has proved fatal in several cases. However, all these hazards can be avoided by proper handling.[19]

Research and development in progress and future developments. Little research and development is presently being done since the basic process for producing methanol has reached a high state of perfection. Future work should be directed toward process improvement and catalyst development. Studies should be made in an effort to reduce manufacturing costs and devise means for increasing the higher hydrocarbon content of the methyl fuel (to increase the heating value). Catalyst development work should be directed toward increasing the production of the higher alcohols in the methyl fuel.

Methanol (methyl fuel) can be used as a feedstock for conversion to a substitute natural gas for supplying distribution lines or energy requirements equipped only for use of gas. Catalytic processes have been developed for the gasification of methanol to methane-rich gas. Further catalyst development is indicated in addition to the perfection of the process for removal of the carbon dioxide from the product gas.

An unsolved long-range problem, determining the source of carbon required to produce methanol, exists. Some research and development is anticipated to determine the best and least-expensive source of CO or CO_2 for this purpose.

3.2.3 Hydrazine

Physical principles and theory. Two processes are used for the commercial production of hydrazine: the Raschig process and the urea process. In the Raschig process the synthesis of hydrazine from ammonia and sodium hypochlorite* takes place in two steps:

$$NH_3 + NaOCl \rightarrow NH_2Cl + NaOH \, .$$

Chloramine (NH_2Cl) is first formed and then reacts with excess ammonia to form hydrazine:

---

*NaOCl is manufactured by reacting Cl_2 with NaOH, both of which are products of brine electrolysis.

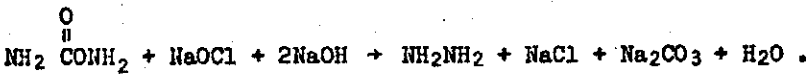
$$NH_2Cl + NH_3 + NaOH \rightarrow NH_2NH_2 + NaCl + H_2O .$$

The first reaction proceeds rapidly, whereas the reaction of chloramine with ammonia is slow and rate determining and requires heat. Chloramine may also react with hydrazine to form ammonium chloride and nitrogen.

$$NH_2NH_2 + 2NH_2Cl \rightarrow 2NH_4Cl + N_2 .$$

The reaction is carried out at elevated temperature (130°C), which favors hydrazine formation, effectively minimizing the decomposition of hydrazine by chloramine, which is independent of temperature. It is necessary to use a large excess of ammonia (20:1 to 30:1). The hydrazine-containing solution is pumped to a crystallizing evaporator, where the sodium chloride and sodium hydroxide are removed, and then to a fractionating column for water removal.

In the urea process, hydrazine is formed by the reaction of sodium hypochlorite and urea* according to the following equation:



$$NH_2\overset{\overset{O}{\|}}{C}ONH_2 + NaOCl + 2NaOH \rightarrow NH_2NH_2 + NaCl + Na_2CO_3 + H_2O .$$

Two solutions are prepared for feed to the reaction vessel. The first is prepared by chlorinating a 30% solution of sodium hydroxide until it has an available chlorine content of 140 to 155 g/liter and a residual sodium hydroxide content of 170 to 190 g/liter. The second solution, which is 43% urea, is prepared by dissolving urea in water while steam is passed through the solution to maintain the temperature at about 5°C, since the dissolution is strongly endothermic. Four volumes of the first solution and one volume of the second solution to which has been added 500 mg of glue per liter are fed continuously to the reactor, where the temperature is allowed to rise to 100°C. The hydrazine is removed in the same manner as in the Raschig process.

<u>Current state of technology</u>. Both the Raschig and urea processes are used at present for the production of hydrazine. The two processes

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*The production of urea requires a supply of CO_2 and thus is subject to a similar problem of a source of carbon as in the production of methanol.

are competitive because the more costly raw materials for the urea process are offset by the capital cost of the equipment required to recover and recycle the ammonia in the Raschig process. At high production levels the Raschig process is less expensive; the break-even point is 1.8 million lb of hydrazine per year. For large tonnage quantities, hydrazine can be produced by the Raschig process for less than 50¢/lb (1966).[20] United States capacity in 1966 was about 35 million pounds per year.

Ultimate potential. The lack of demand for hydrazine in large quantities has apparently discouraged research and process development to a point where it does not appear possible for hydrazine to compete as a potential fuel because of its high production costs.

A design study conducted by the Olin Mathieson Company[21] indicated the possibility of producing hydrazine to sell for 20¢/lb using the Raschig process. However, this required a large installation (1000 tons/day) with optimization of operating variables, utilization of waste heat, etc.

Other processes for making hydrazine have been proposed and demonstrated, but as yet none appears practical. Small quantities of hydrazine are produced in the Haber process for ammonia production. Thus it would appear that a modification of this process might give good yields of hydrazine. However, since hydrazine is an endothermic compound, undergoing decomposition with energy release, its formation must be accomplished under relatively mild conditions. The successful development of a hydrazine process along these lines should yield a product in the same cost range as ammonia, perhaps $50 to $75/ton (2.5¢ to 3.75¢/lb or 266¢ to 400¢/10^6 Btu).

Safety and reliability aspects. The following health and safety factors are quoted from the Olin Mathieson Chemical Corporation's bulletin on anhydrous hydrazine.

"Hydrazine is a toxic material which must be treated with due respect. Harmful effects may result from injection, inhalation of vapors, or contact with the skin. The threshold value, which has been adopted by the American Conference of Governmental Hygienists (1963), is

1 ppm. The maximum tolerable concentration in air breathed for no more than 10 minutes is suggested as 10 ppm.

"Although hydrazine has a readily detectable ammoniacal odor (69-83 ppm), smell should not be relied on as a warning of excessive concentration since membranes of the nose may be desensitized rapidly. Hydrazine vapors are irritating to the eyes, nose, and throat. Inhalation causes dizziness, nausea, and hoarseness. Contact of hydrazine with any body tissue will produce a caustic-like burn if not washed off immediately. Ingestion or absorption through the skin will cause nausea, dizziness, headache, and may prove fatal.

"Liquid anhydrous hydrazine is very stable and nonexplosive. In the absence of decomposition catalysts, it has been heated above 500°F with very little decomposition. Hydrazine vapors, however, present a hazard. Mixtures of hydrazine vapor in air are flammable between the limits of 4.7% and 100% hydrazine by volume. The flammability of hydrazine vapor is decreased by the use of any of several diluents. When burning freely in air, hydrazine (as the liquid) behaves much like gasoline. However, at elevated temperatures, it burns fiercely. Water solutions at any concentration below 40% cannot be ignited. Hydrazine fires and spills are best controlled by deluging with large quantities of water. Anhydrous hydrazine is completely insensitive to shock, friction, or electrical discharge. If it is desirable to monitor any area for the presence of hydrazine vapors, detection devices or sensors may be obtained from commercial sources."

3.2.4 Methane and mixed hydrocarbons from wastes

There have been many proposals for converting waste products to fuels by utilizing either thermochemical or biological processes. Of the 3×10^9 tons of solid organic wastes generated yearly in the U.S., about two-thirds are manure and over 80% are of agricultural origin. Total municipal and industrial wastes are about 0.4×10^9 tons, half of which are currently collected for disposal by municipal agencies.

These solid wastes represent a potential annual source of about 20 x 10^{18} std ft^3 of methane or similar fuels, or about three-fourths of the current annual consumption of natural gas in the U.S.[22] A study prepared for the U.S. Department of the Interior's Bureau of Mines (BuMines)[22a] indicates that more than half the total weight of these wastes is actually water. In 1971, the total amount of dry, ash-free organic waste produced in this country was only 880 million tons with about 136 million tons of dry organic wastes being readily collectable for conversion. This amount would have produced 170 million barrels of oil - roughly 3% of 1971 consumption of crude oil or 12% of imported crude. Alternatively, this amount of waste could have produced 1.36 trillion scf of methane, about 6 percent of 1971 consumption of natural gas.

The Bureau of Mines has reported development of a process for hydrogasification of wastes which utilizes technology developed for coal hydrogenation. They claim potential costs as low as \$0.40 to \$0.50/10^3 ft^3 of gas and suggest the processing of municipal wastes and manure.

Union Carbide has announced an advanced incineration process for converting organic wastes to a fuel gas. Mount Vernon, New York, was reported to be interested in building a prototype unit to process 150 tons of wastes per day. The Union Carbide process develops temperatures of 2600 to 3000°F by partially reacting the wastes with oxygen and produces a fused inorganic waste in addition to the fuel gas. This gas may also be converted to hydrogen, methanol, or methane as economics dictate.

Garrett Research and Development Company is reported to be developing a process to recover liquid and solid fuels by pyrolysis of municipal wastes.

Methane may also be produced by anaerobic decomposition of garbage and other waste materials. The digestion process would not require exotic or expensive equipment since it would take place at 95 to 100°F and at atmospheric pressure. In addition to a gaseous product consisting of 65 to 70% methane and 30 to 35% carbon dioxide, a solid product remains (reduced more than 50% in mass from the original waste) that is useful as a fertilizer or soil conditioner. This solid might be processed pyrolytically to yield additional synthetic fuel.

Other specific waste products which have been suggested for use as a "feedstock" for biological production of methane are waste crank case oil, effluents from paper pulp mills and food processing plants, etc.

While most of the technology required to produce methane from waste products appears to be relatively well developed, only a few plants actually make economic use of the fuel gas. Present trends in the society should improve the feasibility of this process for the following reasons:

1. sharp increases projected in the price of clean gaseous fuels as the result of scarcity;
2. public awareness of the need to improve methods of disposal of solid wastes;
3. greater acceptance of the intrinsic merit of conservation;
4. the likelihood that production of synthetic fuels from wastes will create less pollution than alternatives such as incinerators.

There appears to be a need for systematic evaluation of the alternative methods of converting wastes to synthetic fuels and for relating probable costs to the costs of other substitutes for natural gas produced from coal. If the projections made by proponents of these systems are correct, then it would be in the national interest to increase research and development in this area and to build a number of demonstration projects. The rate of development should be accelerated so that this source of synthetic fuels could be fully applied within ten years. One inherent advantage of producing fuels from wastes is that the processes so far developed or proposed yield methane (or a high-Btu gas mixture) or liquid hydrocarbons which can be utilized in the existing infrastructure, thus minimizing implementation problems.

Among the problem areas which must be considered in developing synthetic fuels from wastes is the cleanliness of the fuels, that is, the suitability of the fuels to unrestricted use as pipeline gas and the economic collection of diffuse wastes sources, particularly agricultural wastes.

It should also be recognized that another study panel, Extraction of Energy Fuels, is considering the research and development requirements of this area.

3.2.5 Fuels via intensive agriculture

While producing fuels from agricultural products is basically an application of solar energy and will be discussed to some extent by the Solar Energy Panel, it fits so well into the subject of this report that some discussion here seems warranted. The fuels that may be produced in this manner are ethanol from fermentation of grains, sugars, or starches; methanol from waste products; and wood from tree farms. Making use of intensive agriculture may be a viable process of producing a gaseous or liquid fuel.[23] The crop processing technology seems to be well developed, but the overall economics have been unfavorable due to the low cost of competing fossil fuels. The application of intensive agricultural methods (i.e., use of optimized nutrients, soil moisture levels, etc., coupled with a multiple crop climate) and the rising price of fossil fuels work toward making this scheme profitable. However, the relatively large amounts of land required to produce a significant fraction of our fuel requirements seem to preclude the use of this concept to areas of very specialized application, for example, ethanol as a replacement for tetraethyl lead (10% in gasoline).*

The use of wood obtained from a tree farm has been proposed[24] as a fuel for a conventional steam-electric power station. Preliminary computations indicate that an intensively farmed area of 400 to 600 sq miles would be required to continuously supply a 1000-MW(e) power station with wood fuel.

Although not usually considered agriculture, growing algae for fuel has often been proposed.[25] Here the fuel could be methane, but again the large land areas required suggest that such a system is not likely to meet a significant fraction of our total energy need

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*This requires 8.8×10^9 gal of alcohol per year or 3.3×10^9 bushels of grain or about 30×10^6 acres of land.

3.3 Use of Coal as an Interim Source of Synthetic Fuels

Other sections of this report deal with the use of hydrogen as a synthetic fuel derived from nonfossil sources. This concept stems from the almost certainty that at some point in time the supply of fossil hydrocarbons (for synthetic fuels and other large-scale uses) will have been depleted. But the combination of our extensive coal reserves and an obvious (though not fully developed) technology for the relatively economical manufacture of hydrogen and methanol from coal suggests that coal be regarded as an interim raw material for these two synthetic fuels. Methane, synthetic crude oil, gasoline, and other fuels (and chemicals as well) also can be produced from coal; limitations of time prevent their detailed consideration here.

The U.S. was estimated[26] to have had 3.21×10^{12} tons of coal at the end of 1969, or the equivalent of 64.4×10^{18} Btu of energy. Only one-half of this coal is believed to be recoverable; however, the U.S. total consumption of nonnuclear energy in 2000 has been estimated to be about 131×10^{15} Btu. A rough conservative assumption can be made that one-half of the energy in the coal could be delivered to end uses in the form of hydrogen and methanol. Thus, even if all nonnuclear energy were to be provided by hydrogen and methanol, coal could be the source of these two synthetic fuels for 120 years at the year 2000 consumption rate. Although "interim" is an unquantitative term, its use here apparently would cover at least the next 100 years.

3.3.1 Hydrogen

As an interim source, fossil fuels can undoubtedly provide hydrogen more immediately and more cheaply than any other alternative. The least-expensive hydrogen (principally for ammonia synthesis and petroleum refining) is presently obtained from natural gas by steam-methane reforming; production from petroleum by steam-naphtha reforming and partial oxidation of heavier stocks has been somewhat more expensive. For the longer term, production from coal appears more desirable because U.S. coal reserves are vastly greater than remaining domestic supplies of natural gas and petroleum, and early and successful production from coal will help minimize our growing dependence on foreign sources of gas and oil. Two methods are reviewed: (1) the steam-oxygen (Synthane) process and (2) the CO_2 (acceptor) process.

Physical principles and theory. When coal is reacted with steam at 450 psi and 1600 to 1800°F, the principal gaseous products are CO, CO_2, and H_2. In addition, small amounts of CH_4 are also produced; the CH_4 yield increases with pressure and becomes a major product at 1000 psi. The coal-steam reaction is highly endothermic, and a large input of heat is required.

In the steam-oxygen process for production of hydrogen from coal, this heat is supplied by adding pure oxygen to the steam; the oxygen-coal reaction produces CO, CO_2, and heat. The CO produced in both the coal-steam and coal-oxygen reactions is then reacted with additional steam in a shift reactor to produce more hydrogen and CO_2. The CO_2 is removed by scrubbing the final gas with monoethanolamine (MEA) or potassium hydroxide; both CO_2 absorbents are regenerated for reuse by heating. Pure CO_2 is a by-product of this process, and the final hydrogen is 97 to 98% pure.

In the CO_2-acceptor process, lime (CaO) is introduced with the coal being reacted with steam (no air or oxygen is added). The CO_2 in the reaction product gas is removed by the lime as rapidly as it is formed to produce calcium carbonate ($CaCO_3$). In the absence of CO_2 the shift reaction (see above) occurs in the main reactor, thereby minimizing or eliminating entirely the need for an external shift reactor and CO_2 scrubber. The necessary heat to support the coal-steam reaction is supplied by both the shift reaction and the reaction of CO_2 with the lime. The calcium carbonate is dissociated to lime and CO_2 in a separate reactor, and the regenerated lime is reused. The heat for lime regeneration is supplied by unburned coal from the main reactor. The CO_2-acceptor process was developed to eliminate the need for pure oxygen required in the steam-oxygen process.

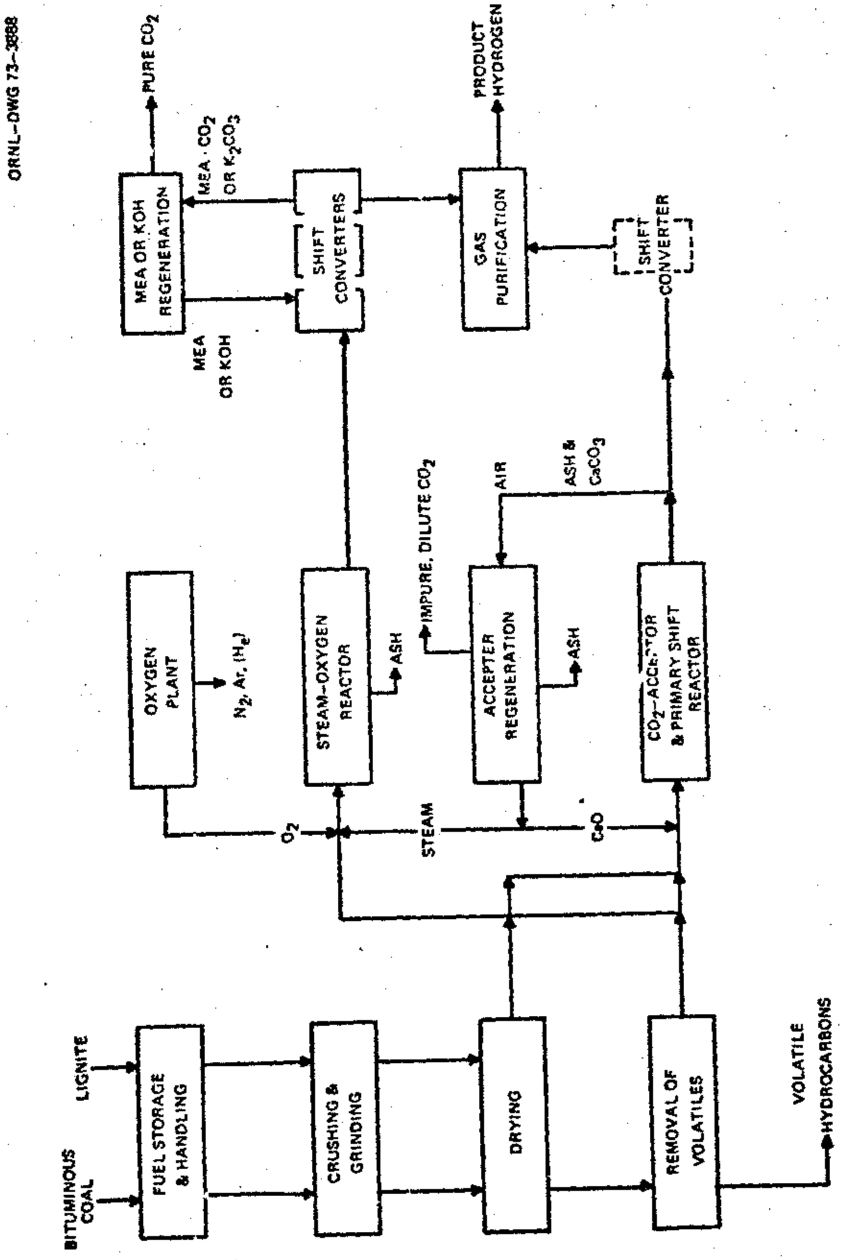
Lignite is a preferred raw material for both processes; bituminous coal can also be used, but only with difficulty in the CO_2-acceptor scheme. Overall hydrogen yields for both fuels and processes are tabulated below.

	Percent of theoretical H_2 yield achieved	
Feed	Steam-oxygen process	CO_2-acceptor process
Lignite	97	90
Bituminous coal	70	(∿80)

The two processes are compared in the composite flow sheet in Fig. 7. In both processes the fuel is first crushed and ground; lignite is then dried, but bituminous coal must also be thermally treated to remove volatile hydrocarbons. The gasification reaction in both processes is done in fluidized beds at 450 psig; lignite is reacted at 1600°F, but bituminous coal requires a temperature of 1800°F because of its lower reactivity. In the steam-oxygen process 12.1 lb of lignite (or 8.7 lb of bituminous coal), 8.8 lb of steam, and 5.2 lb of oxygen are consumed to produce 1 lb of hydrogen. Quantities of lignite and steam are the same in the CO_2-acceptor process, but no oxygen is needed.

Current commercial plants for production of hydrogen from coal. No commercial plants presently exist in the United States for production of hydrogen from coal. The closest counterpart is the Lugi process plant at Sasolburg, South Africa, which produces synthetic gasoline from low-grade domestic coal and is subsidized by the South African government to minimize their petroleum import requirements.

As noted previously, production of hydrogen from fossil fuels involves two operations, production of synthesis gas (CO, and H_2) and conversion of CO to CO_2 with steam (shift reaction) which produces additional H_2. The coal-steam (water gas) reaction has been used commercially for a century to produce low-Btu city gas (H_2, CO, and N_2). However, it has been almost completely abandoned in the United States


ORNL–DWG 73–3888
BITUMINOUS COAL
LIGNITE
FUEL STORAGE & HANDLING
CRUSHING & GRINDING
DRYING
REMOVAL OF VOLATILES
VOLATILE HYDROCARBONS
OXYGEN PLANT
N_2, Ar, (He)
O_2
STEAM
CaO
STEAM–OXYGEN REACTOR
ASH
ACCEPTER REGENERATION
IMPURE, DILUTE CO_2
ASH
CO_2–ACCEPTOR & PRIMARY SHIFT REACTOR
AIR
ASH & $CaCO_3$
MEA OR KOH REGENERATION
PURE CO_2
MEA · CO_2 OR K_2CO_3
MEA OR KOH
SHIFT CONVERTERS
GAS PURIFICATION
PRODUCT HYDROGEN
SHIFT CONVERTER

over the past 30 to 40 years because of the great availability of more desirable natural gas. Its reintroduction to produce synthesis gas (and synthetic methane and hydrogen) in the face of dwindling supplies of domestic natural gas will be with much cleaner and more efficient equipment; thus we will not be faced with a rebirth of the dirty and cumbersome "municipal gas works" of former times. The shift reaction is based on large-scale, well-established technology which includes removal of CO_2 from the final hydrogen product.

Several steam-oxygen processes are in various stages of development.[27] The most advanced is the German Lurgi process, which is commercially available now. However, it is a relatively labor-intensive mechanical process with high maintenance problems; further, its extensive use would require some outflow of dollars in royalties. The Bi-Gas process (Bituminous Coal Research, Inc.) is an entrained bed system and the Synthane process (U.S. Bureau of Mines) a fluidized bed process; both are to be pilot planted in the near future. We have chosen the Synthane process for evaluation as typical of the coal-steam processes. The CO_2-acceptor process (Consolidation Coal Co.) is also a fluidized bed process as is the Union Carbide process. A 30-ton/day CO_2-acceptor pilot plant has been built and is now ready for testing. We have also chosen this process for backup evalution. The Hygas process (Institute of Gas Technology), although the farthest along of all domestic processes, was not considered because it requires hydrogen as one of the feed materials to make methane from coal.

Economics of hydrogen production from coal.* Actual cost experience on the production of hydrogen from coal in the United States does not exist; however, the new process technology is fairly well understood, and reasonably good estimates of both capital and operating costs can be made. These are compared with costs for steam-methane reforming, the most widely used present method for producing hydrogen. The major cost is the fossil fuel cost; therefore we have treated it as a variable in the economic summary provided in this section. We have also treated plant capacity as a variable and have used the values 250, 500, 1000, and 2500 tons/day of hydrogen.

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*Costs shown in this section were developed from the basic data contained in Ref. 11.

Capital costs for the four processes compared are as follows.

Process	Capital cost (10^6 \$) for plant size of 250 tons/day	500 tons/day	1000 tons/day	2500 tons/day
Steam-methane reforming	10.7	17.4	28.3	53.7
Steam-oxygen process for lignite	20.5	33.2	54.0	102.5
Steam-oxygen process for bituminous coal	25.2	40.9	66.4	126.1
CO_2-acceptor process for lignite	25.8	41.9	68.9	129.1

Total annual operating costs, including 15% fixed charges, are provided in the tabulation below for plants for natural gas priced at 60¢/10^3scf (10^6 Btu) and coal or lignite at \$7 per short ton.

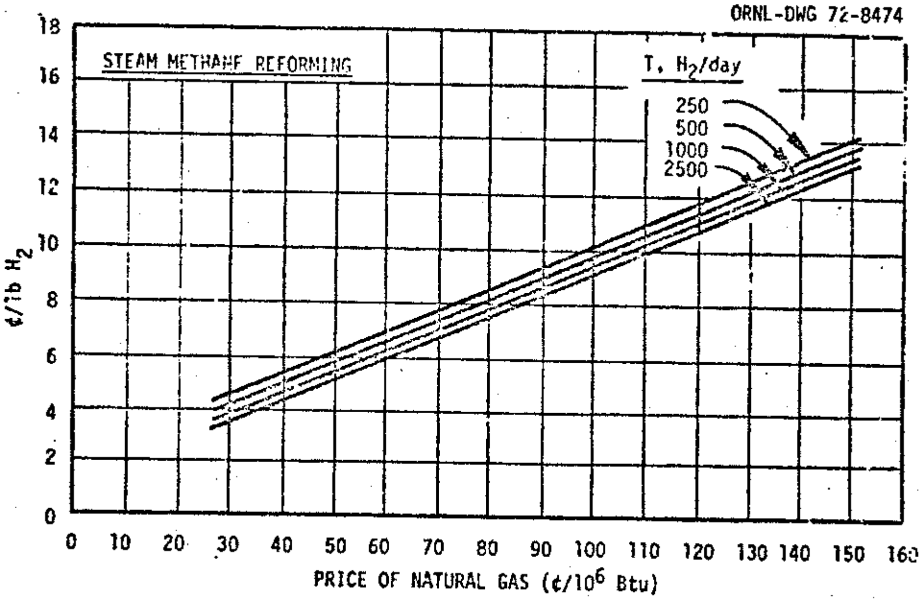
Process	Total annual operating cost (10^6 \$) for plant size of 250 tons/day	500 tons/day	1000 tons/day	2500 tons/day
Steam-methane reforming	11.7	22.4	42.9	102.7
Steam-oxygen process for lignite	16.1	29.1	53.5	121.0
Steam-oxygen process for bituminous coal	15.4	27.1	48.8	108.8
CO_2-acceptor process for lignite	15.8	28.4	51.6	117.0

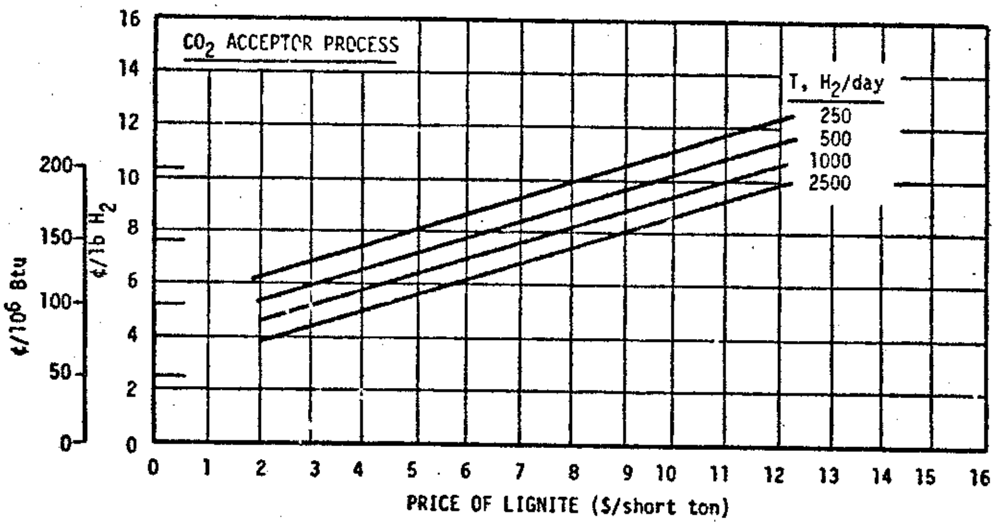
Effects of plant size and raw material cost on the cost of product hydrogen are shown graphically in Fig. 8 for steam-methane reforming and the CO_2-acceptor process. In the former process natural gas cost accounts for from 53% of the total cost at low gas cost and capacity to 90% at high gas cost and capacity; in the lignite processes the corresponding values are 37 and 72%, respectively, and, when bituminous coal is used, 27 and 61%. Thus the capacity vs cost curves for steam-methane reforming are much more closely grouped than those for the coal processes. Further, as natural gas prices rise, use of coal, particularly in large plants, becomes more competitive and at $7/ton (lignite at 52¢/$10^6$ Btu) can produce hydrogen at the same price as steam-methane reforming using natural gas at 75¢/10^6 Btu at 2500 tons H_2/day.

Aside from fossil fuel costs, the percentage breakdown of other costs for plants producing 1000 tons/day of the H_2 are as follows.

	Steam-methane reforming	Steam-oxygen process		CO_2-acceptor process
		Lignite	Bit. coal	
Fixed charges (15%)	33.5	26.3	28.7	37.1
Oxygen		30.8	27.4	
Power	16.5	8.3	7.4	18.1
Direct labor	1.6	1.0	1.0	1.3
Materials	18.3	9.5	8.5	10.7
Maintenance	13.3	14.3	15.7	20.2
Other utilities	5.7	1.4	2.6	1.5
Oper. allocation	5.3	4.1	4.3	5.5
General and administrative	5.8	4.3	4.4	5.6

Ultimate potential. Although we have assumed that hydrogen from coal would be an interim measure, the potential from coal is largely based on domestic coal reserves, particularly when lignite is also


ORNL-DWG 72-8474
STEAM METHANE REFORMING
T, H_2/day
250
500
1000
2500
¢/lb H_2
0
2
4
6
8
10
12
14
16
18
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
PRICE OF NATURAL GAS (¢/10^6 Btu)


CO_2 ACCEPTOR PROCESS
T, H_2/day
250
500
1000
2500
¢/lb H_2
0
2
4
6
8
10
12
14
16
¢/10^6 Btu
0
50
100
150
200
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
PRICE OF LIGNITE ($/short ton)

included. Consumption of bituminous coal and lignite in the United States in 1968 totaled 500 million short tons, very little of which was lignite. The U.S. Bureau of Mines estimates that total coal reserves to 3000 ft depth are 1.547 trillion tons plus an additional 1.3 trillion tons in unmapped and unexplored areas; in addition, 340 billion tons are estimated to be available at depths between 3000 and 6000 ft. Taking this total of known and implied reserves (3.2×10^{12} short tons) and assuming 50% recovery, the total usable reserve is about 1600 billion tons, of which at least 300 billion tons or 19% is lignite, located principally in western North Dakota. The resource to demand ratio (at the 1968 rate) for recoverable coal is thus about 3100 years; this value will, of course, decrease as demand increases. Total heat value of recoverable reserves is about 3.2×10^{19} Btu. United States energy consumption in 1968 was 6×10^{16} Btu, of which 1.3×10^{16} Btu or 22% was derived from coal.[26] By the year 2000 coal is estimated to contribute 28% of our total fossil fuel energy requirement of 0.13×10^{18} Btu; the cumulative (1968-2000) contribution is expected to be 26% of the total of about 3.3×10^{18} Btu. Depletion of recoverable U.S. coal reserves in this period would be about 2%. This is somewhat misleading, because continued exponential growth in requirements beyond the year 2000 would deplete remaining reserves very rapidly.

Under the worst case, if all coal, petroleum, and natural gas were replaced immediately by hydrogen fuel, 25 billion tons of hydrogen* would be required over the next 30 years; using an average of 9.7 tons of coal or lignite per ton of hydrogen, 250 billion tons of coal, representing 16% of recoverable U.S. reserves, would be consumed. Annual coal consumption by the year 2000 would be ∿1%/year (of recoverable reserves).

This example is, of course, an impossible one. If we assume a more rational demand in which about 7 to 8% of the total energy demand in the year 2000 is provided by hydrogen (1.2×10^{16} Btu), hydrogen production capacity would necessarily be 116 million tons/year requiring use of about one billion tons of bituminous coal or 1.4 billion tons of lignite. This capacity would require 137 of the largest (2500 tons/day)

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*Based on low heating value of 51,600 Btu/lb of hydrogen.

hydrogen plants described in the above section, representing a total capital investment in the order of 50 to 60 billion. Large as all these values are, they do not appear incapable of being achieved in the next 20 to 30 years.

Although we have regarded hydrogen production from coal as an interim measure, it must be realized that it is highly unlikely that commercial plants will be available before 1985, or 1980 at best. Since plant lifetimes less than 30 years seem unrealistic, even the first plants would not be phased out before 2010 to 2015. Thus it is imperative that ultimate longer-range systems such as nuclear-water electrolysis combinations be developed as rapidly as possible in order to prevent overly rapid depletion of our enormous but finite coal resources.

Aside from its poor location, lignite, as already noted, is the presently preferred feed for generation of hydrogen from coal. In addition, it is the solid fossil fuel with the lowest average sulfur content, 78% containing <0.8% sulfur. Assuming lignite contains an average of 30% ash and the ash contains 0.01% uranium, the total uranium content of recoverable U.S. lignite* reserves is 10 million tons, or more than three times free world reserves as summarized by the IAEA in 1970.[29] However, only about half of the contained uranium is believed to be recoverable. Inasmuch as most of the present supply of U.S. natural gas comes from a single area (the U.S. Gulf Coast), it is not inconceivable, with improved hydrogen pipeline systems, that hydrogen could also come chiefly from a centralized area.

Alternatively, hydrogen could also be produced from bituminous and subbituminous coal (but not anthracite coal) from a much larger number of areas. Disadvantages would include the use of a less desirable raw material, use of a generally higher sulfur content feed, and, in Appalachia and certain Rocky Mountain areas, environmental concerns with strip mining.

One possibility for the rational overall development of our coal resource could be as follows:

1. Convert the vast lignite deposits in North Dakota, etc., to hydrogen

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*Considerable uncertainty exists in the actual extent of the uranium-bearing lignite deposits.

and recover the uranium and other valuable minerals from the ash.

2. Transport the hydrogen via pipelines to the iron-ore deposits in northern Minnesota and Michigan for use in producing iron and in supplying general process heat to industry.
3. Transport the hydrogen by pipeline to Eastern coal fields for use in coal gasification to high-Btu pipeline gas.

Advantages from such a scheme would accrue from relatively low-cost and high-efficiency (80 to 90% recovery of the resource) surface mining of the lignite. The value of the uranium (and other minerals) recovered from the ash may cover part of the mining cost. Use of the resulting low-cost hydrogen to gasify the higher-cost underground mined Eastern coal results in using only one-third to one-half of the coal that would otherwise be required if the pipeline hydrogen were not available.* Also, of obvious advantage would be a reduction of air pollution levels by making available clean burning gaseous fuels.

Environment and resource effects. The use of the various coal-based processes to produce clean hydrogen fuel presents few environmental problems. These processes are nearly thermoneutral and hence present only minor thermal pollution problems. The dirty head-end operations of crushing, grinding, and drying coal and dolomite (CO_2-acceptor process) can easily be made environmentally acceptable by proper housing and ventilation. In the Synthane process nongaseous waste products include coal ash and char; the latter is available for use as fuel. In the CO_2-acceptor process the char is completely consumed, and only the ash must be disposed of. Both processes also produce CO_2 as a by-product (approximately 23 lb CO_2/lb H_2 produced).

The effect on total coal resources has already been discussed.

When lignite is used as feed, a very interesting possibility is the subsequent recovery of uranium from the waste ash, for which the technology already exists. The total uranium content of North Dakota lignite is many millions of tons. Thus lignite can do "double duty" as a fuel. Some lignite beds contain an average of 0.18% uranium and 45% ash; thus uranium content of ash is 0.40%, which is equivalent to good present-day uranium ore.[28] If we assume average lignite contains only

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*It may even be possible to consider underground coal gasification or liquefication using pipeline hydrogen and thus eliminate mining the deep coal beds.

30% ash and 0.003% (30 ppm) uranium, the amount of potentially recoverable uranium (at 50% recovery) is about 5 million tons, almost twice the free world reserves.[29] At $8/lb the maximum total value of recoverable uranium in U.S. lignite is $80 billion, or about 40¢/ton of lignite. In addition, lignite ash contains up to 0.3% Mo and smaller amounts of V, As, Ge, Se, Co, and Zr,[29] which are valuable by-products.

The only catalyst used in the process is the shift reactor catalyst, which was formerly iron oxide with small additions of chromium oxide; more recently there has been greater use of copper, chromium, and zinc oxides. Thus there seems to be no long-term resource problem for catalysts, particularly since it is always possible to fall back on use of the older type.

Safety and reliability. At this point it is difficult to predict the safety and reliability of full-scale plants to produce hydrogen from coal since the two processes discussed are just entering the pilot plant stage. However, by analogy to commercial reforming and partial oxidation processes using petroleum, and the shift process for converting carbon monoxide and steam to hydrogen and CO_2, safe operation has been experienced for many years.

The steam-oxygen and the Union Carbide processes are more adaptable to a variety of coal feeds than the CO_2-acceptor process although they also appear to work best with lignite. Loss of coal as by-product char is high (30% of the coal heat value); the Bureau of Mines believes addition of small amounts of limestone may increase hydrogen yield and minimize the sulfur content of the char to be used as fuel elsewhere.[27]

The CO_2-acceptor process has the advantage that gasification and the shift reaction both occur in the primary system and that this system is reportedly thermoneutral. The process is quite complex, however, and may be difficult to operate because it requires very close dynamic control of five fluidized beds.[27]

Research and development. If the use of coal to produce clean hydrogen (or methane) fuel is to be considered as an interim measure, the greatest research and development need is for very rapid scaleup of one or more of the alternative processes presently under development.