FINAL REPORT

RENEWABLE HYDROGEN ENERGY SYSTEM STUDIES

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Concerns about urban air quality, acid precipitation, global climate change and energy supply security have led to renewed interest in hydrogen as a low-polluting alternative to fossil fuels. Hydrogen is a high quality, exceptionally clean fuel, which could replace oil and natural gas for transportation, heating and power generation. If hydrogen is made from renewable resources (solar, wind or biomass), it would be possible, in principle, to provide energy on a global scale with greatly reduced greenhouse gas emissions and very low local pollution.

Here we present technical and economic assessments of alternative strategies for developing renewable hydrogen energy systems. The goal of this work is to identify the most promising paths toward use of renewable hydrogen as an energy carrier, highlighting key technologies for research and development. We have focussed on technologies which could be employed over the next few decades.

We consider a variety of sources of hydrogen including electrolytic hydrogen from solar PV, solar thermal, wind, and hydropower, and hydrogen from biomass gasification; various options for storing and transmitting hydrogen; and various important end-uses (e.g. zero emissions vehicles).

In our assessments, we analyze the entire energy system design from production through end-use, as technological choices in one part of the system can have a strong impact on the other components. To evaluate pathways for producing and using hydrogen, we estimate the system performance and cost, the levelized cost of hydrogen production, the costs of hydrogen storage, transmission, distribution and delivery; and the lifecycle cost of energy services to the end-user. Environmental effects (land, water and resource requirements; emissions of pollutants and greenhouse gases) are estimated and infrastructure and consumer issues are discussed.

The results of our study can be summarized as follows:

* **In the early part of the next century, renewable hydrogen could become competitive with other sources of hydrogen.** Based on post-2000 projections for PV, wind and electrolysis technologies, we find that it would be possible to electrolytic hydrogen from PV at a cost of $12-21/GJ and from wind at $16-26/GJ. Because of the modular nature of PV, wind and electrolysis technologies, these costs could be achieved at relatively small scale. For hydrogen production capacity of 0.5 million scf H_2/day (enough to fuel about 300 fuel cell fleet vehicles/day), PV or wind electrolysis would be roughly competitive with small scale steam reforming of natural gas. At large scale (50-100 million scf/day), hydrogen from biomass gasification would be the least costly renewable option. Biomass hydrogen would cost about $6-9/GJ to produce, which would be competitive with hydrogen from natural gas (at DOE projected post-2000 natural gas prices of $4-6/GJ), and probably less expensive than hydrogen from coal gasification.

* **There are good to excellent resources for renewable hydrogen production globally and in most areas of the United States. Land and water requirements would be modest.** With PV electrolysis alone, it would be possible to supply enough hydrogen for all light duty vehicles in the US (assuming 2010 driving levels and that hydrogen fuel cells were used), using only 0.1% of the US land area. With wind power alone, 2% of the US land area (15% of the environmentally developable wind resource) would be needed, and with biomass alone 3% of the US land area (70% of the currently idled cropland) would be needed. Because good local renewable hydrogen resources are available in most parts of the US, it might not be neccessary to build long distance hydrogen pipelines.

* **For gaseous hydrogen delivery systems, compression and storage (for intermittent sources like wind or PV), pipeline transmission, local distribution and delivery as a transportation fuel would add a total of about $6-8/GJ to the cost of hydrogen.**

* **By the early part of the next century, renewable hydrogen could become attractive as a transportation fuel for hydrogen fuel cell vehicles.** Even though renewable hydrogen would be several times as expensive as gasoline, and hydrogen fuel cell vehicles would probably cost considerably more than gasoline vehicles, our analysis suggests hydrogen fuel cell vehicles might compete on a lifecycle cost basis. Assuming that goals for fuel cells and advanced batteries are achieved, this would occur because fuel cell vehicles would be 2-3 times as energy efficient as gasoline vehicles, would have a longer lifetime and lower maintenance costs.

* **Delivered fuel cost alone is not a good indicator of the economic competitiveness of hydrogen as a transportation fuel.** This is particularly true for high quality fuels like hydrogen which can be used very efficiently and cleanly. Better economic indices are: 1) the lifecycle cost of energy services (cents/km); 2) the fuel cost per km; and 3) the "breakeven gasoline price" (e.g. the price of gasoline that would make the lifecycle cost of transportation for a gasoline powered internal combustion engine vehicle equal to that of a hydrogen vehicle). Even if hydrogen is much more expensive than other fuels on an energy basis, it may be able to compete on a lifecycle cost basis for applications where it can be used with higher efficiency than other fuels.

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1.0. INTRODUCTION

Concerns about urban air quality, acid precipitation, global climate change and energy supply security have led to renewed interest in hydrogen as a low-polluting alternative to fossil fuels. Hydrogen is a high quality, exceptionally clean fuel, which could replace oil and natural gas for transportation, heating and power generation. If hydrogen is made from renewable resources (solar, wind or biomass), it would be possible, in principle, to provide energy on a global scale with greatly reduced greenhouse gas emissions and very low local pollution.

Here we present technical and economic assessments of alternative strategies for developing renewable hydrogen energy systems. The goal of this work is to identify the most promising paths toward use of renewable hydrogen as an energy carrier, highlighting key technologies for research and development. In our assessments, we analyze the entire energy system design including hydrogen production, delivery and end-use, as technological choices in one part of the system can have a strong impact on the other components. Our analysis is focussed on technologies which could be employed over the next decade or so.

Several renewable hydrogen production methods are considered including: electrolysis powered by solar photovoltaics, solar thermal electric, wind, and hydroelectricity and gasification of renewably grown biomass. Conceptual designs are presented for renewable hydrogen production systems and levelized hydrogen production costs are calculated using a consistent set of economic assumptions (Table 1). Environmental effects (land and water requirements) and potential resources for renewable hydrogen production are considered. Hydrogen can be stored, transported and delivered to the user in a variety of ways. The design of a hydrogen delivery system strongly depends on the end-use. As an example, we present a case study for hydrogen fuel cell automobiles. The cost of delivering gaseous hydrogen transport fuel to the consumer is estimated (including storage, transmission, distribution and filling station costs), a model for a fuel cell vehicle is presented (DeLuchi and Ogden 1992) and the lifecycle cost of transportation is calculated, as compared to other alternative fueled vehicles. Emissions of air pollutants and greenhouse gases from alternative transportation fuel cycles are compared. A scenario for introducing hydrogen as a transport fuel in the US is sketched (Ogden and DeLuchi 1992).

Finally, possible areas for future research are suggested.

2.0. TECHNOLOGIES FOR PRODUCING HYDROGEN FROM RENEWABLE RESOURCES

In this section, we describe technologies for producing hydrogen from renewable resources. We have focussed on technologies which could be employed over the next ten to twenty years. To facilitate comparison among technologies, the levelized cost of hydrogen production is calculated using a consistent set of economic assumptions (Table 1). The details of the calculations are given in Appendix A). Cost and performance of various technologies are given in Tables 2-13 and hydrogen production costs are summarized in Table 14 and Figure 3.

2.1. SOLAR-POWERED WATER ELECTROLYSIS

In solar-powered electrolysis systems, a source of renewable electricity, such as solar photovoltaic, solar thermal electric, wind or hydro power, is connected to an electrolyzer, which splits water into its constituent elements hydrogen and oxygen. The hydrogen can be used onsite, compressed for storage or transmitted via pipelines to distant users. As an example, Figure 1 shows a solar photovoltaic electrolytic hydrogen system.

2.1.1. Solar-Electric Technologies

Here we review current cost and performance data for solar electric technologies, and projections for the near term (1990s) and long term (post-2000). The costs given below for wind and solar electricity are for intermittent electricity at the production site. Because we are concerned here with electrolytic hydrogen production, rather than electricity production on demand, no electrical energy storage system is included.

2.1.1.1. Hydroelectric Power. Hydroelectricity is a mature, commercial electricity-generation technology. At sites where excess off-peak power is available, hydro power can be very inexpensive, making it attractive for electrolytic hydrogen production. To estimate hydrogen costs, we assume that off-peak hydro power would be available at 2-4 cents/kWhAC, for eight hours per day (Stuart, 1991).

2.1.1.2. Wind Power. There have been substantial improvements in wind technology over the past ten years and today about 1600 MW of wind power is installed around the world. At present, the installed system capital cost is about $1100/kW for 100-200 kW wind turbines. Over the next few years, costs are projected to drop to about $1000/kW for 340 kW turbines with variable speed drives (Smith, 1991; Lucas, McNerney, DeMeo and Steeley, 1990). Beyond the year 2000 costs could drop further to $750-850/kW (Hock, 1990; Cohen, 1989; Smith, 1991; USDOE, March 1990; Cavallo, Hock and Smith, 1992) (Table 2).

At a typical "good" site (with an average hub height wind power density of 350 Watts/m^2), we calculate that for 1990 technology the cost of electricity would be about 11.8 cents/kWhAC (Table 2). At an "excellent" site (with a wind power density of 500 Watts/m^2) the cost of electricity would be about 8.5 cents/kwh. Recent operating experience and design studies have indicated that advanced airfoils, innovative drive controls, drive train

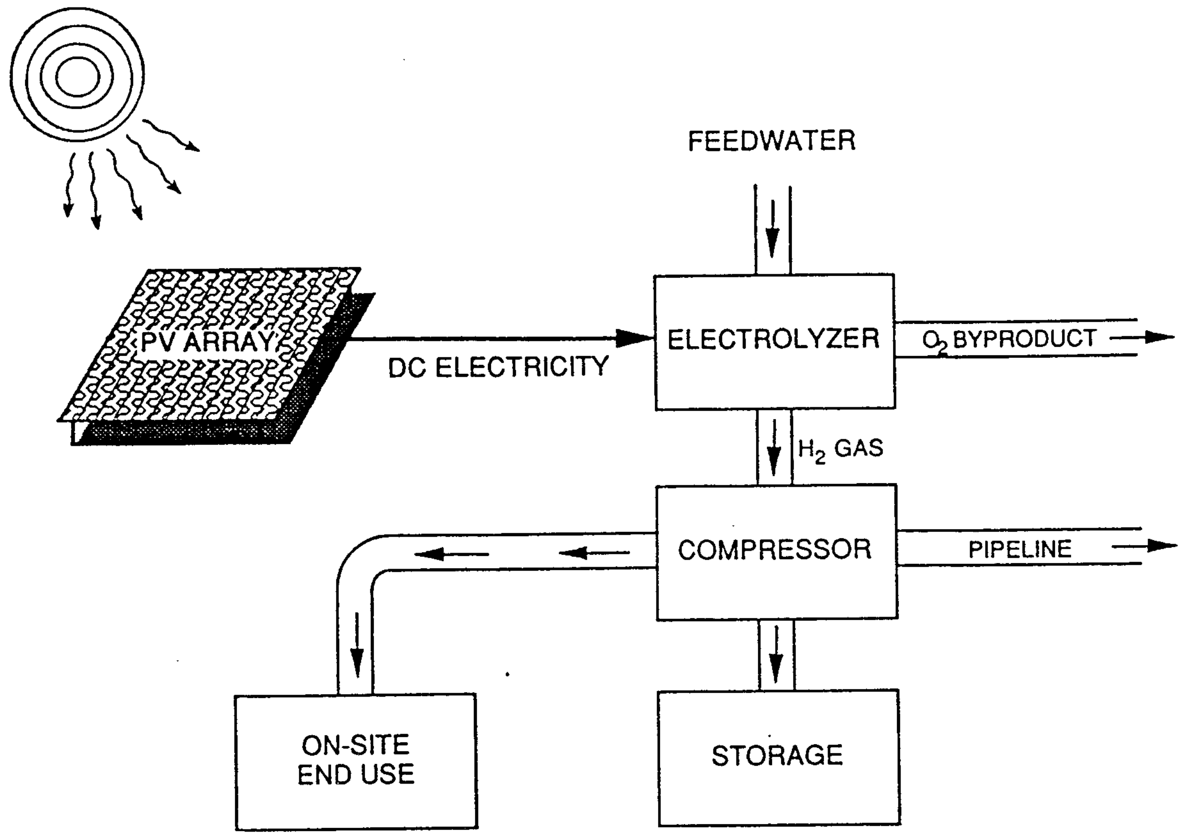


Figure 1. A solar photovoltaic electrolytic hydrogen system

Table 0. Conversion factors

1 EJ = Exajoule (10^{18} Joules) = 0.95 Quadrillion BTUs

1 GJ = Gigajoule (10^{9} Joules) = 0.95 Million BTUs

1 million standard cubic feet H2/day = 28,300 Nm^3 H2/day = 362 GJ/day (HHV)

100 hectares = 1 km^2 = 10^6 m^2 = 0.39 square miles = 247 acres

1 gallon gasoline = 0.1304 GJ (higher heating value)

$1/gallon gasoline = $7.67/GJ = $8.09/MBTU

Hydrogen used by fuel cell passenger automobile = 18 GJ/year or 0.05 GJ/day (for a car with fuel economy equivalent to 74 mpg, driven 10,000 miles/yr)

Table 1. Economic assumptions

All costs are given in average 1989 US dollars.

For hydrogen production plants, compression, storage and transmission systems levelized costs were calculated in **constant 1989 dollars** assuming (EPRI 1986):

Real discount rate = 6.1%
Annual insurance = 0.5% of installed capital cost
Annual property taxes = 1.5% of installed capital cost

All hydrogen costs are based on the higher heating value of hydrogen

Table 2. Cost and performance of wind power technologies

	1990[a]	near term[b]	post 2000[c]
Total installed cost ($/kWp)	1100	1000	750
Turbine output (kW)	100	340	1000
Turbine diameter (m)	17.5	33	52
Hub height (m)	25	30	50
Availability	90%	95%	95%
Annual O&M costs (cents/kWhAC) (including retrofits)	1.5	1.1	0.6
Rent on land (cents/kWh)	0.3	0.3	0.3
System lifetime (years)	25	30	30
System losses	23%	23%	23%
Annual net energy capture per turbine ($kWh/m^2/yr$)			
Wind power density = 350 W/m^2	500	630	750
Wind power density = 500 W/m^2	750	1025	1100
Wind power density = 700 W/m^2	-	1400	1600
Annual average capacity factor			
Wind power density = 350 W/m^2	0.137	0.181	0.182
Wind power density = 500 W/m^2	0.206	0.294	0.267
Wind power density = 700 W/m^2	-	0.402	0.388
AC electricity cost (cents/kWh)			
Wind power density = 350 W/m^2	11.8	7.6	5.5
Wind power density = 500 W/m^2	8.5	5.2	4.1
Wind power density = 700 W/m^2	-	4.2	3.1

Notes on next page

Notes for Table 2:

[a]Cost and performance estimates are for US Windpower 100 kW models (Smith, 1991). See also Cohen et al. (1989).

[b]Costs are estimated for mid 1990s wind turbine technology based on the US Windpower 33 meter diameter variable speed drive model (Smith, 1991). See also Lucas et al. (1989).

[c]Costs and performance projections for advanced wind turbines are from studies by the Solar Energy Research Institute. See Hock et al. (1990) and Appendix F of Idaho National Engineering Lab et al. (1990); (Cavallo, Hock and Smith, 1993).

[d] The annual average capacity factor is given for three levels of average wind power density (350, 500 and 700 Watts/square meter of swept rotor area), measured at the rotor hub height. With present wind turbines, the hub height is typically 30 meters, and the average wind power density is 350 W/m^2 in Class 4 wind regions and about 500 W/m^2 in class 5-6 wind regions. With near term technology, it should be possible to extend the height to 50 meters. In this case, the average power density would be 350 W/m^2 for a class 3 region, and about 500 W/m^2 for a class 4-5 region, and 700 W/m^2 for Class 6 regions. (Class 3, 4 and 5 wind resources are widely found throughout the world; Class 6 is less common.) Estimates for the net annual energy capture are from Smith (1991) for hub height wind power densities of 350 and 500 W/m^2. The annual net energy capture for wind power density of 700 W/m^2 was estimated from Figure 1 in J.M. Cohen et. al. (1989), and from Tables 2 and 4 of Hock et. al. (1991). These include total system losses of 23% and availability of 90% for present technology and 95% for near term and post-2000 technologies.

[e]Levelized electricity costs are calculated in constant 1989 US dollars using the equations in Appendix A and the economic assumtions in Table 1.

improvements and site-dependent optimization strategies could improve the efficiency of energy capture at little or no extra cost (Hock 1990). As these technical improvements are incorporated into the next generation of wind turbines in the early to mid 1990s, the cost of electricity should drop by several cents/kWh. For example, with the introduction of variable speed drive technology, which is now being commercialized by US Windpower, costs of electricity should fall to 7.6 cents/kWh for a good site and 5.2 cents/kWh for an excellent site. In the longer term, electricity costs could reach 3.1 to 5.5 cents/kWh. Wind technology is modular, with little economy of scale beyond typical wind turbine sizes of (50-300 kW).

2.1.1.3. Solar Thermal Electric. In solar thermal-electric systems, solar radiation is converted into high-temperature heat by collecting sunlight over a large area collector and focussing it onto a smaller-area receiver. The heat is then used to power an electric generator. To better match utility electric demand profiles, the heat can be stored for later use or a supplemental fuel (generally natural gas) can be used to provide extra heat when needed. For efficient operation, solar thermal systems require direct sunlight. With central-receiver and parabolic-dish designs, tracking systems must be used to follow the sun. Several types of solar thermal-electric systems have been developed (USDOE, 1989; DeLaquil, 1991; DeLaquil et.al., 1992; USDOE, March 1990) (Table 3).

Parabolic trough collectors concentrate solar radiation 10-100 times, by focussing sunlight onto a central pipe containing oil. The heated oil (at 300-400°C) is used to produce steam, which powers a steam turbine generator. The overall efficiency of converting sunlight to electricity is about 13-17% A natural-gas burner provides supplemental heat when sunlight is inadequate to meet demands. Parabolic trough systems are commercially available at $2800-3500/kW, and produce electricity at a cost of 12-16 cents/kWh. A total of about 350 MW of solar thermal-electric parabolic-trough systems are already installed, mostly in California. With improvements capital costs are projected to drop to $2000-2400/kW, and electricity costs to about 8-12 cents/kWh (Table 3).

In central-receiver systems, an array of moveable flat plate heliostats focuses sunlight on a central-receiver tower, with a concentration of 300-1500 times, and heats a working fluid to 500-1500°C. Steam is raised in a heat exchanger to power a steam turbine, and typically some heat is stored for later use. Efficiencies for these systems are about 8-15%, but are projected to reach 10-16%. Capacity factors with storage would be 25-40% at present, but could reach as high as 55-63%. Central receiver systems have been demonstrated in several 1-10 MW pilot projects, although the technology has not yet been commercialized. To reach economies of scale, the system capacity must be at least 100-200 MW. With present technology, the system capital cost would be about $3000-4000/kW, which, according to our calculations, would result in an electricity cost of about 10-20 cents/kWh. In the near term, capital costs could drop to perhaps $2000-3000/kW, resulting in an electricity cost of 7-12 cents/kWh. In the longer term, with higher capacity factor and more storage, the electricity cost could drop to 5.4-7.6 cents/kWh.

Table 3. Cost and performance of solar thermal electric technologies[a,b]

	Parabolic trough systems 1990	near term	post 2000
Capital cost ($/kW)	2800-3500	2400-3000	2000-2400
Peak Capacity (MWe)	80	80	160
Annual energy efficiency solar mode	13-17%	13-17%	13-17%
Method for enhanced load matching	-- Natural-gas firing --		
Fraction of kWh from gas	25%	25%	25%
Solar capacity factor	22-25%	18-26%	22-27%
O&M cost (cents/kwh)	1.8-2.5	1.6-2.4	1.3-2.0
System lifetime	30	30	30
AC electricity cost (cents/kWhAC)	**11.6-16.0**	**9.8-16.6**	**8.0-11.6**

	Central receiver systems near term	post 2000	
Capital cost ($/kW)	3000-4000	2225-3000	2900-3500
Peak Capacity (MWe)	100	200	200
Annual energy efficiency solar mode	8-15%	10-16%	10-16%
Method for enhanced load matching	-- Thermal Storage --		
Solar capacity factor	25-40%	30-40%	55-63%
O&M cost (mills/kwh)	1.3-1.9	0.8-1.6	0.5-0.8
System lifetime	30	30	30
AC electricity cost (cents/kWhAC)	**9.7-20.0**	**6.8-12.3**	**5.4-7.6**

	Parabolic dish systems near term	post 2000	
Capital cost ($/kW)	3000-5000	2000-3500	1250-2000
Peak Capacity (MWe)	3	30	300
Annual energy efficiency solar mode	16-24%	18-26%	20-28%
Method for enhanced load matching	-- Solar only --		
Solar capacity factor	16-22%	20-26%	22-28%
O&M cost (mills/kwh)	2.5-5.0	2.0-3.0	1.5-2.5
System lifetime	30	30	30
AC electricity cost (cents/kWhAC)[c]	**17-38**	**10.2-22**	**6.1-12.2**

[a]It is assumed in all cases that the system lifetime is 30 years, the price of natural gas is $3/GJ, and that non-fuel O&M costs are 2 cents/kWh. NG = natural gas.

[b]Adapted from USDOE (1990a), DeLaquil et.al. (1993).

[c]Levelized electricity costs are calculated in constant 1989 US dollars, using the equations in Appendix A and the economic assumptions of Table 1, and assuming a Southwestern US location.

Parabolic dishes acheive high concentration (1000-2000 times) and temperatures of over 1500°C. The system consists of an array of parabolic dishes, each of which tracks the sun and focusses light on to a receiver at the focal point of the dish. Electricity is produced either by using a small Stirling engine at each dish, or by having the receiver heat a working fluid which then is piped to a central location to produce steam and electricity. Efficiencies for these systems are about 16-24% and could reach 20-28%. No storage is used, but supplemental heat can be generated to match a utility electric demand profile, as with parabolic trough systems. Parabolic dish systems have been demonstrated in several projects. Individual dishes with Stirling engines have performed well (at efficiencies of up to 29%), but systems with circulating fluids have been plagued by difficulties in the heat transfer process. Stirling/dish systems are modular, and can produce electricity at small size (5-25 kW). In the near term, these systems are projected to cost $3000-5000/kW, with electricity costs of 17-38 cents/kWh. In the longer term, costs of $1250-2000/kW and 6-12 cents/kWh are projected.

Parabolic trough systems are the simplest and most developed solar thermal electric technology, but central receiver and parabolic dish/Stirling designs could reach higher efficiencies and lower costs in the long term. Parabolic trough and central receiver systems would have to be large (100-200 MW) to reach economies of scale. Parabolic dish systems could be much smaller (tens of kilowatts for each unit).

2.1.1.4. Solar Photovoltaics Solar photovoltaic (PV) technologies, which convert sunlight directly into electricity, are advancing rapidly (Zweibel, 1990; Hubbard, 1989). In recent years, the annual production of PV modules has been growing at about 30% per year with over 40 MW manufactured in 1990. PV power is already economically competitive on a lifecycle cost basis for applications at remote sites far from a utility grid, such as charging batteries, pumping water and small-scale (<20 kW) power generation. PV systems require little maintenance. They are modular and can be built as small as a few kilowatts. As costs decrease during the 1990s, PVs should start to become competitive for residential power and central-station peaking power. Unlike solar thermal electric systems, some PV systems can be used in cloudy areas that have only limited direct sunlight.

Various types of solar cells have been developed based on crystalline, polycrystalline and amorphous materials. Commercially available crystalline solar cells are made by growing single crystal cylindrical ingots of silicon or other materials and sawing them into circular wafers 100-200 microns thick. Commercially available polycrystalline solar cells are made by casting silicon into rectangular blocks, which are sawed to form individual solar cells. Crystalline solar cells are more efficient than other technologies -- efficiencies of 35% have been acheived with laboratory crystalline solar cells -- but are more expensive to manufacture. Polycrystalline cells are less efficient -- the best laboratory cells are 17% efficient, and commercial modules are 12% (Zweibel, 1990; Zweibel and Barnett, 1993) -- but less costly to manufacture.

Over the past ten years, thin film solar cells using amorphous silicon, polycrystalline materials and crystalline silicon have been developed. Thin film solar cells typically are 1-5 microns in thickness, as compared to 100-200 microns for grown crystalline silicon or cast polycrystalline materials, and as a result use much less material. They can be manufactured more simply, by various processes that directly deposit the solar cells on glass or ceramics. Although thin-film solar cells are less efficient than other solar cell materials (the best laboratory cells are now about 16% efficient and modules are about 6-8% efficient), they have the potential to reach much lower mass production costs (Carlson and Wagner, 1993; Zweibel and Barnett, 1993).

To produce power, solar cells are connected to form modules. In flat plate modules solar cells are encapsulated between layers of glass. Concentrator modules use plastic Fresnel lenses to concentrate sunlight from a large area onto a small area cell. Modules can be mounted in fixed arrays or tracking arrays can be used to follow the sun. Tracking arrays capture more of the sun's radiation, and are required for concentrators, but are more expensive and complex than fixed, flat plate systems.

Large (>5 MW) PV systems today cost about $4000-9000/kW installed and produce PV electricity for 14 to 35 cents/kWh (Tables 4-6). As the efficiency of solar-cell materials improves and manufacturing processes are scaled-up and refined, the cost of PV systems is expected to drop to $1500-3500/kW the 1990s, with DC electricity costs of 6-14 cents/kWh. By the early part of the next century, with further improvements in solar cell technology and balance of system design (Table 5), thin-film solar-cell or concentrator systems could cost $500-1100/kW, with DC electricity costs of 2.2-4.4 cents/kWhDC. (Costs are given here for DC PV electricity, because this is the form required for electrolysis.)

2.1.1.5. Solar Electricity Costs. In the near term (1990s) off-peak hydropower would offer the lowest electricity costs. By the year 2000, the cost of wind power could be about 4-5 cents/kWh, and in the longer term, both solar PV and wind look attractive (Table 7), offering costs for intermittent electricity in the range 2.2-4.4 cents/kWh.

It is important to reiterate that these are costs for intermittent electricity only, with no storage included. The intermittent electricity costs summarized in Table 7, are not directly comparable to the cost of electricity from a conventional fossil or nuclear power plant. If electricity storage were added, the cost of PV or wind electricity would be increased by about 3-7 cents/kWh (Ogden and Williams 1989).

2.1.2. Electrolysis Technology

The technology of water electrolysis is well established, and several types of electrolyzers have been developed (Dutta, 1990; Fein and Edwards, 1984; Hammerli, 1984; Hammerli, 1990; Leroy and Stuart, 1978; Stuart, 1991; Winter and Nitsch, 1988; Steeb, 1990; Carpetis, 1984; Hug, 1990; IEA, 1991).

Table 4. Cost and performance of solar photovoltaic modules

Solar PV Technology	PV module efficiency			PV module manufacturing cost ($/square meter)		
	1990	near term	post 2000	1990	near term	post 2000
Flat plate modules						
Thin Films						
Amorphous silicon[a]	6%	8-10%	12-18%	100	70	30-55
$CuInSe_2$[b]	10%	10%	15%	200	75-200	45
CdTe[b]	8%	10%	15%	200	75-200	45
Thin film silicon[b]			16%			50
Polycrystalline[b]	13%		17%	250-400		170-340
Crystalline[b]	15%		20%	500-800		200-400
Concentrator modules[c]	20%	25%	35%	300-700	200	150

[a]From Carlson (1989, 1990), (Carlson and Wagner, 1993).

[b]From Zweibel and Barnett (1993). CuInSe = copper indium diselenide; CdTe = cadmium telluride.

[c]Estimates for concentrators are from Boes and Luque (1993).

Table 5. Area-related Balance of System Costs for Large Fixed Flat plate PV Systems (all costs are adjusted to 1989 dollars and given in $\$/m^2$)

	Year	Site Prep.	Support	Foundation	Struct. Subtot.	DC[b] Electrical	Total
JPL[b]	1981	-	49.5	15.0	65.5	-	-
Bechtel[b]	1981	-	30.7	17.4	48.1	-	-
Battelle[c]	1982	11.8	12.6	26.4	39.0	18.4	69.2
Martin Marietta[d]	1982	4.4	80.5	8.9	89.4	(incl. in support)	93.8
EPRI HV[e]	1984	4.8	28.9	10.7	39.7	22.9	67.4
LV[e]		"	"	"	"	18.3	62.8
RCA[f]	1984	2.0	-	-	47.6	4.1	53.6
Sandia HV[g]	1986	1.1	20.8	8.4	29.1	24.4	54.6
LV[g]		1.1	19.4	8.8	28.1	41.0	70.2
USDOE Goals[h]	1987	-	-	-	-	-	54.9
Bechtel[i] (thin-film)	1987	-	-	-	-	10.6-20.8	-
Chronar[j]	1990	0.4	-	-	29.5	8.9	39.9
SERI[k]	1990	-	-	-	35	9	44
this study base case (Sandia support[g] + lowest cost Bechtel elec.[i])		1.1	20.8	8.4	29.1	10.6	40.8
CEES[l] (lowest cost case)	1991	1.1	14.6	5.3	19.9	12.6	33.6

In some studies only some elements of the BOS cost were estimated.
[a] Includes the cost of the DC interface to the electrolyzer.
[b] See (Bechtel, 1983).
[c] See (Carmichael et.al. 1982).
[d] See (Martin Marietta, 1984).
[e] See (S.L. Levy et.al., 1984).
[f] See (J. Stranix and A.J. Firester, 1982).
[g] See (G.T. Noel et.al., 1985).
[h] See (USDOE, May 1987).
[i] See (Bechtel, 1987).
[j] See (R. Matlin, 1989, 1990; T. Candelario et.al., 1991).
[k] See (K. Zweibel, 1990).
[l] See (J. Ogden and K. Happe, 1993).

Table 6. Cost and performance of solar photovoltaic systems[a,b]

	1990	near term	post 2000
Balance of system costs ($\$/m^2$)			
Fixed, flat plate	50-80	40-55	40
1-axis tracking		75	75
2-axis tracking		125	100
Balance of system efficiency[c]	85%	89%	89%
System lifetime (years)	30	30	30
Annual O&M costs			
Fixed, flat plate ($\$/m^2/yr$)	1.2	0.5	0.5
1 or 2-axis tracking ($/kWh)	0.01	0.01	0.01
Indirect costs (% of capital cost)	33%	25%	25%

	Total installed system cost ($/Wp)		
	1990	near term	post 2000
Flat plate systems			
Thin films	3.9-4.4	1.5-3.5	0.5-1.1
Polycrystalline	3.6-5.8		1.7-3.2
Crystalline	5.7-9.2		1.7-3.2
Concentrator systems (2-axis tracking)	4.3-7.4	1.9	1.1

	Cost of electricity, $/kWh-DC[d]		
	1990	near term	post 2000
Flat plate			
Thin films	0.16-0.21	0.061-0.14	0.022-0.044
Polycrystalline	0.14-0.22		0.071-0.13
Crystalline	0.22-0.35		0.068-0.13
Concentrator (2-axis tracking)	0.17-0.28	0.085	0.055

Notes on next page.

Notes to Table 6:

[a]PV system costs except long term balance of system costs are from fixed flat plate systems are from Zweibel (1990).

[b]Long term balance of system costs ($40/m^2) are from R. Matlin (1990), Candelario et.al. (1991), Ogden and Happe (1993).

[c]Equal to DC system efficiency divided by module efficiency.

[d]Levelized cost of DC electricity (in $/kwhDC) in the Southwestern US, with average annual insolation of 271 Watts/m^2.

[e]If AC power were produced instead of DC power, the power conditioning equipment would add an extra $150/kW. The balance of system efficiency for an AC system would be 85% rather than 89% because of energy losses in the inverter which is assumed to be 96% efficient. The cost of power would be about $0.006/kwh greater than the costs shown here.

[f]Estimates for concentrators are from (Boes, 1991) and (Boes and Luque 1993).

Table 7. Current and projected costs for solar electricity (cents/kWh)

Technology	1991	Near term	Post 2000
Wind (700 W/m^2)	-	4.2	3.1
(500 W/m^2)	8.5	5.2	4.1
(350 W/m^2)	11.8	7.6	5.5
Solar thermal electric (SW US)	11-16	11-16	5.5-7.8
Solar PV (SW US)	14-35	7-16	2.2-4.4 (DC) 3.2-5.4 (AC)
Hydropower (Off-peak)	2-4	2-4	2-4

[a]We have shown here the production cost of intermittent electricity at the generation site with no storage. Levelized electricity costs are calculated in constant 1989 US dollars for the economic assumptions in Table 1, using the equations in Appendix A. (See Tables 2-6 for details.) For wind power the annual average wind power density at hub height is shown in parentheses.

Alkaline water electrolysis is a mature, commercially available technology. An aqueous electrolyte (generally 30% potassium hydroxide (KOH) in water) is used, with nickel or nickel-alloy electrodes. Electrolysis cells are configured so that the electrodes are either in "bipolar" mode, in which each electrode has two polarities and is both an anode and a cathode, or in "unipolar" mode, in which each electrode has only one polarity, and is either an anode or a cathode. Unipolar electrolyzers operate at atmospheric pressure and are slightly less expensive than bipolar electrolyzers which can operate up to 3 MPa (450 psia). Most industrial electrolysis systems today are used to produce very pure hydrogen for chemical applications, and are only 10 to 100 kW. A few plants larger than 10 MW have been installed near sources of low cost hydroelectricity (Hammerli 1984). Electrolysis is a modular technology with no significant scale economies above sizes of 2-10 MW (Fein and Edwards, 1984). Cost and performance data and projections for large alkaline-electrolysis systems are summarized in Table 8.

Two other types of electrolyzers are in earlier stages of development. Solid-polymer-electrolyte (SPE) electrolyzers could offer higher current density and higher efficiency (up to 90%) than alkaline electrolyzers, but, at present, require expensive membrane electrolyte materials and platinum catalysts for stable operation. Current research is focussed on finding lower cost electrolyte materials and catalysts. High-temperature electrolysis could offer significantly lower electricity consumption per unit of hydrogen produced, because some of the work of water splitting would be done by heat. However, the operating temperature of 900-1000°C creates many as-yet-unsolved materials and fabrication problems. Over the next ten to twenty years, alkaline electrolysis is likely to remain the technology of choice for solar electrolysis systems (Winter and Nitsch, 1988; Stuart, 1991).

If an intermittent power source such as wind or solar is used, the electrolyzer plant, and the electrodes particularly, must be designed to tolerate variable operation. At present there is only limited operational experience with PV-powered electrolyzers (Steeb, 1990; Steeb et.al. 1992; Hug, 1990; Metz, 1985; Hammerli, 1990; Lehmann 1990; Lehmann 1992; Kaurenen 1992; Selamov, 1992; Szyska, 1992; Stuart, 1992; Divisek, 1992; Ledjeff et.al. 1992; Stucki, 1991; Collier, 1992; Garcia-Conde and Rosa, 1992) and none with wind or solar-thermal-electric-powered electrolyzers. Although there have been no intractable problems with PV-electrolysis experiments to date, the long term performance and reliability of electrolysis systems under intermittent operation is not well known. Several electrolyzer manufacturers and research groups are now studying these issues (see Appendix D).

2.1.3. Solar-Electrolytic Hydrogen Systems

In Tables 9-12 we describe "base-case" post-2000 solar electrolytic hydrogen systems based on wind, PV, solar thermal electric and hydropower. The calculated production cost of hydrogen from PV would be $12-19/GJ, equivalent in energy terms to about $1.5-2.5/gallon of gasoline (Table 9). Wind-electrolytic hydrogen is estimated to cost $16-26/GJ (Table 10). For

Table 8. Advanced alkaline electrolyzers

Electrolyzer Type	Bipolar[a] Present	Bipolar[a] Future	Unipolar[b] Present	Unipolar[b] Future
Rated power (MWe)	10	100	10	100
Pressure (MPa)	3	3	0.1	0.1
Temperature (°C)	90	160	70	70
Type of diaphragm	Asbestos	$CaTiO_3$-Cermet	Asbestos	Synthetic
Rated current density (mA/cm^2)	200	450	134	250
Maximum operating current density (mA/cm^2)	267	600	168	333
Rated voltage (V)	1.86	1.7	1.9	1.74
Efficiency at rated current density (HHV)	73%	90%	73%	90%
(LHV)	62%	76%	62%	76%
Efficiency of rectifier	96%	98%	96%	98%
Feed water (liters/GJ H_2 HHV)	63	63	63	63
Cooling water (m^3/GJ H_2 HHV)	2.5	2.5	2.5	2.5
Capital costs: ($/kW AC) (including rectifier, building)	600	330	600	400
Capital costs for DC plant ($/kW)			474	274
Annual O & M costs (% of capital costs, including feed and cooling water costs and regeneration of KOH)	4%	4%	2%	2%
Lifetime (years)	20	20	20	20

[a]Estimates for bipolar technology are from Nitsch et. al. (1990) for near term electrolysis technology. At present bipolar electrolyzers have 73 % efficiency (HHV) operate at (90 °C) and have capital costs of $ 600/kW AC

[b]Estimates for unipolar technology are for commercially available technology at large scale. From (Craft ,1985; Leroy and Stuart ,1978; Hammerli, 1984; Stuart 1991; Stuart 1992).

Table 9. Post-2000 wind electrolytic hydrogen system parameters

Horizontal axis wind turbine[a]		
Turbine capacity	1000 kW	
Turbine diameter	52 m	
Hub height	50 m	
Total installed system cost	\$750/kWpeak	
Annual O&M cost	\$0.005/kWhAC	
Land rent	\$0.003/kWhAC	
System lifetime	30 years	
System availability	95%	
Array/system losses	23%	
Turbine spacing/turbine diameter	5 x 10	
Hectares/MWe	16	
Efficiency of coupling to electrolyzer[b]	94%	
Atmospheric pressure unipolar electrolyzer[c]		
Rated voltage	1.74 Volts	
Rated current density	250 mA/cm^2	
Max. operating current density	333 mA/cm^2	
Efficiency at max. op. voltage	85%	
Rectifier cost	\$130/kWACin	
Rectifier efficiency	96%	
Installed AC plant capital cost @ max. operating cur. density	\$371/kWACin	
Electrolyzer annual O&M cost	2% of capital cost	
Electrolyzer lifetime	20 years	
Wind resource		
Annual average wind power density W/m^2 (power per unit of area swept by turbine)	700	350
Levelized cost of wind electricity (cents/kWh)	3.1	5.5
Levelized cost of wind hydrogen (\$/GJ)	15.5	26.4

[a] Costs and performance for wind systems are from (Cohen et. al. 1989; Lucas et.al. 1990; Hock et. al. 1990; SERI 1990; Cavallo et.al., 1993)

[b] It is assumed that the wind system produces AC power, which is then rectified to DC for use in electrolysis. AC losses from the wind tower to the electrolyzer are assumed to be 6% (Winter and Nitsch 1988).

[c] Electrolyzer operating characteristics and costs are based on currently available unipolar technology. It is assumed that the rectifier is sized for maximum current density (Hammerli 1984; Leroy and Stuart 1978; Pirani and Stuart 1991; Stucki 1991). The maximum current density is taken to be 1.25 times the rated current density (Winter and Nitsch 1988; Steeb et.al. 1990).

Table 10. Post-2000 PV electrolytic hydrogen system parameters

Thin film PV modules, tilted, fixed flat-plate array (> 10 MWp)[a]	
PV module efficiency	12-18%
PV module manufacturing cost	$30-55/m^2$
Area-related balance of system cost	$40/m^2$
Balance of system efficiency	89%
PV system efficiency	10.7-16.0%
PV annual O&M cost	$0.5/m^2/yr$
PV system lifetime	30 years
PV system indirect cost factor	25%
PV System capital cost	$522-1077/kWDC
Efficiency of coupling to electrolyzer[b]	93% (direct connection)
Cost of coupling to electrolyzer	neglible
Solar Resource	
Annual average insolation[c]	271 Watts/m^2
Land area required in SW US	
10.7% efficient PV system	1.87 hectares/MWe
16.0% efficient PV system	1.25 hectares/MWe
Atmospheric pressure unipolar electrolyzer[d]	
Rated voltage	1.74 Volts
Rated current density	250 mA/cm^2
Max. operating current density	333 mA/cm^2
Efficiency at max. op. voltage	85%
Installed DC plant capital cost @ max. operating cur. density	$231/kWDCin
Electrolyzer annual O&M cost	2% of capital cost
Electrolyzer lifetime	20 years
Cost and peformance of PV hydrogen system	
System efficiency (H2 HHV)/insolation	8.4-12.7%
Total capital cost	$954-1654/kWH2 out

Energy costs		
Module efficiency	18%	12%
Module manuf.cost	$30/m^2$	$55/m^2$
Levelized cost of DC electricity (cents/kWh)	2.2	4.4
Levelized cost of PV hydrogen ($/GJ)	11.6	19.1

Notes on next page.

Notes to Table 10:

[a] Projected efficiencies and manufacturing costs for thin-film PV modules are from (Carlson 1990; Zweibel 1990). Area-related balance of system costs are based on conceptual designs for large fixed, flat plate arrays are from (Matlin 1990) and (Ogden and Happe 1993). Balance of system efficiency for a DC system is derived from USDOE estimates (USDOE 1987). Operation and maintenance costs are projections based on field experience from EPRI (Conover 1989) and SMUD (Shusnar 1985). Indirect costs of 25% are assumed based on Sandia experience with fixed, flat plate arrays (Noel 1985; Zweibel 1990). PV system lifetime of 30 years is taken from USDOE year 2000 goals (Zweibel 1990).

[b] PV/electrolyzer coupling efficiencies are based on small experimental systems (Steeb et.al. 1990; Metz 1985).

[c] Average annual insolation is given for the Southwestern United States.

[d] Electrolyzer operating characteristics and costs are based on currently available unipolar technology. It is assumed that no rectifier is needed. (Steeb 1990). The maximum current density is taken to be 1.25 times the rated current density (Winter and Nitsch 1988; Steeb 1990).

Table 11. Post-2000 solar thermal electric/electrolytic hydrogen system parameters

<u>Central receiver system</u>[a]		
Thermal storage for load matching		
Peak capacity	200 MW	
Total installed system cost	\$2900-3500/kWpeak	
Annual O&M cost	\$0.005-0.008/kWhAC	
Total system capacity factor	55-63%	
System lifetime	30 years	
System availability	95%	
Efficiency of coupling to electrolyzer[b]	94%	
<u>Atmospheric pressure unipolar electrolyzer</u>[c]		
Rated voltage	1.74 Volts	
Rated current density	250 mA/cm^2	
Max. operating current density	333 mA/cm^2	
Efficiency at max. op. voltage	85%	
Rectifier cost	\$130/kWACin	
Rectifier efficiency	96%	
Installed AC plant capital cost @ max. operating cur. density	\$371/kWACin	
Electrolyzer annual O&M cost	2% of capital cost	
Electrolyzer lifetime	20 years	
<u>Solar resource</u>		
Annual average insolation (W/m^2) (Southwestern US)	270 W/m^2	
<u>Energy Costs</u>		
System capital cost (\$/kW)	2900	3500
Levelized cost of solar electricity (cents/kWh)	5.4	7.6
Levelized cost of solar hydrogen (\$/GJ)	22	30

[a] Costs and performance for solar thermal electric systems are from Table 3.

[b] It is assumed that the solar thermal electric produces AC power, which is then rectified to DC for use in electrolysis. AC losses from the solar thermal electric generator tower to the electrolyzer are assumed to be 6% (Winter and Nitsch 1988).

[c] Electrolyzer operating characteristics and costs are based on currently available unipolar technology. It is assumed that the rectifier is sized for maximum current density (Hammerli 1984; Leroy and Stuart 1978; Pirani and Stuart 1991; Stucki 1991). The maximum current density is taken to be 1.25 times the rated current density (Winter and Nitsch 1988; Steeb et.al. 1990).

Table 12. Post-2000 hydropower electrolytic hydrogen system parameters

Off-Peak Hydropower		
Annual Average Capacity Factor (8 hours/day)	33%	
Price of off-peak electricity ($/kWhAC)	0.02-0.04	
Atmospheric pressure unipolar electrolyzer[c]		
Rated voltage	1.74 Volts	
Rated current density	250 mA/cm^2	
Max. operating current density	333 mA/cm^2	
Efficiency at max. op. voltage	85%	
Rectifier cost	$130/kWACin	
Rectifier efficiency	96%	
Installed AC plant capital cost @ max. operating cur. density	$371/kWACin	
Electrolyzer annual O&M cost	2% of capital cost	
Electrolyzer lifetime	20 years	
Energy Costs		
Off-peak electricity cost (cents/kWh)	2	4
Levelized cost of electrolytic hydrogen ($/GJ)	12	19

[a] It is assumed that off-peak hydroelectricity is available for 8 hours per day, and costs 2-4 cents/kWh

[b] It is assumed that the off-peak electricity is AC power, which is then rectified to DC for use in electrolysis. The rectifier efficiency is assumed to be 96%.

[c] Electrolyzer operating characteristics and costs are based on currently available unipolar technology. It is assumed that the rectifier is sized for maximum current density (Hammerli 1984; Leroy and Stuart 1978; Pirani and Stuart 1991; Stucki 1991). The maximum current density is taken to be 1.25 times the rated current density (Winter and Nitsch 1988; Steeb et.al. 1990).

comparison, hydrogen from off-peak hydropower costing 2-4 cents/kWh would cost $12-19/GJ (Table 11), and hydrogen from solar-thermal electricity, based on post-2000 projections, would cost $22-30/GJ (Table 12).

2.2. HYDROGEN FROM BIOMASS GASIFICATION

Hydrogen also can be produced by gasifying at high temperatures biomass feedstocks such as wood chips and forest and agricultural residues. The gasifier output, consisting mainly of hydrogen, carbon monoxide and methane can then be reformed and shifted to produce a mixture of hydrogen and carbon dioxide. The carbon dioxide is then removed, leaving hydrogen (Figure 2).

Biomass gasifiers have been demonstrated at the laboratory and pilot-plant scale. Several biomass gasifiers under development in the US, mainly for methanol production, are probably suitable for hydrogen production as well. All the equipment needed for converting the gasifier output to hydrogen -- methane reformers, shift reactors, CO_2-removal technology, and pressure-swing-adsorption technology for hydrogen purification -- is commercially available and widely used in the chemical process industries.

Table 13 gives cost and performance data for a biomass hydrogen plant processing 1650 dry tonnes of biomass per day and using the Battelle Columbus Laboratory gasification technology (Larson and Katofsky 1992). The cost of biomass hydrogen produced at 1000 psia would be $6.2-8.8/GJ, assuming a biomass feedstock cost of $2-4/GJ. Biomass hydrogen plants would probably exhibit considerable economies of scale and at smaller plants sizes hydrogen costs could be signficantly higher.

2.3. SUMMARY: PRODUCTION COST OF HYDROGEN FROM RENEWABLE RESOURCES

2.3.1. Cost Comparisons with Other Sources of Hydrogen

The cost of producing hydrogen from various renewable and fossil sources is summarized in Table 14 and Figure 3 for present, near-term and post-2000 technologies. As this table shows, the cost of renewable hydrogen is projected to decrease markedly over the next ten to twenty years.

At large scale (for plants producing 50 million scf of hydrogen per day) biomass hydrogen would cost about $6.2-8.8/GJ to produce, making it the least expensive method of renewable hydrogen production (Larson and Katofsky 1992; DeLuchi et al., 1991b; Phillips, 1990). Electrolytic hydrogen from wind, solar PV or off-peak hydropower would cost about twice as much, $12-27/GJ. However, because of their modular nature, electrolytic hydrogen systems could be employed at much smaller scale than biomass gasifiers. At small scales of production -- which one would expect at the beginning of a transition to hydrogen, or if environmental constraints limited the size of any one production area -- hydrogen from biomass might not enjoy any cost advantage over hydrogen from PV or wind electrolysis.

Projected costs for renewable hydrogen would be comparable to those of hydrogen produced from fossil feedstocks (Figure 4). At large scale,

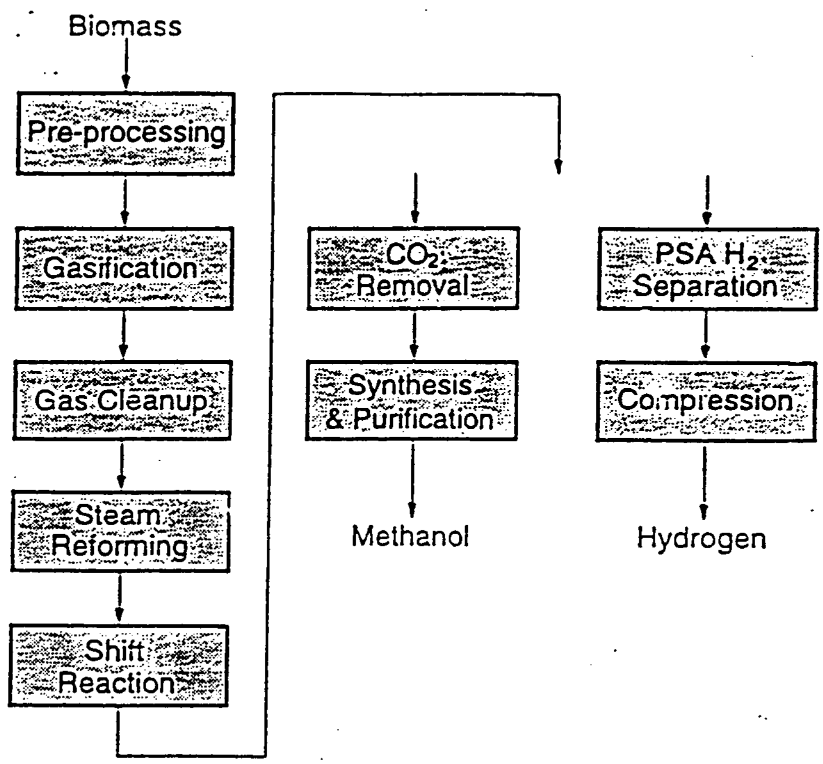


Figure 2. A biomass gasifier hydrogen production system

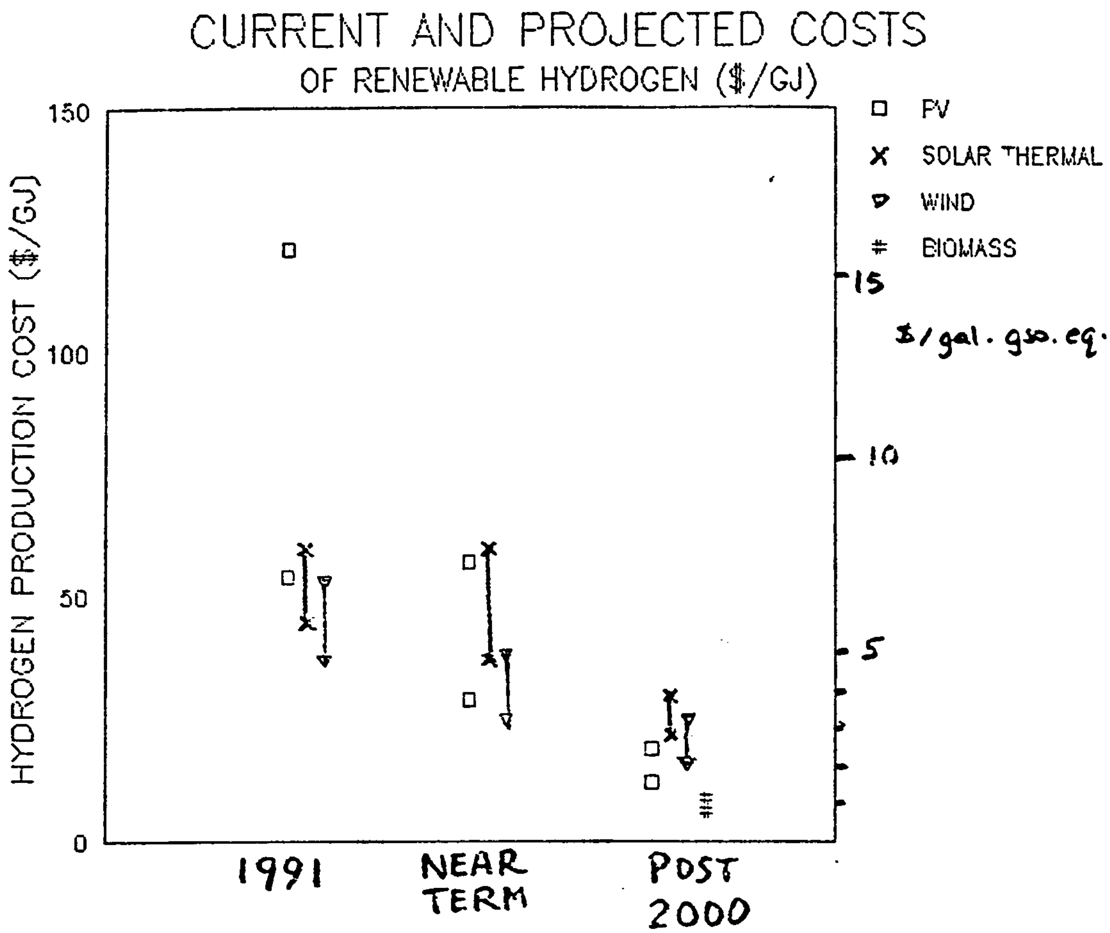


Figure 3. Estimated present, near term (1990s) and post-2000 production costs for renewable hydrogen

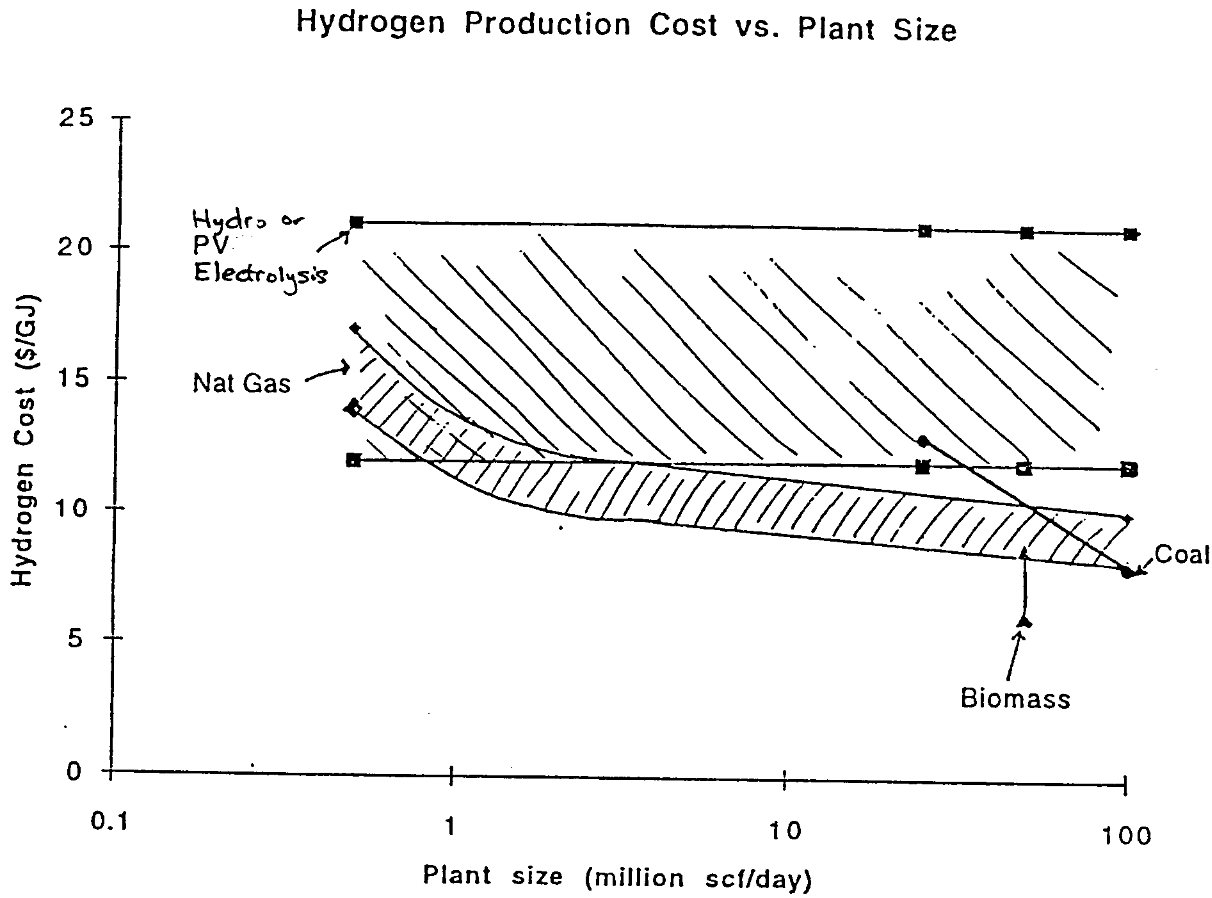


Figure 4. Production cost of hydrogen versus plant size.

Table 13. Production of hydrogen from biomass[a]

Dry tonnes biomass per day	1650
Biomass energy input (GJ/h)	1382
External electricity input (MWe)	18.2
Thermal conversion efficiency	
GJ-hydrogen out/GJ-energy in (biomass+elec)	70.0%
Plant lifetime (years)	25
Plant capacity factor	90%
Total investment cost (10^6 \$)	137
Working capital (10^6 \$)	10.1
Land (10^6 \$)	2.05
Cost of biomass (\$/GJ)	2-4
Variable operating costs excl. biomass (10^6 \$/year)	9.24
Biomass costs (10^6 \$/year)	21.8-43.7
Fixed operating cost (10^6 \$/year)	7.20
Levelized costs (\$/GJ)	
Capital	1.71
Labor, maintenance, chemicals	1.15
Purchased electricity	0.81
Biomass	2.57-5.15
Total	6.24-8.82

[a] Based on the Battelle Columbus Laboratory gasification technology (Larson and Katofsky 1992).

Table 14. Current and projected production costs of hydrogen[a] ($/GJ)[a]

	1991	Near Term	Post 2000
Renewable sources			
Electrolytic hydrogen (for plants producing 0.5 million scf/day (180 GJ))[b] from:			
Solar PV (SW US)	54-121	29-57	12-19
Wind (700 W/m²)			16
(500 W/m²)	37	25	21
(350 W/m²)	54	35	26
Solar thermal (SW US)	45-60	37-63	22-30
Off peak hydroelectricity[c]	12-19	12-19	12-19
Hydrogen from biomass gasification[d]			
Large plant (50 million scf/day)			6.2-8.8
Fossil sources			
Hydrogen from steam reforming of natural gas[e]			
Large plant (100 million scf/day)	6.1-8.1	6.1-8.1	8.1-10.1
Small plant (0.5 million scf/day)	11-14	11-14	14-17
Hydrogen from coal gasification[f]			
Large plant (100 million scf/day)	8	8	8
Medium plant (25 million scf/day)	13	13	13

[a] Levelized hydrogen production costs are given in constant 1989 US dollars.

[b] A hydrogen plant producing 180 GJ/day could provide enough energy to fuel about 1000 fuel cell fleet vehicles, each travelling 48,000 km/yr.

[c]Assuming that off-peak hydroelectricity at existing sites costs 2 to 4 cents per kWh.

[d]Assuming that the biomass feedstock costs $2 to 4 per GJ.

[e]Assuming that natural gas costs $2 to 4 per GJ in the 1990s and $4 to 6 per GJ beyond the year 2000, which is the range projected for the year 2000 for industrial and commercial customers.

[f] Costs for hydrogen from coal gasification are based the steam-iron process (Gregory et. al. 1980), assuming coal costs $1.78/GJ, which is the projected cost for the year 2000.

hydrogen from steam reforming of natural gas would cost \$6-10/GJ (assuming natural gas prices of \$2-6/GJ), comparable to hydrogen from biomass. At smaller scale (0.5 million scf/day or 200 GJ/day), steam reforming would cost about \$11-17/GJ, approximately competitive with solar or wind electrolysis. Coal gasification plants would also exhibit strong scale economies. For large plant sizes, hydrogen from coal would cost about \$8-13/GJ. At a given plant size, hydrogen from biomass gasification would probably be less expensive than hydrogen from coal gasification, because the plant would be less complex.

2.3.2. Cost Sensitivity Studies

The sensitivity of the cost of PV electrolytic hydrogen to changes in the PV and electrolyzer parameters is shown in Figure 5. The PV efficiency is the single most important factor in reducing the cost of PV hydrogen (Figure 6). Other important factors are the PV module manufacturing cost, the PV system lifetime, the PV balance of system cost, and the electrolyzer capital cost (Ogden, 1991).

Similarly, for electrolytic hydrogen from solar thermal electric or wind power, the cost of electricity is the largest factor determining the cost of hydrogen. The issues for low cost hydrogen production are basically the same as for low cost electricity production. For wind systems, it may be possible to reduce system costs, if the system were designed produce DC power to drive an electrolyzer, rather than to produce AC power for the grid.

For biomass hydrogen, feedstock costs are the largest single component of the hydrogen cost (Table 13). For low cost hydrogen from biomass, feedstock costs of \$2-4/GJ would be desirable. It is probable that these costs could be achieved in the future on high-yield plantations growing trees or other energy crops (Larson 1992).

3.0. POTENTIAL CONTRIBUTION OF RENEWABLE HYDROGEN TO FUTURE ENERGY SUPPLY

Unlike fossil fuels, which are unevenly distributed throughout the world, renewable hydrogen can be generated almost anywhere. Using one or more indigenous renewable resources, it would be possible, in principle, to produce large quantities of hydrogen in most parts of the world (Table 15). However, the contributions of various renewable sources of hydrogen to future energy supply will depend not only on the theoretically available resource base (Table 15), but on the land area and water required (Table 16), as well as other environmental effects of large scale renewable energy development and production.

3.1. ELECTROLYTIC HYDROGEN FROM HYDROPOWER

In theory, the global potential for electrolytic hydrogen from hydropower could be significant - 56 EJ per year. However, hydropower systems require large amounts of land and water (Table 16), and can have adverse environmental and social impacts (Moreira et. al., 1992). Moreover, resources are geographically limited to good sites (many of which

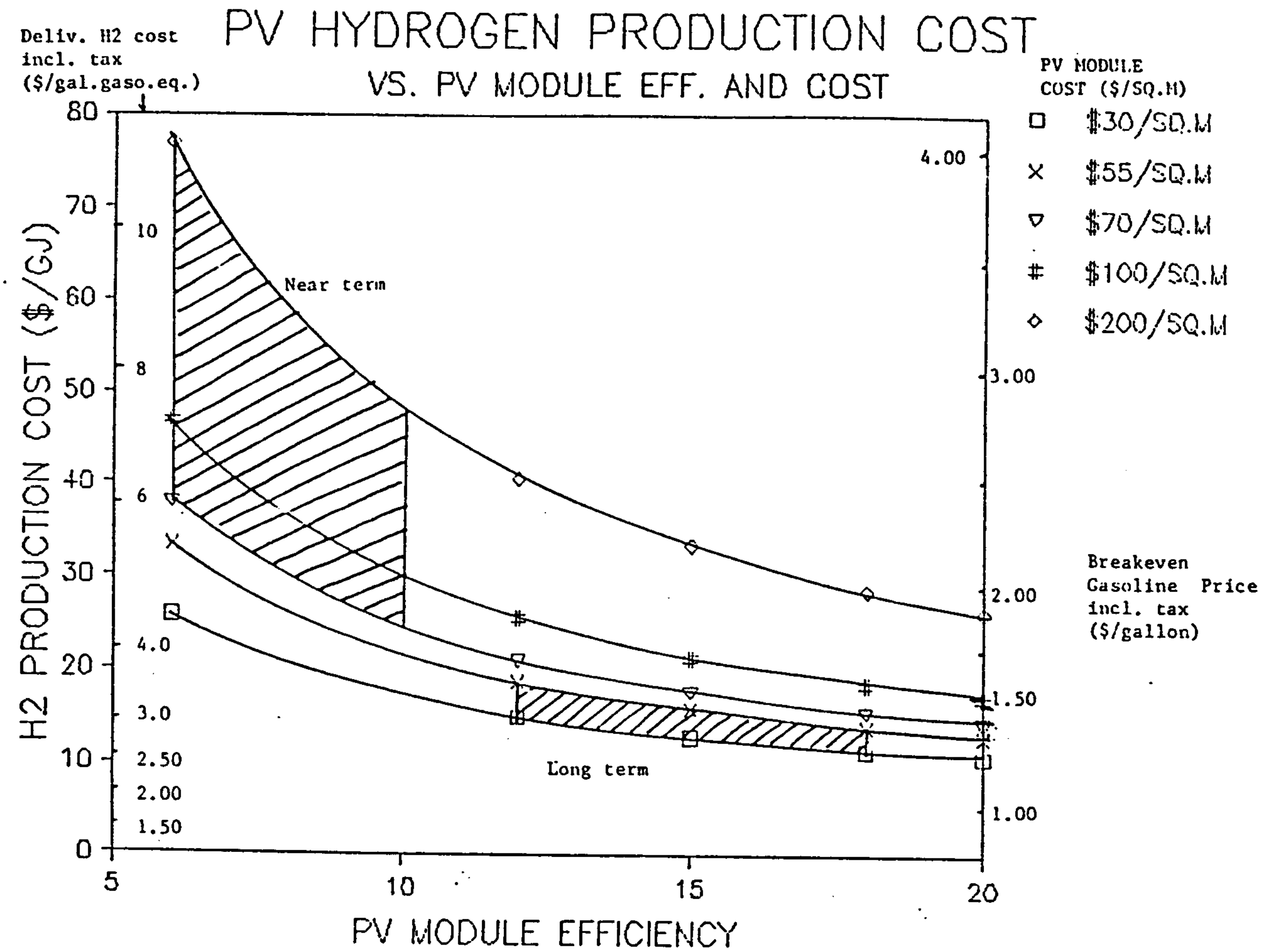
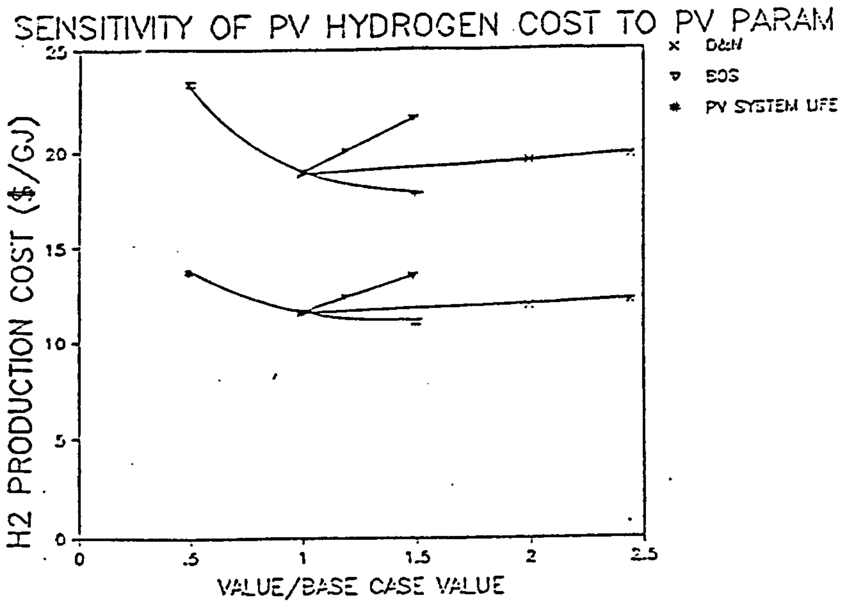


Figure 5a. Sensitivity of the PV hydrogen cost to PV parameters



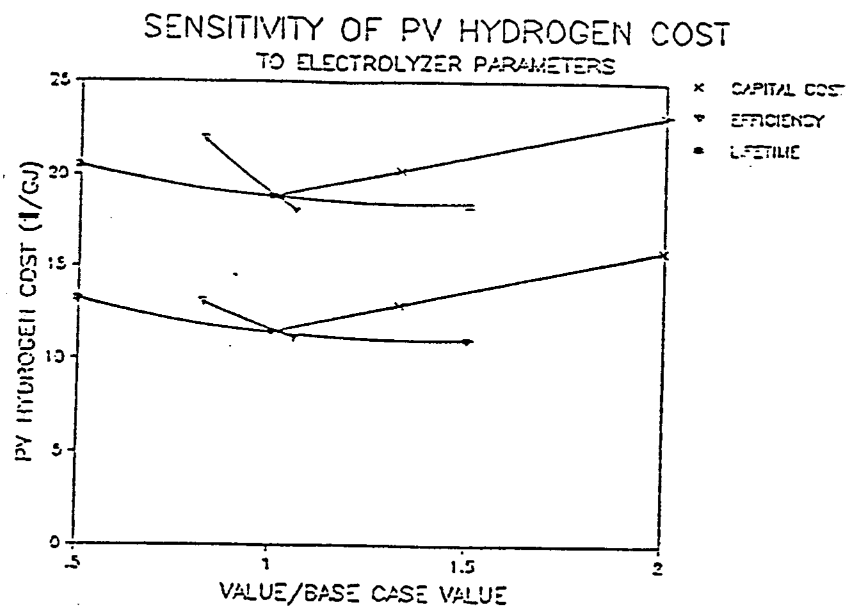


Figure 5b. Sensitivity of the PV hydrogen cost to electrolyzer parameters

Table 15. Potential Resources for Renewable Hydrogen Production[a]

Region	Electrolytic Hydrogen From: Technically Useable Hydro EJ H_2/yr	Total Wind Potential EJ H_2/yr	PV on 1% Land Area EJ H_2/yr	Biomass H2 Produced on 10% of Forest, Woods, Cropland, EJ H_2/yr
Africa	9.1	257	128	18
Asia	15.5	68	103	21
Australia	1.1	75	47	5
N America	9.1	308	94	17
S/C America	11.0	122	77	24
Europe+former USSR	10.6	366	130	24
World	56.3	1196	579	113

Table 16. Land and water requirements per unit of hydrogen energy production

	Land requirements hectares/MWe,peak	Land requirements m^2/(GJ/yr)	Water requirements liters/GJ (HHV)
Electrolytic hydrogen from:			
PV[a]	1.3	1.89	63
Solar Thermal Electric[b]	4.0	5.71	63
Wind[c]	4.7-16	6.3-33	63
Hydroelectric[d]	16-900	11-500	>>63
Biomass Hydrogen [e]	-	50	37,000-74,000

Land requirements (10^6 km^2) to produce hydrogen equivalent in energy to:

from:	Present: US Light Duty Vehicles if powered by fuel cells (4.8 EJ)	Present: US Oil (34 EJ)	Present: World Oil (115 EJ)	Present: World Fossil Fuel (300 EJ)	Projected World Non-Electric Fuel Demand (IPCC)[f] 2025 (286 EJ)	Projected World Non-Electric Fuel Demand (IPCC)[f] 2050 (289 EJ)
PV	0.008	0.079	0.268	0.700	0.667	0.674
Wind	0.13	0.87	2.9	7.7	7.3	7.4
Biomass	0.23	2.2	7.6	19.8	18.9	19.0

Global land area = 137 million km^2
U.S. land area = 7.8 million km^2

Notes to Table 16:

[a] It is assumed that a fixed, flat plate PV system is used, with array spacing so that 1/2 the land area is covered by arrays. The efficiency of the PV array is assumed to be 15%, the DC electrolyzer efficiency is taken to be 80%, based on the higher heating value of hydrogen, and the coupling efficiency between the PV array and the electrolyzer is taken to be 96%. Annual energy production is given for a Southwestern US location with average annual insolation of 271 Watts/m^2. Water requirements are for electrolyzer feedwater.

[b] Land use is estimated for a parabolic trough system, assuming that the efficiency (percentage of the solar energy falling on the collector area that is converted to electricity) is 10%, and that 1/4 of the land area is covered by collectors. (Land use per MW would be similar for central receiver or dish systems.) An electrolyzer with AC efficiency of 79% is used, and the coupling efficiency of the solar thermal electric plant and the electroilyzer is assumed to be 96%. Annual energy production is given for a Southwestern US location with average annual insolation of 271 Watts/m^2. Water requirements are for electrolyzer feedwater only. If wet cooling towers were used for cooling the steam turbine condensors, there would be substantial water losses. The steam turbine would also consume some water during operation.

[c] It is assumed that an array of 33 meter diameter 340 kW wind turbines is used. For areas with a unidirectional or bidirectional wind resource (as in some mountain passes), the wind turbine spacing could be 1.5 diameters in the direction perpendicular to the prevailing wind and 10 diameters in the direction parallel to the prevailing wind (Smith 1991), without interference losses. In this case, the land use would be 4.7 hectares per MW of electric power. For areas with more variable wind direction (such as the Great Plains), the spacing would be 5 diameters by 10 diameters, with a land use of 16 hectares/MWe. An electrolyzer with an AC efficiency of 79% is used. Coupling efficiency between the wind turbine and the electrolyzer is assumed to be 96%. The wind turbine capacity factor is assumed to be 26%, corresponding to a Class 4 site, with hub height of 50 meters. Water requirements are for electrolyzer feedwater.

[d] Land use for hydroelectric power varies greatly depending on the location. The range shown is for large projects in various countries (WEC 1980). Water requirements are for electrolyzer feedwater only. Evaporative losses at the reservoir would probably be much greater than feedwater consumption, depending on the site.

[e] It is assumed that biomass productivity of 15 dry tonnes/hectare/year is achieved, and that the biomass has a higher heating value of 19.38 GJ/dry tonne. The energy conversion efficiency of biomass to hydrogen via gasification in a Battelle Columbus Laboratory gasifier is assumed to be 70.0%. Water use is based on a rainfall of 75-150 cm per year needed to achieve a biomass productivity of 15 dry tonnes/hectare (D.O. Hall et.al., 1992).

[f] Projections are from the IPCC accelerated policy scenario (IPCC 1990).

are already developed). These factors will limit hydropower to a fraction of the technically useable potential, and the global contribution of hydro to a hydrogen energy system would be relatively small. Still, because of its low cost, off-peak hydropower at existing sites might offer an opportunity to help launch electrolytic hydrogen as an energy carrier.

3.2. BIOMASS HYDROGEN

Today, energy could be derived from a variety of biomass feedstocks including residues from the agricultural and forest products industries, urban wastes, and wood derived from better management of existing commercial forests. In the future bioenergy plantations might be developed, using fast growing trees or energy crops. Biomass is likely to be used for generating electricity before it is used for making transportation fuels. By the time biomass hydrogen was produced on a large scale, many of the currently available feedstocks, such as residues or urban wastes, might already be committed to fueling electric plants. Depending on the demand for fuel and the available resources, it might become neccessary to develop biomass plantations, if biomass transportation fuels were produced on a large scale (DeLuchi et.al 1991; Johansson et. al 1992).

The global potential for hydrogen production from biomass plantations could be substantial (see Table 15). However, land and water requirements would be much larger than for solar or wind electrolysis systems (Table 16). To produce an amount of hydrogen equivalent in energy to global oil use today (115 EJ/yr), an amount of land equal to about 10% of the total land area presently committed to forest, woodland and crop land would have to be developed as biomass plantations, assuming that an average productivity of 15 dry tonnes of biomass per hectare per year could be achieved.

Although the land requirements for biomass plantations would be large, there are vast areas of currently unproductive agricultural or deforested land which might be reclaimed for bioenergy. For example, if all the degraded lands in developing countries suitable for reforestation (nearly 8 million km^2) could be developed for biomass hydrogen, about 159 EJ per year could be produced. Biomass might also make a significant contribution in the industrialized countries. Excess cropland within the European Economic Community (some 15 million hectares) could produce about 3.0 EJ of hydrogen per year, and from 30 million hectares of idled cropland in the US, about 5.9 EJ of hydrogen could be produced.

It is clear that land and water requirements will be important issues in the develoment of biomass energy supplies. However, pressure on biomass supplies could be reduced by using energy as efficiently as possible. Indeed, if biomass hydrogen is to play a large role in meeting transportation energy needs, development of highly efficient end-use technologies such as fuel cell vehicles is essential (DeLuchi 1992; Johansson et. al 1992).

In addition to land requirements, the large-scale production of biomass for energy could give rise to a range of other environmental concerns, including use of herbicides and pesticides. It is important that future bioenergy systems be developed in a sustainable fashion (Audubon 1991).

3.3 HYDROGEN FROM WIND POWER

Wind power is a large and widely distributed resource, that would require less land and much less water than biomass (see Tables 15 and 16). In practice, only a fraction of the global wind electrolytic hydrogen potential of almost 1200 EJ per year (see Table 16) could be developed because of rugged terrain and competing uses for land. [For example, in the US, only about 3/4 of the potential wind resource could be developed, if environmental restrictions are applied (Elliott 1990.)] Even with restrictions, however, wind resources would far exceed local electricity demands in many places, and the wind hydrogen potential would be large.

To supply an amount of hydrogen equivalent to current fossil fuel use (300 EJ) would require 6% of the world's land area. If all light duty vehicles in the U.S. were replaced with hydrogen fuel cell vehicles, the projected hydrogen demand (based on projected driving levels in 2010) would be about 4.8 EJ/year. This amount of wind hydrogen could be produced on about 2% of the US land area. Wind hydrogen plants would require only about 2/3 the land areas required for biomass hydrogen. And only a small portion of the total wind farm area would be taken up by the footprints of the turbine towers. The rest of the area might be used for farming or grazing.

3.4 HYDROGEN FROM SOLAR PV

Although PV hydrogen would be more expensive than hydrogen from biomass, it is by far the most widely available and least constrained resource. PV hydrogen could be produced wherever there was adequate insolation. Moreover, PV land requirements would be much lower than for any other option, about 1/30th those for biomass. Enough PV hydrogen to meet the world's foreseeable fuel needs could be produced on about one half of a percent of the earth's land area (2% of the global desert area) (Table 16). If all light duty vehicles in the US were converted to fuel cells, the PV hydrogen requirement could be met with only about 0.1% of the US land area (or about 1% of the US desert area). Because PV systems are modular, small systems might be built on top of buildings, garages or storage areas, with no additional land requirement.

3.5. WATER REQUIREMENTS FOR RENEWABLE HYDROGEN PRODUCTION

The water requirements for electrolytic hydrogen production are modest, and electrolytic hydrogen could be produced even in deserts. Typically, a few percent of the annual rainfall falling on the area covered by a solar hydrogen plant would be sufficient to supply feed water for electrolysis. For example, the annual water consumption of a PV-hydrogen plant corresponds to 2.7 cm of rain per year over an area equal to the plant size, which amounts to only 14 % of the annual rainfall in El Paso, one of the most arid places in the U.S. (Ogden and Williams 1989). Alternatively, it would be possible to produce electrolyzer feedwater by desalination of sea water. [Desalination would require only about 1-2% of the hydrogen energy (Winter and Nitsch, 1988).]

In contrast, achieving a biomass productivity of 15 dry tonnes per hectare per year would require rainfall of 75 to 150 cm per year (D. Hall et.al 1992).

3.6. RENEWABLE HYDROGEN POTENTIAL IN THE UNITED STATES

The renewable hydrogen potential for the United States is illustrated in Table 17. Locally significant resources [defined here as 0.1 EJ/year (enough to fuel several million fuel cell vehicles) or more] are shown in boldface. In most states, the PV resource is the largest and is locally significant, although in some Great Plains states, wind power resources are dominant. In the rightmost column of Table 17 (and in Figure 6), the statewide renewable hydrogen potential is compared to the projected 2010 statewide energy requirement for all light duty vehicles, assuming they were converted to hydrogen fuel cells. It would be possible to produce enough renewable hydrogen fuel locally for statewide transportation needs in all but 4 states. Because renewable hydrogen could be produced almost anywhere in the US long distance pipelines might not be necessary. Instead the best local resource could be used.

Land and water requirements would be relatively modest (Figure 7). With PV electrolysis alone it would be possible to supply enough hydrogen for all light duty vehicles in the US using only 0.1% of the contiguous US land area (1% of the US desert area). Alternatively,hydrogen could be produced from wind power on 2% of the US land area (1/8 of the total wind resource) or from biomass on 3% of the US land area (or about 2/3 of currently idled cropland). Although Figure 7 shows hydrogen production systems as large centralized plants, in practice, many small systems would be built.

4.0. CASE STUDY: HYDROGEN FUEL CELL AUTOMOBILES

Once hydrogen is produced, it must be stored, transported, distributed and delivered to the user in the desired form. Many options are available for storing and transporting hydrogen as a gas or a liquid or in the form of hydrogen bearing energy carriers such as hydrides or methanol. The end-use has a strong influence on how these steps are best accomplished. Here we present a case study of how renewable hydrogen might be used in fuel cell vehicles.

4.1. BACKGROUND

It is becoming increasingly likely that over the next ten to twenty years, significant opportunities could open to introduce hydrogen as a clean transportation fuel. In particular, the California Air Resources has mandated that starting in 1998 2% of all passenger cars and light

Table 17. Potential for Solar Hydrogen Production in the United States[a]

State	Hydrogen (EJ/yr) from Hydroelectric[b] off-peak	undevel.	Biomass[c]	Wind[d]	Solar PV[e]	ratio of total H2 potential to state energy use for transport with FCVs[f]
Alabama	0.018	0.005	0.042	0	**0.810**	6.4
Arizona	0.015	0.021	0	0.029	**2.414**	21.4
Arkansas	0.007	0.012	0.018	0.064	**0.831**	10.9
California	0.056	0.096	0.015	0.171	**2.770**	3.5
Colorado	0.003	0.021	**0.159**	**1.396**	**2.020**	35
Connecticut	0.001	0.002	0	0.015	0.060	0.8
Delaware	0	0.002	0.0001	0.006	0.024	1.3
Florida	0.0003	0.0004	0.010	0	**0.816**	2.0
Georgia	0.013	0.010	0.054	0.003	**0.823**	3.7
Idaho	0.014	0.066	0.064	**0.212**	**1.315**	51
Illinois	0.0002	0.003	0.054	**0.177**	**0.79**	3.1
Indiana	0.0006	0.0007	0	0	**0.478**	2.7
Iowa	0.0008	0.004	**0.161**	**1.600**	**0.794**	28
Kansas	0.00001	0.001	**0.233**	**3.106**	**1.450**	55
Kentucky	0.005	0.011	0.035	0	**0.562**	4.8
Louisiana	0	0.004	0.012	0	**0.671**	4.9
Maine	0.004	0.025	0.004	**0.163**	**0.385**	12.8
Maryland	0.003	0.002	0.001	0.009	**0.131**	1.0
Massachusetts	0.002	0.003	0	0.073	0.097	1.0
Michigan	0.003	0.005	0.016	**0.189**	**0.757**	3.3
Minnesota	0.001	0.003	**0.150**	**1.907**	**1.057**	22
Mississippi	0	0.001	0.060	0	**0.712**	9.2
Missouri	0.003	0.008	**0.122**	**0.151**	**1.039**	7.2
Montana	0.014	0.032	**0.222**	**2.961**	**2.190**	182
Nebraska	0.002	0.003	**0.111**	**2.520**	**1.223**	73
Nevada	0.005	0.0004	0.0003	**0.145**	**2.240**	50
New Hampshire	0.003	0.005	0	0.012	**0.104**	0.3
New Jersey	0.0001	0.0006	0.00007	0.029	0.093	0.5
New Mexico	0.0004	0.0006	0.039	**1.263**	**2.473**	69
New York	0.026	0.016	0.005	**0.180**	**0.546**	2.1
North Carolina	0.012	0.013	0.012	0.020	**0.693**	3.3
North Dakota	0.003	0.004	**0.256**	**3.512**	**1.002**	195
Ohio	0.0008	0.002	0.020	0.012	**0.509**	1.6
Oklahoma	0.005	0.007	0.093	**2.105**	**1.217**	31
Oregon	0.036	0.036	0.042	**0.125**	**1.441**	19
Pennsylvania	0.005	0.020	0.008	**0.131**	**0.557**	2.2
Rhode Island	0.00005	0.0001	0	0.003	0.013	0.6
South Carolina	0.008	0.010	0.021	0.003	**0.455**	4.0
South Dakota	0.010	0.005	**0.169**	**2.99**	**1.212**	168
Tennessee	0.014	0.004	0.025	0.006	**0.584**	3.9
Texas	0.004	0.020	**0.319**	**3.454**	**4.412**	13.8
Utah	0.001	0.015	0.019	0.070	**1.600**	33

Vermont	0.002	0.004	0.00001	0.014	**0.107**	6.4
Virginia	0.005	0.011	0.007	0.035	**0.563**	3.0
Washington	**0.142**	0.070	0.080	0.096	**0.825**	8.9
West Virginia	0.001	0.017	0.00006	0.015	**0.299**	5.6
Wisconsin	0.003	0.004	0.049	**0.163**	**0.675**	6.3
Wyoming	0.002	0.015	0.021	**2.168**	**1.719**	184
Total	0.455	0.660	2.76	31.30	47.56	10.4

[a] Locally significant resources (defined here as 0.1 EJ per year or more) are highlighted in boldface type.

[b] The off-peak hydroelectric potential for hydrogen production is estimated assuming that power equal to the installed capacity in each state could be available 25% of the time for off-peak hydrogen production. It is assumed that all the undeveloped hydropower is devoted to hydrogen production. An AC electrolyzer effciency of 79% is assumed. Hydropower capacity (existing and undeveloped) are from the Federal Energy Regulatory Commission.

[c] The biomass potential is based on lands held in the Conservation Reserve Program, which could be reforested with biomass plantations. It is assumed that biomass productivity of 15 dry tonnes per hectare per year is achieved, and that the biomass has a higher heating value of 19.38 GJ per dry tonne. The higher heating value efficiency of converting biomass to hydrogen via gasification is assumed to be 70%. An additional amount of idled cropland would be available for biomass plantation development. Other sources of biomass such as residues and urban waste are not taken into account. They might add about 6-8 EJ nationally, if they were available (SERI 1990).

[d] The wind energy available in each state is estimated for Class 3 and higher wind resources, assuming that 100% of urban and environmentally sensitive land, 50% of forest land and 30% of argicultural land are excluded (Elliot 1990). An AC electrolyzer effciency of 79% is assumed. The hydrogen produced is:

Wind Class	Hydrogen (EJ/yr)	Land Use (km^2)	% Contiguous US Land area
Class 3	15.2	579449	7.5%
Class 4	14.0	415117	5.4%
Class 5	0.9	27944	0.4%
Class 6	0.9	17203	0.2%
Class 7	0.2	273	0.003%
Total Wind Class 3-7	31.2	1041842	13.6%

[e] The PV hydrogen produced on 1% of the state area is estimated based on the annual average solar resource in each state. A DC electrolysis efficiency of 84% is assumed, with 93% coupling efficiency for the PV array and electrolyzer.

[f] Here the total renewable hydrogen potential in each state is compared to the energy which would be used for light duty vehicles in that state, based on projections for 2010 driving levels, if gasoline light duty vehicles were replaced by fuel cell vehicles with three times greater efficiency.

trucks sold in the state must be zero emission vehicles (ZEVs). By 2001, 5% of light duty vehicles must be ZEVs and by 2003, 10% (CARB, 1991). The only vehicles which could be developed in this time frame to rigorously meet the ZEV standards are fuel cell vehicles run on hydrogen and electric battery vehicles. (Although methanol fuel cell vehicles would not be ZEVs, because the reformer would emit some CO and NOx, emissions would be close to zero, only about 1% those of a comparable gasoline powered car.) Hydrogen fuel cell cars could offer potential advantages as compared to other zero emission or near zero emission vehicles.

- o Because hydrogen storage is less heavy and bulky than advanced electric batteries, the range of a hydrogen fuel cell vehicle would probably be longer.

- o High pressure gas cylinders could be refueled in several minutes, as compared to several hours for recharging electric batteries.

- o Hydrogen could be produced from a variety of widely available renewable sources such as PV and wind, which are much less geographically constrained and potentially larger than biomass. With methanol, biomass is the only renewable energy source which could be used.

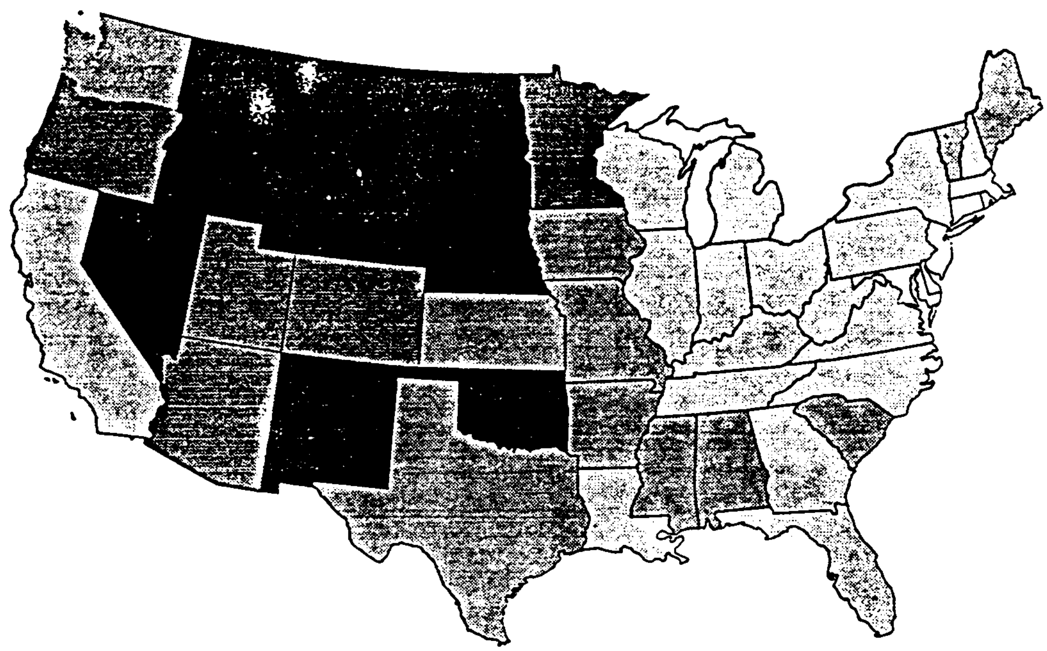
4.2. DELIVERING GASEOUS HYDROGEN FOR USE IN FUEL CELL AUTOMOBILES

Here we estimate the cost of delivering gaseous hydrogen for use in fuel cell vehicles. (Gaseous hydrogen was chosen for reasons discussed below.) The costs of hydrogen compression and storage at the production site (which would be neccessary to level the output of PV or wind electrolyzers), pipeline transmission (if required), local distribution costs and filling station costs are estimated. Because, components of gaseous hydrogen delivery systems (compressors, compressed gas storage systems, pipelines) exhibit considerable economy of scale, costs are calculated for three system sizes (Table 18, Figure 8, see Appendix E for details of the calculations):

* A 10 MW PV or wind hydrogen electrolysis "demonstration" system, producing 0.5 million scf of hydrogen per day supplies transportation fuel for a centrally refueled fleet of 1000 fuel cell cars. Hydrogen is compressed for storage in above ground compressed gas cylinders. Hydrogen fuel cell fleet vehicles with compressed gas storage are refueled onsite from high pressure cascades. Compression adds about $2.4/GJ, storage about $1.4/GJ, and filling station equipment $2.5/GJ, so that delivery adds a total of about $6/GJ to the cost of hydrogen.

* A 750 MW "city supply" system produces about 50 million scf/day of hydrogen, enough to fuel fleet of 300,000 fuel cell passenger cars. Here hydrogen could be produced via PV or wind electrolysis or biomass gasification. For intermitttent systems hydrogen is compressed to 750 psia and stored in underground rock caverns to level the plant output. Compression and storage would not be required for biomass plants, which would operate continuously. Hydrogen is fed into a city gas network and

RENEWABLE H_2 RESOURCES FOR TRANSPORTATION

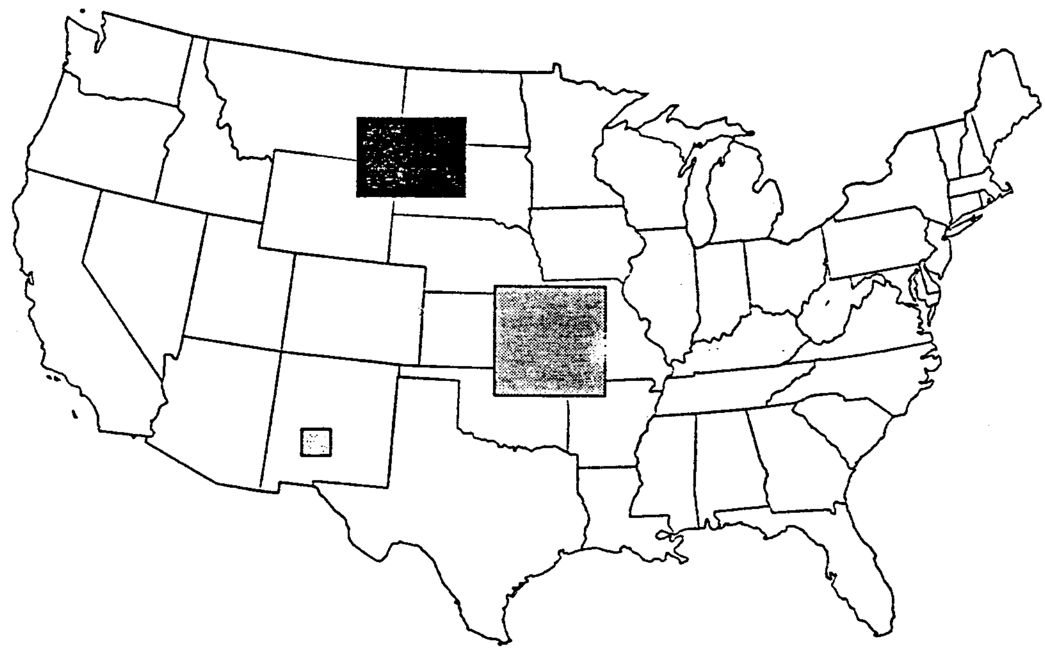


	H_2 (EJ/YR)
HYDRO	1.0
BIOMASS	6.0
WIND	31.0
PV	48.0
TOTAL	86.0

$\frac{H_2 \text{ SUPPLY}}{\text{FCV DEMAND}}$
<1
1–3
3–10
10–30
>30

Figure 6. Ratio of renewable hydrogen resources to demand for hydrogen transportation fuel for each state.

LAND AREA TO SUPPLY U.S. CARS AND LIGHT TRUCKS (4.8 EJ/YR)



	% U.S. LAND AREA	
PV	0.1%	1% U.S. DESERT AREA
WIND	2.0%	15% ENVIRON. DEVEL. U.S. WIND
BIOMASS	3.0%	70% IDLED CROPLAND

Figure 7. Land areas needed to produce renewable hydrogen for fuel cell vehicles, if the only source is PV, wind or biomass.

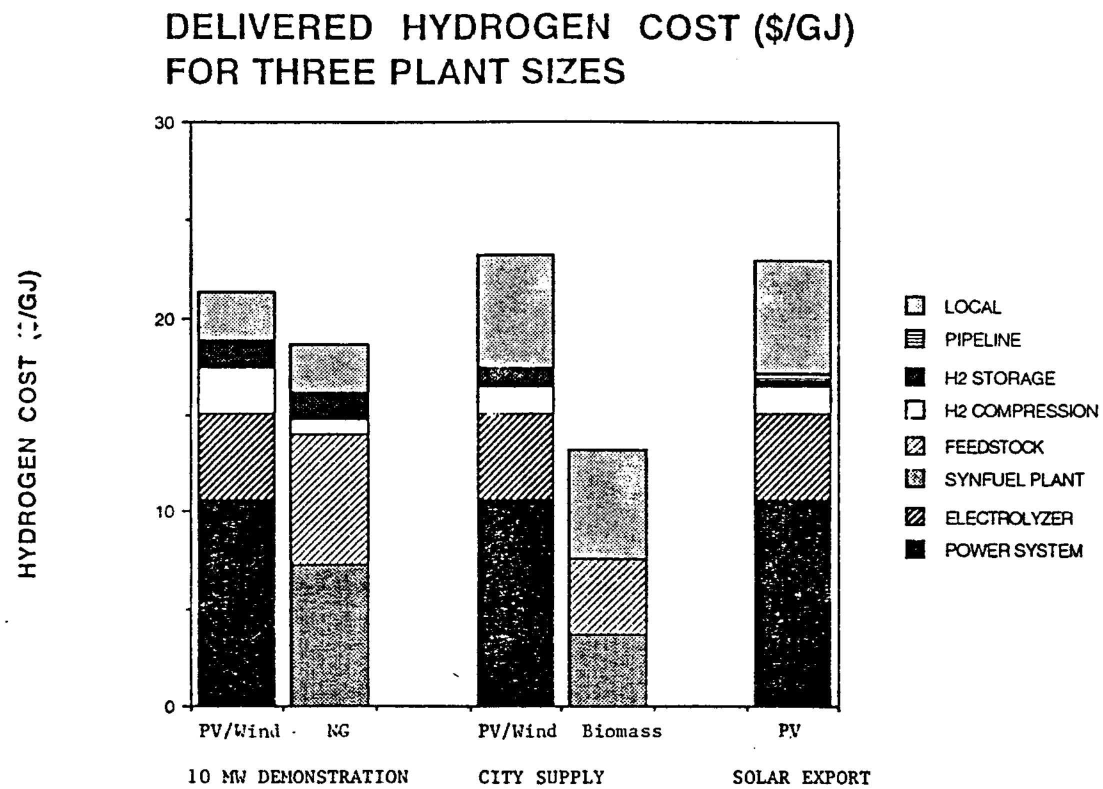


Figure 8. Delivered cost for hydrogen transportation fuel.

Table 18. Delivered Cost of Hydrogen Based on Post-2000 Projections[a]

	Demonstration 10 MWp		City supply 750 MWp			Solar export 75 GWp
	PV	Wind	PV	Wind	Biomass	PV
Capital costs	(millions)		(billions)			(billions)
Power system	5-11	7.5	0.4-0.8	0.6	0.14	40-80
Electrolyzer	2.3	3.7	0.17	0.28		17
Compressor	0.43	0.41	0.02	0.02		1.0
Storage	0.73	0.97	0.04	0.04		1.1
Pipeline	-	-	-	-		1.9
Filling Station	0.5	0.5				
TOTAL	9.2-14.8	13.1	0.6-1	1.0	0.14	60-100
Contributions to hydrogen cost ($/GJ)						
Power System	7.0-14.2	12.8	7.0-14.2	12.8	6.2-8.8	7.0-14.2
Electrolyzer	4.5	6.4	4.5	6.4		4.5
Compression	2.4	2.2	1.4	1.4		1.4
Hydrogen storage	1.4	1.6	1.0	1.0		0.3
Pipeline (1000 mi)	-	-	-	-		0.4
Local Distribution	-	-	0.5	0.5	0.5	0.5
Filling Station	2.5	2.5	5.2	5.2	5.2	5.2
Cost of hydrogen to consumer at filling station						
($/GJ)	17.8-25.0	25.5	19.6-26.8	27.3	11.9-14.5	19.3-26.5
($/GAL.GASO.)	2.32-3.27	3.34	2.55-3.49	3.56	1.55-1.89	2.52-3.46
Breakeven gaso. price w/tax ($/gallon)	1.29-1.60	1.63	1.37-1.68	1.70	1.03-1.14	1.35-1.67
Land used by power system	(hectares)		(km^2)			(km^2)
	12-19	47-160	9-14	35-120	367	900-1400
Energy delivered per year	66,000	76,000 GJ	5 MILLION	7 MILLION GJ		0.5 EJ
Vehicles fueled	1000[b]		300,000[c]			30 MILLION[c]

[a] Costs and performance for PV and wind electrolysis systems are taken from Tables 9 and 10. Hydrogen costs are based on the higher heating value.

[b] For fleet vehicles with efficiency equivalent to 60 mpg gasoline, driven 48,000 km per year.

[c] For passenger vehicles with efficiency equivalent to 60 mpg gasoline, driven 16,000 km per year.

and piped a short distance to about 100 filling stations for passenger cars. Here scale economies reduce compression costs to $1.4/GJ and and storage costs to $1.0/GJ, but local distribution costs of $0.5/GJ and filling station costs of $5.2/GJ must be added, so that delivery adds about $8/GJ to the cost of hydrogen.

* A 75 GW "solar export" PV hydrogen system produces fuel for long distance pipeline transmission to serve 30 million fuel cell vehicles. Hydrogen is stored in depleted gas fields or aquifers, compressed to 1000 psia for pipeline transmission 1000 miles. Local distribution to filling stations occurs at the end of the pipeline. Here, scale economies further reduce storage costs, but long distance pipeline costs must be added, so that delivery adds about $8/GJ to the hydrogen cost.

The total delivered cost of PV or wind hydrogen is about $18-27/GJ (a cost of energy equivalent to about $2.3-3.6/gallon of gasoline), and would be approximately independent of production scale. For biomass hydrogen produced in a "city supply" system, delivered costs would be $12-15/GJ ($1.6-1.9/gallon gasoline). For small, stand-alone fuel production systems, the delivered cost of PV hydrogen would be about the same as that of hydrogen from onsite reforming of natural gas (Table 19, Figure 8). At "city supply scale," the delivered cost of hydrogen from biomass could compete with the cost of hydrogen from centralized, large scale reforming of natural gas (Figure 4).

4.3. ASSESSMENT OF HYDROGEN FUEL CELL VEHICLES

In a fuel cell electric vehicle (FCEV), a hydrogen-air fuel cell provides electricity to an electric drive train similar to those used in battery powered electric vehicles (Lemmons 1990; SAE 1991). Hydrogen fuel can be stored directly (as a compressed gas or hydride), or in the form of methanol, which is reformed onboard the vehicle to produce hydrogen (Figure 9). In some designs peak power demands are met by a small supplemental battery or an ultra-capacitor.

Several types of fuel cells have been proposed for transportation (Table 20). Recent studies by our group (DeLuchi 1992; DeLuchi and Ogden 1992) have modelled fuel cell vehicles, based on the proton exchange membrane (PEM) fuel cell, which offers high power density, quick start-up time, modest operating temperature (100°C) and the potential to reach low costs in mass production. PEM fuel cells are now being developed and should be commercially available within a few years (Prater 1991). A number of fuel cell vehicle demonstration projects are underway (Table 21), and it is expected that several experimental PEM fuel cell vehicles will be tested over the next few years. For supplemental peak power, DeLuchi's model used a bipolar lithium iron disulfide battery, a promising technology now under development, which has the high power density needed for peak power. Several other advanced batteries would have similar costs and energy densities. Compressed hydrogen gas cylinders (at 8000 psia) were chosen for hydrogen storage because they are simple, commercially available, and can be refilled quickly. Various energy storage systems are compared in Table 22. Although compressed hydrogen would have a much lower

Table 19. Delivered cost of solar hydrogen from small plants c.2000[a]

	Electrolysis 10 MWp PV	Electrolysis 10 MWp Wind	Electrolysis 10 MWp Hydro	Steam reforming of natural gas	
Capital costs (10^6 $)					
Power system	5-11	8.5	-	2.1	Reformer plant
Electrolyzer	2.3	4.0	4.0	-	
Compressor	0.5	0.5	0.5	0.1	Compressor
Storage	0.9	0.9	1.3	0.9	Storage
Filling Station	0.5	0.5	0.5	0.5	Filling Station
TOTAL	9-15	14.4	6.3	3.6	TOTAL
Contributions to hydrogen cost ($/GJ)					
Power System	7-14	13.6	-	5.0	Plant capital
Electrolyzer	4.4	5.9	5.2	2.3	O&M
Compression	2.3	2.3	1.1	0.8	Compression
Hydrogen storage	1.4	1.4	1.4	1.4	Storage
Filling Station	2.5	2.5	2.5	2.5	Filling Station
				5.4-8.1	Natural gas
Cost of hydrogen to consumer at station					
($/GJ)	17.8-25.0	25.5	17-24	17-20	
($/GAL.GASO.)	2.5-3.6	3.7	2.4-3.5	2.4-2.7	
Breakeven gasoline price w/tax ($/gallon)	1.29-1.60	1.63	1.25-1.56	1.25-1.38	
Land used by power system (hectares)	12-19	47-160			
Energy delivered/yr	----------- 70-90,000 GJ -------------				
Vehicles fueled[b]	1200	1200	1600	1000	

[a]Costs and performance for PV and wind electrolysis systems are taken from Tables 9 and 10. Costs are given in 1989 $. Hydrogen costs are computed based on the higher heating value. Estimates of the number of hydrogen fuel cell cars assume an efficiency equivalent to 60 miles per gallon gasoline.

[b]Fuel cell fleet vehicles with an efficiency equivalent to 60 miles per gallon gasoline, driven 48,000 km/yr.

Table 20. Characteristics of fuel cells for transportation.[a]

Type of fuel cell	Status[b] (1991)	Specific power[c] (kW/kg)	(kW/l)	Operating temp. (°C)	Contam. by	Start-up time (min)
Phophoric Acid	CA	0.12	0.16	150-250		300
Alkaline	CA	1.49	1.47	65-220	CO, CO_2	120-720
Proton exchange membrane	D	1.33	1.20	25-120	CO	5
Monolithic solid oxide	L	8.3	4.0	700-1000		100

[a] Adapted from (DeLuchi and Ogden, 1992).

[b] CA = commercially available, D = prototype, L = laboratory.

[c] Specific power includes only the fuel cell stack, but no auxiliaries.

FUEL CELL VEHICLE DEMONSTRATIONS

USA

Energy Partners: "Green Car" PEM fuel cell, compressed H2 gas

USDOE: 3 PAFC fuel cell.buses under development for 1993. MeOH reformed onboard to make H2

USDOE/GM: Program to demonstrate PEM fuel cell car by 1996. MeOH is planned for first vehicle, altho other forms of H2 storage will be explored

State of Illinois: Plans to demonstrate PAFC bus fueled with ethanol.

SCAQMD: Funding research on hydrogen vehicles and solar hydrogen. Has proposed Ad Hoc Coalition for Fuel Cells for Transportation

CANADA

Ballard Technologies: PEMFC bus, with comp. H2 storage, due 1993

BELGIUM

Elenco: Alkaline fuel cells test bus operated.

OTHER R&D EFFORTS

USA

Ford Motor Company studying prospects for FCEVs

GERMANY

Siemens : Research on fuel cells for transportation
Daimler-Benz: R&D on fuel cells for transportation

JAPAN: Extensive program in fuel cells for utilities. Several companies show interest in fuel cell vehicles. Mazda H2-O2 PEM fuel cell "golf cart"

Table 22. Onboard energy storage systems for automobiles[a]

Hydrogen storage systems

Storage system	Installed energy density[b] (MJ/liter)	(MJ/kg)	Container Cost ($)[c]	Refuel time[d] (min)	Filling Sta. mark-up[e] ($/GJ)
Carbon wrapped Al cylinder 54 MPa (8000 psia)	3.4	7.0	4000	2-3	5
Liquid hydrogen dewar (-253°C)	5.0	15.0	1000-2000	>5	11
FeTi metal hydride	2-4	1-2	3300-5500	20-30	3
Cryoadsorption (Carbon at -150°C)	2.1	6.3	2000-4000	5	4-5
Thermocooled pressure vessel	2.5	8.0	4000+	5+	5-8+
Organic liquid hydride	0.5	1.0	?	6-10	?

Storage systems for other automotive fuels

Storage system	Installed energy density[b] (MJ/liter)	(MJ/kg)	Container Cost ($)[c]	Refuel time[d] (min)	Filling Sta. mark-up[e] ($/GJ)
Gasoline	32.4	34.0	20	2-3	0.6
Methanol	15.9	14.9	20	2-3	1.2
Batteries:					
Lead-acid	0.187	0.115	$100/kWh	60-360	0.5[f]
Nickel-iron	0.407	0.18	"	"	"
Sodium-sulfur	0.432	0.378	"	"	"
Bipolar Li alloy	0.925	0.511	$15,000	"	"

Notes on next page.

Notes for Table 22:

[a] Adapted from (Ogden and Nitsch, 1992; DeLuchi 1992). It is assumed in all cases that enough energy is stored to travel 400 km.

[b] Energy density is based on the weight and volume of the full container plus auxiliaries.

[c] Cost to the original equipment (automotive) manufacturer

[d] Time to deliver fuel only.

[e] The mark-up (the cost in excess of the hydrogen cost to the filling station operator) needed to cover the full cost of owning and operation the refueling station.

[f] The cost of the home recharging station for the electric battery car, which does not include the price of electricity.

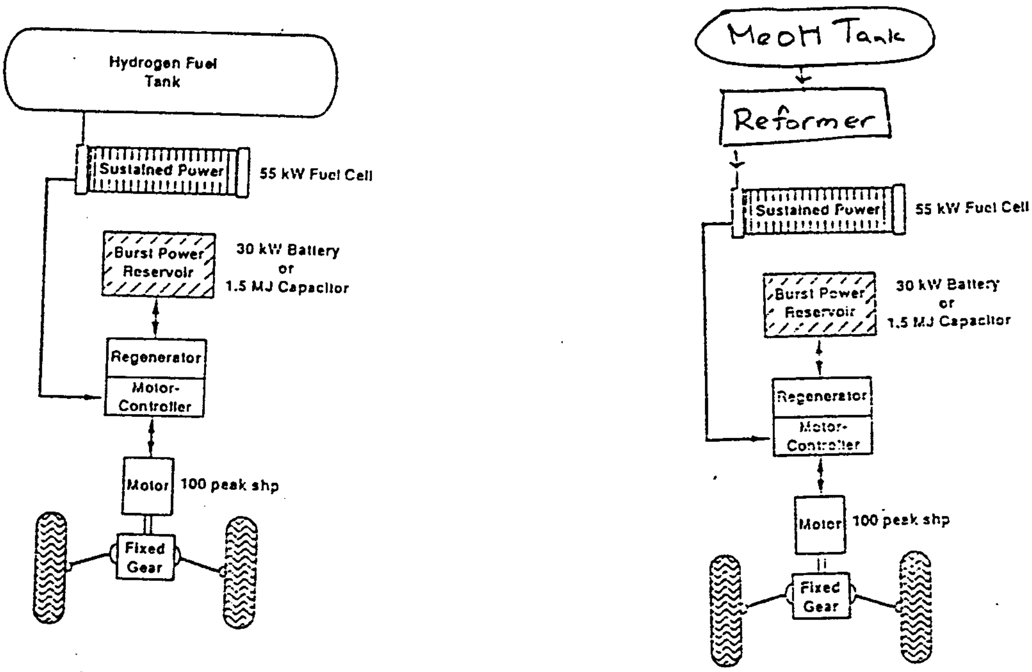


Figure 9. Hydrogen fuel cell vehicles(adapted from I. Kuhn).

energy density than gasoline or methanol, it would have a higher energy density than advanced electric batteries. Moreover, the refueling time for compressed gas cylinders would be 2-3 minutes as compared to several hours for electric batteries.

Based on models by DeLuchi (DeLuchi 1992, DeLuchi and Ogden 1992), hydrogen fuel cell vehicles are compared to gasoline internal combustion engine vehicles (ICEVs), methanol fuel cell vehicles (MeOH FCEVs) and battery powered electric vehicles (BPEVs) (Table 23). Post-2000 cost and performance projections are used for fuel cell, battery, and gasoline vehicle technologies. To facilitate comparison, the weight, range and performance of the vehicles have been chosen to be comparable. The fuel efficiency of the fuel cell vehicles is about 2.5 to 3 times that of the gasoline vehicle. Moreover, the lifetime is assumed to be about 33% longer than a gasoline vehicle and the maintenance cost is less, assumptions which are based on experience with electric battery vehicles.

The initial cost of the fuel cell vehicles is about $8000-9000 higher than that of the gasoline vehicle. The lifecycle cost of transportation is then computed assuming that hydrogen is produced from solar or wind (at a delivered cost of $23.4/GJ without taxes) or from biomass (at a delivered cost of $13.2/GJ) (Table 24). Methanol from biomass is estimated to cost $13.0/GJ delivered, electricity 7 cents/kWh, and gasoline $1.21/gallon (a price projected for the year 2000). Figure 10 shows the lifecycle cost, and also the breakeven gasoline price, which would make the total lifecycle cost of the gasoline vehicle equal to that of the alternative vehicle (DeLuchi and Ogden 1992).

Rather surprisingly, we see that fuel cell vehicles fueled with hydrogen from solar or wind would have a lifecycle cost comparable to that of a gasoline vehicle or an electric battery car. With biomass hydrogen or methanol the lifecycle cost would be even lower. Even though the initial vehicle cost and fuel costs are higher for renewable hydrogen than those for gasoline, the lifecycle cost is about the same (or slightly lower for biomass hydrogen) because:

1) hydrogen can be used 2 to 3 times as efficiently as gasoline, so that the fuel cost per km is less;

2) the lifetime of the fuel cell vehicle is 33% longer so that the contribution of the vehicle cost to the lifecycle cost is only slightly higher than for gasoline;

3) maintenance costs are lower for FCEVs than for ICEVs.

These results illustrate that the delivered fuel cost is not a good indicator of the economic competitiveness of alternative transportation fuels. Better indices are : 1) the total lifecycle cost, 2) the fuel cost per kilometer, and 3) the "breakeven gasoline price" (the gasoline price which would make the lifecycle cost of the gasoline vehicle equal to that of the alternative vehicle).

Table 23. Cost and Characteristics of Alternative Fueled Vehicles

	Vehicle type			
	Battery EV	H2 FCEV	MeOH FCV	Gasoline ICEV
Fuel Storage System	-	Comp.gas @ 55 MPa	Metal tank	Metal tank
Fuel Cell		-----PEM-----------		
Battery	---Bipolar Li alloy/FeS_2------			
Driving range (km)	400	400	560	560
Power to wheels (kW)	85	73	73	101
Delivered fuel price (excl. tax)		(Biomass,PV/wind)		
($/gallon gasoline equiv)	2.54	1.71, 2.97	1.69	1.21
($/GJ)	19.4	13.2, 23.4	13.0	9.3
Refueling time (min)	30-360	2-3	2-3	2-3
Gasoline-equivalent fuel economy (l/100 km)	2.0	3.2	3.8	9.1
(mpg)	120	74.0	62.4	25.9
Curb weight (1000 kg)	1.44	1.24	1.27	1.37
Initial price (1000 $)	28.2	25.4	24.8	17.3
Vehicle life (1000 km)	257	257	257	193
Annual maintenance cost($)	388	434	450	516

LIFECYCLE COST OF TRANSPORTATION FOR ALTERNATIVE VEHICLES(CENTS/KM)

Cost Component	Battery EV	Solar/wind H2 FCV	Biomass H2 FCV	Biomass MeOH FCV	Gasoline ICEV
Purchased electricity	1.48	0.20	0.20	0.22	
Vehicle (excl.fuel cell, battery, storage)	7.59	7.18	7.18	7.22	11.17
Battery	7.08	2.15	2.15	2.03	
Fuel storage system		0.81	0.81	0.02	
		(comp.H2 gas @55 MPa)			
Fuel cell system		2.23	2.23	2.62	
Fuel for vehicle (excl. taxes)		1.96	1.13	1.33	2.82
Maintenance	1.69	1.89	1.89	1.96	2.89
Misc. other costs	5.12	4.91	4.91	4.87	4.56
Total cost (cents/km)	22.96	21.33	20.50	20.29	21.45
Breakeven gasoline price incl. tax ($/gal)	2.11	1.43	1.09	1.00	1.50

Adapted from (DeLuchi and Ogden 1992).

Table 24. Production and Consumer Costs for Alternative Renewable Fuels[a]
($ per GJ)

	Alternative sources of hydrogen[b]		Methanol
	Wind/PV	Biomass	from biomass
Production cost	15.3[c]	7.5[d]	10.2[d]
Compression	1.4[e]	-[e]	-
Storage	1.0[f]	-[f]	-
Local distribution	0.5	0.5	-
Refueling station	5.2	5.2	2.8[g]
Cost to consumer	23.4	13.2	13.0

Notes are on the next page:

Notes for Table 24.

[a] Adapted from (DeLuchi and Ogden, 1993).

[b] See Tables 9, 10, 13.

[c] This hydrogen production cost is a mid-range value for wind and photovoltaic (PV) power sources expected in the 2000+ time period, for the assumed discount rate. In the case of wind power, it is estimated that hydrogen can be produced at a cost in the range $13.0 to $20.6 per GJ, for projected ac wind electricity costs in the range $0.026 to $0.040 per kWh. In the case of photovoltaic power, it is estimated that hydrogen can be produced at a cost of $11.6 to $19.1 per GJ, for DC PV electricity costs in the range $0.022 to $0.044 per kWh. In both cases it is assumed that hydrogen is produced at atmospheric pressure using unipolar electrolyzers.

[d] Both methanol and hydrogen can be produced from biomass via thermochemical gasification. The present analysis is based on the use of biomass feedstocks costing $3 per GJ. The gasifier involved is the Battelle Columbus Laboratory (BCL) gasifier, which is under development and not yet commercially available. In the gasification process, the biomass is heated and converted into a gaseous mixture consisting mainly of methane, carbon monoxide, and hydrogen. This gaseous fuel mixture can then be converted into methanol or hydrogen, using well-established industrial technologies (Larson and Katofsky, 1992).

[e] For the present analysis it is assumed that hydrogen produced from intermittent renewable sources is generated using electrolyzers operated at atmospheric pressure, so that the hydrogen must be compressed before it enters the pipeline. The output of the hydrogen-from-biomass plant would be hydrogen pressurized to 7.5 MPa (1.098 psia), so that in this case no further pressurization is needed before the hydrogen is put into the pipeline.

[f] Hydrogen storage is needed with intermittent renewable sources in order to keep the distribution lines operating at near capacity. In the case of hydrogen derived from biomass these storage costs would be small and are neglected here, as the biomass hydrogen plant would be producing hydrogen continuously.

[g] The cost for local distribution plus the cost for refueling operations is estimated to be $0.050 per liter ($0.19 per gallon of methanol), or $2.77 per GJ (DeLuchi and Ogden 1992).

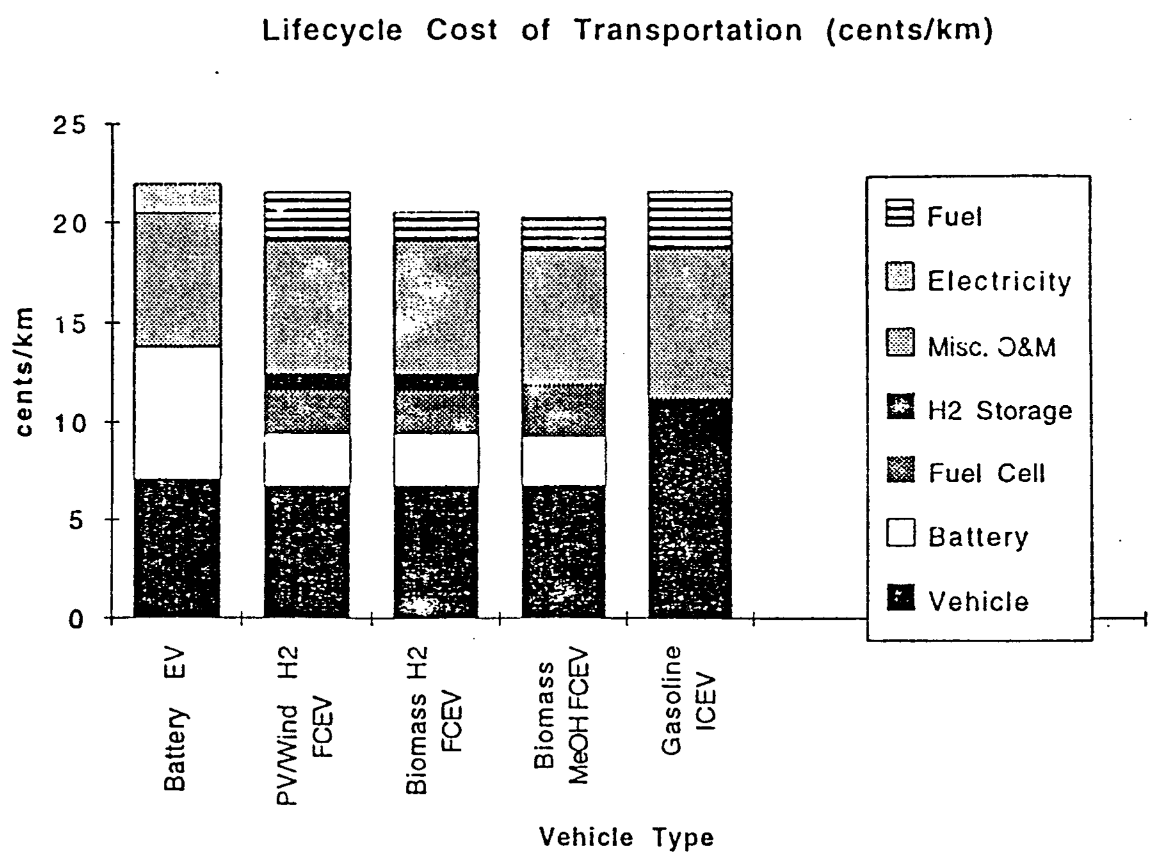


Figure 10. Lifecycle cost of transportation for alternative fueled vehicles

Even though PV hydrogen devlivered as transport fuel would cost $2.3-3.3/gallon gasoline on an energy equivalent basis, the breakeven gasoline price would be only $1.29-1.60/gallon. For biomass, the energy equivalent cost would be $1.5-1.9/gallon gasoline, but the breakeven price would be only $1.09/gallon. Even if renewable hydrogen technologies do not meet their long term goals, hydrogen might be attractive as a transport fuel. The relationship between the delivered cost and the breakeven cost is shown for PV hydrogen in Figure 11, as a function of PV module cost and efficiency. For near term projections for thin film technologies (efficiencies of 6-10% and module costs of $70-200/m^2, the breakeven gasoline price would be $1.5-4.0/gallon gasoline (less than the gasoline price in many parts of the world today), even though the delivered cost of hydrogen ($37-78/GJ, a cost of energy equivalent to $4-10/gallon gasoline) seems prohibitively large.

4.4. EMISSIONS FROM ALTERNATIVE VEHICLES

Tailpipe emissions could be essentially eliminated by switching from internal combustion engine vehicles to electric battery or hydrogen fuel cell vehicles. (With onboard reforming of methanol, fuel cell vehicle tailpipe emissions would be near zero.) However, the overall fuel cycle emissions depend on the source of electricity or fuel. Table 25 shows the emissions of air pollutants and greenhouse gases for various alternative fuel cycles, relative to the emissions from gasoline powered automobiles (Ogden and DeLuchi, 1992). The entire fuel cycle (fuel production, storage, distribution and use in a vehicle) is considered.

If the current US power mix were used to recharge battery powered electric vehicles, the total cycle emissions of some pollutants (SO_x and particulates) could actually increase relative to gasoline. However, if all solar electricity were used, the cycle emissions would be zero. Clearly, the total cycle emissions are quite sensitive to the sources of electricity used for recharging, and will be different for different electric utilities.

Similarly, the fuel cycle emissions for hydrogen fuel cell vehicles depend on source of hydrogen, and on any other energy used (e.g. electricity for hydrogen compression) in hydrogen storage, transmission and distribution. Initially, hydrogen for fuel cell vehicles will probably come from natural gas. Even though CO_2 emissions would occur in reforming natural gas to make hydrogen, and conversion energy losses would be about 20%, the overall greenhouse gas emissions would be reduced by 43%, compared to gasoline ICEVs. This occurs because fuel cell vehicles would be about 3 times as efficient as internal combustion engine vehicles. With hydrogen from biomass, further reductions in greenhouse gases could be realized. Some greenhouse gases would be emitted due to fossil fuel use for cultivation, harvesting and fertilization of biomass crops. With solar electrolytic hydrogen, greenhouse gas emissions would be eliminated from the end-use and fuel production steps. The only emissions would be from electricity used during hydrogen compression at the filling station. If solar electricity were used for compression, the fuel cycle emissions would be zero.

Table 25. Percentage change in gm/km emissions from alternative-fuel light-duty vehicles, relative to gasoline vehicles, year-2000[a]

Feed/Fuel/Vehicle	Criteria pollutants[b] NMOC	CO	NO_x	SO_x	PM	Greenhouse Gases[c]
NG/methanol/ICEV	-50	0	0	-100	lower	-2
U.S. power mix/BPEV	-95	-99	-56	+321	+153	-11
NG/hydrogen/FCEV	-100	-100	-100	-100	-100	-43
Biomass/hydrogen/FCEV	-100	-100	-100	-100	-100	-67[e]
Biomass/methanol/FCEV	-90	-99	-99	-100	-100	-86[e]
Solar/hydrogen/FCEV	-100	-100	-100	-100	-100	-87[e]
Solar/hydride/ICEV	-95	-99	?[d]	-100	lower	-88[e]
Solar power/BPEV	-100	-100	-100	-100	-100	-100
All-solar/H_2/FCEV	-100	-100	-100	-100	-100	-100[f]
Baseline emissions on gasoline, g/km	0.48	3.81	0.28	0.03	0.01	305.3

[a]The percentage changes shown are with respect to the baseline g/km emissions shown at the bottom of this table. ICEV = internal-combustion-engine vehicle; BPEV = battery-powered electric vehicle; FCEV = fuel-cell vehicle. Adapted from DeLuchi (1992).

[b] The estimates of relative emissions are based on data reported in (Sperling and DeLuchi, 1992) and (DeLuchi and Ogden, 1992).

[c] The percentage changes refer to the sum of emissions of CO_2, CH_4, N_2O, CO, NO_x, and NMOCs (Non-methane organic compounds) from the entire fuel production and use cycle (excluding the manufacture of vehicles and equipment). Emissions of gases other than CO_2 have been converted to an equivalent amount of CO_2, where equivalent is defined in terms of global warming caused over a certain time period. Results are based on (DeLuchi, 1991).

[d] Hydrogen internal combustion engine vehicles tested to date have shown a very wide range of NO_x emissions. A hydrogen engine can be designed to operate very lean and will have very low NO_x emissions due to the reduced temperature. However, if such an engine is operated at full power, which requires an air-fuel mixture of 1:1, the NO_x emissions will increase substantially.

[e] With renewable hydrogen or methanol, greenhouse gas emissions are reduced, but are not neccessarily zero. With biofuels, some emissions result from fossil fuel use while cultivating, fertilizing and harvesting biomass. For these cases, it is assumed that hydrogen is compressed at the service station using the projected mix of power sources in the US in the year 2000 (EIA, 1991).

[f] If solar power were used for compression, greenhouse gas emissions for solar hydrogen would be zero.

Of the various options considered, only solar electrolytic hydrogen used in fuel cell vehicles and solar electricity used to charge battery powered electric cars could be strictly zero emission fuel cycles. However, other cycles with fuel cell vehicles (natural gas to hydrogen, biomass to hydrogen, biomass to methanol) could give substantial reductions in pollutants and greenhouse gases.

4.5. A POSSIBLE SCENARIO FOR INTRODUCING RENEWABLE HYDROGEN AS A TRANSPORTATION FUEL IN THE US

Large and rapidly growing markets for ZEVs are likely to open over the next ten to twenty years. (By 2003, several hundred thousand ZEVs per year would be required in California alone.) Because of their much faster refueling time fuel cell vehicles could eventually serve a much larger fraction of the passenger car market than battery powered electric vehicles (BPEVs). To compete economically with BPEVs, however, FCEVs would have to be developed, tested and commercialized on a large enough scale to significantly reduce fuel cell costs.

The first prototype hydrogen FCEVs could be developed within the next few years. Testing in small experimental fleets is the first step toward gaining experience with vehicle and refueling technology and evaluating consumer acceptance. Beyond this, the next step might be the introduction of modest sized fleets of several hundred to a few thousand vehicles, which would be centrally refueled. With a committment from industry, it is possible that these fleets could be ready around the year 2000 in response to the California market. If hydrogen FCEVs proved successful in fleet service, the hydrogen distribution network might be expanded to general consumers. During the early decades of the next century, FCEVs might come to capture a large share of the ZEV market.

How would hydrogen be produced to satisfy these potential markets? In the 1990s, experimental fleets would probably use truck delivered industrial hydrogen derived from natural gas (Figure 11). After the year 2000, larger government or utility owned fleets might be introduced. A 1000 car fleet would require about 75,000 GJ of hydrogen per year or 0.5 million scf/day. At this scale, it would be less costly to produce hydrogen at the filling station, either from small scale steam reforming of natural gas or via electrolysis (Table 19). [By the early part of the next century, wind and PV hydrogen would become roughly cost competitive with small scale steam reforming of natural gas (assuming natural gas costs $4-6/GJ in this time frame). At this small scale biomass hydrogen would probably be too expensive.] In the longer term, large numbers of FCEVs might be introduced as general purpose passenger cars. Hydrogen fuel would be produced in a centralized large plant and made available to urban consumers at local filling stations. To supply a city with hundreds of thousands of FCEVs, biomass hydrogen would be the least expensive renewable source. Even though many regions of the world (including most of the US) are close to good solar, wind or biomass resources, it might be neccessary in areas such as Northern Europe to transmit hydrogen long distances (Winter and Nitsch 1988, Ogden and Nitsch 1992). For a large (0.5 EJ/yr) 1600 km pipeline, the delivered cost of PV hydrogen would be about the same

HYDROGEN TRANSPORTATION FUEL DEMAND

MARKET	# ZERO EMISSION H2 FUEL CELL VEHICLES	HYDROGEN DEMAND (MILLION) SCF/DAY)	POTENTIAL SUPPLY
EXPERIMENTAL FLEETS - LATE 1990s	5-50	0.002-0.02	INDUSTRIAL H2
CENTRALLY REFUELED TEST FLEETS 2000-2010	1000	0.5	SMALL STEAM REFORMING OR ELECTROLYSIS AT REFUEL. SITE
CITY SUPPLY IN URBAN AREAS NEAR GOOD H2 SUPPLY	100,000 - 1,000,000	15-150	LARGE CENTRAL BIOMASS, PV OR WIND H2 PLANTS W/LOCAL DISTRIB
SOLAR EXPORT TO AREAS FAR FROM GOOD H2 RESOURCES > 2025	30 MILLION	4,500	PIPELINE PV HYDROGEN

Figure 11. Meeting the demand for hydrogen transportation fuel

as for a local city supply, because increased transmission and distribution costs would be offset by savings in large scale storage and compression costs.

We have sketched one possible scenario for developing a transportation system based on fuel cell vehicles, using direct storage of compressed hydrogen gas. Other options such as reforming methanol onboard the vehicle to make hydrogen would give quite different delivery and end-use systems.

5.0. CONCLUSIONS

The results of our hydrogen energy systems studies to date can be summarized as follows:

* Based on post 2000 projections for PV, wind and electrolysis technologies, we find it would be possible to produce electrolytic hydrogen at a cost of $12-21/GJ for PV and $16-26/GJ for wind. Because of the modular nature of PV, wind and electrolysis, these production costs could be achieved at relatively small scale. At large scale, hydrogen from biomass gasification would be the least expensive renewable option, costing about $6.2-8.8/GJ to produce.

* There are good to excellent resources for renewable hydrogen production globally and in most areas of the United States. It would be possible to produce enough fuel for light duty fuel cell vehicles from local resources in all but 4 states. Land and water requirements would be modest. With PV electrolysis alone it would be possible to supply enough hydrogen for all light duty vehicles in the US using only 0.1% of the contiguous US land area (1% of the US desert area). With biomass about 2/3 of the present idled cropland (3% of the US land area) would be needed.

* For gaseous hydrogen delivery systems, compression and storage (for intermittent sources such as PV or wind), pipeline transmission, local distribution and delivery as tranportation fuel would add a total of about $6-8/GJ to the hydrogen cost.

* Even though renewable hydrogen would be several times as expensive as gasoline and fuel cell cars would probably be considerably more expensive than gasoline vehicles, hydrogen fuel cell vehicles might, in the long term, compete on a lifecycle cost basis with gasoline and electric battery vehicles. Assuming that goals for fuel cells and batteries are acheived, this would occur because fuel cell vehicles would be 2-3 times as energy efficient as gasoline vehicles, and would have a longer lifetime and lower maintenance costs.

* Our analysis of alternative transportation fuels indicates that the delivered fuel cost alone is not a good indicator of the total cost of energy services. This is particularly important for high quality energy carriers like hydrogen which can be used very efficiently. Fuel costs per kilometer would be less with PV or wind hydrogen used in a fuel cell car than with gasoline used in an internal combustion engine. Moreover, considerations such as refueling time and range could have as large an impact

on consumer choices as cost.

* The transportation case study also illustrates the importance of considering the whole system from several points of view (energy producer, consumer, environmental/resource).

6.0. FUTURE RESEARCH DIRECTIONS

Thus far, we have assessed a range of methods for producing hydrogen from renewables (considering performance, economics and resource issues), and several options for storing, delivering and using hydrogen as a transport fuel. In the future we would like to continue and expand these studies. Some topics of potential interest are listed below.

1) Assess the role of natural gas in a transition toward renewable hydrogen.

2) Improve our models of fuel cells and fuel cell systems.

3) Assess fuel cells for residential heating and cogeneration.

4) Investigate the economics of biomass hydrogen production at various plant sizes.

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APPENDIX A

Methods for calculating the levelized cost of solar electricity and hydrogen

We have computed the levelized cost of electricity in constant 1989 US dollars, using the economic assumptions in Table A.1, which are suggested by EPRI for utility-owned power plants (EPRI, 1986).

For wind electricity the electricity cost is given by:

Ce(\$/kWh) = (CRF + INS + TAX) x Ct(\$/kW) x Pt (kW)/[Et (kWhr/yr)] + COM(\$/kWh)

where:

Ce = levelized production cost of wind electricity (\$/kWhAC)
CRF = capital recovery factor = $i/[1-(1+i)^{-N}]$
i = real discount rate
N = system lifetime (years)
INS = annual insurance fraction of captal cost
TAX = annual property tax fraction of capital cost
Ct = installed capital cost of turbine at rated power (\$/kW)
Pt = rated power per turbine (kW)
Et = net annual energy capture per turbine (kWh/yr)
COM = annual operation and maintenance costs including blade replacements (\$/kWh)

The net annual energy capture per turbine includes the effect of all losses such as array interference losses, blade fouling, wiring losses, etc. The net energy capture can be measured or estimated from the gross annual energy capture:

Et = Ea x (1-Ls) x a

where:

Ea = gross annual energy capture per turbine (kWh/yr)
Ls = system losses for an array of turbines (due to array interference, blade fouling, wiring losses, etc.)
a = availability

The gross annual energy capture is the amount of power the turbine would generate per year in the absence of losses, at 100% availability. The gross annual energy capture can be estimated from the turbine power output characteristic (power output as a function of wind speed) and the wind speed distribution for the site.

Sometimes, the annual energy capture is expressed in kWh/m^2 of swept rotor area. In this case, the kwh/yr can be calculated can be calculated:

$$E\ (kwh/yr) = E\ (kwh/m^2/yr) \times A$$

where:

A = area swept by turbine blades (m^2) = $pi \times (d/2)^2$
d = turbine diameter (m)

The annual average capacity factor for the system at a particular wind power energy density can be defined by:

$$p = Et/(Pt \times a \times 8760 \text{ hours/yr})$$

where:

p = annual average capacity factor for system
Pt = turbine rated power capacity (kW)
a = availability

The levelized cost of electricity can be expressed in terms of the annual avergae capacity factor as:

$$Ce\ (\$/kWh) = (CRF + INS + TAX) \times Ct\ (\$/kW)/(8760 \text{ hr/yr} \times p \times a) + COM\ (\$/kWh)$$

For solar thermal electric systems the cost of electricity is given by:

$$Ce(\$/kWh) = (CRF + INS + TAX) \times Cst(\$/kW) \; / \; (8760 \text{ h/yr} \times p \times a) + COM(\$/kWh) + Pgas(\$/GJ)/nelec \times 0.0036 \text{ GJ/kWh} \times fgas$$

where:

Ce = levelized production cost of solar electricity ($/kWhAC)
CRF = capital recovery factor = $i/[1-(1+i)^{-N}]$
i = real discount rate
N = system lifetime (years)
INS = annual insurance (as a fraction of capital cost)
TAX = annual property tax (as a fraction of capital cost)
Cst = installed capital cost of system ($/kWpeak)
p = total system capacity factor = solar capacity factor x 1/(1-fgas)
= kwh generated annually/(8760 x system capacity)
a = plant availability
COM = annual operation and maintenance costs ($/kWh)
Pgas = gas price ($/GJ) = gas price ($/MBTU)/1.055
nelec = efficiency of steam-turbine electricity generation from gas = .29
fgas = kWh generated annually from gas/total kWh generated annually

The cost of photovoltaic electricity in $/kWh is given by:

$$Ce = \{(CRF + INS + TAX) \times (1+ID) \times [(Cmod + Cbos) + Cpc \times Ip \times nmod \times nbos] + Com\} / (nmod \times nbos \times nt \times insol \times 8760)$$

where:

Ce = levelized production cost of solar electricity ($/kWh)
CRF = capital recovery factor = $i/[1 - (1 + i)^{-N}]$
i = real discount rate
N = PV system lifetime (years)
INS = insurance cost (as a fraction of capital cost)
TAX = property tax (as a fraction of capital cost)
ID = indirect cost factor
Cmod = capital cost of PV modules ($\$/m^2$)
Cbos = area-related balance-of-system capital cost ($\$/m^2$)
Ip = maximum insolation (kW/m^2) = 1.1 kW/m^2
nmod = PV module efficiency
nbos = balance of system efficiency (= system effiency/module efficiency)
Cpc = power-related balance of system capital cost ($/kWpeak)
nt = solar cell average temperature correction
= 0.9 (crystalline solar cells); = 1.0 (thin film solar cells)
insol = annual average insolation on tilted, fixed-flat-plate array (kW/m^2)
Com = annual O&M cost ($\$/m^2$/year)

For a DC photovoltaic system, the cost of power-related balance-of-system equipment would be $75/kW; for an AC system, $150/kW.

For a DC system nbos = 89%; for an AC system nbos = 85%.

The levelized cost of electrolytic hydrogen Ceh (in \$/GJ) for a large DC electrolysis plant can be expressed as (Leroy and Stuart, 1978; Hammerli, 1984; Hammerli, 1990):

$$Ceh = Cehc + Cehe$$

where:

Cehc = capital component of electrolysis cost (\$/GJ)
= [1/(nr x 8760 hours/year x 0.0036 GJ/kWh)] x [(CRFel + INS + TAX + OM)/CF] x Celec

Cehe = DC electricity cost component of electrolysis cost (\$/GJ)
= Ce/(0.0036 GJ/kWh)/ne,

and:

- nr = electrolyzer efficiency at rated voltage = (Vr/1.481 volts)
- Vr = rated voltage of electrolyzer (in volts)
- CRFel = capital recovery factor = $d/[1 - (1 + d)^{-Nel}]$
- d = real discount rate
- Nel = electrolyzer lifetime (years)
- TAX = annual property plus income tax (as a fraction of capital cost)
- INS = annual insurance cost (as a fraction of capital cost)
- OM = operation and maintenance cost (as a fraction of capital cost)
- CF = electrolyzer capacity utilization factor = no x pelec
- no = coupling efficiency between power source and electrolyzer
- pelec = annual average capacity factor of power source
- Celec = installed capital cost of electrolysis plant (\$/kWDCin)
  = Cem x {(1-f1) x (ir/i) + f1 + 0.5 x f2 x [1 + (ir/i)]}
- Cem = electrolyzer cells and accessories unit capital cost (\$/kW of DC power input, at V = Vr)
- f1 = fraction of electrolyzer cells and accessories capital cost that is independent of current
- f2 = installation-related costs, as a fraction of the cells and accessory cost--half of this cost is independent of the operating current density and the other half increases linearly with operating current density
- ir = rated electrolyzer current density (in milliamps per square cm)
- i = operating current density (in milliamps per square cm)
- ne = electrolyzer efficiency (DC input power to hydrogen energy figured on a higher heating value basis) = 1.481/V
- V = operating voltage of electrolyzer (in volts)
- Ce = cost of DC electricity (in \$ per kWh)

Typical values for f1, f2, ir, i, Vr, V, and Cem are shown in Table A.2

For an AC electrolysis plant, terms are added for the rectifier capital cost and O&M. The total hydrogen cost is:

$$Ceh = Cehc + Cehe$$

where:

Cehc = capital component of electrolysis cost ($/GJ)
= [1/(nr x nrect x 8760 hours/year x 0.0036 GJ/kWh)]
x [(CRFel + INS + TAX + OM)/CF x Celec x nrect +
(CRFrect + INS + TAX + OM)/CF x Crect]

Cehe = AC electricity cost component of electrolysis cost ($/GJ)
= Ce/(0.0036 GJ/kWh)/(ne x nrect),

Crect = capital cost of rectifier ($/kWACin)
nrect = rectifier efficiency AC to DC conversion
CRFrect = capital recivery factor for rectifier
= $d/[1 - (1 + d)^{-Nrect}]$
Nrect = rectifier lifetime (years)
Ce = cost of AC electricity (in $ per kWh)

and the other variables are the same as for the DC plant. Typical values for these variables are given in Table A.2

Table A.1. Economic parameters used in the analysis

	Investment in electricity and hydrogen production, transmission, and distribution[a]
0.061	Real rate of return on investment
0.005	Yearly insurance cost, fraction of initial capital cost
0.015	Yearly property taxes, fraction of initial capital cost

[a]These values are suggested by the Electric Power Research Institute for utility-owned electricity- production systems (EPRI, 1986).

Table A.2. Cost and performance of large PV electrolysis plants[a]

	Unipolar	Bipolar	SPE (projected)
Vr = rated voltage (V)	1.74	1.85	1.65
V = operating voltage range (V)	1.7-2.0	1.7-2.0	1.65
ir = rated current density (mA/cm^2)	134	215	1076
i = operating current density Range(mA/cm^2)	134-320	250-1000	1000-2000
ne = efficiency at V=Vr (=H_2 out[HHV]/DC in	0.85	0.80	0.90
f1 = capital cost fraction independent of current	0.90	0.80	0.50
f2 = installation cost as a fracton of capital cost	0.45	0.45	0.75
Cem= capital cost of electrolyzer modules ($/kWDCin)	189	222 (1 atm.) 283 (30 atm.)	222
Celec= installed capital cost DC electrolysis plant at rated current density ($/kWDCin)	274	322 (1 atm.) 410 (30 atm.)	388
OM = annual operation and maintenance cost as a fraction of capital cost per year	2%	2%	2%
Nel = electrolyzer lifetime(yr)	20	20	20
Crect = capital cost of rectifier ($/kWACin)	130	130	130
nrect = rectifier efficiency	96%	96%	96%
Nrect = rectifier lifetime(y)	10	10	10

[a]Parameters other than capital and O&M costs are from Leroy and Stuart (1978). The capital estimates for large unipolar electrolyzers and pressurized bipolar electrolyzers are from Craft (1985). Capital costs for atmospheric pressure bipolar and SPE electrolyzers are from Fein and Edwards (1984). Operation and maintenance costs are from Hammerli (1984).

APPENDIX B. Cost and performance parameters for the hydrogen refueling station[a]

FCEV	Hydrogen refueling: input data
	Compressor station:
300[b]	Fixed cost of compressor ($/hp, 1975$)
2.10[b]	Compressor cost per unit of output ($/hp/million standard ft^3 [SCF] of hydrogen/day, 1975$)
2.07	Ratio of PPI for current year to PPI for 1975
0.070[c]	Cost of electricity to the commercial sector ($/kWh)
0.05[d]	Annual cost of servicing, labor, and new parts (fraction of initial cost)
0.20	Salvage value of compressor (fraction of initial cost)
288.80	Initial temperature of hydrogen (degrees K)
50	Initial pressure of hydrogen (psi)
1.05	Compressor output pressure divided by vehicular storage pressure
6	Number of stages of compression
0.85	Compressor efficiency
	Storage and refueling equipment:
0.27[e]	Cost of storage cascade, including manifolding, support, safety equipment, and transportation ($/SCF/1000-psi storage)
0.016	Storage capacity of station (SCF) divided by total SCF demanded during peak period
0.10	Gas deliverable from storage at max. vehicular storage pressure (fraction of total SCF of storage)
9,000[f]	Cost of refueling equipment, including meters and safety equipment ($/refueling line)
0.15	Salvage value of storage and refueling (fraction of station initial cost)
0.02	Annual cost of servicing, labor, and new parts (fraction of initial station cost)
	Land, building, and other initial costs:
0.03	Other station capital and engineering cost (fraction of cost of compressor, storage, refueling)
20,000	Cost of buildings ($)
2,500	Cost of hook up to gas line ($)
200,000	Price of land ($/acre)
4500	Land required for buildings, exits and entrances (sq ft)
150	Land required per refueling bay (sq ft/bay)
50.0	Land required for gas storage (sq ft land/1000 SCF storage x 1000 psi pressure)
0.03	Real rate of increase in value of land (fraction of original cost per year)
	Hydrogen throughput:
8	Number of refuelling lines (or bays)
400	Rate of delivery of gas to vehicle (SCF/minute [SCFM])
2.5	Average length of time spent pulling in and out of refueling bay, removing and replacing pump, and paying (min)
0.33	Ratio of average non-peak demand to peak demand (assume peak demand = station capacity)
2.00	Hours of peak (maximum) demand rate
20	Hours open per day
360	Days open per year
0.75	Fraction of tank filled per refueling
	Operating costs:
7.50	Wage rate ($/hr)
1.50	Average number of shifts per hour
1.60	Overhead on salaries (multiplier)
5,000	Other station operating cost: supplies, water, sewage, garbage, etc. ($/yr)

Table A.3. (cont.)

	Hydrogen refueling: calculated results
	Compressor:
632	Compressor power needed (kW)
1,400	Required capacity of compressor (SCFM at 1 atm, 293.15 K)
3.03	Ratio of compressor capacity (SCFM) to non-peak hydrogen demand (SCFM, per non-peak operating hour)
1.00	Ratio of compressor capacity (SCFM) to peak hydrogen demand (SCFM)
7.9	Average compressor operating hours per operating day
	Hydrogen:
8,400	Final pressure of hydrogen from compressor (psi)
1.38[9]	Hydrogen compressibility factor
1.47[9]	Ratio of specific heats of hydrogen
	Demand for fuel:
76,658	Hydrogen throughput (million Btu/yr)
$2.40 \cdot 10^6$	Hydrogen throughput (SCF/yr at 1 atm, 293.15 K)
778	SCF per vehicle (at 1 atm, 293.15 K)
1,400	Maximum hydrogen demand rate in an hour (SCFM at 1 atm, 293.15 K)
4.5	Vehicles per hour per refueling line, non-peak hours
13.5	Maximum station capacity (vehicles per refueling line, one hour; assume this is peak)
857	Average number of vehicles per operating day
4.45	Total refueling time per car, incl. pulling into bay, delivering fuel, and paying (min)
	Storage system and land:
26,319	Required hydrogen storage capacity at station (SCF)
0.1	Non-peak demand provided by station storage (hrs)
0.134	Land required (acres)
	Cost:
57	Cost of compressor engine ($/hp, 1975$; based on a regression of $/hp and hp)
980	Compressor cost ($/kW)
619,471	Capital cost of compressor ($)
58,896	Capital cost of storage cascade ($)
22,511	Other station capital and engineering cost ($)
26,890	Cost of land ($)
822,268	Total initial cost of station, incl. all equipment, installation, and engineering cost ($)
424,489	Total station operating cost ($/yr)
73,650	Levelized total initial cost, including resale of land and equipment ($/yr)
6.50	**Hydrogen retail mark up, before all taxes, $/million Btu**

Notes for Table A.3:

[a]See DeLuchi (1991b) for documentation and sources not shown here.

[b]We derived these coefficients from a cost-function graph presented in Darrow et al. (1977). Compressor manufacturers we have spoken with recently have confirmed our cost results (Barker, 1991; Tothe, 1991; Ward, 1991).

[c]This is the commercial-sector price projected by the EIA (1990b) for the year 2000.

[d]This is the maintenance-cost factor estimated by two major compressor manufacturers, Dresser-Rand (Tothe, 1991) and Norwalk (Barker, 1991).

[e]Based on an estimate done for us by CP Industries (Carrozza, 1991) of the cost of a 44,400-SCF storage cascade designed specifically for hydrogen at 9300 psi.

[f]According to one supplier, a custom-produced complete refueling system designed to deliver 400 to 500 SCFM of natural gas at 3600 psi would cost about $11,000 (Patterson, 1991). Mass production would bring this cost down considerably. However, the cost of a 8,000 or 9,000-psi system would be higher than the cost of a 3600-psi system.

[g]Calculated as a nonlinear function of the temperature and pressure of hydrogen, using data from the National Bureau of Standards (Hilsenrath et al., 1955) and CP Industries (Dowling, 1991).

APPENDIX C

DATA FOR
HYDROGEN COMPRESSION, STORAGE, TRANSMISSION AND DISTRIBUTION

Table C.1 Gaseous hydrogen: compression, storage and transmission[a]

Pipeline diameter:	1.7 m	
Pipeline pressure:	10 MPa	
Hydrogen flow rate:	29.6 GW H_2 (HHV) = 8.3 million Nm^3/h	
Capacity factor (daily storage assumed):	69%	
Useable storage volume:	355 GWh H_2	
Storage losses (compressor drive):	2.9 %	
Transmission distance: (to Central Europe from:)	2000 km S. Spain	3300 km N. Africa
Number of compressor stations[b]:	4	8
Mechanical compressor power (3 MPa electrolyzer pressure assumed):	720 MW	975 MW
Transmission efficiency if H_2-fueled gas turbines are used for compressor drive:	91.5 %	88.5 %
Pipeline capital cost:	$ 1900/m	
Compressor station capital cost:	$ 1100/kW	
Underground storage[c]:	$ 2.4/kWh H_2	
Total specific capital cost:	$ 177/kW H_2	$ 338/kW H_2[d]
Annual O&M cost:	1.5 % of capital cost	
Lifetime:	30 years	

[a] Reference technology from Nitsch et.al. (3).
[b] Optimized number with respect to pipeline diameter and pressure cost
[c] Existing underground storage volume assumed (e.g. depleted gas field)
[d] Includes underwater pipeline of 300 km length which has five times higher capital cost than overland pipeline

Table C.2. Liquid hydrogen: liquefaction, storage and transmission[a]

Unit power of liquefaction plant:	118 MW H_2
Electricity consumption:	0.23 $kWh_e/kWh\ H_2$
Capacity factor (adapted to electricity production from PV)[b]:	32%
Total efficiency (electrolysis included) LH_2/electr.:	74.6 %
Capital cost of LH_2-plant:	\$ 515/kW H_2
Annual O&M cost (including cost for cooling water):	6 % of capital cost
Lifetime:	30 yr
Unit size of LH_2-tanker:	26000 m^3 LH_2 (= 0.26 PJ LH_2)
Unit size of storage vessel:	27500 m^3 LH_2
Transmission distance:	5700 km
Overall transmission efficiency at 17 transport cycles/year including storage and filling losses:	89 %[c]
Mean annual energy flow (8300 h/yr):	0.149 GW H_2
Capital cost of total system related to mean annual energy flow:	\$ 1646/kW H_2
Annual O&M cost:	1.5 % of capital cost
Lifetime:	30 yr

[a] Reference technologies from (3) for mature technology
[b] PV: 2100 h/yr, electrolysis and LH_2-plant: 2800 h/yr at rated power.
[c] Storage losses 0.03 % per day; filling losses 8 %

APPENDIX D.

SURVEY OF SOLAR ELECTROLYTIC HYDROGEN PROJECTS

A number of groups around the world are conducting research on electrolytic hydrogen production using renewable electricity. In this section, we give brief descriptions of some ongoing projects. The information presented here was gathered in part during two recent visits to Europe.

In September of 1991, I visited German hydrogen researchers as part of my NREL-supported research. The purpose of the visit was twofold. First I met with researchers at DLR, Stuttgart, a center of PV electrolysis research, in order to get a better picture of the current status of German PV hydrogen research and to discuss their latest experimental results on PV hydrogen production. I also worked with Dr. Joachim Nitsch, the head of the Energy Analysis Group at DLR, on an article we are co-authoring entitled "Solar Hydrogen," which will appear in a forthcoming book on renewable energy. Second, I presented the results of my SERI sponsored research at the 2nd IEA Technical Workshop on Hydrogen Production. This workshop, which was attended by about 50 scientists and engineers mostly from Europe, Japan, Canada and the US provided an excellent opportunity to learn about ongoing solar hydrogen experiments.

In July of 1992, I presented a paper on hydrogen research supported by NREL at the 9th World Hydrogen Energy Conference in Paris. Here I received an update on various solar hydrogen projects and learned that several new experiments had been started since September 1991. I have included this information as well.

BELGIUM

Researchers at Hydrogen Systems, a Belgian company, are studying the possibility of using wind powered electrolyzers for hydrogen production.[1]

BRAZIL

Researchers at the University of Uberlandia, Brazil and the University of Miami, USA, have done an analysis of using excess Brazilian hydropower to produce electrolytic hydrogen for direct reduction of iron ore as part of steel making.[2]

CANADA

Electrolyzer, Inc. with support from the Ontario Ministry of Energy and The South Coast Air Quality Management District has operated a small PV electrolysis experiment in Toronto for about a year. The system performed quite well with a direct connection between the electrolyzer and the PV array. Electrolyzer is also exploring the impllcations of intermittent operation on electroyzer design.[3]

The provincial government of Quebec is also supporting the Euro-Quebec project to produce hydrogen from Canadian hydropower for liquifaction and transport to Europe (see below).

CHINA

Conceptual designs are being carried out at Jiotang University for PV electrolysis systems.[4-4] The Chinese government is also supporting research in advanced electrolysis for use with solar power.[5]

FINLAND

A self-sufficient, stand-alone PV hydrogen system is being built at Helsinki University. The system is designed to provide electric power for a constant load of up to 2 kWh/day. Because of Helsinki's far Northern climate, seasonal hydrogen storage is included, as well as daily storage of PV energy in electric batteries.[6]

FORMER SOVIET UNION

A small (100 Watt) PV electrolysis experiment was set up at the Radiation Research Division of the Azerbaijan Academy of Sciences.[7]

A 6 kW stand alone PV power plant was built at the Gelenjuk Research Laboratory on the Black Sea by scientists at the Research Production Amalgamation KVANT, Moscow, Russia. Storage batteries are used to provide electricity at night, and electrolytic hydrogen and oxygen are also produced and stored for use in a fuel cell during long periods of low insolation. The system components were tested separately and together.[8]

GERMANY

Germany has the world's largest and most comprehensive research and development program in hydrogen energy technology. Federal government spending on hydrogen (including fuel cells) is about $26 million DM per year ($14 million per year), with similar amounts being spent by local governments and by industry. The German program includes research on hydrogen production (they have focussed in particular on PV powered electrolysis), as well as storage, transmission, and end-use systems (automobiles, heating systems, steam generators, fuel cells). Work ranges from basic science to demonstration projects.[9]

PV hydrogen research is conducted in several places.

1) DLR, Stuttgart is one of the largest centers of PV hydrogen research. A wide range of experimental and theoretical studies of PV electrolyzers have been carried out.[10] The HYSOLAR joint project between Germany and Saudi Arabia (see below) is also co-managed

by researchers at DLR Stuttgart.

2) The Solar Wasserstoff Bayern project is a 270 kW PV electrolysis system located in Bavaria, built by a consortium including Bayernwerk (a state utility), BMW, Linde, MBB and Siemens. Testing of the components began in 1991, and the entire syem is scheduled to to begin taking continuous data in the fall of 1992.[11] A number of different PV, electrolysis and fuel cell technologies will be tested.

3) KFA, Julich, which was originally a nuclear laboratory, is now becoming involved in solar energy research. Their long standing program in electrolysis technology has now shifted its emphasis toward issues having to do with intermittent operation with solar or wind sources.[12]

4) Researchers at the Fraunhofer Institute for Solar Energy Studies, Freiburg, have built a 2.1 kW PV electrolysis system for residential applications [13]

5) A new group has formed with members at several universities, called the "Center for Solar Energy and Hydrogen Research".

ITALY

A pre-feasibility study was done on the possibility of using hydropower in Zaire to produce hydrogen for export to Southern Europe via pipeline.[14]

NORWAY

A project similar to the Euro-Quebec project (see below) has been proposed for using excess hydropower in Norway to produce hydrogen, which would be liquified for export to Germany. A conceptual design study has been carried out by Ludwig Bolkow Systemtechnik and Norsk Hydro for 20 MW and 100 MW electrolysis systems powered by hydroelectricity. An existing site in Norway, where electrolytic hydrogen is already produced for fertilizer production, was taken as a basis for the study.[15]

SPAIN

In 1990 a program on solar hydrogen production was begun in the Instituto Nacional Tecnica Aerospacial (INTA) Energy Laboratory. A 8.5 kW PV array was coupled to a 7.0 kW alkaline electrolyzer. The plant was designed to test different types of technologies and was finished in spring of 1992. Initial data were presented at the 9th World Hydrogen Energy Conference in Paris, June 22-25, 1992.[16]

SWITZERLAND

Membrane (PEM) type electrolyzers were operated under both simulated and real PV power sources for several years by scientists at the Paul Scherrer Institute. Although this work has been recently discontinued, PEM electrolyzers show some advantages in that they have a rapid start-up time during intermittent operation.[17]

UNITED STATES

Researchers at Humboldt State University (Humboldt, California) have built a 10 kW PV electrolysis system. Hydrogen and oxygen are stored, and will be used in a fuel cell to produce electricity at night. The system has now operated for about a year.[18]

Researchers at the Florida Solar Energy Center are designing a PV electrolysis system based on unipolar electrolysis.[19]

The South Coast Air Quality Management District with Electrolyzer, Inc. of Canada are planning to test a PV electrolysis system at the University of California, Riverside.[20]

JOINT PROJECTS INVOLVING SEVERAL COUNTRIES

The Euro-Quebec Hydro-Hydrogen Pilot Project is a joint venture between the Joint Research Center Ispra of the Commission of European Communities and the provinical government of Quebec, involving both European and Canadian companies. The project proposes to use 100 MW of excess hydropower in Canada to produce electrolytic hydrogen, which will then be liquified and shipped to Germany for use a fuel for transport fuel, cogeneration, steel fabrication and augmentation of natural gas for home heating and industrial use. Phase I of this project (an initial assessment) was completed in 1987. Phase II, a detailed conceptual design characterizing the system was completed in 1991, and Phase III, demonstration of hydrogen vehicle and aviation technologies, has been approved. The overall funding for the project to date has been about 30 million ECU ($30 million).[21]

The HYSOLAR project, a joint effort between Germany and Saudi Arabia, is a demonstration of solar hydrogen production and utilization systems. A 10 kW PV electrolyzer has operated for several years at DLR, Stuttgart. A 2 kW PV electrolysis system was installed in Jeddah, Saudi Arabia. A 350 kW PV concentrator array near Riyadh, Saudi Arabia (which was originally built as part of the joint US/Saudi SOLERAS program) will be used to power an electrolyzer now being redesigned after inital tests in 1991. Operation should start at the end of 1992.[22] Since the project's beginning in 1986, about 48 million DM ($27 million) has been spent. 28 million DM ($16 million) has been approved for the next four years.

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APPENDIX E

PRESENTATIONS AND PUBLICATIONS BASED ON RESEARCH PERFORMED UNDER THIS CONTRACT

1. J.M. Ogden and M.A. DeLuchi, "Solar Hydrogen Transportation Fuels," presented at the Third Annual Meeting of the National Hydrogen Association, Arlington, VA, March 18-20, 1992.

2. J.M. Ogden, "Renewable Hydrogen Energy Systems Studies," presented at the NREL Hydrogen Program Review Meeting, Honolulu, Hawaii, May 6-7, 1992.

3. J.M. Ogden, "Solar Photovoltaic Electrolytic Hydrogen Systems Studies," presented at the NREL Photovoltaics Advanced R&D Program Review Meeting, Denver, Colorado, May 13-15, 1992.

4. J.M. Ogden, "Hydrogen from Renewable Resources," presented at the Annual Meeting of the American Solar Energy Society, Cocoa Beach, Florida, June 12-18, 1992.

5. J.M. Ogden and M.A. DeLuchi, "Renewable Hydrogen Transportation Fuels," presented at the 9th World Hydrogen Energy Conference, Paris, France, June 22-25, 1992.

6. J.M. Ogden, "Prospects for Renewable Hydrogen Energy Systems," presented at the IEA/OECD, Paris, France, June 26, 1992.

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9. J.M. Ogden and M.A. DeLuchi, "Renewable Hydrogen as a Transportation Fuel," presented at the Solar/Electric Vehicle '92 Conference, the Northeast Sustainable Energy Association, Boston, MA, October 9-10, 1992.

10. J.M. Ogden, "Hydrogen as a Transportation Fuel," presented at the 2nd South Coast Air Quality Management District/American Lung Association Alternative Fuels Conference, Riverside, CA, October 27, 1992.

11. J.M. Ogden, "Solar Hydrogen Energy Systems," Mechanical Engineering Dept. seminar presented at the University of California, Riverside, October 28, 1992.

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ABSTRACT

If hydrogen is produced from renewable resources, it would be possible in principle to produce and use energy on a large scale with greatly reduced greenhouse gas emissions and very little local pollution. Here we present technical and economic assessments of alternative strategies for developing renewable hydrogen energy systems. The goal of this work is to identify the most promising paths toward use of renewable hydrogen as an energy carrier, highlighting key technologies for research and development.

We consider a variety of sources of hydrogen including electrolytic hydrogen from solar PV, solar thermal, wind, and hydropower, and hydrogen from biomass gasification; various options for storing and transmitting hydrogen; and several important end-uses, transportation and cogeneration. To evaluate pathways for producing and using hydrogen, we estimate the system performance and cost, the levelized cost of hydrogen production, the costs of hydrogen storage, transmission, distribution and delivery; and the lifecycle cost of energy services to the end-user. Environmental effects (land, water and resource requirements; emissions of pollutants and greenhouse gases) are estimated and infrastructure and consumer issues are discussed. Our results can be summarized as follows:

* In the early part of the next century, renewable hydrogen could become cost competitive with other sources of hydrogen. For on-site fuel production at small scale, PV electrolysis systems (producing hydrogen at $12-21/GJ) could compete with steam reforming of natural gas. At large scale hydrogen from biomass gasification would cost about $6-9/GJ, which would be competitive with hydrogen from natural gas (at DOE projected post-2000 natural gas prices of $4-6/GJ), and probably less expensive than hydrogen from coal gasification.

* There are good to excellent resources for renewable hydrogen production globally and in most areas of the United States. Land and water requirements would be modest. With PV electrolysis alone it would be possible to supply enough hydrogen for all light duty vehicles in the US using only 0.1% of the contiguous US land area (1% of the US desert area). With biomass about 2/3 of the present idled cropland (3% of the US land area) would be needed.

* For gaseous hydrogen delivery systems, compression and storage, pipeline transmission, local distribution and delivery as tranportation fuel would add a total of about $6-8/GJ to the hydrogen cost.

* Even though renewable hydrogen would be several times as expensive (per unit of energy) as gasoline and fuel cell cars would probably be more expensive than gasoline vehicles, hydrogen fuel cell vehicles might be able compete on a lifecycle cost basis with gasoline and electric battery vehicles. Assuming that goals for fuel cells and batteries are acheived, this would occur because fuel cell vehicles would be 2-3 times as energy efficient as gasoline vehicles, and would have a longer lifetime and lower maintenance costs. Our analysis of alternative transportation fuels indicates that the delivered fuel cost alone is not a good indicator of the total cost of energy services. Hydrogen can compete with gasoline on a lifecycle cost basis, even though it costs more per unit of energy.