HYDROGEN ENERGY SYSTEMS STUDIES

Joan M. Ogden

Center for Energy and Environmental Studies
Princeton University
Princeton, NJ 08544

Abstract

In this progress report (covering the period May 1998 -September 1998), we summarize results from technical and economic assessments of hydrogen energy systems. Generally, the goal of our research is to illuminate possible pathways leading from present hydrogen markets and technologies toward wide scale use of hydrogen as an energy carrier, highlighting important technologies for RD&D. This work was carried out as part of the systems analysis activity of the US Department of Energy Hydrogen R&D Program under Contract No. DE-FG36-95G010061.

Result from two studies are described. Both were begun in November 1997 and were completed in September 1998.

Task 1. We assessed potential supplies and demands for hydrogen energy in the New York City/New Jersey area. The goal of this study is to provide useful data and suggest possible implementation strategies for the New York City/New Jersey area, as the Hydrogen Program plans demonstrations of hydrogen vehicles and refueling infrastructure.

Task 2. We assessed the implications of CO_2 sequestration for hydrogen energy systems. The goals of this work are a) to understand the implications of CO_2 sequestration for hydrogen energy system design; b) to understand the conditions under which CO_2 sequestration might become economically viable; and c) to understand design issues for future low-CO_2 emitting hydrogen energy systems based on fossil fuels.

Introduction

Summary of Approach/Rationale

Since 1986, researchers at Princeton University's Center for Energy and Environmental Studies have carried out technical and economic assessments of hydrogen energy systems. Our approach has been to assess the entire hydrogen energy system from production through end-use from several perspectives (fuel producer, consumer, society) considering technical performance, economics (e.g. capital cost, delivered hydrogen cost, cost of energy services), infrastructure, environmental and resource issues. The goal of our work is to illuminate possible pathways leading from present hydrogen markets and technologies toward wide scale use of hydrogen as an energy carrier, highlighting important technologies for RD&D. This work has been part of the systems analysis activity of the DOE Hydrogen Program since 1991.

Past Results

In the late 1980s and early 1990s we focussed on the long term potential of hydrogen derived from renewables (solar, wind, biomass). These studies suggested that renewable hydrogen used in energy efficient end-use devices (e.g. fuel cells) could become economically competitive, beginning in the next century. More recently we have explored how a transition to large scale use of hydrogen energy might begin, starting with the use of hydrogen from natural gas.

Over the past few years our focus has been on strategies for producing, distributing and using hydrogen as a fuel for zero emission vehicles. We have looked in detail at various near term options available for providing hydrogen transportation fuel to vehicles (production of hydrogen from natural gas or off-peak power). We have also considered longer term options such as gasification of biomass or MSW and hydrogen from wind or solar. In FY '95 and FY '96 we assessed the potential impact of advances in small scale hydrogen production technologies (steam reforming of natural gas, electrolysis using off-peak power) on the cost of hydrogen transportation fuel. In particular, we assessed the possibilities for low cost, small scale hydrogen production from natural gas. During FY'96 (July 1995-July 1996), we completed a case study of developing a hydrogen refueling infrastructure in Southern California.

In FY'97 and FY'98 (July 1996-November 1997), we studied the prospects for using hydrogen as a fuel for fuel cell vehicles, compared to vehicles witrh onboard reformation of methanol or gasoline. Vehicle performance and cost and refueling infrastructure issues were considered.

In FY'98 (November 1997-September 1998), two projects were completed::

* an assessment of potential supplies and demands for hydrogen transportation fuel in the New York City/New Jersey area and

* an assessment of the implications of CO2 sequestration for the design of hydrogen energy systems.

This progress report summarizes the results of these two studies

Publications

Table 1 and the attached bibliography summarize Princeton CEES work related to hydrogen and fuel cells. Studies supported by the USDOE Hydrogen R&D Program are indicated with a star "*".

Papers on our DOE sponsored work on hydrogen infrastructure and fuel cell vehicle modeling have been presented to a variety of audiences including talks at the Society of Automotive Engineers Topical Technical Conference on Fuel Cell Vehicles (March 1998), two National Hydrogen Association Meetings (March 1997 and March 1998), the '97 World Car Conference (January 1997), the Aspen Energy Forum (July 1997), and the SAE Fall Fuels and Lubricants Meeting (October 1998). Two papers based on our DOE sponsored work have been accepted for publication in peer reviewed journals and will appear in 1999 (one in the International Journal of Hydrogen Energy and one in the Journal of Power Sources).

We have presented talks on our work on Hydrogen Energy Systems and CO_2 Sequestration at the DOE Workshop on Fuels Decarbonization and Carbon Sequestration (July 1997), the 9th National Hydrogen Association Meeting (March 1998), the 12th World Hydrogen Energy Conference (June 1998) and the 10th National Hydrogen Association Meeting (April 1999).

Current Year Results

Task 1: Assessment of Potential Supplies and Demands for Hydrogen Energy in The New York City/New Jersey Area (November 1997-September 1998)

The New York City/New Jersey metropolitan area is a possible candidate for "Clean Cluster" type demonstrations of hydrogen energy technologies. Like California, New York City and New Jersey have severe urban air quality problems and are considering the use of zero and low emission vehicles. Unlike California, relatively little analysis has been done looking into the possibilities for hydrogen and fuel cell vehicles.

As part of this year's research, we carried out a preliminary study of potential hydrogen demands and supplies in the New York City/New Jersey area, similar to our earlier work in Southern California (Ogden 1997, Ogden 1999). This study builds on our previous work on hydrogen infrastructure, and on preliminary studies at CEES on the potential for hydrogen production from muncipal solid waste (Larson, Chen and Worrell 1996.).

In particular, we address the following questions:

Task 1.1. What are potential demands for hydrogen for transportation markets in the New York City/New Jersey area. We consider centrally refueled applications such as urban buses, vans and fleet autos, as well as public automobiles.

Task. 1.2. What are potential supplies for hydrogen for transportation markets in the New York City/New Jersey area. considering:

* truck delivered or pipeline delivered merchant hydrogen,

* hydrogen byproduct from chemical plants and refineries,

* onsite hydrogen production from steam reforming of natural gas at small scale,

* electrolytic hydrogen from off-peak power,

* hydrogen from gasification of municipal solid waste.

Task 1.3 What is the production cost and delivered cost of hydrogen transportation fuel from these various sources.

Summary of Results

Task 1.1: What are potential demands for hydrogen for transportation markets in the New York City/New Jersey area.

* There is a strong impetus to develop low polluting vehicles in the New York City/New Jersey area, which may present opportunities for hydrogen and fuel cell vehicles. Both the New York City metropolitan area and the state of New Jersey are currently non-attainment areas for ozone, carbon monoxide and particulates. New York state has a zero emission vehicle mandate, similar to the California ZEV regulations, and in August 1997 passed legislation offering tax credits for the incremental cost of alternative fueled vehicles and refueling stations, including hydrogen. New York City has undertaken a variety of efforts to introduce alternative vehicles. New York is probably second only to California in its commitment to alternative vehicles. New Jersey has a smaller but active program in alternative fueled vehicles, and a growing awareness of fuel cells and hydrogen, encouraged by the presence of several fuel cell companies, hydrogen suppliers and large scale hydrogen users such as refineries based in the state. New Jersey recently decided to develop a state Climate Change Action Plan, and has endorsed a National LEV standard.

* Both the New York City area and New Jersey are potentially large markets for alternative transportation fuels. There are significant numbers of urban transit buses, almost all run on Diesel fuel, a large population of other centrally refueled fleet vehicles, and large, grographically concentrated populations of passenger vehicles.Tables 2 and 3 shows data for buses, centrally refueled fleets and passenger cars in New York and New Jersey. Using assumptions about energy consumption, if these vehicles were converted to run on hydrogen fuel cells, based on earlier studies (Ogden, Kreutz and Steinbugler 1998), the potential hydrogen demand can be estimated.

* If siginficant numbers of vehicles in New York City or New Jersey were converted to hydrogen, a large hydrogen demand would develop.

    o The current light duty vehicle population in New Jersey is about 5.7 vehicles (including 1.0 million light trucks). The average annual mileage is 10,330 miles/yr, and the average fuel economy is 20.3 mpg. Vehicle miles are projected to increase from their 1995 level of 187 million miles/day to 209 million miles/day in 2010. We assume that the average fuel economy of light duty vehicles can be increased by a factor of four over present levels through a combination of lighter weight, more streamlined design (which could improve fuel economy by perhaps a factor of 1.5) and adoption of fuel cells rather than ICEs (which would increase fuel econony by another factor of 2.5). In this case, we find that the statewide average fuel economy would be 80 mpg equivlent. The hydrogen needed would be about 1000 million scf/day to supply all NJ light duty vehicles in 2010.

    o There are about 5300 buses in New Jersey including commercial and public fleets. Virtually all the buses are centrally refueled. The total energy use by buses in New Jersey in 1990 was estimated to be 5.9 Trillion BTU/yr of Diesel. Assuming that a fuel cell bus would acheive a 50% higher fuel economy than a Diesel, the hydrogen needed to power New Jersey's fuel cell transit buses would be about 33 million H2/day.

    o For New York City, the total vehicle miles are estimated to be 19 billion/year for light duty vehicles (or 52 million vehicle miles/day). The energy use is 127 million GJ/yr. Assuming that fuel cell vehicles could improve fuel economy from the current average of 20 mpg to 80 mpg, the corresponding hydrogen use for all NYC light duty vehicles would be about 250 million scf H2/day.

    o New York City's 3600 public transit buses log a total of about 90 million bus-miles, requiring perhaps 15 million scf/day of hydrogen, if fuel cell buses were used.

o State level data on energy consumption in centrally refueled fleets of autos and trucks are not generally available. However, about 220,000 fleet autos and 265,000 fleet trucks are located in New York State and 136,000 fleet autos and 154,000 fleet trucks in New Jersey. Nationally, a sizeable fraction of heavy delivery trucks (65%) and service trucks (44%) are estmated to be centrally refueled, which would facilitate use of an alternative fuel such as hydrogen. Moreover, an estimated 75-80% of large business, government and utility fleets are centrally refueled. Nationally, the average number of vehicles in non-transit fleets is 200, but the median is 33, siggesting that there are a few large fleets and many small ones. Although it is difficult to quantify non-transit fleet markets from the available data, it is possible that on the order of 100,000 cars in the New York/New Jersey region, might be centrally refueled. Since fleet cars tend to be driven about twice as far as non-fleet cars, fueling a fleet of 100,000 cars would require about 20 million scf of hydrogen per day. Fleet trucks would require a larger amount of hydrogen.

Task 1.2: What are potential hydrogen supplies in the New York City/New Jersey area.

* There are a variety of potential near term hydrogen supplies in the New York City/New Jersey area, which could be used to provide hydrogen transportation fuel. These include truck delivered merchant hydrogen, byproduct hydrogen from refineries and chemical plants, onsite hydrogen production via small scale steam reforming of natural gas, onsite hydrogen production via small scale water electrolysis. In the longer term hydrogen might be produced from large scale steam reforming of natural gas with pipeline distribution or gasification of municipal solid waste.

* Industrial gas companies in the NYC/NJ area generally meet hydrogen demands in the range needed for refueling stations (0.1-2.0 million scf H2/day) via truck delivery of either liquid hydrogen or compressed hydrogen gas. The hydrogen is originally produced at distant Chloralkali plants, and trucked into the area, rather than at nearby large steam methane reformers dedicated to merchant hydrogen production, as in Southern California. There are currently no industrial hydrogen pipelines operating in the New York City/New Jersey area, except perhaps within refineries. Several industrial gas companies (Air Products and Chemicals, Praxair, BOC Gases, Air Liquide, MG Gases) serve this area.

* Excess byproduct hydrogen may be available from refineries and chemical plants located in New Jersey. Several large chemical/refinery complexes are found in New Jersey located in: 1) the Newark area, 2) the Philadelphia/Camden area, 3) the area near the Delaware Memorial Bridge at the NJ/DE border, which

has both refineries and a Chloralkali plant. It appears likely that some hydrogen may be available from such sources, totalling perhaps a few million scf/day, enough for a few hundred buses.

* There is a significant amount of off-peak power available in New Jersey (total generation capacity is approximately 18,000 MW, and in theory about one third to half this capacity could be available for off-peak power generation), but the price of off-peak power is presently high, on the order of 7 cents/kWh . This may make it difficult for onsite electrolysis to compete as a source of hydrogen. Many analysts believe that the price of off-peak power should eventually go down with deregulation and utility restructuring, although the ultimate price is difficult to predict.

* In New York City, lower cost off peak power rates (about 3.5 cents/kWh) are available to large industrial or commercial customers. Electrolysis will still be a more costly method than onsite steam reforming of natural gas.

* Onsite production of hydrogen from natural gas in small steam refomers is another possibility. However, the cost of natural gas is moderately high in the region, as New York and New Jersey are at the "end of the pipeline" bringing gas from the Gulf states. Natural gas costs are about $4.4/GJ to a large industrial/commercial customer in New York City, and $4.9/GJ in New Jersey. Moreover, there is little excess capacity in the existing natural gas interstate pipelines serving the New Jersey/New York City area. In the winter, gas delivery is limited by long distance pipeline capacity (rather than local distribution pipelines). Increasing natural gas supplies to the region (for example, to produce enough hydrogen to meet the demands for a large fleet of vehicles) could be costly if it entailed building new interstate natural gas pipeline capacity. Supplying enough natural gas to make hydrogen for all light vehicles in New Jersey (assuming fuel cell vehicles are used) would increase the natural gas flow into the state by perhaps 25%. There are currently plans to expand pipeline capacity into the Northeast for heating.

* Gasification of municipal solid waste is an intriguing longer term possibility for hydrogen production in the New York City/New Jersey area. (A system for hydrogen production from MSW gasification has not been commercialized although the component technologies are available) This would also help solve the problem of waste disposal, a serious issue in a region where landfill space is virtually exhausted. Preliminary calculations show that if all the non-recycleable waste streams in New York City were used to make hydrogen for fuel cell vehicles about 44% of New York City's estimated 19 billion light duty vehicle miles could served by this resource alone. Equivalently all of transit buses in New York City could be served by about 16% of the MSW. A similar fraction of LDVs in New Jersey could be served if all New Jersey's municipal solid waste were gasified for hydrogen production. The economics of this approach depend upon the scale of the plant (nominally a MSW to hydrogen

plant might produce 25 million scf H2/day, enough for a fleet of perhaps 250,000 fuel cell cars, although smaller plants may be possible), and the tipping fee.

* Because the New York City/New Jersey region has higher energy prices than many regions of the US, onsite small scale hydrogen production may be more expensive than in regions with lower energy costs. For example, projected costs in Southern California are somewhat lower than in New York and New Jersey.

* Figures 1 and 2 summarize the potential hydrogen supplies and demands in New Jersey. In the near term, refinery excess hydrogen and hydrogen from natural gas would be sufficient to get started. Or hydrogen could be produced via onsite reforming of natural gas. In the longer term gasification of MSW may be an interesting option.

Task 1.3: What is the production cost and delivered cost of hydrogen transportation fuel from these various sources.

The delivered cost of hydrogen transportation fuel depends on energy prices. In Table 5, natural gas and electricity prices are shown for New Jersey and New York. Based on refueling system designs developed in earlier studies (Ogden 1998), we have calculated the delivered cost of hydrogen transportation fuel as a function of refueling station size for a range of supply options including:

* Centralized production of hydrogen from natural gas with delivery by liquid hydrogen truck

* Centralized prodction of hydrogen via steam reforming of natural gas with local gaseous pipeline delivery (shown for low demand density and high demand density cases).

* Onsite production of hydrogen via small scale reforming of natural gas

* Onsite production of hydrogen via small scale electrolysis using off-peak power

The estimated cost of hydrogen transportation fuel from various sources is estimated in Figure 3 for energy prices in New York and New Jersey. We see that hydrogen from natural gas offers the lowest delivered transportation fuel cost. Because of the relatively high cost of off-peak power (3.5 cents/kWh in New York and 7 cents/kWh in New Jersey), electrolytic hydrogen is a more expensive alternative.

The delivered cost of hydrogen transportation fuel in New York City/New Jersey area varies from about $15-40/GJ depending on the station size and the supply option.

Data Sources

Data on vehicle energy use and alternative vehicles were obtained from the New Jersey Board of Public Utilities Energy Department (NJBPU), the New Jersey Department of Environmental Protection (NJDEP), the New Jersey Department of Transportation (NJDOT), and the NJ Office of Sustainability, the New York Power Authority, NYSERDA, the Northeast Alternative Vehicle Consortium and the Northeast Sustainable Energy Association.

For current energy prices in the area, we contacted the individual electric and gas utilities in the area (Public Service Gas and Electric, GPU/Jersey Central Power &Light, Atlantic Electric Company, Rockland Electric, New Jersey Natural Gas, South Jersey Gas, and Elizabethtown Gas, Consolidated Edison, New York Power Authority, Brooklyn Union Gas, Lilco), and using data from annual reports of the NJBPU.

For an understanding of current merchant hydrogen infrastructure in the area, we contacted Air Products, Praxair, and BOC Gases.

For data on hydrogen production in refineries and other chemical plants (Chloralkali, etc.), we collected data from the industrial gas companies, as well as from oil companies (Mobil and Exxon).

For data on the availability and content of municipal solid waste as a feedstock for hydrogen production, we contacted the New Jersey DEP, the New York Power Authority and the NY Department of Sanitation.

For data on fleet vehicles, and vehicle populations we consulted studies by the NJDOT, the NJBPU, Oak Ridge National Laboratory, the American Automobile Manufacturers' Association, and the Federal Highway Administration.

For estimates of hydrogen production, distribution and refueling systems, we utilized data collected in earlier studies of hydrogen infrastructure.

Methods Of Analysis

Where necessary, engineering models of hydrogen production, distribution and refueling station equipment are being developed or adapted from our earlier work on hydrogen infrastructure.

The levelized cost of hydrogen production, delivered hydrogen cost and lifecycle costs of transportation are estimated using standard microeconomic techniques.

Interaction With Other Groups/Technology Transfer

Understanding the potential demand for hydrogen vehicles in New York City and New Jersey involved interactions with the state and local governmental groups involved in alternative vehicles and energy, and with local gas and electric utilities.

These include the New Jersey Board of Public Utilities Energy Department, the New Jersey Department of Environmental Protection (NJDEP), which is rapidly developing an interest in hydrogen and fuel cells, and the New Jersey Department of Transportation (NJDOT), which is currently sponsoring H-Power's development of small scale fuel cells as battery replacements for highway warning signs. Governor Whitman of New Jersey has issued an order to develop a statewide "Climate Change Action Plan".

We have had several meetings with New Jersey officials involved in assessing the potential of new technologies to reduce greenhouse gas emissions in New Jersey. One of the most active interchanges thusfar has been with the NJ Department of Environmental Protection. We have given a number of briefings to this group, and to others in the newly created NJ Office of Sustainability and in the New Jersey Science and Technology Group on fuel cell vehicles, hydrogen and CO_2 sequestration. There is a growing interest in hydrogen and fuel cells in New Jersey, that may make it attractive as a potential site for hydrogen vehicle implementation.

Other valuable data were obtained from the New York Power Authority, NYSERDA and the Northeast Alternative Vehicle Consortium.

Task 2. Implications Of CO_2 Sequestration For Hydrogen Energy Systems (November 1997-September 1998)

Recently, it has been proposed that hydrogen could be produced at large scale via steam reforming of natural gas, or gasification of coal or biomass, with low cost separation of CO_2 and permanent sequestration underground, for example in depleted gas wells or in deep aquifers. The basic idea is sketched in Figure 4, showing hydrogen production from hydrocarbon feedstocks, with separation of CO_2 during the process. CO_2 is piped to a site for underground storage. The hydrogen is compressed and transmitted to distant users via high pressure hydrogen pipelines. A hydrogen energy system with sequestration would allow the continued large scale use of fossil fuel resources while greatly reducing CO_2 emissions into the atmosphere.

While CO_2 sequestration is an active research topic, under investigation by the USDOE (USDOE 1997, Socolow 1997) and internationally (Herzog 1997), there has been relatively little work done linking this idea to concepts of hydrogen energy systems. Indeed, CO_2 sequestration raises a host of interesting hydrogen systems questions. These include the following.

* What is the cost of hydrogen production with CO_2 sequestration compared to other hydrogen production methods? How does it compare to localized hydrogen production from natural gas and to fuel cycles with no net CO2 emissions (e.g. hydrogen from solar, wind or biomass)? How does the cost vary

with demand? What are the potential impacts of new technologies for steam reforming and CO2 separation?

* When would it make sense to start sequestering CO2? In particular, at what scale of hydrogen production could you begin sequestering CO2? How large a hydrogen demand must be in place before sequestering CO2 and distributing hydrogen become economically attractive? Answering this question involves understanding the economies of scale of hydrogen production, CO2 separation and sequestration, and pipeline transmission.

* What are plausible scenarios for a transition toward a large scale hydrogen energy system with sequestration? Under what conditions will pipeline hydrogen (produced via large scale steam reforming and transmitted long distances via pipeline) compete with locally produced hydrogen (either at the city scale -- in a single city-sized refomer plant) or onsite (e.g. via small scale steam reforming at a hydrogen refueling station)?

To study these questions we completed the following tasks as part of our work for the Hydrogen R&D Program in FY'98.:

Task 2.1: Understand scale economy issues for hydrogen energy systems with sequestration.

Task 2.1a. What are the scale economies of current and developing technologies for steam methane reforming and CO2 separation?

Task 2.1b. What are the scale economies of local and long distance hydrogen pipeline transmission? Using pipeline transmission models developed at Princeton, we estimate the cost of hydrogen pipeline transmission as a function of pipeline pressure, flow rate, and pipeline length.

Task 2.1c. What are the scale economies of pipeline transmission and sequestration of CO2? What determines the rate at which CO2 can be injected at the sequestration site?

Task 2.1d. How does the cost of hydrogen with CO2 sequestration vary with the energy demand and the distance of the hydrogen plant and sequestration site from the demand?

Task 2.1e. What is the cost of hydrogen with CO2 sequestration, compared to other hydrogen supply options (including "carbon-free" options such as renewable hydrogen), as a function of demand?

Task 2.2. Estimate the conditions under which pipeline hydrogen with sequestration will compete with other options. How large must the demand be? How close must the

hydrogen production be to the demand? What are the potential impacts of new steam reforming technologies?

Task 2.3. Sketch possible scenarios for a transition toward a large scale hydrogen energy system employing CO2 sequestration.

Example: Understanding design issues for natural gas-based hydrogen energy systems with CO_2 sequestration.

As an example, we consider a system with hydrogen production from natural gas and sequestration of CO_2. As shown in Figure 5 there are a number of options for delivering hydrogen to users, and for capturing CO_2. Key questions are

* "where do you make the hydrogen?" (hydrogen can be made at small scale at the user's site; at city scale with local distribution; or at large scale near the source of natural gas with long distance hydrogen pipeline transmission.)

and

* "where do you capture the CO_2?" (In theory CO_2 could be captured at small scale and collected, or captured at city scale and piped some distance to a sequestration site, or captured at a hydrogen production facility at the natural gas field and re-injected into gas wells).

* when does hydrogen from natural gas with CO2 sequestration compete with other low CO2 options?

The answers to these questions depend on scale economies in:

* hydrogen production,

* CO_2 separation,

* pipeline transmission of hydrogen, natural gas and CO_2,

* CO_2 injection at the sequestration site

To size the various components in the system, we first must estimate the potential hydrogen demand and associated CO_2 production.

Hydrogen Demand

Table 5 shows hydrogen flows needed to supply various end-use demands. Projected hydrogen demand varies over a wide range from 0.04 GJ/day for a single fuel cell car to 0.3 million GJ/day if all the cars in the Los Angeles Basin converted to hydrogen fuel cells

to 3 million GJ/day to equal the energy in the current natural gas flow in the Southern Californmia Gas system.

Production of Hydrogen from Natural Gas

Catalytic Steam Reforming

Catalytic steam reforming of natural gas is a well known, commercially available process for hydrogen production (Rostrup-Nielsen 1984, Twigg 1989). Hydrogen production is accomplished in several steps: steam reforming, water gas shift reaction, and hydrogen purification. (Figure 6 shows material flows for a typical hydrogen production plant based on steam reforming of natural gas.)

The steam reforming reaction

$$CH_4 + H_2O \text{ <-> } CO + 3\ H_2 \qquad \Delta h = +206.16 \text{ kJ/mol } CH_4 \quad (1)$$

is endothermic and is favored at higher temperatures, and lower pressures. Typical reformers operate at anywhere from 3 atm, 700^{o}C to 15-25 atm, 850^{o}C. External heat needed to drive the reaction is often provided by the combustion of abut 20% of the incoming natural gas feedstock (purge gases from the hydrogen purification system are often used in addition). Heat transfer to the reactants is accomplished indirectly through a heat exchanger. Methane and steam react in catalyst filled tubes. Typically, the mass ratio of steam-to-carbon is about 3 or more to avoid "coking" or carbon build-up on the catalysts. (At lower steam to carbon ratios, solid carbon can be produced via side reactions.)

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

$$CO + H_2O \text{->} \quad CO_2 + H_2 \qquad \Delta h = -41.15 \text{ kJ/mol } CO \quad (2)$$

which "converts" CO to H_2. This reaction is favored at temperatures of less than about 600^{o}C, and can take place as low as 200^{o}C, with sufficiently active catalysts. The gas exiting the shift reactor contains mostly H2 (70-80%) plus CO_2, CH_4, and small quantities of H_2O and CO. For hydrogen production, the shift reaction is often accomplished in two stages. A high temperature shift reactor operating at about 350-475^{o}C accomplishes much of the conversion, followed by a lower temperature (200-250^{o}C) shift reactor which brings the CO concentration down to a few percent by volume or less.

Hydrogen Purification

The gas exiting the shift reactors contains (on a dry basis) about 77% hydrogen,19% CO2, 3% CH4, and 1% CO with traces of N2. For most hydrogen applications, the gas must be further purified. Since CO2 is the largest impurity, CO2 separation is done as part of the hydrogen purification process.

The required degree of purification depends on the application.

For most industrial applications, hydrogen purities exceeding 95% are required. If hydrogen is stored and transported to distant users as a fuel suitable for use in fuel cell vehicles, purities approaching 99.999% are probably desirable.

Until about 10-20 years ago, conventional SMR plants used a chemical or physical absorption step after the shift reactors to remove CO2 (Steinberg and Cheng 1988). The CO2-free gas then undergoes a methanation step, converting any remaining CO to CH4, yielding hydrogen purities of 95-98% (see Figure 6a).

More recently, pressure swing absorption (PSA) systems (Sircar 1988) have come into common use to produce hydrogen at up to 99.999% purity (Figure 6b). In addition to producing a higher purity (and therefore more valuable) product, PSA systems offer lower energy costs than chemical absorption systems, which require significant heat input to regenerate the absorbing solvent, and lower hydrogen production cost (Steinberg and Cheng 1988).

CO2 removal is a required step in hydrogen production via SMR. Thus, a “base case” hydrogen plant, whether based on SMR/PSA (Figure 6b) or SMR/absorption (Figure 6a) involves CO2 removal from the hydrogen-rich gas exiting the shift reactor. Along with the CO2, other impurities such as CH4, CO, H2O, and N2 are removed. For CO2 sequestration, separation of pure CO2 from the mix is required, which can involve some additional equipment and energy input.

Cost of Steam Methane Reformers

Steam reformers have been built over a wide range of sizes, from 0.1 million scf H2/d to several hundred million scf H2/day. The specific capital cost ($ per kW of hydrogen output) for various hydrogen production systems is shown as a function of plant size (in million scf H2/day) in Figure 7. Conventional steam methane reformer technology is shown, as well as advanced small scale reformers based on fuel cell reformer technology (Halvorson and Farris 1997). Estimates for the mass produced capital cost of advanced small scale "fuel cell type" reformers are shown for various levels of cumulative production (1 unit up to 10,000 units), based on recent studies by Directed Technologies, Inc. (Thomas et.al. 1997). We see that the capital cost of small scale steam methane reformers could be significantly reduced with advanced technology.

However, the production cost of hydrogen would still be less for centralized production than for decentralized small scale production, because the feedstock cost will be less at a

large central hydrogen plant than at a refueling station. As shown in Figure 8, feedstock costs dominate the total cost of hydrogen production.

Local Distribution of Hydrogen Transportation Fuel

Of course, centrally produced hydrogen must be distributed to users, which adds distribution costs. The cost of small scale, local gaseous pipeline transmission is shown in Figure 9 as a function of pipeline length and number of fuel cell vehicles served. Costs are lowest for large flow rates and short pipelines (e.g. large, geographically concentrated hydrogen demands). Figure 10 shows local hydrogen pipeline transmission costs including the costs of compressing and storing hydrogen at a large centralized hydrogen production plant and installing a city scale network of 3" diameter pipelines to take hydrogen to refueling stations. The total transmission cost varies with the density of the hydrogen demand, e.g. the number of cars per square mile. Local distribution costs vary from about $2/GJ H2 for a dense population of H2 fuel cell cars (say 3000 cars per square mile, equivakent to assuming that all the cars in downtown Los Angeles or Denver convert to hydrogen) to $5/GJ or more for a sparser population of cars (e.g.assuming 10% of the vehicle population in downtown urban areas or 100% of vehicles in a suburban area convert to hydrogen). The sparser the demand, the longer the pipeline network must be to reach consumers, and the higher the cost.

Centralized vs. Decentralized Production of Hydrogen from Natural Gas

The delivered cost of hydrogen transportation fuel is shown in Figure 11 including hydrogen production, local pipeline distribution (for centralized production) and refueling stations. We see that decentralized production with advanced reformers can compete with centralized pipeline production, because of pipeline distribution costs. In the early stages of developing a hydrogen infrastructure, small scale onsite steam reforming will be lower cost. As demand increases, the cost of pipeline transmission is reduced, and the cost of centralized production approaches that of decentralized production.

This suggests that a hydrogen infrastructure will build up using onsite production. A large, geographically concentrated demand will be required before centralized production with pipeline distribution can compete.

Technologies for capturing CO2 during hydrogen production

Let us now assume that we want to sequester CO_2. The first step is separating a pure stream of CO2 during hydrogen production. The CO2 is then compressed to 8-10 MPa, transmitted via pipeline to a sequestration site such as an aquifer or depleted gas field, and injected underground.

CO2 separation during hydrogen production

In hydrogen production from natural gas, the gas exiting the shift reactor contains typically 77% hydrogen, 19% CO2, 3% methane and 1% CO by volume on a dry basis. To purify hydrogen, CO2 must be removed, along with other contaminants.

Various types of hydrogen purification technologies have been employed including chemical or physical absorption systems and pressure swing adsorption (Sircar 1988). At present, hydrogen producers generally prefer pressure swing adsorption systems (PSA), as they cost less than chemical absorption systems, require less enrgy input and produce hydrogen at higher purity (up to 99.999% purity as compared to 95-98% purity with absorption systems).

In chemical or physical absorption systems, a pure stream of CO2 is generated during purification. There is essentially no extra cost for CO2 separation in this type of system. The drawback is that the hydrogen purity is only 95-98%, with the primary impurities being CH4 and CO. Moreover, the energy input required to regenerate the absorbing fluid can be substantial especially for chemical absorption systems using solvents such as MEA or DEA. For physical absoprtion systems such as Selexol, the energy cost is lower than with chemical absorption systems, but the hydrogen purity is in the range 95-98%.

In PSA based systems configured for hydrogen purification, all the impurities CO2, CO, CH4, H20 are removed in a mixture, leaving very pure hydrogen (up to 99.999%). Separating CO2 from the contaminant mix requires an additional set of PSA beds and a compressor stage to boost the pressure between beds.

The additional cost of separating CO2 in a SMR/PSA system has been estimated by Moore (Moore 1997) -- see Table 8. Here a vaccum swing adsorption (VSA) CO2 separation system is retrofitted to a 80 million scf/day steam methane reforming hydrogen plant with a PSA unit. A VSA is similar to a PSA, but operates at less than atmospheric pressure. As shown in Table 8, the extra installed capital cost for the CO2 separation system is about $8.4-9.2 million, or about 17-18% of the total capital cost for a plant this size (which would cost about $50 million installed). In this system about 50% of the carbon in the natural gas feedstock is captured as CO2.

The VSA compressor requires electrical input of about 106 kWhe/tonne CO2 separated.

The incremental cost of CO2 separation per tonne of CO2 separated can be estimated (assuming an annual capital charge rate of 15%)

Incremental cost of CO2 separation= 0.15 x $8.4 million/(771 tonne CO2/d x 365 d/y) + 105 kWhe/tonne CO2 x $0.05/kWh = $4.48 + 5.25/tonne CO2 = $9.7/tonne CO2

Given that 35.6 GJ of hydrogen is produced per tonne of CO2, we find that the incremental cost of CO2 separation in a VSA system adds

Added H2 cost for CO2 separation
= $9.7/tonne CO2/(35.6 GJ H2/tonne CO2) = $0.27/GJ H2.

This is about 5-7% of the cost of hydrogen production in a large SMR plant.

Another estimate of CO2 separation costs is given by Katofsky (Katofsky 1993, Williams et.al 1995). In Katofsky's design, a PSA with two sets of beds and a recycle compressor is employed to produce a pure stream of CO2, as well as 99.999% pure hydrogen. Here the PSA system capital cost is about 30% of the total hydrogen plant capital cost (Williams et.al 1995). This compares with a typical PSA capital cost equal to about 10% of the total plant cost, for a PSA without CO2 separation (Moore 1996). The incremental capital cost of CO2 separation via added PSA beds is then about 20% of the total plant cost, which is similar to Moore's estimate above.

Katofsky's design captures about 70% of the CO2 in the natural gas feed. The plant size is 152.5 million scf H2/day, and 5.5 kg of CO2 are captured for every kg of hydrogen produced. The daily CO2 production is 2025 tonnes/d. The installed cost of the hydrogen plant with VSA is estimated to be about $170 million. Taking 20% of this cost or $34 million as the incremental cost for CO2 separation, and a PSA recycle compressor load of 100 kWhe/tonne CO2, we find a cost of separation of

0.15 x $34 million/(2025 tonnes CO2/day x 365 d/y) + 100 kwhe/tonne CO2 x $0.05/kWh = $6.9/tonne CO2 + 5.0/tonne CO2 = $11.9/tonne CO2.

The added cost of CO2 separation per GJ of hydrogen produced is approximately

$11.9/tonne CO2 x 5.5 tonne CO2/tonne H2 x 1 tonne H2/142 GJ= $0.46/GJ H2.

This rough estimate is higher than that of Moore, adding 9-10% to the cost of hydrogen production.

Scale economies for CO2 separation

The added capital cost of equipment for CO2 separation can be assumed to scale approximately with the total plant capital. For large SMR plants, a capital cost scale factor of 0.57 is used (Williams et.al 1995). The cost of electricity for compression will be less sensitive to scale.

CO2 Compression at the Hydrogen Plant

Once CO2 is separated it must be compressed to superctitical pressures (about 8 MPa) for pipeline tramsmission to a sequestration site (Skovholt 1995, Holloway 1996, Hendriks 1994).

The energy requirements for CO2 compression at the hydrogen plant have been estimated by Hendriks (1994). Compression from to 0.1 Mpa (1 atm) to 8 MPa is assumed. The

power requirement for a 5 stage compressor with 85% efficiency is 301 kJe/kg CO2, or 83.6 kWhe/tonne CO2.

According to Hendriks, the capital cost of a 500 tonne/h CO2 compressor is about $17 milllion or $407/kWe. The total installed cost of the CO2 compressor with housing and infrastructure is estimated to be about $730/kWe.

The CO2 compression costs at the hydrogen plant are then

0.15 x $17 million /(500 tonne/h x 0.9 x 8760 h/y) + 83.6 kWhe/tonne CO2 x $0.05/kWhe = 0.65 + 4.18 = $4.83/tonne CO2

The added cost of CO2 compression for Moore's case (where 3.99 kg of CO2 is produced per kg of H2) is about

$0.14/GJ H2

For Katofsky's design the added cost of CO2 compression is about

$0.19/GJ H2.

Incremental Costs at the Hydrogen Plant for Separating and Compressing CO2

The total costs at the hydrogen plant for separating CO2 and compressing it to pipeline pressure are for the two SMR/PSA cases:

> For 50% recovery of carbon from NG feedstock (Moore): $0.27/GJ + $0.14/GJ = $0.41/GJ H2 or $14.5/tonne CO2 = $53/tonne Carbon
>
> For 70% recovery of carbon from NG feedstock (Katofsky) : $0.46/GJ + 0.19/GJ = $0.65/GJ H2 or $16.7/tonne CO2 = $61/tonne Carbon

These costs are less than those for removing CO2 from power plant flue gases, which are more typically $30-60/tonne CO2 for systems using chemical absorption of CO2 (Hendriks 1994). Moreover, CO2 capture adds only about 10-15% to the cost of producing hydrogen via SMR as compared to a 60-100% cost increase for electricity when CO2 is removed from flue gases in a coal-fired power plant [Hendriks 1994]. CO2 sequestration during hydrogen fuel production is an attractive way of removing CO2 from the energy system.

Feasibility of CO2 Capture and Collection from Many Small Steam Reformers

In principle, it would be possible to separate CO2 at a small hydrogen plant, for example at a hydrogen refueling station with an onsite steam methane reformer. However, the incremental cost of small scale separation and compression would be large, perhaps $2-3/GJ H2. Moreover, cost of a CO2 collection system to a central point for pipeline delivery to a sequestration site would be about the same as a system for distributing hydrogen to users from a central H2 production plant. If CO2 sequestration is desired, centralized hydrogen production will always be less costly because of the high cost of capturing and collecting CO_2 from many small dispersed sources. This is shown in Figure 12. But centralized production implies that a large demand has built up for hydrogen -- otherwise onsite reforming would be less costly. Thus, CO2 sequestration is unlikely to be introduced until a large demand for hydrogen is in place.

Long distance CO2 pipeline transmission costs

Once hydrogen is produced and CO_2 separated and compressed, the CO_2 must be piped to a sequestration site. The size of the CO2 transmission pipeline and injection system depends on the amount of CO2 produced,w hich in turn depends on the level of hydrogen produciton required. In Table 8, we relate CO2 production to the hydrogen demand for various end-uses. We assume the hydrogen plant has the process flow diagram shown in Figure 13 (Katofsky 1993) where 70% of the carbon in the incoming natural gas feed (or 5.5 kg CO2 per kg H2) is captured for sequestration.

The cost of CO2 pipeline transmission has been estimated in a detailed engineering study carried for the Conmission of European Communities (Holloway et. al. 1996), for a range of flow rates from 2 million tonnes to 50 million tonnes CO2 per year. As shown in Table 8, the CO2 flow rate from a hydrogen energy system would be toward the lower end of this range. For a single hydrogen car, with hydrogen made from natural gas about 0.5 tonnes of CO2 would be emitted per year. So the CO2 pipeline systems considered in the CEC study are appropriate for an hydrogen energy system serving 4 million cars at a minimum. In Figure 14, we show the added cost of CO2 pipelines for various associated hydrogen production rates, and pipeline lengths. (We have extrapolated the CEC results to find pipeline costs at smaller CO2 flow rates). We see that at large CO2 flow rates (and large co-produced hydrogen flows) and short pipeline distances, the incremental cost of CO2 pipeline transmission is small: less than $1/GJ H2, assuming that the sequestration site is less than 300 km away from the hydrogen plant, and that the hydrogen demand is equivalent to 10-100% of the cars in the Los Angeles Basin. At small hydrogen demands (less than 100 million scf H2/day), the cost of CO2 pipeline transmission rises rapidly.

CO2 Injection and Storage at the Sequestration Site

Various authors (Hendriks 1994, Holloway et.al 1996) have estimated the cost of CO2 injection and storage in underground geological formations such as aquifers and depleted gas wells. At sequestration site, pipeline CO2 is compressed, if needed, prior to injection. Injection wells, typically 1-3 km in depth are drilled into aquifers, or depleted gas or oil wells can be used.

Injection rates for CO2 depend on the permeability of the undergound formation, the thickness of the storage reservoir and the alllowable overpressure. Flow rates vaty from 2 to 20 Nm3 per second or 340 to 3400 tonnes CO2 per day per well.

Storage costs in onshore aquifers are estimated to be $2-8/tonne CO2. In a large onshore gas field, costs of $0.5-3/tonne CO2 are typical. If additional compression is needed at the injection wellhead, this adds up to $0.5/tonne CO2.

Figure 15 (adapted from Hendriks 1994) shows the cost of injection as a function of injection flow rate. For reference we show the associated hydrogen energy demand, An injection well which strores CO2 at a rate of 340 tonnes/d could handle the output of a hydorgen plant producing 25 million scf H2/day. Even at this modest rate of hydrogen production, the cost of storage are only about $8/tonne CO2 or $0.3/GJ hydrogen. At larger CO2 flow rates, which would be needed for low CO2 pipeline costs, storage would add about $0.1/GJ or less to the cost of hydrogen.

Comparison of the Cost of Long Distance Pipeline Transmission for Hydrogen, Natural Gas and CO2

The cost of long distance pipeline transmission is shown for hydrogen, natural gas and CO2 in Figure 16. At large flow rates the cost contribution of long distance hydrogen transmission to the delivered fuel cost is small, perhaps 10-20% of the delivered hydrogen cost. Methane transmission is roughly 1/3 to 1/2 as costly as hydrogen transmission, for the same energy flow rate. The decision to make hydrogen at the gas field depends on the flow rate, and also on the possibility of enhanced gas recovery (Blok et.al. 1997).

Cost for CO2 Sequestration vs. Hydrogen Demand

The total cost of CO2 sequestration including CO2 separation and compression at the hydrogen plant, CO2 pipelines, and CO2 injection into an underground aquifer are shown in Figure 17 and Table 9. The hydrogen demand level has a profound impact on the cost of CO2 sequestration.

* CO2 sequestration is well suited to large scale energy systems (greater than 100 million scf H2/d). At hydrogen production levels of about 1-10 million scf/d, CO2 pipeline scale economies significantly increase the delivered hydrogen cost. At these scales, other low CO2 hydrogen options such as hydrogen from renewables may be competitive.

* CO2 sequestration requires centralized hydrogen production, which in turn requires a large, geographically concentrated demand to compete with onsite reforming.

* Collection of CO2 from many small onsite SMRs is not economically attractive. Central hydrogen production with hydrogen distribution will be less costly.

* At large scale (1000 million scf H2/day, an amount that could fuel all the cars in Los Angeles, if they used hydrogen fuel cells), the added cost of CO2 sequestration is about $1/GJ, or 20% of the hydrogen production cost). The largest contribution to this cost is CO2 separation at the hydrogen plant, using a double bed PSA system and compressor. This suggests that innovative CO2 separation schemes during hydrogen production will be important for hydrogen energy systems with sequestration.

How do scale economies influence the design of energy systems with CO_2 sequestration?

To justify putting a centralized hydrogen production plant and local hydrogen distribution pipeline system in place, a large, geographically concentrated hydrogen demand is needed. If you <u>don't</u> want to collect CO_2, and natural gas is plentiful, you may choose to make hydrogen onsite in advanced small scale reformers. If CO_2 sequestration is desired, the economics will always favor centralized hydrogen production, because of the high cost of separating and collecting CO_2 at small scale. The level of hydrogen demand required to implement a hydrogen energy system with CO_2 sequestration is probably something like 10-100% of cars in Los Angeles.

Large CO_2 flows are needed to make long distance transmission attractive. The associated hydrogen production is equal to that in 1 to 10 large refineries (in terms of chemical markets) or enough hydrogen about 10-100% of the cars in the Los Angeles Basin (in terms of energy markets).

Introduction of CO_2 sequestration requires a large hydrogen demand If PEM fuel cells are successfully commercialized for vehicles or combined heat and power, this could provide

impetus toward such a market (Williams 1997). In the nearer term (before the build-up of large hydrogen energy markets), one could look for large scale point sources of CO_2 associated with hydrogen production from fossil fuels, which are currently vented, but could be captured at small additional cost and sequestered. Some possibilities are steam methane reformers in oil refineries ("reduced CO_2" gasoline?) or in ammonia manufacture. These may be about the right scale to consider CO_2 sequestration.

Summary of results

* Engineering/economic models were developed of pipeline transmission for hydrogen, methane and CO_2, and hydrogen production with alternative methods of CO_2 separation.

* There are strong scale economies in gaseous pipeline transmission, hydrogen production, CO_2 separation and CO_2 injection which influence the design of a hydrogen energy system with CO_2 sequestration.

* If gases are piped long distances, a large flow rate is required to assure low transmission costs. Because of CO_2 pipeline scale economies, a large flow of CO_2 would be needed to reach low transmission costs, unless sequestration could be done near the site of hydrogen production. Large CO_2 flows imply a large geographically concentrated demand for the co-produced hydrogen would be required, before CO_2 sequestration could be done at low cost. The required hydrogen energy demand would be equivalent to the fuel required for 10%-100% of the cars in the LA Basin (assuming hydrogen fuel cell cars were used), assuming the CO_2 must be piped 300-1000 km to a sequestration site.

* At large flows, the cost of hydrogen pipeline transmission is small, less than 10% (20%) of the cost of hydrogen production over a distance of 300 km (1000 km). The added cost of long distance CO2 transmission is less than 5% of the hydrogen production cost for very large flow rates (e.g. for an energy system which could serve half the cars in LA).

* It is not economically or technically attractive to collect CO_2 from many small dispersed sources. CO_2 sequestration favors large, centralized hydrogen production with local hydrogen pipeline distribution to users.

* Because of advances in small scale methane reformer technologies, it is likely that onsite production of hydrogen from natural gas (for example at refueling stations) will be economically preferable to centralized production with local hydrogen pipeline distribution until a large demand for hydrogen has developed. Once a large hydrogen demand is in place, pipeline distribution may become competitive.

* Initially, demand for hydrogen energy would probably be met by onsite production from natural gas. Once a large demand was present, CO_2 sequestration could be considered. When CO_2 sequestration was implented, a switch to centralized production with local hydrogen distribution would also take place.

* In the near term, large scale industrial production of hydrogen via steam methane reforming (e.g. in oil refineries or chemical plants) might produce enough byproduct CO_2, for CO_2 sequestration to be considered, if a sequestration site is near enough.

Data Sources

Data on CO_2 separation operations during hydrogen production were obtained via discussions with hydrogen producers and industrial gas companies.

Data on various aspects of CO_2 sequestration were also gathered at the USDOE workshop on Fuels Decarbonization and Carbon Sequestration held in Washington DC in July 1997.

Data on hydrogen pipeline systems were available from our earlier studies for the hydrogen program. Data on CO2 pipelines were obtained from the literature and from discussions with researchers at Argonne National Laboratory.

Methods Of Analysis

Engineering models of hydrogen production, CO_2 separation, hydrogen and CO_2 pipeline transmission and hydrogen refueling station equipment are being developed.

The levelized cost of hydrogen production, delivered hydrogen cost and lifecycle costs of transportation are estimated using standard microeconomic techniques.

Interaction With Other Groups/Technology Transfer

We have interacted with other researchers at MIT, Argonne National Laboratory, Air Products and Chemicals, and Mobil and benefitted from discussions with analysts at the USDOE, Directed Technologies Inc. and Energetics.

Plans for Future Work

Assessment Of Hydrogen-Fueled Proton Exchange Membrane Fuel Cells For Distributed Generation And Cogeneration

Proton exchange membrane fuel cells (PEMFCs) are highly efficient power generators, achieving up to 50-60% conversion efficiency, even at very small sizes (down to the household level -- 3-5 kW). PEMFCs have zero pollutant emissions when fueled directly with hydrogen, and near zero emissions when coupled to reformers. These attributes make them potentially attractive for a variety of applications including electric vehicles and distributed generation and cogeneration of heat and power in buildings.

Over the past few years, there have been intense efforts worldwide to develop low-cost PEMFC systems. While the the primary focus has been on vehicle applications, an equally important application may be combined heat and power generation in commercial and residential buildings. The development of inexpensive PEMFC power systems for automotive applications may have powerful implications for the parallel development of analogous systems for residential-scale generation of distributed electric power and heat.

There are several reasons why PEMFCs might become competitive for buildings applications before they appear in vehicles:

1) The cost barrier is lower for PEMFC cogeneration systems than for automotive applications. To compete with internal combustion engines in automobiles, PEMFCs must achieve stringent cost goals of perhaps $50/kW. Recent studies indicate that significant cogeneration markets in commercial buildings could open for PEMFC stack costs of perhaps $300-500/kW (corresponding to complete system costs of $1000-1500/kW) (Arthur D. Little 1995). Residential markets might open at stack costs of $200-400/kW (O'Sullivan 1998).

2) The technical challenges are in many respects less severe for stationary power generation than for vehicles. (Start-up behavior and transient operation is likely to be less of a problem for power generation than for vehicles which are characterized by rapidly varying loads; heat and water management issues should be much easier; weight and volume constraints are less stringent; peak power devices will not be needed; control systems should be simpler; robustness and resistance to mechanical shocks during driving will not be an issue.) In one respect, technical requirements are more demanding for cogeneration applications: a longer operating lifetime (50,000-100,000 hours) would be needed for a stationary power system as compared to perhaps 5000 hours for vehicles.

Over the next year, researchers at Princeton Center for Energy and Environmental Studies will carry out a series of detailed technical and economic assessments with the goal of understanding the prospects for hydrogen fueled PEM fuel cell cogeneration technology for residential applications. We concentrate on hydrogen derived from natural gas, a primary energy source which is widely available today, and is likely to give the lowest hydrogen cost in the near term.

We compare three types of PEM fuel cell cogeneration systems which could provide heat and power to residential users (see Figure 18).

Case 1) a centralized "neighborhood" scale (200-1000 kW) natural gas reformer/PEM fuel cell system which distributes heat (via district heating) and electricity (via wire) to 40-200 residential users. .

Case 2) a centralized "neighborhood" scale natural gas reformer, which produces hydrogen or a hydrogen rich gas for distribution to users. Each house has a small hydrogen fueled (5 kWe) PEM fuel cell providing electricity and heat.

Case 3) individual natural gas reformers coupled to 5 kW PEM fuel cells at each house.

For each case energy storage (in the form of hydrogen storage, hot water storage or electric batteries) could be used to meet time varying energy demands. Connections to the electric utility system could be made at the household or neighborhood level, allowing dispatch of power.

In the proposed work, engineering and economic models of PEM fuel cell based cogeneration systems will be developed. The potential advantages and disadvantages of each configuration will be investigated in terms of overall energy efficiency, performance, economics (capital cost, delivered cost of electricity and heat), and greenhouse gas emissions. PEMFC cogeneration systems will be compared to other alternatives for production of residential heat and power.

Acknowledgments

The systems studies reported here were performed with support from U.S. Department of Energy Hydrogen R&D Program, under contract No. DE-FG36-95G010061.

For useful conversations, the author would like to thank James Cannon (Inform), Ed Danielli (Praxair), Richard Doctor (Argonne National Laboratory), Sarah Edwards (Princeton U.), Barbara Heydorn (SRI), Howard Herzog (MIT), John Houghton (USDOE), Joe Iannucci (Distributed Utilities Associates), Gib Jersey (Mobil), Cameron Johnson (NJDEP), Rene Lapierre (Mobil), Michael Kerr (Praxair), Paul Kydd (BOC), Eric Larson (Princeton U.), Michael Levine (BOC Gases), Sheila Lynch (NAVC), David Macmillan (NJBPU), Robert Miller (Air Products and Chemicals, Inc), Robert Moore (Air Products and Chemicals, Inc.), Stuart Nagourney (NJDEP), David Nahmias (National Hydrogen Association), Venki Raman (Air Products and Chemicals, Inc.), Susan Romeo (CALSTART), Robert Socolow (Princeton University), Mike Strizki(NJDOT), Sandy Thomas (Directed Technologies, Inc.) and Robert Williams (Princeton University).

References

Arthur D, Little, "Fuel Cells for Building Cogeneration Applications - Cost/Performance Requirements and Markets," Final Report, to the Building Equipment Division, Office of Building Technologies, U.S. Department of Energy, Contract No. DE-AC01-89-CE23821, January 1995.

K. Blok, R.H. Williams, R.E. Katofsky, and C.A. Hendriks, “Hydrogen Production from Natural Gas, Sequestration of Recovered CO2 in Depleted Gas Wells and Enhanced Natural Gas Recovery,” Energy, vol. 22, No. 2/3, pp. 161-168, 1997.

Chen, J., Plug Power, personal communication, February 26, 1998.

Dennis, E.B. May 1994. "Design and Feasibility of a Gaseous Hydrogen Refueling Station Based on Small Scale Steam Reforming of Natural Gas," Princeton University senior thesis, Department of Chemical Engineering.

Ernst, W. D., “Plug Power Fuel Cell Development Program”, Proceedings of the Annual Automotive Technology Development Customer’s Coordination Meeting, DOE-OTT, Dearborn, MI, October 27-30, 1997.

EPRI, “American Power Corp and EPRI Form Collaborative Alliance to Field Test Fuel Cells for Powering Homes and Businesses”, Electric Power Research Institute press release, December 3, 1997.

Halvorson, T., R. Victor and P.J. Farris , January 19-22, 1997."Onsite Hydrogen Generator for Vehicle Refueling Application," to appear in Proceedings of the '97 World Car Conference, Riverside, CA.

C. Hendriks, “Carbon Dioxide Removal from Coal-Fired Power Plants,” Ph.D. Thesis, Univsersity of Utrecht, Department of Science, Technology and Society, Utrecht, the Netherlands, 1994.

Herzog, H.J., ed., 1997. "Carbon Dioxide Removal," Proceedings of the Third International Conference on Carbon Dioxide Removal, Cambridge, MA, 9-11 September 1996, Energy Conversion and Management, Vol. 38, Suppl., 689 pp.

Sam Holloway, "An Overview of the Joule II Project : The Underground Disposal of CO_2", Energy Conversion Management, vol. 37, No.s 6-8, p., 1149-1154, 1996.

S. Holloway, ed., “The Underground Disposal of Carbon Dioxide, Chapter 8: Technoeconomics of Underground Disposal” British Geological Survey, Final Report for Contract No. JOU2 CT92-0031, ISBN 0 85272 280 X, Comission of the European Communities, February 1996.

IEA Greenhouse Gas R&D Programme, “Precombustion Decarbonization,” Report Number PH2/19, June 1998, prepared by Foster Wheeler.

James, B., G. Baum and I. Kuhn August 1994. "Technology Development Goals for Automotive Fuel Cell Power Systems," Argonne National Laboratory Report No. ANL-94/44.

Olav Kaarstad and Harry Audus, "Hydrogen and Electricity from Decarbonised Fossil Fuels" , 3rd International Conference on Carbon Dioxide Removal, September 1996

R. E. Katofsky, “Production of Fluid Fuels from Biomass,” Princeton University Center for Energy and Environmental Studies Report No. 279, June 1993.

E. Larson, E. Worrell and J. Chen, "Clean Fuels from Municipal Solid Waste for Fuel Cell Buses in Metropolitan Areas," Resources, Conservation and Recycling, v. 17, p. 273-298, 1996.

Robert Moore, Air Products and Chemicals, Inc., private communications 1996, 1997.

Ogden, J.M., E.D. Larson and M.A. Delucchi May 27, 1994. “An Assessment of Renewable Transportation Fuels and Technologies,” report to the US Congress Office of Technology Assessment.

Ogden, J.M., E. Dennis, M. Steinbugler and J. Strohbehn Jan. 18, 1995. "Hydrogen Energy Systems Studies," final report to USDOE for Contract No. XR-11265-2.

Ogden, J., T. Kreutz, S. Kartha and L. Iwan November 26, 1996. " Assessment of Technologies for Producing Hydrogen from Natural Gas at Small Scale," Princeton University Center for Energy and Environmental Studies Draft Report.

Ogden, J.M. January 19-22, 1997. "Infrastructure for Hydrogen Fuel Cell Vehicles: A Southern California Case Study," Proceedings of the '97 World Car Conference, Riverside, CA.

J. Ogden, M. Steinbugler and T. Kreutz, "Hydrogen as a Fuel for Fuel Cell Vehicles," Proceedings of the 8th National Hydrogen Association Meeting, Alexandria, VA, March 11-13, 1997.

O’Sullivan, J., Electric Power Research Institute, personal communication, January 19, 1998.

S. Sircar, “Pressure Swing Adsorption,” Air Products Technical Paper, presented at the NATO Advanced Study Institute on Adsorption Science and Technology, 17-29 July 1988.

O. Skovholt, "CO2 Transportation System," Energy Conservation Management, Vol. 34, No. 9-11, pp. 1095-1103, (1993).

Socolow, R.H., ed., "Fuels Decarbonization and Carbon Sequestration: Report of a Workshop," Princeton University Center for Energy and Environmental Studies Report No. 301, September 1997.

Meyer Steinberg and H.C. Cheng, "An Assessment of Hydrogen Production by Conventional and Advanced Processes," Brookhaven National Laboratories, January 1988.

Steinbugler, M. September 17-19, 1996. "How Far, How Fast, How Much Fuel: Evaluating Fuel Cell Vehicle Configurations," presented at the Commercializing Fuel Cell Vehicles Conference, Intertech Conferences, Hyatt Regency O'Hare, Chicago.

Thomas, C.E., I.F. Kuhn, B.D. James, F.D. Lomax, and G.N. Baum, "Affordable hydrogen supply pathways for fuel cell vehicles," International Journal of Hydrogen Energy, v. 23, No. 6, 1998.

Robert Williams, Eric Larson, Ryan Katofsky and Jeff Chen, "Methanol and Hydrogen from Biomass for Transportation with Comparisons to Methanol and Hydrogen from Natural Gas and Coal," Princeton University, Center for Energy and Environmental Studies Report No. 292, July 1995

Williams, R.H., Fuel decarbonization for fuel cell applications and sequestration of the separated CO2, in *Eco-restructuring: Implications for Sustainable Development*, W. Ayres (ed.), UN University Press, Tokyo, Japan. 1998, pp. 180-222.

Figures

Tables

Table 1a. Hydrogen and Fuel Cell Related Research at the Center for Energy and Environmental Studies, Princeton University, 1986-Present (* = USDOE Supported Research) -- see attached Bibliography

YEAR	TOPIC	INVESTIGATORS	REF.S
*1985-1991	Design and economics of solar PV/ electrolytic hydrogen systems	J. Ogden, R. Williams	[1-4]
*1991-1993	Renewable hydrogen energy systems studies	J.Ogden	[4-5]
*1991-present	Assessments of hydrogen fuel cell vehicles	M. Delucchi, M. Steinbugler, J. Ogden, T. Kreutz R. Williams, L. Iwan	[8-11,13-16, 24, 25, 31, 34, 47-50]
1991-1993	Production of hydrogen and methanol from biomass	E.Larson, R. Katofsky, R. Williams	[6-8]
*1993-present	Production of hydrogen from municipal solid waste	E. Larson, J. Chen, E. Worrell, R. Williams	[14, 17, 29]
*1993-present	Role of natural gas in a transition to hydrogen	J. Ogden, J. Strohbehn, E.Dennis	[12,13,16]
*1993-present	Assessments of fuels for fuel cell vehicles	R. Williams, J. Ogden, E. Larson, R. Katofsky, J. Chen, M. Steinbugler	[14, 14a, 31]
*1993-1994	Assessment of using the existing natural gas transmission and distribution system w/H2	J. Ogden, J. Strohbehn	[12,16]
*1993-present	Development of refueling infrastructure for hydrogen vehicles	J. Ogden, E. Dennis, K. Montemayor	[12,13,16, 21,22,23,27, 30, 33, 48-50]
*1993-1995	Assessment of PEM fuels cells for residential cogeneration	M. Steinbugler, J. Ogden, K. Kissock, R. Williams, T. Kreutz	[16]
*1994-1996	Assessment of small scale methane reformer technologies	J.Ogden	[22, 26]
*1995- present	Studies of CO2 sequestration	R. Williams, R. Socolow, J. Ogden	[28, 36, 37, 39, 40, 41, 42, 44, 45]
*1996-present	Comparison of hydrogen, methanol and gasoline as fuels for fuel cell vehicles	J. Ogden, T. Kreutz, M. Steinbugler	[24, 25, 31, 38]
*1996-present	Models of onboard fuel processors for fuel cell vehicles	T. Kreutz, J. Ogden, S. Kartha	[25, 31, 32]
*1998-present	Novel methods for producing hydrogen from coal	R. Williams	[42, 45]

BIBLIOGRAPHY OF FUEL CELL AND HYDROGEN RELATED WORK AT PRINCETON CENTER FOR ENERGY AND ENVIRONMENTAL STUDIES (See Table 1)

1. J.M. Ogden and R.H. Williams, Solar Hydrogen : Moving Beyond Fossil Fuels, World Resources Institute, Washington DC, October 1989.

2. J.M. Ogden and R.H. Williams, "Electrolytic Hydrogen from Thin Film Solar Cells," International Journal of Hydrogen Energy, v. 15, 1990, p.155.

3. J.M. Ogden, "Cost and Performance Sensitivity Studies for Solar Photovoltaic/Electrolytic Hydrogen Systems," Solar Cells, v. 30, No. 1-4, May 1991, p. 515.

4 J.M. Ogden and J. Nitsch, "Solar Hydrogen," Chapter 22 in T. Johansson, H. Kelly, A.K.N. Reddy and R.H. Williams, Renewable Energy: Fuels and Electricity from Renewable Sources, Island Press, Washington, DC, 1993.

5. J.M. Ogden, Renewable Hydrogen Energy Systems Studies, final report for NREL Contract No. XR-2-11265-1, June 24, 1993.

6. E.D. Larson and R.E. Katofsky, "Production of Methanol and Hydrogen from Biomass," Princeton University, Center for Energy and Environmental Studies Report No. 271 July 1992.

7. Katofsky, R.E., "Production of Fluid Fuels from Biomass," Princeton University, Center for Energy and Environmental Studies Report No. 279, June 1993.

8. M.A. DeLuchi, E.D. Larson and R.H. Williams, "Hydrogen and Methanol from Biomass and its Use in Fuel Cell and Internal Combustion Engine Vehicles," Princeton University, Center for Energy and Environmental Studies Report No. 250, August 1991.

9. J.M. Ogden and M.A. DeLuchi, "Solar Hydrogen Transportation Fuels," Chapter 8, in D. Greene and D. Santini, eds., Proceedings of the Conference on Transportation and Global Climate Change, American Council for an Energy Efficient Economy, Washington, DC, 1993.

9a. Delucchi, M.A. 1992. "Hydrogen Fuel Cell Vehicles," UCD-ITS-RR-92-14, Institute of Transportation Studies, University of California, Davis.

10. M.A. DeLuchi and J.M. Ogden, "Solar Hydrogen Fuel Cell Vehicles," Transportation Research-A, Vol. 27A, No. 3, pp. 255-275.

11. J.M. Ogden, E.D. Larson and M.A. Delucchi, "An Assessment of Renewable Transportation Fuels and Technologies," report to the US Congress Office of Technology Assessment, May 27, 1994.

12. J.M. Ogden, J.W. Strohbehn and E. Dennis, “Hydrogen Energy Systems Studies,” Proceedings of the USDOE Hydrogen Program Review Meeting, April 19, 1994.

13. J.M. Ogden, E. Dennis and J.W. Strohbehn, “A Technical and Economic Assessment of the Role of Natural Gas in a Transition to Hydrogen Transportatio Fuel,” presented at the 10th World Hydrogen Energy Conference, Cocoa Beach, FL, June 21-24, 1994.

14. J.M. Ogden, E.D. Larson, R.H. Williams, R. Katofsky, J. Chen, and M. Steinbugler,"Fuels for Fuel Cell Vehicles," presented at the Vice President's Meeting on Fuel Cell Vehicles, Partnership for a New Generation of Vehicles, Washington DC, July 27, 1994.

14a. R.H. Williams, "Fuel Cells, Their Fuels and the US Automobile," First Annual World Car Conference," University of California at Riverside, Riverside, CA, June 20-24, 1993.

15. M. Steinbugler, and J.M. Ogden, "Design Considerations for Fuel Cell Vehicles," presented at the Fuel Cell Seminar, November 28-December 1, 1994.

16. J.M. Ogden, E. Dennis, M. Steinbugler, and J. Strohbehn, "Hydrogen Energy Systems Studies," Final Report to NREL for Contract No. XR-11265-2, January 18, 1995.

17. J.S. Chen, "The Production of Methanol and Hydrogen from Municipal Solid Waste," Princeton University, Center for Energy and Environmental Studies Report No. 289, March 1995.

18.J.M. Ogden, E. Dennis and K. Montemayor, "Development of Refueling Infrastructure for Hydrogen Vehicles," Proceedings of the 6th National Hydrogen Association Meeting, March 7-9, 1995.

19. J.M. Ogden, E.D. Larson and M.A. Delucchi, "Assessment of Renewable Transportation Fuels and Technologies," Proceedings of the American Solar Energy Society Meeting, Minneapolis, MN, July 17-20, 1995.

20. J.M. Ogden, "Refueling Infrastructure Needs for Fuel Cell Vehicles," presented at the Society of Automotive Engineers Topical Technical Conference on Fuel Cells for Transportation, Alexandria, VA April 1, 1996.

21. J.M. Ogden, "Options for Refueling Hydrogen Vehicles: A Southern California Case Study", presented at the 7th National Hydrogen Association Meeting, Alexandria, VA, April 3, 1996.

22. J.M. Ogden, T.G. Kreutz, M. Steinbugler, A Cox, J. White, "Hydrogen Energy Systems Studies," USDOE Hydrogen R&D Program Review Meeting, Miami, FL, April 29-May 2, 1996.

23. J.M. Ogden, "Development of Refueling Infrastructure for Hydrogen Vehicles," Proceedings of the 11th World Hydrogen Energy Conference, Stuttgart, Germany, June 2 23-28, 1996.

24. M. Steinbugler and J. Ogden, "Fuel Economy and Range Estimates for Fuel Cell Vehicles," '96 Fuel Cell Seminar, Orlando, FL, Nov 17-20, 1996.

25. T. Kreutz, M. Steinbugler and J. Ogden, "Onboard Fuel Reformers for Fuel Cell Vehicles: Equilibrium, Kinetic and System Modelling," 96 Fuel Cell Seminar, Orlando, FL, Nov 17-20, 1996.

26. J. Ogden, T Kreutz, S. Kartha and L. Iwan, " Assessment of Technologies for Producing Hydrogen from Natural Gas at Small Scale," Princeton University Center for Energy and Environmental Studies Draft Report, November 26, 1996.

27. J. Ogden, A Cox and J. White, " Case Study of Developing Hydrogen Refueling Infrastructure in Southern California," Princeton University Center for Energy and Environmental Studies Draft Report, December 9, 1996.

28. R. Williams, "Fuel Decarbonization for Fuel Cell Applications and Sequestration of the Separated CO2," Princeton Center for Energy and Environmental Studies Report No. 295, January 1996.

29. E. Larson, E. Worrell and J. Chen, "Clean Fuels from Municipal Solid Waste for Fuel Cell Buses in Metropolitan Areas," Resources, Conservation and Recycling, v. 17, p. 273-298, 1996.

30. J.M. Ogden, "Infrastructure for Hydrogen Fuel Cell Vehicles: A Southern California Case Study," Proceedings of the '97 World Car Conference, Riverside, CA, January 19-22, 1997.

31. J. Ogden, M. Steinbugler and T. Kreutz, "Hydrogen as a Fuel for Fuel Cell Vehicles," Proceedings of the 8th National Hydrogen Association Meeting, Alexandria, VA, March 11-13, 1997.

32. S. Kartha, S. Fischer and T. Kreutz, "Analysis of Onboard Fuel Procesing Designs for PEM Fuel Cell Vehicles," 96 Fuel Cell Seminar, Orlando, FL, Nov 17-20, 1996.

33. J.M. Ogden, M. Steinbugler, E. Dennis, S. Kartha, L. Iwan, A. Jones, J. Strohbehn, "Hydrogen Energy System Studies," Proceedings of the 1995 US DOE Hydrogen Program Review, vol. 1, April 18-21, 1995, Coral Gables, FL, NREL/CP-430-20036, United States Department of Energy, National Renewable Energy Laboratory, Golden, CO, September 1995.

34. M. Steinbugler, "How Far, How Fast, How Much Fuel: Evaluating Fuel Cell Vehicle Configurations," presented at the Commercializing Fuel Cell Vehicles Conference, Intertech Conferences, Hyatt Regency O'Hare, Chicago, September 17-19, 1996.

35. J. Ogden, "Prospects for Non-carbon Fuels," presentation to the ASPEN Energy Forum, Aspen Institute, Aspen, CO, July 1997.

36. J. Ogden, "Hydrogen Systems and CO2 Sequestration," DOE Workshop on Fuels Decarbonization and CO2 Sequestration, July 28-30, 1997, Washington, DC.

37. J. Ogden, "Hydrogen Systems and CO2 Sequestration, " 9th National Hydrogen Association Meeting, Arlington, VA, March 3-5, 1998.

38. J. Ogden, "Refueling Infrastructure," invited panel presentation to the SAE TOPTEC on Fuel Cell Vehicles, March 17-19, 1998, Cambridge, MA.

39. J. Ogden, M. Steinbugler, T. Kreutz, "Hydrogen Energy System Studies," Proceedings of the USDOE Hydrogen Program Review Meeting, Alexandria, VA, April 28-30, 1998.

40. J. Ogden, "A Technical and Economic Assessment of Hydrogen Energy Systems with CO_2 Sequestration," presented at the 12th World Hydrogen Energy Conference, Buenos Aires, Argentina, June 21-June 26, 1998.

41. R. Socolow, ed., “Fuels Decarbonization and carbon Sequestration: Report of a Workshop,” Princeton University Center for Energy and Environmental Studies, report No. 302, September 1997.

42. R.H. Williams, “Hydrogen Production form Coal and Coal Bed Methane Using Byproduct CO2 for Enhanced Methane Recovery with CO2 Sequestration in the Coal Bed,” Princeton University Center for Energy and Environmental Studies, report No. 309, August 1998

43. Williams, R.H., E.D. Larson, R.E. Katofsky, and J. Chen, Methanol and hydrogen from biomass for transportation, *Energy for Sustainable Development: The Journal of International Energy Initiative,* **1**(5), 1995, pp. 18-34.

44. Williams, R.H., Fuel decarbonization for fuel cell applications and sequestration of the separated CO2, in *Eco-restructuring: Implications for Sustainable Development,* W. Ayres (ed.), UN University Press, Tokyo, Japan. 1998, pp. 180-222.

45. Williams, R.H. “Fuel Cells, Coal and China,” presented at the 9th National Hydrogen Association Meeting, Arlington, VA, April 2-4, 1998.

46. J. Ogden, "Hydrogen: A Low Polluting Energy Carrier for the Next Century," Pollution Prevention Review, vol. 8, No. 4, Autumn 1998.

47. T. Kreutz and J. Ogden, “Transient Effects in Fuel Cell Vehicles with Onboard Fuel Processors,” 1998 Fuel Cell Seminar, Palm Springs, CA, November 16-18, 1998.

48. J. Ogden, T. Kreutz, and M. Steinbugler, “Fuels for fuel cell vehicles: vehicle design and infrastructure issues,” Society of Automotive Engineers Technical paper No. 982500 , October 1998.

49. J. Ogden, "Developing a Refueling Infrastructure for Hydrogen Vehicles: A Southern California Case Study," accepted for publication September 1998, to appear in International Journal of Hydrogen Energy, 1999.

50. J. Ogden, M. Steinbugler and T. Kreutz, "A Comparison of Hydrogen, Methanol and Gasoline as Fuels for Fuel Cell Vehicles," accepted for publication November 1998, to appear in Journal of Power Sources, 1999.

51. J. Ogden, “Hydrogen,” article in the Oxford Encyclopedia of Global Change, accepted for publication December 1998, to appear in 1999.

Table 1b. Industrial, Government and Academic Contacts

INDUSTRY

Industrial Gas Suppliers

Air Products and Chemicals, Praxair
BOC Gases
MG Gases

Reformer Manufacturers

Howe-Baker Engineering
Hydrochem
Haldor-Topsoe
KTI
Hydrogen Burner Technology

Electric and Gas Utilities

Public Service Gas &Elec.,Jersey Central Power &Light, Atlantic Electric Company, Rockland Electric, New Jersey Natural Gas, South Jersey Gas, and Elizabethtown Gas, Consolidated Edison, New York Power Authority, Brooklyn Union Gas, Lilco

Fuel Cell Developers

Ballard Power Systems
International Fuel Cells
Energy Partners
H-Power

Oil Companies

Exxon
Mobil

Electrolysis Manufacturers

Electrolyser, Inc.
Teledyne

Automotive Companies

Ford
GM
Chrysler
Daimler-Benz
Toyota
Mazda

Engineering/Research Co.

Directed Technologies, Inc.
Arthur D. Little
Xerox/Clean Air Now Project
Gas Research Institute
Glyn Short (consultant)

GOVERNMENT

National Laboratories

National Renewable Energy Laboratory
Lawrence Livermore National Laboratories
Los Alamos National Laboratories
Argonne National Laboratories
Sandia National Laboratories
Oak Ridge National Laboratories

US Department of Energy

South Coast Air Quality Management District

California Air Resources Board

Los Angeles Metropolitan Transit Authority

New Jersey Department of Environmental Protection

New Jersey Department of Transportation

New Jersey Board of Public Utilities, Energy Department

New Jersey Transit

NYSERDA

Northeast Alternative Vebicle Consortium

Federal Highway Administration

ACADEMIC INSTITUTIONS

University of California at Davis
University of California at Riverside
University of Michigan
TexasA&M
Humboldt State University
Georgetown University
MIT

Table 0. 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/kg H2 = $7.05/GJ (HHV)

1 gallon gasoline = 130.8 MJ (HHV);
$1/gallon gasoline = $7.67/GJ (HHV)

All costs are given in constant $1993.

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

Table 2. Vehicle Data for New York and New Jersey

TOTAL MOTOR VEHICLE REGISTRATIONS (thousands of vehicles)

	New York	New Jersey
Passenger Cars	7910	4600
Light Trucks	1960	1010
Heavy Trucks	15	21
Commercial Buses	13	5.2
TOTAL	10,274	5910

Source: Motor Vehicle Facts and Figures 1997, American Automobile Manufacturers Association

TRANSIT BUSES

	New York City	New Jersey
Number of Buses	3600	1900
Miles travelled/yr (ave.)	25,000	41,000
Fraction centrally refueled	100%	>90%
# Buses/garage	80-200	80-200
Equiv. fuel economy	3.5 mpg	5.3 mpg

LIGHT DUTY VEHICLES

	New York City	New Jersey
Motor gasoline consumed/yr (billion gallons/y) (trillion BTU/y)	 0.95 120	 3.2 403
Vehicle miles travelled/yr (billions veh.mi/y)	19	64
Average fuel economy (miles per gallon gasoline)	20	20

FLEET VEHICLES 1997

	New York	New Jersey
Total # Fleets 10+ vehicles	6555	3843
Fleet Autos (% total auto)	224,002 (2.8%)	136,624 (3.0%)
Fleet Trucks Class 1-5 (% tot lt.truck	265,901 (13.5%)	153,846 (15.1%)
All Fleet Vehicles (incl. Heavy Trucks, Buses) (%all vehicle)	669,401 (6.6%)	407,983 (6.9%)

Source: Motor Vehicle Facts and Figures 1997,
American Automobile Manufacturers Association

Average fleet LDV in US travels about twice as far as average LDV, so fleets use proportionally more energy.

Table 3. Data for Fleet Vehicles

Vehicle Type	% Centrally Refueled
Transit Bus	97%
School Bus	93%
Heavy Delivery Truck	65%
Service Truck	44%
Taxi/Limo	36%
Large Business, Utility or Government fleets	75-80%

For non-transit fleets, average size = 200, median = 33
=> many small fleets, a few very large ones

Table 4. Assumed Characteristics Of Hydrogen Fuel Cell Vehicles

	PEMFC Bus		PEMFC Car
	NYC	NJ	
Miles/yr	25,000	41,000	11,000
Fuel economy (mpeg)	7 mpeg		106 mpeg
Fuel Storage	H2 gas @ 3600 psi		H2 gas @ 5000 psi
H2 Stored onboard	13,000 scf		1550 scf (3.75 kg)
Range (mi)	250		425
Energy use/yr (GJ/yr)	524	859	13.7
Ave. H2 use/day (scf H2/day)	4196	6880	112

Table 5a. Assumed Energy Prices in New York City

Application	Annual Average Electricity Cost ($/kWh)
Onsite Reforming Station Pipeline Hydrogen Station LH2 Station	 8.3 cents/kWh
Onsite Electrolysis Station (customers in the 0.4-8.0 MW range) Continuous Operation Off-peak Operation	 4.7 cents/kWh 3.5 cents/kWh

Source: Consolidated Edison of New York

Natural Gas Price to Onsite Reforming Station	
General service	$4.3/GJ (1 million scf H2/d) $4.4/GJ (0.1 million scf H2/d)
High load factor service	$2.3/GJ (1 million scf H2/d) $3.5/GJ (0.1 million scf H2/d)

This is the price of natural gas delivered to a commercial or industrial customer for non-heating loads. Two gas rate schedules are shown one for "general service" and one for high load factor customers (constant demand for gas), and two levels of gas demand: for onsite SMR hydrogen refueling stations dispensing 0.1 and 1.0 million scf H2/d.

Source: Brooklyn Union Gas

Table 5b. Assumed Energy Prices in New Jersey

Application	Annual Average Electricity Cost ($/kWh)
Onsite Reforming Station Pipeline Hydrogen Station LH2 Station	 9.5 cents/kWh
Onsite Electrolysis Station Continuous Operation Off-peak Operation	 9.5 cents/kWh 7.1 cents/kWh

Natural Gas Price	$4.9/GJ

Source: Public Service Gas and Electric, Newark, NJ

Table 6. Hydrogen Demand: Scales Of Interest

DEMAND	H_2 FLOW (GJ/day)
1 fuel cell car	0.037
1 fuel cell bus	2.4
10 fuel cell buses	24
100 fuel cell buses	240
1% of cars in LA Basin (c. 2010)	3330
All buses in LA	8770
H2 Production at Large Refinery	34,300
10% of cars in LA Basin	33,300
100% of cars in LA Basin	333,000
Energy Flow = NG Flow in LA Basin	3,000,000

Table 7 . Cost of CO_2 Separation During H2 Production Via Large Scale SMR

Hydrogen Production	80 million scf/day 193 tonnes/day 27,440 GJ/day HHV
CO_2 Production	850 ton/day (771 tonnes/day) 0.17 scf CO2/scf H2 3.80 kg CO2/kg H2
CO_2 Purity	95%
CO_2 pressure	1 atm
Power required for VSA Compressor	3400 kW
Equipment Cost of PSA only	$4-4.5 million
Equipment Cost of VSA only, including compressor	$6-6.6 million
Added factor for freight, taxes, installation	15%
Owner's costs and engineering	25%
Total installed capital cost for PSA only (no CO_2 recovery)[a]	$5.6-6.3 million
Total installed capital cost for PSA + VSA (CO_2 recovery)	$14-15.5 million
Incremental installed capital cost for CO_2 recovery	$8.4-9.2 million
Incremental Levelized Hydrogen Production Cost for CO_2 Separation[b]	
Incremental Capital Cost for VSA	$0.12-0.13/GJ HHV H2 $0.017-0.019/kg H2
Cost for VSA Compressor Power @ 6 cents/kWh	$0.17/GJ HHV 0.024/kg H2
Total Incremental Cost for CO_2 Separation in PSA	$0.29-0.30/GJ HHV $0.041-0.043/kg H2
Typical Hydrogen Production Cost in Large SMR	$5-6/GJ H2, depending on NG price

Source: Bob Moore, Air Products, private communications, May 1997.

a. The total capital cost was obatined by multiplying the equipment cost by 1.40 to account for taxes, freight, installation, owner's costs and engineering.

b. Levelized costs were obtained assuming an annual capital charge factor of 15%.

Table 8. H_2 DEMAND AND CO_2 PRODUCTION VIA SMR

DEMAND	H_2 FLOW (million scf/day)	CO_2 Produced via SMR (million tonnes/yr)
1 fuel cell car	0.000108	5.3×10^{-7}
1 fuel cell bus	0.0071	3.5×10^{-5}
10 fuel cell buses	0.071	3.5×10^{-4}
100 fuel cell buses	0.71	3.5×10^{-3}
1% of cars in LA Basin (c. 2010)	9.7	0.048
All buses in LA	25.6	0.125
H2 Production at Large Re	100	0.49
10% of cars in LA Basin	97.2	0.48
100% of cars in LA Basin	972	4.8
NG Energy Flow in LA Bas	8605	42

For the hydrogen plant design in Figure 13 (Katofsky 1993)

Table 9. Cost of CO2 Sequestration vs. Hydrogen Demand

Hydrogen Demand	1 million scf H2/day	10 million scf H2/d	100 million scf H2/d	1000 million scf H2/d
H2 End-Use	9000 H2 fuel cell cars	90000 H2 fuel cell cars or 1400 H2 fuel cell buses	10% of cars in LA Basin, if H2 fuel cell cars	100% of cars in LA Basin, if H2 fuel cell cars
H2 Supply	Onsite SMR	10 Onsite SMRS	100 million scf H2/d central SMR plant	Ten 100 million scf H2/d central SMR plants
Assoc. CO2 Production	13.3 tonnes CO2/d	133 tonnes CO2/d	1330 tonnes CO2/d	13,300 tonnes CO2/d
Cost of CO2 Separation ($/GJ H2)	2.5	2.5	0.46	0.46
Cost of CO2 Compression ($/GJ H2)	included above	included above	0.19	0.19
CO2 Collection System ($/GJ H2)	n.a.	5	n.a.	0.1
Cost of 300 km CO pipeline ($/GJ H2)	80	8	1	0.3
# Injection wells (at up to 3400 tonnes CO2/d per well)	1	1	1	4
CO2 Injection and Storage in Aquifer	15	1.5	0.15	0.04
TOTAL COST OF SEQUESTR. ($/GJ H2) ($/tonne CO2)	98 2530	17 439	1.80 47	1.09 28

FY'99 SUMMARY TABLE

Task Title: Hydrogen Energy Systems Studies: Task 1: Development of Hydrogen Vehicle Refueling Infrastructure in New York City/New Jersey area; Task 2: Implications of CO2 Sequestration for Hydrogen Energy Systems	**Contractor**: Princeton University	**Principal Investigator**: Dr. Joan M. Ogden

Objective: Generally, the goal of our work is to illuminate possible pathways leading from present hydrogen markets and technologies toward wide scale use of hydrogen as an energy carrier, highlighting important technologies for RD&D. In particular, the goals of this work are:

Task 1: Hydrogen infrastructure in NY/NJ area: to provide useful data and suggest possible implementation strategies as the Hydrogen Program plans demonstrations of hydrogen vehicles and refueling infrastructure.

Task 2: Hydrogen Energy systems and CO2 sequestration: to study the implications of CO2 sequestration for future low CO2 emitting hydrogen energy systems based on fossil fuels

Approach/Rationale: Since 1986, researchers at Princeton University's Center for Energy and Environmental Studies have carried out technical and economic assessments of hydrogen energy systems. Our approach has been to assess the entire hydrogen energy system from production through end-use from several perspectives (fuel producer, consumer, society) considering technical performance, economics (e.g. capital cost, delivered hydrogen cost, cost of energy services), infrastructure, environmental and resource issues.

Analytic Methods/Assumptions: Where necessary, engineering models of hydrogen production and distribution systems and CO2 sequestration technologies have been developed. The levelized cost of hydrogen production, delivered hydrogen cost and lifecycle costs of transportation are estimated using standard microeconomic techniques.

Data Sources: A large number of industry, government and academic sources have provided the data needed for our systems studies (see description in text and in Table 2 of attached synopsis for a partial list of data sources.)

Key Results:

Task 1: Study of H2 infrastructure in New York City/New Jersey area.

* If hydrogen fuel cell vehicles were widely adopted, there would be a significant demand for hydrogen. If all NJ buses were converted to H2 FCVs, demand would be about 30 million scf H2/day. If all of NJ light duty vehicles were converted to H2 FCVs, the demand would be about 1000 million scf H2/day. In New York City, the total demand for H2 FC buses would be 20 million scf/day, and for all light duty vehicles 250 million scf/day.

* There are a variety of near term potential supplies for hydrogen in the NYC/NJ area including: truck delivered merchant hydrogen, byproduct hydrogen from chemical plants and refineries, hydrogen from natural gas, electrolytic hydrogen from off-peak power. In the longer term, hydrogen might be produced from municipal solid waste gasification, a resource which could supply all the bus fuel and a significant fraction of the light duty vehicle fuel needed in NYC/NJ.

Task 2: Implications of CO2 Sequestration for Hydrogen Energy Systems

*Engineering/economic models of pipeline transmission for hydrogen, methane and CO2 have been developed.

*There are strong scale economies in gaseous pipeline transmission, hydrogen production, CO2 separation and CO2 injection which influence the design of a hydrogen energy system with CO2 sequestration.

*Because of CO2 pipeline scale economies, a large flow of CO2 would be needed to reach low transmission costs, unless sequestration could be done near the site of hydrogen production. Large CO2 flows imply a large geographically concentrated demand for the co-produced hydrogen would be required, before CO_2 sequestration could be done at low cost. The required hydrogen energy demand would be equivalent to the fuel required for 10%-100% of the cars in the LA Basin (assuming hydrogen fuel cell cars were used).

*It is not economically or technically attractive to collect CO_2 from many small dispersed sources. CO_2 sequestration favors large, centralized hydrogen production with local hydrogen pipeline distribution to users.

*In the near term, large scale production of hydrogen via steam methane reforming (e.g. in oil refineries or chemical plants) might produce enough byproduct CO2, for CO2 sequestration to be considered, if a sequestration site is near enough.

Task Title: Hydrogen Energy Systems Studies: Task 1: Development of Hydrogen Vehicle Refueling Infrastructure in New York City/New Jersey area; Task 2: Implications of CO2 Sequestration for Hydrogen Energy Systems	**Contractor**: Princeton University	**Principal Investigator**: Dr. Joan M. Ogden

Sensitivity of Key Results to Data, Methodology and Assumptions:
Sensitivity studies are included as an important part of our technology assessments. For example, our results on hydrogen production with CO2 sequestration look at the effects of system scale.

Plans for Future Work:
* Assessment of PEM fuel cells for residential cogeneration
* Assessment of costs for maintaining/developing new gasoline infrastructure

Publications/Awards: Recent Publications (Jan. 1998- present) Include:

J. Ogden, "Hydrogen Energy Systems and CO2 Sequestration, " presentation at the 9th National Hydrogen Association Meeting, Arlington, VA, March 3-5, 1998

J. Ogden, "Refueling Infrastructure," invited panel presentation, Proceedings of the SAE TOPTEC on Fuel Cell Vehicles, March 17-19, 1998, Cambridge, MA.

J. Ogden, M. Steinbugler, T. Kreutz, "Hydrogen Energy System Studies," Proceedings of the USDOE Hydrogen Program Review Meeting, Alexandria, VA, April 28-30, 1998.

J. Ogden, "A Technical and Economic Assessment of Hydrogen Energy Systems with CO2 Sequestration," presented at the 12th World Hydrogen Energy Conference, Buenos Aires, Argentina, June 21-June 26, 1998.

J. Ogden, "Developing a Refueling Infrastructure for Hydrogen Vehicles: A Southern California Case Study," accepted for publication September 1998, to appear in International Journal of Hydrogen Energy, 1999.

J. Ogden, "Hydrogen: A Low Polluting Energy Carrier for the Next Century," Pollution Prevention Review, vol. 8, No. 4, Autumn 1998.

J. Ogden, T. Kreutz, and M. Steinbugler, "Fuels for fuel cell vehicles: vehicle design and infrastructure issues," Society of Automotive Engineers Technical paper No. 982500 , October 1998.

J. Ogden, M. Steinbugler and T. Kreutz, "A Comparison of Hydrogen, Methanol and Gasoline as Fuels for Fuel Cell Vehicles," accepted for publication November 1998, to appear in Journal of Power Sources, 1999.

T. Kreutz and J. Ogden, "Transient Effects in Fuel Cell Vehicles with Onboard Fuel Processors," Proceedings of the 1998 Fuel Cell Seminar, Palm Springs, CA, November 16-18, 1998.

J. Ogden, "Hydrogen," article in the Oxford Encyclopedia of Global Change, accepted for publication December 1998, to appear in 1999.

J. Ogden, "Stretegies for Developing Low-Emission Hydrogen Energy Systems: Implications of CO2 Sequestration," to appear in the Proceedings of the 10th National Hydrogen Association Meeting, Arlington, VA, April 7-9, 1999.

Students Associated With the Program: Bruce Lin M.S. candidate, Department of Mechanical and Aerospace Emgineering, Princeton University; Sarah Edwards '00 (B.S. MAE), Anastacia Rohrman '99 (B.S. MAE) Princeton University, Carin Lundquist '99 (B.S. MAE), Princeton University

Industry Sources: Our work uses data obtained from a variety of industry sources (see Table 2). Companies we have contacted include: Air Products and Chemicals, Inc., Praxair, BOC, Public Service Gas and Electric, Jersey Central Power &Light, Atlantic Electric Company, Rockland Electric, New Jersey Natural Gas, South Jersey Gas, Elizabethtown Gas, Consolidated Edison, New York Power Authority, Brooklyn Union Gas, Exxon, Mobil, Electrolyser, Inc., Teledyne, American Automobile Manufacturers' Association, Directed Technologies, Inc, Arthur D. Little

Figure 1.
POTENTIAL NEAR TERM H2 DEMANDS AND SUPPLIES IN NEW JERSEY

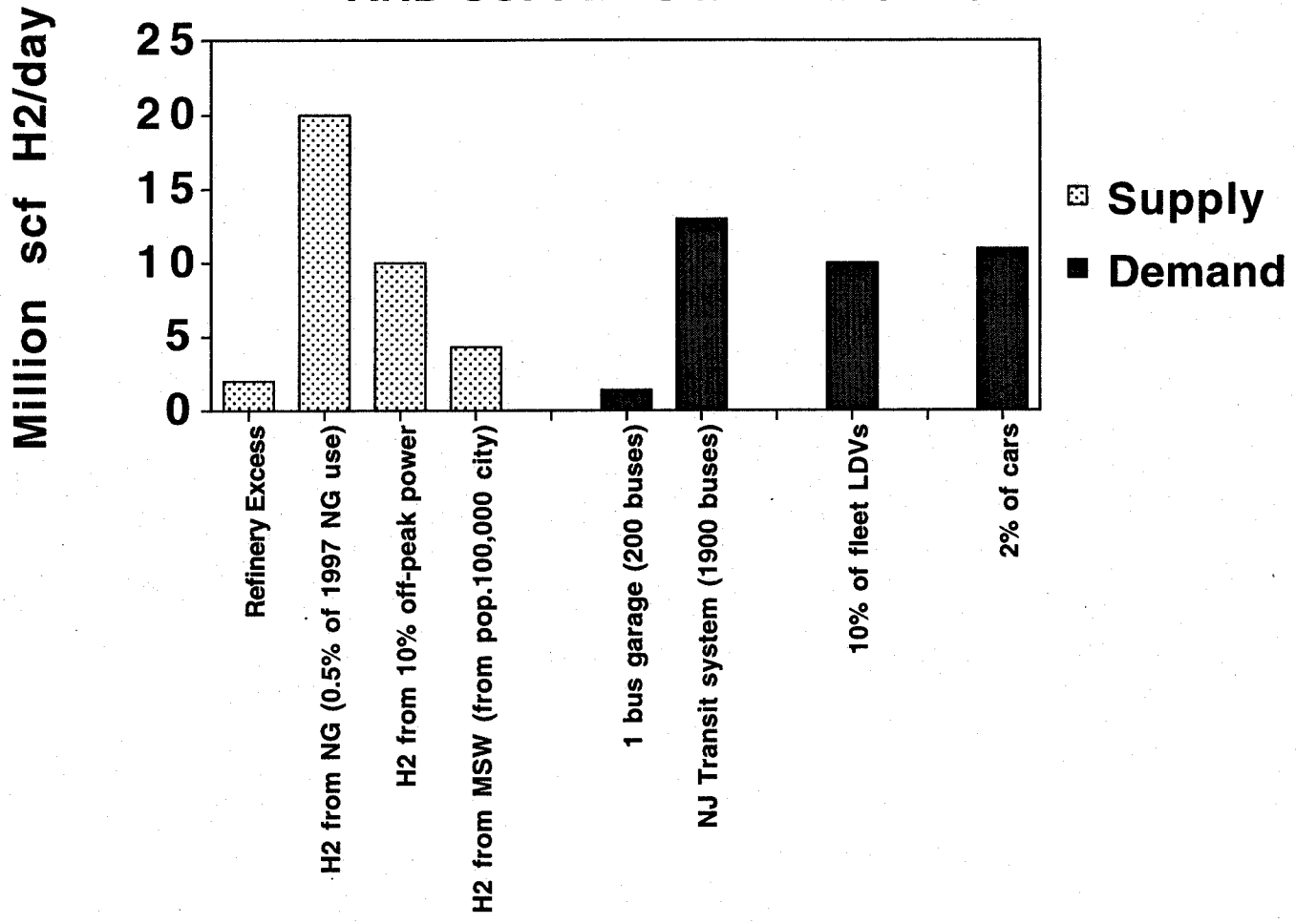


Figure 2.
POTENTIAL LONG TERM H2 DEMANDS AND SUPPLIES IN NEW JERSEY

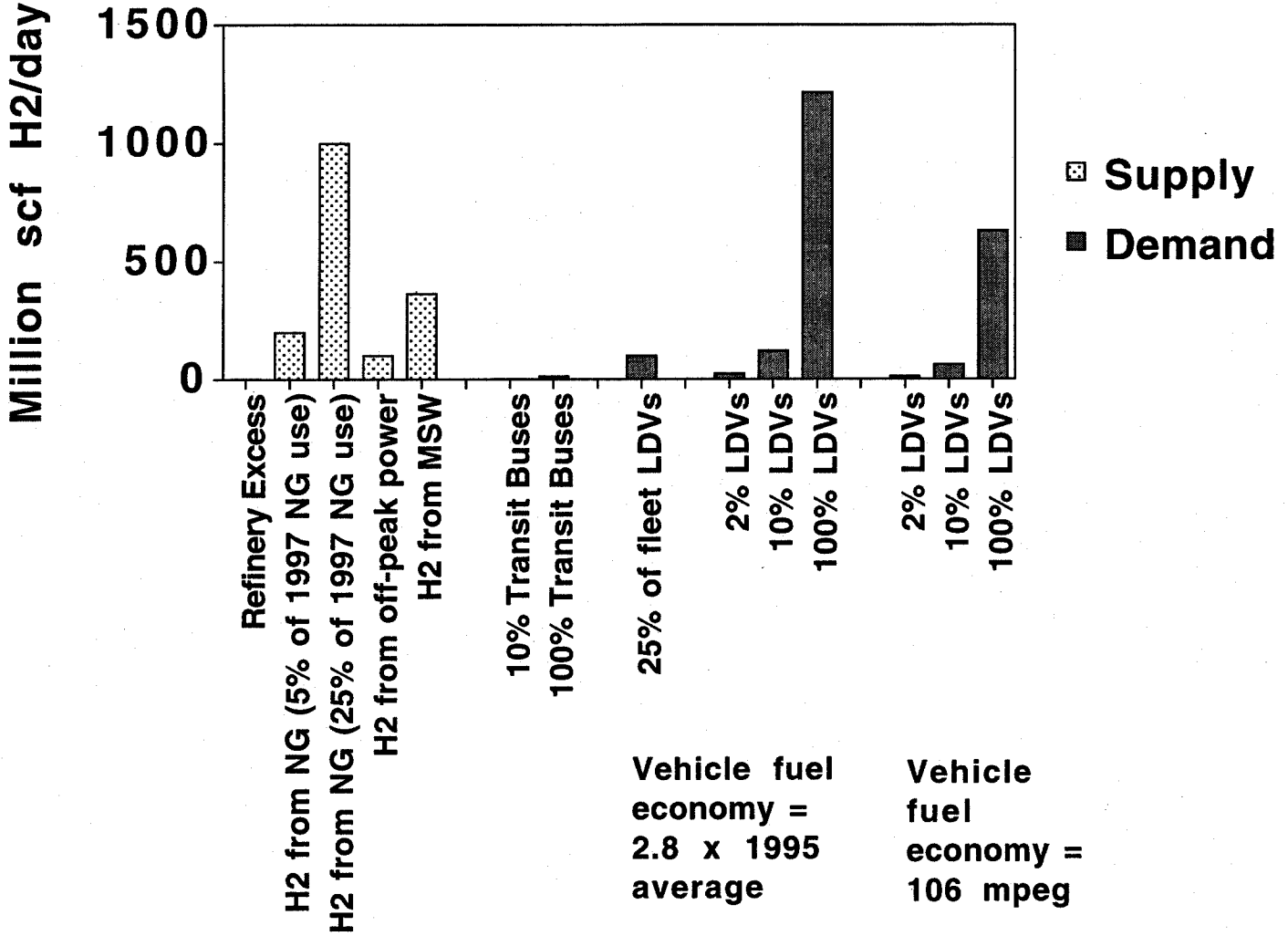
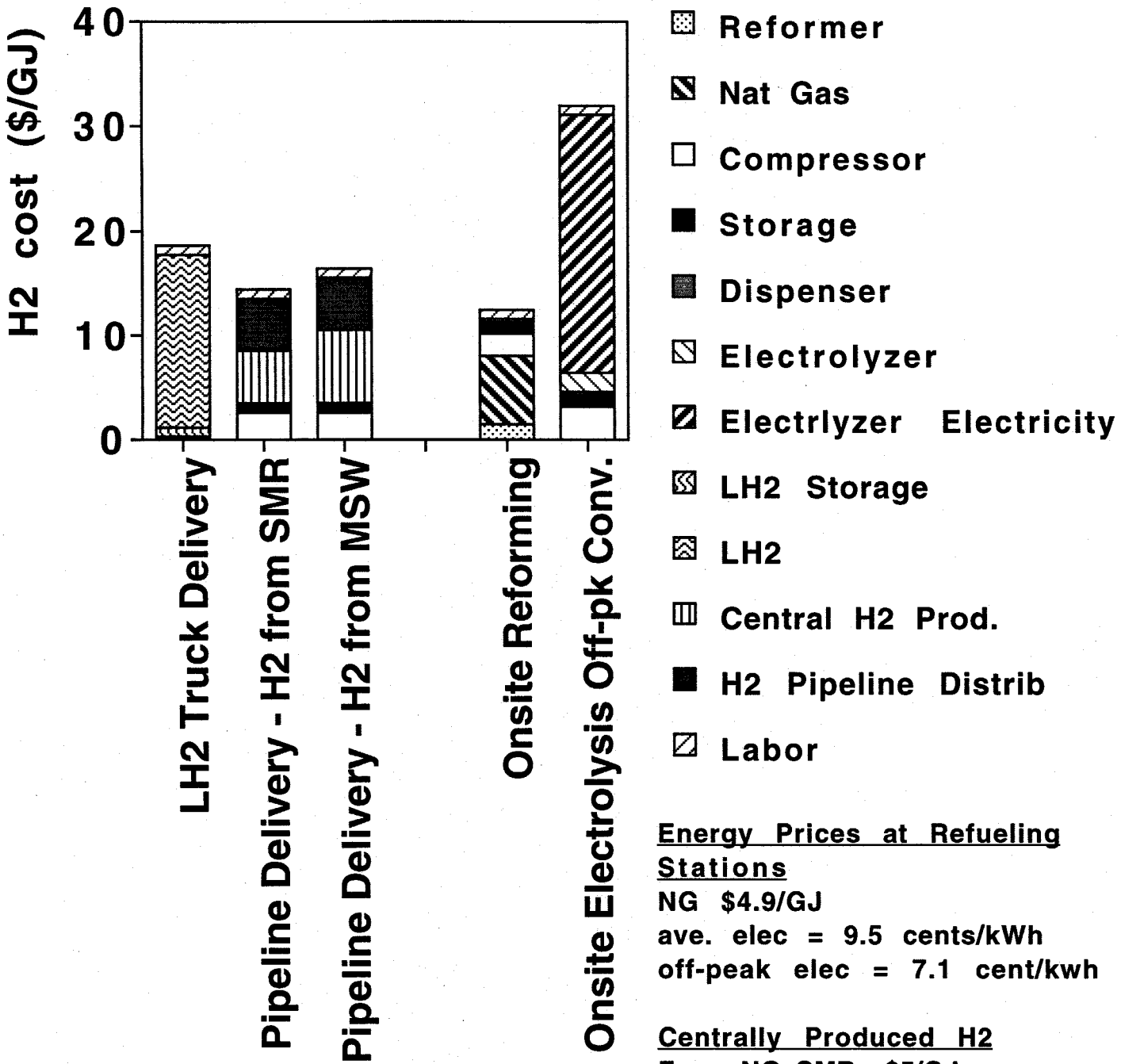


Figure 3.
Delivered Cost of H2 Transportation Fuel ($/GJ): NJ Energy Prices



Central H2 Production w/H2 Distribution

Onsite H2 Production

Energy Prices at Refueling Stations

NG $4.9/GJ

ave. elec = 9.5 cents/kWh

off-peak elec = 7.1 cent/kwh

Centrally Produced H2

From NG SMR $5/GJ

From MSW Gasif. $7/GJ

(based on $50/ton MSW tip fee)

Figure 4.
Production of H2 from Hydrocarbons w/CO2 Sequestration

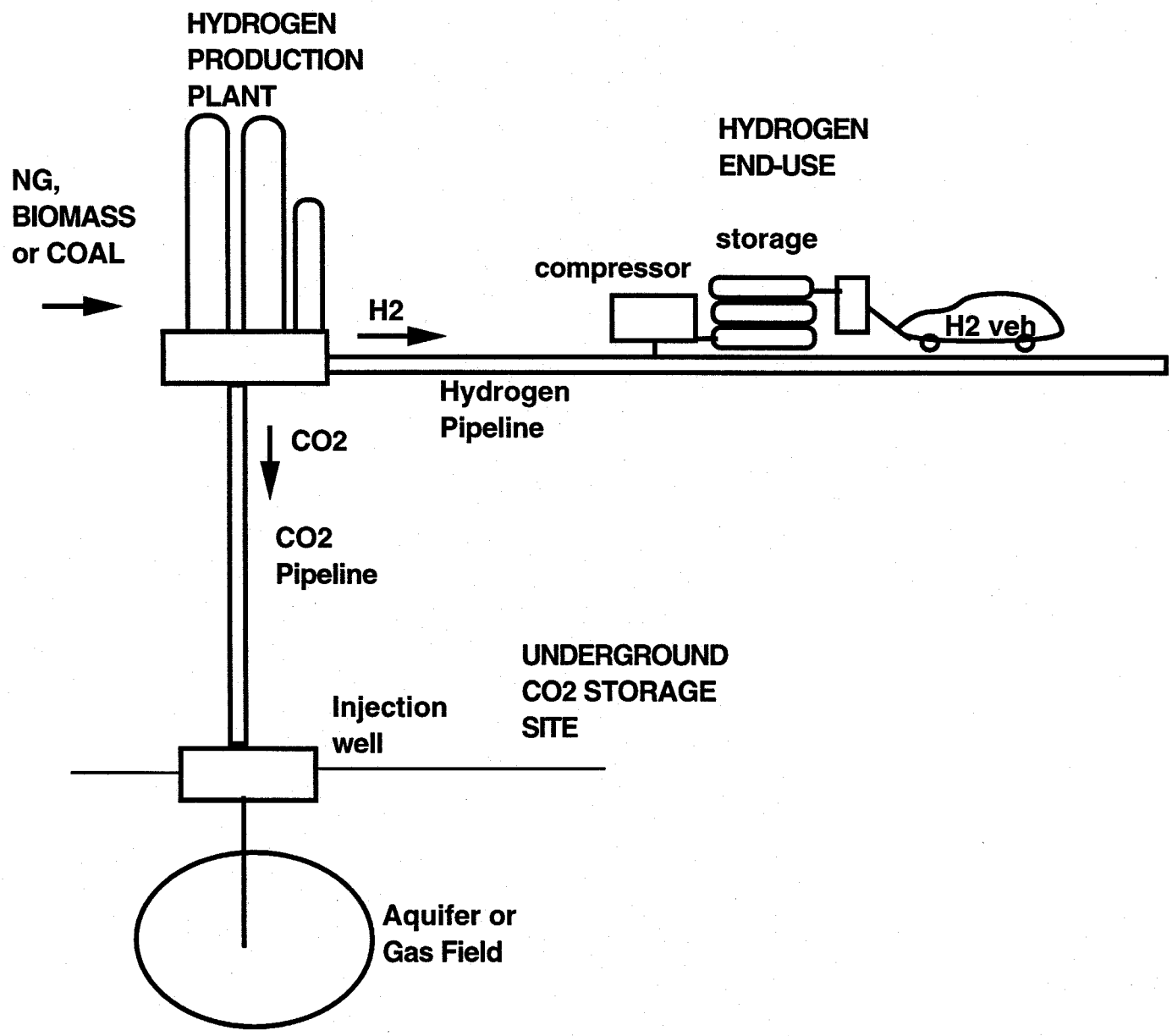


Figure 5. Various Options for Making Hydrogen from Natural Gas with CO2 Sequestration

QUESTIONS:
Where do you make hydrogen?

When does it make sense to sequester CO2?

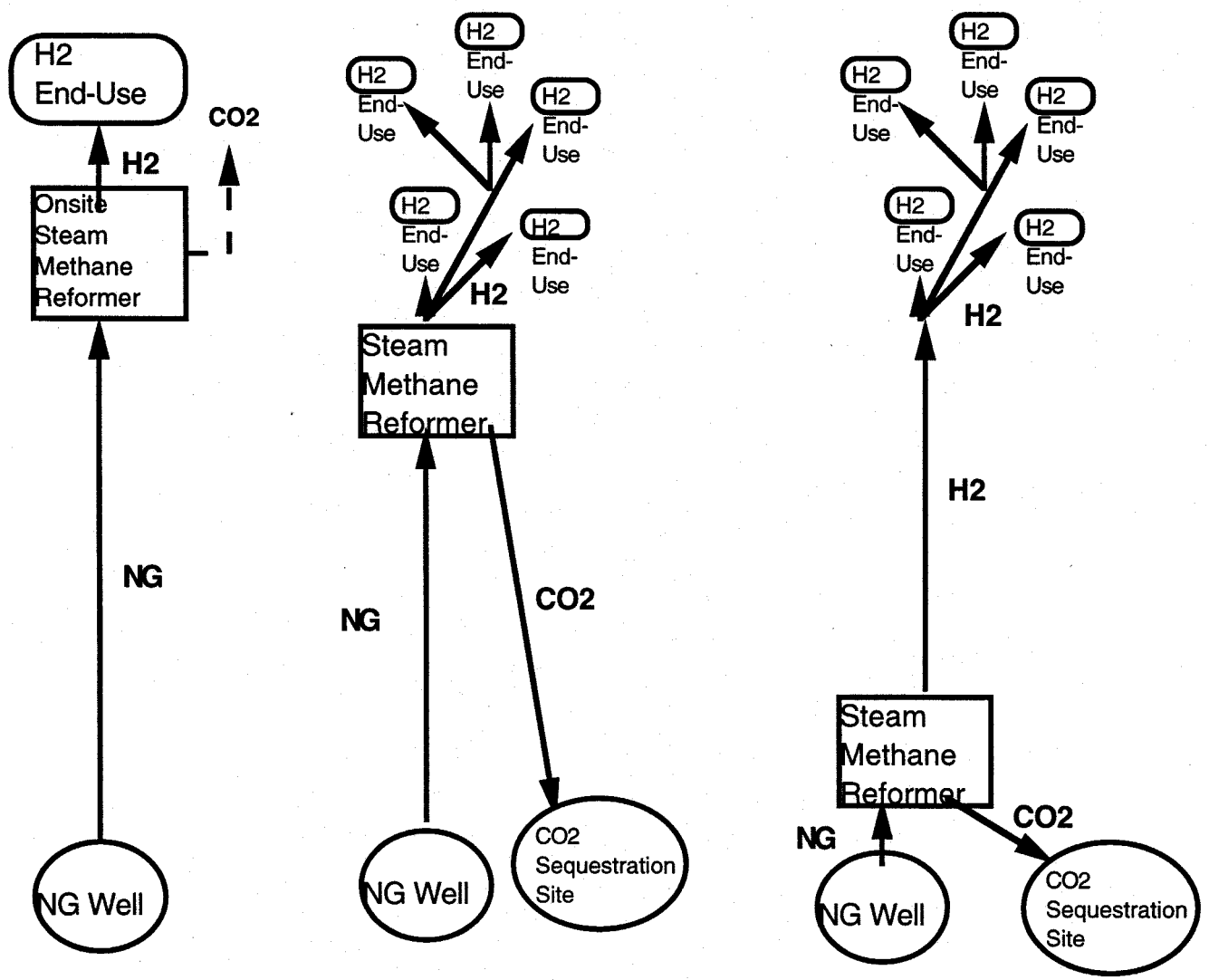
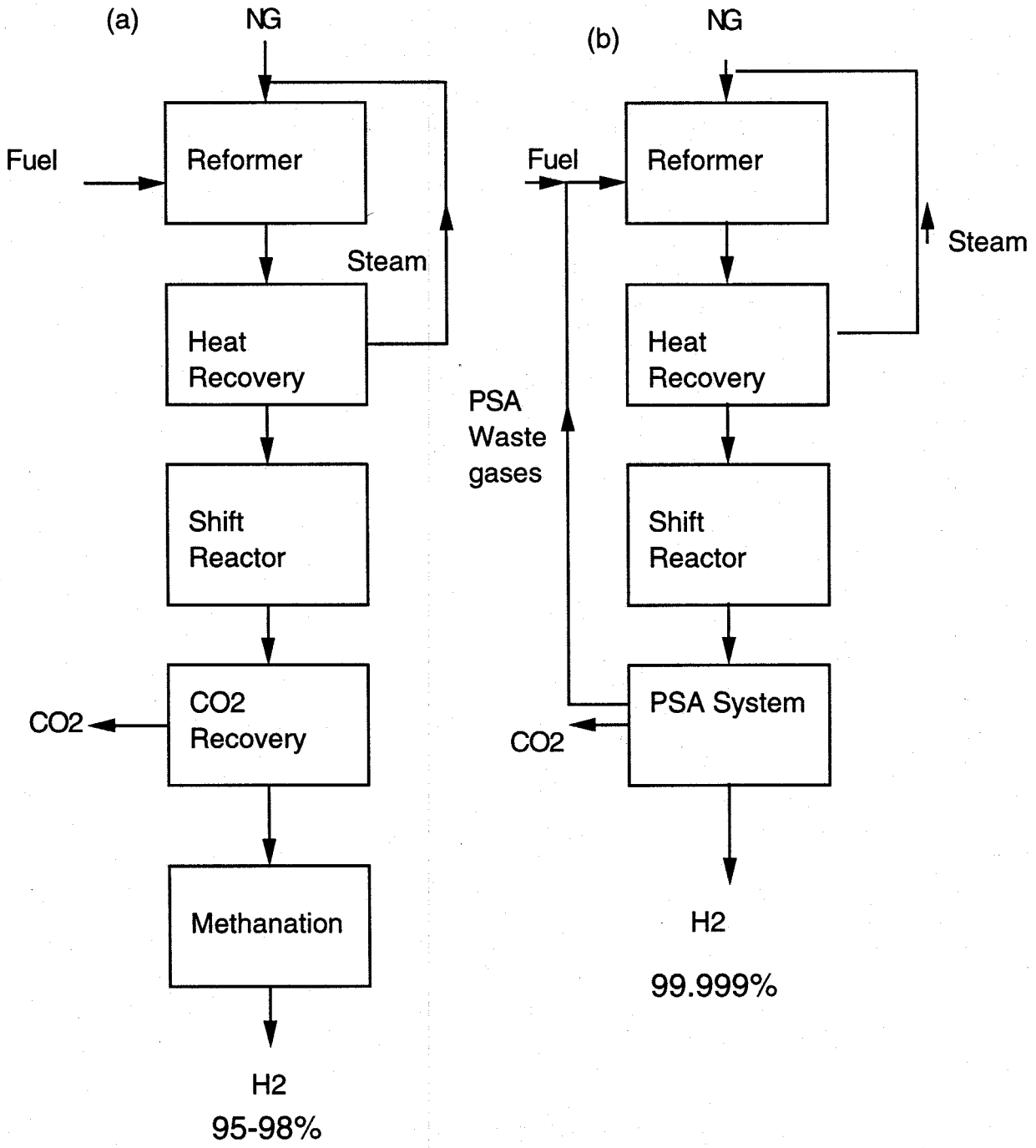


FIGURE 6. Alternative Configurations for Producing Hydrogen and CO2 from Natural Gas via Steam Methane Reforming:
a) with Chemical or Physical Absorption
b) with a Pressure Swing Adsorption System



Adapted from Steinberg and Cheng 1988

Figure 7. Capital Cost of Conventional and Advanced Small Steam Methane Reformers vs. H2 Output Capacity for Various Levels of Mass Production

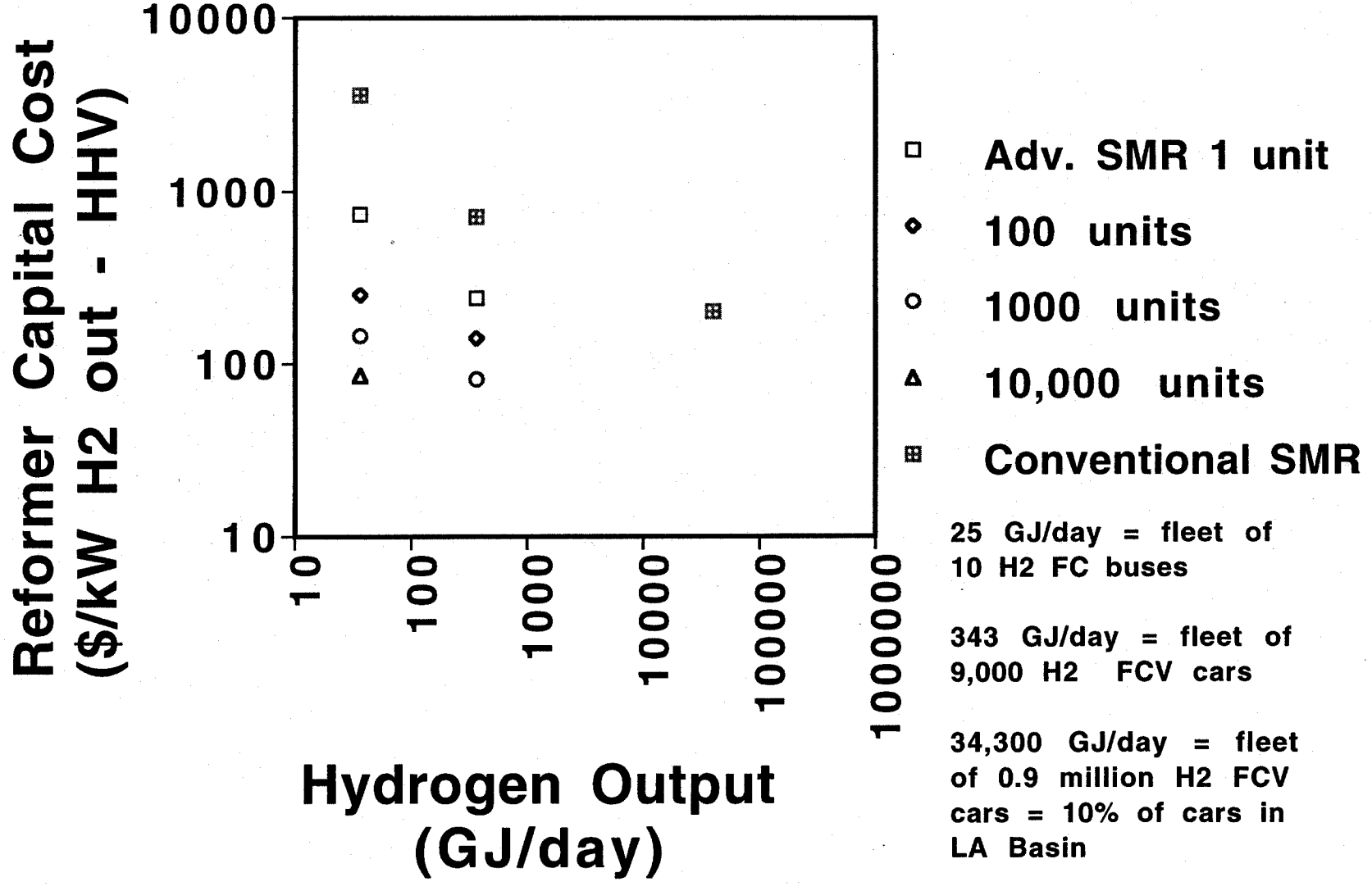


Figure 8. Hydrogen Production Cost in Small vs. Large Steam Methane Reformers ($/GJ)

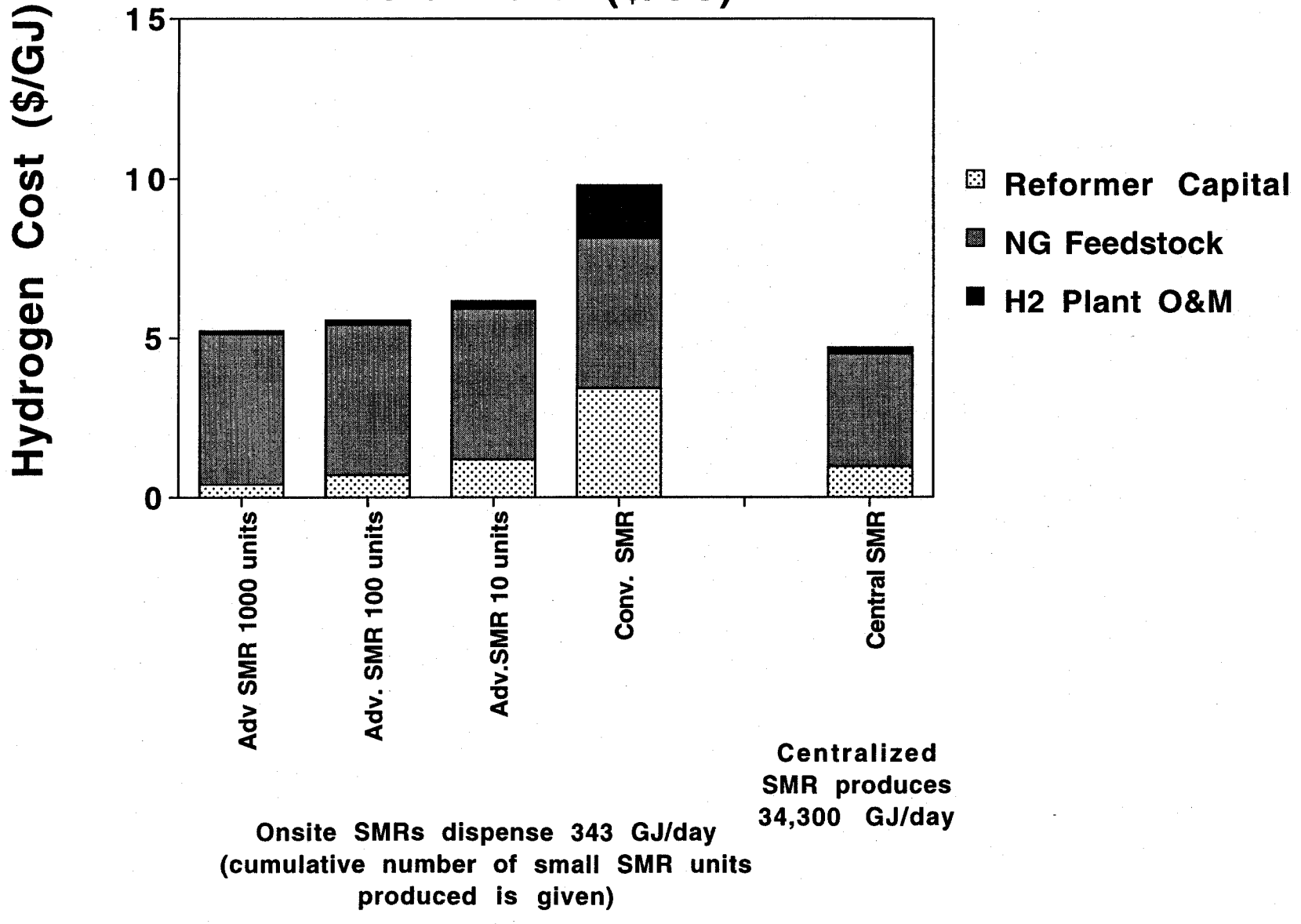
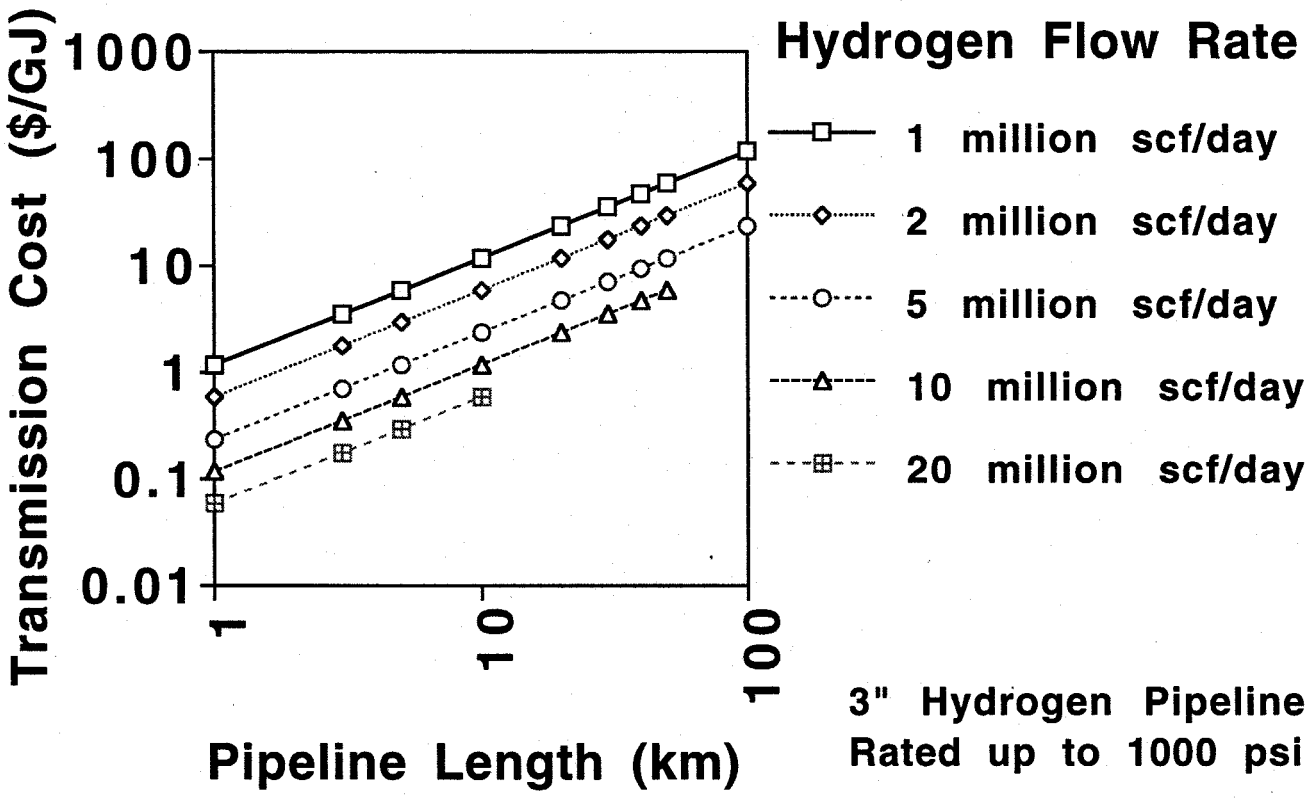


Figure 9. Levelized Cost of Hydrogen Pipeline Transmission vs. Pipeline Length and Flow Rate



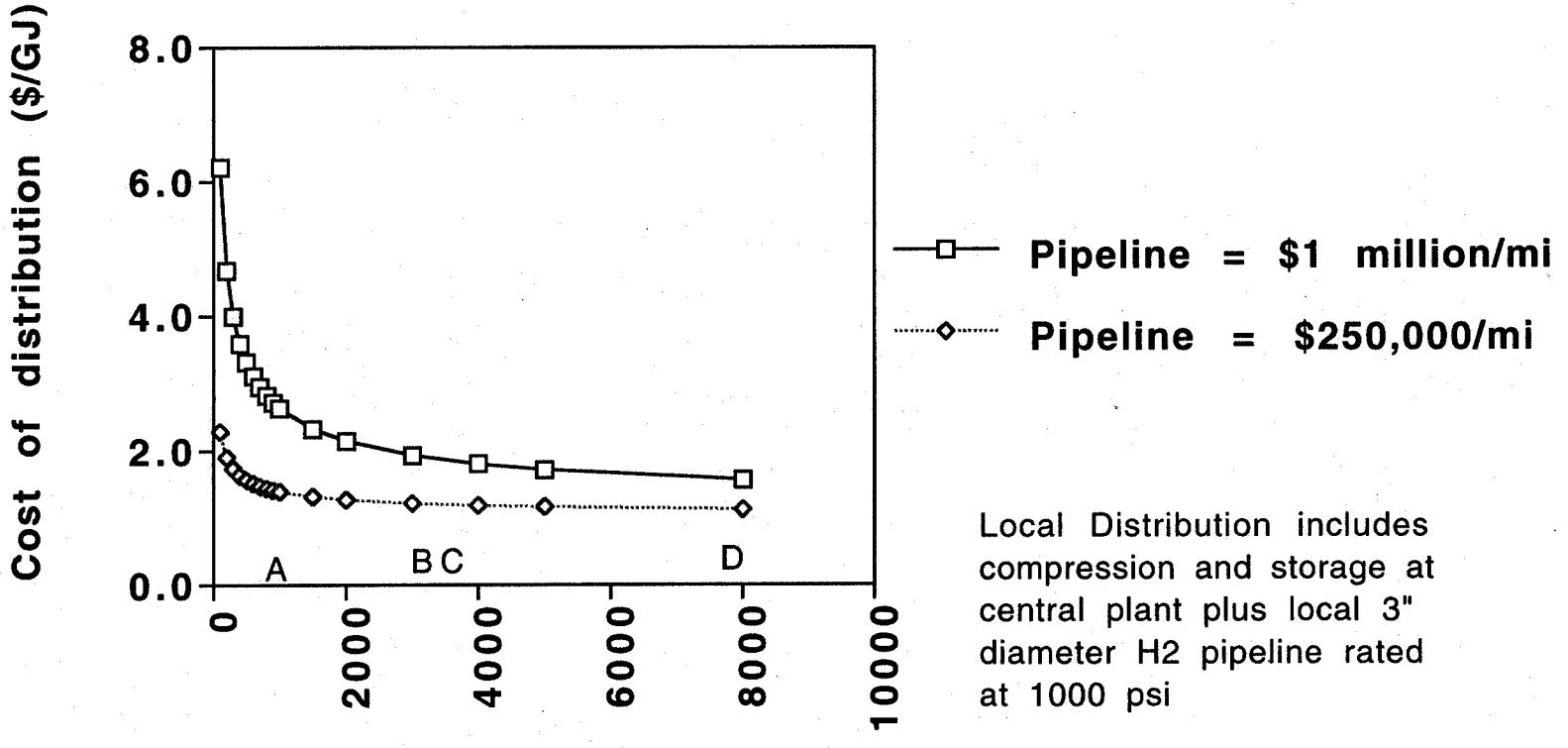
3" Hydrogen Pipeline
Rated up to 1000 psi

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

Figure 10. 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

Figure 11. Delivered Cost of Hydrogen Transportation Fuel: Onsite vs. Centralized Production in SMRs

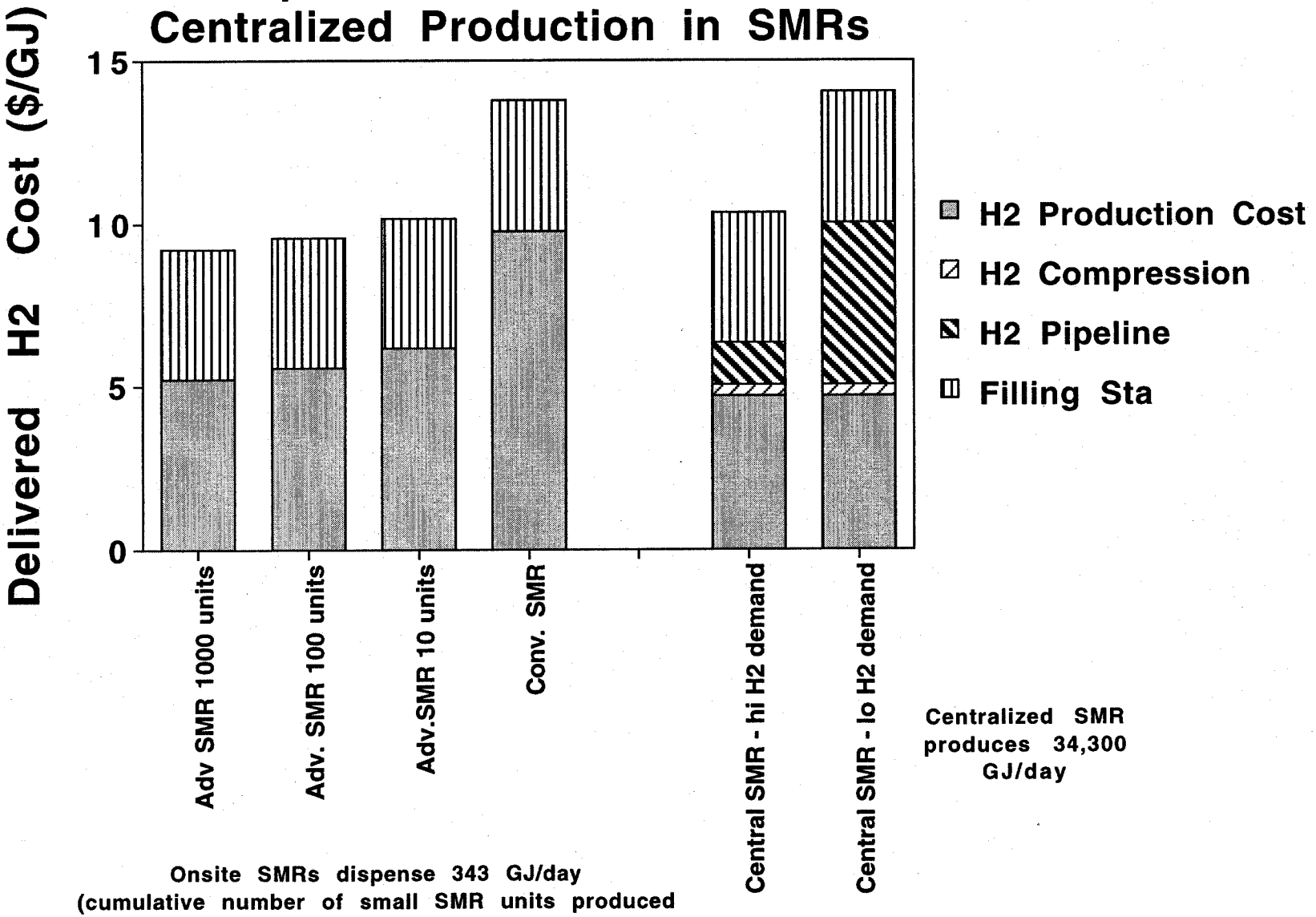


Figure 12. Delivered H2 Cost with CO2 Separation and Collection Central vs. Onsite SMR

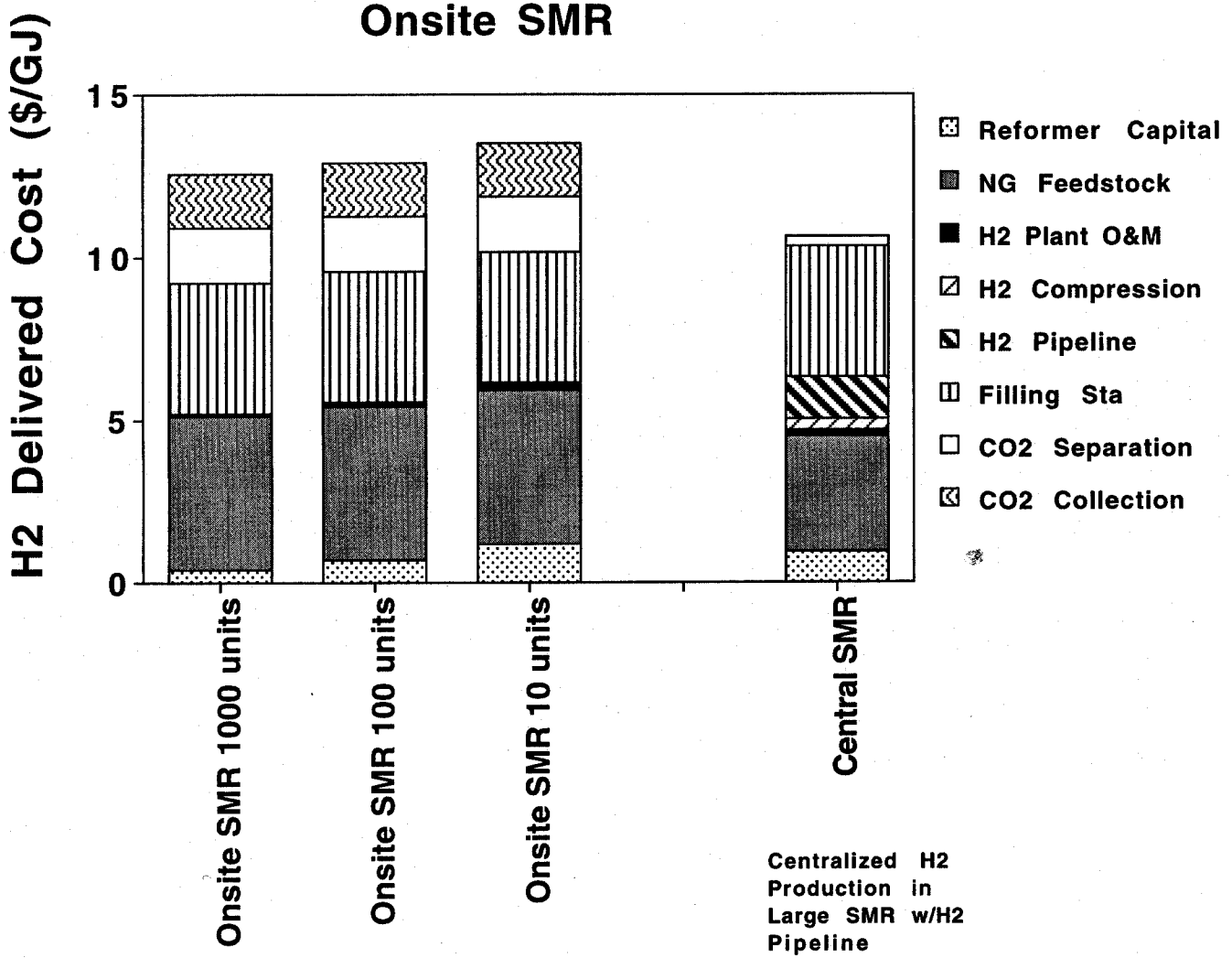
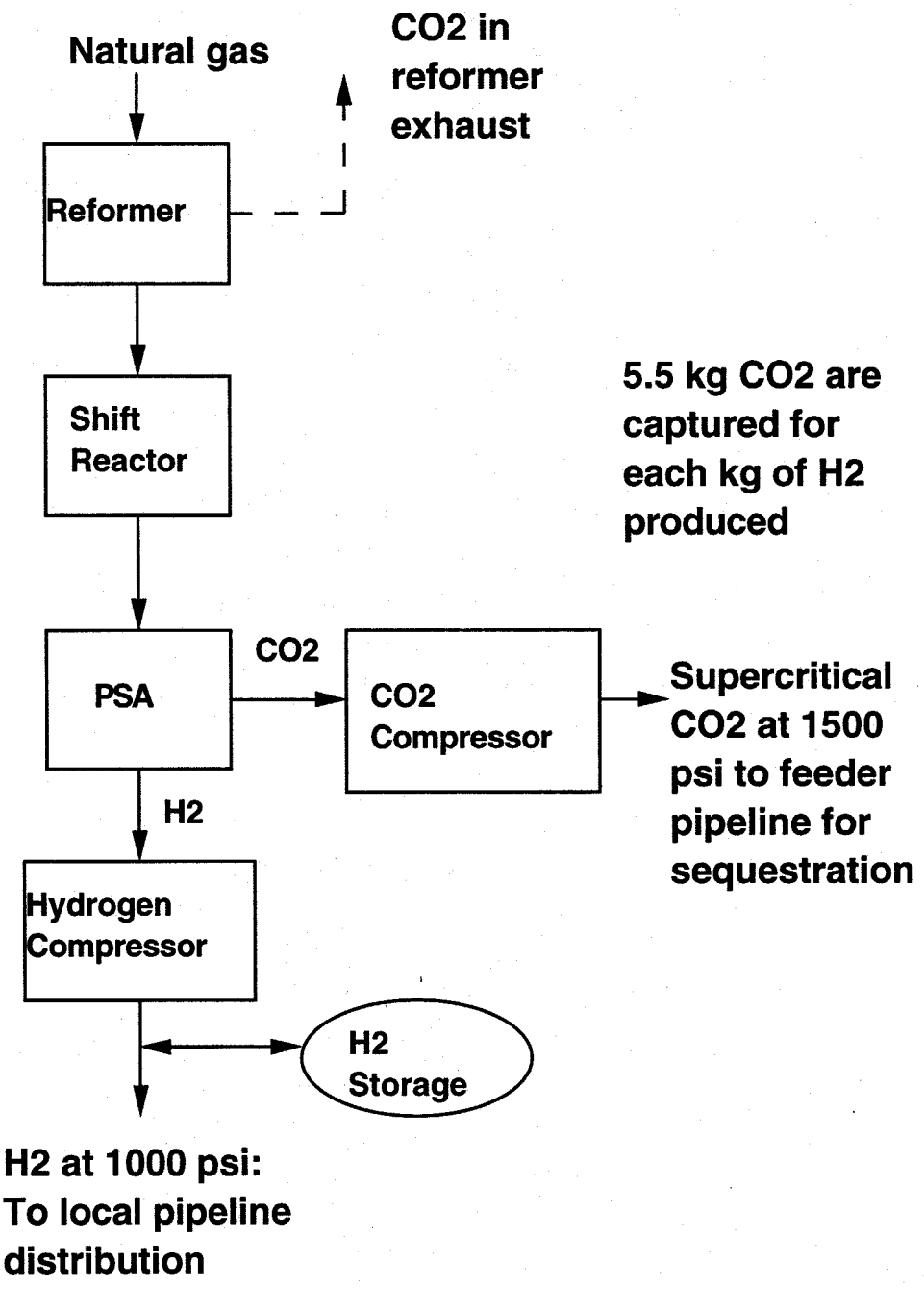
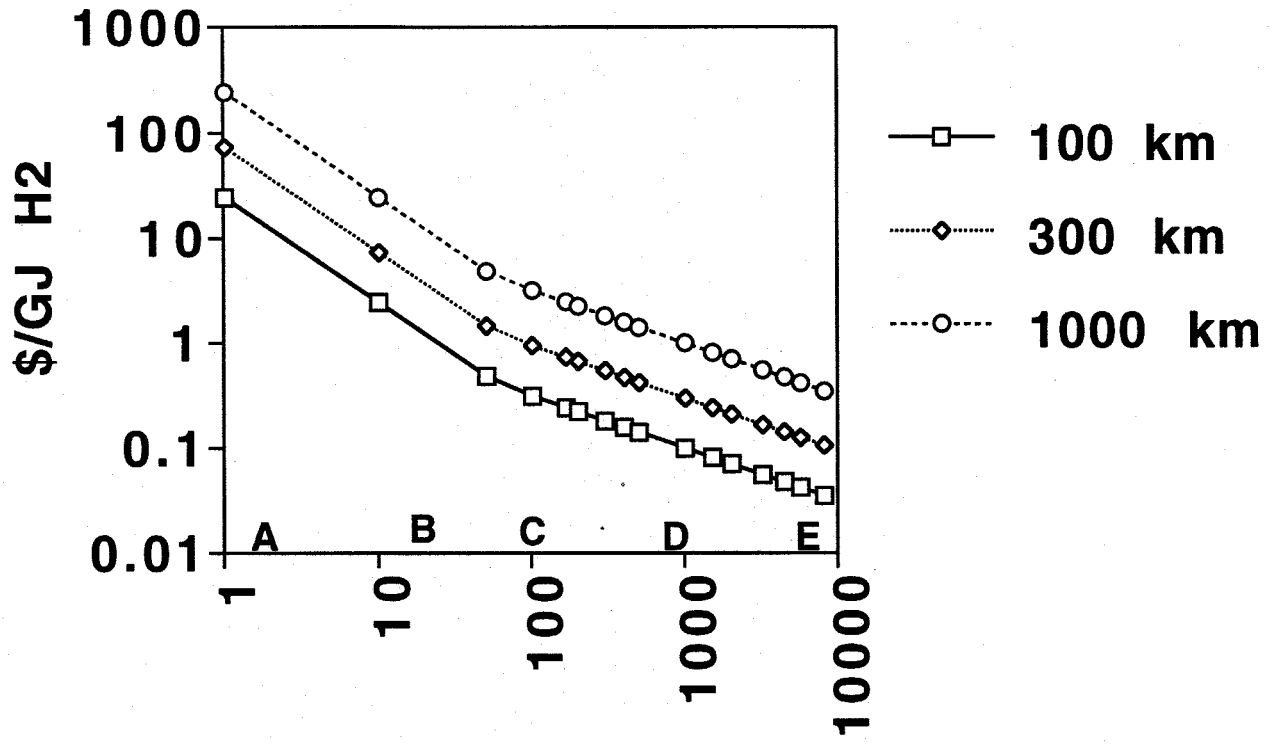


Figure 13. PRODUCTION OF HYDROGEN VIA STEAM REFORMING OF NATURAL GAS WITH SEPARATION AND COMPRESSION OF CO2 BYPRODUCT



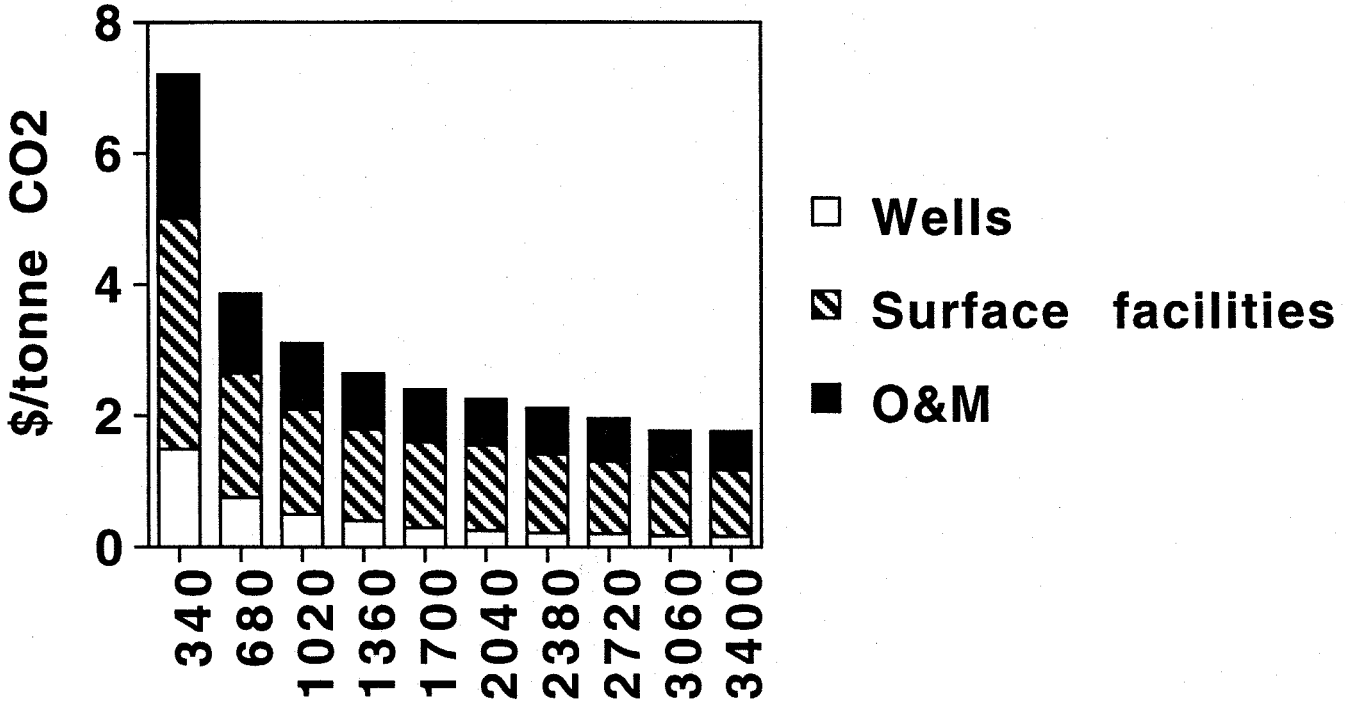
70% of the Carbon in the natural gas feedstock is captured for sequestration; the remaining 30% is emitted with reformer exhaust gases

Figure 14.
Added Cost of CO2 Pipeline Transmission in $/GJ of Co-produced Hydrogen



A = 1 refueling station (9000 car fleet)
B = All buses in LA Basin
C = 10% of cars in LA Basin
D = 100% of cars in LA Basin
E = 50% of cars in US

Figure 15. Cost of CO2 Injection and Storage in Underground Aquifer vs. CO2 injection rate per well



Adapted from Hendriks 1994

$25.6/tonne CO2
=$1/GJ H2

assuming flows in Figure 13

1000 tonnes CO2/day is equiv. to byproduct CO2 from a H2 plant producing 75 million scf H2/day

Figure 16.
Cost of Gas Transmission 300 km for H2, NG, CO2

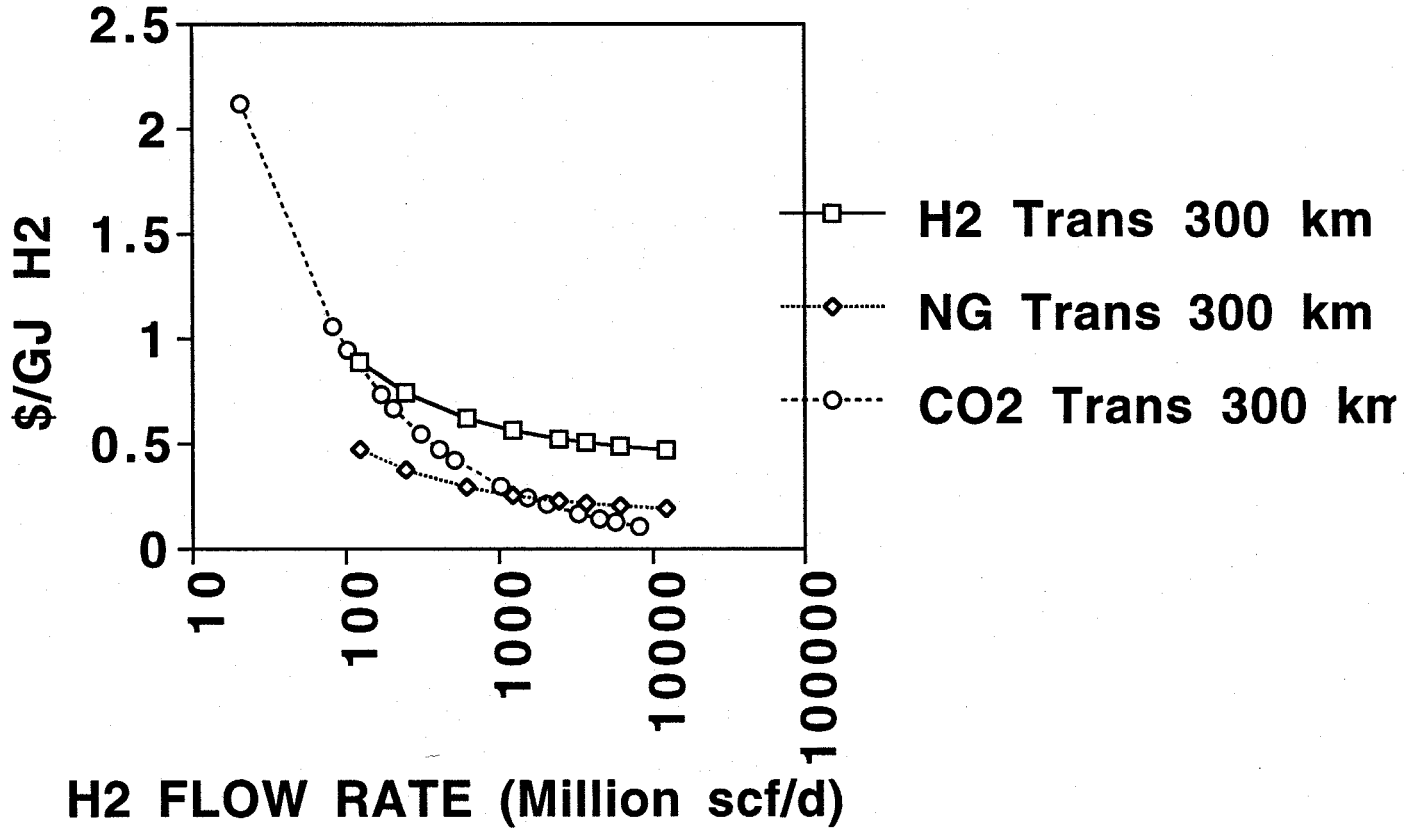
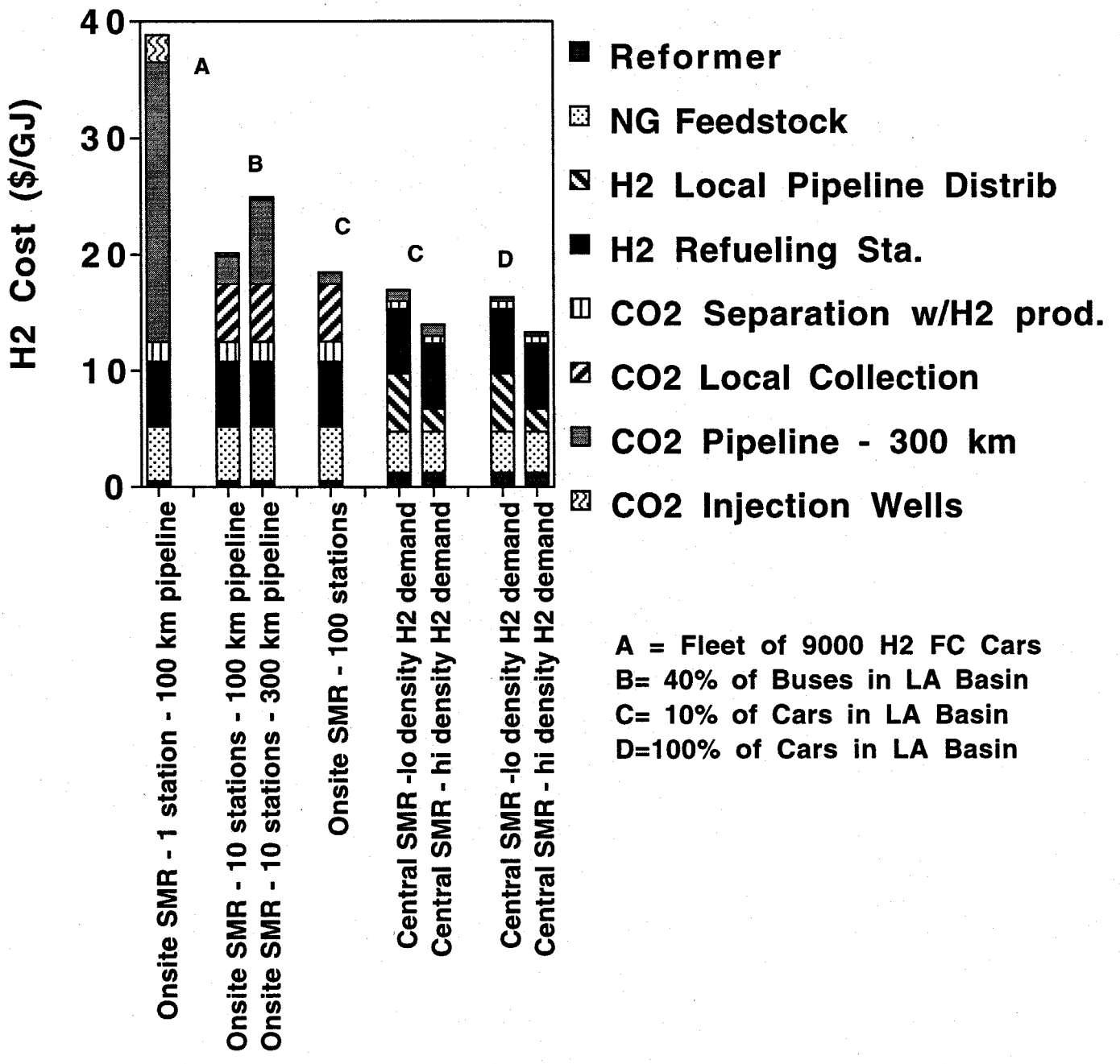


Figure 17.
Hydrogen from Nat Gas w/CO2 Sequestration: Delivered Cost of H2 Transportation Fuel



A = Fleet of 9000 H2 FC Cars
B= 40% of Buses in LA Basin
C= 10% of Cars in LA Basin
D=100% of Cars in LA Basin

$1/GJ H2
= $25.6/tonne CO2
= $94/tonne Carbon

Figure 18. CONFIGURATIONS FOR PEMFC COGENERATION FOR RESIDENTIAL USERS