PROSPECTS FOR BUILDING A HYDROGEN ENERGY INFRASTRUCTURE

Joan M. Ogden

PU/CEES Report No. 318

July 1999

Center for Energy and Environmental Studies
Princeton Environmental Institute
Princeton University
Princeton, NJ 08544-5263
(609) 258-5445
www.princeton.edu/~cees
ogden@princeton.edu

This paper will also appear as a chapter in *Annual Review of Energy and the Environment*, Vol. 24, 1999.

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Joan M. Ogden
Center for Energy and Environmental Studies
Princeton University
Princeton, NJ 08544 USA

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, wind or nuclear. 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 is 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.

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 with respect to 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 largest 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 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 to 10 years (Steinbugler and Williams 1998). Eight major automakers have announced plans to commercialize fuel cell vehicles in the 2004-2005 timeframe. If low cost fuel cell vehicles are successfully developed, they would provide a driver toward use of hydrogen.

Hydrogen can be made from a variety of widely available feedstocks such as natural gas, coal, biomass, wastes, solar, wind or nuclear. If hydrogen is made from non-fossil energy sources or decarbonized fossil sources with separation and sequestration of CO_2, 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, 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 (Bockris 1980, Winter and Nitsch 1988, Ogden and Williams 1989, Ogden and Nitsch 1993). More recently, the idea of a hydrogen energy system based on production of hydrogen from fossil fuels with separation and sequestration of byproduct CO_2 has been proposed (Williams 1996, Audus, Karstaad and Koval 1996, Socolow et al. 1997).

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, describe likely areas for technological progress. We estimate the cost of developing a hydrogen infrastructure, as compared to 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 electric 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 are 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 to current vehicles. These include fuel cells, hybrid internal combustion engine/battery 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 (PNGV). Advanced Diesel/battery hybrids might also achieve high efficiency and acceptable cost, but currently emissions remain an issue, especially with respect to particulates (NRC 1998). (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 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 vehicles are likely to be lower cost and more efficient than those with onboard fuel processors (Ogden, Kreutz and Steinbugler 1998, Thomas et al. 1998). The lower first cost of the hydrogen fuel cell vehicle and its higher efficiency combine to give a lower lifecycle cost than fuel cell 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 will 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 at small sizes, making them potentially attractive for distributed generation.

The possibility for 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, where it is eventually emitted to the atmosphere from the vehicle, which limits 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 produced per day (scf/day), normal cubic meters per day (Nm^3/day), Gigajoules per day (GJ/day) or kW of hydrogen output (on a continuous basis). In this paper, specific capital costs for production plants are expressed as $/kW of hydrogen output capacity. All energy and power units are given, based on the higher heating value of hydrogen.

Hydrogen storage capacity is given in volume units (scf or Nm^3), in tonnes or in energy stored (GJ). Capital costs for storage are given in $ per tonne of hydrogen stored or $/GJ stored.

In this paper, the levelized cost of hydrogen production, transmission or storage is given in $/GJ of hydrogen on a higher heating value basis. (1 Gigajoule = 10^9 joules = 0.95 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 (million scf/day) to more familiar quantities, we show in Table 2, typical energy demands expressed in scf H2 per day and GJ/day, ranging from hydrogen required for one fuel cell car to 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 producing 25-100 million scf/day could fuel a fleet of about 225,000-900,000 hydrogen fuel cell cars. A small scale steam methane reformer 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 US primary energy use (about 5% of US natural gas use) goes to hydrogen production for chemical applications. A variety of hydrogen production processes are commercially available today: thermochemical methods, which are used to derive hydrogen from hydrocarbons, and electrolysis of water, where electricity is used to split water into its constituent elements hydrogen and oxygen. Potential future hydrogen production methods 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 and projections for technical progress, and economics including capital costs for production equipment, conversion efficiency and 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," comprised 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 for hydrogen production (Rostrup-Nielsen 1984, Twigg 1989). In the US, most hydrogen today (over 90%) is manufactured via steam reforming of natural gas (Heydorn 1995). Hydrogen production is accomplished in several steps: steam reforming, water gas shift reaction, and hydrogen purification (see Figure 1).

The steam reforming reaction

$$CH_4 + H_2O \leftrightarrow CO + 3\ H_2$$

is endothermic and requires external heat input. Economics favor reactor operation at pressures of 3-25 atmospheres and temperatures of 700^oC to 850^oC. The external heat needed to drive the reaction is often provided by the combustion of a fraction of the incoming natural gas feedstock (up to 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:

$$CO + H_2O \rightarrow CO_2 + H_2$$

The gas exiting the shift reactor contains mostly H2 (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 up to 99.999% purity.

The energy conversion efficiency [= hydrogen out (HHV)/energy input (HHV)] of large scale steam methane reformers is perhaps 75-80%, although 85% efficiencies might be achieved with good waste heat recovery and utilization (Katofsky 1993).

Steam methane reformers have been built over a wide range of sizes. For large scale chemical processes such as oil refining, steam reformers produce 25 to 100 million standard cubic feet of hydrogen per day. (In energy terms, this is enough hydrogen to power a fleet of about 225,000 to 900,000 hydrogen fuel cell cars, each driven 11,000 miles per year.) These systems consist of long (12 meter) catalyst filled tubes, and operate at temperatures of 850 degrees C and pressures of 15-25 atm, which neccessitates use of expensive alloy steels. Capital costs for a 20 million scf H2/day steam reformer plant (including the reformer, shift reactor and PSA) are about $200/kW H2 output; for a 200 million scf/day plant capital costs are estimated to be about $80/kW H2 (DTI et al. 1997).

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 about $750/kW H2 at 1 million scf/day and $4000/kW H2 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. Steam methane refomers in the range 2000 to 120,000 scf H2/day have been developed for use with fuel cells, and have recently been adapted for stand-alone hydrogen production (Halvorson et al. 1997). 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 (3 atm, 700^{o}C), which relaxes materials requirements. Estimates of mass produced costs for small "fuel cell type" steam methane reformers indicates that the capital cost for hydrogen production plants in the 0.1 to 1.0 million scf/day range would be $150-180/kW H2 assuming that 1000 units were produced (DTI et al. 1997). (Costs are given on a higher heating value basis, and for the purpose of comparison, do not include hydrogen compression, storage or dispensing to vehicles.) The capital costs per unit of hydrogen production ($/kW H2) 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 according to

$CH_4 + 1/2\ O_2 \ \text{->}\ CO + 2\ H_2$

The 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 (Loftus 1994). 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 refineries. Large systems generally incorporate an oxygen plant, since operation with pure oxygen rather than air reduces the size and cost of the reactors.

Small scale partial oxidation systems, using oxygen in air, have recently become commercially available, but are still undergoing intensive R&D (Moard 1995, Loftus 1994, Mitchell et al. 1995). Partial oxidation systems are under development by Arthur D. Little and its spin-off company Epyx (ADL 1994, Loftus 1994, Mitchell et al. 1995) and by Hydrogen Burner Technology (Moard 1995). Small scale partial oxidation systems have a fast response time, making them attractive for following rapidly varying loads, and can handle a variety of fuels, including methane, ethanol, methanol, and gasoline.

Because they are more compact, and do not require indirect heat exchange (as in steam reforming), it has been suggested that small partial oxidation systems could be lower cost than 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 (Ogden et al. 1996). Developing low cost purification technologies is key if POX systems are to be used for small-scale stationary hydrogen production. Another approach is using 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 (Dyer 1999).

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 (Katofsky 1993, Chen 1995, Williams et al. 1995). Coal gasification was the preferred method of hydrogen production in the United States earlier in this century (prior to the availability of low cost natural gas) and is still practiced in China and Europe. Initially, this was done through the K-T (Koppers-Topzek) method, although newer coal gasification options are now available (Steinberg and Cheng 1988, EPRI 1993, Lee 1996). Biomass gasification systems resemble those for coal, but biomass gasifiers operate at lower temperatures, and the clean-up requirements are different, as biomass contains little sulfur (Larson 1999). Gasifiers for municipal solid waste have also been developed for use in electricity production, and could be adapted for hydrogen production (Chen 1993). Biomass and waste gasifier hydrogen systems have not been commercialized, but probably could be in a few years, as all the component technologies are available.

The capital cost for large gasification systems is about \$700/kW H2 for biomass and \$800/kW H2 for coal, although improvements in high temperature gas separation technology may reduce these costs (Williams 1999). Conversion efficiency from biomass or coal to hydrogen is about 60-65%.

Williams et al. (1995) have compared the cost of hydrogen production via large scale gasification of coal, biomass or wastes (Figure 4). 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 (Williams 1999, Dyer 1999).

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 CO_2 could then be sequestered underground in secure geological formations such as deep saline aquifers or depleted gas fields (Herzog 1997, Blok et al. 1997, Williams 1998, Audus et al. 1996, Socolow et al. 1997). This would allow continued use of fossil primary sources to produce transportation fuel production with greatly reduced emissions of carbon dioxide to the atmosphere.

Steam methane reforming plants or coal or biomass gasifier plants could be configured to allow separation and capture of CO_2 at low additional cost (Blok et al. 1997, Williams

1998). Various estimates show that carbon dioxide capture, pipeline transmission and sequestration underground would add only a few $/GJ, or perhaps 10% to the delivered cost of hydrogen transportation fuel, assuming that CO_2 separation, pipeline transport and sequestration were done on a sufficiently large scale (Hendriks 1994, Holloway 1996, Williams 1998, Ogden 1999).

For example, studies carried out for the European community indicate that the cost of CO_2 pipeline transmission several hundred kilometers to an underground injection site would add less than $1/GJ to the cost of co-produced hydrogen (Hendriks 1994, Holloway 1996, Skovholt 1996, Williams 1998). The cost of injecting CO_2 into a deep saline aquifer or depleted gas well is likely to be an order of magnitude lower than transmission costs (Hendriks 1994, Holloway 1996). The incremental cost of separating CO_2 during hydrogen production from natural gas is estimated to be less than $1/GJ (Ogden 1999). In some cases, it may be feasible to produce hydrogen via steam reforming at the natural gas field and reinject by-product CO_2, gaining a credit for enhanced gas recovery (Blok et al. 1997). In this case, sequestration could improve the economics of hydrogen production via a byproduct credit for the extra natural gas produced.

Since 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 (Socolow et al. 1997). This is particularly true in countries such as China and India with huge coal resources and rapidly growing transportation energy demand (Williams 1998).

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

$$2\ H_2O \rightarrow 2\ H_2 + O_2.$$

Any source of electricity can be used, including intermittent (time varying) sources such as off-peak power, solar or wind (Ogden and Nitsch 1993).

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 transients well. Experimental designs for electrolyzers have been developed using solid oxide electrolytes and operating at temperatures of 700 to 900°C. High temperature electrolysis systems offer higher efficiency of converting electricity to hydrogen, as some of the work to split water is done by heat, but materials requirements are more severe.

Electrolyzers are typically about 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 ranging from a few kilowatts to hundreds of megawatts. Capital costs for electrolyzers have been estimated by various authors (Thomas and Kuhn 1995, Fein and Edwards 1984, Ogden and Nitsch 1993, DTI et al. 1997). The capital cost of alkaline systems varies with size, although there is little scale economy above sizes of perhaps a few 100 kW (Fein and Edwards 1984). Hydrogen plant costs for commercially available large-scale alkaline electrolysis systems are currently about $500-600/kW, with projected costs as low as $300/kW (Ogden and Nitsch 1993). Thomas and Kuhn have estimated recently that mass-produced small PEM electrolyzers might cost less than $300/kW H2 out (HHV) even at sizes of only a few kW (DTI et al. 1997).

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 (1-2 cent/kWh) power is available, for example excess hydropower. Another niche market for electrolytic hydrogen may be remote sites, where conventional fuels are expensive due to high transport costs and wind power can be used to produce hydrogen (Rambach 1999).

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 $ per kilowatt of hydrogen output ($/kW H2) computed on a higher heating value basis. Steam methane reformers 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 about 1 cent/kWh, electrolytic hydrogen production might be economically competitive.

While 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) which 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 the reader is referred to recent conference proceedings (USDOE 1998, Bolcich and Veziroglu 1998). New production techniques fall into several general categories:

1) Innovations in technologies for deriving hydrogen thermochemically from hydrocarbon feedstocks. This includes advances in reforming technologies such as "sorbent enhanced reforming" which reduce costs by combining reforming, shift and purification stages (Hufton et al. 1998), catalytic cracking of natural gas (Steinberg 1998, Muradov 1996), and advanced systems for producing hydrogen from coal (Steinberg 1998). Advanced membrane technologies for gas separation (for example, the "ion transport membrane" or ITM system under development at Air Products and Chemicals, Inc.) can simplify the design of hydrogen production systems based on partial oxidation or gasification (Dyer 1999, Williams 1999). Also included here are development of advanced gasification or pyrolysis systems for coal, wastes and biomass (Williams et. al 1996, Spath and Mann 1998) and novel biomass to hydrogen methods (Antal 1998).

2) Advanced electrochemical routes to hydrogen production. These include advanced electrolysis systems, such as those using proton exchange membranes or solid oxide materials as electrolytes. Also included are photocatalytic and photoelectrochemical (Khaaselev and Turner 1998) 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 Winter and Nitsch 1988 for a description of the principles involved).

3) Biological hydrogen production. This includes controlled production of hydrogen by algae or bacteria in light driven bio-reactors (Schulz et al. 1998, Kitajima et al. 1998, Modigal and Holle 1998).

Of these alternatives, some like sorbent enhanced reforming; gasification of biomass or wastes; and PEM electrolyzers could probably be commercialized within a few years. Longer term options are photoelectrochemical methods, where the short lifetime of the cells due to corrosion currently limit their practicality, and biological hydrogen production, where 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.

Large Scale Stationary Storage of Hydrogen: Underground Gas Storage in Aquifers, Caverns

Very large quantities of gaseous hydrogen could be stored underground at several hundred to 1000 psi in depleted oil or gas fields, aquifers or salt or rock caverns (Carpetis 1981, Taylor et. al 1986, Blazek et al. 1992, Venter and Pucher 1998). 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 (Taylor et. al 1986). Underground formations typically have very large capacities, up to 1 billion Normal cubic meters of gas for aquifers or gas fields, and millions of Normal cubic meters of gas for caverns.

For gas wells and aquifers, only a fraction (typically ranging from 1/3 to 2/3) of this capacity is accessible per storage cycle, as 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 to 10 million Normal cubic meters of hydrogen per storage cycle, equivalent to the fuel needed each day by a large refinery complex or by a fleet of 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 per GJ to the cost of hydrogen (Taylor et al., 1986, Blazek et al. 1992, Venter and Pucher 1998). Higher costs are found (Blazek et al. 1992, Venter and Pucher 1998), 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 which 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 5 hydrogen vehicle refueling stations could carry a flow of 5 million scf hydrogen per day. Assuming that the pipeline operated at 1000 psi, the storage volume available in the pipeline would be 340,000 scf, only about 7% of the total daily flow rate.

Stationary Storage at Intermediate and Small Scale

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 degrees C.) Liquid hydrogen is stored in cryogenic dewars, vessels designed to minimize heat loss. Hydrogen dewars range in size 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 and 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 a long distance, where gaseous pipeline costs would be prohibitive. For these reasons, merchant hydrogen (e.g. hydrogen that is delivered for industrial purposes) is often liquified for storage and delivery by truck. (About one third of merchant hydrogen delivery is by liquid hydrogen truck, the remainder by compressed gas truck or short distance pipeline.)

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 (Peschka 1992). Liquefaction and storage typically add $5-10/GJ to the cost of liquid hydrogen (Ogden and Williams 1989, Directed Technologies, Inc. et al. 1997) depending on the scale of the liquifier, about as much as the cost of gaseous hydrogen production (see Figure 4). 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 (Ogden 1998, Ogden et al. 1998, DTI et al. 1997).

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 psia, typically holding 6000 to 9000 scf per vessel (Taylor et al. 1986, Ogden et al. 1995). 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 (Ogden et al. 1995, DTI et al. 1997). Compression from production pressure (typically 1 to 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 and Edwards (1984) found that storage in pressure vessels added $2-20/GJ depending on the application. Ogden et al. (1995) have estimated that costs for compression and pressure vessel storage of 0.025 to 0.5 million scf 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 23-234 million scf/day, finding additional costs of $2-4/GJ (DTI et al. 1997).

Storing Hydrogen Onboard Vehicles

Unlike gasoline or alcohol fuels, which are easily handled liquids at ambient conditions, hydrogen is a light-weight 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 pp. 54-55 for a discussion of hydrogen safety.) Moreover, it must be capable of storing enough hydrogen to provide a reasonable travelling range, and good dormancy (ability to retain hydrogen for a long period of time without leakage).

A number of alternative methods for onboard hydrogen storage have been considered (Block et al. 1988, Arthur D. Little 1994, James et al. 1996). 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 travelling range in a mid-size hydrogen fuel cell automobile.

Several methods have been demonstrated for storing hydrogen on experimental vehicles.

1. Compressed gas storage in high-pressure cylinders. This method 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 mini-vans (Dircks 1998). Ford has explored this option in a recent assessment (James et al. 1996, Sims 1996), as have researchers at Lawrence Livermore National Laboratory and Thiokol (Mitlitsky 1996, Mitlitsky, Weisberg and Myers1999).

2. Liquid hydrogen storage in a small dewar. Researchers at DFVLR in Stuttgart (Winter and Nitsch 1988, Peschka 1992), BMW (Braess and Strobl 1996), Los Alamos National Laboratory (Stewart 1982), Messer Griesham (Michel et al. 1998), and Linde (Wetzel 1998) have developed technologies for LH2 storage on vehicles and refueling. One variant of the Daimler-Benz NECAR IV uses liquid hydrogen.

3. Metal hydrides are compounds where hydrogen is absorbed by a metal under pressure and is released when heat is applied (Andresen and Maeland 1977, Barnes 1988). This technology was employed by Daimler-Benz in its experimental hydrogen vehicles in the 1970s and 1980s (Buchner 1984) and by Toyota in a 1997 hydrogen fuel cell demonstration vehicle (Hoffmann 1997)

Each onboard storage method has advantages and drawbacks.

Compressed gas is simple to implement, refilling is as rapid as 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 (over 10% hydrogen by weight) and large, but probably acceptable, volume. Conceptual designs have been developed by Ford Motor Company for lightweight potentially low cost ($500-1000 per tank in mass production) high pressure (5000 psi) hydrogen tanks holding over 10% hydrogen by weight, which can be refilled in 3 minutes or less (James et al. 1996). Recently, Mitlitsky has estimated that a tank carrying 3.9 kg (enough hydrogen to power a mid-size fuel cell car about 380 miles) would weigh less than 40 kg, and would take up perhaps 190 liters of space (Mitlitsky, Weisberg and Myers 1999). 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 minutes). 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 to compressed gas cylinders (several thousand psi).

Liquid hydrogen is attractive in that it offers low weight and volume per unit energy. This has led some researchers to prefer liquid hydrogen, as the most capable of providing a long range (Braess and Strobl 1998). With liquid hydrogen, boil-off of cryogenic liquid from storage (poor dormancy) and refueling losses have been issues (Peschka 1992). Liquid hydrogen vehicle onboard storage and refueling systems have undergone significant improvements in recent years (Wetzel 1998, Michel et al. 1998), so that these problems are much improved. For example, less than 1% boil-off would be expected per day from a current liquid hydrogen tank (Wetzel 1998), 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 liquification. If greenhouse gas emission reduction and efficient use of primary resources are motivations for adopting hydrogen, liquid hydrogen routes are less attractive than 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), which would allow operation on compressed gas for short trips, and operation on liquid hydrogen when a long range was needed (Aceves and Berry 1998). Such systems are undergoing preliminary tests, and would reduce the energy used as compared to a pure liquid hydrogen system.

Considering both storage and refueling technologies, the most promising near term alternative is probably compressed gas storage (James et al. 1996). 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 onboard to travel a long distance (Steinbugler and Ogden 1994, Thomas 1996). 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 (Ogden et al. 1995, Ogden, Kreutz and Steinbugler 1998).

Novel Approaches to Hydrogen Storage

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

1) Storage of hydrogen in carbon materials.
Carbon is an attractive medium for hydrogen storage as 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 nano-fibers (Chambers et al. 1998), recently reporting storage of over 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 nano-tubes (Dillon et al. 1997, Ye et al. 1999). Others have proposed storing hydrogen in fullerenes (Wang et al. 1998, Tarasov et al. 1998), or in activated carbon at low temperatures (J.A Schwarz 1993, P. Benard and R. Chahine 1998).

2) Development of improved metal hydrides and alternative hydrides. One goal is to develop metal hydrides which store more than a few weight percent hydrogen, which are potentially low cost, and are readily charged and discharged. For a review of metal hydride technology the reader is referred to (Andresen and Maeland 1977, Barnes 1988, Verbetsky 1998). Polyhydride materials (Jensen 1998) are an alternative approach, and liquid organic hydrides have been considered as a method for bulk hydrogen storage and transport (Newson et al. 1998).

3) Various researchers have proposed high pressure gas storage of hydrogen in glass microspheres (Souers et al. 1978, Woerner et al. 1979, Rambach 1996), which can be transported in bulk without the need for an external pressure vessel. Others have proposed hydrogen storage in zeolites (Darkrim and Malbrunot 1998) or as a cryogenic "slush" (Fujiwara 1998), 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.

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 R&D 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 as 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 than the merchant system. However, it could provide a technological springboard for the early phases of developing a hydrogen energy system.

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 which is expected to increase to 6 EJ/yr by 2010, primarily because of higher hydrogen demand for oil refining (Chemical and Engineering News 1996). While most hydrogen is produced where it is needed and consumed onsite, 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 (Heydorn 1995, Kerr 1993). Most merchant hydrogen today is produced as a byproduct of chemical activities such as oil refining or chloralkali plants (Heydorn 1995). 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 2-3 million hydrogen fuel cell cars. Technology to safely handle these quantities of hydrogen is well established in industrial settings (Linney and Hansel 1996).

Long Distance Pipeline Transmission of Hydrogen

It is standard commercial practice in the chemical industries today to transport large quantities of gaseous hydrogen (up to 100 million scf/day) over long distances (100 miles or more) at high pressures (up to 1500 psia) in pipelines specifically designed for hydrogen. The characteristics of existing hydrogen pipelines have been described in several studies (Leeth 1979, Kelly and Hagler 1980, Christodoulou 1984, Pottier et al. 1988, and Kerr 1993). In this section, we first review some of the data in these studies. Based on models developed by Christodoulou (1984), 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 largest hydrogen pipelines operating today are about 12" diameter, and are capable of transmitting 100 million scf/day of hydrogen (enough for a fleet of about 900,000 fuel cell cars). No hydrogen embrittlement or undue safety problems have been reported for these lines. It is interesting to note that gaseous hydrogen pressures of up to 100 bar (1470 psi) have been routinely handled in an Air Liquide pipeline (Pottier et al. 1988) and that the total gaseous hydrogen flow in all high pressure transmission lines today is about 320 million scf/day (42 million GJ/yr) or enough to provide fuel for a fleet about 3 million hydrogen fuel cell passenger cars.

Pottier et al. (1988) estimate that the capital cost of pipelines designed for hydrogen transmission would be about 50% higher than for natural gas transmission lines. The cost of installation would also be higher, since special care would be needed with welds. This is consistent with earlier estimates by Leeth (1979) which showed that the capital cost of hydrogen transmission pipelines was about 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 (Leeth 1979).

The cost of compression is also higher, as about three times more compressor power per unit of energy transmitted is needed to compress hydrogen than natural gas (Leeth 1979). The specific capital cost ($/kW) of hydrogen compressors is estimated to be 20-30% higher than 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 (1984) found hydrogen transmission costs of less than $1/GJ for optimized 500 km, large scale hydrogen pipelines. Pottier et al. (1988) estimated costs of about $0.28-0.42/GJ for a 100 km pipeline. And Leeth estimated hydrogen transmission costs of less than $0.15/GJ/100 miles of pipeline for large hydrogen flows. Although generally about 50% higher than costs for natural gas transmission, hydrogen pipeline transmission costs are still quite small compared to large scale hydrogen production costs of $5-8/GJ.

A sample calculation comparing the cost of energy transmission in $/GJ 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 1.5-3 times 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: acceleration of crack growth when pipeline pressure is cycled. Studies conducted starting in the 1970s and 1980s (Jewett 1973, Hoover et al. 1981, Holbrook et al. 1982, Cialone et al. 1984, Holbrook et al. 1986, Walter and Chandler 1993, Blazek et al. 1993) 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, SO_2, O_2 or other gases (Cialone et al. 1984). 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 or 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.

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 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 (Ogden et al. 1995, DTI et al. 1997, Ogden 1999). 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 per 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 (3-6 inch) diameter pipeline are typically $1,000,000 per mile. In flat, rural areas, pipeline costs can be much lower, perhaps $250,000 per 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% for engineering services for a pipeline through flat terrain costing $500,000/mile (Kydd 1996).] The cost of hydrogen delivery varies from less than $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 case of distributing 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 assumed that a network of 3" 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 about 600 cars per 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 per mile, Figure 7 shows that local distribution can cost $2-5/GJ, depending on the density of cars. We find that a geographically 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 less than about 300 cars per square mile (300 cars per square mile is equivalent to about 10% of the vehicle population in a typical urban area in the US), the costs of pipeline transmission rise rapidly, and other distribution methods (liquid hydrogen truck) 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 times the energy flow rate as 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, starting the 1970s (Johnson et al. 1977; Jasionowski and Huang 1980; Jasionowski, Johnson and Pangborn 1979, Pangborn, Scott and Sharer 1977). Their results were summarized in a recent article (Blazek et al. 1992). 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 cause for concern, as hydrogen permeates the pipe 4-6 times as readily as natural gas.

A similar study was done recently of a gas distribution system in the city of Munich (Buenger et al. 1994). The authors found no technical barriers to using up to 100% hydrogen in existing low pressure natural gas distribution systems. Little change in NOx or CO_2 emissions from the utility system was seen at 5% hydrogen by volume. Significant reductions in NOx and CO_2 were seen with hydrogen percentages of 60% or more. It was observed that up to 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 at least 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.

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 (Ogden et. al 1995, Ogden 1997, Directed Technologies et al. 1997, Ogden, Kreutz and Steinbugler 1998, Thomas et al. 1998, Ogden 1999).

Ongoing hydrogen vehicle demonstrations include gaseous hydrogen refueling stations. For example, Air Products and Chemicals is providing hydrogen for fuel cell 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, California, and at the Schatz Energy Center, in Humboldt California. More such systems are planned as part of the recently announced California fuel cell initiative (Hoffmann 1999).

For a pipeline hydrogen system, a gaseous hydrogen refueling station is projected to add about $4-6/GJ to the delivered cost of hydrogen (Ogden et al. 1998).

DESIGN AND ECONOMICS OF HYDROGEN ENERGY SYSTEMS

Here we explore how the components of a hydrogen energy system (production plants, transmission and distribution systems, 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, while 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 case study for the specific case of Southern California, a location where hydrogen and fuel cell 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 which must be served.

Table 2 shows hydrogen consumption for various end-uses ranging from a single hydrogen fuel cell car through implementation of hydrogen in large energy markets. A single hydrogen fuel cell automobile driven 11,000 miles per year (the US average) is projected to use about 109 scf H2/day. A hydrogen fuel cell bus driven 50,000 miles/yr is projected to use about 8000 scf H2/day (Ogden 1999). 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 (about 1 million cars), about 100 million scf of H2 per day must be produced. Providing hydrogen for 3600 urban transit buses (the estimated number in Los Angeles) would require about 25 million scf/day.

Either centralized or decentralized hydrogen supply could be used. A large chemical industry steam methane reformer today produces 25-100 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 liquified and delivered by truck. Alternatively, small reformers or electrolyzers in the 0.1-1.0 million scf/day range could be sited at individual refueling stations, each serving 60-600 cars per 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 about \$2/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/GJ for densities of 300 cars per 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 (less than 300 cars per 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 H2/day, to the size of a single hydrogen refueling station producing 0.1-1.0 million scf/day.

Hydrogen production in a centralized SMR is less costly than in small scale distributed SMR, because natural gas feedstock costs are lower at a large plant, than at a refueling station. [Scale economies are important for conventional steam methane reformers. However, if advanced, small, low cost, " fuel cell" type reformers are developed, capital costs per kW of hydrogen output would be similar for large and small SMR systems (see Figure 4).] 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 only compete with other options where off-peak electricity prices are low, or where costs for other feedstocks is high.

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

Using Figures 4-7 and specific information about energy prices and vehicle populations in Southern California, we estimate 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 employ commercial or near commercial technologies for hydrogen production, storage and distribution. [For details on the design and economics of these systems, the reader is referred to several recent studies of hydrogen refueling infrastructure (Ogden et al. 1995, Ogden 1997, Directed Technologies et al. 1997, Ogden, Kreutz and Steinbugler 1998, Thomas et al. 1998, Ogden 1999).] Near term hydrogen supply options include (see Figure 8):

- hydrogen produced from natural gas in a large, centralized steam reforming plant, and truck delivered as a liquid to refueling stations,
- hydrogen produced in a large, centralized steam reforming plant, and delivered via small scale hydrogen gas pipeline to refueling stations,
- hydrogen from chemical industry sources (e.g. excess capacity in refineries which have recently upgraded their hydrogen production capacity, etc.), with pipeline delivery to a refueling station.
- 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)
- 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 or nuclear power (Figure 9). Thermochemical hydrogen production systems might include sequestration of byproduct CO_2.

In Figure 10, we show the estimated delivered cost of hydrogen transportation fuel for Southern California (Ogden 1999). 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 cars or 140 fuel cell buses). A comparison shows that:

- Delivered costs for hydrogen transportation fuel range from $11-25/GJ (equivalent on an energy basis to $1.6-3.8/gallon 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 km can be comparable to current costs (Ogden, Kreutz and Steinbugler 1998).

- 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.

- Truck delivered liquid hydrogen might also be attractive for early demonstration projects, as the capital requirements for the refueling station would be relatively small (Figure 11), and no pipeline infrastructure development would be required (Ogden et al. 1995, Ogden et al. 1996). However, delivered fuel costs are higher, because of the high cost of liquefaction.

- 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 steam methane reformer plant. (Centrally 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 MSW.) The cost of pipeline distribution is given for two cases: a "low density" case which serves a car population density of 300 cars per square mile (similar to the average vehicle density in the Los Angeles Basin or 10% of the city vehicle population density), and "high density" case of 3000 cars per 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).

- 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 about 3 cents/kWh, placing the cost of hydrogen well above that of onsite steam reforming (Figure 10). But off-peak power at 1 cent/kWh, electrolysis competes with onsite steam reforming. Off-peak power is available at 1 cent/kWh in some locations such as Brazil (Moreira 1998), which have excess off-peak hydropower. The amount of very low cost off-peak power available in Brazil (1000-2000 MW) might fuel 1 to 2 million hydrogen fuel cell automobiles.

- 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 H2/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: 1) Liquid hydrogen delivery via truck from existing hydrogen production capacity, 2) pipeline hydrogen delivery from a nearby large hydrogen plant or refinery, 3) onsite production from steam reforming of natural gas and 4) 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 1.41 million cars, with 153 refueling stations, where each station dispenses1 million scf H2/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 where about 18% of the cars were hydrogen fuel cell vehicles.) Options for providing hydrogen are: 1) liquid hydrogen delivery via truck from new centralized steam reformer capacity, 2) pipeline hydrogen delivery from a new centralized hydrogen plant, 3) onsite production from steam reforming of natural gas and 4) onsite production from electrolysis.

A breakdown of hydrogen infrastructure capital costs is shown in Figure 11. For the large scale system, hydrogen steam reformer plant costs $100 million. A liquifier adds about $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 about $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 per 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. 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 gaseous (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 $1.4-11.4 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 about $440-870 million or $310-620/car. For the case of advanced onsite steam reforming, the capital cost is about $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 per 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 was not as developed (so that construction of the pipeline could avoid extensive road crossings, etc.) the capital cost could be reduced as well.]

As shown in Figure 3, large biomass or coal hydrogen plants would cost perhaps three times as much as a large SMR plant with the same hydrogen output. The overall hydrogen infrastructure capital requirement might be increased by about 40%, as compared to a system based on centralized steam reforming of natural gas. Innovative technologies for gas separation might reduce the capital cost of gasifier plants (Williams 1999).

Hydrogen Infrastructure Capital Costs Compared to 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 (DOE 1990). However, recent studies (Ogden, Kreutz and Steinbugler 1998; Thomas et al. 1998) found that the off-vehicle infrastructure capital costs for hydrogen are similar to those 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, as 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 about 50% more efficiently onboard a vehicle than 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 (Mark 1998).

The conventional wisdom (DOE 1990) that hydrogen infrastructure is much more capital intensive than methanol or gasoline is only true for small market penetrations of hydrogen or methanol vehicles. Once a large number of alternative 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 utilizing methanol, SMD or gasoline are likely to be more expensive and less energy efficient than hydrogen fuel cell cars (Ogden, Kreutz and Steinbugler 1998, Thomas et al.1998). If the concept of "infrastructure" is expanded to include hydrogen production equipment (fuel processors) onboard gasoline or methanol fuel cell cars, we see that methanol vehicles are projected to cost $500 more per car and SMD vehicles $1000 more per car than hydrogen vehicles. Hydrogen appears to have the lowest overall capital costs, including costs both on and off the vehicle (Ogden, Kreutz and Steinbugler 1998, Thomas et al. 1998).

Lifecycle Cost of Automotive Transportation

Comparing the delivered cost of hydrogen transportation fuel on an energy cost basis ($/GJ), we find that hydrogen is 50-100% more costly than gasoline. However, hydrogen can be used about 50% more efficiently in fuel cells than 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: 1) to achieve the same performance, vehicles with onboard fuel processors weigh more, 2) fuel cells perform better on pure hydrogen than on reformed gasoline or methanol, which is a mixture of gases, 3) 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) could be slightly less for hydrogen than for methanol or gasoline fuel cell vehicles.

The projected capital costs of fuel cell vehicles as compared to 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 NOx, 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 to conventional energy systems.

Fuel cycle emissions are all 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 NOx 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 (Delucchi 1989, Ogden, Larson and Delucchi

1994, Berry 1996, Thomas et al. 1998, Williams 1996). The total fuel cycle carbon emissions per kilometer are shown in Figure 13 for gasoline, methanol and hydrogen, used in mid-size automobiles powered by internal combustion engines or fuel cells based on estimates by Williams (1998). Various primary resources are considered for hydrogen production (natural gas, biomass, coal, solar, wind and nuclear) and methanol production (natural gas, biomass, 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 internal combustion engine 4-5 passenger automobile with fuel economy of 42 miles per gallon gasoline (based on Ford's aluminum intensive design). (Emissions from a current 26 mpg gasoline ICEV are shown as well). Fuel economies for fuel cell vehicles are taken to be 71 mpg equivalent for gasoline (with onboard partial oxidation reforming), 69 mpg for methanol (with onboard steam reforming) and 106 mpg for hydrogen (Ogden, Kreutz and Steinbugler 1998).

With hydrogen from natural gas, the most likely near term feedstock, greenhouse gas emissions from a hydrogen FCV are reduced by over 60%, as compared to an efficient future gasoline ICEV. CO_2 emissions can be reduced by another 20%, if the CO_2 is separated during hydrogen production, and then sequestered. With hydrogen from coal, the fuel cycle emissions for a hydrogen FCV are reduced about 30%, as compared to a gasoline ICEV. With carbon sequestration, fuel cycle emissions from coal H2 powered FCV are only 30% of those from a gasoline ICEV. If hydrogen is made from renewable energy sources such as biomass, solar 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 CO_2 emissions for hydrogen powered transportation can be substantial, exceeding those of gasoline (Thomas et al. 1998). 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 which 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 CO_2 emission levels -- or more (Hendriks 1994, Holloway 1996).

In the longer term (or where locally preferred) renewable resources such as wastes, biomass, solar or wind might be brought into use. It has been estimated that hydrogen derived from biomass produced on about 2/3 of currently idled cropland in the US would be sufficient to supply transportation fuel to all the cars in the US, if they used fuel cells (Ogden and Nitsch 1993). Municipal solid waste could be gasified to produce transportation fuel for perhaps 25-50% of the cars in US metropolitan areas (Larson, Worrell and Chen 1996). 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 three times that for hydrogen from natural gas (Ogden and Nitsch 1993). The collector area required for PV hydrogen production for one hydrogen fuel cell car is about 25 m^2, assuming average US insolation. It has been estimated that projected global 2050 fuel demands of about 300 EJ/yr could be met by solar hydrogen produced on about 0.5% of the world's land area. If about 14% of developable wind power in the United States were used to produce hydrogen this could power all US cars, assuming they were run on hydrogen fuel cells (Ogden and Nitsch 1993).

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 (Hord 1978). 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 with gasoline, which puddles rather than dispersing, and where fumes can build up and persist. Hydrogen is non-toxic, which is also an advantage. Other aspects of hydrogen are potential safety concerns, especially its wide flammability limits and the 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, which 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 to real 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.

According to a 1994 hydrogen vehicle safety study by researchers at Sandia National Laboratories (Ringland et al. 1994), "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 Company (Ford Motor Company 1997) 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 employed and standardized, there has been a considerable effort in recent years to develop codes and standards for hydrogen and fuel cell systems. The United States Department of Energy 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 (Ohi 1999). 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: fuel cells, hydrogen vehicles, 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 alternative 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 increased and became 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 CO_2. [Centralized hydrogen production is required to make CO_2 sequestration economic, otherwise the cost of gathering CO_2 from many small sources is prohibitive (Ogden 1999).]

In other areas, such as 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 there was 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 manufacture for fertilizer (Williams 1998) or co-produce electricity (Williams 1999).

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 CO_2 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 steam methane reformers could be put in place within a few months time; 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 one million hydrogen fuel cell cars on the road within relatively short distance (a few tens of km) 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 non-energy 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 is growing 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 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 (Chemical and Engineering News 1999). Another interesting possibility is the idea of "independent fuel producers" analogous to independent power producers, who are now building 100-200 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 partner 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 (Williams NHA 1998). 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.

ACKNOWLEDGMENTS

Discussions with my colleagues at Princeton's Center for Energy and Environmental Studies over a period of many years have been instrumental in helping formulate the ideas expressed here: I would especially like to thank Robert Williams, Eric Larson, Robert Socolow, Thomas Kreutz, Supramaniam Srinivasan and Margaret Steinbugler (now at United Technologies Research Center). I would also like to acknowledge expert programming assistance from Costi Tudan (Multimedia Engineering Computation Atelier, Princeton University) in estimating vehicle energy demand densities from Geographic Information System data. For insightful comments on an earlier draft of this manuscript, I would like to thank Sigmund Gronich (United States Department of Energy), Eric Larson (Princeton University), David Nahmias (National Hydrogen Association), Ron Sims (Ford Motor Company), Pam Spath (National Renewable Energy Laboratory), Sandy Thomas (Directed Technologies, Inc.) and Reiner Wurster (Ludwig-Bolkow Systemtechnik). I would also like to acknowledge the reviewers for Annual Reviews of Energy and the Environment, who made for numerous useful suggestions for improving this paper.

LIST OF FIGURES

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TABLES

Table 1. Conversion Factors And Economic Assumptions

1 GJ (Gigajoule) = 10^9 Joules = 0.95 Million BTU
1 EJ (Exajoule) = 10^{18} Joules = 0.95 Quadrillion (10^{15}) BTUs

1 million standard cubic feet (scf)
= 26,850 Normal cubic meters (m_N^3)
= 343 GJ (HHV)

1 million scf/day = 2.66 tons/day
= 3.97 MW H_2 (based on the HHV of hydrogen)

1 scf H_2 = 343 kJ (HHV) = 325 BTU (HHV); 1 lb H_2 = 64.4 MJ (HHV) = 61.4 kBTU (HHV) = 187.8 scf
1 m_N^3 = 12.8 MJ (HHV); 1 kg H_2 =141.9 MJ (HHV) = 414 scf

1 gallon 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 gasoline = $7.67/GJ (HHV)

1 gallon 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 methanol = $15.4/GJ (HHV)

All costs are given in constant $1995.

Capital recovery factor for hydrogen production systems, distribution systems and refueling stations = 15%

Table 2. Hydrogen Demand and Supply: Scales Of Interest

DEMAND	H2 FLOW (scf/d)	H2 FLOW (GJ/day)
1 fuel cell car (driven 11,000 miles/yr)	109	0.038
1 fuel cell bus (driven 50,000 miles/yr)	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 LA Basin	9 million	3200
H2 Production at Large Refinery	100 million	34,300
10% of cars in LA Basin	90 million	32,000
100% of cars in LA Basin	900 million	320,000
Energy Flow = NG Flow in LA Basin	9 billion	3,000,000

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

Table 3. Weight and Volume of Onboard Hydrogen Storage Systems for a Mid-Size Hydrogen Fuel Cell Automobile

For systems holding 3.9 kg of hydrogen[c]

Fuel	Storage System	Total Weight: Fuel + Storage System (kg)	Total Volume: Fuel + Storage System (liters)
Compressed gas hydrogen at 5000 psi[a]	Advanced pressure cylinder	32.5 (12% H_2 by weight)	186 (700 Wh/liter)
Liquid Hydrogen[b]	Dewar	28.5 (14% H_2 by weight)	116
Metal Hydride[b]	Metal hydride ($FeTiH_{1.8}$) container with heat exchanger	325 (1.2% H_2 by weight)	100

a. Based on estimates by Mitlitsky (Mitlitsky, Weisberg and Myers 1999) for a 5000 psi pressure tank holding 3.9 kg of hydrogen

b. Adapted from (James et al. 1996). 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 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 2/3 power of the weight of hydrogen stored. The container 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.

c. Storage of 3.9 kg of hydrogen is sufficient for a range of about 400 miles in a lightweight mid size passenger car using a hydrogen fuel cell (Ogden, Kreutz and Steinbugler 1998).

Table 4. Hydrogen Transmission Pipelines

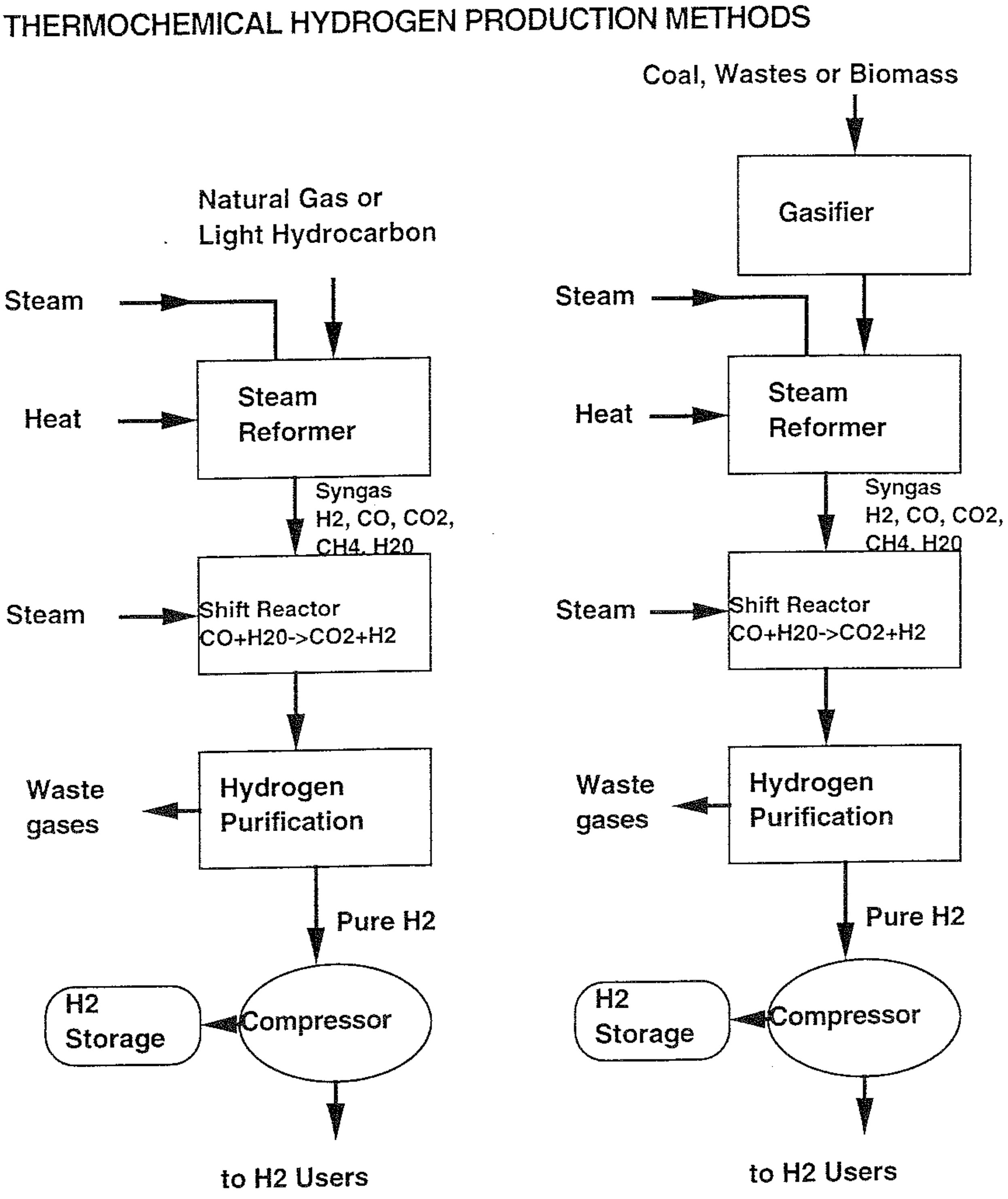
Company	Location	H2 Flow (Million scf/day)	Length (km)	Pipe Diam. (in)	Pipeline Pres. (psi)	H2 Purity	Years Oper.	Source
PRAXAIR	Texas City-Bayport-Port Arthur, TX	100		8"			since 1970s	(Kerr 1993, Leeth 1979)
	Carney's Point, NJ	6						(Kerr 1993)
	Whiting, IN	5						(Kerr 1993)
AIR PRODUCTS AND CHEMICALS	LaPorte, TX	40	200	4-12"	50-800	99.5%	Since 1970s	(Kerr 1993, Kelley and Hagler 1980)
	Plaquemine, LA	30						(Kerr 1993)
CHEMISCHE WERK HULS, AG	Ruhr Valley, GERMANY	100	220	4-12"	360	95%	Since 1938	(Kelley and Hagler 1980, Leeth 1979, Pottier 1988)
ICI	Teeside, ENGLAND	20	16		750	95%	Since 1970s	(Kelley and Hagler 1980)
AIR LIQUIDE	FRANCE, BELGIUM	17	340	4"	1470	99.995 %	Since mid-1980s	(Pottier et al. 1988)

Table 5.
Safety Related Properties of Hydrogen, Methane and Gasoline

	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 (meter/sec)	2.0	0.51	0.17
Buoyant velocity in air (meter/sec)	1.2-9.0	0.8-6.0	non-buoyant
Ignition energy at stoichiometric mixture (milliJoules)	0.02	0.29	0.24
Ignition energy at lower flammability limit (milliJoules)	10	20	n.a.
Toxicity	non-toxic	non-toxic	toxic in concentrations> 500 ppm

adapted from J. Hord, 1978.

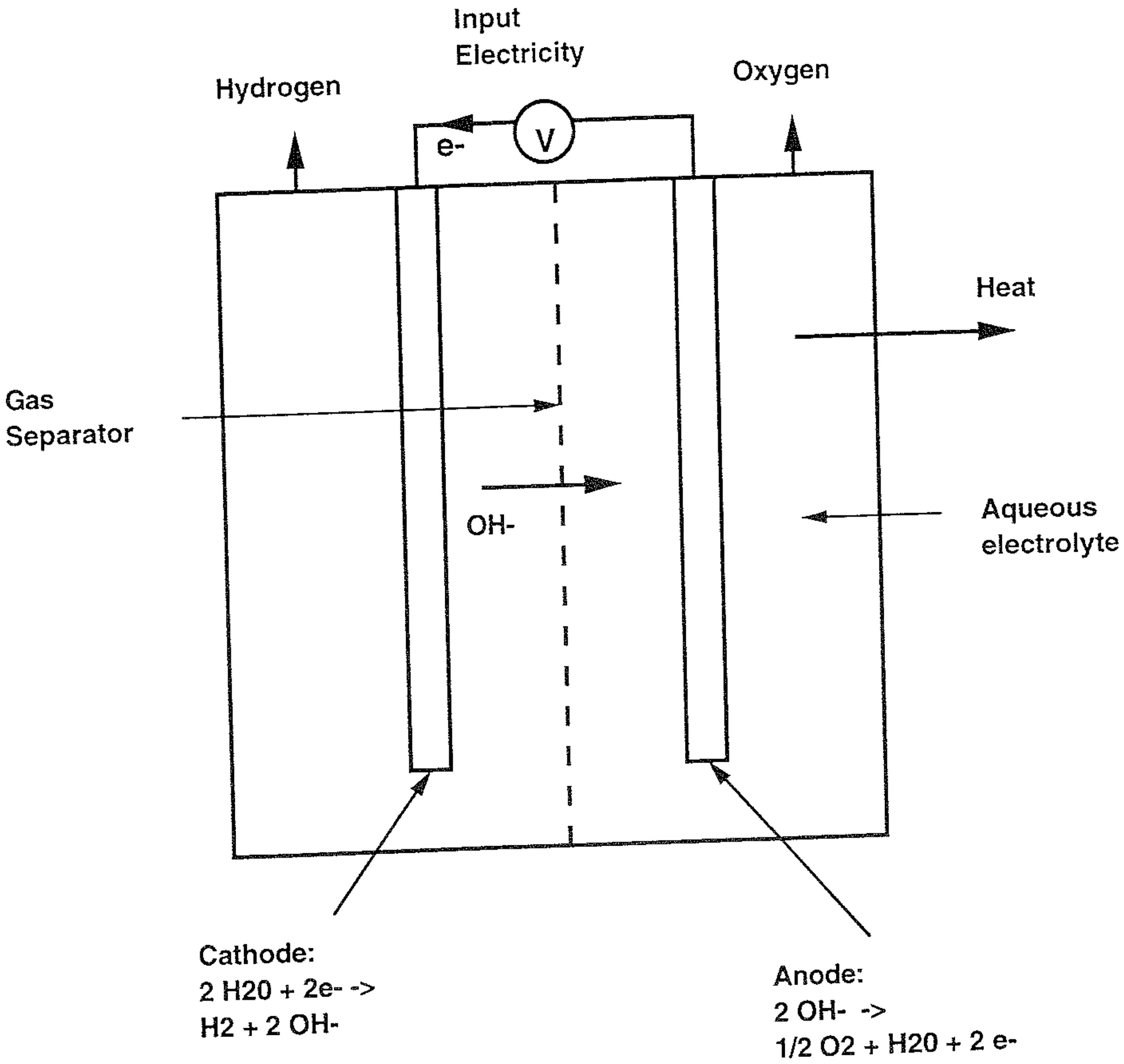
Fig. 1



THERMOCHEMICAL HYDROGEN PRODUCTION METHODS
Natural Gas or Light Hydrocarbon
Steam
Heat
Steam Reformer
Syngas H2, CO, CO2, CH4, H20
Steam
Shift Reactor CO+H20->CO2+H2
Waste gases
Hydrogen Purification
Pure H2
H2 Storage
Compressor
to H2 Users
Coal, Wastes or Biomass
Gasifier
Steam
Heat
Steam Reformer
Syngas H2, CO, CO2, CH4, H20
Steam
Shift Reactor CO+H20->CO2+H2
Waste gases
Hydrogen Purification
Pure H2
H2 Storage
Compressor
to H2 Users

Fig. 2

HYDROGEN PRODUCTION VIA WATER ELECTROLYSIS

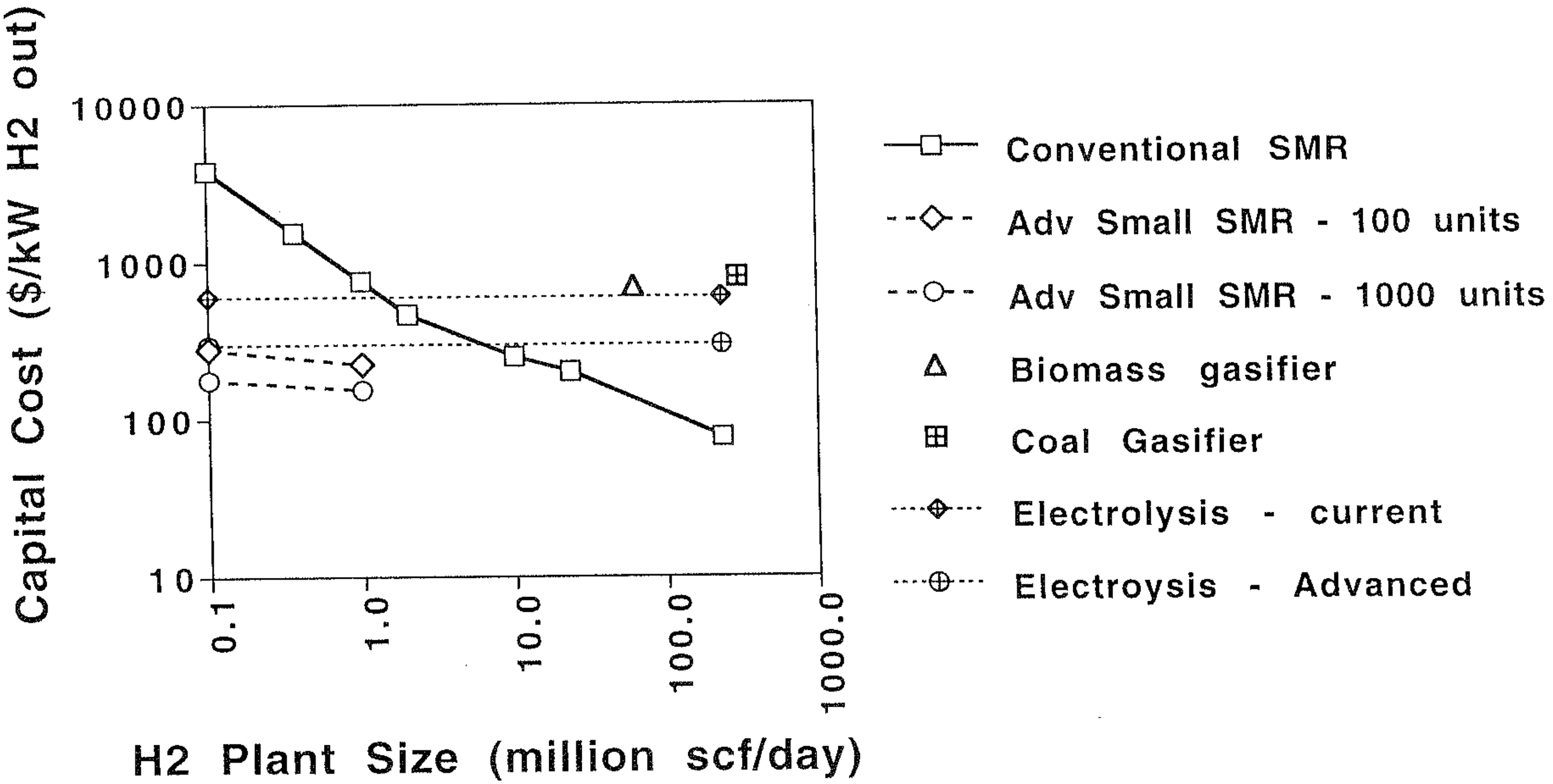


Overall Reaction:

H_2O -> H_2 + 1/2 O_2

Fig. 3

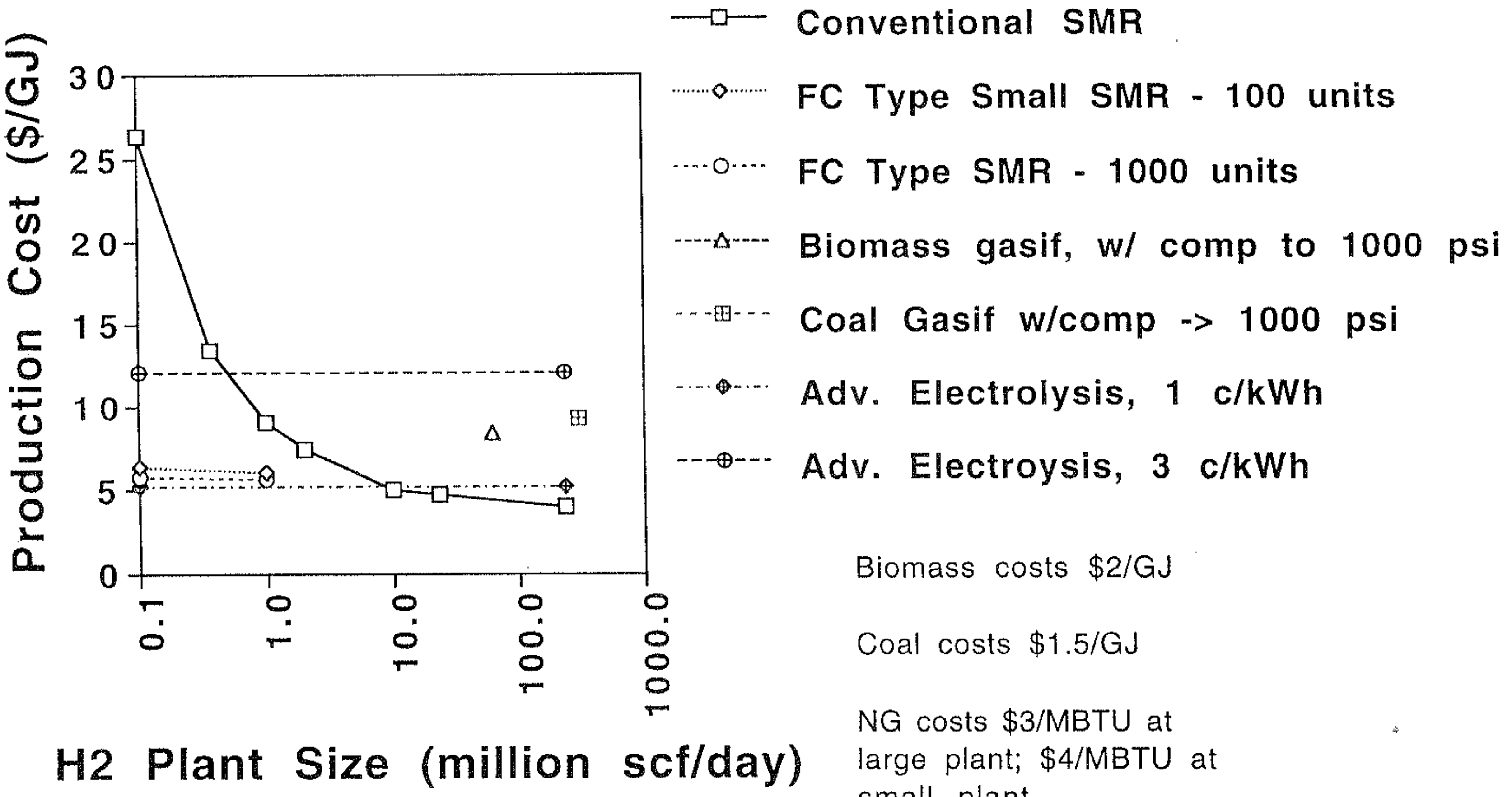
Capital Cost of Hydrogen Production Systems
($ per kW of Hydrogen Output Capacity)



1 million scf/day = 4.0 MW H2 out

Fig. 4

Levelized Production Cost of Hydrogen ($/GJ)

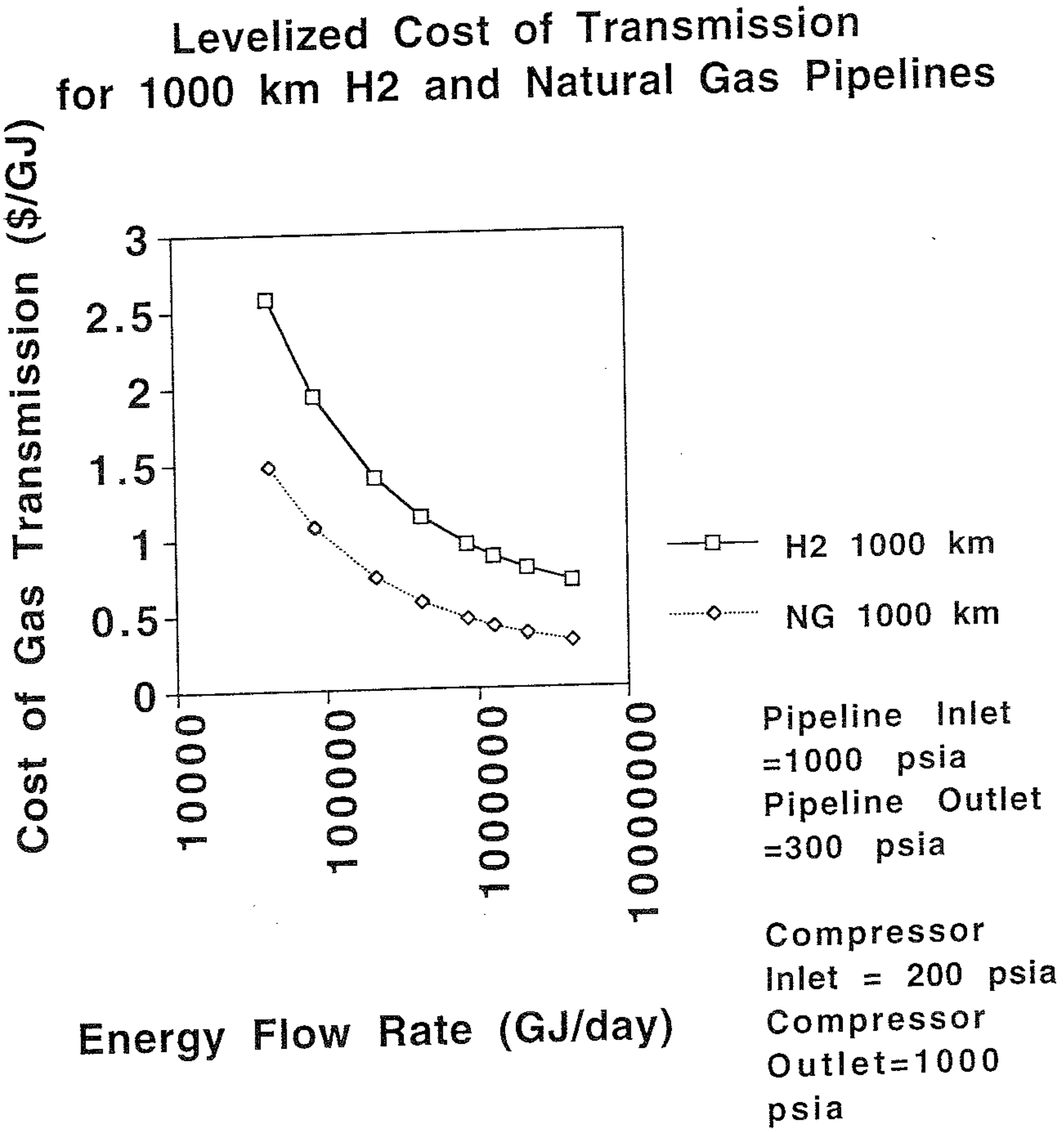


Biomass costs $2/GJ

Coal costs $1.5/GJ

NG costs $3/MBTU at large plant; $4/MBTU at small plant

Fig. 5

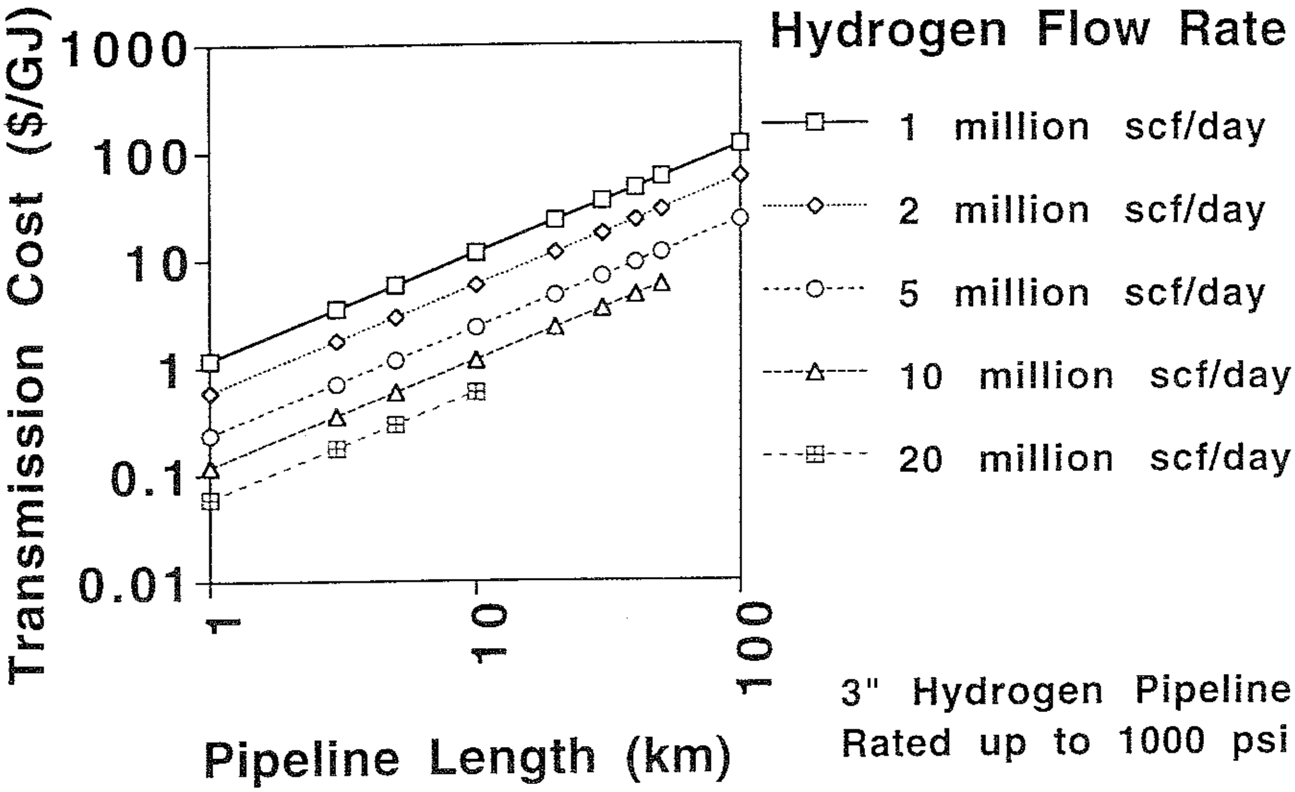


Pipeline Inlet
=1000 psia
Pipeline Outlet
=300 psia

Compressor
Inlet = 200 psia
Compressor
Outlet=1000
psia

Fig. 6

Levelized Cost of Hydrogen Pipeline Transmission vs. Pipeline Length and Flow Rate



3" Hydrogen Pipeline
Rated up to 1000 psi

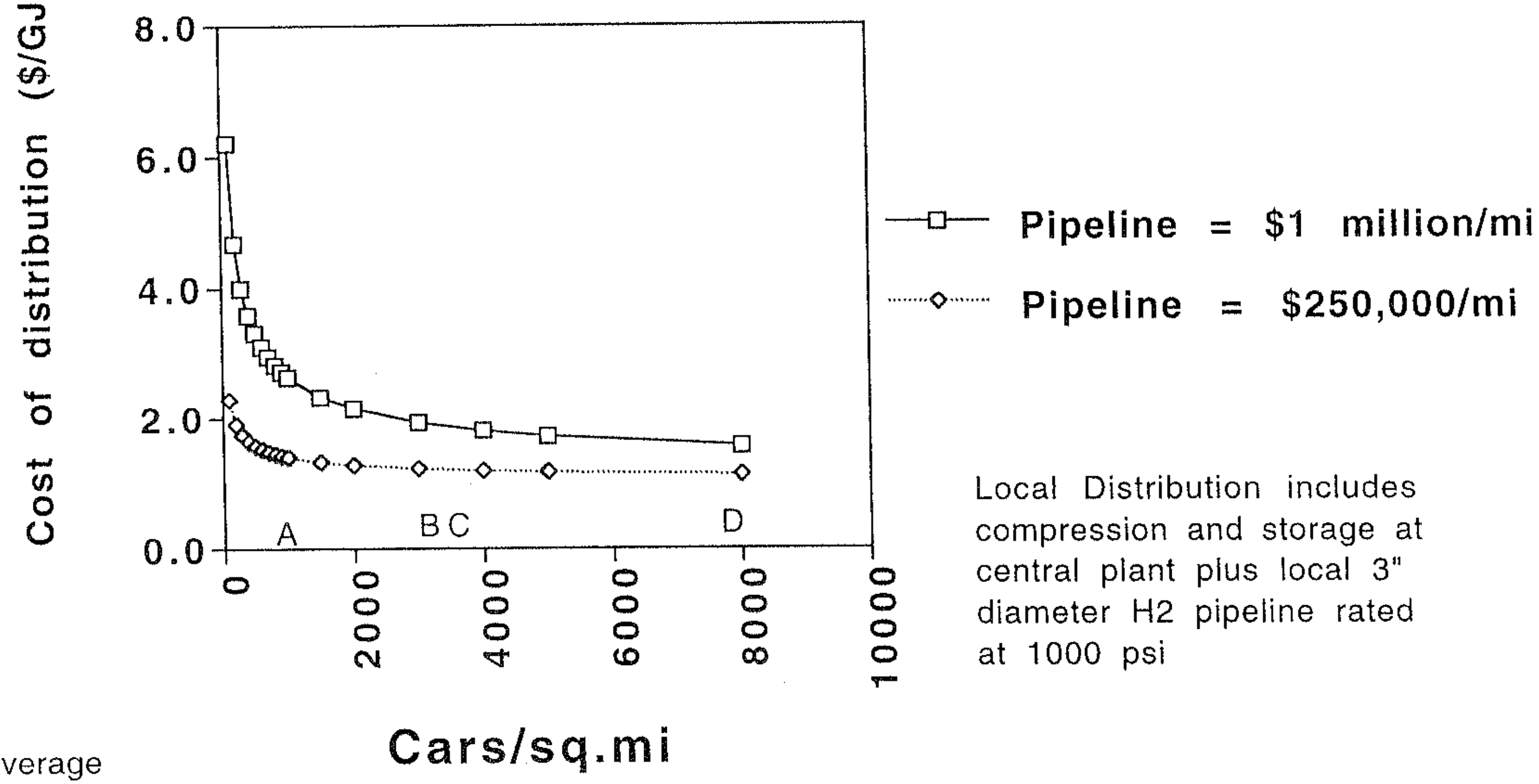
Pipeline cost =
$1 million/mile

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

Fig. 7

Levelized Cost of Local Distribution of Hydrogen Transportation Fuel vs. Density of Cars



Local Distribution includes compression and storage at central plant plus local 3" diameter H2 pipeline rated at 1000 psi

A = NJ average
B = Downtown Denver
C = Downtown Los Angeles
D = Downtown Newark. NJ

Radial spoke distribution pattern from central plant producing 100 million scf H2/day. Ten spokes, 10 refueling stations on each spoke. Central compression to 1000 psi and 1/2 day's storage

Fig. 8

Near Term Gaseous H2 Supply Options

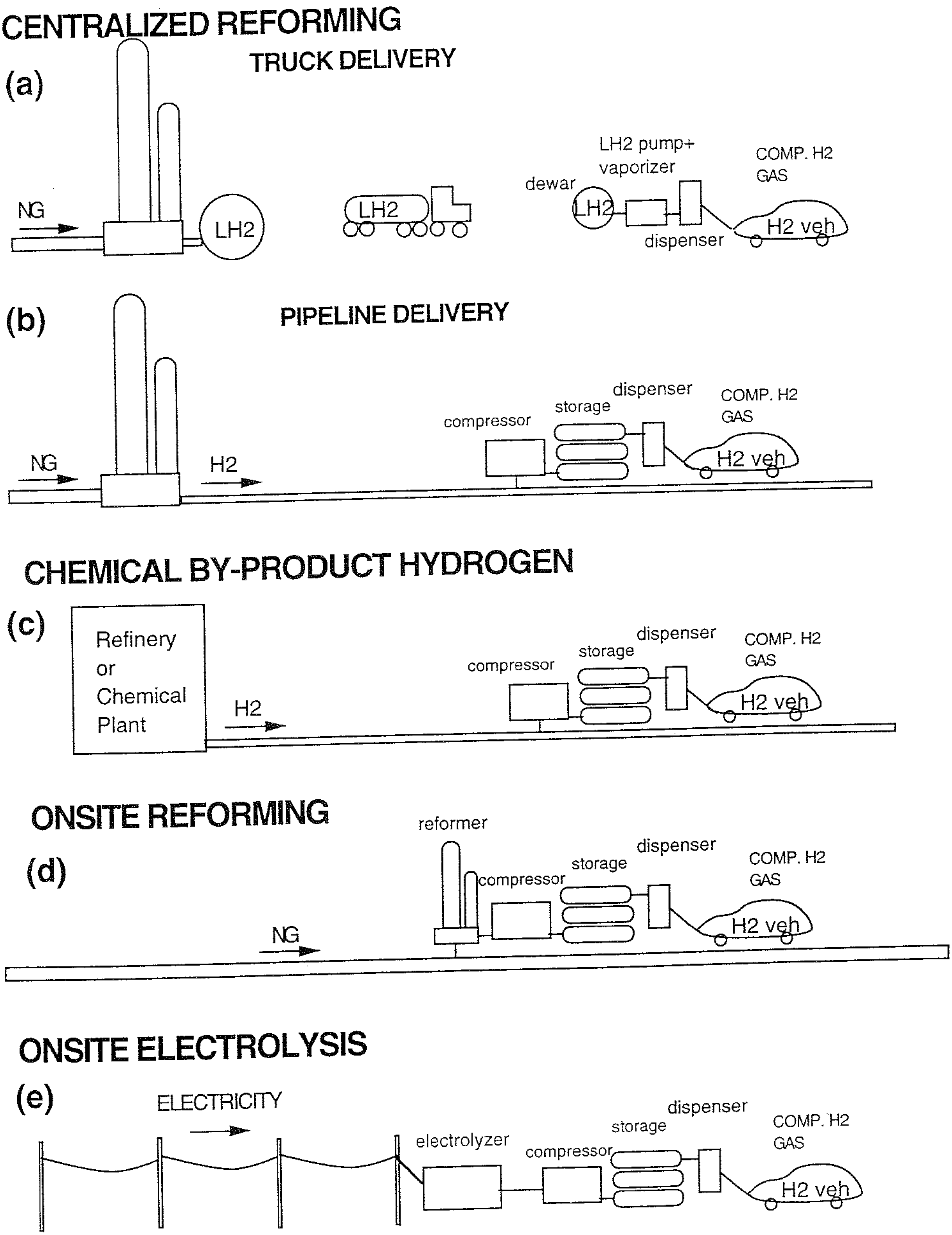
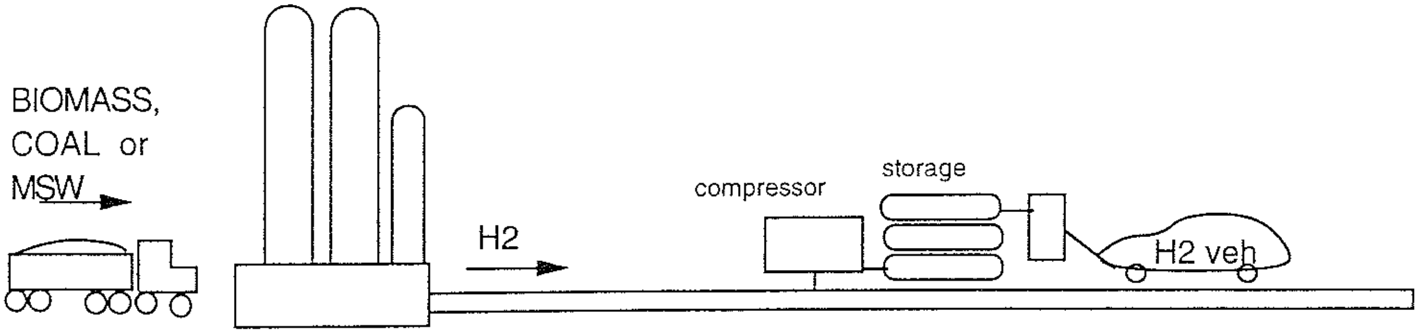


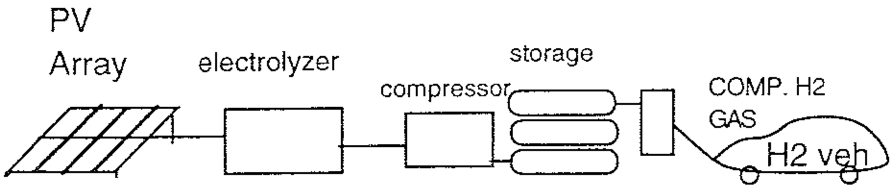
Fig. 9

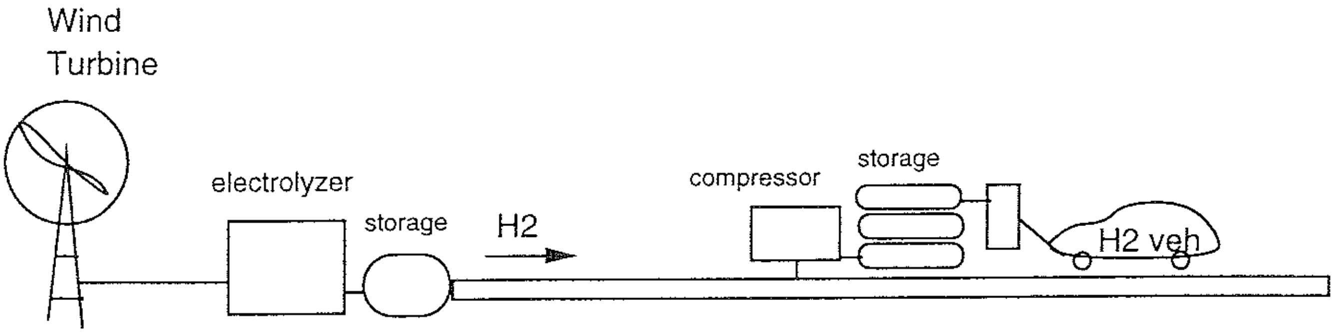
Long Term H2 Supply Options

H2 via BIOMASS, COAL or MSW GASIFICATION



SOLAR or WIND ELECTROLYTIC HYDROGEN





H2 FROM HYDROCARBONS w/CO2 SEQUESTRATION

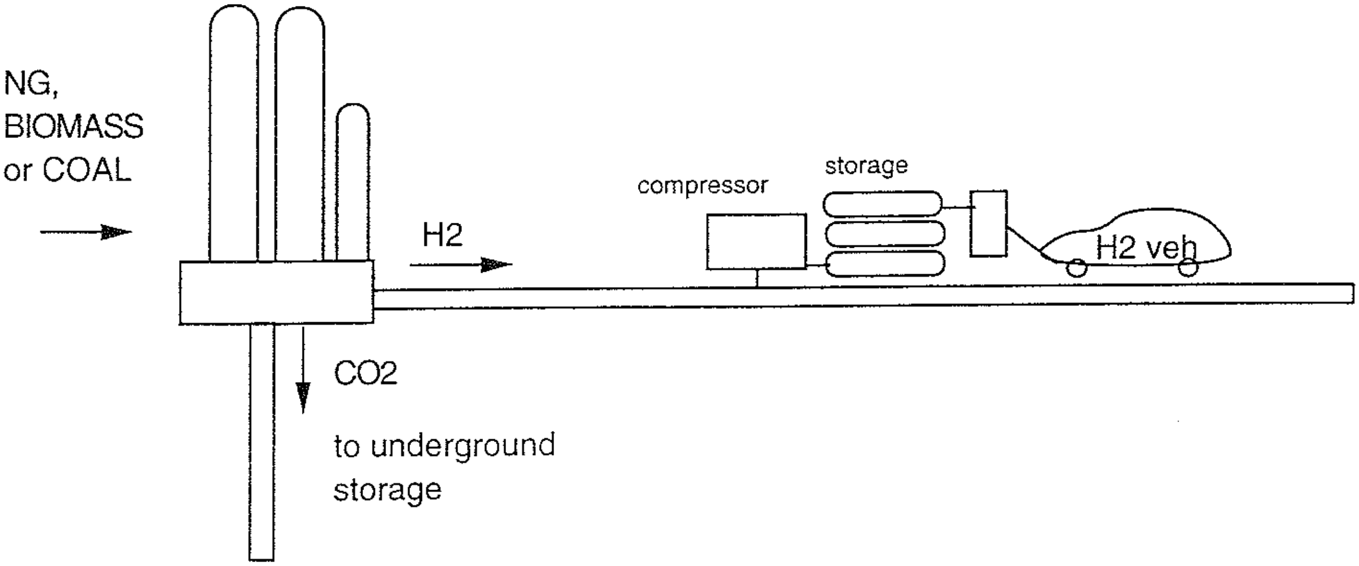
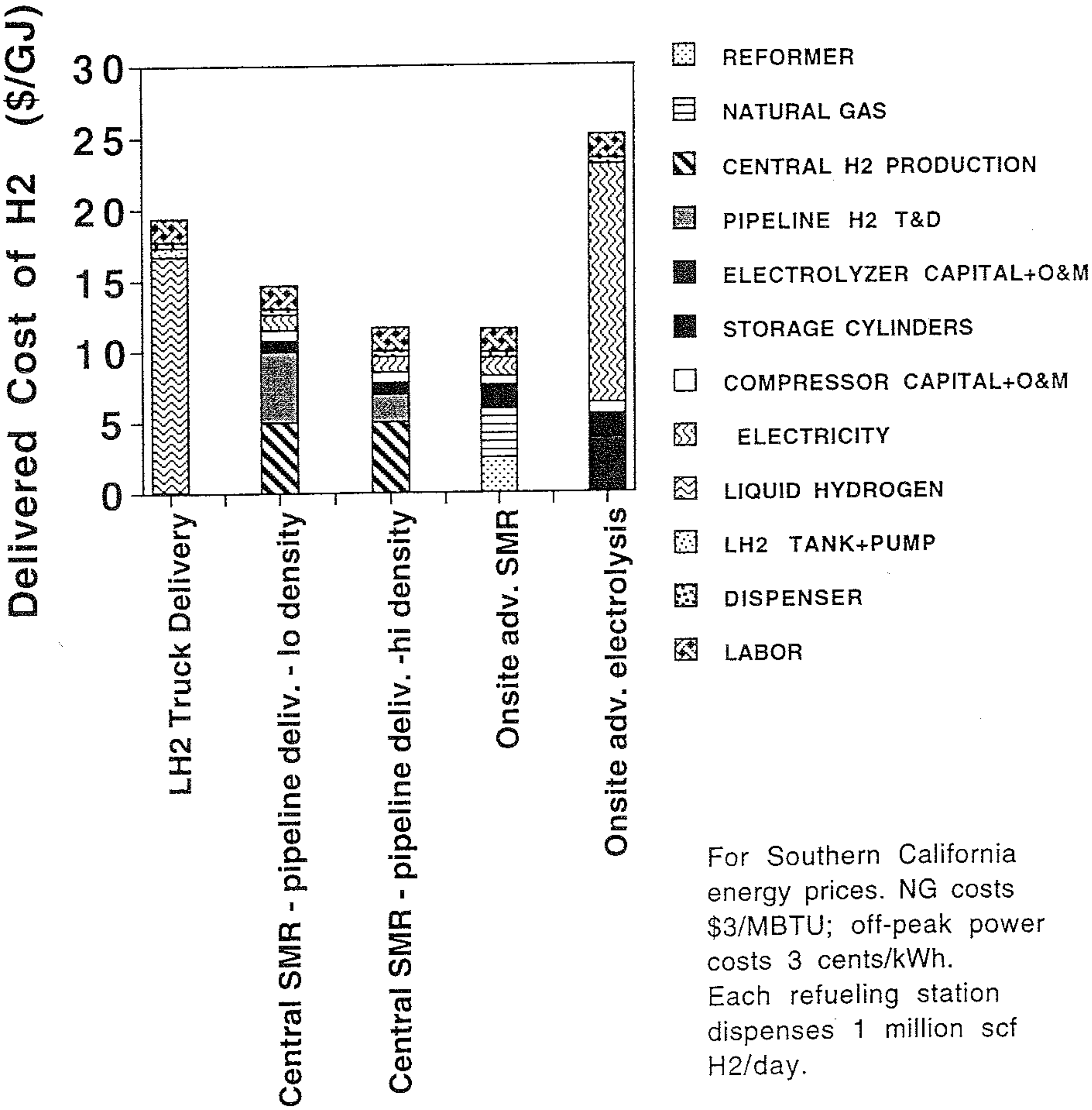


Fig. 10

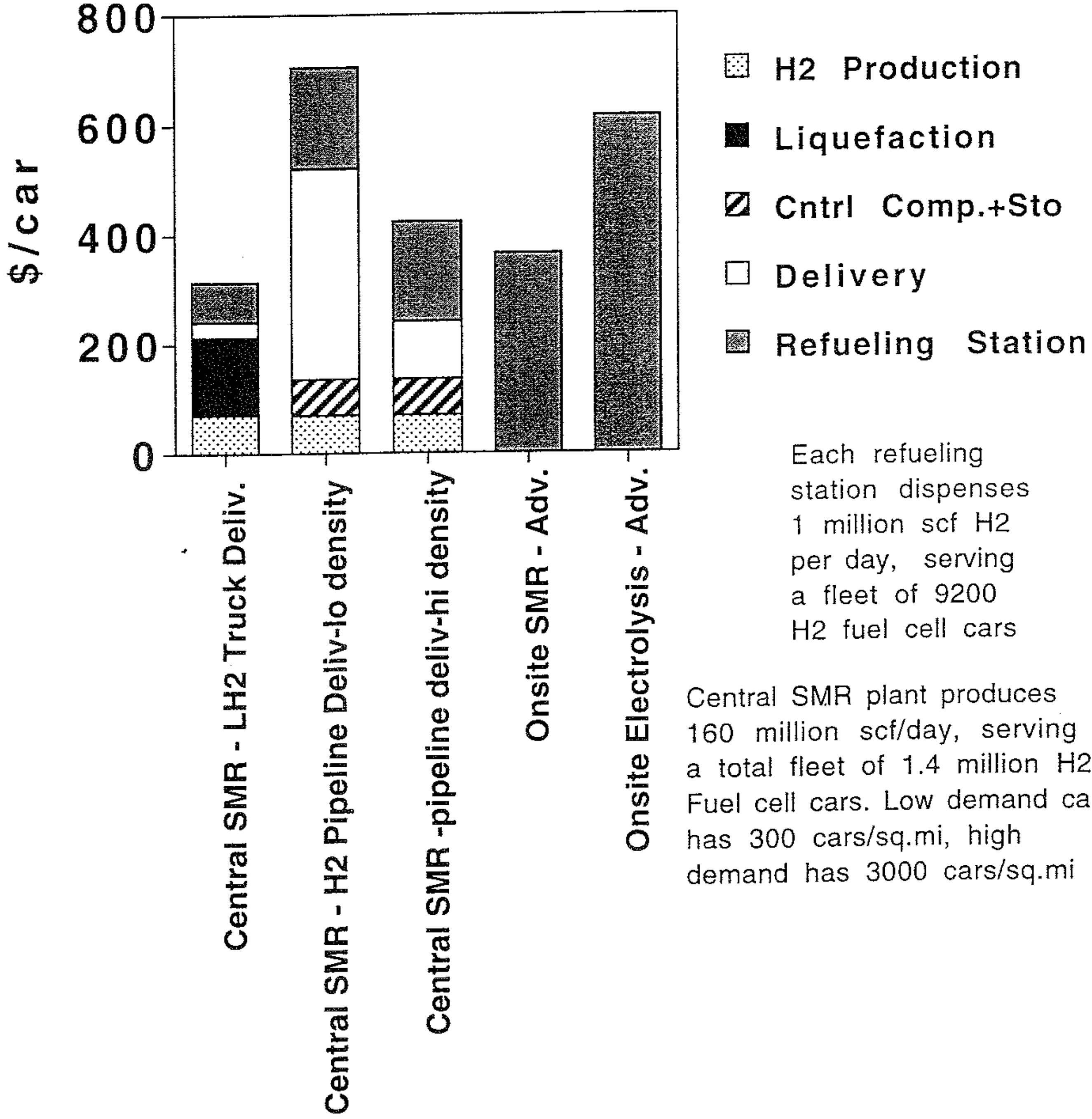
Delivered Cost of Hydrogen Transportation Fuel ($/GJ)



For Southern California energy prices. NG costs $3/MBTU; off-peak power costs 3 cents/kWh. Each refueling station dispenses 1 million scf H2/day.

Fig. 11

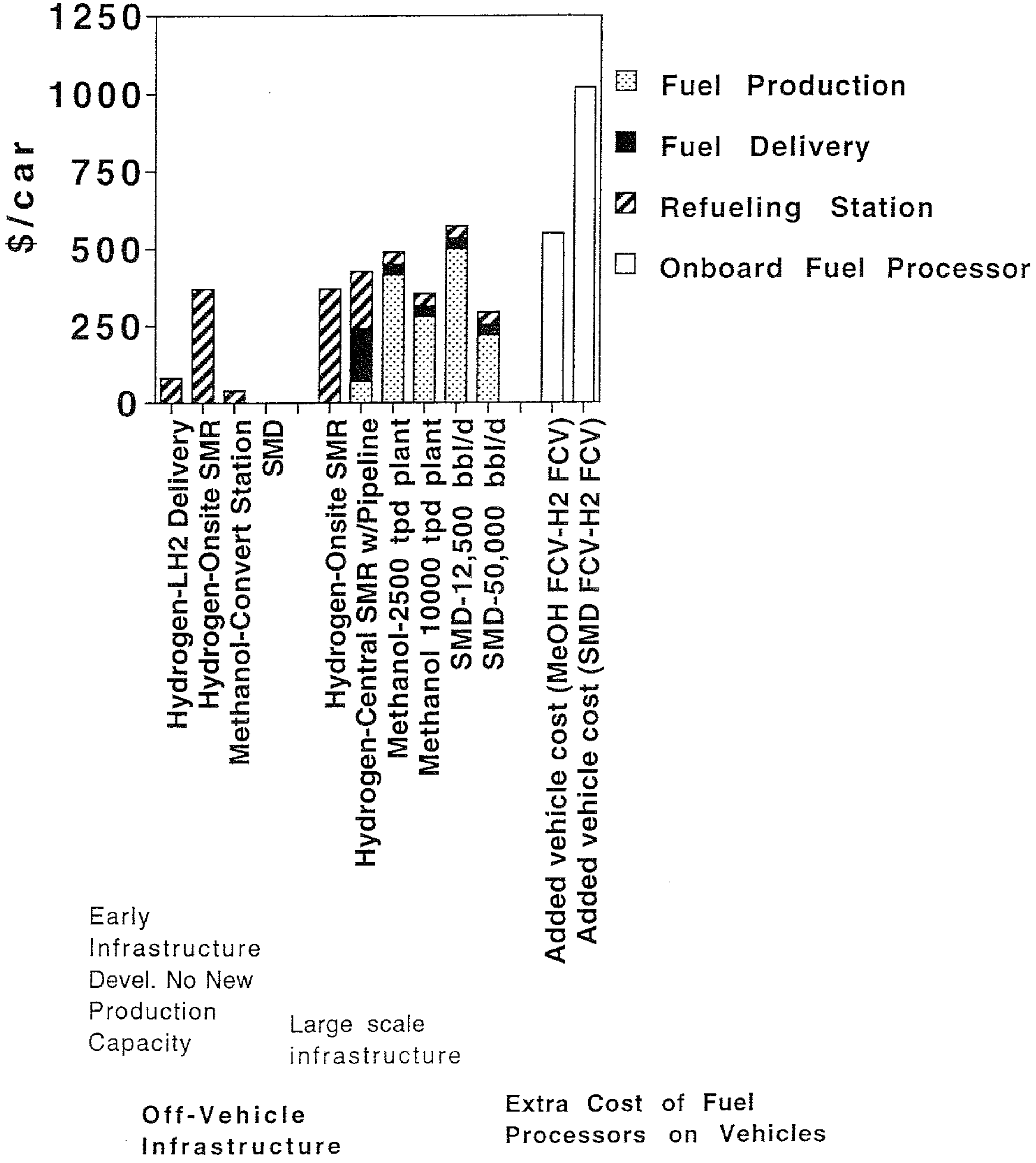
Capital Cost of H2 Infrastructure ($/car)



Each refueling station dispenses 1 million scf H2 per day, serving a fleet of 9200 H2 fuel cell cars

Central SMR plant produces 160 million scf/day, serving a total fleet of 1.4 million H2 Fuel cell cars. Low demand case has 300 cars/sq.mi, high demand has 3000 cars/sq.mi

Fig. 12



Capital Cost of Fuel Infrastructure and Onboard Fuel Processing for Hydrogen, Methanol and SMD Fuel cell Vehicles

Fig. 13

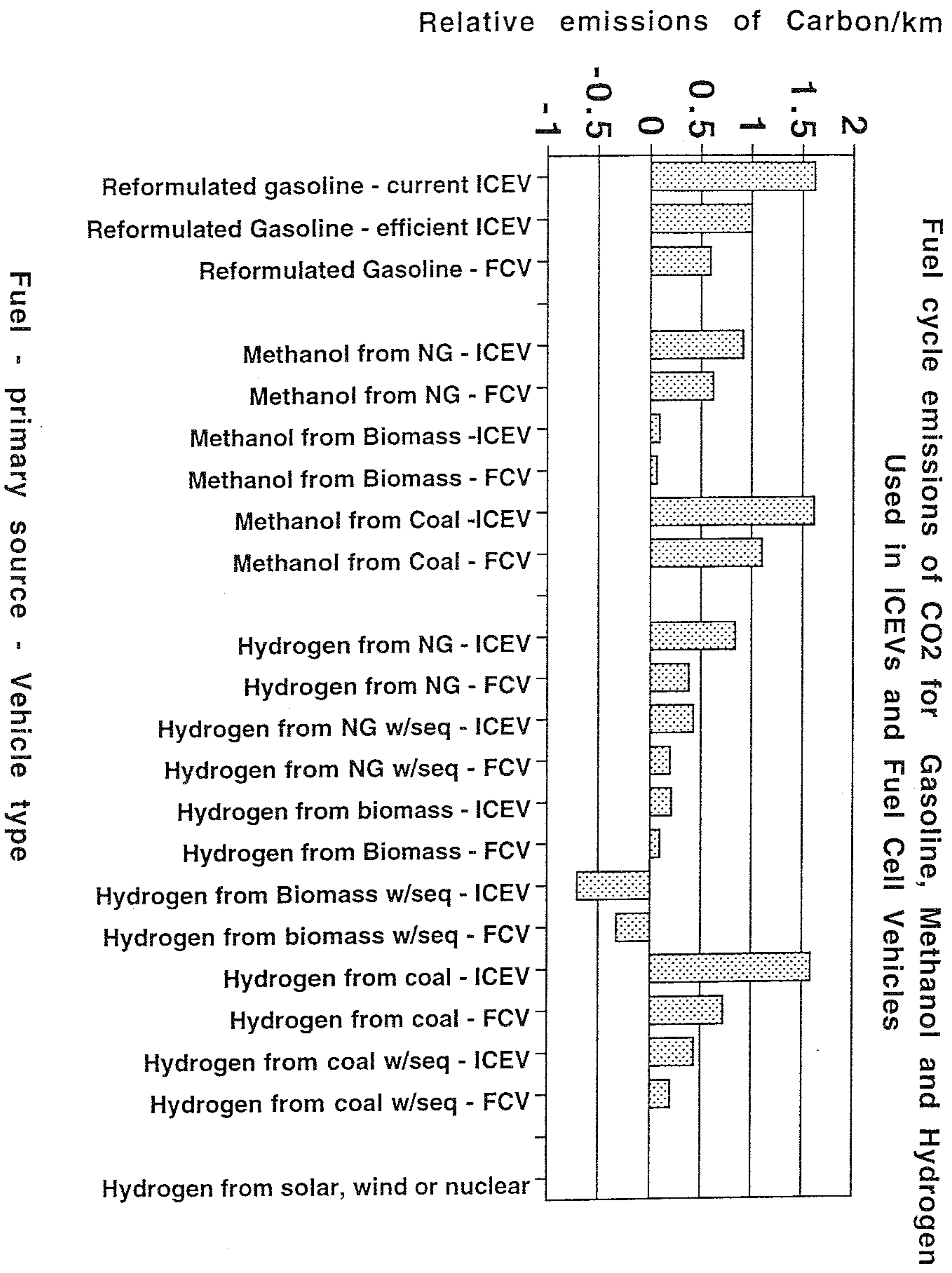

Relative emissions of Carbon/km
-1
-0.5
0
0.5
1
1.5
2
Fuel cycle emissions of CO2 for Gasoline, Methanol and Hydrogen
Used in ICEVs and Fuel Cell Vehicles
Reformulated gasoline - current ICEV
Reformulated Gasoline - efficient ICEV
Reformulated Gasoline - FCV
Methanol from NG - ICEV
Methanol from NG - FCV
Methanol from Biomass -ICEV
Methanol from Biomass - FCV
Methanol from Coal -ICEV
Methanol from Coal - FCV
Hydrogen from NG - ICEV
Hydrogen from NG - FCV
Hydrogen from NG w/seq - ICEV
Hydrogen from NG w/seq - FCV
Hydrogen from biomass - ICEV
Hydrogen from Biomass - FCV
Hydrogen from Biomass w/seq - ICEV
Hydrogen from biomass w/seq - FCV
Hydrogen from coal - ICEV
Hydrogen from coal - FCV
Hydrogen from coal w/seq - ICEV
Hydrogen from coal w/seq - FCV
Hydrogen from solar, wind or nuclear
Fuel - primary source - Vehicle type

Fig. 14a

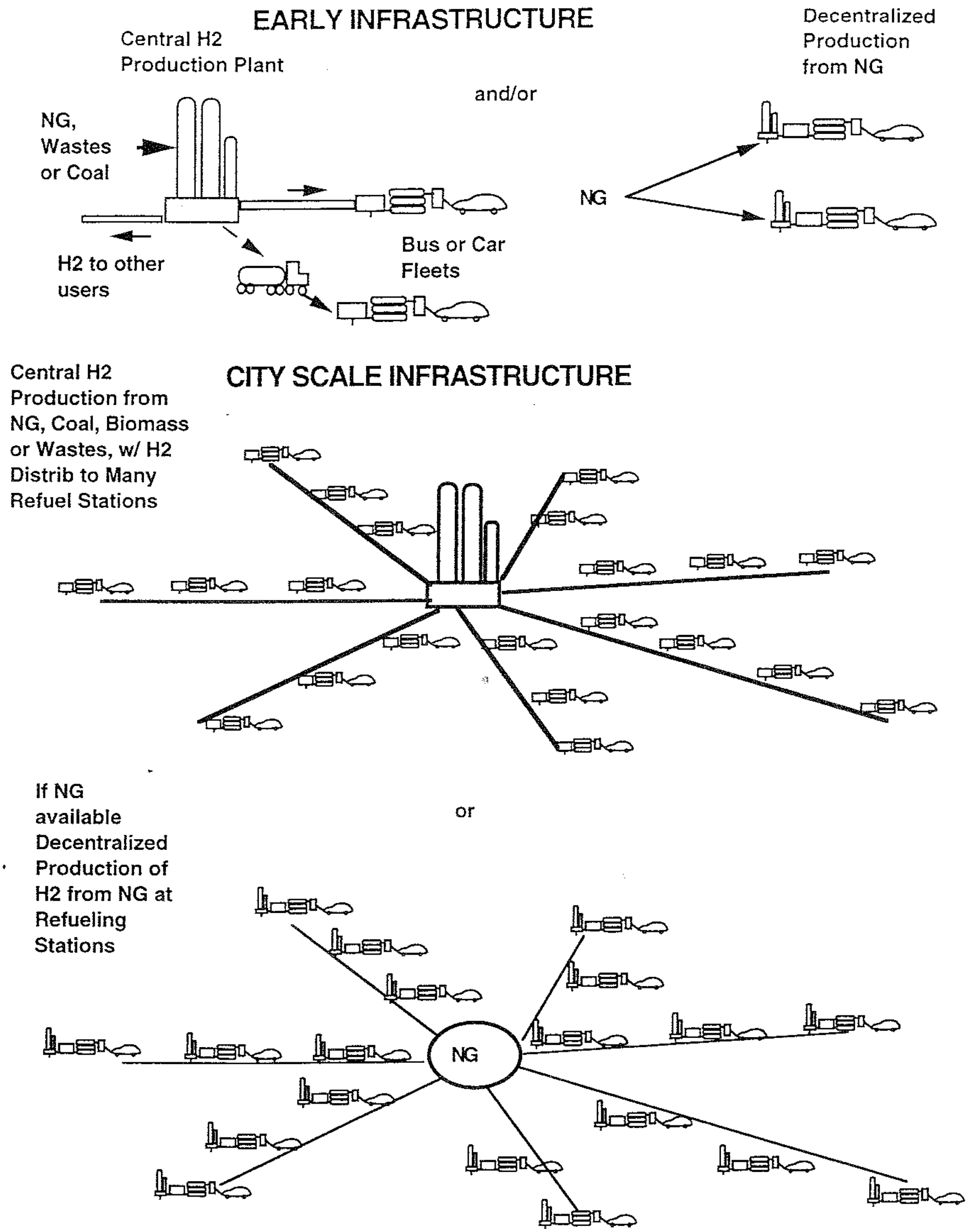
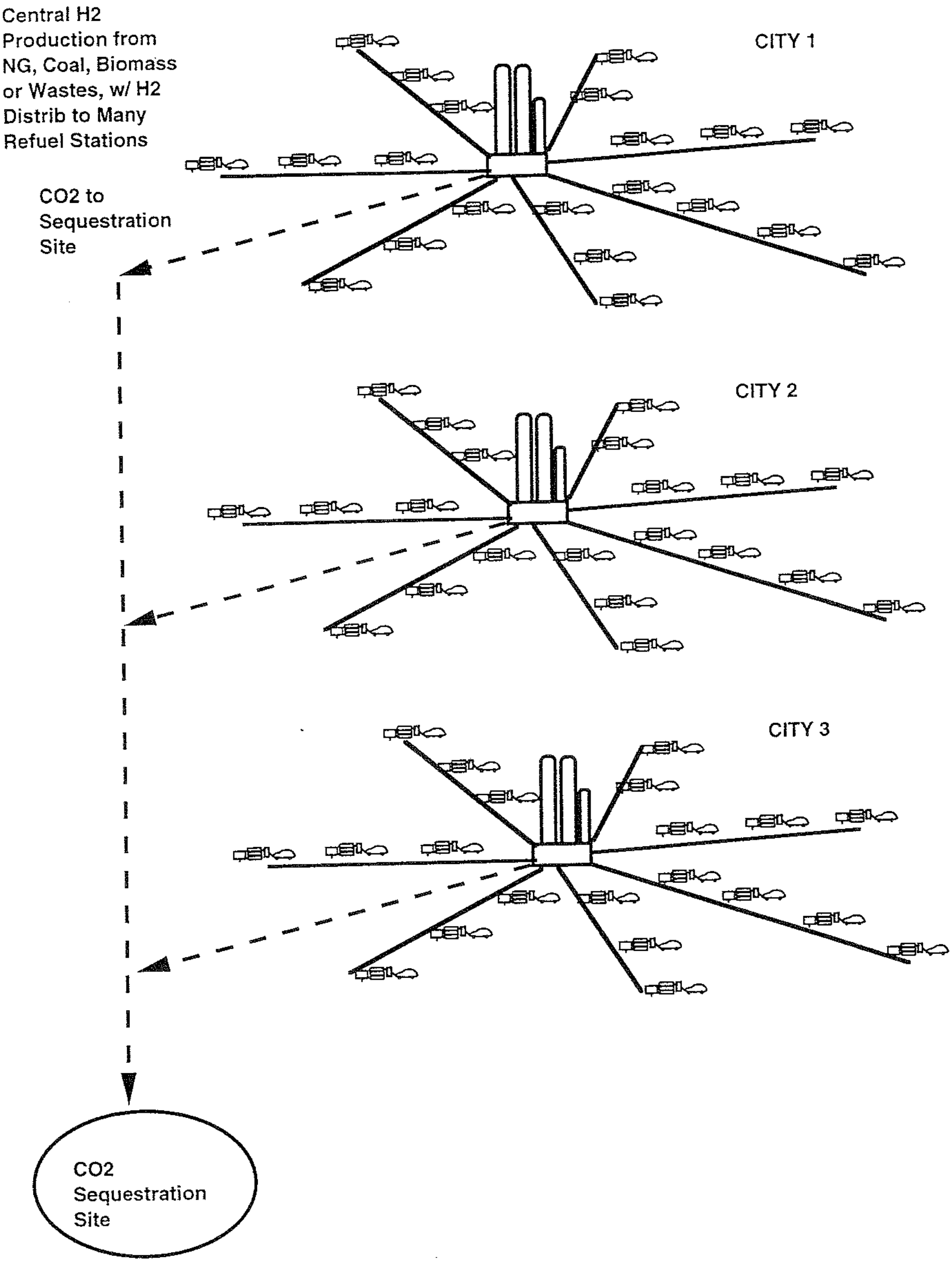

EARLY INFRASTRUCTURE
Central H2
Production Plant
and/or
Decentralized
Production
from NG
NG,
Wastes
or Coal
NG
H2 to other
users
Bus or Car
Fleets
Central H2
Production from
NG, Coal, Biomass
or Wastes, w/ H2
Distrib to Many
Refuel Stations
CITY SCALE INFRASTRUCTURE
or
If NG
available
Decentralized
Production of
H2 from NG at
Refueling
Stations
NG

Fig. 14b



HYDROGEN ENERGY ECONOMY W/CO2 SEQUESTRATION