liquid and gaseous fuel can be obtained simply by heating coal, due to coal's small natural hydrogen content, but the yield is low.

Figure 13.—Schematic Diagrams of Processes for Producing Various Synfuels From Coal



SOURCE: Office of Technology Assessment.

by cleaning the gas, adjusting the ratio of carbon monoxide to hydrogen in the gas, and pressurizing it in the presence of a catalyst. Depending on the catalyst, the principal product can be gasoline (as in the Fischer-Tropsch process) or methanol. The methanol can be used as a fuel or further reacted in the Mobil methanol-to-gasoline (MTG) process (with a zeolite catalyst) to produce Mobil MTG gasoline. The composition of the gasoline and the quantities of other products produced in the Fischer-Tropsch process can also be adjusted by varying the temperature and pressure to which the synthesis gas is subjected when liquefied.

With commercially available gasifiers, part of the synthesis gas is methane, which can be purified and sold as a byproduct of the methanol or gasoline synthesis. * However, the presence of methane in the synthesis gas increases the energy needed to produce the liquid fuels, because it must be pressurized together with the synthesis gas but does not react to form liquid products. Alternatively, rather than recycling purge gas (containing increasing concentrations of methane) to the methanol synthesis unit, it can be sent to a methane synthesis unit and its carbon monoxide and hydrogen content converted to SNG. With "second generation" gasifiers (see below), little methane would be produced and the methanol or gasoline synthesis would result in relatively few byproducts.

There are three large-scale gasifiers with commercially proven operation: Lurgi, Koppers-Totzek, and Winkler. Contrary to some reports in the literature, all of these gasifiers can utilize a wide range of both Eastern and Western coals, * * although Lurgi has not been commercially proven with Eastern coals. In all cases, the physical properties of the feed coal will influence the exact design and operating conditions chosen * for a gasifier. For example, the coal swelling index, ease of pulverization (friability), and water content are particularly important parameters to the operation of Lurgi gasifiers, and the Koppers-Totzek gasifier requires that the ash in the coal melt for proper operation, as do the Shell and Texaco "second generation" designs.,

it is expected that the developing pressurized, entrained-flow Texaco and Shell gasifiers will be superior to existing commercial gasifiers in their ability to handle strongly caking Eastern coals with a rapid throughput. This is achieved by rapid reaction at high temperatures (above the ash melting point). These temperatures, however, are achieved at the cost of reduced thermal efficiency and increased carbon dioxide production.

The Fischer-Tropsch process is commercial in South Africa, using a Lurgi gasifier, but the United States lacks the operating experience of South Africa and it is unclear whether this will pose problems for commercial operation of this process in the United States. The methanol synthesis from synthesis gas is commercial in the United States, but a risk is involved with putting together a modern coal gasifier with the methanol synthesis, since these units have not previously been operated together. Somewhat more risk is involved with the Mobil MTG process, since it has only been demonstrated at a pilot plant level. Nevertheless, since the Mobil MTG process involves only fluid streams* * the process can probably be brought to commercial-scale operation with little technical difficulty.

Direct Liquefaction

The direct liquefaction processes produce a liquid hydrocarbon by reacting hydrogen directly with coal, rather than from a coal-derived synthesis gas. However, the hydrogen probably will be produced by reacting part of the coal with steam to produce a hydrogen-rich synthesis gas, so these processes do not eliminate the need for coal

---

*For example, the synthesis gas might typically contain 13 percent methane. Following methanol synthesis, the exiting gases might contain 60 percent methane, which is sufficiently concentrated for economic recovery.

* •For example, Sharman (R. B. Sharman, "The British Gas/Lurgi Slagging Gasifier—What It Can Do," presented at Coal Technology '80, Houston, Tex., Nov. 18-20, 1980) states: "It has been claimed that the fixed bed gasifiers do not work well with swelling coals. Statements such as this can still be seen in the literature and are not true. In postwar years Lurgi has given much attention to the problem of stirrer design which has much benefited the Westfield Slagging Gasifier. Substantial quantities of strongly caking and swelling coals such as Pittsburgh 8 and Ohio 9, as well as the equivalent strongly caking British coals have been gasified. No appreciable performance difference has been noted between weakly caking and strongly caking high volatile bituminous coals. "

*Including steam and oxygen requirements.

**The physical behavior of fluids is fairly well understood, and processes involving only fluid streams can be scaled up much more rapidly with minimum risk than processes involving solids.

gasification. The major differences between the processes are the methods used to transfer the hydrogen to the coal, while maximizing catalyst life and avoiding the flow problems associated with bringing solid coal into contact with a solid catalyst, but the hydrocarbon products are likely to be quite similar. The three major direct liquefaction processes are described briefly below, followed by a discussion of the liquid product and the state of the technologies' development.

The solvent-refined coal (SRC I) process was originally developed to convert high-sulfur, high-ash coals into low-sulfur and low-ash solid fuels. Modifications in the process resulted in SRC II, which produces primarily a liquid product. The coal is slurried with part of the liquid hydrocarbon product and reacted with hydrogen at about 850° F and a pressure of 2,000 per square inch (psi).[5] As it now stands, however, feed coal for this process is limited to coals containing pyritic minerals which act as catalysts for the chemical reactions.

The H-coal process involves slurrying the feed coal with part of the product hydrocarbon and reacting it with hydrogen at about 650° to 700° F and about 3,000 psi pressure in the presence of a cobalt molybdenum catalyst.[6] A novel aspect of this process is the so-called "ebullated" bed reactor, in which the slurry's upward flow through the reactor maintains the catalyst particles in a fluidized state. This enables contact between the coal, hydrogen, and catalyst with a relatively small risk of clogging.

The third major direct liquefaction method is the EXXON Donor Solvent (EDS) process. In this process, hydrogen is chemically added to a solvent in the presence of a catalyst. The solvent is then circulated to the coal at about 800° F and 1,500 to 2,000 psi pressure.[7] The solvent then, in chemical jargon, chemically donates the hydrogen atoms to the coal; and the solvent is recycled for further addition of hydrogen. This process circumvents the problems of rapid catalyst deactivation and excessive hydrogen consumption.

In all three processes, the product is removed by distilling it from the slurry, so there is no residual oil* fraction in these "syncrudes. " Because of the chemical structure of coal, the product is high in aromatic content. The initial product is unstable and requires further treatment to produce a stable fuel. Refining** the "syncrude" consists of further hydrogenation or coking (to increase hydrogen content and remove impurities), cracking, and reforming; and current indications are that the most economically attractive product slate consists of gasoline blending stock and fuel oil,[8] but it is possible, with somewhat higher processing costs, to produce products that vary from 27 percent gasoline and 61 percent jet fuel up to 91 percent gasoline and no jet fuel.[9]

The gasoline blending stock is high in aromatics, which makes it suitable for blending with lower octane gasoline to produce a high-octane gasoline. Indications are that the jet fuel can be made to meet all of the refinery specifications for petroleum-derived jet fuel.[10] However, since the methods used to characterize crude oils and the products of oil refining do not uniquely determine their chemical composition, the refined products from syncrudes will have to be tested in various end uses to determine their compatibility with existing uses. Because of the chemistry involved, these syncrudes appear economically less suitable for the production of diesel fuel.***

---

[5] Engineering Societies Commission on Energy, Inc., op. cit.

[6] Cameron Engineering, Inc., "Synthetic Fuels Data Handbook," 2d cd., compiled by G. L. Baughman, 1978.

[7] Ibid.

*Residual oil is the fraction that does not vaporize under distillation conditions. Since this syncrude is itself the byproduct of distillation, all of the fractions vaporize under distillation conditions.

● *At present, it is not clear whether existing refineries will be modified to accept coal syncrudes or refineries dedicated to this feedstock will be built. Local economics may dictate a combination of these two strategies. Refining difficulty is sometimes compared to that of refining sour Middle East crude when no high-sulfur residual fuel oil product is produced (i.e., refining completely to middle distillates and gasoline) (see footnote 8). This is moderately difficult but well within current technical capabilities. One of the principal differences between refining syncrudes and natural crude oil, however, is the need to deal with different types of metallic impurities in the feedstock.

[8] UOP, Inc., and System Development Corp., "Crude Oil vs. Coal Oil Processing Compassion Study," DOE/ET/031 17, TR-80/009-001, November 1979.

[9] Chevron, "Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Processes, Third Interim Report: Processing of SRC II Syncrude," FE-21 35-47, under DOE contract No. EF-76-C-01-2315, Apr. 30, 1981.

[10] Ibid.

* * *The product is hydrogenated and cracked to form saturated, single-ring compounds, and to saturated diolefins (which would tend to form char at high temperatures). The reforming step pro-

None of the direct liquefaction processes has been tested in a commercial-scale plant. All involve the handling of coal slurries, which are highly abrasive and have flow properties that cannot be predicted adequately with existing theories and experience. Consequently, engineers cannot predict accurately the design requirements of a commercial-scale plant and the scale-up must go through several steps with probable process design changes at each step. As a result, the direct liquefaction processes are not likely to make a significant contribution to synfuels production before the 1990's. At this stage there would be a substantial risk in attempting to commercialize the direct liquefaction processes without additional testing and demonstration.

Gasification

The same type of gasifiers used for the liquefaction processes can be used for the production of synthetic fuel gases. The first step is the production of a synthesis gas (300 to 350 Btu/SCF). * The synthesis gas can be used as a boiler fuel or for process heat with minor modifications in end-use equipment, and it also can be used as a chemical feedstock. Because of its relatively low energy density and consequent high transport costs, synthesis gas probably will not be transported (in pipelines) more than 100 to 200 miles. There is very little technical risk in this process, however, since commercial gasifiers could be used.

The synthesis gas can also be used to synthesize methane (the principal component of natural gas having a heat content of about 1,000 Btu/SCF). This substitute or synthetic natural gas (SNG) can be fed directly into existing natural gas pipelines and is essentially identical to natural gas. There is some technical risk with this process, since the methane synthesis has not been demonstrated at a commercial scale. However, since it only involves fluid streams, it probably can be scaled up to commercial-scale operations without serious technical difficulties.

As mentioned under "Indirect Liquefaction, " there are several commercial gasifiers capable of producing the synthesis gas. The principal technical problems in commercial SNG projects are likely to center around integration of the gasifier and methane synthesis process.

Shale Oil

Oil shale consists of a porous sandstone that is embedded with a heavy hydrocarbon (known as kerogen). Because the kerogen already contains hydrogen, a liquid shale oil can be produced from the oil shale simply by heating the shale to break (crack) the kerogen down into smaller molecules. This can be accomplished either with a surface reactor, a modified in situ process, or a so-called true in situ process.

In the surface retorting method, oil shale is mined and placed in a metal reactor where it is heated to produce the oil. In the "modified in situ" process, an underground cavern is excavated and an explosive charge detonated to fill the cavern with broken shale "rubble." Part of the shale is ignited to produce the heat needed to crack the kerogen. Liquid shale oil flows to the bottom of the cavern and is pumped to the surface. In the "true in situ" process, holes are bored into the shale and explosive charges ignited in a particular sequence to break up the shale. The "rubble" is then ignited underground, producing the heat needed to convert the kerogens to shale oil.

The surface retort method is best suited to thick shale seams near the surface. The modified in situ is used where there are thick shale seams deep underground. And the true in situ method is best suited to thin shale seams near the surface. The surface retorting method requires the mining and disposal of larger volumes of shale than the modified in situ method and the true in situ method requires only negligible mining. It is more difficult, using the latter two processes, however, to achieve high oil yields of a relatively uniform quality, primarily because of difficulties related to controlling the underground combustion and

---

duces aromatics from the saturated rings. The rings can also be broken to form paraffins, but the resultant molecules and other paraffins in the "oil" are too small to have a high cetane rating (the cetane rating of one such diesel was 39 (see footnote 9), while petroleum diesels generally have a centane of 45 or more (E. M. Shelton, "Diesel Fuel Oils, 1980, " DOE/BETC/PPS-80/5, 1980)). Polymerization of the short chains into longer ones to produce a high-cetane diesel fuel is probably too expensive.

**Assuming the gas consists primarily of carbon monoxide and hydrogen.

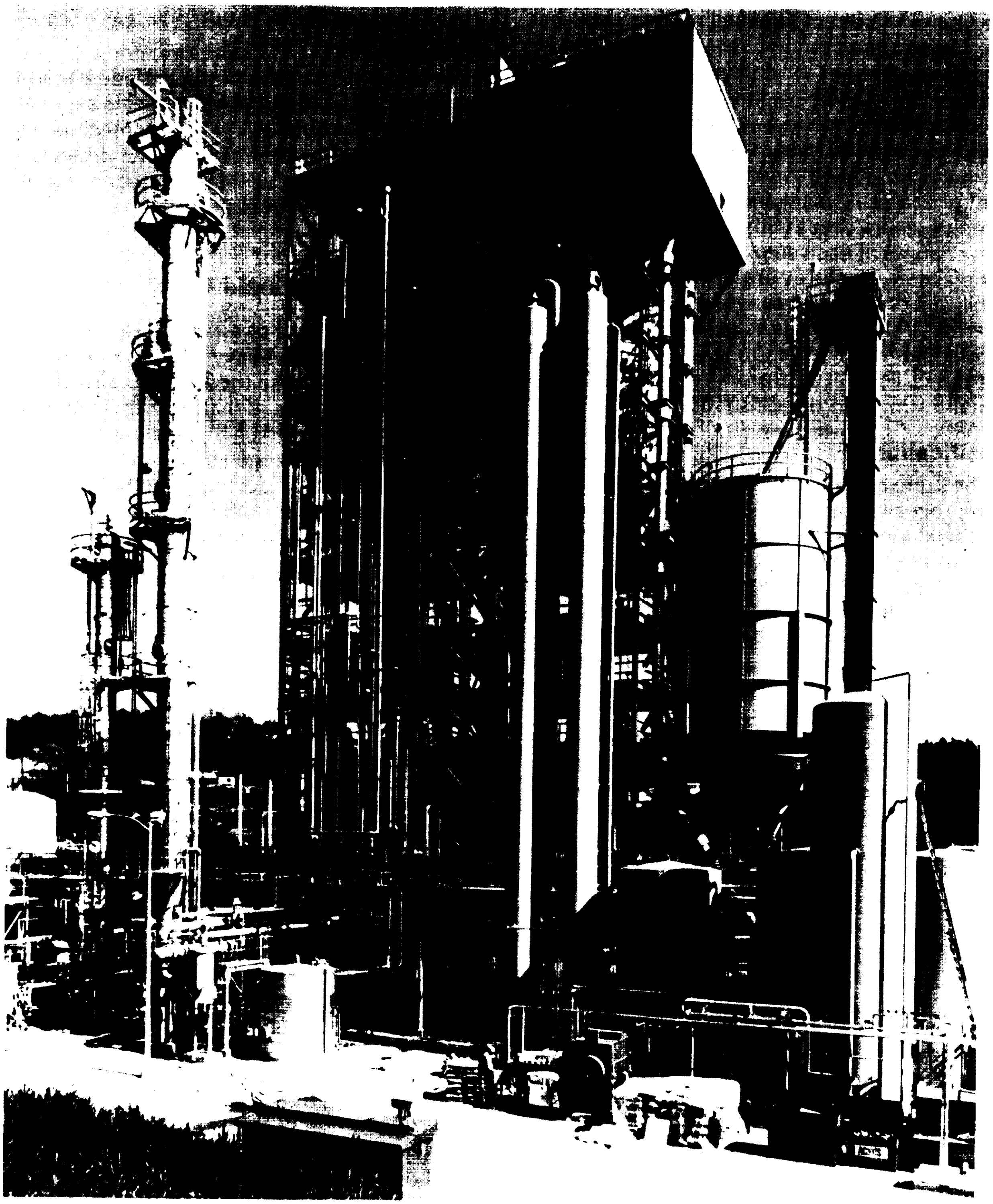


Photo *credit:* Department *of* Energy

Synthane pilot plant near Pittsburgh, Pa., converts coal to synthetic natural gas ensuring that the resultant heat is efficiently transferred to the shale. It is likely, however, that these problems can be overcome with further development work.

The shale oil must be hydrogenated under conditions similar to coal hydrogenation (800° F, 2,000 psi)[11] to remove its tightly bound nitrogen, which, if present, would poison refinery catalysts.

The resultant upgraded shale oil is often compared to Wyoming sweet crude oil in terms of its refining characteristics and is more easily refined than many types of higher sulfur crude oils currently being refined in the United States. Refining shale oil naturally produces a high fraction of diesel fuel, jet fuel, and other middle distillates. The products, however, are not identical to the fuels from conventional crude oil, so they must be tested for the various end uses.

Shale oil production is currently moving to commercial-scale operation, and commercial facilities are likely to be in operation by the mid to late 1980's. Because of completed and ongoing development work, the risks associated with moving to commercial-scale operation at this time are probably manageable, although risks are never negligible when commercializing processes for handling solid feedstocks.

Synthetic Fuels From Biomass

The major sources of biomass energy are wood and plant herbage, from which both liquid and gaseous fuels can be synthesized. These syntheses and the production of some other synfuels from less abundant biomass sources are described briefly below.

Liquid Fuels

The two liquid fuels from biomass considered here are methanol ("wood alcohol") and ethanol ("grain alcohol"). Other liquid fuels from biomass such as oil-bearing crops must be considered as speculative at this time.[12]

Methanol can be synthesized from wood and plant herbage in essentially the same way as it is produced from coal. One partially oxidizes or simply heats (pyrolyzes) the biomass to produce a synthesis gas. The gas is cleaned, the ratio of carbon monoxide to hydrogen adjusted, and the resultant gas pressurized in the presence of a catalyst to form methanol. As with the indirect coal processes, the synthesis gas could also be converted to a Fischer-Tropsch gasoline or the methanol converted to Mobil MTG gasoline.

Methanol probably can be produced from wood with existing technology, but methanol-from-grass processes need to be demonstrated. Several biomass gasifiers are currently under development to improve efficiency and reliability and reduce tar and oil formation. Particularly notable are pyrolysis gasifiers which could significantly increase the yield of methanol per ton of biomass feedstock. Also mass production of small (5 million to 10 million gal/y r), prefabricated methanol plants may reduce costs significantly. With adequate development support, advanced gasifiers and possibly prefabricated methanol plants could be commercially available by the mid to late 1980's.

Ethanol production from grains and sugar crops is commercial technology in the United States. The starch fractions of the grains are reduced to sugar or the sugar in sugar crops is used directly. The sugar is then fermented to ethanol and the ethanol removed from the fermentation broth by distillation.

The sugar used for ethanol fermentation can also be derived from the cellulosic fractions of wood and plant herbage. Commercial processes for doing this use acid hydrolysis technology, but are considerably more expensive than grain-based processes. Several processes using enzymatic hydrolysis and advanced pretreatments of wood and plant herbage are currently under development and could produce processes which synthesize ethanol at costs comparable to those of ethanol derived from grain, but there are still significant economic uncertainties.[13]

---

[1] ‘Chevron, "Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Processes, First Interim Report: Paraho Shale Oil, "Report HCP/T23 15-25 UC90D, Department of Energy, July 1978,

[12] *Energy From Biological* processes, op. cit.

[13] Ibid

Fuel Gases

By 2000, the principal fuel gases from biomass are likely to be a low-energy gas from airblown gasifiers and biogas from manure. Other sources may include methane (SNG) from the anaerobic digestion of municipal solid waste and possibly kelp.

A relatively low-energy fuel gas (about 200 Btu/SCF) can be produced by partially burning wood or plant herbage with air in an airblown gasifier. The resultant gas can be used to fuel retrofitted oil- or gas-fired boilers or for process heat needs. Because its low energy content economically prohibits long-distance transportation of the gas, most users will operate the gasifier at the place where the fuel gas is used. Several airblown biomass gasifiers are under development, and commercial units could be available within 5 years.

Biogas (a mixture of carbon dioxide and methane) is produced when animal manure or some types of plant matter are exposed to the appropriate bacteria in an anaerobic digester (a tank sealed from the air). Some of this gas (e.g., from the manure produced at large feedlots) may be purified, by removing the carbon dioxide, and introduced into natural gas pipelines, but most of it is likely to be used to generate electricity and provide heat at farms where manure is produced. The total quantity of electricity produced this way would be small and, to an increasing extent, would be used to displace nuclear- and coal-generated electricity. A part of the waste heat from the electric generation can be used for hot water and space heating in buildings on the farm, however.[14] A small part of the biogas (perhaps 15 percent corresponding to the amount occurring on large feedlots) could be purified to SNG and introduced into natural gas pipelines.

Biogas can also be produced by anaerobic digestion of municipal solid waste in landfills and kelps. Any gas so produced is likely to be purified and introduced into natural gas pipelines.

Manure digesters for cattle manure are commercially available. Digesters utilizing other manures require additional development, but could be commercially available within 5 years. The technology for anaerobic digestion of municipal solid waste was not analyzed, but one system is being demonstrated in Florida.[15] In addition, if ocean kelp farms prove to be technically and economically feasible, there may be a small contribution by 2000 from the anaerobic digestion of kelp to produce methane (SNG),[16] but this source should be considered speculative at present.

---

[14] TRW, "Achieving a production Goal of 1 Million B/D of Coal Liquids by 1990," March 1980.

[15] I. E., Associates, "Biological Production of Gas," contractor report to OTA, April 1979, available in Energy From *Biological Processes, Vol III:* Appendixes, Part C, September 1980,

[16] *Energy From* Biological *Processes,* op. cit.

COST OF SYNTHETIC FUELS

There is a great deal of uncertainty in estimating costs for synthetic fuels plants. A number of factors, which can be predicted with varying degrees of accuracy, contribute to this uncertainty. Some of the more important are considered below, followed by estimates for the costs of various synfuels.

Uncertainties

For most of the synfuels, fixed charges are a large part of the product costs. Depending on assumptions about financing, interest rates, and the required rate of return on investment, these charges can vary by more than a factor of 2. In many cases, differences in product cost estimates can be explained solely on the basis of these differences. For most of the biomass fuels, the cost of the biomass feedstock is also highly variable, and this has a strong influence on the product cost.

The cost of synfuels projects, and particularly the very large fossil fuel ones, is also affected by: 1) construction delays, 2) real construction cost increases (corrected for general inflation) during construction, and 3) delays in reaching full production capacity after construction is completed, due to technical difficulties. These factors are usually not included in cost estimates, but they are likely to affect the product cost.

Another factor that should be considered is the state of development of the technology on which the investment and operating cost estimates are based, As technology development proceeds, problems are discovered and solved at a cost, and the engineer's original concept of the plant is gradually replaced with a closer and closer approximation of how the plant actually will look. Consequently, calculations based on less developed technologies are less accurate. This usually means that early estimates understate the true costs by larger margins than those based on more developed and well-defined technologies. This is particularly true of processes using solid feedstocks because of the inherent difficulty with scaling-up process streams involving solids. Figure 14 illustrates cost escalations that can occur, by summarizing the increases in cost estimates for various energy projects as technology development proceeded. Table 42 also illustrates this point by showing average cost overruns that have occurred in various types of large construction projects.

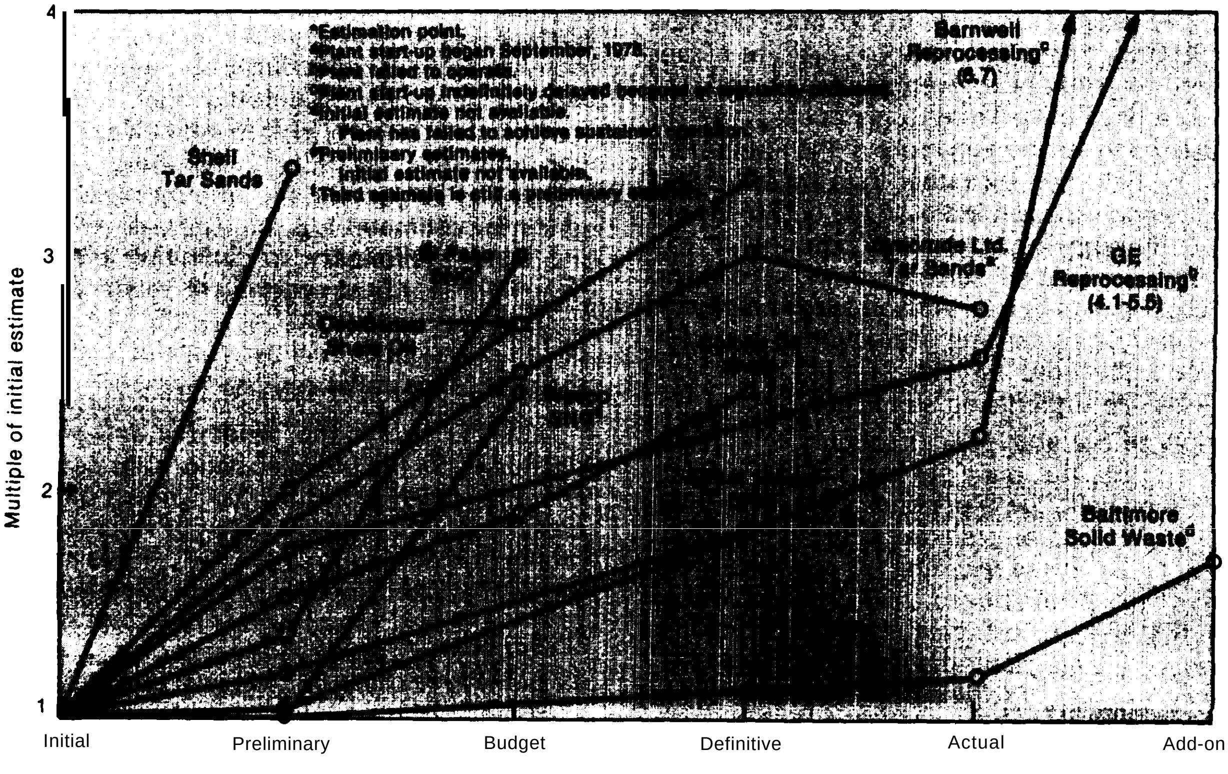
It should be noted, however, that the period of time in which most of the project evaluations

Table 42.-Average Cost Overruns for Various Types of Large Construction Projects

System type	Actual cost divided by estimated cost
Weapons systems.	1.40-1.89
Public works	1.26-2.14
Major construction	2.18
Energy process plants	2.53

SOURCES: Rand Corp., "A Review of Cost Estimates In New Technologies: **Implications** for Energy Process **Plants,"** prepared for U.S. Department of Energy, July 1979; **Hufschmidt** and **Gerin,** "Systematic Errors In Cost Estimates for Public Investment Projects," in ***The Analysis*** of ***Public*** Output, Columbia University Press, 1970; and R. Perry, et al., "Systems **Acquisition** Strategies," Rand Corp., 1970.

Figure 14.—Cost Growth in Pioneer Energy Process Plants (constant dollars)



SOURCE: "A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants," Rand Corp. R-2481- DOE, July 1979, in table 42 were made had high escalation rates for capital investment relative to general economic inflation. Historically this has not been the case; and if future inflation in plant construction more nearly follows general inflation, the expected synfuels investment increases from preliminary design to actual construction would be lower than is indicated in figure 14 and table 42.

When judging the future costs and economic competitiveness of synfuels, one must therefore also consider the long-term inflation in construction costs. To a very large extent, the ability to produce synfuels at costs below those of petroleum products will depend on the relative inflation rates of crude oil prices and construction costs.

Although economies of scale are important for synfuels plants, there are also certain diseconomies of scale—factors which tend to increase construction costs (per unit of plant capacity) for very large facilities as compared with small ones. First, the logistics of coordinating construction workers and the timely delivery of construction materials become increasingly difficult as the construction project increases in size and complexity. Second, construction labor costs are higher in large projects due to overtime, travel, and subsistence payments. Third, as synfuels plants increase in size, more and more of the equipment must be field-erected rather than prefabricated in a factory. This can increase the cost of equipment, although in some cases components may be "mass-produced" on site, thereby equaling the cost savings due to prefabrications. Some of these problems causing diseconomies of scale can be aggravated if a large number of synfuels projects are undertaken simultaneously.

Many of the above factors would tend to increase costs, but once several full-scale plants have been built, the experience gained may help reduce production costs for future generations of plants. Delays in reaching full production capacity can be minimized, and process innovations that reduce costs can be introduced. in addition, very large plants that fully utilize the available economies of scale can be built with confidence. Consequently, the first generation units produced are likely to be the most expensive, if adjustments are made for inflation in construction and operating costs.

An example of this can be found in the chemical industry, where capital productivity (output per unit capital investment) for the entire industry has increased by about 1.4 percent per year since 1949.[17] In some sectors, such as methanol synthesis, productivity has increased by more than 4 percent per year for over 20 years.[18] Much of this improvement is attributable to increased plant size and the resultant economies of scale: Because the proposed synfuels plants are already relatively large, cost decreases for synfuels plants may not be as large and consistent as those experienced in the chemical industry in recent years; however, because of the newness of the industry, some decreases are expected.

Investment Cost

For purposes of cost calculations, previous OTA estimates[19][20] were used for oil shale and biomass synfuels (adjusted, in the case of oil shale, to 1980 dollars) and the best available cost estimates in the public literature were used for coal-derived synfuels. These latter estimates were compared[21] to the results of an earlier Engineering Societies' Commission on Energy (ESCOE) study[22] of coal-derived synfuels, which used preliminary engineering data. Since the best available cost estimates correspond roughly to definitive engineering estimates, the ESCOE numbers were increased by 50 percent, the amount by which engineering estimates typically increase when going from preliminary to definitive estimates. When these adjustments were made and the costs expressed in 1980 dollars, the two sources of cost estimates for coal-based synfuels produced roughly comparable results. *s

Table 43 shows the processes and product slates used for the cost calculations. As described above, a variety of alternative product slates are possible, but these were chosen to emphasize the production of transportation fuels. Table 44 gives the best available investment and operating costs

---

[17] E. J. Bentz & Associates, Inc., "Selected Technical and Economic Comparisons of Synfuel Options, " contractor report to OTA, 1981.

[18] Ibid.

[19] *An* Assessment of Oil *Shale* Technologies, op. cit.

[20] *Energy From Biological Processes,* op. cit.

[21] E. J. Bentz & Associates, Inc., op. cit.

[22] Engineering Societies Commission on Energy, Inc., OP. cit.

[23] E. J. Bentz & Associates, Inc., Op. cit.

Table 43.—Selected Synfuels Processes and Products and Their Efficiencies

Process	Fuel products (percent of output)	Energy efficiency (percent)[a]: Fuel products (percent of input coal and external power)	Energy efficiency (percent)[a]: Tranportation fuel products (percent of input coal and external power)
Oil shale	Gasoline (19)[b] Jet fuel (22) Diesel fuel (59)	N.A.[c]	N.A.[c]
Methanol/synthetic natural gas (SNG) from coal	Methanol (48)[d] SNG (49) Other (3)	65	33
Methanol from coal	Methanol (100)[ef]	55[g]	55[g]
Coal to methanol/SNG, Mobil methanol to gasoline	Gasoline (40)[d] SNG (52) Other (8)	63	27
Coal to methanol, Mobil methanol to gasoline	Gasoline (87)[d] Other (13)	47	41
Fischer-Tropsch/SNG from coal	Gasoline (33)[d] SNG (65) Other (2)	56	17
Direct coal liquefaction	Gasoline (33)[fh] Jet fuel (49) Other (18)	57	47
SNG from coal	SNG (100)[f]	59	0
Methanol from wood	Methanol (100)[i]	47[f]	47[h]
Ethanol from grain	Ethanol (100)[i]	N.A.[c]	N.A.[c]

[a] Higher heating value of products divided by higher heating value Of the coal plus imported energy.

[b] R. F. Sullivan, et al., "Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Processes," first interim report, prepared by Chevron for Department of Energy, April 1978, NTIS No FE-2315-25.

[c] Not applicable

[d] Max Schreiner, "Research Guidance Studies to Assess Gasoline From Coal to Methanol-to-Gasoline and Sasol-Type Fischer. Tropsch Technologies," prepared by Mobil R&D Co. for the Department of Energy, August 1978, NTIS No. FE-2447-13.

[e] DHR, Inc., "Phase I Methanol Use Options Study," prepared for the Department of Energy under contract No, DE-AC01-79PE-70027, Dec. 23, 1980,

[f] K. A. Rogers, "Coal Conversion Comparisons," Engineering Societies Commission on Energy, Washington, D.C., prepared for the Department of Energy, July 1979, No. FE-2488-51.

[g] Sullivant and Frumking (footnote h) give 57 percent, DHR (footnote e) gives 52 percent.

[h] R, F, Sullivan and H. A. Frumkin, "Refining and Upgrading of Synfuels by Advanced Catalytic Processes," third interim report, prepared by Chevron for the Department of Energy, Apr. 30, 1980, NTIS, No. FE-2315,47 Products shown are for H-Coal. It is assumed that same product slate results from refined EDS liquids.

[i] OTA, *Energy From Biological* processes, *Volume* //, September 1980, GPO stock No. 052-003-00782-7.

SOURCE: Office of Technology Assessment

(excluding coal costs) in 1980 dollars for the various processes, with all results normalized to the production of 50,000 barrels per day (bbl/d) oil equivalent of product to the end user (i.e., including refining losses). Only a generic direct liquefaction process is included because current estimation errors appear likely to be greater than any differences between the various direct liquefaction processes.

Based on the history of cost escalation in the construction of chemical plants, one can be nearly certain that final costs of the first generation of these synfuels plants will exceed those shown in table 44 (with the exception of ethanol which is already commercial), Using a methodology developed to estimate this cost escalation, Rand Corp. has examined several synfuels processes and derived cost growth factors, or estimates of how much the capital investment in the synfuels plant is likely to exceed the best available engineering estimates. Some of the results of the Rand study are shown in table 45. Also shown is the expected performance of each plant if it were built today, expressed as the percentage of designed fuel production that the plant is likely to achieve.

The figures reflect Rand's judgment that direct liquefaction processes require further development before construction of a commercial-scale plant should be attempted; but the calculations also indicate that even the first generation of near-commercial processes are likely to be more ex-

Table 44.—Best Available Capital and Operating Cost Estimates for Synfuels Plants Producing 50,000 bbl/d Oil Equivalent of Fuel to End Users

Process	Capital investment (billion 1980 dollars)	Annual operating costs (exclusive of coal costs) (million 1980 dollars)
Oil shale [a]	$2,2	$250
Methanol/SNG from coal [b]	2.1	150
Methanol from coal [c]	2.8	200
Coal to methanol/SNG, Mobil methanol to gasoline [b]	2.4	170
Coal to methanol, Mobil methanol to gasoline [b]	3.3	230
Fischer-Tropsch/SNG from coal [b]	2.5	190
Direct coal liquefaction [d]	3.0	250
SNG [e]	2..2	150
Methanol from wood [f]	2.9	610 (wood at $30/dry ton) (wood at $45/dry ton) 860
Ethanol [f]	1.8	($3/bu. corn) 1,112 ($4.50/bu. corn)

[a] Office of Technology Assessment, An *Assessment* of 0// *Shale Technologies,* June 1980, $1.7 billion Investment in 1979 dollars becomes $1.9 billion In 1980 dollars for 50,000 bbl/d of shale oil. Assuming 88 percent refining efficiency, one needs 57,000 bbl/d of shale 011 to produce 50,000 bbl/d 011 equivalent of products, at an investment of $1.9 billion/0.88 -$2.2 billion.

[b] Derived from R. M. Wham, et al., "Liquefaction Technology Assessment-Phase 1: Indirect Liquefaction of Coal to Methanol and Gasoline Using Available Technology," Oak Ridge National Laboratory, ORNL-5664, February 1981.

[c] From DHR, Inc., "Phase I Methanol Use Options Study," prepared for the Department of Energy under contract No. DE-AC01-79PE-70027, Dec. 23, 1980, one finds that the ratio of investment cost of a methanol to a Mobil methanol-to-gasoline plant Is 0.85. Assuming this ratio and the value for a methanol-to-gasoline plant from footnote b, one arrives at the investment cost shown. The operating cost was increased in proportion to investment coat. Thia adjustment is necessary to put the costs on a common basis. These values are 50 percent more than the estimates given by DHR (reference above) and Badger (Badger Plants, Inc., "Conceptual Design of a Coal to Methanol Commercial Plant," prepared for the Department of Energy, February 1978, NTIS No. FE-2416-24). In order to compare Badger with this estimate, It was necessary to scale down the Badger plant (using a 0.7 scaling factor) and inflate the result to 1980 dollars (increase by 39 percent from 1977).

[d] Exxon Research and Engineering Co., "EDS Coal Liquefaction Process Development, Phase V," prepared for the Department of Energy under cooperative agreement DE-FCO1-77ETIOO89, March 1981. Investment and operating cost assumes an energy efficiency of 82.5 percent for the refining process. Refinery Investment of up to S700 million Is not included in the capital investment.

[e] Rand Corp., "Cost and Performance Expectations for Pioneer Synthetic Fuels Plants," report No. R-2571-DOE, 1981.

[f] Office of Technology Assessment, Energy From Biological Processes, Volume *II,* September 1980, GPO stock No. 052-003-00782-7; i.e., 40 million gallons per year methanol plant costing S88 million, 50 million gallons per year ethanol plant costing $75 million,

SOURCE: Office of Technology Assessment.

Table 45.—Estimates of Cost Escalation in First Generation Synfuels Plants

Process	Cost growth factor derived by Rand [a] for 90 percent confidence interval [b]	Revised investment cost (billion 1980 dollars)	Expected performance for 90 percent confidence interval [b] (percent of plant design)
Oil shale	1.04-1.39	2.3-3.1	57-85
Coal to methanol to gasoline (Mobil, no SNG byproduct). .,	1.06-1.43	3.5-4.7	65-93
Direct coal liquefaction (H-Coal)	1.52-2.38a	4.0-6 .3a	25-53
SNG	0.95-1.23	2.1-2.7	69-97

[a] Based on Rand @@ in which best estimate for H-Coal is $2.2 billion for 50,000 bbl/d of product syncrude. With 82.5 Percent refining efficiency, this becomes $2.7 billion for 50,000 bbl/d of product to end user.

[b] In other words, 90 percent probability that actual cost growth factor or Performance will fall in the interval.

SOURCE: Office of Technology Assessment; adapted from Rand Corp., "Cost and Performance Expectations for Pioneer Synthetic Fuels Plants," R-2571-DOE, 1981.

pensive and less reliable than the best conventional engineering estimates would indicate. This analysis indicates that it is quite reasonable to expect first generation coal liquefaction plants of this size to cost $3 billion to $5 billion or more each in 1980 dollars.

Consumer Cost

The consumer costs of the various synfuels are shown in table 46. These consumer costs are based on the estimates in table 44 and the economic assumptions listed in table 47. The effect on the calculated product cost of varying some of the economic assumptions is then shown in table 48.

With these economic assumptions, delivered liquid fossil synfuels costs (1980 dollars) range from $1.25 to $1.85 per gallon of gasoline equivalent (gge) for 100 percent equity financing and $0.80 to $1.25/gge with 75 percent debt financing at 5 percent real interest (i. e., relative to inflation), In 1981 dollars, these estimates become $1.40 to 2.10/gge and $0.90 to $1.40/gge, respectively. This compares with a reference cost of gasoline from $32/bbl crude oil of $1.20/gal (plus $0.1 7/gal taxes).

Extreme caution should be exercised when interpreting these figures, however. They represent the best current estimates of what fossil synfuels will cost after technical uncertainties have been resolved through commercial demonstration. They do not include any significant cost increases that may occur from design changes, hyperinflation in construction costs, or construction delays. They most likely represent a lower limit for the synfuels costs.

Table 46.—Consumer Cost of Various Synthetic Transportation Fuels

	1000/0 equity financing, IO% real return on investment			25°/0 equity/75% debt financing, 10% real return on investment		
	Plant or refinery gate product cost	Delivered consumer cost of fuel [a]		Plant or refinery gate product cost	Delivered consumer cost of fuel [a]	
Process	1960 dollars per barrel oil equivalent (5.9 MMBtu/B)	1960 dollars per gallon gasoline equivalent (125 k Btu/gal)	1980 $/MMBtu	1980 dollars per barrel oil equivalent (5.9 MMBtu/B)	1960 dollars per gallon gasoline equivalent (125 k Btu/gal)	1980 $/MMBtu
Reference cost of gasoline from $32/bbl crude oil . .	47	1.20	9.50		1.20	9.50
Oil shale.	52[b]	1.30	10.40	3 3[b]	0.90	7.20
Methanol/SNG from coal . .	43	1.30[c d]	10.60[c]	25	0.95[c d]	7.50[c]
Methanol from coal	58	1.60[d]	13.00	33	1.10[d]	8.60
Coal to methanol/SNG, Mobil methanol to gasoline	49[e]	1.25C [d]	10.00[c]	29[e]	0.80[c d]	6.40[c]
Coal to methanol, Mobil methanol to gasoline . . .	67[e]	1.60[d]	12.90	38[e]	1.00[d]	8.10
Fischer-Tropsch/SNG from coal	52[e]	1 .30[c]	10.40[c]	3o[e]	0.85[c]	6.70[c]
Direct coal liquefaction . . .	77[f]	1.85	14.60	5 1[f]	1.25	10.20
SNG from coal		1.15[g]	9.10[g]		0.75[g]	5.90[g]
Methanol from wood	68 (79)[h]	1.65 (2.05)[h]	14.70 (16.60)[h]	49 (60)[h]	1.45 (1.70)[h]	11.60 (13.40)[h]
Ethanol from grain	71 (87)’	1.60 (2.15)’	14.50 (17.10)’	60 (75)’	1.55 (1.90)’	12.60 (15.10)’

[a] Assuming $0.20/physical gallon delivery charge and mark-up; fuel taxes not included.

[b] Includes $6/bbl refining cost. Derived from R. F. Sullivan, et al., “Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic processes,” first interim report by Chevron Research Corp. to the Department of Energy, April 1978, by increasing cost of $4.50/bbl by 22 percent to reflect 19S0 dollars and adjusting for 88 percent refinery efficiency.

[c] Assumes coproduct SNG selling for same price per MMBtu at the Plant gate ss the liquid product.

[d] Although the plant or refinery gate cost of methanol is lower than MTG gasoline, the delivered consumer cost Of methanol is higher due to the higher cost of delivering a given amount of energy in the form of methanol aa compared with gasoline, because of the lower energy content per gallon of the former.

[e] Aii necessary refining is included in the conversion Plant.

[f] Includes $14/bbl refining cost from R. F. Sullivan and H. A. Frumkin, “Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Processes, Third Interim Report,” report to the Department of Energy, Apr. 30, 19S0, NTIS No. FE-2315-47. Refining costs fOr EDS and H-Coal are assumed to be the same as SRC Il. Note, however, that refining costs drop to $10/bbl for production of heating oil and gasoline and Increase to $16.50/bbl for production *of gasoline only.*

[g] $1.49/MMBtu delivery charge and markup, which corresponds to the 1980 difference between the wellhead and residential price of natural gas. Energy Information Administration, U.S. Department of Energy, “19S0 Annual Report to Congress,” vol. 2, DOE/EIA-0173 (S0)/2, pp. 117 and 119.

[h] Assumes $30/dry ton wood. Number in parentheses corresponds to $45/dry ton wood.

[i] Assumes $3/bu. corn. Number in parentheses corresponds to $4.50/bu. corn.

SOURCE: Office of Technology Assessment.

Table 47.—Assumptions

1, Project life—25 years following 5-year construction period for fossil synfuels and 2-year construction period for biomass synfuels.
2.10 year straight-line depreciation.
3. Local taxes and property insurance as in K. K. Rogers, "coal Conversion Comparisons," ESCOE, prepared for U.S. Department of Energy under contract No. EF-77-C-01-2468, July 1979.
4.10 percent real rate of return on equity investment with: 1) 100 percent equity financing, and 2) 75 percent debt/25 percent equity financing with 5 percent real interest rate.
5.90 percent capacity or "onstream factor."
6. Coal costs $30/ton delivered to synfuels plant (1980 dollars).
7.46 percent Federal and 9 percent State tax.
8. Working capital = 10 percent of capital investment.

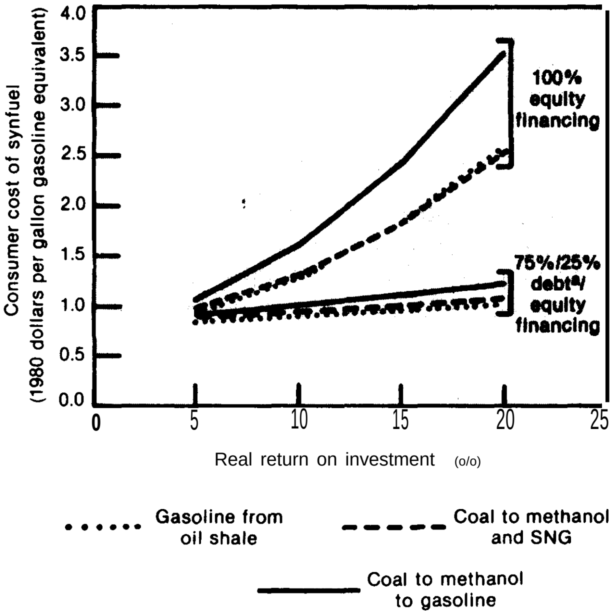
SOURCE: Office of Technology Assessment.

Table 48.—Effect of Varying Financial Parameters and Assumptions on Synfuels' Costs

Change	Effect on synfuels cost
Plant operates at a 50 percent on stream factor rather than 90 percent	Increase 60-70%
Increase capital investment by 50 percent	Increase 15-35%
8-year construction rather than 5-year	Increase 5-20%
Increase coal price by $15/ton . .	Increase $5-7/bbl

SOURCE: Office of Technology Assessment.

Figure 15.—Consumer Cost of Selected Synfuels With Various Aftertax Rates of Return on Investment



a5% real interest rate on debt.

SOURCE: Office of Technology Assessment

Because cost overruns and poor plant performance lower the return on investment, investors in the first round of synfuels plants are likely to require a high calculated rate of return on investment to ensure against these eventualities. Put another way, anticipated cost increases (table 45) would lead investors to require higher product prices than those in table 46 before investing in synfuels.

The effects on product costs of various rates of return on investment are shown in figure 15 for selected processes, and the effect of changes in various other economic parameters is shown in table 48. As can be seen, product costs could vary by more than a factor of 2 depending on the technical, economic, and financial conditions that pertain.

Nevertheless, it can be concluded that factors which reduce the equity investment and the required return on that investment and those which help to ensure reliable plant performance are the most significant in holding synfuels costs down. These factors do not always act unambiguously, however. Inflation during construction, for example, increases cost overruns, but inflation after construction increases the real (deflated) return on investment. The net effect is that the synfuels cost more than expected when plant production first starts, but continued inflation causes the prices of competing fuels to rise and consequently allows synfuels prices—and returns on investment —to rise as well. Similarly, easing of environmental control requirements can reduce the time and investment required to construct a plant, but inadequate controls or knowledge of the environmental impacts may lead to costly retrofits which may perform less reliably than alternative, less polluting plant designs.

Another important factor influencing the cost of some synthetic transportation fuels is the price of coproduct SNG. In table 46 it was assumed that any coproduct SNG would sell for the same price per million Btu (MMBtu) at the plant gate as the liquid fuel products, or from $4 to $9/

MMBtu, which compares with current well head prices of up to $9/MM Btu[24] for some decontrolled gas. (These prices are averaged with much larger quantities of cheaper gas, so average consumer prices are currently about $3 to $5/MMBtu.) However, the highest wellhead prices may not be sustainable in the future as their "cushion" of cheaper gas gets smaller, causing averge consumer prices to rise. This is because consumer prices are limited by competition between gas and competing fuels—e.g., residual oil—and probably cannot go much higher without causing many industrial gas users to switch fuels. Large quantities of unconventional natural gas might be produced at well head prices of about $10 to $1 l/MMBtu,[25] so SNG coproduct prices are unlikely to exceed this latter value in the next two decades. If the SNG coproduct can be sold for only $4/MMBtu or less, synfuels plants that do not produce significant quantities of SNG will likely be favored. However, for the single-product indirect liquefaction processes, advanced high-temperature gasifiers, rather than the commercially proven Lurgi gasifier assumed for these estimates, may be used. This adds some additional uncertainty to product costs.

Despite the inability to make reliable absolute cost estimates, some comparisons based on technical arguments are possible. First, oil shale probably will be one of the lower cost synfuels because of the relative technical simplicity of the process: one simply heats the shale to produce a liquid syncrude which is then hydrogenated to produce a high-quality substitute for natural crude oil. However, handling the large volumes of shale may be more difficult than anticipated; and, since the high-quality shale resources are located in a single region and there is only a limited ability to disperse plants as an environmental measure, large production volumes could necessitate particularly stringent and therefore expensive pollution control equipment or increase waste disposal costs.

Second, regarding the indirect transportation liquids from coal, the relative consumer cost (cost per miles driven) of methanol v. synthetic gasoline will depend critically on automotive technology. Although methanol plants are somewhat less complex than coal-to-gasoline plants, the cost difference is overcome by the higher cost of terminalling and transporting methanol to a service station, due to the latter's lower energy content per gallon. With specially designed engines, however, the methanol could be used with about 10 to 20 percent higher efficiency than gasoline. This would reduce the apparent cost of methanol, making it slightly less expensive (cost per mile) than synthetic gasoline. * Successful development of direct injected stratified-charge engines would eliminate this advantage, while successful development of advanced techniques for using methanol as an engine fuel could increase methanol's advantage. * *

This analysis shows that there is much uncertainty in these types of cost estimates, and they should be treated with due skepticism. The estimates are useful as a general indication of the likely cost of synfuels, but these and any other cost estimates available at this time are inadequate to serve as a principal basis for policy decisions that require accurate cost predictions with consequences 10 to 20 years in the future.

DEVELOPING A SYNFUELS INDUSTRY

Development of a U.S. synfuels industry can be roughly divided into three general stages. During the first phase, processes will be developed and proven and commercial-scale operation established. The second phase consists of expanding the industrial capability to build synfuels

---

[24] Process Gas Consumer Group, Process Gas Consumers *Report,* Washington, D. C., June 1981.

[25] J. F. Bookout, Chairman, Committee on Unconventional Gas Sources, "Unconventional Gas Sources," National Petroleum Council, December 1980.

*If gasoline has a $0.10/gge advantage in delivered fuel price for synfuels costing $1 .50/gge, methanol would have an overall $0.20/gge advantage when used with a specially designed engine. This could pay for the added cost of a methanol engine in 2 to 4 years (assuming 250/gge consumed per year).

**For example, engine waste heat can be used to decompose the methanol into carbon monoxide and hydrogen before the fuel is burned. The carbon monoxide/hydrogen mixture contains 20 percent more energy than the methanol from which it came, with the energy difference coming from what would otherwise be waste heat.

plants. in the third stage, ynfuels production is brought to a level sufficient for domestic needs and possibly export. Current indications are that the first two stages could take 7 to 10 years each. Some of the constraints on this development are considered next, followed by a description of two synfuels development scenarios.

Constraints

A number of factors could constrain the rate at which a synfuels industry develops. Those mentioned most often include:

- Other Construction Projects. –Construction of, for example, a $20 billion to $25 billion Alaskan natural gas pipeline or a $335 billion Saudi Arabian refinery and petrochemical industry, if carried out, would use the same international construction companies, technically skilled labor, and internationally marketed equipment as will be required for U.S. synfuel plant construction.[26]
- Equipment. –Building enough plants to produce 3 million barrels per day (MMB/D) of fossil synfuels by 2000 will require significant fractions of the current U.S. capacity for producing pumps, heat exchangers, compressors and turbines, pressure vessels and reactors, alloy and stainless steel valves, draglines, air separation (oxygen) equipment, and distillation towers.[27] [28] [29] [30]
- critical Materials. -Materials critical to the synfuels program include cobalt, nickel, molybdenum, and chromium. Two independent analyses concluded that only chromium is a potential constraint.[31] [32] (Currently, 90 percent of the chromium used in the United States is imported.) However, development of 3 MMB/D of fossil synfuels production capacity by 2000 would require only 7 percent of current U.S. chromium consumption .[33]
- Technological Uncertainties. -The proposed synfuels processes must be demonstrated and shown to be economic on a commercial scale before large numbers of plants can be built.
- Transportation. — If large quantities of coal are to be transported, rail lines, docks, and other facilities will have to be upgraded.[34] New pipelines for syncrudes and products will have to be built.
- Manpower.–A significant increase in the number of chemical engineers and project managers will be needed. For example, achieving 3 MMB/D of fossil synfuels capacity by 2000 will require 1,300 new chemical engineers by 1986, representing a 35-percent increase in the process engineering work force in the United States.[35] More of other types of engineers, pipefitters, welders, electricians, carpenters, ironworkers, and others will also be needed.
- Environment, Health, and Safety. -Delays in issuing permits; uncertainty about standards, needed controls, and equipment performance; and court challenges can cause delays during planning and construction (see ch. 10). Conflicts over water availability could further delay projects, particularly in the West (see ch. 11).
- Siting. –Some synfuels plants will be built in remote areas that lack the needed technical and social infrastructure for plant construction. Such siting factors could, for example, increase construction time and cost.
- Financial Concerns. –Most large synfuels projects require capital investments that are large relative to the total capital stock of the company developing the project. Consequently, most investors will be extremely cautious with these large investments and banks may be reluctant to loan the capital without extensive guarantees.

---

[26] *Business* Week, Sept. 29, 1980, p. 83.

[27] Ibid.

[28] Bechtel International, Inc., "Production of Synthetic Liquids From Coal: 1980-2000, A Preliminary Study of Potential Impediments," final report, December 1979.

[29] TRW, op. cit.

[30] Mechanical Technology, Inc., "An Assessment of Commercial Coal Liquefaction Processes Equipment Performance and Supply," January 1980.

[31] Ibid.

[32] Bechtel International, Inc., op. cit.

[33] Ibid.

[34] *The Direct Use* of Coal: Prospects and Problems of Production and Combustion, OTA-E-86 (Washington, D. C.: U.S. Congress, Office of Technology Assessment, April 1979).

[35] Bechtel International, Inc., Op. cit.

None of these factors can be identified as an overriding constraint for coal-derived synfuels, although the need for commercial demonstration and the availability of experienced engineers and project managers appear to be the most important. There is still disagreement about how important individual factors like equipment availability actually will be in practice. However, the more rapidly a synfuels industry develops, the more likely development will cause significant inflation in secondary sectors, supply disruptions, and other externalities and controversies. But the exact response of each of the factors in synfuels development is not known. For oil shale, on the other hand, the factor (other than commercial demonstration) that is most likely to limit the rate of growth is the rate at which communities in the oil shale regions can develop the social infrastructure needed to accommodate the large influx of people to the region.[36]

The major impacts of developing a large synfuels industry are discussed in chapters 8 through 10, while two plausible synfuels development scenarios are described below.

Development Scenarios

Based on previous OTA reports[37] [38] estimates of the importance of the various constraints discussed above, and interviews with Government and industry officials, two development scenarios were constructed for synthetic fuels production. It should be emphasized that these are not projections, but rather plausible development scenarios under different sets of conditions. Fossil synthetics are considered first, followed by biomass synfuels; and the two are combined in the final section.

Fossil Synfuels

The two scenarios for fossil synthetics are shown in table 49 and compared with other estimates in figure 16. It can be seen that OTA scenarios are reasonably consistent with the other projections, given the rather speculative nature of this type of estimate.

Table 49.—Fossil Synthetic Fuels Development Scenarios (MMB/DOE)

Fuel	Year 1980	1985	1990	1995	2000
Low estimate					
Shale oil	—	O	0.2	0.4	0.5
Coal liquids	—	—	0.1	0.3	0.8
Coal gases	—	0.09	0.1	0.3	0,8
Total	—	0.1	0.4	1.0	2.1
High estimate					
Shale oil	—	O	0.4	0.9	0.9
Coal liquids	—	—	0.2	0.7	2.4
Coal gases	—	0.09	0.2	0.7	2.4
Total	—	0.1	0.8	2.3	5.7

SOURCE: Office of Technology Assessment

In both scenarios, the 1985 production of fossil synthetic fuels consists solely of coal gasification plants, the only fossil synfuels projects that are sufficiently advanced to be producing by that date. For the high estimate it is assumed that eight oil shale, four coal indirect liquefaction, and three additional coal gasification plants have been built and are operating by 1988-90. If no major technical problems have been uncovered, a second round of construction could proceed at this time.

Assuming that eight additional 50,000-bbl/d plants are under construction by 1988 and that construction starts on eight more plants in 1988 and the number of starts increases by 10 percent per year thereafter, one would obtain the quantities of synfuels shown for the high estimate. Ten-percent annual growth in construction starts was chosen as a high but probably manageable rate of increase once the processes are proven.

Oil shale is assumed to be limited to 0.9 MMB/D because of environmental constraints and, possibly, political decisions related to water availability. Some industry experts believe that neither of these constraints would materialize because, at this level of production, it would be feasible to build aqueducts to transport water to the region, and additional control technology could limit

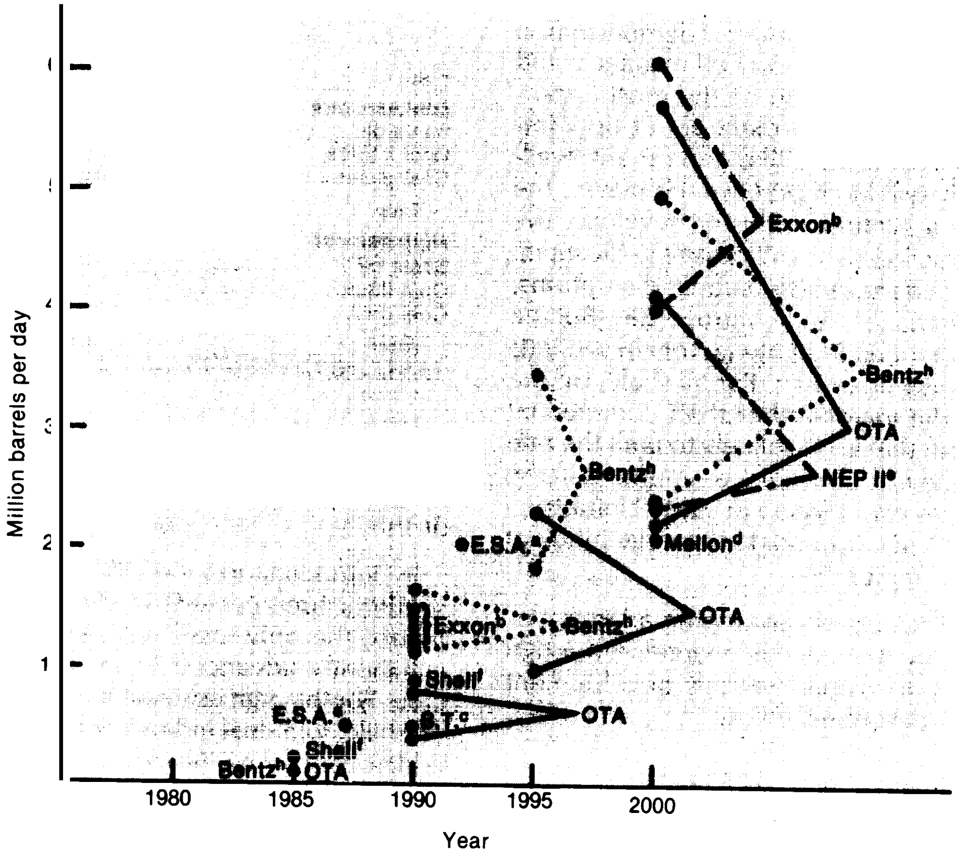
---

[36] *An Assessment* of *Oil Shale* Technologies, op. cit.

[37] Ibid.

[38] *Energy From Biological Processes,* op. cit.

Figure 16.—Comparison of Fossil Synthetic Fuel Production Estimates



[a] Energy Security Act, Public Law 96-294 6/30/80, sec. 100 (a) (2).
[b] Exxon Energy Outlook, December 1979. These data are consistent with those in Exxon Energy Outlook, December 1980.
[c] Bankers Trust Forecast—as reported in *Synfuels*, Aug. 15, 1980.
[d] Mellon Institute Forecast—as reported in *Synfuels*, Aug. 22, 1980.
[e] National Energy Plan II, May 1979.
[f] National Transportation Policy Study Commission Report, July 1979.
[g] Shell National Energy Outlook, preliminary version, Feb. 19, 1980.
[h] E. J. Bentz and Associates, "Selected Technical and Economic Comparisons of Synfuel Options," contractor report to OTA, April 1981.

SOURCE: E. J. Bentz and Associates, "Selected Technical and Economic Comparisons of Synfuel Options," contractor report to OTA, 1981; modified by OTA.

plant emissions to an acceptable level. If this is done and salt leaching into the Colorado River does not materialize as a constraint, perhaps more of the available capital, equipment, and labor would go to oil shale and less to the alternatives.

The low estimate was derived by assuming that project delays and poor performance of the first round of plants limit the output by 1990 to about 0.4 MMB/D. These initial problems limit investment in new plants between 1988-95 to about the level assumed during the 1981-88 period, but the second round of plants performs satisfactorially. This would add 0.6 MMB/D, assuming that the first round operated at 60 percent of capacity, on the average, while the second round operated at 90 percent of capacity (i.e., at full capacity 90 percent of the time). Following the second round, new construction starts increase as in the high estimate.

In both estimates, it is assumed that about half of the coal synfuels are gases and half are liquids.

This could occur through a combination of plants that produce only liquids, only gases, or liquid/gas coproducts. Depending on markets for the fuels, the available resources (capital, engineering firms, equipment, etc.) could be used to construct facilities for producing more synthetic liquids and less synthetic gas without affecting the synfuels total significantly.

When interpreting the development scenarios, however, it should be emphasized that there is no guarantee that even the low estimate will be achieved. Actual development will depend critically on decisions made by potential investors within the next 2 years. In addition to businesses' estimates of future oil prices, these decisions are likely to be strongly influenced by availability of Federal support for commercialization, in which commercial-scale process units are tested and proven. Unless several more commercial projects than industry has currently announced are initiated in the next year or two, it is unlikely that even the low estimate for 1990 can be achieved.

Biomass Synfuels

Estimating the quantities of synfuels from biomass is difficult because of the lack of data on the number of potential users, technical uncertainties, and uncertainties about future cropland needs for food production and the extent to which good forest management will actually be practiced. OTA has estimated that from 6 to 17 quadrillion Btu per year (Quads/yr) of biomass could be available to be used for energy by 2000, depending on these and other factors.[39] At the lower limit, most of the biomass would be used for direct combustion applications, but there would be small amounts of methanol, biogas, ethanol from grain, and gasification as well.

Assuming that 5 Quads/yr of wood and plant herbage, over and above the lower figure for bioenergy, is used for energy by 2000 and that 1 Quad/yr of this is used for direct combustion, then about 4 Quads/yr would be converted to synfuels. If half of this biomass is used in airblown gasifiers for a low-Btu gas and half for methanol synthesis (60 percent efficiency), this would result in 0.9 million barrels per day oil equivalent (MMB/DOE) of low-Btu gas and 0.6 MMB/DOE of methanol (19 billion gal/yr). *

The 0.9 MMB/DOE of synthetic gas is about 5 percent of the energy consumption in the residential/commercial and industrial sectors, or 9 percent of total industrial energy consumption. Depending on the actual number of small energy users located near biomass supplies, this figure may be conservative for the market penetration of airblown gasifiers. Furthermore, the estimated quantity of methanol is contingent on: 1) development of advanced gasifiers and, possibly, prefabricated methanol plants that reduce costs to the point of being competitive with coal-derived methanol and 2) market penetration of coal-derived methanol so that the supply infrastructure and end-use markets for methanol are readily available. OTA's analysis indicates that both assumptions are plausible.

In addition to these synfuels, about 0.08 to 0.16 MMB/DOE (2 billion to 4 billion gal/yr) of ethanol** could be produced from grain and sugar

Box D.-Definitions of Demonstration and Commercial-Scale Plants

. After laboratory experiments and bench-scale testing show a process to be promising, a demonstration plant may be built to futher test and "demonstrate" the process, This plant is not intended to be a moneymaker and generally has a capacity of several hundred to a few thousand barrels per day. The next step may be various stages of scale up to commercial scale, in which commercial-scale process units are used and proven, although the plant output is less than would be the case for a commercial operation. For synfuels, the typical output of a commercial unit may be about 10,000 bbl/d. A commercial plant would then consist of several units operating in parallel with common coal or shale handling and product storage and terminal facilities.

---

[39] Ibid.

*If advanced biomass gasifiers methanol can be produced with an overall efficiency of 70 percent for converting biomass to methanol, this figure will be raised to 0.7 MMB/DOE or 22 billion gal/yr.

**Caution should be exercised when interpreting the ethanol levels, however, since achieving this level will depend on a complex balance of various forces, including Government subsidies, market demand for gasohol, and gasohol's inflationary impact on food prices.

crops, and perhaps 0.1 MMB/DOE of biogas and SNG from anaerobic digestion. * Taking these contributions together with the other contributions from biomass synfuels results in the high and low estimates given in table 50.

Summary

Combining the contributions from fossil and biomass synfuels results in the two development scenarios shown in figure 17. Coal-derived synfuels provide the largest potential. Ultimately, production of fossil synfuels is likely to be limited by the demand for the various synfuel products, the emissions from synfuels plants, and the cost of reducing these emissions to levels required by law. Beyond 2000, on the other hand, synfuels from biomass may be limited by the resource availability; however, development of energy crops capable of being grown on land unsuitable for food crops, ocean kelp farms, and other speculative sources of biomass could expand the resource base somewhat.

---

*The total potential from manure is about 0.14 MMB/DOE, but the net quantitity that may be used to replace oil and natural gas is probably no more than so percent of this amount. In addition, there may be small contributions from municipal solid waste and, possibly, kelp.

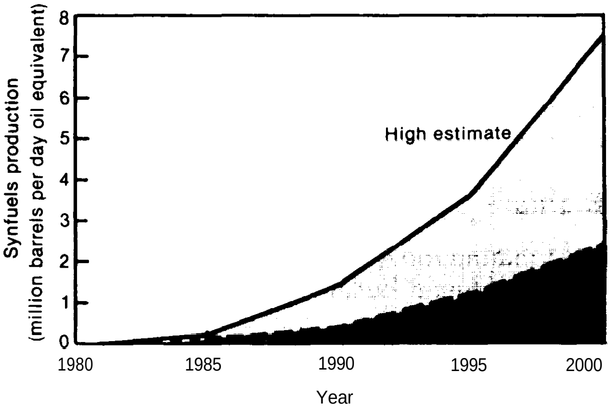
Table 50.—Biomass Synthetic Fuels Development Scenarios (MMB/DOE)

Fuel	1980	1985	1990	1995	2000
Low estimate					
Methanol [ab]	–	(e)	(e)	(e)	0.1
Ethanol [c]	(e)	(e)	(e)	(e)	(e)
Low- and medium-energy fuel gas [a]	(e)	(e)	(e)	0.1	0.1
Biogas and methane [d]	(e)	(e)	(e)	(e)	
Total	(e)	(e)	(e)	0.2	0.3
High estimate					
Methanol [ab]	–	(e)	0.1	0.3	0.6
Ethanol [c]	(e)	(e)	0.1	.	.
Low- and medium-energy fuel gas	(e)	0.1	0.3	0.7	0.9
Biogas and methane [d]	(e)	(e)	0.1	0.2	0.2
Total	(e)	0.1	0.6	1.3	1.8

[a] From wood and plant herbage and possibly municipal solid waste.
[b] Ethanol could also be produced from wood and plant herbage, but methanol Is likely to be a less expensive liquid fuel from these sources.
[c] From grains and sugar croPs.
[d] From animal manure, municipal solid waste, and, possibly, kelp.
[e] Less than 0.1MMB/DOE.

SOURCE: Office of Technology Assessment.

Figure 17.—Synthetic Fuel Development Scenarios



SOURCE: Office of Technology Assessment.