

PROSPECTS FOR BUILDING A HYDROGEN ENERGY INFRASTRUCTURE

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■ **Abstract** About two-thirds of primary energy today is used directly as transportation and heating fuels. Any discussion of energy-related issues, such as air pollution, global climate change, and energy supply security, raises the issue of future use of alternative fuels. Hydrogen offers large potential benefits in terms of reduced emissions of pollutants and greenhouse gases and diversified primary energy supply. Like electricity, hydrogen is a premium-quality energy carrier, which can be used with high efficiency and zero emissions. Hydrogen can be made from a variety of feedstocks, including natural gas, coal, biomass, wastes, solar sources, wind, or nuclear sources. Hydrogen vehicles, heating, and power systems have been technically demonstrated. Key hydrogen end-use technologies such as fuel cells are making rapid progress toward commercialization. If hydrogen were made from renewable or decarbonized fossil sources, it would be possible to have a large-scale energy system with essentially no emissions of pollutants or greenhouse gases. Despite these potential benefits, the development of a large-scale hydrogen energy infrastructure is often seen as an insurmountable technical and economic barrier. Here we review the current status of technologies for hydrogen production, storage, transmission, and distribution; describe likely areas for technological progress; and discuss the implications for developing hydrogen as an energy carrier.

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INTRODUCTION

Motivations for Developing Hydrogen as a Fuel

Combustion of fluid fuels for transportation and heating contributes over half of all greenhouse gas emissions and a large fraction of air pollutant emissions. Continued reliance on current fuels and end-use technologies poses significant challenges in air pollution, greenhouse gas emissions, and energy supply security, particularly in the transportation sector.

A variety of alternative fuels have been proposed to address these problems, including methanol, ethanol, methane, synthetic liquids from natural gas or coal, and hydrogen. Of these, hydrogen offers perhaps the greatest potential benefits in terms of reduced emissions of pollutants and greenhouse gases and diversified primary energy supply, but it is widely perceived as posing the largest technical and economic challenges.

Like electricity, hydrogen is a high-quality energy carrier, which can be used with very high efficiency and zero or near-zero emissions at the point of use. It has

been technically demonstrated that hydrogen can be used for transportation, heating, and power generation, and it could replace current fuels in all their present uses. Low-temperature fuel cells, which operate on hydrogen or hydrogen-rich gases, are undergoing rapid development worldwide for stationary power and vehicle applications, with commercialization planned within the next 5–10 years (1). Eight major automakers have announced plans to commercialize fuel cell vehicles in the 2004–2005 timeframe. If low-cost fuel cell vehicles were successfully developed, this could encourage greater use of hydrogen.

Hydrogen can be made from a variety of widely available feedstocks, such as natural gas, coal, biomass, wastes, solar resources, wind, and nuclear resources. If hydrogen could be made from nonfossil energy sources or decarbonized fossil sources with separation and sequestration of CO₂, it would be possible to have a large-scale energy system with essentially no emissions of air pollutants (e.g. nitrogen oxides, sulfur oxides, particulates, and hydrocarbons) or greenhouse gases during fuel production or use.

The idea of a “hydrogen economy” or large-scale hydrogen energy system has been explored several times, first as a complement to a largely nuclear electric energy system (where hydrogen was produced electrolytically from off-peak nuclear power) and later as a storage mechanism for intermittent renewable electricity, such as photovoltaics and wind power (2–5). More recently, the idea of a hydrogen energy system based on production of hydrogen from fossil fuels with separation and sequestration of byproduct CO₂ has been proposed (6–8).

Despite the potential attractions of a zero-emission hydrogen energy economy, the development of hydrogen energy infrastructure is often seen as an insurmountable technical and economic barrier to the use of hydrogen as an energy carrier. The prevailing wisdom is that development of a hydrogen infrastructure will cost many times more than developing such a system for a liquid fuel.

In this article, we review the current technical and economic status of technologies for hydrogen production, storage, transmission, and distribution and describe likely areas for technological progress. We estimate the cost of developing a hydrogen infrastructure, as compared with other alternatives. Finally, we discuss possible scenarios for developing hydrogen as an energy carrier. Emphasis is given to use of hydrogen fuel in transportation markets, although hydrogen can be used for electricity generation or cogeneration as well.

Definitions and Underlying Assumptions

A hydrogen energy infrastructure is defined as the system needed to produce hydrogen, store it, and deliver it to users. This includes hydrogen production systems (for converting primary-energy sources or other energy carriers to hydrogen), hydrogen storage capacity (needed to match time-varying fuel demands to production output), long-distance transmission systems (if hydrogen is to be transported long distances from the production site to users), local pipeline distribution systems (analogous to a system of natural gas utility pipes), and equipment for dispensing

hydrogen to users (for example, hydrogen compressors and dispensers at vehicle refueling stations).

Development of Markets for Hydrogen Energy

Although hydrogen infrastructure rather than hydrogen end-use systems is the focus of this review, successful commercialization of hydrogen end-use systems, such as fuel cell vehicles or fuel cell heat and power systems, is a key precondition for the development of a hydrogen infrastructure.

What will drive adoption of hydrogen rather than other alternative transportation fuels? There are a variety of advanced vehicle/alternative-fuel combinations that have the potential to significantly improve fuel economy and reduce fuel cycle emissions, as compared with current vehicles. These include fuel cells, hybrid internal combustion engine-/battery-powered vehicles, and electric battery-powered vehicles.

Recent studies comparing future transportation alternatives suggest that fuel cell vehicles are a promising technology for meeting future goals for zero tailpipe emissions, high efficiency, good performance, and low cost in mass production (9). Advanced diesel/battery hybrids might also achieve high efficiency and acceptable cost, but currently emissions remain an issue, especially regarding particulates (9). (Development of new, low-sulfur fuels for diesel engines may help ameliorate this problem.) Although it is too early to "pick a winner" among emerging advanced transportation technologies, fuel cells are regarded as a leading contender.

It is possible that fuel cell-powered vehicles will be commercialized first with onboard fuel processors (to produce hydrogen for the fuel cell from other more easily handled fuels such as methanol or gasoline), rather than with hydrogen stored directly onboard. However, hydrogen fuel cell-powered vehicles are likely to be lower cost and more efficient than those with onboard fuel processors (10, 11). The lower first cost of the hydrogen fuel cell-powered vehicle and its higher efficiency combine to give a lower lifecycle cost than fuel cell-powered vehicles run on liquid fuels. If fuel cell vehicles become widely used, there is reason to believe that the market will move toward hydrogen as a fuel.

Another possible market for hydrogen is in combined heat and power applications in buildings. It has been suggested that fuel cells could become competitive in these markets first, where cost barriers are less stringent than for automotive markets. Initially, hydrogen for fuel cells would be made in natural gas reformers coupled to the fuel cells. Eventually, hydrogen might be made centrally and distributed to users in buildings. Fuel cell power systems could be made in small sizes, making them potentially attractive for distributed generation.

The possibility of separating and sequestering carbon during production of hydrogen from fossil fuels is another unique potential benefit of a hydrogen energy system. Other fossil-based synthetic fuels, such as methanol or synthetic middle distillates, carry fossil carbon in the fuel, and it is eventually emitted into the atmosphere from the vehicle, which would limit the extent to which greenhouse

gas emissions could be reduced. Hydrogen production with sequestration of CO_2 gives a lever to reduce carbon emissions in the transportation sector, without curtailing the future use of fossil resources.

Units for Hydrogen Production and Use

Hydrogen production capacity is usually given in units of standard cubic feet (scf) produced per day, normal cubic meters (Nm^3) per day, gigajoules per day, or kilowatts of hydrogen output (on a continuous basis). In this paper, specific capital costs for production plants are expressed as dollars (\$) per kilowatt of hydrogen output capacity. All energy and power units are given, based on the higher heating value (HHV) of hydrogen.

Hydrogen storage capacity is given in volume units (scf or Nm^3), in tons, or in energy stored (gigajoules). Capital costs for storage are given in \$ per ton of hydrogen stored or \$ per gigajoule stored.

In this paper, the levelized cost of hydrogen production, transmission, or storage is given in \$ per gigajoule of hydrogen on a higher heating value basis. ($1 \text{ GJ} = 10^9 \text{ J} = 0.95 \text{ million Btu.}$)

Table 1 contains useful conversion factors for relating these units to others and also contains physical properties of hydrogen and other fuels.

To relate rather unfamiliar hydrogen production units (millions of scf/day) to more familiar quantities, we show, in Table 2, typical energy demands expressed in scf of H_2 per day and gigajoules per day, ranging from hydrogen required for one

TABLE 1 Conversion factors and economic assumptions^a

1 GJ = 10^9 J = 0.95 million Btu
1 EJ = 10^{18} J = 0.95 quadrillion (10^{15}) Btus
1 million standard cubic feet (scf) = 26,850 normal cubic meters (Nm^3) = 343 GJ (HHV)
1 million scf/day = 2.66 tons/day = 3.97 MW of H_2 /day (based on the HHV of hydrogen)
1 scf of H_2 = 343 kJ (HHV) = 325 Btu (HHV);
1 pound of H_2 = 64.4 MJ (HHV) = 61.4 kBtu (HHV) = 187.8 scf
1- Nm^3 = 12.8 MJ (HHV); 1 kg of H_2 = 141.9 MJ (HHV) = 414 scf
1 gallon of gasoline = 130.8 MJ (HHV) = 115,400 Btu/gallon (LHV)
Gasoline heating value = 45.9 MJ/kg (HHV) = 43.0 MJ/kg (LHV)
\$1/gallon of gasoline = \$7.67/GJ (HHV)
1 gallon of methanol = 64,600 Btu/gallon (HHV) = 56,560 Btu/gallon (LHV)
Methanol heating value = 22.7 MJ/kg (HHV) = 19.9 MJ/kg (LHV)
\$1/gallon of methanol = \$15.4/GJ (HHV)

^aAll costs are given in constant 1995 dollars.

The capital recovery factor for hydrogen production systems, distribution systems, and refueling stations = 15%.

TABLE 2 Hydrogen demand and supply: scales of interest^a

Demand	H ₂ flow	
	Standard cubic feet/day	(GJ/day)
1 fuel cell car (driven 11,000 miles/year)	109	0.038
1 fuel cell bus (driven 50,000 miles/year)	8000	2.7
10 fuel cell buses	80,000	27
100 fuel cell buses or 7000 fuel cell cars	800,000	270
1% of cars in the Los Angeles Basin	9 million	3200
H ₂ production at large refinery	100 million	34,300
10% of cars in the Los Angeles Basin	90 million	32,000
100% of cars in the Los Angeles Basin	900 million	320,000
Energy flow = NG flow in the Los Angeles Basin	9 billion	3,000,000

^aValues in the table have been rounded.
It is assumed that a hydrogen fuel cell car has an average fuel economy of 106 miles/gallon of gasoline equivalent.

fuel cell-powered car to that required for a modest-sized fleet to full-scale use of hydrogen in transportation markets. Hydrogen production systems are also shown. A typical refinery-scale steam methane reformer (SMR) producing 25–100 million scf/day could fuel a fleet of ~225,000–900,000 hydrogen fuel cell-powered cars. A small-scale SMR or electrolyzer rated at 0.1–1.0 million scf/day could fuel a fleet of 900–9000 hydrogen fuel cell cars or 14–140 buses.

HYDROGEN PRODUCTION

Hydrogen is made at large scale today (mostly from natural gas) for use in chemical processes such as oil refining and ammonia production. About 1% of U.S. primary energy use (~5% of U.S. natural gas use) goes to hydrogen production for chemical applications. A variety of hydrogen production processes are commercially available today, including thermochemical methods, which are used to derive hydrogen from hydrocarbons, and electrolysis of water, during which electricity is used to split water into its constituent elements, hydrogen and oxygen. Future potential methods of hydrogen production involving direct conversion of sunlight to hydrogen in electrochemical cells or biological hydrogen production are being researched at a fundamental-science level.

In this section, we describe methods of hydrogen production, the current status of and projections for technical progress, and its economics, including capital costs for production equipment, conversion efficiency, and the levelized cost of hydrogen production.

Thermochemical Production Methods

Hydrogen is made thermochemically by processing hydrocarbons (such as natural gas, coal, biomass, or wastes) in high-temperature chemical reactors to make a synthetic gas or “syngas,” composed of H_2 , CO , CO_2 , H_2O , and CH_4 . The syngas is further processed to increase the hydrogen content, and hydrogen is separated out of the mixture at the desired purity. Figure 1 shows process steps for typical hydrogen production plants based on thermochemical methods.

1. Steam Reforming of Methane Catalytic steam reforming of methane (the main component of natural gas) is a well-known, commercially available process

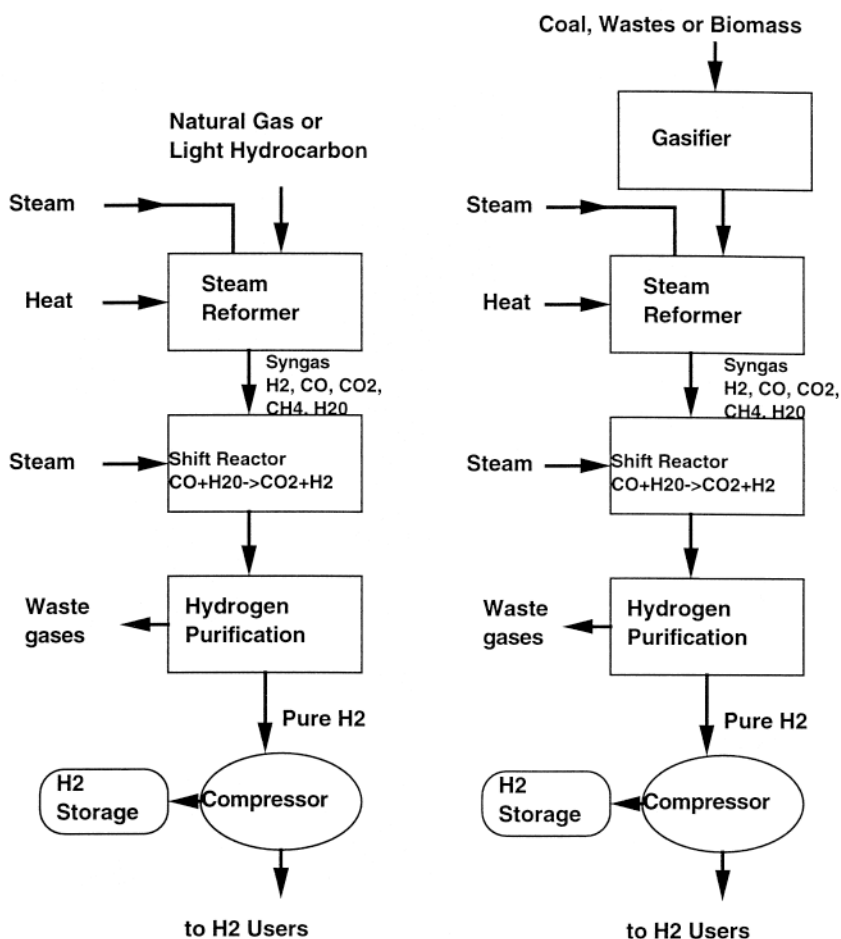
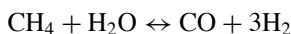


Figure 1 Thermochemical processes for producing hydrogen.

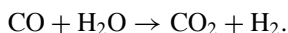
for hydrogen production (12, 13). In the United States, most hydrogen today (>90%) is manufactured via steam reforming of natural gas (14). Hydrogen production is accomplished in several steps: steam reforming, water gas shift reaction, and hydrogen purification (see Figure 1).

The steam reforming reaction



is endothermic and requires external heat input. Economics favor reactor operation at pressures of 3–25 atm and temperatures of 700°C–850°C. The external heat needed to drive the reaction is often provided by the combustion of a fraction of the incoming natural gas feedstock ($\leq 25\%$) or from burning waste gases, such as purge gas from the hydrogen purification system.

After reforming, the resulting syngas is sent to one or more shift reactors, where the hydrogen concentration is increased via the water-gas shift reaction



The gas exiting the shift reactor contains mostly H_2 (70%–80%) plus CO_2 , CH_4 , and small quantities of H_2O and CO .

Hydrogen is then purified. The degree of purification depends on the application. For industrial hydrogen, pressure swing adsorption (PSA) systems or palladium membranes are used to produce hydrogen at $\leq 99.999\%$ purity.

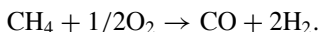
The energy conversion efficiency [=hydrogen out (HHV)/energy input (HHV)] of large-scale SMRs is perhaps 75%–80%, although 85% efficiencies might be achieved with good waste heat recovery and use (15).

SMRs have been built over a wide range of sizes. For large-scale chemical processes such as oil refining, steam reformers produce 25 million to 100 million scf of hydrogen/day. (In energy terms, this is enough hydrogen to power a fleet of ~225,000–900,000 hydrogen fuel cell cars, each driven 11,000 miles/year.) These systems consist of long (12-meter), catalyst-filled tubes, and they operate at temperatures of 850°C and pressures of 15–25 atm, which necessitates use of expensive alloy steels. Capital costs for a 20-million-scf-of- H_2 /day steam reformer plant (including the reformer, shift reactor, and PSA) are about \$200/kW of H_2 output; for a 200-million-scf/day plant, capital costs are estimated to be about \$80/kW of H_2 (16).

Refinery type (high-pressure, high-temperature) reformers can be scaled down to as small as 0.1–1.0 million scf/day (the scale needed for producing hydrogen at refueling stations), but scale economies in the capital cost are significant (the capital cost is ~\$750/kW of H_2 at 1 million scf/day and \$4000/kW of H_2 at 0.1 million scf/day). At small sizes, a more cost-effective approach is to use a lower pressure and temperature reformer, with lower-cost materials. SMRs in the range of 2000 to 120,000 scf of H_2 /day have been developed for use with fuel cells, and these have recently been adapted for stand-alone hydrogen production (17). In these systems the heat transfer path is curved, to make the device more

compact, and the reformer operates at a lower temperature and pressure (700°C and 3 atm), which relaxes materials requirements. Estimates of mass production costs for small “fuel cell type” SMRs indicate that the capital cost for hydrogen production plants in the 0.1-million–1.0-million scf/day range would be \$150–\$180/kW of H₂, assuming that 1000 units were produced (16). (Costs are given on a higher-heating-value basis, and for comparison, do not include hydrogen compression, storage, or dispensing to vehicles.) The capital costs in dollars per kilowatt of hydrogen production are similar for fuel cell type small reformers and conventional, one-of-a-kind large reformers, assuming that many small units are built. Energy conversion efficiencies of 70%–80% are possible for these units.

2. Partial Oxidation of Hydrocarbons Another commercially available method for deriving hydrogen from hydrocarbons is partial oxidation (POX). Here methane (or some other hydrocarbon feedstock such as oil) is oxidized to produce carbon monoxide and hydrogen as shown by the reaction



This reaction is exothermic, and no indirect heat exchanger is needed. Catalysts are not required because of the high temperature. However, the hydrogen yield per mole of methane input (and the system efficiency) can be significantly enhanced by use of catalysts (18). A hydrogen plant based on partial oxidation includes a partial-oxidation reactor, followed by a shift reactor and hydrogen purification equipment. Large-scale, partial-oxidation systems have been used commercially to produce hydrogen from hydrocarbons such as residual oil, for applications such as those in refineries. Large systems generally incorporate an oxygen plant, because operation with pure oxygen rather than air reduces the size and cost of the reactors.

Small-scale, partial-oxidation systems that use oxygen in air have recently become commercially available, but these systems are still undergoing intensive research and development (18–20). Partial oxidation systems are under development by Arthur D. Little, Inc., and its spin-off company Epyx (18, 20–22) and by Hydrogen Burner Technology (19). Small-scale, partial-oxidation systems have a fast response time, making them attractive for following rapidly varying loads, and these systems can handle a variety of fuels, including methane, ethanol, methanol, and gasoline.

Because POX systems are more compact and do not require indirect heat exchange (as in steam reforming), it has been suggested that the costs of small partial-oxidation systems could be less than those of small steam reformers. Although the partial-oxidation reactor is likely to be less expensive than a steam reformer vessel, the downstream shift and purification stages are likely to be more expensive (23). Developing low-cost purification technologies is key if POX systems are to be used for small-scale, stationary hydrogen production. Another approach is to use pure oxygen feed to the POX, which incurs high capital costs for small-scale oxygen production, but eliminates the need to deal with nitrogen downstream.

Oxygen enrichment of incoming air is another way of reducing, but not eliminating, the amount of nitrogen. Innovative membrane technologies may allow lower-cost oxygen for POX reactors (24).

3. Gasification of Biomass, Coal, or Wastes In these systems, solid hydrocarbon feedstocks such as biomass (plant material such as agricultural residues, forest product wastes, or energy crops), coal, or wastes are gasified at high temperature to produce a syngas, which is then processed to increase the hydrogen fraction and purified to produce hydrogen at the required purity (15, 25, 26). Coal gasification was the preferred method of hydrogen production in the United States earlier in this century (before the availability of low-cost natural gas), and it is still practiced in China and Europe. Initially, this was done through the K-T (Koppers-Totzek) method, although newer coal gasification options are now available (27–29). Biomass gasification systems resemble those for coal, but biomass gasifiers operate at lower temperatures, and the clean-up requirements are different, because biomass contains little sulfur (28a). Gasifiers for municipal solid waste have also been developed for use in electricity production, and could be adapted for hydrogen production (25). Biomass- and waste-gasifier hydrogen systems have not been commercialized, but probably could be in a few years, because all of the component technologies are available.

The capital cost for large gasification systems is about \$700/kW of H₂ for biomass and \$800/kW of H₂ for coal, although improvements in high-temperature gas separation technology may reduce these costs (30). Conversion efficiency from biomass or coal to hydrogen is ~60%–65%.

Williams et al (26) have compared the cost of hydrogen production via large-scale gasification of coal, biomass, or wastes. The hydrogen production cost is generally higher for biomass-, coal-, or waste-derived hydrogen than for hydrogen produced via steam reforming, although development of novel membrane separation materials may narrow the cost gap (24, 30).

Technologies for Sequestering Carbon During Thermochemical Hydrogen Production

It has been suggested that carbon dioxide could be captured during hydrogen production from hydrocarbon feedstocks. The CO₂ could then be sequestered underground in secure geological formations such as deep saline aquifers or depleted gas fields (6, 8, 31, 32). This would allow continued use of fossil primary sources to produce transportation fuel with greatly reduced emissions of carbon dioxide into the atmosphere.

Steam methane-reforming plants or coal- or biomass-gasifier plants could be configured to allow separation and capture of CO₂ at low additional cost (6, 32). Various estimates show that carbon dioxide capture, pipeline transmission, and sequestration underground would add only a few dollars per gigajoule, or perhaps 10%, to the delivered cost of hydrogen transportation fuel, assuming that CO₂

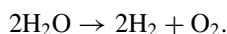
separation, pipeline transport, and sequestration were done on a sufficiently large scale (6, 33–35).

For example, studies carried out for the European community indicate that the cost of CO₂ pipeline transmission over several hundred kilometers to an underground injection site would add <\$1/GJ to the cost of coproduced hydrogen (6, 33, 36, 37). The cost of injecting CO₂ into a deep saline aquifer or depleted gas well is likely to be an order of magnitude lower than transmission costs (33, 36). The incremental cost of separating CO₂ during hydrogen production from natural gas is estimated to be <\$1/GJ (35). In some cases, it may be feasible to produce hydrogen via steam reforming at the natural gas field and to reinject by-product CO₂, gaining a credit for enhanced gas recovery (32). In this case, sequestration could improve the economics of hydrogen production via a byproduct credit for the extra natural gas produced.

Because fossil fuels currently offer the lowest hydrogen production cost, it is likely that they will continue to be used for hydrogen production, where available. Thus, carbon sequestration may be a key element of a future hydrogen energy system based on fossil fuels, but with very low carbon emissions (8). This is particularly true in countries such as China and India with huge coal resources and rapidly growing transportation energy demand (38).

Electrolysis of Water

In water electrolysis, electricity is passed through a conducting aqueous electrolyte, breaking down water into its constituent elements, hydrogen and oxygen (Figure 2) via the reaction



Any source of electricity can be used, including intermittent (time-varying) sources such as off-peak power, solar, or wind sources (5).

Various types of electrolyzers are in use. Commercially available systems today are based on alkaline technology. Proton exchange membrane (PEM) electrolyzers have been demonstrated, are in the process of being commercialized, and hold the promise of low cost. PEM electrolyzers also have advantages of quick start-up and shutdown and the ability to handle transient operating conditions well. Experimental designs for electrolyzers have been developed using solid-oxide electrolytes and operating at temperatures of 700–900°C. High-temperature electrolysis systems offer higher efficiency for converting electricity to hydrogen, because some of the work to split water is done by heat, but material requirements are more severe.

Electrolyzers are typically ~70%–85% efficient on a higher-heating-value basis [efficiency = hydrogen out (HHV)/electricity in].

Water electrolysis can be used to produce hydrogen over a wide range of scales from a few kilowatts to hundreds of megawatts. Capital costs for electrolyzers have been estimated by various authors (5, 16, 39). The capital cost of alkaline systems vary with size, although there is little scale economy above sizes of perhaps a few

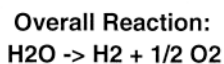
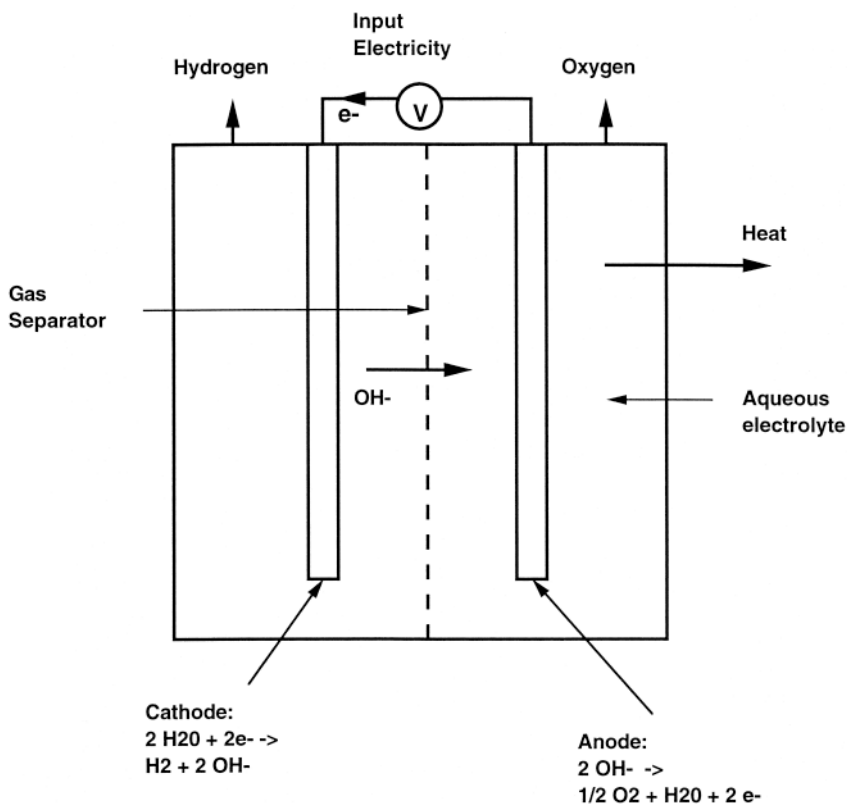


Figure 2 Electrolytic hydrogen production.

hundred kilowatts (39). Hydrogen plant costs for commercially available large-scale alkaline electrolysis systems are currently ~\$500–\$600/kW, with projected costs as low as \$300/kW (5). Thomas and Kuhn have estimated recently that mass-produced small small-PEM electrolyzers might cost <\$300/kW of H_2 out (HHV), even at sizes of only a few kilowatts (16).

The production cost of electrolytic hydrogen is strongly dependent on the cost of electricity. Electrolytic systems are generally competitive with steam reforming of natural gas only where low-cost (\$0.01–\$0.02/kWh) power is available, for example excess hydropower. Another niche market for electrolytic hydrogen may be remote sites, where conventional fuels are expensive owing to high transport costs, and wind power can be used to produce hydrogen (40).

Summary: Economic Comparison of Hydrogen Production Methods

In Figures 3 and 4, we compare the installed capital cost and levelized production cost of hydrogen for various production methods. Capital costs are given in dollars per kilowatt of hydrogen output computed on a higher-heating-value basis. SMRs

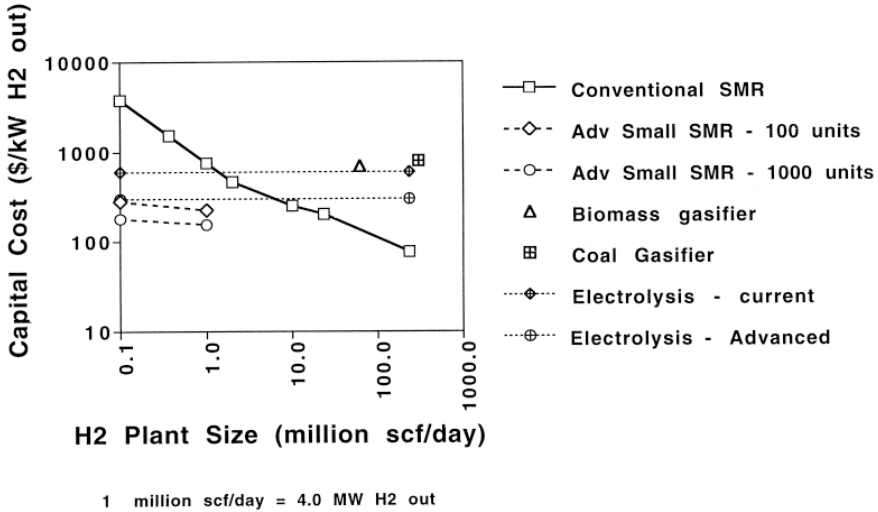


Figure 3 Capital cost of hydrogen production systems (dollars per kilowatt of H₂ output) versus plant size (in millions of standard cubic feet per day).

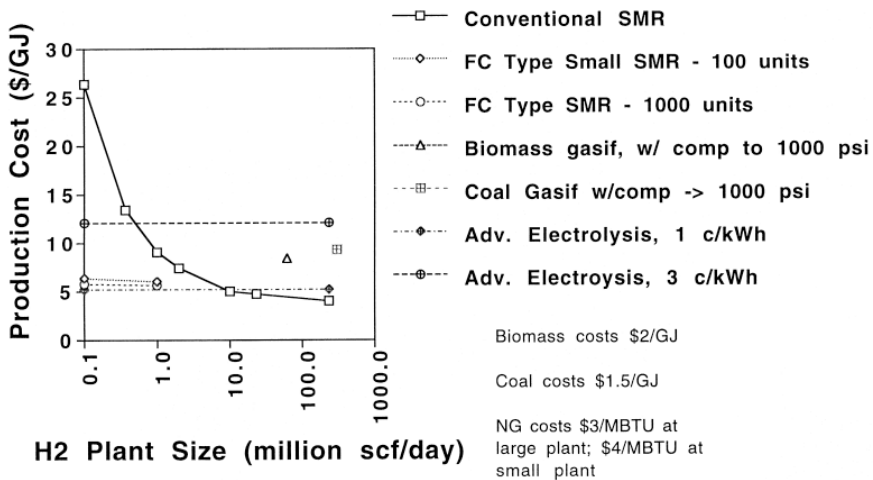


Figure 4 Levelized cost of hydrogen production (dollars per gigajoule) versus plant size (in millions of standard cubic feet per day).

offer the lowest capital cost over a wide range of scales. The levelized cost of production is seen to depend on the cost of the primary-energy feedstock and the scale of production. In regions such as North America, where low-cost natural gas is widely available, steam reforming of natural gas is usually the least costly option. In China, where natural gas is limited, coal is used for hydrogen production. In Brazil, where significant quantities of off-peak hydropower may be available at $\sim \$0.01/\text{kWh}$, electrolytic hydrogen production might be economically competitive.

Although production cost is important, it is the delivered cost to the consumer (including the cost of transporting the hydrogen from the production plant to the consumer) that determines the least-cost hydrogen supply option for a particular site. This is discussed in later sections.

Experimental Methods of Hydrogen Production

A variety of novel approaches to hydrogen production are being investigated in the laboratory. For a sampling of the latest research in this area, see recent conference proceedings (41, 42). New production techniques fall into several general categories:

1. *Innovations in Technologies for Deriving Hydrogen Thermochemically from Hydrocarbon Feedstocks* Innovations in techniques for deriving hydrogen thermochemically from hydrocarbon feedstocks include advances in reforming technologies, such as “sorbent enhanced reforming,” which reduce costs by combining reforming, shift, and purification stages (43), catalytic cracking of natural gas (44, 45), and advanced systems for producing hydrogen from coal (44). Advanced membrane technologies for gas separation [for example, the ion transport membrane (ITM) system under development at Air Products and Chemicals, Inc., Allentown, PA] can simplify the design of hydrogen production systems based on partial oxidation or gasification (24, 30). Also included here is development of advanced gasification or pyrolysis systems for coal, wastes, and biomass (26, 46, 46a) and novel biomass to hydrogen methods (47).

2. *Advanced Electrochemical Routes to Hydrogen Production* Advanced electrochemical routes to hydrogen production include advanced electrolysis systems, such as those using proton exchange membranes or solid-oxide materials as electrolytes. Also included are photocatalytic and photoelectrochemical (48, 48a) systems, which use sunlight to drive hydrogen-producing reactions in wet electrochemical cells splitting water, HBr, or HI. In addition, thermochemical water splitting methods are under investigation for use with high-temperature heat (see 3 for a description of the principles involved).

3. *Biological Hydrogen Production* Biological hydrogen production includes controlled production of hydrogen by algae or bacteria in light-driven bioreactors (49–51).

Some of these alternatives, for example sorbent-enhanced reforming, gasification of biomass or wastes, and PEM electrolyzers, could probably be commercialized within a few years. Longer-term options include photoelectrochemical methods, in which the short lifetime of the cells caused by corrosion currently limits their practicality, and biological hydrogen production, in which the lifetime of the hydrogen-producing organisms and the efficiency of converting light to hydrogen are unresolved issues.

HYDROGEN STORAGE

If hydrogen is widely used as a future energy carrier, storage will be needed to meet time-varying demands for fuel, as is the case for natural gas and gasoline today. This includes large-scale bulk storage of hydrogen, intermediate-scale “buffer” storage, and small-scale storage near the point of use, for example, fuel storage on vehicles.

Stationary-storage technologies used commercially by today’s industrial-gas suppliers of chemical hydrogen are applicable in a future hydrogen energy system. Onboard hydrogen storage systems for vehicles are being developed. Here we review the status of commercially available hydrogen storage technologies and discuss options now under development.

A. Large-Scale Stationary Storage of Hydrogen

Very large quantities of gaseous hydrogen could be stored underground at several hundred to 1000 pounds per square inch (psi) in depleted oil or gas fields, aquifers, or salt or rock caverns (52–55). Underground hydrogen storage has been done commercially in two cases: ICI stored 95% pure hydrogen in salt caverns at Teeside, England, for use by industrial customers, and Gaz de France stored town gas containing 50% hydrogen in an aquifer (53). Underground formations typically have very large capacities, ≤ 1 billion Nm^3 of gas for aquifers or gas fields and millions of Nm^3 of gas for caverns.

For gas wells and aquifers, only a fraction (typically from one- to two-thirds) of this capacity is accessible per storage cycle, because the rest of the volume must be filled with “cushion gas” to maintain pressure. Rock caverns allow perhaps 25% turnover in capacity per storage cycle, and wet salt caverns may approach 100% turnover. These systems could provide on the order of 1 million–10 million Nm^3 of hydrogen per storage cycle, equivalent to the fuel needed each day by a large refinery complex or by a fleet of from 0.3- to 3.0-million hydrogen fuel cell cars.

The levelized cost of large-scale underground storage is estimated to add about \$2–\$6/GJ to the cost of hydrogen (53–55). Higher costs are found (54, 55), if the storage system is cycled seasonally—only once or twice per year, rather than daily or monthly. For natural gas, large-scale seasonal underground storage is used in North America today, primarily because of the strong winter peak for gas-fired

residential heating. Assuming that hydrogen is used mostly for transportation rather than heating, seasonal fluctuations would not be as large, so little, if any, seasonal storage capacity would be needed. Rather, storage on a daily to weekly scale would be appropriate, implying lower storage costs.

Another option that has been proposed for handling daily fluctuations in demand is “pipeline packing,” storing hydrogen in gas distribution pipelines. However, for relatively short local pipelines, the storage capacity would be small. For example, a 30-km, 3-inch-diameter hydrogen distribution pipeline serving five hydrogen vehicle refueling stations could carry a flow of 5 million scf of hydrogen/day. Assuming that the pipeline operated at 1000 psi, the storage volume available in the pipeline would be 340,000 scf, only $\sim 7\%$ of the total daily flow rate.

B. Stationary Storage at Intermediate and Small Scales

For intermediate to small-scale hydrogen storage, liquid hydrogen and compressed hydrogen gas in cylinders are used in industry today.

1. Liquid Hydrogen Storage Hydrogen is liquefied by reducing the temperature to very low levels. (Hydrogen becomes liquid at -253°C .) Liquid hydrogen is stored in cryogenic dewars, vessels designed to minimize heat loss. Hydrogen dewars range in capacity from a few kilograms for laboratory use to hundreds of tonnes.

An advantage of liquid hydrogen over compressed gas is that dewars are more compact than compressed gas cylinders so that truck delivery is less costly, because more energy can be delivered per truckload with liquid than with gas. Liquid hydrogen is favored, if modest quantities of hydrogen are to be transported long distances, where pipeline costs for gaseous-hydrogen transport would be prohibitive. For these reasons, merchant hydrogen (e.g. hydrogen that is delivered for industrial purposes) is often liquefied for storage and delivery by truck. (About one-third of merchant hydrogen delivery is by liquid-hydrogen truck, and the remainder by short-distance pipeline or compressed-gas truck.)

A disadvantage of liquid hydrogen is that the capital cost of liquefaction and storage equipment is significant. Moreover, there is a large energy cost; electricity equivalent to about one-third or more of the energy value of the hydrogen is needed to liquefy (56). Liquefaction and storage typically add \$5–\$10/GJ to the cost of liquid hydrogen (4, 16) depending on the scale of the liquefier, about as much as the cost of gaseous-hydrogen production (see Figure 2). For a large-scale energy system, the energy conversion losses and higher costs make liquefaction and truck delivery less attractive than gaseous pipeline distribution or onsite production from natural gas (10, 16, 57).

2. Above-Ground Compressed-Gas Storage For storing relatively small amounts of hydrogen (on the order of a few million scf or less), industrial consumers

of hydrogen sometimes use above-ground compressed-gas storage in pressure tanks. Compressed gas pressure vessels are commercially available at pressures of 1200–8000 psi, typically holding 6000–9000 scf/vessel (53, 58). Pressure vessels are configured in rows or in stacks of tanks. Tank storage is modular with little economy of scale. Capital costs for pressure vessel storage are \$3000–\$5000/GJ of storage capacity (16, 58). Compression from production pressure (typically 1–15 atm) to storage pressure adds capital and electricity costs. Hydrogen compressors are commercially available over a wide range of sizes.

In a survey of small industrial hydrogen users, Fein & Edwards (39) found that storage in pressure vessels added \$2–\$20/GJ depending on the application. Ogden et al (58) have estimated that costs for compression and pressure vessel storage of 0.025 million to 0.5 million scf of hydrogen at a hydrogen refueling station might add \$2.5–\$4/GJ to the delivered cost of hydrogen. Another recent study considered the cost of storing 0.6 day's production at a central hydrogen plant producing 23 million–234 million scf/day, finding additional costs of \$2–\$4/GJ (16).

C. Storing Hydrogen on Board Vehicles

Unlike gasoline or alcohol fuels, which are easily handled liquids at ambient conditions, hydrogen is a lightweight gas and has the lowest volumetric energy density of any fuel at normal temperature and pressure. A viable onboard automotive hydrogen storage system must be compact, lightweight, low cost, rugged, easily and rapidly refillable, and, of course, safe. (See below for a discussion of hydrogen safety.) Moreover, it must be capable of storing enough hydrogen to provide a reasonable traveling range and good dormancy (i.e. the ability to retain hydrogen for a long period of time without leakage).

A number of alternative methods for onboard hydrogen storage have been considered (21, 59, 60). These are shown in Table 3, which gives the projected volume and weight of alternative hydrogen storage systems containing 3.5 kg of hydrogen, enough for a 380-mile traveling range in a midsize hydrogen fuel cell automobile.

Several methods have been demonstrated for storing hydrogen on experimental vehicles. Each onboard storage method has advantages and drawbacks.

1. Compressed Gas Storage in High-Pressure Cylinders Storing compressed gas in high-pressure cylinders has been used recently in the Ballard and Daimler-Benz fuel cell buses and in the Daimler-Benz NECAR I and NECAR II fuel cell minivans (61). Ford has explored this option in a recent assessment (60, 62), as have researchers at Lawrence Livermore National Laboratory and Thiokol (63, 64).

2. Liquid Hydrogen Storage in a Small Dewar Researchers at DFVLR (3, 56), BMW (65), Messer Griesham (67), and Linde (68) have developed technologies for liquid H₂ storage on vehicles and for refueling. One variant of the Daimler-Benz NECAR IV uses liquid hydrogen.

TABLE 3 Weight and volume of onboard hydrogen storage systems for a mid size hydrogen fuel cell automobile and for systems holding 3.9 kg of hydrogen^a

Fuel	Storage system	Total weight: fuel + storage system (kg)	Total volume: fuel + storage system (liters)
Compressed-gas hydrogen at 5000 psi ^b	Advanced pressure cylinder	32.5 (12% H ₂ by weight)	186 (700 Wh/liter)
Liquid hydrogen ^c	Dewar	28.5 (14% H ₂ by weight)	116
Metal hydride ^c	Metal hydride (FeTiH _{1.8}) container with heat exchanger	325 (1.2% H ₂ by weight)	100

^aStorage of 3.9 kg of hydrogen is sufficient for a range of ~400 miles in a lightweight midsize passenger car using a hydrogen fuel cell (10).

^bBased on estimates by Mitlitsky et al (64) for a 5000-psi pressure tank holding 3.9 kg of hydrogen.

^cAdapted from Ref. 60. In this reference it is assumed that 6.8 kg of hydrogen is stored. This is adjusted to 3.9 kg to make it comparable to the estimate for pressure tanks. For metal hydrides, it is assumed that the storage weight and volume scale directly with the amount of hydrogen stored. For liquid hydrogen, it is assumed that the container weight scales as the two-thirds power of the weight of hydrogen stored. The container's inside volume is assumed to scale directly with the weight of hydrogen stored; it is assumed that the thickness of the container stays the same.

3. Metal Hydride Storage Metal hydrides are compounds in which hydrogen is absorbed by a metal under pressure and is released when heat is applied (69, 70). This technology was used by Daimler-Benz in its experimental hydrogen vehicles in the 1970s and 1980s (71) and by Toyota in a 1997 hydrogen fuel cell demonstration vehicle (72)

Compressed gas is simple to implement, refilling is as rapid as that for gasoline (a few minutes or less), dormancy is good, and the energy requirements for compression are modest. (Electrical requirements for compression to high pressure are typically 5%–7% of the energy content of the hydrogen and can be lower if hydrogen is produced at high pressure.) Although the energy density per unit weight and volume is low with conventional steel pressure cylinders, advanced composite, high-pressure cylinders hold the promise of acceptable weight (>10% hydrogen by weight) and large, but probably acceptable, volume. Conceptual designs have been developed by Ford Motor Co. for lightweight, potentially low-cost (\$500–\$1000/tank in mass production), high-pressure (5000 psi) hydrogen tanks holding >10% hydrogen by weight, which can be refilled in ≤3 min (60). Recently, Mitlitsky et al have estimated that a tank carrying 3.9 kg (enough hydrogen to power a mid-sized fuel cell car ~380 miles) would weigh <40 kg, and would take up perhaps 190 liters of space (64). Tests of these lightweight pressure cylinders will be conducted by researchers at Lawrence Livermore National Laboratory and Thiokol later this year.

By contrast, current onboard metal hydride systems store only 1%–1.5% hydrogen by weight, are costly, and require a relatively long recharge time (10–20 min). Heat must be applied on the vehicle to release hydrogen, which involves use of an onboard burner and heat exchanger. An advantage is the relative compactness of metal hydrides and the relatively low charging pressure (several hundred psi) as compared with compressed gas cylinders (several thousand psi).

Liquid hydrogen is attractive in that it offers low weight and volume per unit of energy. This has led some researchers to prefer liquid hydrogen, as the most capable of providing a long range (65). With liquid hydrogen, boil-off of cryogenic liquid from storage (poor dormancy) and refueling losses have been issues (56). On-board storage and refueling systems for liquid-hydrogen-powered vehicles have undergone significant improvements in recent years (67, 68), so that these problems are much less severe. For example, <1% boil-off would be expected per day from a current liquid-hydrogen tank (68), and refueling could be accomplished in a few minutes. Still, the total fuel cycle energy efficiency is significantly lower for liquid hydrogen than for gaseous hydrogen, because of the large amount of energy required for liquefaction. If greenhouse gas emission reduction and efficient use of primary resources are motivations for adopting hydrogen, liquid-hydrogen routes are less attractive than are those for gaseous hydrogen. Moreover, liquid hydrogen is likely to give a higher delivered fuel cost than compressed hydrogen gas for a large-scale energy system, because of the high cost of liquefaction. Recently, researchers at Lawrence Livermore National Laboratories have proposed using a hybrid compressed-gas/liquid-hydrogen storage system (made up of insulated high-pressure cylinders), that would allow operation on compressed gas for short trips and operation on liquid hydrogen when a long range was needed (73). Such systems are undergoing preliminary tests and would reduce the energy used as compared with a pure liquid-hydrogen system.

Considering both storage and refueling technologies, the most promising near-term alternative is probably compressed-gas storage (60). It appears that hydrogen could be stored in advanced compressed-gas cylinders at acceptable cost, weight, and volume for vehicle applications. This is true in part because hydrogen can be used so efficiently in fuel cells that relatively little fuel is needed on board to travel a long distance (74, 75). Development of lightweight, low-cost, high-pressure tanks is a priority. Liquid hydrogen appears to be technically feasible, especially with improved systems, but ultimately, cost and energy efficiency considerations favor compressed gas for a hydrogen energy system (10, 58).

D. Novel Approaches to Hydrogen Storage

A variety of innovative storage methods for hydrogen are being researched.

1. Storage of Hydrogen in Carbon Materials Carbon is an attractive medium for hydrogen storage because it is readily available and potentially low cost. A

number of approaches based on hydrogen storage in various types of carbon are being pursued. A team of scientists at Northeastern University is investigating hydrogen adsorption in graphite nanofibers (76), recently reporting storage of >50% hydrogen by weight. If this result is verified, it could have strong implications for future hydrogen storage systems. Work is also ongoing on hydrogen storage in carbon nanotubes (77, 78). Others have proposed storing hydrogen in fullerenes (80), or in activated carbon at low temperatures (81, 82).

2. Development of Improved Metal Hydrides and Alternative Hydrides One goal is to develop metal hydrides that store more than a few weight percent of hydrogen, which are potentially low cost and are readily charged and discharged. For a review of metal hydride technology, the reader is referred to (69, 70, 83). Polyhydride materials (84) are an alternative approach, and liquid organic hydrides have been considered as a method for bulk hydrogen storage and transport (85).

3. High-Pressure Gas Storage in Glass Microspheres Various researchers have proposed high-pressure storage of gaseous hydrogen in glass microspheres (86–88), which can be transported in bulk without the need for an external-pressure vessel. Others have proposed hydrogen storage in zeolites (89) or as a cryogenic “slush” (90), for use in advanced planes and rockets.

Although these approaches offer potential improvements in energy storage density or cost, all are still far from commercialization.

E. Summary of Storage Options

Existing, commercially available, stationary-storage options could be used in a future hydrogen energy system. Development of practical, high-pressure, lightweight, low-cost onboard compressed-gas hydrogen storage for automotive applications remains a high priority. A range of research and development projects on advanced hydrogen storage concepts are being pursued. Improving hydrogen storage systems has proven to be a difficult challenge. If a breakthrough hydrogen storage technology were successfully developed, it might speed the introduction of hydrogen as a fuel.

HYDROGEN TRANSMISSION, DISTRIBUTION, AND DELIVERY

Unlike systems in place for electricity, natural gas, or gasoline, there is at present no widespread transmission and distribution system bringing hydrogen to consumers. However, the technologies needed to build such a system have already been developed and are used today in a small but significant “merchant hydrogen” infrastructure, which delivers hydrogen to industrial users. The merchant hydrogen system delivers fuel at perhaps 1% of the scale needed to serve major energy

markets. Because the demand for merchant hydrogen is small in energy terms and geographically sparse, a fully developed hydrogen energy system will look quite different from the merchant system. However, it could provide a technological springboard for the early phases of developing a hydrogen energy system.

A. Description of the Current Industrial-Hydrogen Transmission and Distribution System

Hydrogen is widely used in the chemical industries today, for oil refining, ammonia production, and methanol production. About 1.5 EJ of hydrogen is consumed each year in the United States, an amount that is expected to increase to 6 EJ/year by 2010, primarily because of higher hydrogen demand for oil refining. Although most hydrogen is produced where it is needed and consumed on site, a small fraction termed merchant hydrogen—perhaps 5% of total production—is transported to distant users via liquid-hydrogen truck, compressed-gas truck, or gas pipeline (14, 91). Most merchant hydrogen today is produced as a byproduct of chemical activities such as oil refining or chloralkali plants (14). Some is produced from steam reforming of natural gas in dedicated hydrogen production plants. The total amount of merchant hydrogen transported in the United States today could fuel a fleet of perhaps 2 million–3 million hydrogen fuel cell–powered cars. Technology to safely handle these quantities of hydrogen is well established in industrial settings (92).

B. Long-Distance Transmission of Hydrogen

It is standard commercial practice in the chemical industries today to transport large quantities of gaseous hydrogen (≤ 100 million scf/day) over long distances (≥ 100 miles) at high pressures (≤ 1500 psi) in pipelines specifically designed for hydrogen. The characteristics of existing hydrogen pipelines have been described in several studies (91, 93–96). In this section, we first review some of the data in these studies. Based on models developed by Christodoulou (95), we then calculate flow rates in hydrogen and natural gas pipelines and compare the economics of hydrogen and natural transmission.

Table 4 lists high-pressure hydrogen pipelines now in service in North America and Europe. The diameters of the largest hydrogen pipelines operating today are ~ 12 in, and these pipelines are capable of transmitting 100 million scf/day of hydrogen (enough for a fleet of $\sim 900,000$ fuel cell cars). No hydrogen embrittlement or undue safety problems have been reported for these lines. It is interesting that gaseous-hydrogen pressures of ≤ 100 bar (1470 psi) have been routinely handled in an Air Liquide pipeline (96) and that the total hydrogen flow in all high-pressure transmission lines today is ~ 320 million scf/day (42 million GJ/year) or enough to provide fuel for a fleet of ~ 3 million hydrogen fuel cell passenger cars.

Pottier et al (96) estimate that the capital cost of pipelines designed for hydrogen transmission would be $\sim 50\%$ higher than for natural gas transmission lines. The cost of installation would also be higher, because special care would be needed

TABLE 4 Hydrogen transmission pipelines

Company	Location	H ₂ flow (millions of scf/day)	Length (km)	Pipe diameter (inches)	Pipeline pressure (psi)	H ₂ purity	Years in operation	Source
PRAXAIR	Texas City- Bayport-Port Arthur, TX	100		8			Since 1970s	(91, 93)
	Carney's Point, NJ	6						(91)
	Whiting, IN	5						(91)
Air Products and Chemicals	LaPorte, TX	40	200	4–12	50–800	99.5%	Since 1970s	(91, 94)
	Plaquemine, LA	30						(91)
Chemische Werk Huls, AG	Ruhr Valley, Germany	100	220	4–12	360	95%	Since 1938	(93, 94, 96)
ICI	Teeside, England	20	16		750	95%	Since 1970s	(94)
Air Liquide	France, Belgium	17	340	4	1470	99.995%	Since mid-1980s	(96)

with welds. This is consistent with earlier estimates by Leeth (93), which showed that the capital cost of hydrogen transmission pipelines was $\sim 40\%$ higher than for natural gas. Pipe costs would be higher because embrittlement-resistant steels would be specified. Also, the pipeline diameter would be perhaps 20% larger for hydrogen to achieve the same energy flow rate (93).

The cost of compression is also higher, because about threefold more compressor power per unit of energy transmitted is needed to compress hydrogen than natural gas (93). The specific capital cost of hydrogen compressors is estimated to be 20%–30% higher than the cost of those for natural gas (Pottier et al 1988).

Despite the higher costs for hydrogen pipelines and compressors, the overall contribution of long-distance hydrogen transmission is quite small for high pressures and flow rates. Christodoulou (95) found hydrogen transmission costs of $< \$1/\text{GJ}$ for optimized 500-km, large-scale hydrogen pipelines. Pottier et al (96) estimated costs of $\sim \$0.28$ – $\$0.42/\text{GJ}$ for a 100-km pipeline. And Leeth (93) estimated hydrogen transmission costs of $< \$0.15/\text{GJ}/100$ miles of pipeline for large hydrogen flows. Although generally $\sim 50\%$ higher than costs for natural gas transmission, hydrogen pipeline transmission costs are still quite small compared with large-scale hydrogen production costs of $\$5$ – $\$8/\text{GJ}$.

A sample calculation comparing the cost of energy transmission in dollars per gigajoule for natural gas and hydrogen pipelines is shown in Figure 5. Assuming that the pipelines carry the same energy flow, we see that the overall cost of hydrogen transmission is about 1.5- to 3-fold that for natural gas over a range of pipeline sizes. The cost of compression is an important factor, especially at very large flow rates (e.g. on the scale of total gas use in a large city in the United States).

It has been proposed that the existing natural gas pipeline system might be converted to using hydrogen or hydrogen blends. One concern here is hydrogen embrittlement, that is, acceleration of crack growth when pipeline pressure is cycled. Studies conducted starting in the 1970s and 1980s (54, 98–102) indicate that hydrogen embrittlement of commonly used natural gas pipeline steels cannot be ruled out and could lead to accelerated crack growth and pipeline failure. Embrittlement can be avoided by coating pipes or by adding small quantities of CO, SO₂, O₂, or other gases (102). Embrittlement is avoided altogether in pipelines designed for hydrogen by using types of steel not subject to embrittlement.

Hydrogen can be made from a variety of feedstocks, many of which (e.g. natural gas and coal) are more easily and cost effectively transported long distances than hydrogen itself. Hydrogen can then be made as needed at the “city gate” and distributed by local pipeline. Long-distance hydrogen pipelines might be used to bring large amounts of very-low-cost hydrogen (produced where feedstock costs are exceptionally low) to a region where such feedstocks are absent or are costly to import.

C. Local Pipeline Distribution of Hydrogen

It would be technically feasible to build a local pipeline system for gaseous hydrogen distribution. Consider the case of hydrogen distribution for use in vehicles. Here the distribution system would not be as widespread as the current natural gas

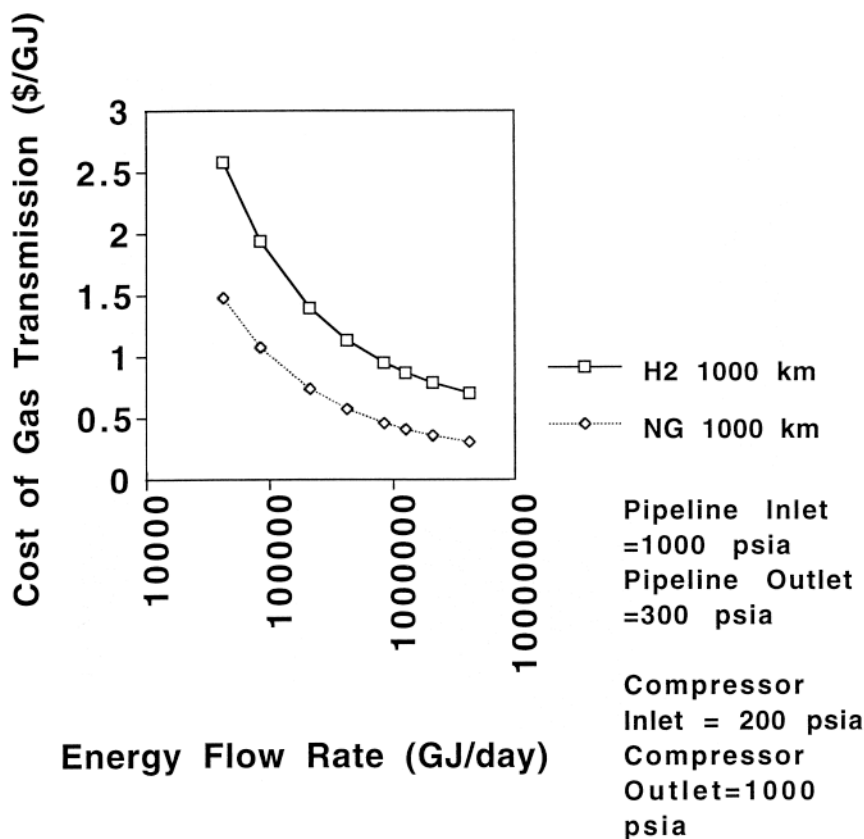
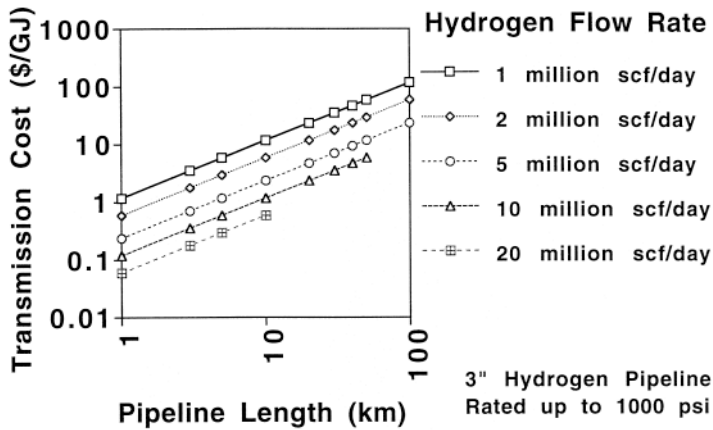


Figure 5 Estimated cost of long-distance hydrogen pipeline transmission versus flow rate and pipeline length.

utility network, which reaches individual homes as well as industrial customers. Instead of serving every building, as with natural gas, hydrogen would be piped to a smaller number of refueling stations, located along major roads, where a number of vehicles are refueled, as with gasoline today. (For combined heat and power applications in buildings, a more extensive distribution system might be needed.)

The cost of local hydrogen pipeline distribution for vehicle fuel has been estimated (16, 57, 58). Installed costs for local hydrogen pipelines operating from central hydrogen production sites to refueling stations can be estimated as a function of the pipeline length and number of vehicles served. Pipeline capital costs vary from \$250,000 to \$1,000,000/mile depending on the terrain and on the level of urbanization. [In highly developed areas such as the urban United States, installed pipeline capital costs for a small (3- to 6-inch)-diameter pipeline are typically \$1,000,000/mile. In flat, rural areas, pipeline costs can be much lower, perhaps



Pipeline cost =
\$1 million/mile

Inlet Pressure = 1000 psia
Outlet Pressure > 200 psia

1 million scf/day serves a fleet of 9200 Fuel Cell Cars
or 140 Fuel Cell Buses

Figure 6 Estimated cost of local hydrogen distribution as a function of pipeline length and flow rate.

\$250,000/mile. In developing countries, lower labor costs may bring down the total installed cost for small-scale pipelines. In the United States, 15%–20% of the total installed cost is for pipeline labor, and another 15%–20% is for engineering services for a pipeline through flat terrain costing \$500,000/mile (104).] The cost of hydrogen delivery varies from <\$1/GJ (for high flow rates and short pipeline lengths) to \$10/GJ for small flow rates and long distances (see Figure 6). Pipeline delivery is favored for short distances and large flow rates.

Consider the distribution of hydrogen transportation fuel via a pipeline network from a central production plant throughout a city or region. Figure 7 shows the cost of local hydrogen pipeline distribution as a function of vehicle population density (cars per square mile) and pipeline capital cost. It is assumed that a network of 3-inch-diameter hydrogen pipelines radiating from a central plant is built. Along each spoke of the pipeline network, a series of refueling stations is located, each serving ~600 cars/day. Hydrogen storage at the central plant is used to meet fluctuating demands throughout the day. The extent of the required pipeline system (length of each spoke) depends on the geographic concentration of the demand. Assuming that the cost of the pipeline is \$1 million/mile, Figure 7 shows that local distribution can cost \$2–5/GJ, depending on the density of cars. We find that a geographically

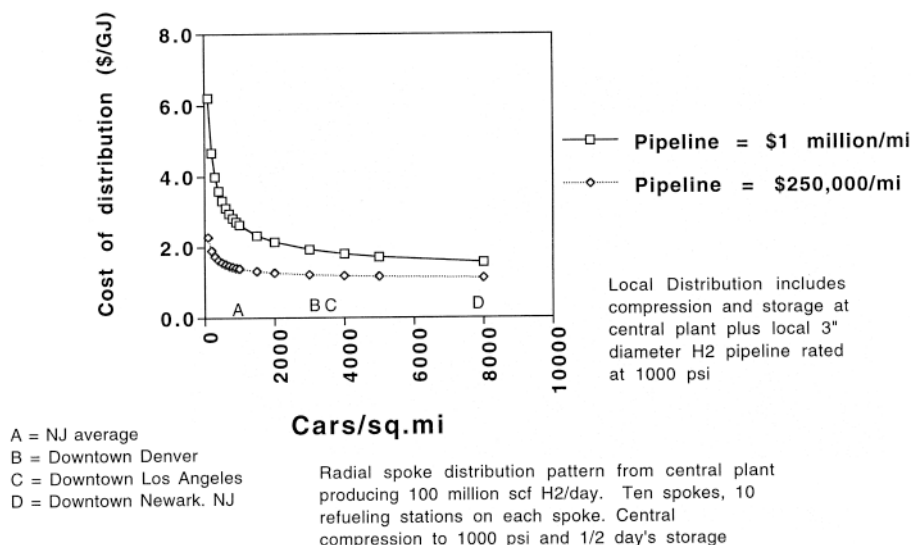


Figure 7 Cost of local hydrogen distribution from a 100 million-standard cubic feet/day plant as a function of vehicle population density.

concentrated demand is needed to bring down the costs of hydrogen local-pipeline distribution. This graph illustrates the cost-benefit of building up a geographically concentrated demand before implementing centralized hydrogen production dedicated to vehicles. At vehicle densities of <300 cars/square mile (300 cars/square mile is equivalent to ~10% of the vehicle population in a typical urban area in the United States), the costs of pipeline transmission rise rapidly, and other distribution methods (liquid hydrogen trucks) or strategies (onsite production) may give a lower delivered hydrogen cost.

Moving beyond transportation markets into home heating or combined heat and power could involve considerably more infrastructure development. Bringing hydrogen to every house would involve a larger pipe network, handling perhaps 10-fold the energy flow rate of a transportation fuel distribution system (see Table 2). It has been suggested that hydrogen could be used in existing utility distribution systems for natural gas—either as pure hydrogen or as an additive to natural gas. Much of the published work on using hydrogen and hydrogen blends in the existing natural gas distribution system was carried out by the Institute of Gas Technology (IGT), starting in the 1970s (54, 105–108). Their results were summarized in a recent article by Blazek et al (54). The IGT studies showed that hydrogen blends in any proportion up to 100% hydrogen could be used in local distribution systems with relatively minor changes, such as replacing seals and meters. (End-use systems would have to be changed at hydrogen concentrations of perhaps 15%–20% hydrogen by volume.) Increasing use of plastic piping in local natural gas distribution systems is potentially a cause for concern, because hydrogen permeates the pipe four- to sixfold as readily as natural gas.

A similar study was done recently of a gas distribution system in the city of Munich (109). The authors found no technical barriers to using up to 100% hydrogen in existing low-pressure natural gas distribution systems. Little change in NO_x or CO_2 emissions from the utility system was seen at 5% hydrogen by volume. Significant reductions in NO_x and CO_2 were seen with hydrogen percentages of $\geq 60\%$. It was observed that $\leq 60\%$ hydrogen could be used in the Munich gas distribution system with no regulatory changes. (This high proportion of hydrogen is allowed under existing safety laws, because manufactured gas rich in hydrogen was used in the gas system until the 1970s.) The authors suggested that percentages of $\leq 60\%$ hydrogen be used for environmental reasons.

For hydrogen vehicles, it is likely that a pure hydrogen distribution network would be developed along major highways, rather than converting the natural gas system. For home hydrogen energy in existing buildings, conversion or adaptations of the existing natural gas system might be considered. For new construction, there would be several options for providing heat and electricity. The choice here would be decentralized electricity and heat production versus centralized production with distribution.

D. Gaseous-Hydrogen Refueling Stations

The technologies to compress, store, and dispense gaseous hydrogen to vehicles are commercially available. Many are analogous to existing systems for compressed natural gas vehicles (16, 58, 110, 111).

Ongoing hydrogen vehicle demonstrations include gaseous-hydrogen refueling stations. For example, Air Products and Chemicals, Inc., is providing hydrogen for fuel cell-powered public-transit buses in Chicago in a small system with delivery of liquid hydrogen which is then vaporized to provide gas at pressures of 3000 psi. Electrolyser, Inc., is providing hydrogen to fuel cell buses in British Columbia, Canada. Other gaseous-hydrogen refueling systems are operating at the University of California, Riverside, at Xerox in Canoga Park, CA, and at the Schatz Energy Center, in Humboldt, CA. More such systems are planned as part of the recently announced California fuel cell initiative (112).

For a pipeline hydrogen system, a gaseous-hydrogen refueling station is projected to add about \$4–\$6/GJ to the delivered cost of hydrogen (10).

DESIGN AND ECONOMICS OF HYDROGEN ENERGY SYSTEMS

Here we explore how the components of a hydrogen energy system (production plants, transmission and distribution systems, and refueling stations) might be put together to provide hydrogen fuel on a large scale. Because hydrogen can be produced in a number of ways, the design of a hydrogen energy system is site specific, depending on the type of demand, the local energy prices (for natural gas, coal, electricity, etc), and the availability of primary resources.

Clearly, a large variety of different hydrogen energy systems could be analyzed. Many of these systems, although locally important, would have limited application on a global-energy scale. In the interests of space and of keeping the reader's attention, we have restricted our discussion to what we see as potentially one of the most important applications: developing infrastructure to supply compressed hydrogen gas to zero-emission vehicles. (Compressed gas was chosen as the most likely near-term storage medium for hydrogen—see discussion of onboard vehicle storage options above.) Further, we present a specific case study for Southern California, a location where hydrogen- and fuel cell-powered vehicles are being demonstrated and where a high degree of political will to implement cleaner transportation technologies is evident.

Estimating the Demand for Hydrogen Energy

The first step in designing a system to deliver hydrogen transportation fuel is characterizing the hydrogen demand to be served. Table 2 shows hydrogen consumption for various end uses ranging from a single hydrogen fuel cell-powered car through implementation of hydrogen in large energy markets. A single hydrogen fuel cell automobile driven 11,000 miles/year (the U.S. average) is projected to use ~ 109 scf of H_2 /day. A hydrogen fuel cell bus driven 50,000 miles/year is projected to use ~ 8000 scf of H_2 /day (57). The total number of vehicles to be served determines the total hydrogen production capacity needed. For example, to serve 10% of the automotive fleet in the Los Angeles area (~ 1 million cars), ~ 100 million scf of H_2 /day must be produced. Providing hydrogen for 3600 urban transit buses (the estimated number in Los Angeles) would require ~ 25 million scf/day.

Either centralized or decentralized hydrogen supply could be used. A large chemical industry SMR today produces 25 million–100 million scf/day, enough to serve 2.5%–10% of the cars in Los Angeles. Hydrogen could be piped from a large central plant to users in local pipelines or liquefied and delivered by truck. Alternatively, small reformers or electrolyzers in the range of 0.1 million–1.0 million scf/day could be sited at individual refueling stations, each serving 60–600 cars/day.

The geographical concentration of the demand (number of vehicles per square mile) is important for determining the type of distribution system and the cost of local distribution. As shown in Figure 7, local pipeline transmission costs vary from $\sim \$2/\text{GJ}$ for vehicle densities of 3000 cars per square mile, (equal to 100% of cars in densely populated urban areas such as downtown Denver or Los Angeles), to $\$5/\text{GJ}$ for densities of 300 cars/square mile (equivalent to more sparsely populated suburban areas such as averages for New Jersey or to 10% of urban vehicles). At even sparser demand concentrations (< 300 cars/square mile), pipeline transmission costs rise rapidly, and other hydrogen supply strategies are preferable.

The proximity of the demand to primary resources for hydrogen production is also important. This determines the most viable alternative by determining the local energy prices.

Selecting the Lowest-Cost Hydrogen Supply Option: General Considerations

From the hydrogen production and delivery costs shown in Figures 4–7, we can make a preliminary selection of a least-cost system for a given level of demand and given energy prices. Where low-cost natural gas is available, the production cost is lowest from steam methane reforming, over a wide range of production sizes, ranging from a large central system producing 100 million scf of H_2 /day, to the size of a single hydrogen refueling station producing 0.1 million–1.0 million scf/day.

Hydrogen production in a centralized SMR is less costly than in small-scale distributed SMRs, because natural gas feedstock costs are lower at a large plant than at a refueling station. [Scale economies are important for conventional SMRs. However, if advanced, small, low-cost, “fuel cell”-type reformers are developed, capital costs per kilowatt of hydrogen output would be similar for large- and small-SMR systems (see Figure 3).] However, hydrogen distribution costs from a central plant to users can be significant (Figure 7). When natural gas is available, a key question is the degree of centralization of fuel production. If distribution costs are high, decentralized production may be the lowest-cost option.

With coal and, to a lesser extent, biomass or wastes, large-scale plants are favored because of scale economies in production equipment. (However, biomass hydrogen plant size is limited by the cost of transporting biomass over a long distance.) For gasification-based technologies, a large demand is needed to use the output of the plant, and a geographically concentrated demand is needed to keep local distribution pipeline costs low. Generally, biomass and coal gasifier systems will be competitive only where low-cost natural gas is not available and only when a large concentrated demand has developed. (Development of low-cost, small gasifier systems could change this outlook.)

Electrolytic hydrogen can produced over a wide range of scales, but can compete with other options only where off-peak electricity prices are low or where costs for other feedstocks are high.

Estimating the Delivered Cost of Hydrogen Transportation Fuel: A Southern California Case Study

Using Figures 3–7 and specific information about energy prices and vehicle populations in Southern California, we have estimated the cost of different hydrogen supply options. Southern California was chosen as a case study because it is a region with severe air pollution problems and because the state of California has demonstrated political will to implement lower-polluting transportation technologies.

A number of near-term possibilities for producing and delivering compressed gaseous-hydrogen transportation fuel can be considered, which use commercial or nearly commercial technologies for hydrogen production, storage, and distribution.

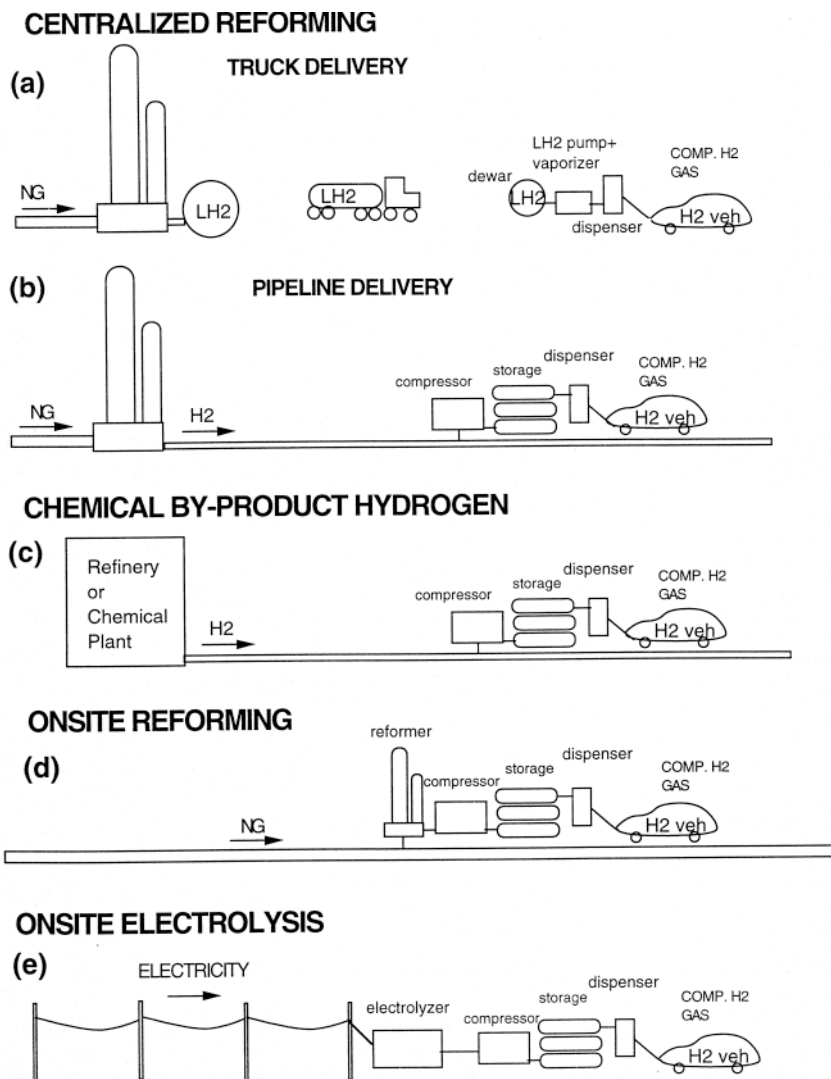
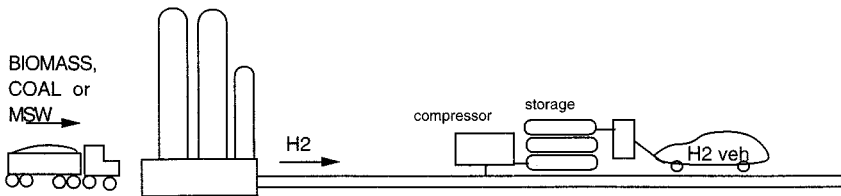


Figure 8 Near-term options for supplying hydrogen transportation fuel.

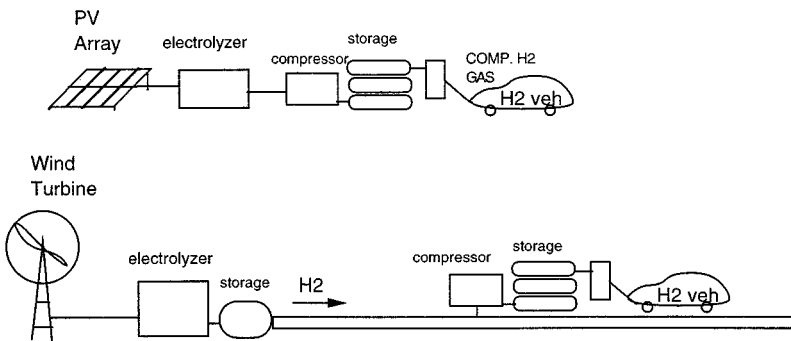
[For details on the design and economics of these systems, see several recent studies of hydrogen refueling infrastructure (10, 16, 57, 58, 110, 111).] Near-term hydrogen supply options include (see Figure 8) (a) hydrogen produced from natural gas in a large, centralized steam reforming plant and truck delivered as a liquid to refueling stations; (b) hydrogen produced in a large, centralized steam reforming plant and delivered via small-scale hydrogen gas pipelines to refueling stations; (c) hydrogen from chemical industry sources (e.g. excess capacity in refineries that have recently upgraded their hydrogen production capacity, etc) with pipeline

delivery to a refueling station; (d) hydrogen produced at the refueling station via small-scale steam reforming of natural gas (in either a conventional steam reformer or an advanced steam reformer of the type developed as part of fuel cell cogeneration systems); and (e) hydrogen produced via small-scale water electrolysis at the refueling station. In the longer term, other centralized methods of hydrogen production might be used, including gasification of biomass, coal, or municipal solid waste or electrolysis powered by wind, solar energy, or nuclear power (Figure 9). Thermochemical hydrogen production systems might include sequestration of by-product CO_2 .

H2 via BIOMASS, COAL or MSW GASIFICATION



SOLAR or WIND ELECTROLYTIC HYDROGEN



H2 FROM HYDROCARBONS w/CO2 SEQUESTRATION

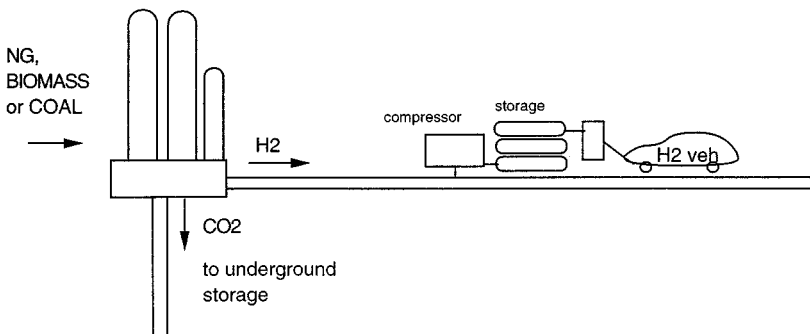


Figure 9 Long-term options for supplying hydrogen transportation fuel.

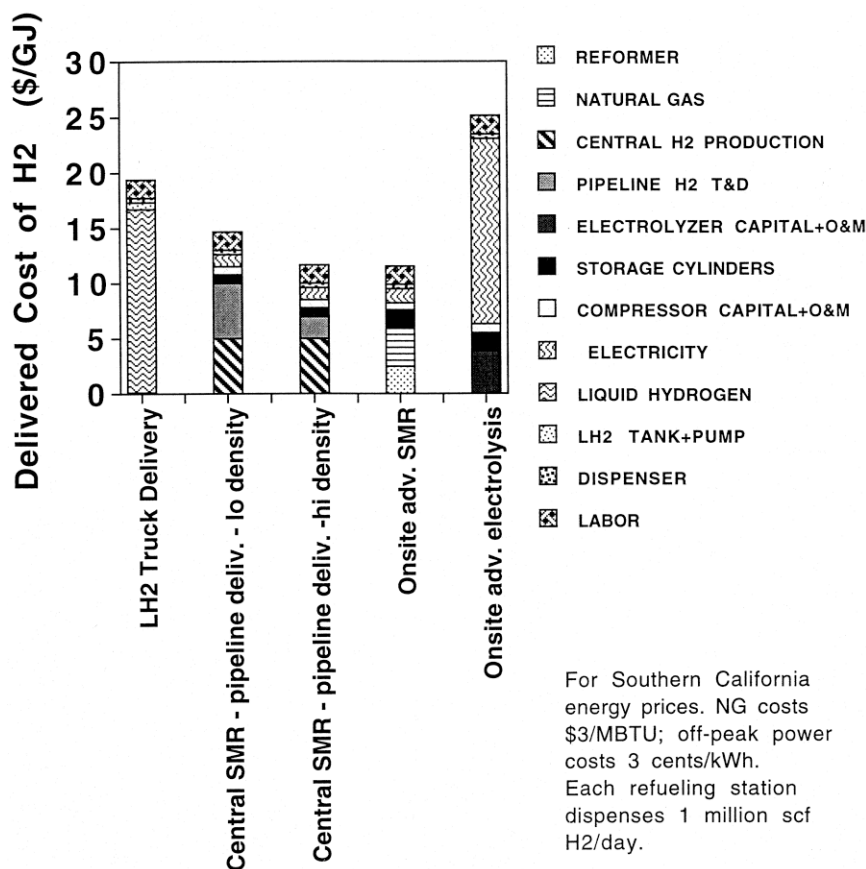


Figure 10 Delivered cost of hydrogen transportation fuel from various primary sources.

In Figure 10, we show the estimated delivered cost of hydrogen transportation fuel for Southern California (57). The delivered costs are shown for each technology for refueling stations dispensing 1 million scf/day (each station could fuel a total fleet of about 9000 fuel cell-powered cars or 140 fuel cell-powered buses). A comparison shows the following significant results.

1. Delivered costs for hydrogen transportation fuel range from \$11–\$25/GJ (equivalent on an energy basis to \$1.60–\$3.80/gallon of gasoline) depending on the technology. This is substantially more than untaxed gasoline. However, hydrogen can be used more efficiently than gasoline in a fuel cell car (because gasoline incurs conversion losses in an onboard gasoline fuel processor), so the fuel cost per kilometer can be comparable to current costs (10).

2. For Southern California energy prices and resource availability (widespread availability of low-cost natural gas), onsite production of hydrogen via advanced small-scale steam reforming of natural gas is the lowest-cost option and has the advantage that no hydrogen distribution system is required.
3. Truck-delivered liquid hydrogen might also be attractive for early demonstration projects, because the capital requirements for the refueling station would be relatively small (Figure 11) and no pipeline infrastructure development would be required (57, 110). However, delivered fuel costs are higher, because of the high cost of liquefaction.
4. Under certain conditions, a local gas pipeline bringing centrally produced hydrogen to users could offer low delivered costs. Our example assumes that it costs \$5/GJ to produce hydrogen in a large SMR plant. (Centrally

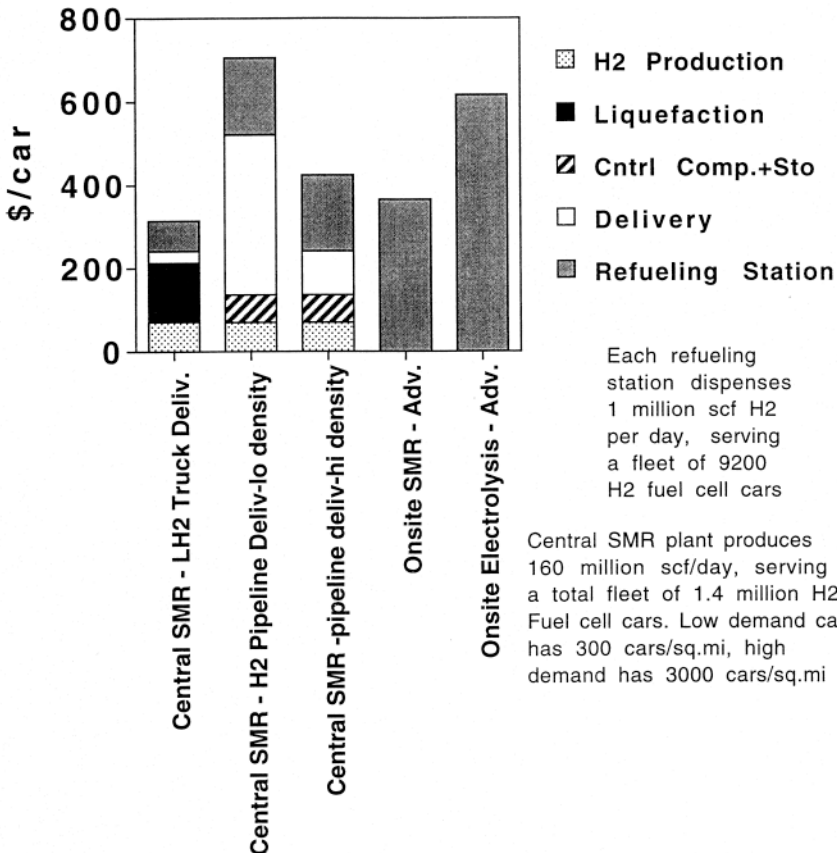


Figure 11 Infrastructure capital costs for various hydrogen production methods.

produced hydrogen ranges in cost from \$3/GJ for refinery excess to \$5–\$9/GJ for large-scale steam reforming to \$8–\$10/GJ for hydrogen from biomass, coal, or municipal solid waste.) The cost of pipeline distribution is given for two cases: a “low-density” case, in which a car population density of 300 cars/square mile (similar to the average vehicle density in the Los Angeles Basin or 10% of the city vehicle population density) is served, and a “high-density” case of 3000 cars/square mile (similar to the vehicle population in the city center). For a small-scale hydrogen pipeline system to be economically competitive with onsite small steam reforming, a high demand would be required (Figure 10). Alternatively, a small demand might be served by a nearby, low-cost supply of hydrogen (for example, a bus garage located near a hydrogen production plant).

5. Onsite electrolysis would be more expensive than other options, unless the cost of off-peak power is very low. In Southern California, the cost of off-peak power is \sim \$0.03/kWh, placing the cost of hydrogen well above that of onsite steam reforming (Figure 10). But at an off-peak power cost of \$0.01/kWh, electrolysis competes with onsite steam reforming. Off-peak power is available at \$0.01/kWh in some locations such as Brazil (113), which have excess off-peak hydropower. The amount of very-low-cost off-peak power available in Brazil (1000–2000 MW) might fuel 1 million–2 million hydrogen fuel cell automobiles.
6. In this range of hydrogen demands at a refueling station, no one supply option is favored under all conditions. (For different energy prices and demands, the relative delivered hydrogen costs would be different.)

Capital Cost of Hydrogen Infrastructure

The capital cost of hydrogen infrastructure is often cited as a “show stopper” for hydrogen vehicles. In Figure 11, we show the capital cost of building a hydrogen-refueling infrastructure for the various options discussed above. We consider two levels of infrastructure development.

Early Development of a Distribution System and Refueling Stations to Bring Excess Hydrogen from Existing Hydrogen Capacity to Users or to Produce It Onsite We assume that no new centralized hydrogen production capacity is needed. Two refueling stations serve a total fleet of 18,400 cars, each station dispensing 1 million scf of H_2 /day to 650 cars/day. (Alternatively, this level of infrastructure development could serve 2 bus garages, each housing 140 hydrogen fuel cell buses.) The options for providing hydrogen include (a) liquid hydrogen delivery via truck from existing hydrogen production capacity, (b) pipeline hydrogen delivery from a nearby large hydrogen plant or refinery, (c) onsite production from steam reforming of natural gas, and (d) onsite production from electrolysis.

Development of New Hydrogen Production, Delivery and Refueling Capacity to Meet Growing Demands for Hydrogen Transportation Fuel

The system serves a total fleet of 1.4 million cars, with 153 refueling stations, where each station dispenses 1 million scf of H_2 /day to 650 cars/day. (For reference, there are projected to be 7.8 million cars in Los Angeles in 2010. So, this case would be equivalent to a fleet in Los Angeles for which about 18% of the cars were hydrogen fuel cell-powered vehicles.) Options for providing hydrogen are (a) liquid-hydrogen delivery via truck from new centralized steam reformer capacity, (b) pipeline hydrogen delivery from a new centralized hydrogen plant, (c) onsite production from steam reforming of natural gas, and (d) onsite production from electrolysis.

A breakdown of hydrogen infrastructure capital costs is shown in Figure 11. For the large-scale system, a hydrogen steam reformer plant costs \$100 million. A liquefier adds ~\$200 million, plus \$40 million for liquid hydrogen delivery trucks and \$104 million for refueling stations with liquid hydrogen delivery. Alternatively, hydrogen can be distributed as a gas. A hydrogen compressor at the central plant adds \$17 million and half a day's storage to meet time-varying demand for fuel costs adds ~\$50 million. The extent of the required pipeline system depends on the geographic concentration of the demand. For a "low-density" case, with a vehicle population of 300 cars/square mile, the pipeline system consists of 10 spokes, each stretching 40 miles from the central plant. The capital cost of the pipeline is \$385 million. For the high-density case, with 3000 cars/square mile, each spoke is only 12 miles long, and the total pipeline capital cost is \$122 million. Refueling stations add \$260 million for gaseous-hydrogen delivery. The total capital cost is less with liquid-hydrogen delivery than with gaseous-hydrogen delivery (Figure 11), but the delivered fuel cost is higher for liquid hydrogen (Figure 10) because of the high energy cost of liquefaction.

The range of infrastructure capital costs for a system serving 18,400 fuel cell cars is about \$1.4 million–\$11.4 million or \$80–\$620/car. (The \$80/car is for liquid-hydrogen truck delivery including station costs only; no new production capacity or delivery trucks are included.) The range of infrastructure capital costs for a system serving 1.41 million fuel cell cars is ~\$440 million–\$870 million or \$310–\$620/car. For advanced onsite steam reforming, the capital cost is ~\$516 million, or \$370/car.

For centralized production with pipeline delivery through a highly developed urban area such as Los Angeles, the capital cost of the hydrogen pipeline is assumed to be \$1 million/mile and accounts for almost half the total infrastructure capital cost. [In a location with lower labor costs, the total pipeline cost might be reduced somewhat. If the location is not as developed (so that construction of the pipeline could avoid extensive road crossings, etc), the capital cost can be reduced as well.]

As shown in Figure 3, large biomass or coal hydrogen plants would cost perhaps threefold as much as a large SMR plant with the same hydrogen output. The overall capital requirement of a hydrogen infrastructure might be increased by ~40%, as compared with a system based on centralized steam reforming of natural gas.

Innovative technologies for gas separation might reduce the capital cost of gasifier plants (30).

Hydrogen Infrastructure Capital Costs Compared with Those for Methanol, Gasoline, and Synthetic Middle Distillates

How does the capital cost of developing a hydrogen-refueling infrastructure compare with costs for other transportation fuels such as methanol, gasoline, or synthetic middle distillates (SMD) from natural gas? It is often stated that developing a hydrogen infrastructure is much more costly than developing infrastructure for liquid fuels (114). However, recent studies (10, 11) found that the off-vehicle infrastructure capital costs for hydrogen are similar to those for methanol or SMD, once a high level of fuel use is achieved. [This is shown in Figure 12, which compares infrastructure costs (including fuel production, fuel delivery, and refueling stations) for hydrogen, methanol, and SMD in terms of capital cost for infrastructure per car served. Early infrastructure development (where no new fuel production capacity is needed) and large-scale infrastructure (with new production capacity) are shown.]

This is a surprising result, because one would expect a liquid-fuel-based infrastructure to be inherently less costly than one for a gaseous fuel. Even though the fuel distribution system is less costly for liquid fuels than for hydrogen, fuel production plant costs are higher for methanol and SMD than for hydrogen. Moreover, hydrogen can be used $\sim 50\%$ more efficiently on board a vehicle than can methanol or SMD, so that the overall capital cost per car for fuel infrastructure is lower. Costs for maintaining or expanding the gasoline-refueling infrastructure to meet future needs are also considerable, probably several hundred dollars per car served (115).

The conventional wisdom (114) that hydrogen infrastructure is much more capital intensive than methanol or gasoline is true only for small market penetrations of hydrogen or methanol vehicles. Once a large number of alternatively fueled vehicles are on the road, the capital cost is large to develop any new fuel, because new production capacity is costly. Moreover, zero-emission fuel cell cars using methanol, SMD, or gasoline are likely to be more expensive and less energy efficient than hydrogen fuel cell cars (10, 11). If the concept of "infrastructure" is expanded to include hydrogen production equipment (fuel processors) on board gasoline or methanol fuel cell cars, we see that methanol vehicles are projected to cost \$500 more/car and SMD vehicles \$1000 more/car than hydrogen vehicles. Hydrogen appears to have the lowest overall capital costs, including costs both on and off the vehicle (10, 11).

Lifecycle Cost of Automotive Transportation

Comparing the delivered cost of hydrogen transportation fuel on an energy cost basis (dollars per gigajoule), we find that hydrogen is 50%–100% more costly than gasoline. However, hydrogen can be used $\sim 50\%$ more efficiently in fuel cells than

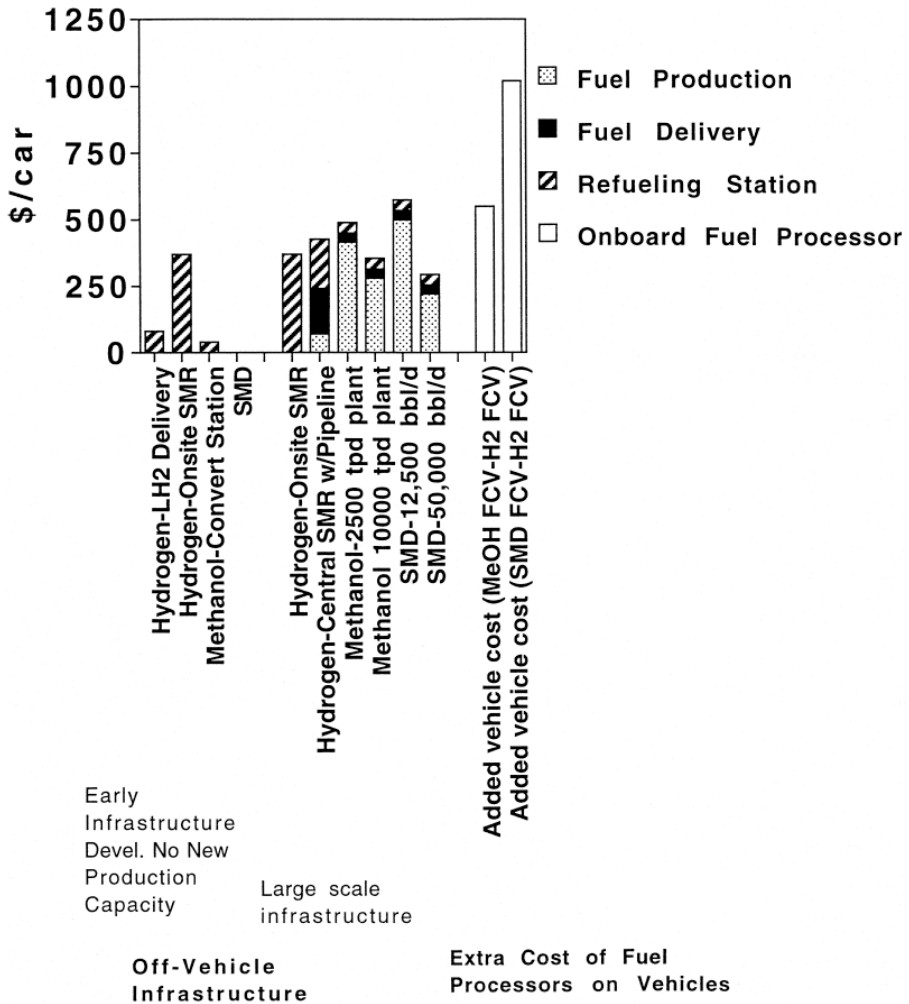


Figure 12 Capital cost of refueling infrastructure for hydrogen, methanol, and synthetic middle distillates from natural gas.

gasoline or other liquid fuels, so that the fuel cost per kilometer traveled can be comparable.

There are several reasons why hydrogen fuel cell vehicles are more energy efficient than fuel cell vehicles with onboard fuel processors: (a) to achieve the same performance, vehicles with onboard fuel processors weigh more, (b) fuel cells perform better on pure hydrogen than on reformed gasoline or methanol, which is a mixture of gases, and (c) there are energy conversion losses in making hydrogen in fuel processors.

Studies of the projected cost of hydrogen-fueled transportation have shown that, if fuel cell vehicles reach projected costs in mass production, the total lifecycle cost of transportation (accounting for vehicle capital costs, operation and maintenance costs, and fuel costs) could be slightly less for hydrogen than for methanol or gasoline fuel cell vehicles.

The projected capital costs of fuel cell vehicles as compared with competing internal-combustion-based technologies such as diesel/battery hybrids are still uncertain, although fuel cells appear to be competitive to within the accuracy of projected costs. However, hydrogen does appear to have advantages over liquid fuels as a fuel for fuel cell vehicles.

ENVIRONMENTAL AND SAFETY CONSIDERATIONS

Emissions of Greenhouse Gases and Air Pollutants

Hydrogen can be used with zero or near-zero emissions at the point of use. When hydrogen is burned in air, the main combustion product is H_2O , with traces of NO_x , which can be controlled to very low levels. No particulates, CO, unburned hydrocarbons, or sulfur oxides are emitted. With hydrogen fuel cells, water vapor is the only emission. Moreover, the total fuel cycle emissions of pollutants and greenhouse gases (such as CO_2 , which could contribute to global climate change) can be much reduced compared with those of conventional energy systems.

Fuel cycle emissions are all of the emissions involved in producing, transmitting, and using an alternative fuel. For example, for hydrogen made from natural gas, there would be emissions of CO_2 and NO_x at the hydrogen production plant, emissions associated with producing electricity to run hydrogen pipeline compressors (the nature of these emissions would depend on the source of electricity), and zero local emissions if the hydrogen is used in a fuel cell. The more efficient the end-use device (e.g. a fuel cell vehicle), the lower the fuel cycle emissions per unit of energy service (e.g. emissions per mile traveled).

Total fuel cycle emissions of greenhouse gases and other pollutants have been estimated for hydrogen vehicles by several authors (26, 111, 116–118). The total fuel cycle carbon emissions per kilometer are shown in Figure 13 for gasoline, methanol, and hydrogen, used in mid-sized automobiles powered by internal combustion engines or fuel cells, based on estimates by Williams et al (26). Various primary resources are considered for hydrogen production (natural gas, biomass, coal, solar energy, wind, and nuclear resources) and methanol production (natural gas, biomass, and coal). The effect of sequestration of carbon is shown for hydrogen production from natural gas, biomass, and coal. Emissions are indexed to a future, efficient gasoline-powered internal combustion engine in a four- to five-passenger automobile with fuel economy of 42 miles/gallon (mpg) of gasoline (based on Ford's aluminum intensive design). (Emissions from a current 26-mpg gasoline internal combustion engine vehicle are shown as well). Fuel economies for fuel cell vehicles are taken to be 71 mpg equivalent for gasoline (with onboard partial

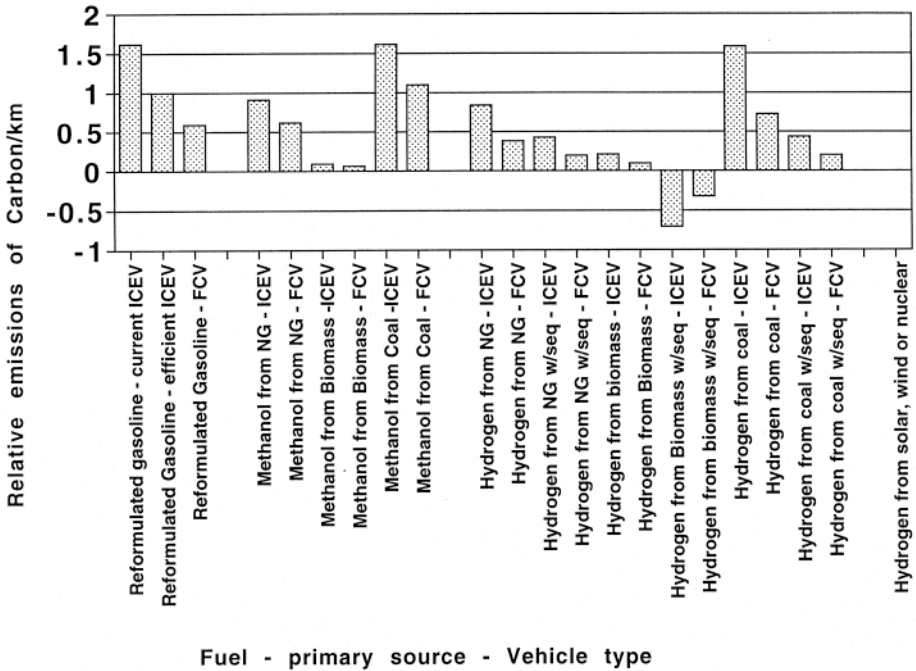


Figure 13 Fuel cycle emissions of greenhouse gases from hydrogen production and use in vehicles.

oxidation reforming), 69 mpg for methanol (with onboard steam reforming), and 106 mpg for hydrogen (10).

With hydrogen from natural gas, the most likely near-term feedstock, greenhouse gas emissions from a hydrogen fuel cell-powered vehicle are reduced by >60%, as compared with an efficient future gasoline internal-combustion-engine vehicle. CO₂ emissions can be reduced by another 20%, if the CO₂ is separated during hydrogen production and then sequestered. With hydrogen from coal, the fuel cycle emissions for a hydrogen fuel cell vehicle are reduced ~30%, as compared to a gasoline internal-combustion-engine vehicle. With carbon sequestration, fuel cycle emissions from coal-generated-H₂-powered fuel cell vehicles are only 30% of those from a gasoline internal-combustion-engine vehicle. If hydrogen is made from renewable energy sources such as biomass, solar resources, or wind, the fuel cycle greenhouse gas emissions are virtually eliminated. Emissions from electrolytic-hydrogen production depend on the source of the low-cost electricity. In cases such as Brazil, where the source is hydropower, greenhouse gas emissions should be essentially zero. In the United States, where the marginal generation mix includes coal-fired power plants, lifecycle CO₂ emissions for hydrogen-powered transportation can be substantial, exceeding those of gasoline (111). With biomass hydrogen and carbon sequestration, it would be possible to have a net negative

carbon balance; carbon would be removed from the atmosphere. It would be possible to envision a future energy system based on hydrogen and fuel cells with little or no emissions of pollutants or greenhouse gases in fuel production, distribution, or use.

Resource, Land, and Water Use for Hydrogen Production

Can hydrogen be produced sustainably? As mentioned above, there are a variety of primary sources that can be used to make hydrogen. Over the next few decades and probably well into the next century, fossil sources such as natural gas or coal may offer the lowest costs in many locations, with small contributions from electrolysis powered by low-cost hydropower. If the fuel decarbonization/carbon sequestration route is pursued, underground-storage capacities for carbon dioxide in deep saline aquifers may be as much as several hundred years—at present CO₂ emission levels—or more (33, 34).

In the longer term (or where locally preferred), renewable resources such as wastes, biomass, solar resources, or wind might be brought into use. It has been estimated that hydrogen derived from biomass produced on about two-thirds of currently idled cropland in the United States would be sufficient to supply transportation fuel to all of the cars in the United States, if they used fuel cells (5). Municipal solid waste could be gasified to produce transportation fuel for ~25%–50% of the cars in U.S. metropolitan areas (119). Solar and wind power are potentially huge resources for electrolytic hydrogen production, which could meet projected global demands for fuels, although the delivered cost is projected to be about two- to threefold that for hydrogen from natural gas (5). The collector area required for photovoltaic-hydrogen production for one hydrogen fuel cell car is ~25 m², assuming average U.S. insolation. It has been estimated that projected global 2050 fuel demands of 300 EJ/year could be met by solar hydrogen produced on ~0.5% of the world's land area. If ~14% of developable wind power in the United States were used to produce hydrogen, this could power all U.S. cars, assuming that they were run on hydrogen fuel cells (5).

Safety Issues

When hydrogen is proposed as a future fuel, the average person may ask about the Hindenburg, the Challenger, or even the hydrogen bomb. Clearly, consumers will not accept hydrogen or any new fuel unless it is as safe as our current fuels. In this section, we discuss hydrogen safety, in particular as compared with fuels like natural gas and gasoline, which are accepted today and have good safety records.

Table 5 shows some safety-related physical properties of hydrogen, natural gas, and gasoline (120). In some respects hydrogen is clearly safer than gasoline. For example, it is very buoyant and disperses quickly from a leak. (Experiments have shown that it is difficult to build up a flammable concentration of hydrogen, except in an enclosed space, because the hydrogen disperses too rapidly.) This contrasts

TABLE 5 Safety related properties of hydrogen, methane, and gasoline^a

	Hydrogen	Methane	Gasoline
Flammability limits (% volume)	4.0–75.0	5.3–15.0	1.0–7.6
Detonability limits (% volume)	18.3–59.0	6.3–13.5	1.1–3.3
Diffusion velocity in air (m/s)	2.0	0.51	0.17
Buoyant velocity in air (m/s)	1.2–9.0	0.8–6.0	Non-buoyant
Ignition energy at stoichiometric mixture (mJ)	0.02	0.29	0.24
Ignition energy at lower flammability limit (mJ)	10	20	n.a.
Toxicity	Non-toxic	Non-toxic	Toxic in concentrations of > 500 parts per million

^aAdapted from J. Hord, 1976.

with gasoline, which puddles rather than dispersing, and in which fumes can build up and persist. Hydrogen is nontoxic, which is also an advantage. Other aspects of hydrogen are potential safety concerns, especially its wide flammability limits and low ignition energy.

Hydrogen has a wide range of flammability and detonability limits, e.g. a wide range of mixtures of hydrogen in air will support a flame or an explosion. In practice, however, it is the lower flammability limit that is of most concern. For example, if the hydrogen concentration builds up in a closed space through a leak, problems might be expected when the lower flammability limit is reached. Here the value is comparable to that for natural gas.

The ignition energy (e.g. energy required in a spark or thermal source to ignite a flammable mixture of fuel in air) is low for all three fuels compared with that of commonly encountered sources such as electrostatic sparks. The ignition energy is about an order of magnitude lower for hydrogen than for methane or gasoline at stoichiometric conditions (e.g. at the mixture needed for complete combustion). But at the lower flammability limit, the point where problems are likely to begin, the ignition energy is about the same for methane and hydrogen.

Safe handling of large quantities of hydrogen is routine in the chemical industries. Proposed use of hydrogen in vehicles has raised the question of whether this experience can be translated into robust, safe hydrogen vehicle and refueling systems for the consumer. Several recent studies have addressed this question.

In a 1994 hydrogen vehicle safety study by researchers at Sandia National Laboratories (121), “There is abundant evidence that hydrogen can be handled safely, if its unique properties—sometimes better, sometimes worse, and sometimes just different from other fuels—are respected.” A 1997 report on hydrogen safety by Ford Motor Co. (122) concluded that the safety of a hydrogen fuel cell vehicle would be potentially better than that of a gasoline or propane vehicle, with proper engineering.

To assure that safe practices for using hydrogen fuel are used and standardized, there has been a considerable effort in recent years to develop codes and standards for hydrogen and fuel cell systems. The USDOE through the National Renewable Energy Laboratory (NREL), the National Hydrogen Association (a hydrogen industry group in the United States), and the International Energy Agency all have ongoing hydrogen codes and standards activities. NREL has helped organize a United States-Canadian expert group, which is developing a hydrogen safety sourcebook (123). The National Fire Protection Agency in the United States and the International Standards Organization (ISO) are currently developing hydrogen standards. In addition, fuel cell vehicle manufacturers are developing recommended practices for fuel cell vehicles and hydrogen systems, as part of fuel cell vehicle demonstrations.

POSSIBLE SCENARIOS FOR DEVELOPMENT OF HYDROGEN INFRASTRUCTURE

Assuming that hydrogen end-use technologies are successfully developed and that the environmental case for hydrogen becomes compelling enough to warrant its widespread use, how is a hydrogen energy system likely to develop?

The technical building blocks for a future hydrogen energy system already exist. The technologies for producing, storing, and distributing hydrogen are well known and widely used in the chemical industries today. Hydrogen end-use technologies, including fuel cells, hydrogen vehicles, and power and heating systems are undergoing rapid development. Still the costs and time constants inherent in changing the present energy system mean that building a large-scale hydrogen energy system would probably take many decades.

Because hydrogen can be made from many different sources, a future hydrogen energy system could evolve in a variety of ways. In industrialized countries, hydrogen might get started by “piggybacking” on the existing energy infrastructure. Initially, hydrogen could be made where it was needed from more widely available energy carriers, avoiding the need to build an extensive hydrogen pipeline distribution system. (This could help avoid the “chicken and egg” problem of introducing alternative transportation fuels—large numbers of alternatively fueled vehicles can’t be used until the fuel infrastructure is widely developed and vice versa.) For example, in the United States, where low-cost natural gas is widely

distributed, hydrogen will probably be made initially from natural gas, in small reformers located near the hydrogen demand (e.g. at refueling stations). As demand increases and becomes more geographically dense, centralized production with local pipeline distribution would become more economically attractive. Eventually, hydrogen might be produced centrally and distributed in local gas pipelines to users. A variety of low or zero net carbon-emitting sources of hydrogen might be brought in at this time. For example, centralized production would enable large-scale production of hydrogen from fossil fuels with separation and sequestration of CO₂. [Centralized hydrogen production is required to make CO₂ sequestration economical; otherwise the cost of gathering CO₂ from many small sources is prohibitive (35).]

In other areas, as in many developing countries where there is little existing energy infrastructure and projected rapid growth in demand for transportation fuels, it might be preferable to develop centralized hydrogen production (for example from coal or biomass) with local hydrogen pipeline distribution from the beginning, provided that there is enough market for hydrogen to justify building a large hydrogen plant, as required for low-cost gasification. Initial markets need not be entirely transportation fuels; some of the plant output could go to industrial processes such as ammonia manufacturing for fertilizer (38, 124) or to coproduce electricity (30).

A possible sequence for developing a hydrogen infrastructure based on hydrocarbon fuels is shown in Figure 14, starting with early infrastructure, and progressing to city-scale systems and eventually to a "hydrogen economy" with CO₂ sequestration. An evolution toward use of hydrogen would begin with production from existing energy sources, near the point of use. Once a large, geographically concentrated demand evolved, hydrogen might be made centrally, and carbon sequestration could be done. (Although it is not explicitly shown in this figure, electrolysis could play a role to the extent that very-low-cost power is available.)

Assuming that the political will exists to introduce a zero-emission transportation system, how rapidly could hydrogen become a major energy carrier? The limiting factor is not hydrogen infrastructure. It is technically and economically feasible to put a hydrogen infrastructure in place within a few years. (For example, small onsite SMRs could be put in place within a few months; building a large steam reformer plant serving a million fuel cell cars would take only 2–3 years.) Instead, the development of hydrogen end-use systems such as fuel cells and their penetration into transportation or power markets will probably determine the pace of introducing hydrogen as an energy carrier. It is unlikely that economics alone will motivate the commercialization of hydrogen. The development of such markets will probably depend on political will to move toward a zero-emission energy system and on the relative economics of hydrogen versus other low-polluting alternative fuels.

Building a geographically concentrated demand for energy will take time. Getting 1 million hydrogen fuel cell cars on the road within relatively short distance

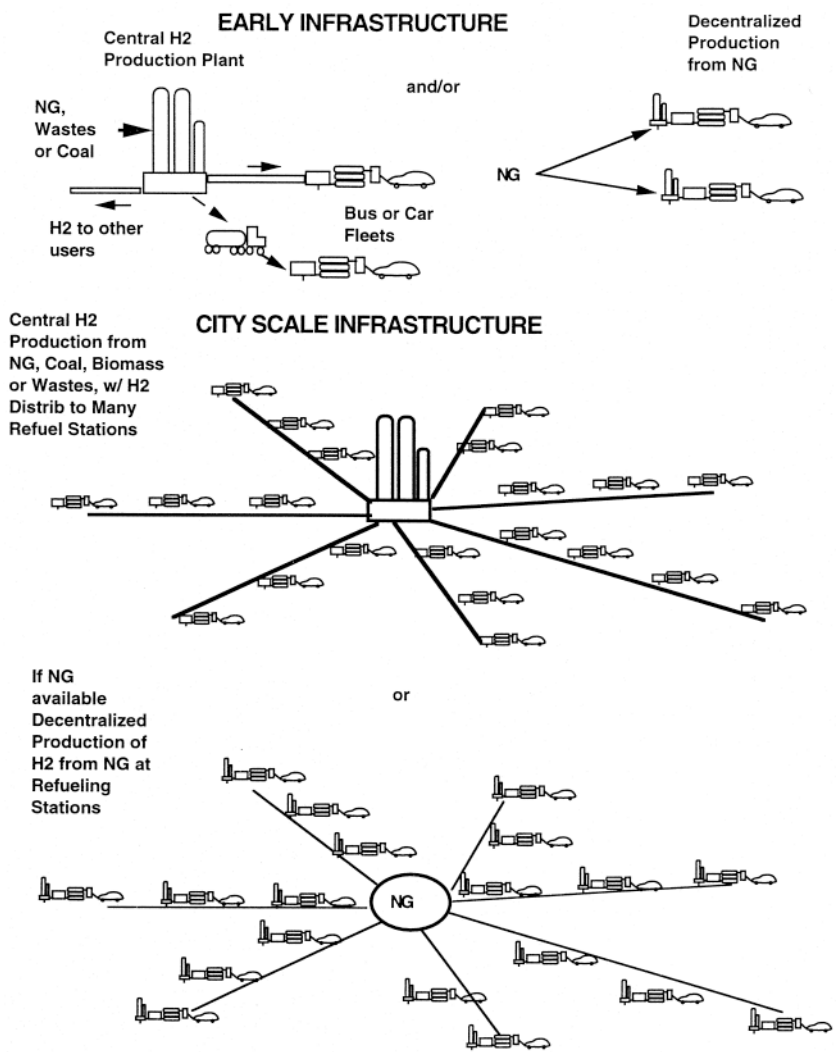


Figure 14 Scenarios for developing hydrogen energy infrastructure: early infrastructure, city-scale infrastructure options, and hydrogen energy system with CO₂ sequestration.

(a few tens of kilometers) of a large hydrogen plant (e.g. converting at least 10% of a big city to hydrogen) would probably take longer than building the hydrogen plant—unless stringent rules were imposed mandating zero-emission vehicles. So the early infrastructure will be built in small increments, until the demand becomes large enough and dense enough to support a central plant. Central plants can be part of early hydrogen vehicle refueling infrastructure development, if other

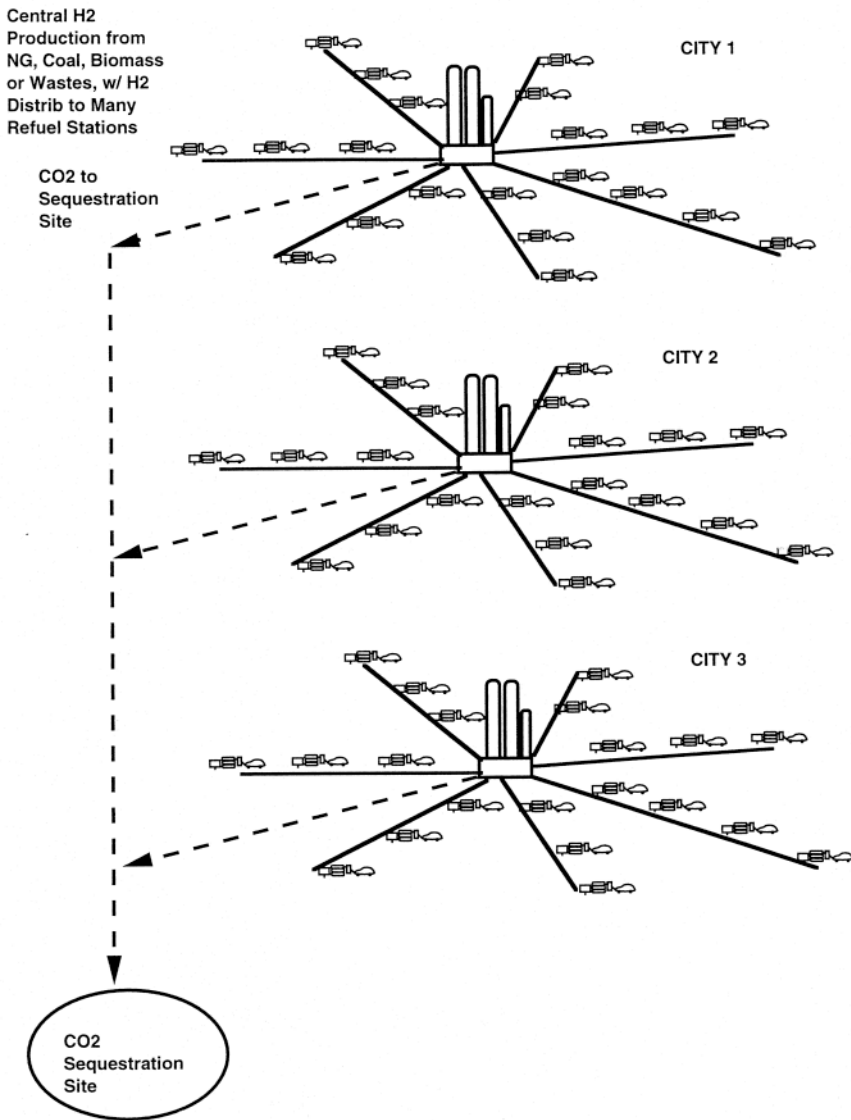


Figure 14 (continued)

nonenergy uses for hydrogen are present and only some of the plant output is used for transportation.

The start-up phase of a hydrogen transportation system would be accelerated if transportation demand grows rapidly enough to build a large new demand in just a few years (for example in some developing countries).

Who will develop hydrogen as an energy carrier? The current merchant hydrogen system is the purview of a few industrial gas companies, which supply hydrogen on a much smaller scale than would be required for larger energy markets. If hydrogen is developed at large scale, these companies would have significant experience with hydrogen. However, the oil companies (the largest onsite hydrogen producers and users today) would be well positioned in terms of technical knowledge and experience with transportation fuel markets. Exxon has maintained a fuel cell research program for many years. Mobil has allied with Ford's fuel cell vehicle program, and Shell Oil has recently announced formation of a new hydrogen business unit (125). Another interesting possibility is the idea of "independent fuel producers," analogous to independent power producers, who are now building 100- to 200-MW power plants around the world. An independent fuel producer would contract to supply a city with hydrogen fuel at a certain price for a certain length of time. Such a company might collaborate with a hydrogen vehicle provider, offering a "clean-transportation" package for bus or fleet markets initially and later for public transportation fuel.

It is technically possible to build a hydrogen energy system today. A hydrogen vehicle-refueling infrastructure will probably cost no more than a new system for other alternative fuels such as methanol or synthetic middle distillates, assuming a large level of use. A key step toward development of a hydrogen infrastructure is development of enabling technologies, such as automotive fuel cells and onboard hydrogen storage systems on the end-use side and gasifier-based hydrogen production systems and sequestration systems on the hydrogen supply side. Small-scale reformer technology will be important in the early stages of a hydrogen energy system. In the longer term, development of lower-cost, more efficient large-scale coal-to-hydrogen systems will be important in countries such as India and China (38). Biomass hydrogen could also play a role in many developing countries. The viability of carbon sequestration needs further investigation to keep the fossil hydrogen option open in a future energy system with low greenhouse gas emissions.

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