

use today, but rather it is meant to indicate that synthetic jet fuels may be similar to naphtha-based wide-cut* jet fuels, such as JP-4, or kerosene-based narrow-cut* jet fuels, such as JP-5 or JP-8.

The USAF Scientific Advisory Board Ad Hoc Committee on Future Air Force Energy Needs has recommended that the Air Force make the transition from JP-4 to JP-8. This recommendation was prompted by the considerable competition that exists for the naphtha fraction of crude oil, particularly for the production of low-lead and lead-free gasoline and for petrochemical feedstocks, which is driving the costs of naphtha-based JP-4 into the premium fuel category.⁽²⁴⁾ A recent DoD directive has been issued prescribing that all new turbine-powered aircraft be designed to operate on JP-8, as well as on JP-5 and JP-4, which should give the DoD more flexibility in procurement of aviation fuels in the future.⁽²⁵⁾

A synthetic jet fuel with characteristics similar to the kerosene- or naphtha-based jet fuels in use today probably represents the best compromise between volumetric and gravimetric heats of combustion of any of the fuels noted in Table 2. The fact that such a fuel would also be largely compatible with existing patterns of jet fuel storage, distribution, and use also makes a synthetic JP fuel attractive.

FUEL PRODUCTION PROCESSES

Overview

A multitude of possible techniques exist for producing the three synthetic jet fuel candidates from the various U.S. domestic energy resources. Figure 23 illustrates a representative, but by no means exhaustive, set of techniques for producing the fuels from energy resource alternatives to diminishing reserves of domestic crude oil and natural gas. Note that several of the primary energy resources, including coal, could, in principle, be used to produce any of the jet

*Wide-cut and narrow-cut refer to the boiling temperature range over which each fuel is recovered during the distillation of the crude-oil product (whether it be a petroleum crude or a synthetic crude derived from coal or oil shale).

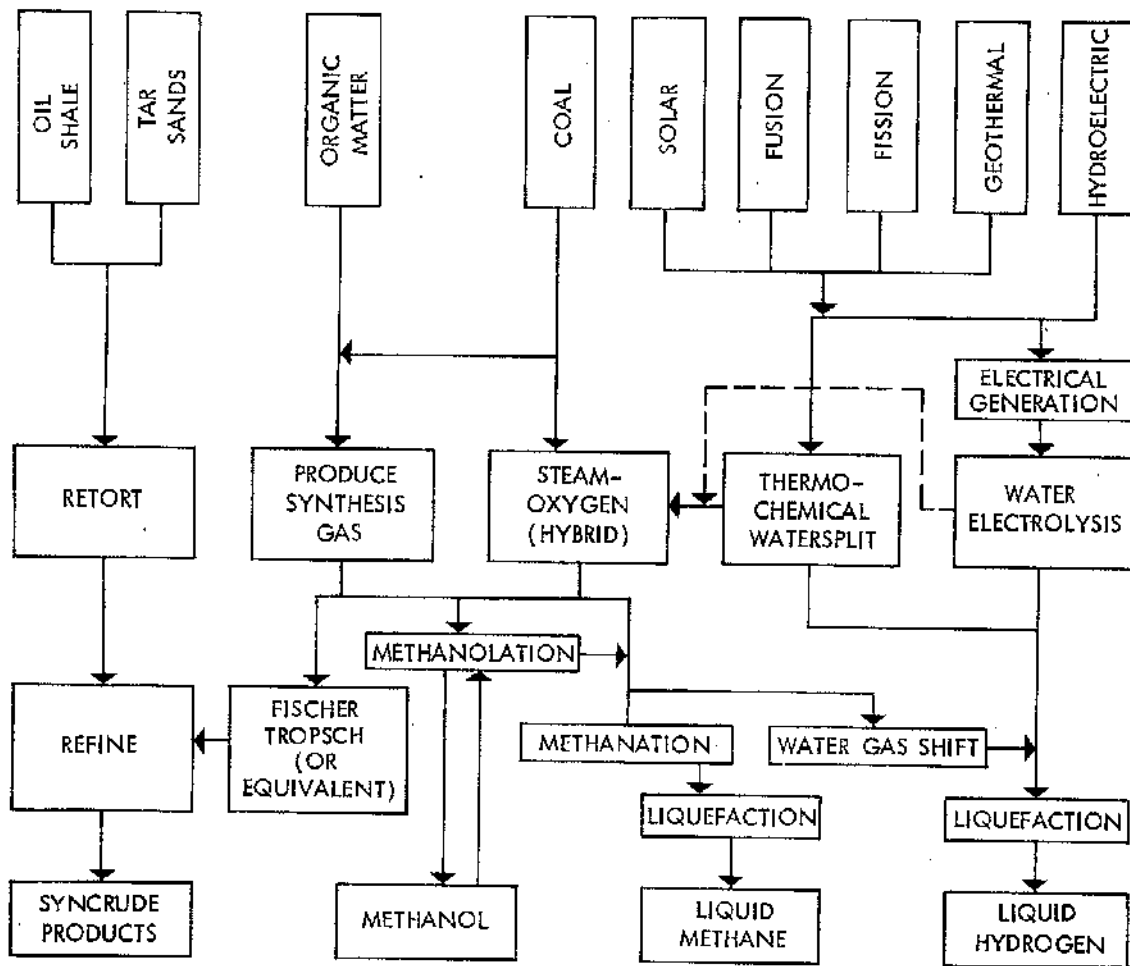


Fig. 23—Overview of synthetic fuel production processes

fuels of interest. Oil shale could also assume such a role, although attention thus far has focused on deriving premium liquid crude feedstocks from oil shale.

Note also in Fig. 23 that hydrogen can be derived from water using any of the energy resources that many postulate will be the ultimate major sources of energy for the United States and the world (e.g., solar, nuclear fusion, and nuclear fission). This attribute may become increasingly important at some time in the indeterminate future when fossil resources may become too valuable to use for energy purposes.

The production of the hydrocarbon fuel alternatives, synthetic JP and liquid methane, from renewable resources is more limited. In particular, a long-term commitment to the use of biomass or waste products

seems to be the only alternative if fossil fuels are not available at some indefinite time in the future. This discounts the possibility of using atmospheric carbon dioxide as a source of carbon in the synthesis of these fuels. The limited investigations of this concept suggest that such a process would be extremely costly both in an energy and in a fiscal sense. (26,27)

Figure 23 illustrates some of the potential opportunities for synergism between the different energy supply processes. For example, the electrolysis of water using nuclear-generated electricity results in hydrogen and oxygen. The hydrogen might be used directly as a gaseous fuel, liquefied for transportation applications, or pipelined to a conventional refinery for use in the refining of crude oil. The oxygen produced by electrolysis might profitably be used in a coal gasification plant, where air separation facilities normally constitute a major component of plant costs.

When one considers the resource base of each of the resources in Fig. 23, the present and foreseeable technology for converting these resources into the jet fuels of interest, and the evolving energy R&D technologies being emphasized in the United States today, particular resources and technologies assume greater importance than others during the 50 year time period of interest considered in this fuels assessment. In particular, the size of the domestic coal resource base, the maturity of the coal extraction industry, the fact that coal gasification processes are on the verge of commercialization, the fact that large coal liquefaction demonstration plants are scheduled to be built during the next three years, and the aggressive efforts of ERDA in developing advanced coal conversion technologies all tend to indicate that coal's role in supplying energy to the United States will expand significantly between now and the end of the century. For similar reasons, much the same can be said of oil shale's future role in supplying energy.

Assessing the potential future contribution of the other carbonaceous resources is more difficult. Domestic tar sand resources, particularly in comparison to the other fossil resources, do not appear adequate to support a major synthetic fuels industry. Some technologies for generating energy from urban wastes have already been commercialized,

although the emphasis to date has been on either direct combustion for electric power generation or the conversion of wastes to liquid or gaseous fuel forms for local power generation.^(28,29) There are still many unanswered questions relating to the ultimate role of energy crops.⁽³⁰⁾

The discussion below gives an abbreviated overview of the production of the three jet fuel alternatives using coal and oil shale as energy sources. Also discussed is the production of hydrogen using nuclear power as an energy source, probably the most viable noncarbonaceous energy source from which hydrogen may be produced, at least throughout this century.

Synthetic JP Production

Synthetic JP from Coal. Synthetic JP production from coal has two major process steps: (1) coal liquefaction to produce a synthetic crude oil, and (2) the refining of that synthetic crude oil to jet fuel and other products. The liquefaction and refining facilities may be separate or integrated. The conversion of coal into a liquid basically entails reducing the carbon-to-hydrogen weight ratio, almost always by adding hydrogen. The hydrogen is usually derived from water (in the form of steam). The energy to generate the steam and to separate the hydrogen from water is most economically obtained from the coal itself.^(31,32)

Some of the key parameters associated with the four major technologies for producing coal liquids are shown in Table 3. None of the technologies have yet been commercialized in the United States, although pilot plants using the first three technologies have been built or are scheduled to be completed before the end of this decade. In the comparative fuel evaluation presented later in this section, the direct hydrogenation H-Coal process is used as a representative coal liquefaction technology because it provides the largest yield of liquid products, provides a premium synthetic crude oil suitable for refining into jet fuels, and because it is a process that is receiving strong support from ERDA.

Table 3

COAL LIQUEFACTION TECHNOLOGIES

Process Type	Product Yields ^a	Process Pressures (Atmospheres)	Thermal Efficiencies	Process Names/Developers	Status
Carbonization/pyrolysis	.7-1.6 bbl 4000-9300 SCF	1-70	55-65	COED, FMC Corporation COALCON, Coalcon Company	36 T/D ^b pilot plant completed operations in November 1974 2600 T/D demonstration plant scheduled for operation by February 1979
Direct hydrogenation	2.5-3.2 bbl 2000-3000 SCF	136-272	60-75	H-Coal, Hydrocarbon Research Inc. SYNTHOIL, Bureau of Mines	3 T/D plant operating, 600 T/D H-COAL pilot plant scheduled for operation by July 1978 .5 T/D SYNTHOIL unit operating, 10 T/D pilot plant scheduled for operation by July 1977
Extraction	2-3 bbl 3500-4500 SCF	20 (extraction) 285 (hydrocracking)	60-70	SRC, Pittsburgh & Midway Mining Company CSF, Consolidation Coal Company	50 T/D pilot plant operating since September 1974, 6 T/D plant also operating 25 T/D plant shutdown in 1970, reactivated in 1974
Fischer-Tropsch	1.5-2 bbl	17-30	40-70	SASOL, South African Coal, Oil, Gas	5000 bbl/day commercial plant operating in South Africa

SOURCE: Refs. 29, 31-33.

^aYields in barrels of liquids and standard cubic feet of gases per ton of moisture-free and ash-free coal.

^bTons of coal input per day.

The technology for refining crude oils into a spectrum of products is highly advanced in the United States. Major oil companies in cooperation with ERDA, NASA, the Navy, and the Air Force are now attempting to determine through analytical procedures and experimental tests the unique process requirements for refining coal syncrudes into military fuels. Early work by the Sun Oil Company⁽³⁴⁾ and the Atlantic Richfield Company (ARCO)⁽³⁵⁾ is now being extended by the Exxon Research and Engineering Company under contract to the Air Force Aero-Propulsion Laboratory to assess the feasibility and process requirements for producing jet fuels from coal-derived crude oils. Following an experimental phase, material, equipment, and processing requirements will be assessed overall, as will the potential increase in jet fuel availability as a function of broadened specifications.⁽³⁶⁾

The results of these studies indicate that the distillation of coal syncrudes produces more material in the kerosene (narrow-cut jet fuel) boiling range than is the case with typical natural crude oils (Table 4). This is a favorable result, since the major proportion of DoD liquid-fuel consumption is in the form of jet fuel. This could assume even greater importance in the future as the Air Force changes from wide-cut, naphtha-based JP-4 to narrow-cut JP-8.

Table 4

DISTILLATION YIELDS OF CRUDE OIL AND COAL SYNCRUDE

Boiling Range (°F)	Distillation Yields (volume percent)		
	East Texas Crude	H-Coal Syncrude ^a	COED Syncrude ^a
C ⁵ -400 (gasoline)	40	37	33
400-515 (kerosene)	14	26	27
525-650 (heating oil)	12	17	24
650-975 (fuel oil)	20	20	16
975+	14	--	--
	100	100	100

SOURCE: Refs. 31 and 35.

^aDerived from Illinois No. 6 coal.

Nevertheless, virtually all of the laboratory experiments to date suggest that straight-run distillation of synthetic coal crudes will not produce a product that can meet current jet fuel specifications, but rather results in a product high in aromatic content and deficient in hydrogen. This high aromatic content can create hot spots and burn-throughs in jet engine combustors, generate excessive smoke and infrared signatures, raise fuel freezing points, and accelerate the wear of engine seals. (5,37,38) However, these same laboratory experiments indicate that high-pressure hydrotreating (1000 to 3000 psi), which is not uncommon in today's refineries, can reduce the aromatic content to a few percent, resulting in a fuel product that can meet most of current jet fuel specifications. The experiments also suggest that the amount of processing required can be a strong function of the coal and liquefaction process used. For instance, the ARCO results indicate that middle distillate fractions of syncrudes from western coals have less than one-half the aromatic content of midwestern coals, which could have an important bearing on refining costs.

In summary, current evidence suggests that coal syncrudes can be refined into jet fuels that meet most of current narrow-cut jet fuel specifications, given some hydrotreating of the kerosene fraction. (The analysis in the next section assumes a refinery with both hydrotreating facilities and hydrocracking facilities to maximize jet fuel production.) The optimum tradeoff between hydrotreatment at the refinery and new or modified engine designs to cope with off-specification fuels has not yet been determined. It is not yet apparent whether coal syncrude refineries will initially be dedicated facilities or whether a more economic strategy will be to blend coal syncrudes with existing natural crude oils before refining.

Synthetic JP from Oil Shale. Synthetic JP production from oil shale involves (1) a retorting process in which the shale is crushed and heated to release the crude shale oil product from the shale, and (2) the refining of the crude shale oil into synthetic JP and other products. The oil shale may be mined and processed in a surface retort or processed *in situ* and pumped to the surface.

The three major processes closest to commercialization are the PARAHO process, the TOSCO-II process, and the Union Oil process--all developed largely by private sector R&D. ERDA and Occidental Petroleum are concentrating on the *in situ* techniques, which may allow the recovery of oil from shale deposits that are not readily recoverable using conventional mining techniques and at the same time reduce the problems posed by spent shale disposal. (29,39,40)

Crude shale oils derived from major domestic deposits in Colorado have been refined in laboratories and in a conventional crude-oil refinery. The results of these tests indicate that it is both feasible and practical to refine crude shale oil into military fuels meeting most product specifications. The largest program to date was sponsored by the Navy Energy and Natural Resources R&D Office in which 10,000 barrels of crude shale oil were refined in a conventional crude-oil refinery. (39)

The refined fuels, including JP-4, JP-5, and JET-A, while meeting most specifications, were found to be high in particulate matter and gum content and exhibited poor storage and thermal stability. However, in the judgment of the investigators, these problems were probably a consequence of the particular refinery setup and could be ameliorated by higher pressure hydrogenation (2000 to 3000 psi) and clay treatment. The refined fuels were delivered to a number of government laboratories, including the Air Force Aero-Propulsion Laboratory, for test and evaluation. After further treatment, the JP-4 was successfully used on a routine T-39 flight. (39)

The other major refining experiment now currently under way is Exxon's refining of coal syncrudes and shale syncrudes into jet fuels for the Air Force Aero-Propulsion Laboratory. Exxon is refining barrel-quantity samples from the PARAHO, TOSCO, and Occidental processes. Preliminary results reported by Exxon indicate that most specifications for JET-A and JP-4 can be met. All of the fuel blends produced in Exxon's laboratory setup using normal severity hydrotreatment had satisfactory thermal stability. Exxon has also observed that only the TOSCO shale-oil product provides a reasonable yield of wide-cut, JP-4-type jet fuel. They attribute this to the fact that many of the development

facilities use the light condensable liquids and gases as fuel within the processes. They also attribute the small quantity of wide-cut material to the high altitude of the facilities, which causes the product to lose its more volatile components in the heated storage tanks.⁽³⁶⁾ Whether this will continue to be the case with full-scale commercial facilities is an open question.

In summary, results indicate that shale oils can be refined to meet most or all of current jet fuel specifications and also that they can probably be refined in existing crude-oil refineries with only modest adjustments to those facilities. Whether economics will ultimately dictate that shale oils be refined to current specifications or that future engines be designed to operate on a broader range of fuels has yet to be determined.

Liquid Methane from Coal

The production of liquid methane from coal involves (1) a gasification process that can occur above ground or *in situ* to convert the coal into a raw synthesis gas, (2) a methanation step to upgrade the methane content of the gas, and (3) a liquefaction process to cool the gas to its liquid state of -249°F.

Characteristics of the major surface coal gasification techniques are noted in Table 5. Present utility and pipeline company planning indicates that the Lurgi process will probably constitute the backbone of any initial commercial-scale coal gasification industry in the United States.^(29,33) ERDA has recently awarded phase I (design phase) contracts to two contractors for demonstration size facilities that will process from 2000 to 7300 tons per day of coal using a slagging Lurgi process and the COGAS process (coal-oil-gas, a variation of the COED coal liquefaction process). The entire demonstration program is scheduled to be completed by 1984. Because present planning suggests that some version of the Lurgi process is likely to be one of the first coal gasification technologies commercialized domestically, the comparative fuels evaluation presented later in this section assumes Lurgi technology is employed to produce gaseous methane.^(29,33)

Table 5
MAJOR COAL GASIFICATION PROCESSES

Process	Gasifier Bed Design	Pressure (Atmospheres)	Temperatures (°T)	Gasifying Medium	Residue	Developer	Status
Lurgi	Fixed	30	900-2000	Steam, oxygen	Ash	American Lurgi	Commercialized in 1936
Koppers-Totzek	Entrained	1	2000-3300	Steam, oxygen	Slag	Koppers Company	Commercialized in 1952
Winkler	Fluidized	1	1350-1850	Steam, oxygen	Ash	Davy International	Commercialized in 1926
B4-Gas	Entrained	68-102	1700-3000	Steam, oxygen	Slag	Bituminous Coal Research, Inc.	120 T/D ^a pilot plant scheduled for operation by June 1976
HYGAS [®]	Fluidized	68	1000-1850	Steam, oxygen, hydrogen	Ash	Institute of Gas Technology	75 T/D pilot plant operating since October 1971
Synthane	Fluidized	68	800-1800	Steam, oxygen	?	Bureau of Mines	72 T/D pilot plant scheduled for operation by May 1976
CO ₂ Acceptor	Fluidized	10-20	1500-1900	Steam, air, dolomite	Ash	Consolidation Coal Company	40 T/D pilot plant operating since October 1972

SOURCE: Refs. 29, 33, 41-43.

^atons of coal input per day.

Once coal has been gasified and the resulting synthesis gas methanated, it can be introduced into conventional high-pressure pipelines for distribution to a methane liquefaction plant that would normally be located near an air base to minimize the problems of distributing large quantities of cryogenic methane.

The technology for the liquefaction of natural gas on a large commercial scale is well established, with major plants being located in Algeria, Libya, Borneo, the USSR, and Alaska.⁽⁴⁴⁾ The basic liquefaction process consists first of purifying the gaseous methane, to ensure that no hydration or solidification of impurities occurs to block passages in the liquefaction heat exchangers. Typically, the gas is then cooled through a heat exchange process to a temperature of -259°F. The liquid methane is then stored in insulated tanks for later use.⁽⁴⁵⁾

Large methane liquefaction complexes typically derive their electrical energy for compression equipment from the gaseous methane entering the complex. These fuel expenditures, together with losses, account for about 17 percent of the gaseous methane entering the liquefaction plant.⁽⁴⁵⁾

In summary, technologies commercially proven, albeit in other countries, or new technologies under development in this country, could be used to convert coal to a liquid methane fuel suitable for aircraft applications.

Liquid Hydrogen Production

The production of liquid hydrogen considered here involves (1) obtaining gaseous hydrogen via coal gasification or water-splitting processes, (2) a possible purification of the gaseous product, (3) the liquefaction of the gaseous hydrogen, and (4) an ortho to para energy conversion of the liquid hydrogen that renders it suitable for storage.

The traditional method of producing gaseous hydrogen from coal consists of reacting coal with steam and oxygen to form a synthesis gas. A subsequent water gas shift reaction and removal of the carbon dioxide and residual carbon monoxide result in a gas rich in hydrogen.^(43,46)

Although the current emphasis in the United States is on the development and commercialization of high-Btu coal gasification processes, these same processes already described could be used with some modifications to produce gaseous hydrogen. The modifications would include a requirement for water gas shift equipment to increase the hydrogen and carbon monoxide content of the synthesis gas at the expense of methane production.⁽⁴⁶⁾ The analysis of the three fuel alternatives as derived from coal, to be presented in a succeeding subsection, presumes that the above modifications are made to a Lurgi high-Btu coal gasification plant to enable it to produce a gaseous hydrogen product. A less traditional second-generation approach is being explored by the Institute of Gas Technology under ERDA sponsorship, in which hydrogen is produced by the decomposition of steam by iron oxide. A small pilot plant was scheduled to begin operating during the last quarter of 1976 to demonstrate the feasibility of producing hydrogen for HYGAS[®] high-Btu coal gasifiers using the steam-iron approach.^(43,47,48)

Gaseous hydrogen can also be produced using nonfossil resources by splitting water molecules electrolytically, thermally, or thermochemically. Water electrolysis is a simple, clean, proven technology for generating hydrogen. Numerous analyses have shown that the large electricity requirements of the process result in electrolytic hydrogen costs two to three times as much as hydrogen produced from coal. Understandably, then, there is much interest in developing alternative water-splitting schemes to reduce energy requirements and costs.⁽⁴⁹⁻⁵²⁾

Because of the enormous technical problems associated with producing hydrogen by the direct thermal decomposition of water, researchers have begun investigating the feasibility of thermally decomposing water by a sequential operation of multistep chemical reactions.^(53,54) Preliminary laboratory investigation of this technique indicates that it might theoretically approach the efficiency of coal gasification processes sometime in the future.⁽⁵⁰⁾ Hence, while it is now in a primitive state of development, thermochemical water-splitting may represent a long-term nonfossil-based option for producing hydrogen.

Whether the gaseous hydrogen is produced from coal or by water-splitting techniques using nuclear energy, it must be purified and

liquefied and must undergo an ortho to para energy conversion to render it suitable for storage and eventual use in an aircraft; otherwise, as much as 70 percent of the liquid product could be lost due to boil-off. The basic technology for liquefying hydrogen on a large scale was developed in support of the U.S. space program; the largest commercially built and operated plant has a capacity of 60 tons per day of liquid hydrogen. However, the scale of production would have to be significantly increased to support aviation applications; about 2500 tons per day might be required to support a large airport or air base. (55,56)

Hydrogen liquefaction is an extremely energy-intensive process, requiring large amounts of electric power to drive the compression equipment used in liquefaction. A recent and comprehensive study of hydrogen liquefaction by the Linde Division of Union Carbide indicates that a large liquefaction facility would consume 5.67 kWh(e) for every pound of hydrogen liquefied. (55) At current thermal to electrical conversion efficiencies, the thermal energy required to generate the electricity to liquefy the hydrogen exceeds the energy content of the hydrogen itself. For this reason, unlike methane liquefaction facilities, hydrogen liquefaction plants typically do not use gaseous hydrogen as a source of energy for power generation but rather use purchased electric power generated offsite.

Linde estimates that with equipment improvements, employing only a partial ortho to para energy conversion (requiring that consumption occur within 50 hours after liquefaction) and improved tail gas recovery, the electric power requirement could be reduced by 19 percent in the post-1985 time period. They also estimate that tail gas recovery and reductions in leakage could halve gaseous hydrogen losses in the liquefaction process. (55) However, even with these improvements, the hydrogen liquefaction process would remain very energy-intensive, with costs being very sensitive to the cost of the electric power.

OBSERVATIONS

We have surveyed major domestic energy resource alternatives to crude oil and natural gas that might be used in the synthesis

of military jet fuels in the future, the characteristics of the most attractive alternatives, and some of the production processes by which the fuels might be obtained. This survey indicates that jet fuels derived from oil shale and coal have the potential for beginning to make a contribution to jet fuel supplies between now and the end of the century because of the size of the resource bases and the pace of development of fuel conversion technology for these resources. The comparatively small size of the U.S. bituminous tar sand resource base and the lack of aggressive efforts to exploit this resource make it unlikely that tar sands will be a major energy source for jet fuels. The current technology emphasis for exploiting organic energy sources is not directed toward producing synthetic liquids suitable for jet fuel production but rather toward solutions to urban waste problems, in the process generating useful energy (primarily electricity) for local consumption.

Liquid hydrogen appears to be the only jet fuel readily producible from noncarbonaceous energy resources, primarily through the use of heat and/or electricity for water-splitting. However, these processes are markedly less economic than producing hydrogen from coal, both in an energy sense and in a cost sense. For this reason, it seems highly unlikely that any initial liquid hydrogen jet fuel industry in the United States would rely on an energy resource other than coal.

Thus, a pragmatic view of the resources and technologies involved, subject to change as the long-term technologies develop, is that at least between now and the end of the century, coal and oil shale are the most attractive domestic energy resource alternatives to crude oil and natural gas for the production of synthetic JP, liquid methane, or liquid hydrogen. Since development of fuel conversion technology for oil shale is focusing on the production of distillate products, such as synthetic JP-type fuels, a comparison of synthetic JP derived from oil shale and coal is subsequently examined in Sec. IV.

COMPARISON OF JET FUEL ALTERNATIVES DERIVED FROM COAL

To compare the three jet fuel alternatives on a consistent basis, the individual energy conversion facilities employing the technologies

already described were assembled into representative fuel supply systems with specific coal resource supply locations and fuel consumption points (Fig. 24). The previously described assessment of resources, plus material in the appendix, provided the necessary information to locate major coal deposits, while a representative, yet manageable, basing scheme was adapted from a related applications analysis of very large airplanes.⁽⁸⁾ The fuels are first compared in terms of the energy requirements for their production and distribution.

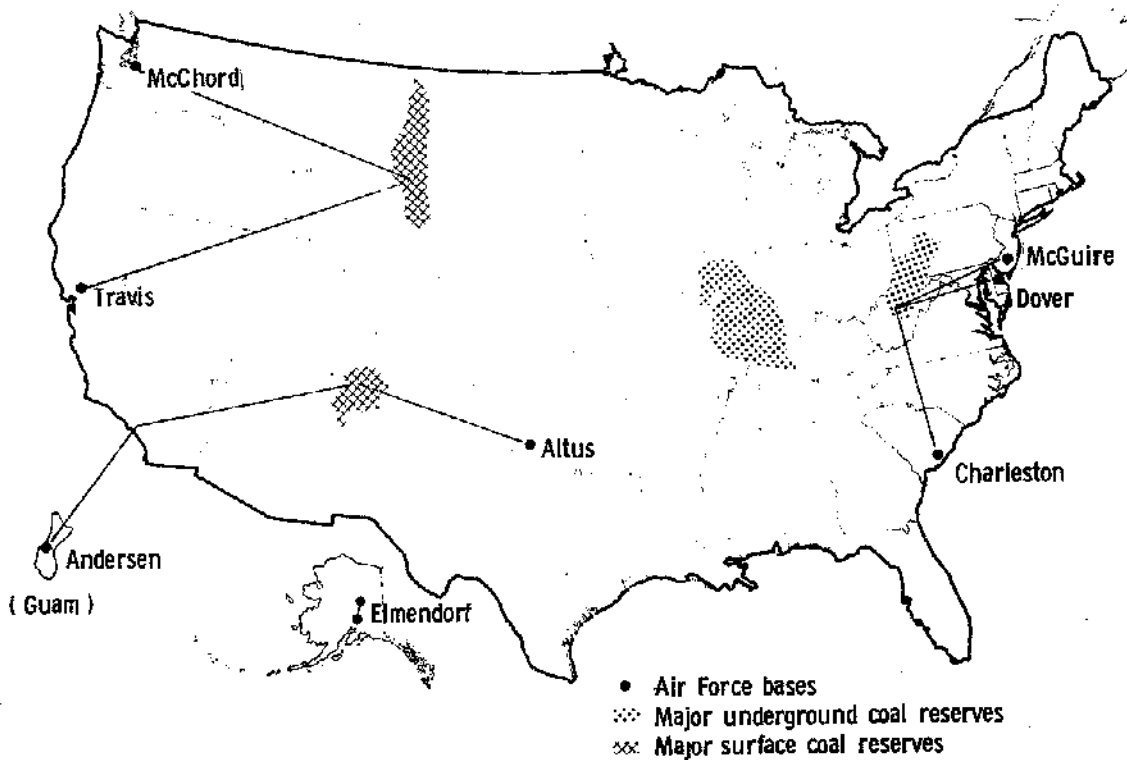


Fig. 24— Fuel supply paths

Energy Requirements for Fuel Production

Consideration of the energy expenditures required for fuel production is motivated by several factors. An understanding of the technical reasons why certain fuel production processes are more energy-intensive than others can lead to a greater understanding of the reasons why fuel alternatives differ in cost. Consideration of the energy required to produce and distribute a fuel also permits a complete assessment

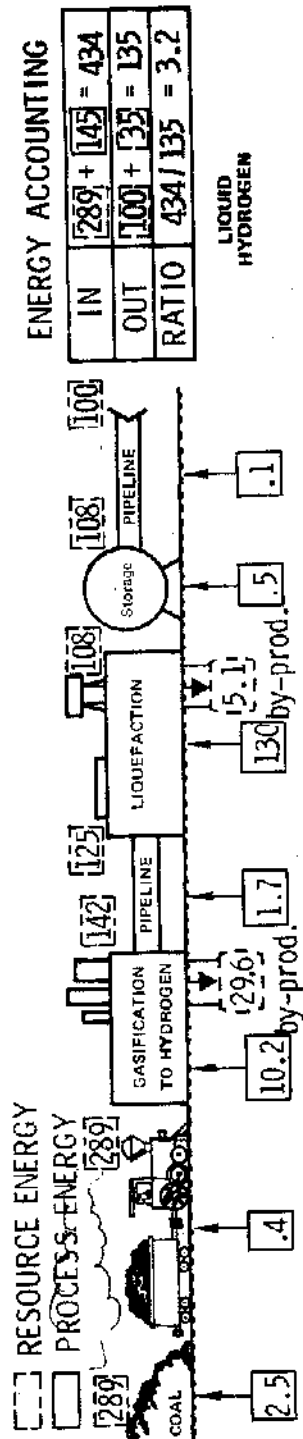
of the total energy intensiveness of a given aircraft-fuel alternative, including not just the fuel burned on board an aircraft, but also the energy required to convert the fuel to a form suitable for use in an aircraft. Finally, it seemed prudent to identify the total energy requirements that particular fuel alternatives would impose on the nation's energy resource base, since the Air Force will be competing for these energy supplies with many other users in the marketplace.

Figure 25 shows the major components of representative fuel supply systems being developed from a variety of sources. (11,28,31,43,45,46,55-60)

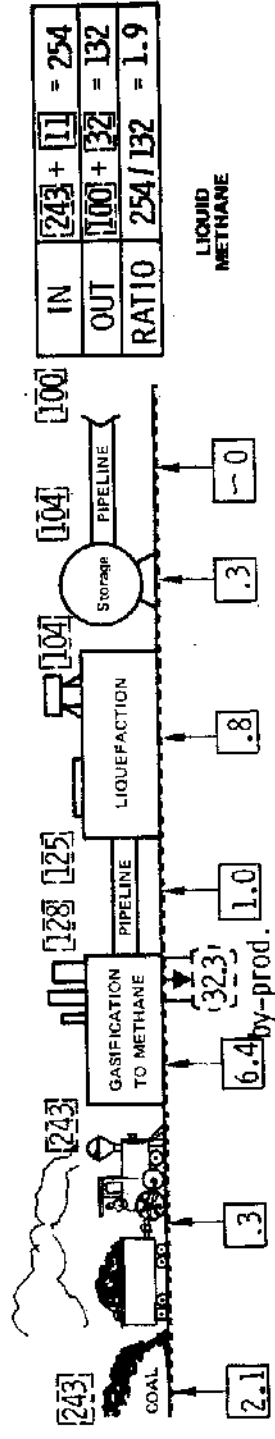
Let us focus first on the details of the liquid hydrogen supply system. Typically, surface-mined western coal could be transported from the mine a short distance (about ten miles, for example) via a diesel train to a coal gasification plant that uses Lurgi technology, where the coal would be gasified, shifted, and purified to hydrogen. The long-haul distribution leg would consist of a high-pressure pipeline to a liquefaction facility near the air base. The example shown is equivalent to pipelining the gaseous hydrogen from the Wyoming Powder River Basin to the West Coast of the United States, a distance of about 900 miles. The gaseous hydrogen would then be converted to a liquid state, would undergo the ortho to para conversion, and would then be stored in cryogenic tanks for ultimate distribution to an aircraft fueling manifold via a short liquid hydrogen pipeline about two miles in length.

In Fig. 25, the numbers enclosed by dashed lines trace the flow of resource energy (energy derived from the primary energy resource-- coal) from extraction to ultimate distribution. In this example, 289 Btu of coal are required to deliver 100 Btu of hydrogen and 35 Btu of by-products. Of course, other energy must also be expended to fuel the diesel train, build the facilities, generate the electricity required for liquefaction, etc. This energy, termed process energy, is shown below the elements of the fuel supply system. Of primary interest is the large process energy expenditure associated with hydrogen liquefaction and the ortho to para conversion, which is roughly equivalent to the resource energy content of the gaseous hydrogen entering the facility. As a consequence of this expenditure, about 3.2 Btu of energy must be input for every Btu of liquid hydrogen and by-products output.

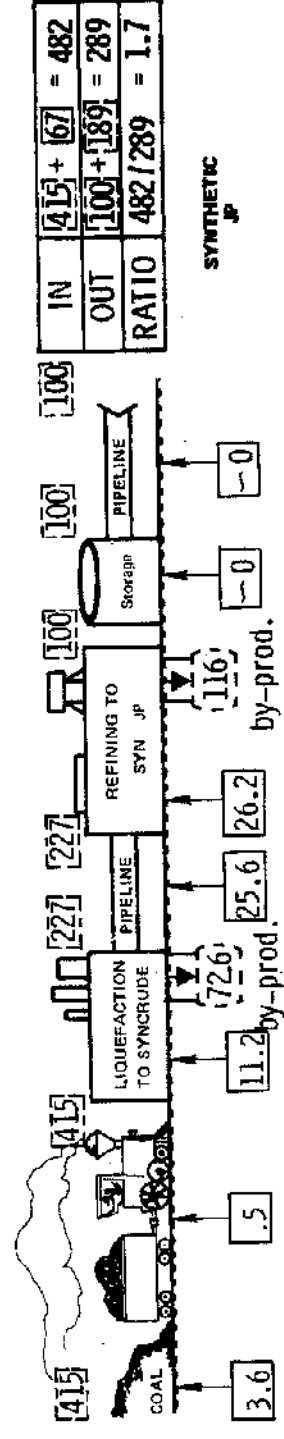
POSSIBLE
FUTURE
ENERGY
RATIOS



(2.6)



(1.8)



(1.6)

Fig. 25 Energy flow for synthetic fuels

Thus, the liquid hydrogen supply process is significantly more energy-intensive than today's crude-oil supply system, which requires about 1.2 Btu of energy input for every Btu of refined products output.*

The components of the liquid methane system are essentially analogous to the liquid hydrogen system. A Lurgi gasifier is also used in the liquid methane supply system, but in this case the product gas undergoes a methanation reaction which results in a pipeline quality gas which is high in methane. The liquid methane supply process requires less energy than the liquid hydrogen process, primarily because methane liquefaction requires only about 10 to 15 percent of the electric power required for hydrogen liquefaction.⁽⁴³⁾ In this instance, the literature suggests that typically, part of the gaseous methane is used to generate the electricity for liquefaction because the scale of electricity required is sufficiently low as to not preclude on-site power generation.^(28,43,45) With resource energy (the gaseous methane) supplying the energy for electric power generation, the process energy shown in Fig. 25 for methane liquefaction accordingly reflects only the energy required to build the facility. The methane supply process also requires less energy than the hydrogen process because pipelining gaseous methane requires only about 20 to 25 percent of the pumping energy required when pumping gaseous hydrogen. This is in part due to the lower volumetric heating value of hydrogen (275 Btu per standard cubic foot versus 912 Btu per standard cubic foot for methane).⁽²¹⁾ The energy accounting shows that 1.9 Btu of energy must be input for every Btu of liquid methane and by-products output.

For the synthetic JP supply system, more coal is required than for the other two alternatives. This is because it is estimated that less than one-half of every barrel of syncrude produced by the H-Coal high-pressure hydrogenation process could be refined to yield a kerosene-like jet fuel; the bulk of the remainder constituting unleaded motor

* All of the energy values cited in the comparison are net or low heating values, in which the heat of condensation of water is not included. This is appropriate for controlled combustion systems such as aircraft engines, in which the combustion products are discharged as a gas.

gasoline, which should find a ready market around the year 2000.⁽³¹⁾ Thus the greater coal requirement is a direct reflection of the greater amount of energy being delivered. The comparatively large process energy required for syncrude refining is also significant. This is a consequence of the hydroprocessing that the coal syncrude must undergo, primarily because of the characteristically high aromatic content of coal syncrude liquids. In the example shown, the syncrude refinery is structured to maximize the output of jet fuel by hydrocracking the heavier distillate fractions to jet fuel and lighter products, primarily gasoline. If a lower yield of jet fuel were acceptable, the energy requirements could be reduced. The energy accounting shows that the synthetic JP supply process requires that 1.7 Btu of energy be input for every Btu of synthetic JP and by-products output.

The energy expenditures shown in Fig. 25 are largely characteristic of current or short-term technology. The energy ratios shown on the far right might result if some postulated improvements in the fuel supply systems were to occur in the future. As might be expected, because the hydrogen supply process is highly energy-intensive, it profits the most from possible improvements in technology. In developing possible future energy ratios, it was assumed that hydrogen gasification efficiency might be increased to 70 percent with the introduction of advanced second-generation equipment. A modest 4 percent reduction in pumping energy required for the gaseous hydrogen pipeline is assumed. The most significant improvement would be due to better thermal to electrical conversion efficiencies--from the 33 percent efficiencies of today to an optimistic 50 percent in the future. It is further assumed that the improvements in the hydrogen liquefaction process discussed earlier could be implemented, with the exception of the partial ortho to para energy conversion requiring consumption within 50 hours of production. This does not seem viable from an Air Force perspective, because of the uncertainty of needing to draw large quantities of fuel out of storage for contingency situations on an irregular basis. Additionally, analyses of hydrogen storage requirements, which considered the reliability of the individual units of the liquid hydrogen supply process, have indicated that a storage capacity equivalent to 4 to 13

days of daily production could be required to assure a continuous supply of liquid hydrogen during subsystem module production outages.⁽⁵⁶⁾ In developing the future energy ratio, it was further assumed that the loss of liquid hydrogen in pipelining it to the aircraft fueling manifold might be halved if extensive efforts were made to recover vaporized fuel. This is a particularly optimistic assumption, since NASA experience with handling liquid hydrogen for space applications indicates that only about two-thirds of the liquid hydrogen delivered to the Kennedy Space Center is actually used in launch vehicles; the remainder is lost during tanker transfers, to boil-off during storage, and for fulfilling gaseous hydrogen requirements for purging tanks, etc.⁽⁶¹⁾

For the liquid methane supply process, it is also assumed that gasification efficiency improves to 70 percent, the gaseous pipeline energy requirements are reduced by 4 percent, and energy losses in the liquid methane pipeline are halved. For the synthetic JP process, it is assumed that the energy intensiveness of the syncrude pipeline is improved modestly. The rather severe energy requirement for the syncrude pipeline shown in Fig. 25 is based on the assumption that all of the pumping energy is derived from electric power. This assumption was more a result of lack of clear available information on other more efficient types of pipeline pumping than on any technological limitation on using other more efficient energy sources for pumping.⁽⁵⁷⁾

The admittedly optimistic set of assumptions for future improvements in the liquid hydrogen supply process was deliberately assembled to test the hypothesis that liquid-hydrogen-fueled aircraft would be less energy-intensive in the future than the other alternatives. However, even with this rather optimistic outlook, a related Rand analysis indicates that for a large class of military missions, the lower on-board consumption of energy of a subsonic liquid hydrogen transport aircraft is more than offset by the large energy expenditures associated with the fuel production and distribution process.⁽⁸⁾ Thus, while all of the synthetic fuel alternatives require larger energy expenditures than today's crude-oil supply process, the liquid hydrogen supply process appears to be dominantly more energy-intensive than the processes by which the other two coal-derived fuels are obtained.

Costs of Fuel Production

It is difficult to estimate in an absolute sense the costs of synthetic jet fuels produced from coal in the absence of any operating commercial facilities in the United States. However, by making consistent assumptions about coal costs, electricity costs, financing rules, distribution systems, consumption points, etc., insights can be gained into the relative costs of producing the three fuel alternatives. Such an approach is taken below in comparing the costs of producing the three fuel alternatives. The sensitivities of these fuel costs to alternative assumptions in the key parameters are then systematically explored.

Basic estimates of the delivered costs of the three fuel alternatives were developed for the fuel supply paths shown in Fig. 24, using technologies commensurate with those illustrated in Fig. 25. Underground-mined West Virginia bituminous coal constituted the energy source for East Coast air bases, while surface-mined western subbituminous coal drawn from the Four Corners region of New Mexico, the Wyoming Powder River Basin, and Alaska was assumed to be used for the other bases. The minemouth cost of the eastern coal was assumed to be \$20 per ton and the western coal \$5 per ton, the large cost difference primarily being due to the greater productivity possible in surface mining in comparison to underground mining.⁽⁶²⁾ Of course, in making relative comparisons between the costs of the three fuels, consistency in assumed coal costs across the alternatives is more important than precise cost estimates. However, as of June 1974, utilities in the eastern United States were paying from about \$17 to \$23 per ton for coal from eastern underground mines, whereas utilities in the west were paying from \$4 to \$9 per ton for coal from western surface mines; hence, these assumed costs are within the range of costs characteristic of the 1974 time period.⁽⁶³⁾ Since then, coal costs have risen in some markets, with some short-term contracts for underground-mined coal exceeding \$40 per ton. As a consequence, the sensitivity analysis will include the impact of higher coal costs on delivered fuel costs. Costs associated with the energy conversion facilities, adapted from source data, are noted in Table 6. These costs are also treated in a parametric fashion in the sensitivity analysis. The information in

Table 6
ENERGY CONVERSION FACILITY COSTS
(In 1974 dollars)^a

Facility ^b (250 Billion Btu of Fuel Output per Stream Day)	Investment Cost ^c (\$ millions)	Annual Operating Cost Excluding Energy ^d (\$ millions)	Process Electricity Costs per Stream Day ^e (\$)	Other Process Energy Costs per Stream Day ^f (\$)
Coal gasification to hydrogen	648	44	--	--
Hydrogen liquefaction	631	27	394,000	--
Coal gasification to methane	432	39	--	--
Methane liquefaction	86	5	--	--
Coal liquefaction to syncrude	423	32	--	--
Syncrude refinery	123	7	4,430	47,340

SOURCES: Refs. 31, 45, 46, 55, and 60.

^a Costs are those prevailing during the first half of 1974. Adjustments were made to source data using the Chemical Engineering Plant Cost Index. (64) The reader is cautioned that resource energy costs are not included. These costs vary according to coal costs, types of coal, efficiencies of the processes, and distribution distances, all of which are accounted for in Fig. 26.

^b Technologies represented are those previously mentioned in the energy evaluation. The energy output of the facilities includes not just hydrogen, methane, and synthetic JP fuel products, but also other fuel by-products such as gasoline, LPG, low-Btu gas, naphthas, phenols, etc. The energy production of these facilities (250 billion Btu per stream day) is approximately equivalent to the energy content of 45,000 barrels of crude oil.

^c Investment costs include a 28 percent ownership cost over and above basic facility investments to cover interest during construction, working capital, start-up capital, etc.

^d Sulfur and ammonia by-products are credited against operating costs. Sulfur was valued at \$25 per long ton, ammonia at \$100 per long ton.

^e Electricity valued at 15 mills per kWh. Four of the facilities use resource energy, either from coal or gaseous methane, for the generation of on-site electricity. A stream day is one day of plant operation at full capacity.

^f Syncrude refinery requires supplemental plant fuel for hydrogen generation valued at \$1.94 per million Btu.

Table 6 was integrated with distribution and storage cost information (21,56-58) to develop the cost estimates for the three fuels shown in Fig. 24.

The fuel costs shown in Fig. 26 represent the average cost in dollars per 1 million Btu of fuel energy to deliver each of the three fuel alternatives to the consumption points shown in Fig. 24. This measure of cost is used rather than the more traditional cost per gallon, because the vastly different volumetric heat contents of the three fuels make a cost per gallon comparison meaningless. However, as a benchmark, as of June 1976, the Air Force was paying the Defense Fuel Supply Center (DFSC) 42 cents per gallon for JP-4, which is equivalent to about \$3.45 per million Btu.⁽⁶⁵⁾ The fuel costs reflect the mix of eastern and western coal, the mix costing 54 cents per million Btu, or \$9.64 per ton.

Because the energy conversion facilities contribute significantly to the cost of the three fuels, the major cost categories have been identified according to the fixed (capital charges), operating (recurring labor costs, property taxes, raw materials, etc.), and energy costs for these facilities. As would be expected from an examination of Table 6, all of the energy conversion facilities are quite capital-intensive. These capital charges are a strong function of the method by which the plants are financed, which is explored in the sensitivity analysis. The energy flow analysis showed large electrical energy requirements for hydrogen liquefaction. This energy expenditure constitutes a major cost component of liquid hydrogen production, even for a comparatively modest electricity cost of 15 mills per kWh assumed in the computations. If credits are applied for the energy by-products, particularly for the large gasoline by-product, costs of \$8.20, \$3.56, and \$2.91 per million Btu are obtained for the liquid hydrogen, liquid methane, and synthetic JP, respectively.* Thus, liquid hydrogen

* Energy by-products, including the gasoline output of the syncrude refinery, were valued in proportion to their share of the energy output of each facility. Such an assumption might tend to slightly overstate the cost of the synthetic JP, since in the past, light refined products from crude-oil refineries, including gasoline, have commanded a higher price in the marketplace than the kerosene used for jet fuel production.

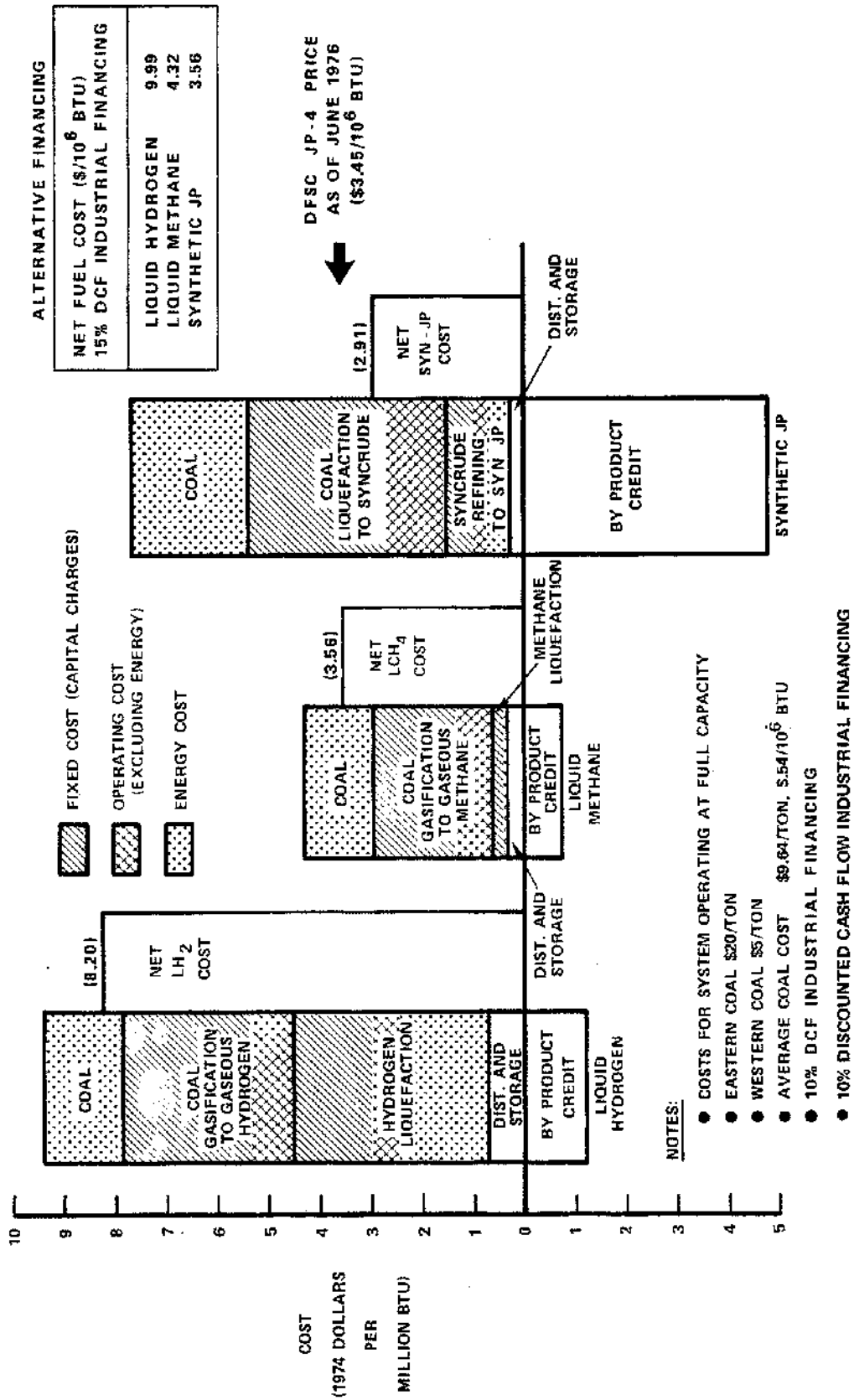


Fig. 26 -- Fuel costs

production appears to be considerably more costly than production of the other two alternatives.

The costs noted above were developed assuming a 10 percent discounted cash flow return on investment after taxes.* It has been suggested that to attract private industry to enter synthetic fuel production as well as to generate the equity required for the rapid build-up of a synthetic fuels industry might require investment returns of 15 percent or more.⁽⁶⁶⁾ Under such conditions, fuel costs could easily reach the levels shown in the box in Fig. 26.

An important distinction should be made between the "cost" of a fuel and its "price." The costs shown on the bars in Fig. 26 represent the operator's cost plus a 10 percent return on investment; they do not necessarily reflect the price that the fuel would sell for on the open market. The coal syncrude cost associated with the synthetic JP production in the example is \$11.33 per barrel. The cost of the refined synthetic JP is about 37 cents per gallon and the gasoline is about 33 cents per gallon (excluding state and federal taxes). These costs are roughly commensurate with current market prices for refined petroleum products. Thus, it seems apparent that synthetic fuels only begin to become competitive in the environment of the petroleum prices prevailing today. Of course, world oil prices reflect far more than cost plus a 10 percent return on investment. Since large quantities of Middle East oil could be pumped to the surface and transported to the United States for about \$1.50 a barrel plus profit, jet fuel could potentially be produced from imported crude oil at costs on the order of one-quarter to one-half those associated with the production of a coal-derived jet fuel.⁽²⁴⁾ Hence, private industry is presently unwilling to assume the risks of initiating a synthetic fuels industry, given the uncertainties in future world crude-oil prices.

The costs developed in Fig. 26 are subject to considerable uncertainty, depending on trends in coal costs, electricity costs, the method by which the energy conversion facilities are financed, possible growth in investment and operating costs, and the manner in which the

* Sixteen year depreciation schedule, 30 year project life.

energy is delivered, among other factors. The sensitivity of the cost of the three fuel alternatives to these parameters is systematically explored in Fig. 27. It should be emphasized that while the costs developed in Fig. 26 were those associated with supplying a set of air bases, the parametric analysis uses a single air base for example purposes. The nominal baseline from which the excursions in cost were examined is shown in Fig. 27.

Figure 27 illustrates that coal cost is one of the major determinants of the cost of the three fuel candidates. It is also important to note that the liquid hydrogen supply process is more sensitive to coal costs than are the other two alternatives. This is a consequence of the fact that any increases in upstream costs (e.g., coal costs) more adversely affect the downstream costs (e.g., fuel costs) of those processes that are less efficient, and, hence, recover less of the more costly coal resource energy in the final fuel product.

The hydrogen production process is also more sensitive to unfavorable changes in the other parameters as well. This is clearly the case in Figs. 27(b) and (c). It is interesting to note that even with a doubling of the capital investment and operating costs (excluding energy) of the liquid methane and synthetic JP alternatives, the liquid hydrogen product is still considerably more costly. Liquid hydrogen costs are also very vulnerable to increases in electricity costs because of the large electric power requirements for liquefaction illustrated in Fig. 27(d).

By examining the slopes of the curves in Figs. 27(e) and (f), it is clear that it is more economical to locate coal liquefaction or gasification plants near the minemouth so that produce gases or liquids can be transported by more economic pipeline methods. However, the lack of water for coal conversion facilities in the arid western states, to be discussed subsequently, may require that the coal be transported by rail to areas where water is more abundant. This would tend to increase the delivered costs of each of the three fuel alternatives.

In addition to the more obvious effects of resource costs, capital costs, financing, etc., on synthetic fuel costs, the dramatic

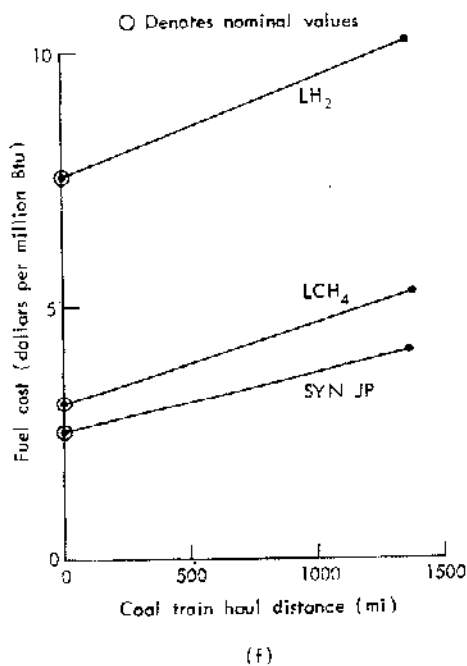
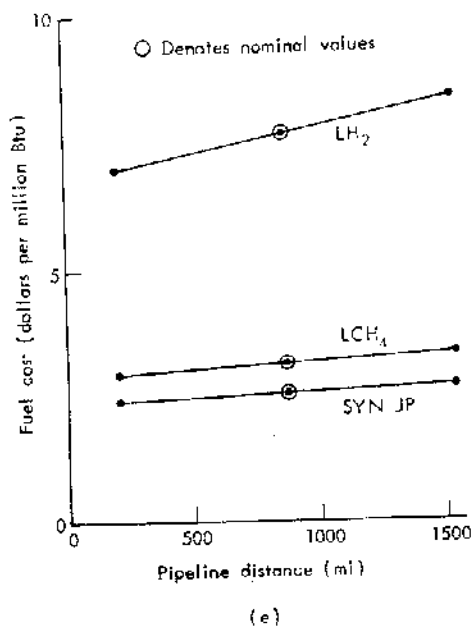
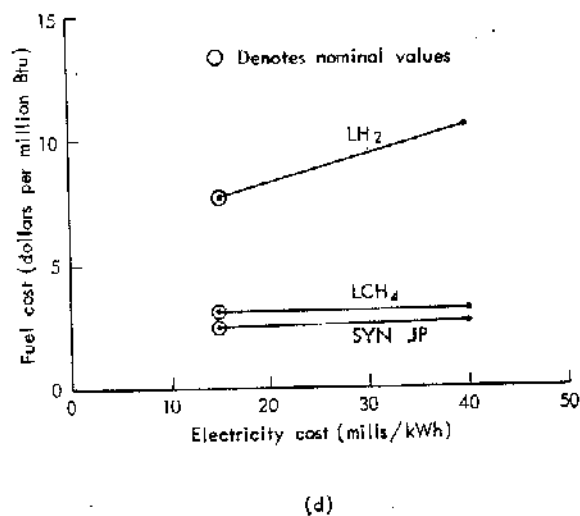
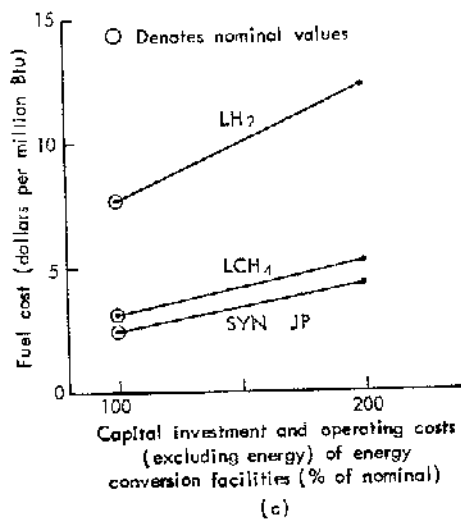
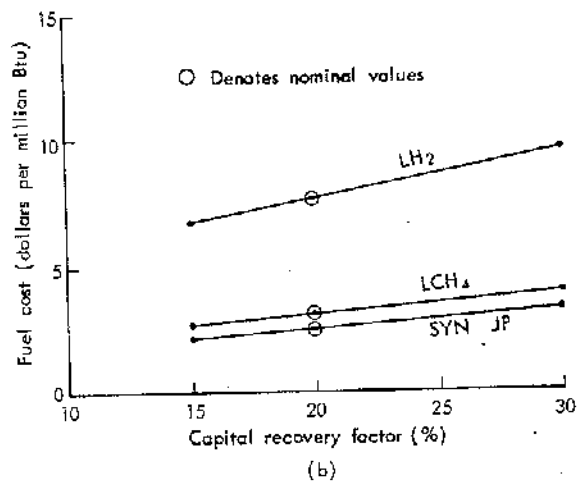
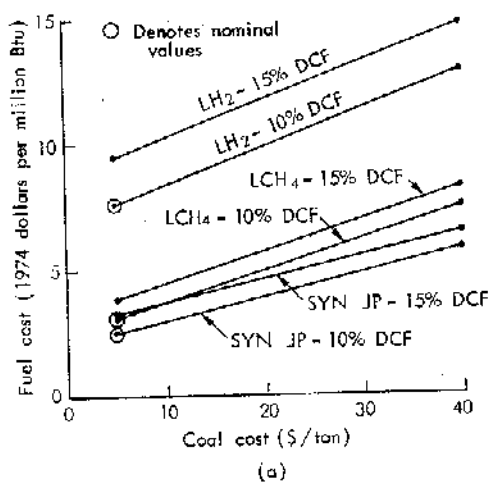


Fig. 27—Fuel cost sensitivities

differences in aviation fuel demands by the military during peacetime and wartime operations could have a pronounced effect on fuel costs. The costs shown in Fig. 26 are associated with a fuel system operating at full capacity, assuming all the fuel produced could find a market with the Air Force and other users. However, if a fuel supply system, sized to meet a contingency or wartime requirement, is underutilized during peacetime, Air Force synthetic fuel costs could rise. The results shown in Fig. 28 apply if there are no alternative markets for the excess liquid hydrogen, liquid methane, or refined syncrude products during peacetime. If such a situation prevailed, the liquefaction or refinery facility owner would have to cover his substantial fixed costs by charging a higher price for the lesser amount of liquid hydrogen, liquid methane, or synthetic JP being produced. We will consider a single air base example to illustrate this effect.

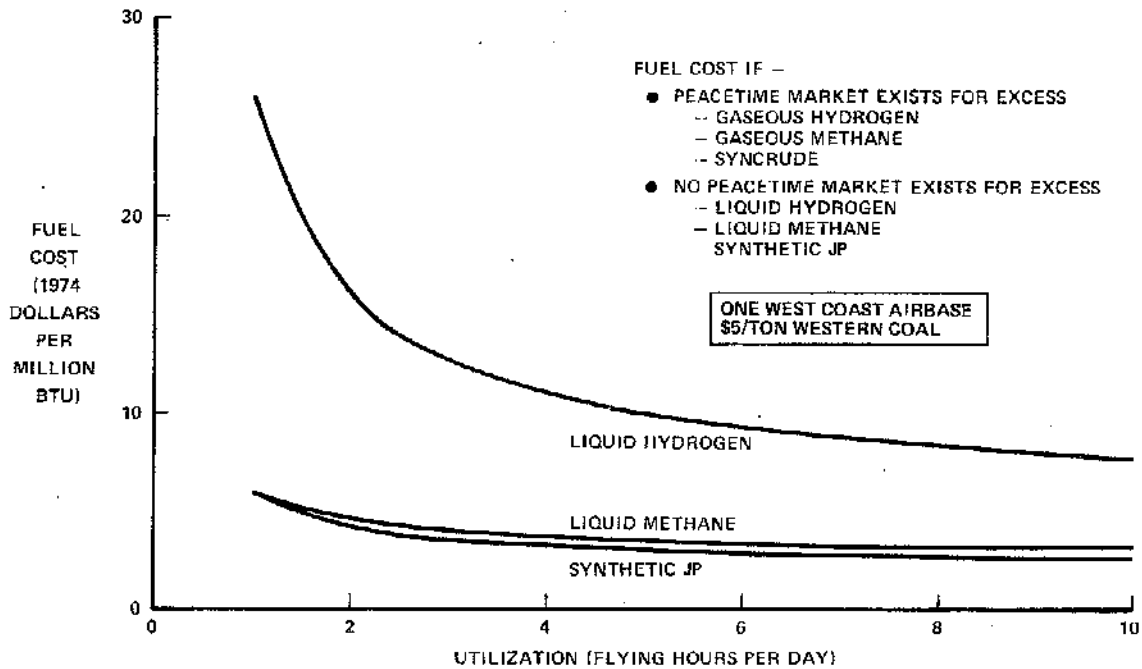


Fig. 28 — The effect on fuel costs of reduced aircraft use during peacetime

In Fig. 28, aircraft utilization rate is used as a measure of the use of a fuel supply system. The fuel supply system was sized to support transport aircraft that might fly 10 hours per day during a contingency situation. However, during peacetime such aircraft might fly only about 1.5 to 2.0 hours per day, about the same number of hours as the Air Force's C-5A heavy airlifter today. The cost of the liquid hydrogen could rise dramatically at such a low utilization rate. The cost increase associated with the other two fuel alternatives is not nearly as severe because of the lower capital intensiveness of the methane liquefaction plant and the coal syncrude refinery. Furthermore, for the synthetic JP alternative, it seems far more likely that the refined syncrude products would be assimilated during peacetime into existing petroleum markets by the turn of the century.*

Of course, the notion of complete reliance by the Air Force on just synthetic fuels is somewhat idealistic; and thus the potential supply of synthetic fuels and petroleum fuels in the future needs to be assessed in the context of competition for these fuels, and the extent to which competitors could use alternative fuels if Air Force requirements were to increase in a contingency. To cite an example, the commercial airlines might also be users of synthetic jet fuels. However, they might not qualify as interruptible users, since 17 percent of all long-range and 100 percent of all cargo or cargo-convertible aircraft might be used as part of the U.S. Civil Reserve Air Fleet during a major contingency situation.

We can summarize the analysis of fuel production costs by noting that liquid hydrogen appears to be considerably more expensive than the other two fuel alternatives. Of course, to make a complete assessment of the relative cost of the three fuel alternatives, we must

* Another alternative would be to size the fuel system to more closely match peacetime fuel requirements and provide for the wartime requirement by maintaining large quantities of the fuels in storage. However, this would not completely ameliorate the problem of liquid hydrogen cost, particularly when the sophisticated and expensive storage of liquid hydrogen is compared to the cheaper storage available for liquid methane, and the comparatively unsophisticated storage needed for refined syncrude products (Refs. 56, 58).

consider the use of the fuels in aircraft. A related Rand mission analysis of large transport-class airplanes (e.g., gross weights of 1 to 2 million pounds) fueled by synthetic JP, liquid hydrogen, liquid methane, or nuclear propulsion has indicated that for a broad class of present and future mission applications, a synthetic-JP-fueled aircraft is significantly more cost effective than the other alternatives, for fuel costs in the range of those cited in Fig. 26. Nuclear propulsion begins to look attractive only for station-keeping missions that require large station radii (greater than 400 n mi) and extremely long loiter times on station (e.g., hundreds of hours). At present, no missions requiring such a capability are apparent.⁽⁸⁾ Only major reductions in the costs of liquefying gaseous hydrogen would improve the relative attractiveness of liquid hydrogen.

Resource Availability

In addition to the cost and energy considerations associated with fuel production, resource issues must also be considered, such as the rate of coal production required to support a synthetic fuels industry and the long-term availability of coal under such rates of production. There is also the question of whether currently available water resources in the western United States would be adequate for the coal conversion facilities that might be located adjacent to large surface-mineable coal deposits.

The rate at which U.S. coal production might expand will depend to a substantial degree on the success or failure of competing energy technologies to lessen the nation's dependence on crude-oil imports. ERDA has developed six scenarios, indicated in Fig. 29, which cover a spectrum of possible paths of evolution for the U.S. energy system, each of which would require significant growth in U.S. coal production.⁽¹⁷⁾ ERDA's results indicate that domestic coal production would have to expand at an average annual rate of more than 5 percent to accommodate the evolving coal needs of a synthetic fuels industry and demands by other users for coal. Other investigations suggest growth rates as high as 7 percent per year.⁽⁶⁷⁾ A 7 percent growth rate corresponds to a doubling of production capacity every 10 years.

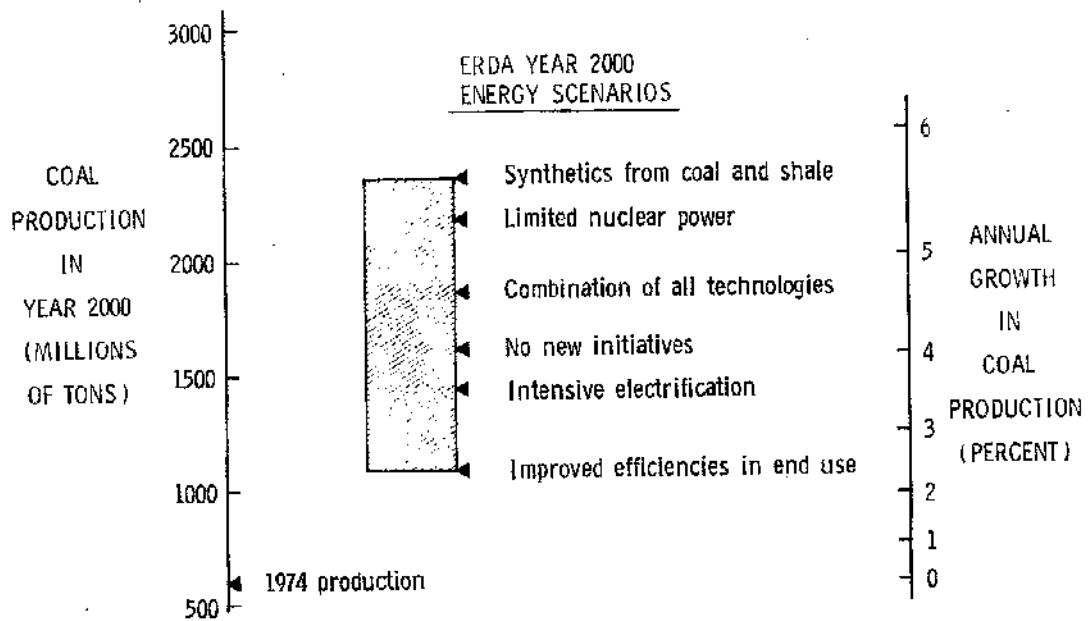


Fig. 29—Coal use in ERDA energy scenarios (from Ref. 17)

It has been suggested that this would require opening two new major coal mines each month for 10 years. This high growth rate can be contrasted with what happened during the 1960s, when only 13 new major coal mines were opened. (68)

This growth in coal production can be measured against estimates of currently economically recoverable domestic coal reserves to gain insights into coal's availability for the future. Shown in Fig. 30 is cumulative coal production by year for several annual growth rates, with the 5 to 7 percent growth rates highlighted. The National Petroleum Council (NPC) estimate shown includes only measured and indicated reserves above the depth of 1000 feet in thick seams. (62) The United States Bureau of Mines (USBM) further includes coal seams of intermediate thickness. (69) Complete information on the ERDA estimate is not available; however, it clearly includes some coal from the inferred reserves category as well as some coal from the unmapped and unexplored category. (17)

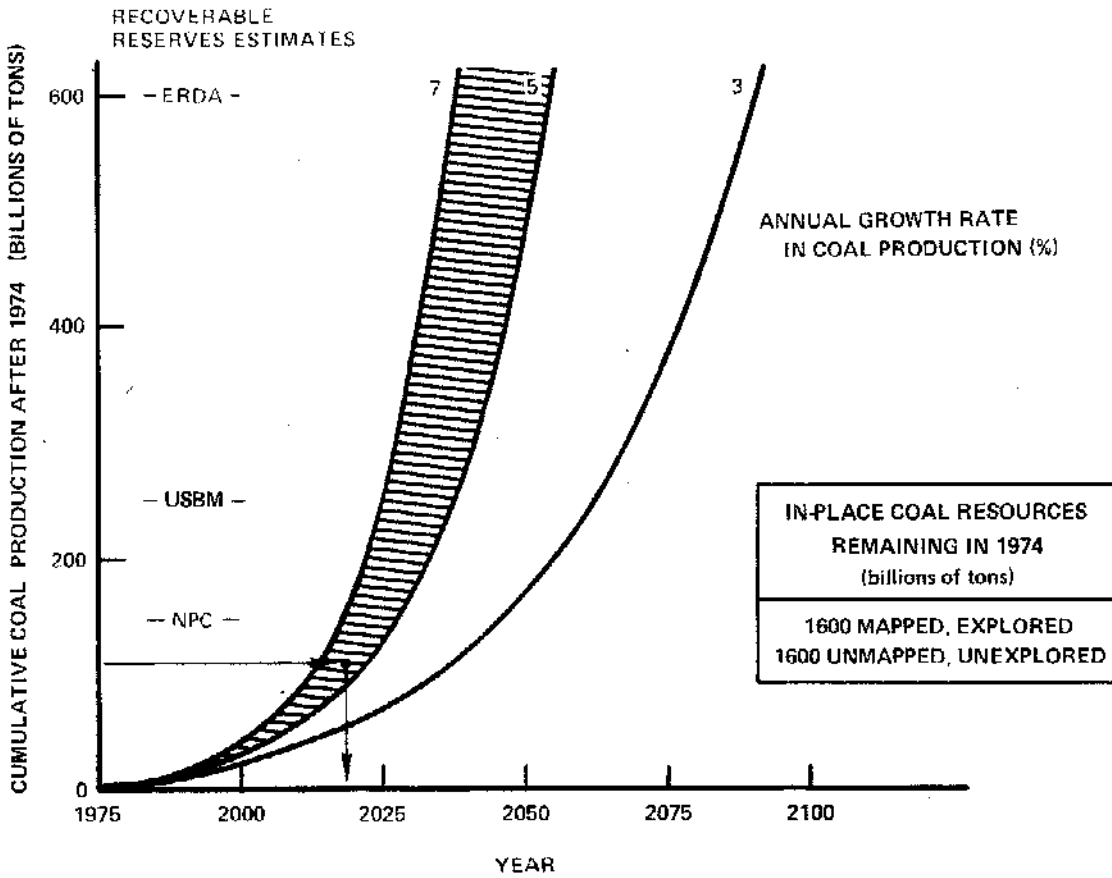


Fig. 30 — Coal resource depletion trends
(from Refs. 17, 62, 67, and 69)

In interpreting Fig. 30, an analogy may be made to the current problems being experienced with domestic petroleum production. Price and availability problems really began shortly after domestic production peaked, forcing users to search for alternative sources of energy-- in this case imported petroleum. In the case of coal, note that one-half of the currently economically recoverable reserves might be depleted during the first or second quarter of the next century if the high growth rates suggested were to be sustained. Thus, the size of the resource base is adequate to supply an increasing fraction of U.S. energy needs into the next century even at the high growth rate. Further

mapping and exploration should further expand the definition of the economically recoverable coal resource base. Of course, environmental and other factors will exert a restraining influence on coal growth, some of which will be discussed subsequently in this section.

The specific coal requirements for producing the three fuel alternatives have already been shown in Fig. 25 on an energy basis. If the Air Force had derived all of its jet fuel for FY 1975 from coal, the coal requirements for the liquid methane option would have been equivalent to about 9 to 12 percent of U.S. coal production, liquid hydrogen from 11 to 15 percent, and synthetic JP from 15 to 21 percent, depending on whether bituminous or subbituminous coal were the energy source.* Recalling the energy flow analysis, the synthetic JP option requires the most coal because of the large gasoline by-product. If the electricity for hydrogen liquefaction were generated using coal, the liquid hydrogen option would require about the same amount of coal as the synthetic JP option yet would deliver about half as much energy. While these annual coal requirements for synthetic jet fuel production seem large compared to current production levels, none of the alternatives would deplete even 0.1 percent of the currently economically recoverable reserves in any given year.

In addition to consideration of coal production capacity, the ability and likelihood of a coal synthetic fuels industry meeting the jet fuel needs of the military and other users by the year 2000 must also be assessed. Shown on the left of Fig. 31 are two estimates[†] of what the potential synthetic jet fuel production capacity might be by the year 2000, with the uncertainty in the ultimate yield of jet fuel highlighted. (17,62) To put these two estimates of capacity into

* Assuming that subbituminous coal has a heat value of 7800 Btu per pound, bituminous coal 10,820 Btu per pound, and domestic coal production of 600 million tons per year.

[†] The NPC estimate shown in Fig. 31 is an extrapolation of their 1985 estimate. In both cases, resulting synthetic jet fuel outputs were calculated using coal inputs estimated by NPC and ERDA, and the synthetic JP fuel supply process energy expenditures shown in Fig. 25. Information in Fig. 31 is derived from Refs. 21, 62, and personal communication from William Vance, Defense Energy Information Service, October 1975.

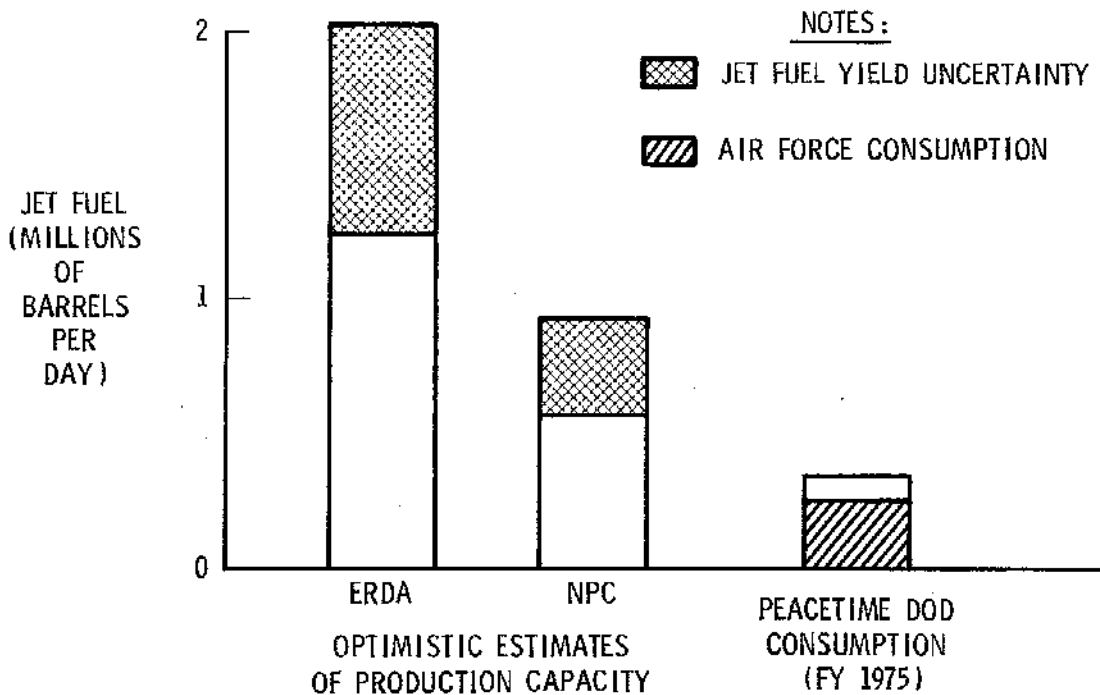


Fig. 31 — Projections of coal-based jet fuel production capacity in 2000

perspective, the Synfuels Interagency Task Force recently recommended a synthetic fuels commercialization program to the President's Energy Resources Council that would result in only 50,000 barrels per day of coal syncrude liquids by 1985, 20,000 barrels per day of which might optimistically be refined to jet fuel.⁽⁶⁶⁾ Clearly, to reach the production levels projected by ERDA and NPC would require a major build-up between 1985 and 2000. This conclusion is essentially unchanged when projections of high-Btu coal gasification capacity are considered, the closest analogy that can be made to the gasification facilities required for the liquid methane or liquid hydrogen supply processes.

These estimates of capacity can be compared with overall DoD and Air Force peacetime jet fuel demands, the Air Force accounting for over three-quarters of that demand.* If the more conservative NPC projection is used, we note that while military peacetime needs might

* Personal communication from William Vance, Defense Energy Information Service, October 1975.

potentially be satisfied, they would constitute a large fraction of the overall market. If Air Force jet fuel needs were to double during a wartime situation--characteristic of past Air Force experience in South-east Asia--capacity would be taxed even more. These Air Force demands for jet fuel should also be considered in the context of overall U.S. jet fuel demands. During 1975 U.S. commercial air carriers consumed nearly twice that consumed by the military.* Thus it seems highly unlikely that a coal-based synthetic fuels industry alone could satisfy all of the demands for jet fuel in the year 2000. More probably, those demands would have to be met by a combination of energy resources, including crude oil, coal, and oil shale.

Growth of a synthetic fuels industry to the rate of production of 1 to 2 million barrels per day indicated in Fig. 31 may be hindered by a lack of water in the arid western states, which contain a significant fraction of the nation's surface-mineable coal deposits.^(70,71) Recall that water is a major source of hydrogen in coal gasification and liquefaction processes. The water availability problem is graphically illustrated in Fig. 32, which shows the water requirements for the synthetic fuel facilities postulated to be located near abundant coal reserves in New Mexico and Wyoming to serve the western air bases shown in Fig. 24.[†] Also shown are the water requirements for the NPC's postulated New Mexico and Wyoming coal conversion facilities. A coal liquefaction plant could consume over six barrels of water for every barrel of syncrude output.⁽³¹⁾ However, the liquefaction plant is not inherently any more water intensive than the gasification facilities; the greater water requirement reflects the larger amount of energy that is delivered because of the gasoline by-product. The results shown

* Personal communication from Evans Whiley, Civil Aeronautics Board, November 1975.

[†] The annual coal inputs for these energy conversion facilities sized to support a fleet of large airplanes⁽⁸⁾ flying a wartime rate of 10 hours per day would be 67 million tons for coal gasification to hydrogen, 61 million tons for coal gasification to methane, and 104 million tons for coal liquefaction to syncrude. Refer to Ref. 62 for NPC's postulated coal requirements.

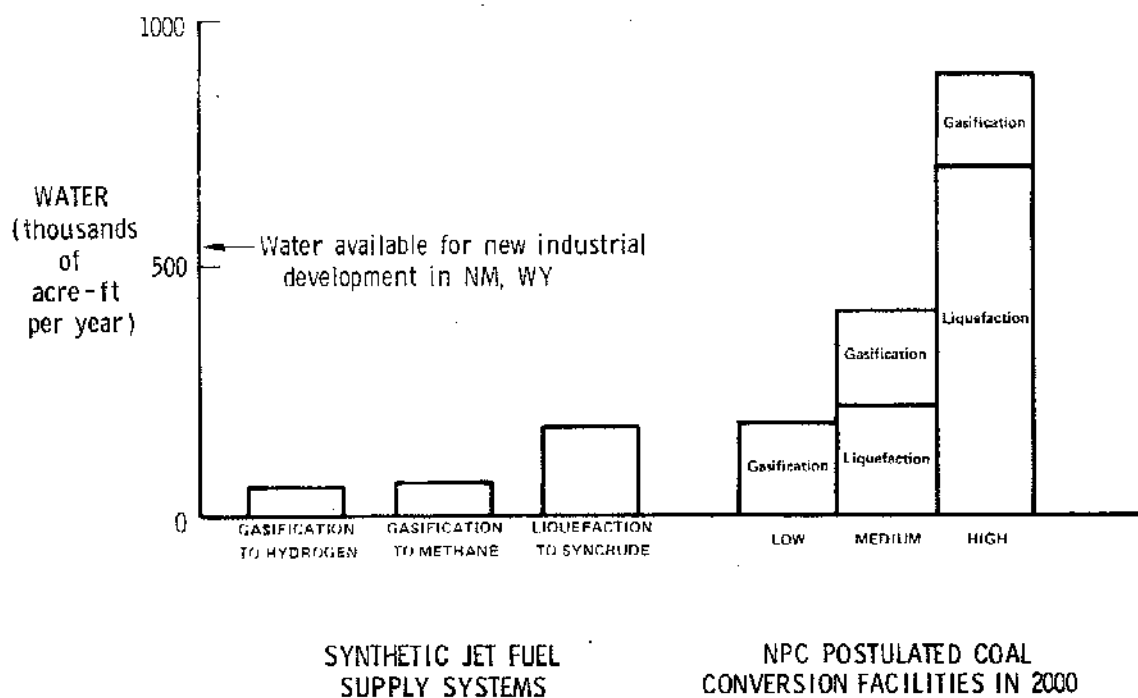
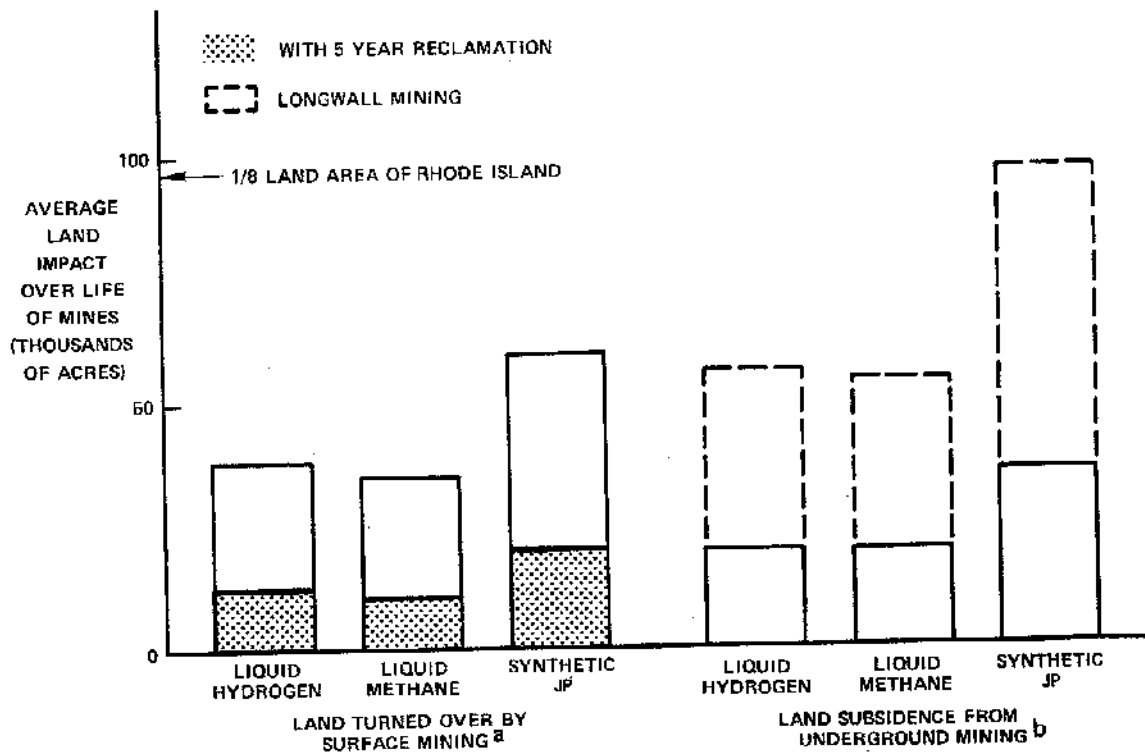


Fig. 32 — Water requirements for coal conversion facilities in New Mexico and Wyoming (from Refs. 31, 60, 62, 70, and 71)

in Fig. 32 indicate that additional costs may be incurred to develop new water supplies for the facilities, or additional distribution costs may be incurred to ship the coal to areas with more abundant water supplies.

Environmental Issues

The development of a synthetic fuels industry will create new sources of land, water, and air pollution. In the present analysis, a mix of eastern and western coal was used for the fuel supply systems to minimize distribution distances. Figure 33 shows the average land impact of the surface mining in Wyoming, New Mexico, and Alaska required to support the fuel supply systems of the three alternative jet fuels considered.⁽⁷²⁾ The land area that must be turned over in surface mining depends on the coal requirements of the fuel supply process, the coal recovery rate, the heating value of the coal, the coal density, and particularly, the thickness of the coal seam. For



^a Annual surface coal production is analogous to that associated with Fig. 32 with the addition of assumed surface coal production in Alaska, which results in annual coal production of 83, 76, and 132 million tons for hydrogen, methane, and syncrude facilities, respectively.

^b Annual underground coal production assumed to be 36, 35, and 61 million tons for hydrogen, methane, and syncrude facilities, respectively.

Fig. 33 — Impact on the land of coal extraction for synthetic fuels (from Ref. 72)

example, the average coal seam thickness in the Wyoming Powder River Basin is triple that of coal found in the Four Corners area of New Mexico (39 feet, as compared to 12 feet).⁽⁷²⁾ Hence, more land must be turned over in New Mexico than in Wyoming to obtain an equivalent amount of coal.

Figure 33 indicates a greater land impact for the synthetic JP alternative only because of the larger amount of energy being delivered. The land impact of the mining required to support the supply of liquid hydrogen reflects only the mining of coal needed to provide the resource energy for the process. If it is assumed that the process electricity for hydrogen liquefaction is also derived from coal, the land impact would be far greater than that shown in Fig. 33. The Rhode Island land area is used as a point of reference because some have suggested that in the United States an area somewhat greater than the land area of that state has already been stripped and not been reclaimed.

The ability to reclaim land overlying surface-mineable coal deposits is the subject of considerable controversy. If the mined land could be reclaimed in five years, the average land impact could be significantly reduced, as is shown in Fig. 33. Some suggest, however, that complete reclamation may be impossible. In that situation, in an absolute sense, the total amount of land turned over and unreclaimed would be twice that shown in Fig. 33.

The strip mining impacts shown in Fig. 33 are those that would occur in supplying part of the energy requirements for a fleet of very large airplanes.⁽⁸⁾ If all of the Air Force's current jet fuel energy needs were to be supplied by western surface-mineable coal deposits, the amount of land turned over annually in the synthetic JP supply process could range from 1900 to 7000 acres, depending on whether Powder River Basin coal or Navajo coal from the Four Corners area were to be used. Hence, any major commitment by the Air Force to use jet fuels derived from surface-mineable western coal deposits could have a sizable land impact.

There is quite a different impact associated with underground mining--that of subsidence of the undermined area. The lower bars on Fig. 33 represent the land impact of room and pillar mining used to support the synthetic fuel supply systems for the East Coast air bases shown in Fig. 24. In room and pillar mining, the most prevalent type of underground coal mining practiced in the United States today, pillars of coal are left standing in the mine to reduce the amount of subsidence. Increased adoption of the longwall mining technique, in

which almost all the coal is removed, would enhance recovery but increase subsidence, as shown in Fig. 33.

In addition to the land impact of the coal mining required to support a synthetic fuels industry, the environmental pollutants from the coal conversion facilities must also be assessed. Table 7 compares the environmental pollutants from a conventional coal-fired steam power plant, a coal gasification plant, and a coal liquefaction facility, all sized to process an equivalent amount of coal.⁽⁷²⁾ These results must be interpreted with caution, since no commercial-size gasification or liquefaction facility has yet been built in this country. Indeed, one of the major objectives of the "information" program recommended by the Synfuels Interagency Task Force is to gain environmental impact data on synthetic fuel facility operations.⁽⁶⁶⁾ The estimates of coal conversion facility pollutants indicate that the new facilities may represent no greater threat to the environment than a conventional electric power plant, and perhaps less. In the case of air pollutants, the new facilities would remove most of the sulfur contained in the coal from a concentrated stream of hydrogen sulfide gas, rather than "scrubbing" sulfur dioxide out of the exhaust products of coal combustion. The "sludge" that results from this scrubbing process is one of the reasons the power plant has greater solid waste products. In addition, the coal conversion facilities recover some of the potential nitrogen air pollutants in the form of aqueous ammonia, rather than releasing them to the atmosphere as oxides of nitrogen. It is likely that much of this pollution control technology will be incorporated in future coal-fired power plants as well.

Finally, it should be noted that, while in comparison with a coal-fired power plant, the pollutant discharges from coal conversion facilities may not represent any increased threat to the environment, these plants may be built in areas of the west that now have a comparatively pristine environment, in which case they may represent a substantial threat to the environment in a relative sense.