atory and bench-scale work on both the steam-oxygen processes and CO_2-acceptor process are well along, and pilot plants for both methods are now being built. We can only urge that this work be provided with sufficient funds and manpower to greatly accelerate the efforts so that demonstration plants can be started in the next few years.

Both processes are relatively inefficient in converting heat energy of coal to heat content of hydrogen, about 45 to 50% compared with 65% for synthetic methane. Similarly, neither process is as coal conserving as might be desired. Research leading to greater efficiency seems therefore in order.

Since oxygen is used in the steam-oxygen process mainly to supply heat for the highly endothermic carbon-steam reaction, use of nuclear heat should be evaluated as an alternative. This is particularly important if coal is to be conserved. The CO_2-acceptor process, since it is thermoneutral, is less likely to benefit from such an external heat source but does require heat to decompose the $CaCO_3$.

If coal does become a major source for our gaseous and liquid fuels, the problems associated with increasing production rates by a factor of from 5 to 10 are likely to be severe. Development of improved mining techniques or perhaps in-situ gasification processes should be given serious consideration.

3.3.2 Methanol

Earlier in this report (Sect. 3.2.2) methanol was discussed as a fuel in the context of its currently widespread manufacture from natural gas. Briefly again, that process consists of the reaction of natural gas with steam to obtain a synthesis gas containing carbon monoxide, carbon dioxide, and hydrogen, followed by the conversion of these reactants into methanol and water. The synthesis of methanol from coal will differ from the natural gas-based process only in the first step, that is, the preparation of a synthesis gas of carbon oxides and hydrogen. The conversion of synthesis gas to methanol is rather independent of the source of the synthesis gas, although the relative compositions of carbon monoxide, carbon dioxide, and hydrogen do have some effect. Therefore the preparation of a methanol synthesis gas from coal is the not yet commercialized technology needed to implement methanol from coal.

Fortunately, much work is being done to develop processes to obtain methane and/or hydrogen from coal to replace pipeline gas, and this technology is directly applicable to the production of methanol synthesis gas. The preceding section of this report described the manufacture of hydrogen from coal. There the reaction of steam and coal with the addition of heat result in a gaseous mixture containing carbon oxides and hydrogen. For hydrogen as the product, the carbon monoxide is further reacted with steam to get more hydrogen and carbon dioxide, and separation of the carbon dioxide leaves the product gas, 97 to 98% hydrogen. For methane as the product, the mixture of carbon oxides and hydrogen is converted in a different kind of reactor into methane and water, with the methane becoming pipeline gas. Again for methanol as the product, the synthesis mixture of carbon oxides and hydrogen can be reacted under still different conditions to produce methanol.

Much bench-scale and pilot-plant work has been done to date on the production of synthesis gas from coal, but no U.S. commercial plants have been built although some may be imminent. The economics and technology for synthesis gas from coal therefore are not well defined. Nevertheless, an estimate has been developed for the economics of methanol from coal and is presented in Table 5.* It should be noted that the information for this estimate was hastily developed and should be considered preliminary.

As shown in Table 5, the production cost for methanol has been estimated to be 8.51¢/gal. Of this amount 3.02¢/gal or about 35% is for coal when coal is available at $7/ton, or about 27¢/$10^6$Btu. The next largest cost item is 2.69¢/gal, or about 32% of the total, for capital cost. This capital cost charge to the product is undoubtedly low since the fixed charge rate of 15%/year barely covers depreciation, insurance, and taxes, and probably leaves inadequate return on investment, even for a public utility. Nevertheless, the 15%/year rate is used in order to

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*This estimate was developed with the assistance of Chemical Construction Corporation.

Table 5. Economics of synthesis of 20,000 tons/day of methanol (MeOH) from coal

			Cost		
Item	Unit	Units /day	$/unit	$/day	¢/gal MeOH
		Synthesis gas manufacture (Capital for plant: \$260 x 10^6)			
Coal[a]	Ton	26,000	7.00	182,000	3.02
Chemicals				1,000	0.02
Process water	10^3 gal	6,250	0.20	1,250	0.02
Cooling water	10^3 gal	346,000	0.02	6,920	0.11
Operating labor	Man-hr	960	4.00	3,840	0.06
Supervision				380	0.01
Maintenance				35,600	0.59
Overhead				4,220	0.07
Precapital manufacturing cost				235,110	3.90
Capital charges at 15%/year				106,800	1.77
Total cost				341,910	5.67 (99¢/10^6 Btu)
		Methanol synthesis from provided Syngas (Capital for plant: \$135 x 10^6)			
Steam	10^3 lb	38,200	0.65	24,800	0.41
Fuel	10^6 Btu	21,600	0[b]		
Electricity	kWhr	100,000	0.01	1,000	0.02
Cooling water	10^3 gal	540,000	0.02	10,800	0.18
Catalyst and chemicals				15,000	0.25
O&M labor and supervision				50,000	0.83
Overhead				14,000	0.23
Precapital manufacturing cost				115,600	1.92
Capital charges at 15%/year				55,400	0.92
Subtotal				171,000	2,84
Total cost				512,910	8.51 (148¢/10^6 Btu)

[a] Combined raw material and fuel.

[b] Purge gas from synthesis gas plant.

be consistent with the other economic estimates in this report. The other cost elements for methanol from coal are relatively minor. Both the manufacture of synthesis gas from coal and the manufacture of methanol from synthesis gas are patented processes requiring a royalty fee. Little information is available about these fees, although in one instance the license for the synthesis of methanol from gas required a one-time fee of about 1.4% of the plant capital cost.

The plant size of 20,000 tons/day was arbitrarily chosen as providing methanol equivalent in heating value to that of the gasoline produced by a 160,000-bbl/day petroleum refinery. Refiners are increasingly moving to refineries of this size, presumably in response in part to the trade-off between size of marketing territory and capital economies of scale. Actually, there appears to be little or no economy of scale for synthetic methanol plants much beyond a size of 4000 tons/day, and so 20,000 tons/day may be nonoptimum. Optimization of size would, of course, require additional systems analyses.

The environmental effects of plants making methanol from coal should be no different than the combined effects of plants making hydrogen from coal or methanol from natural gas. The environmental effects of these plants have been described in earlier sections of this report.

Intensified research and development in the manufacture of synthesis gas from coal is in order. The uncertainties of the economics and technology for methanol from coal are predominantly in the preparation of the synthesis gas. It should again be noted that coal-derived synthesis gas can be used for hydrogen, methane, gasoline, and chemicals in addition to methanol. If, as a result of this overall study of synthetic fuels, methanol evolves as one of the most attractive synthetics, then a more rigorous engineering and economic study of methanol from coal should be performed.

4. STORAGE AND TRANSPORTATION OF SYNTHETIC FUELS

The technology and practice of storage and transportation of the major candidate "synthetic" fuels have been extensively developed and demonstrated on a significant scale. Hydrogen gas is being produced and distributed in and among refineries under conditions that would simulate a fuel gas production and distribution system. There are, however, no existing hydrogen transmission or distribution systems in which booster compressors are utilized. Liquid hydrogen equivalent to over 100 billion ft^3 (stp) has been produced and distributed in support of the space program. Production of ammonia for fertilizer has reached a scale of distribution in which large interstate pipelines are now operating in addition to the extensive barge, rail, and truck systems that have been built to achieve economical distribution. Because of the seasonal nature of agricultural chemicals supply, large storage complexes have also been developed. Methanol has long been a basic tonnage petrochemical and distribution by all means has been fully developed.

4.1 Storage of Fuels

The estimated investment for storing energy in the form of a synthetic fuel is given in Table 6 and illustrated in Fig 9. The storage of gaseous hydrogen in pressure vessels appears to be hopelessly noncompetitive for the full range of storage capacity. This is due to the combination of low specific volume of the gas and the high cost of the pressure vessel. The adaptation of gaseous storage might be enhanced by using the transmission line as an inventory device (line packing). Table 7 shows a comparison of the energy storage capacity of 300 mile-long transmission lines of various inside diameters between 1 and 3 feet holding hydrogen at 1000 psia. The table lists the equivalent weight of hydrogen in pounds, equivalent gallons of liquid hydrogen, the number of megawatt hours in a water electrolysis plant

	Fuel volume		Unit investment	Approximate specific energy content of fuel and container	
	10^6 Btu	1000 ft	($\$/10^6$ Btu)	Btu/lb	10^6 Btu/ft^3
Gaseous hydrogen[a]	2[b]	0.046	750.	1,200	0.4
	50[b]	0.16	720.		
	14,300[c]	866.	350.		
Liquid hydrogen	2	0.009	1000.	8,000	0.14
	50	0.220	300.		
	36,000	158.6	26.		
Hydrogen as magnesium hydride			160.[d]	> 5,000	> 0.25
Ammonia	2	0.006	85.		
	50	0.147	10.	6,000	0.25
	552,000	1619.	2.9		
Liquefied natural gas	2	0.004	350.		
	50	0.090	140.	6,700	0.35
	2,100,000	3770.	3.5		
Methanol	2	0.005	18.		
	50	0.117	3.	8,000	0.51
	604,000	1413.	0.8		
Gasoline/fuel oil	2	0.002	15.	16,000	0.95
	50	0.060	2		
	1,370,000	1638.	0.4		

[a] Very large underground storage in aquifers or plowshare caverns is projected to cost \$3 to $\$6/10^6$ Btu.

[b] 2400-psig tank.

[c] Mined cavern, 900 psig.

[d] Magnesium at 40¢/lb, no container or heat exchanger included. (This system is currently unproven.)

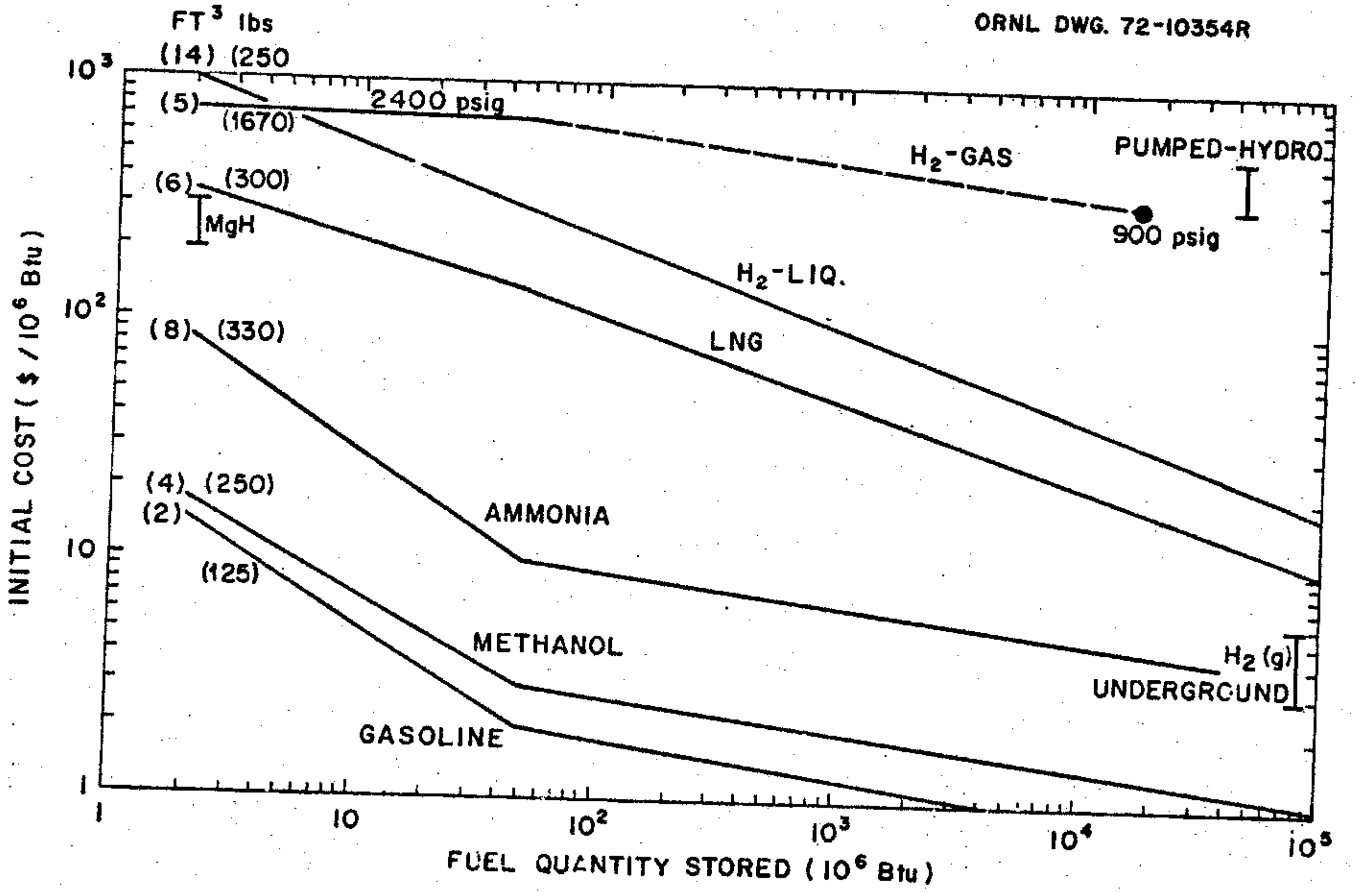
ORNL DWG. 72-10354R
FT^3 lbs
(14) (250
(5) (1670)
2400 psig
H$_2$-GAS
PUMPED-HYDRO
900 psig
(6) (300)
MgH
H$_2$-LIQ.
LNG
(8) (330)
AMMONIA
(4) (250)
(2) (125)
METHANOL
GASOLINE
H$_2$ (g)
UNDERGROUND
INITIAL COST ($ / 10^6 Btu)
1
10
10^2
10^3
10^4
10^5
FUEL QUANTITY STORED (10^6 Btu)

Table 7. Energy storage capacity of a 300-mile transmission line of various inside diameters holding hydrogen at 1000 psia

	Pipe diameter		
	1 ft	2 ft	3 ft
Weight of hydrogen, lb	0.42×10^6	1.68×10^6	3.78×10^6
Equivalent gallons of liquid hydrogen	0.72×10^6	2.9×10^6	6.5×10^6
Energy required to fill the line to 1000 psia, MWhr	84×10^3	33.6×10^3	75.6×10^3
Energy available after combustion, Btu (lower heating value)	22×10^9	88×10^9	197×10^9

required to fill the line, and the total combustion heat available at the lower heating value of hydrogen. If transmission lines can be designed to operate at a variable pressure (e.g. 500 to 1000 psia), these lines would represent a significant storage capacity. If gaseous hydrogen is the preferred working medium, evaluation of gaseous storage systems such as mined or plowshare type caverns, aquifers, depleted gas wells, or undersea bladder devices should all be investigated to determine the feasibility and likely extent of their employment. An aquifer storage system at Baynes, France, has been in operation for over ten years, first with manufactured gas and now with natural gas. It has a capacity of 7 x 10^6 ft^3 at 570 psia.

Liquid hydrogen storage has been practiced in volumes up to 1,000,000 gallons. Because of the extremely low temperature of liquid hydrogen, use of premium insulation and the low specific volume will cause a much higher unit storage cost for liquid hydrogen than is experienced in conventional hydrocarbon systems. It should be recognized that the storage costs, particularly for the smaller volumes, are based on present technology and production techniques. With further development and use of mass production systems, it is expected that the values shown for the unconventional types should decrease by as much as a factor of 2.

The cost of a compression and/or liquefaction system should be added to the cost of storage in assessing the utility of hydrogen energy systems. The cost of hydrogen gas compression might typically be 15¢ to 50¢ per 10^6 Btu (0.8 to 2.6¢/lb) for a wide range of delivery pressures and equipment utilization factors. The cost of hydrogen liquefaction might typically be $1 to $2 per 10^6 Btu (5.2 to 10.4¢/lb) for a wide range of system capacities and utilization factors. The electrical power requirement alone is about 5 kWhr/ lb H_2. These costs are usually more significant than tankage costs and must be considered in the design and evaluation of liquid hydrogen storage systems.

Evaporation losses from large liquid hydrogen storage systems (typically ∿0.03%/day) make their feasibility on a small scale questionable. If hydrogen matures as the energy source, a new portable storage system will likely be required. If hydrogen could be reversibly stored as a hydride at near the density of liquid hydrogen and if it could be made available at a moderate pressure, the chances are excellent that a practical fuel tank can be developed. Several hydride storage systems have been investigated which indicate that a large number of binary and tertiary metal systems are available for this use. Magnesium and alloys of Mg and Cu or Ni[30] will release H_2 at 1 atm at temperatures of from 440°F to 540°F. Also some intermetallic compounds of the composition AB_5,[31] where A is a rare-earth metal and B is nickel or cobalt, are reported to absorb and desorb large quantities of hydrogen at near room temperature. There are also some possible applications where two or more different hydride systems can be used in a hydrogen liquefaction system.

Ammonia, methanol and LNG storage systems are well developed for use in industry and are unlikely to see significant cost reductions. Ammonia/LNG storage systems are costly relative to systems for storing unpressurized liquids. In addition, adaptation of the equipment from industrial to consumer type operation introduces additional problems. These fuels can, however, be considered as a means for storing hydrogen since, in particular, NH_3, N_2H_4, and CH_3OH can be readily decomposed to yield H_2. The hydrogen density in these compounds is from 1.5 to 2.0 times that of liquid hydrogen. Still lower effective heating values would, however, result since the heat of dissociation must be supplied.

4.2 Transportation of Fuels

The comparison of the characteristics of the various candidate synthetic fuels as a medium of energy transport, particularly with reference to commercially practiced energy transfer, is difficult to generalize on. In selecting among the various methods of energy transfer, the following items must be analyzed to select the optimum system.

1. the specific routing, particularly with regard to detours to avoid restricted right-of-way or costly crossings such as navigable

waterways;

2. the carrying capacity of the system;

3. the degree of utilization of the system;

4. the cost of overcoming resistance losses and its effect on arriving at an optimum design;

5. the efficiency of the energy conversion devices which will operate on the transferred energy.

A detailed analysis of these factors for a particular logistic problem can produce different selections for an optimum energy transmission system.

Table 8 presents some generalized nonoptimized information which attempts to compare the major candidate energy transportation methods. These comparisons are near the largest energy transmissions systems practicable for that candidate form in a <u>near-urban</u> environment. The results of this type of analysis, although not directly comparable, show that many methods of energy transfer are competitive subject to the above considerations. Therefore, as a result of any detailed systems analysis, it is not likely that the transportation of energy alone will be decisive in the selection of an optimum energy distribution system or medium. While Table 8 shows only relative pipeline transmission costs, some recent analyses by the Institute of Gas Technology[32] give absolute cost estimates for transporting natural gas and hydrogen. An average cross-country cost for natural gas transmission today is reported to be 1.5¢ to 1.7¢/10^6 Btu per 100 miles. Hydrogen transmission cost would be 2.6 times this cost since compressor size and horsepower must be considerably increased and a more expensive fuel (hydrogen) used to power the compressors. By increasing the pipeline operating pressure from the "usual" 750 psia to 2000 psia, this factor could be reduced to about 1.5.

The advantage in pipelining fuels is the ability to scale this type of system up to very large capacities with the resultant effect of the economy of scale being to lower unit-energy transfer cost. The use of pipeline transport of energy will therefore be superior for the transmission of energy over long distances and/or transmission of very

Table 8. Energy transmission — relative transportation costs (near-urban environment)

	Volume (10^6 Btu/hr)	Size	Investment per 100 miles (10^6\$)	Total cost, operating plus investment[a] per 100 miles (¢/10^6 Btu)
H_2 gas	21,000	36-in. pipe	68[b,c]	5.7[c]
NH_3	21,000	36-in. pipe	62[b,c]	5.0[c]
CH_3OH	21,000	30-in. pipe	52[b,c]	4.2[c]
Natural gas	21,000	36-in. pipe	62[b,c]	5.1[c]
H_2 Liquid	550	3-in. pipe	79[d]	250.0
H_2 Liquid	1,800	1,150,000-gal barge	2.4	6.9
H_2 Liquid	62	13,000-gal trailer	0.15	34.0
Electric (superconducting line)	13,600	4,000-MVA line	140	19.3
Electric (aboveground)	8,500	2500 MW, 750 kV	30	8.3
Electric (belowground)	8,500	2500 MW, 345 kV	~300	~100

[a] Unit cost assumption: 100% utilization of facility, 15% = fixed charge rate (depreciation, interest, return on investment), operating power 6 mills/kWhr.

[b] Reported pipeline costs can vary by as much as a factor of 4, depending on terrain, congestion, etc.

[c] For cross-country straight lines, 50% reduction is likely.

[d] No reliquefaction included.

large blocks of energy. Relative to natural gas, the volumetric flow of hydrogen must be quite high because of its low specific heat content, although the low molecular weight compensates considerably, resulting in similar system performance. The primary penalty in transmitting hydrogen over methane is the increased cost of recompression, which amounts to a relatively small fraction of the cost of a transmission system in a near-urban environment. This penalty may be offset by the potential efficiency gain of hydrogen energy conversion devices and the resultant flow decreases in the hydrogen energy transmission system. An area of concern in the transmission of hydrogen, however, is in the admission of this gas into older existing mains since the leakage coefficient is three to six times that of methane. Techniques of sealing older natural gas systems would therefore have to be developed to avoid their total replacement in transition to use by hydrogen.

Pipeline transport of liquid hydrogen is by far too costly to be a competitive method of energy transport except over very short distances or for transfer of energy blocks very much larger than that which is practiced today. However, where it might be practicable to transmit electricity via cryogenic or superconductive cable, simultaneous transmission of liquid hydrogen through the cryogenic power conduit could alter even this conclusion.

From the above, although some generalizations are apparent, it is not possible to clearly identify a superior mode of energy trancport. This can only be accomplished after a detailed systems and engineering analysis and after giving due consideration to the synergistic benefits of combining several forms of energy transport.

4.3 Safety

Industry's safety record in handling the candidate synthetic fuels has been impressive. However, additional consideration concerning the safe handling of certain fuels would be necessary before they could be made generally available to the public. Properties of special concern to the designer of safe hydrogen systems include its high diffusivity and low ignition energy.[33] For ammonia systems, toxicity and corrosivity are properties of concern.

4.4 Research and Development

The research and development needs within the fuel storage and transportation field are being covered to a considerable extent within the industrial sector. Some of the items which should be considered for future support include:

1. development of hydride storage systems;
2. handling of hydrogen and hydrogen-hydrocarbon mixtures in gas pipelines (this would include research into long-term hydrogen metal interactions, particularly hydrogen environment embrittlement);[34]
3. techniques for insuring consumer safety;
4. large-scale hydrogen gas and liquid storage.

5. USE OF SYNTHETIC FUELS

This section will consider the end use of hydrogen and derivative synthetic fuels in the major energy sectors of the U.S. economy: namely, industrial, urban, transportation, and electricity generation. The discussion of industrial utilization includes uses both as a fuel and as a chemical reagent.

The use of oxygen, often a co-product of hydrogen production, is discussed only to a limited extent. It is nevertheless recognized that finding productive, economic uses for oxygen can have a large impact on the viability of the "hydrogen economy." Oxygen does have many uses, and the demand is continuing to increase. Since it is relatively simply produced from air, it is not generally transported long distances, so that the use point is usually near the place of production.

5.1 Hydrogen

5.1.1 Industrial uses of hydrogen

At present, use of hydrogen as a fuel outside the U.S. space program is almost nil, but its chemical uses are large and growing. Of the 2.06×10^{12} ft^3(5.8 million tons) consumed commercially in 1968,[26] 42% (870×10^9 scf) was used for ammonia synthesis, 38% (775×10^9 scf) in petroleum refining, and 20% (413×10^9 scf) for other uses including synthesis of methanol, naphthalene, cyclohexane, benzene, analine, aldehydes, and hydrochloric acid, and for hydrogenation of unsaturated fats and oils. Small amounts were also used as a metallurgical reductant. By the year 2000 median U.S. consumption (for nonfuel uses) is expected to be 9.1×10^{12} ft^3 ; ammonia synthesis is expected to account for 34% of total use; petroleum refining, 50%, and other uses, 16%. The uncertainty in the total annual use in the year 2000 is nearly an order of magnitude. This large uncertainty is based mainly on the difficulty of estimating how much coal and shale oil may be converted annually to liquid and gaseous fuels by that time and, to a lesser extent, on how extensively it will be utilized in conventional petroleum refining processes and how great a shift occurs in use of hydrogen in lieu of carbon as a metallurgical reductant. Typical hydrogen requirements in its major present and future industrial applications are summarized in Table 9.

Ammonia synthesis. Over two-thirds of all the ammonia consumed in the U.S. is used directly or indirectly as fertilizer in agriculture; the remainder is used in petrochemical synthesis, in inorganic chemicals and plastics manufacture, as a refrigerant, and in a variety of smaller uses. The current U.S. ammonia production capacity is estimated to be 20 x 10^6 tons/year and is projected to be about 30 x 10^6 tons by 1985. The natural gas requirement for the projected 1985 production will be about 1 X 10^{12} ft^3. In terms of hydrogen usage, this production rate would require about 12,000 tons/day of hydrogen capacity.

Petroleum refining and petrochemical production. Hydrogen is used in two ways in petroleum refining: (1) in hydrotreating (using catalytic reforming) for desulfurizing petroleum feedstocks, for hydrogenating olefins and other unsaturated hydrocarbons, for producing cyclic compounds such as cyclohexane, and in treating lube oils and kerosine-base jet fuels, and (2) in hydrocracking heavy petroleum fractions to produce lighter grades, principally gasoline. In fact, about half of all petroleum currently processed in the United States is so converted to gasoline. As indicated in Table 9, the hydrogen requirement (per bbl) for hydrocracking is about ten times that for hydrotreating. Use of hydrogen in petroleum refining is expected to increase rapidly in the future and to surpass the amount used for ammonia synthesis before 1980. About 15% of total hydrogen consumption is currently used in petrochemical production. The largest use is in methanol production (see Section 3.2); about 35 to 40% of this production is then converted to formaldehyde.

Coal gasification. Although coal would likely be used in the near term to produce hydrogen via the steam-carbon reactions, it may be that

Table 9. Typical Industrial Hydrogen Requirements

Use	Standard cubic feet/unit of product
Ammonia synthesis	70,000-80,000/short ton of NH_3
Methanol synethesis	36/lb of CH_3OH
Petroleum refining (Ave.)	$\leq$610/bbl crude oil
Hydrotreating	
Naphtha	50/bbl
Coking distillates	750/bbl
Hydrocracking	2000-2500/bbl
Coal conversion to -	
Liquid fuels	6000-7000/bbl synthetic oil
Gaseous fuel	~1560/1000 scf synthetic gas
Oil shale conversion to -	
Liquid fuel	1300/bbl synthetic oil
Gaseous fuel	1200/1000 scf synthetic gas
Iron ore reduction	20,000/short ton of iron
Process heat	$3070/10^6$ Btu
or	~$2700/10^3$ lb process steam
Municipal solid wastes conversion	$1870/10^3$ scf methane

for some applications methane would be a more desirable product. In this case hydrogen is required to react with CO and, if an external source of economic hydrogen is available, it could be used for this purpose instead of using coal to produce the hydrogen. In this case coal would be partially oxidized, perhaps with by-product electrolytic oxygen, to CO and then converted to methane. An alternative process, hydrogasification, may be used wherein hydrogen is reacted directly with carbon at high temperatures to produce methane. To illustrate the amount of coal which could be conserved by this process, Ref. 36 shows that the production of 250 X 10^6 scfd of high-Btu gas via the M. W. Kellogg process, which does not require an external source of hydrogen, uses 13,200 tons/day of coal. The same amount of gas could be produced utilizing an external source of hydrogen from only about 4500 tons/day coal. Thus, perhaps under some circumstances, coal gasification could become a very large user of hydrogen.

Metallurgical uses of hydrogen. Use of hydrogen as a metallurgical reductant in lieu of carbon (coke) has long been known to be feasible; however, only very limited use has been made of this technology so far. Since the production of iron (89 million tons in 1968) far outshadows the production of all other metals combined, hydrogen reduction of iron ore is of greatest significance in this area. Several processes have been developed, but none are yet economically competitive with the conventional blast furnace.[37] It was estimated by the U.S. Bureau of Mines that by the year 2000 production of about 30 million tons of iron using 600 billion ft^3 of hydrogen may be feasible.* Use for nonferrous metallurgy (copper, zinc, and lead) is equally feasible but would be less hydrogen consuming, both per unit of output and in total. The incentives to use hydrogen as the iron ore reductant would appear to be:

1. Flexibility in plant location and size: The iron-ore could be reduced at the mine mouth using pipeline hydrogen. Also size scaling economics do not appear to be as strong for H_2-reduction as for blast furnace plants.
2. Coke is becoming scarce.
3. Pollution problems with coke production and blast furnace operation

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*Equivalent to a hydrogen production rate of about 4400 tons/day.

are essentially eliminated. Reduction of oxide ores in fluidized beds would result in the production of only water and slag. Reduction of sulfide ores (copper, lead, zinc, nickel, etc.) would produce hydrogen sulfide which could be oxidized to sulfur for storage in its innocuous form.

Process heat/steam. High-pressure hydrogen available at a reasonable cost from a pipeline network is likely to find wide use in providing industrial furnace heat and process steam. Heat used in industry represents about one-third of the total energy consumed in the U.S., and there appears to be no basic restriction to the substitution of hydrogen for other fuels for this use. In fact, the use of hydrogen could eliminate a large part of the atmospheric pollutants contributed by this sector. An example of the impact of the use of hydrogen follows:

1. For the year 2000 it is estimated that about 12 x 10^{15} Btu as methane (NG + SNG) will be used by industry for miscellaneous heat.
2. If half of this use is met by hydrogen, it would require hydrogen production facilities of about 160,000 tons/day which in turn would require, for the electrolytic production route, a power capacity of 290,000 MWe.

If a dual pipe (hydrogen and oxygen) system were available or, as dictated by economic tradeoffs, oxygen from an air liquefaction plant, process steam could be produced directly. With this arrangement, a simple pipe-combustor-attemporator would be substituted for the current massive water tube steam generators. Thus, considerable savings in capital and other resources at this point may be realized, and at the same time no gaseous effluents* would be released to the environment. For example, in 1970 alone an industrial steam boiler capacity of 68 x 10^6 lb/hr (861 units)[38] was sold, representing an investment of about \$400 x 10^6 . If this market grows at a rate of 4%/year by the year 2000 the annual sales will be 220 x 10^6 lb/hr boiler capacity (∿ \$1.3 billion). To supply half this demand would require a hydrogen production capacity of about 23,000 tons/day.

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*Waste heat release would be less due to no, or less, stack losses — also, the pure warm water produced by hydrogen combustion may find many productive uses.