A TECHNICAL AND ECONOMIC ASSESSMENT OF RENEWABLE TRANSPORTATION FUELS AND TECHNOLOGIES

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EXECUTIVE SUMMARY

Introduction

Despite significant reductions in tailpipe emissions over the past two decades, motor vehicles still account for 30 to 70% of all urban air pollution in the US and up to 30% of emissions of carbon dioxide related to energy use. In most countries of the world, ground transportation uses petroleum based fuels exclusively, and is hence vulnerable to supply and price volatility of the world oil market. Environmental and energy supply concerns are motivating a search for lower-polluting and more widely produced alternatives to petroleum transportation fuels and to internal combustion engines.

To address environmental and energy supply problems posed by our current transportation system, the most attractive strategies are those where fuels could be *(1)* produced economically on a large scale from domestic resources and *(2)* produced and used with minimal emissions of criteria air pollutants (NO_x, CO, unburned hydrocarbons, particulates, SO_x) and greenhouse gases.

If transportation fuels were derived from renewable sources (solar, wind, hydropower, biomass), emissions of greenhouse gases would be largely eliminated. In the United States, as in many areas of the world, potential renewable energy resources are vast and could ultimately meet foreseeable transportation energy demands, especially if coupled with high efficiency vehicles. If renewable fuels were used in zero or near-zero emission vehicles (e.g. battery powered electric vehicles or fuel cell electric vehicles), emissions of local pollutants would be eliminated or greatly reduced.

In this report, we review the technical and economic prospects for and R&D challenges facing transportation systems based on renewable fuels. We perform quantitative analyses only for light-duty vehicles, but some of our conclusions apply to heavy-duty vehicles as well. We concentrate our assessments on several fuels (ethanol, methanol, electricity and hydrogen) which could be used with significantly reduced emissions of conventional pollutants and greenhouse gases and which could be produced on a large scale from domestic renewable resources. We first review the status of technologies for producing and delivering these fuels and the potential renewable energy resources of the US. We then outline the status of alternative vehicle technologies--internal combustion engine vehicles (ICEVs), battery powered electric vehicles (BPEVs), hybrid (ICE/BPE) vehicles, and fuel cell electric vehicles (FCEVs)--and discuss the performance, economics, and emissions characteristics of these vehicles using alternative renewable fuels. Finally, we sketch possible transition paths from the current petroleum/internal combustion engine vehicle (ICEV) based transportation systems toward ultimate use of renewable fuels in zero or near-zero emission vehicles.

Potential Resources for Renewable Fuels Production

Large potential resources exist for renewable fuels production in the US (and in most areas of the world). It is possible in principle to supply projected US demands for transportation fuels using only renewable resources. Biomass (for the production of methanol or hydrogen) could conceivably meet all transportation energy needs if implemented together with high-efficiency vehicle technology (FCEVs). Land or water constraints would probably arise with less efficient vehicle technology. Wind and, especially, solar resources are much larger and it would be possible to produce electricity or electrolytic hydrogen in most areas of the US. Although wind- or solar-derived fuels would not be resource-constrained, high vehicle efficiencies would also be desirable with these fuels to help offset the high capital intensity of producing them.

Projected Economics of Transportation Using Renewable Fuels

Assuming cost targets for renewable fuels production technologies are met through ongoing research, development and demonstration efforts, renewable fuels in the year 2000 and beyond will be considerably less costly than if they were to be produced today, but will still be more costly than projected post-2000 prices for fossil-derived transportation fuels. (The retail price we assume as a baseline for reformulated gasoline in this period is $1.18/gallon ($1.49/gallon with taxes), based on a world crude oil price of $26.4/barrel, in

1991$.) Table ES1 gives baseline alternative-fuel production costs we estimate for the post-2000 time frame.

Despite higher fuel costs with renewable fuels, if high-efficiency vehicle technologies, especially the FCEV, reach their commercial cost targets, the total owning and operating cost

Table ES1. Baseline delivered retail fuel prices (in 1991$) assumed in our analyses.[a]

			Components of delivered fuel cost ($/GJ)				Delivered cost to consumer ($/GJ)
Transport fuel	Feedstock/ electricity source	Feedstock/ electricity cost	Production	Storage	Distri-bution	Filling station	
Methanol	Biomass	$2.5/GJ	10.4	0	1.9	1.2	14.0
Methanol	Natural gas	$3.0/GJ	7.5	0	1.9	1.2	10.6
Methanol	Coal	$1.75/GJ	10.0	0	1.9	1.2	13.1
Ethanol	Biomass	$2.5/GJ	9.1	0	1.5	0.9	11.5
Ethanol	Corn	$1/bushel	16.3	0	1.5	0.9	18.7
Hydrogen	Biomass	$2.5/GJ	8.7	0	0.5	4.4	13.6
Hydrogen	PV	3.8 c/kWh	17.2	2.4	0.5	4.4	24.5
Hydrogen	Wind	4.7 c/kWh	22.8	2.4	0.5	4.4	30.1
Hydrogen	Natural gas	$3/GJ	5.8	0	0.5	4.4	10.7
Hydrogen	Coal	$1.75/GJ	9.0	0	0.5	4.4	13.9
Hydrogen	Nuclear	5.3 c/kWh	21.2	0	0.5	4.4	26.1
CNG	Natural gas	$3/GJ	3.0	0	1.7	2.6	7.3
Reform. gasoline	Crude oil	$26.4/bbl	7.34 (97 c/gal)	0 (0 c/gal)	0.99 (13 c/gal)	0.61 (8 c/gal)	$8.95/GJ ($1.18/gal)
Utility residential electricity rates for recharging battery-powered electric vehicles							
Off-peak power							6 c/kWh
Conventional utility, 1993							7.5 c/kWh
Conventional utility, 2000							8 c/kWh
Renewables-intensive utility (post-2000)		6.4 c/kWh					7.9 c/kWh

(a) See Table 5.1a in the text.

per-kilometer for a variety of renewably-fueled transportation systems could be competitive with the cost projected for year-2000 gasoline/ICEVs. Table ES2 and ES3 show the baseline lifecycle cost (cents per km) results from our analysis of ICEVs and EVs (battery-powered or fuel-cell electric vehicles), respectively (including vehicle and fuel taxes). The result for each fuel/vehicle combination is also expressed in terms of a breakeven gasoline price, which is the retail price of gasoline (with taxes) at which the total lifecycle cost of the alternative fuel/vehicle is equal to the total lifecycle cost of the gasoline/ICEV.

Table ES2. Baseline cost results (in 1991$) from the analysis of ICEV systems.

Item	Reformulated Gasoline	Methanol (from biomass)	Ethanol (from biomass)	Compressed natural gas (CNG)	Compressed hydrogen gas (from biomass)
Fuel retail price, excluding taxes *($/gal. gasoline equiv.)* *($/GJ$_{HHV}$)*	1.18 8.95	1.85 14.0	1.52 11.5	0.96 7.30	1.79 13.6
Full retail price of vehicle, incl. taxes ($)	17,976	17,912	17,903	19,483	24,550
Levelized annual maintenance cost ($/year)	396	392	392	370	392
Total lifecycle cost (cents per km)	21.01	22.32	21.38	20.45	24.57
Breakeven gasoline price ($ per gallon)	n.a.	2.04	1.64	1.26	2.97

(a) See Table 5.4 in the text.

A range of renewable options give lifecycle costs comparable to that projected for the gasoline/ICEV. Among all fuel/vehicle options considered in this study, the projected lifecycle costs (and breakeven gasoline prices) are lowest for the methanol and hydrogen FCEVs (Table ES3). By comparison, the baseline 400-km range battery-powered electric vehicle is somewhat more expensive. There is a fair degree of uncertainty in some of the key assumptions we have used in our cost analysis. However, the results of cost sensitivity analyses included in the body of this report indicate that these two conclusions are relatively robust.

Projected Emissions for Alternative Fuel/Vehicle Systems

Tailpipe emissions of pollutants such as NO_x, CO, particulates, and non-methane organic gases (NMOGs) could be substantially reduced with ICEVs run on methanol, ethanol or hydrogen. With battery powered electric vehicles or fuel cell vehicles using hydrogen or methanol, tailpipe emissions would be essentially eliminated altogether. Table ES4 summarizes estimated ranges of reductions in criteria pollutants for alternative fuel vehicles relative to the year-2000 gasoline/ICEV.

Emissions of greenhouse gases (GHGs) would be reduced substantially compared to a gasoline/ICEV with any renewable fuel used in either an ICEV or an EV (Table ES5). The reductions would be especially large with fuel cell electric vehicles because of their high efficiency compared to ICEVs. The use of natural gas to make alternative fuels would also reduce GHG emissions, but to a lesser extent. With coal as the feedstock for fuels production, there would be increased GHG emissions with ICEVs and relatively modest reductions with FCEVs.

Table ES3. Baseline cost results (in 1991$) from the analysis of EV systems.[a]

Item	Gasoline *(640 km range)*	BPEV *(160 km range)*	BPEV *(250 km range)*	BPEV *(400 km range)*	FCEV Methanol *(560 km range)*	FCEV Hydrogen *(250 km range)*	FCEV Hydrogen *(400 km range)*
Fuel retail price, excl. taxes *($/gal. gasoline equiv.)*	1.18	2.20	2.20	2.20	1.85	1.79	1.79
($/GJ)	8.95	6 c/kWh	6 c/kWh	6 c/kWh	14.0	13.6	13.6
Full retail price of vehicle, incl. taxes ($)	17,976	20,409	21,179	26,210	21,709	22,530	25,091
Levelized annual maintenance cost ($ per year)	396	336	336	336	389	376	376
Total lifecycle cost (cents/km)	21.01	21.08	21.15	22.41	19.58	19.64	20.09
Breakeven gasoline price ($ per gallon)	n.a.	1.52	1.55	2.07	0.89	0.92	1.11

(a) See Table 5.5 in the text.

Table ES4. Percentage change in grams per km emissions of criteria pollutants from alternative-fuel light-duty vehicles relative to comparable gasoline vehicles, circa year 2000.[a]

Fuel/Vehicle		Criteria Pollutants				
	NMOG *(evap.)*	NMOG *(tailpipe)*	CO	NO_x	SO_x	PM
ICEVs						
flex.fuel methanol (M85)	-58 to -67	-50 to -58	0 to -10	0 to -10	up to -100	less
dedicated methanol (M100)	-81 to -92	-66 to -77	-10 to -30	0 to -20	up to -100	less
dual fuel CNG	-100	-87 to -93	-20 to -40	0	up to -100	less
dedicated CNG	-100	-89 to -95	-30 to -50	0 to -10	up to -100	less
flexible fuel ethanol (E85)	-36 to -49	-23 to -36	0 to -10	0 to -10	up to -100	less
dedicated hydrogen	-100	-?? to -99	-?? to -99	0 to ??	up to -100	to -100
EVs						
BPEV/US power mix	-100	-94 to -99	-95 to -99	-60 to -80	more	more
BPEV/solar power	-100	-100	-100	-100	-100	-100
FCEV/methanol	-?? to -99	-100	-?? to -99	-?? to -99	up to -100	-100
FCEV/hydrogen		-100	-100	-100	-100	-100

(a) See Table 5.10 in the text.

Paths toward large-scale use of renewable transportation fuels

Various evolutionary paths leading from current technologies toward use of renewable fuels in zero emission vehicles can be sketched. Assuming that air quality, global warming and energy supply security are strong concerns over the next few decades, the progression would be toward transportation fuels and vehicle technologies offering reduced tailpipe emissions and higher energy efficiency and toward more reliance on domestically available renewable sources.

Early initial steps (before the year 2000) could be the introduction of BPEVs and/or ICEVs operating on compressed natural gas, methanol or hydrogen made from natural gas, or ethanol made from corn. Reductions in pollutant emissions would be modest (ethanol and methanol) to significant (CNG) to dramatic (hydrogen and BPEV). Reductions in greenhouse gas emissions would be nil (ethanol) to slight (methanol and BPEV) to significant (CNG and

Table ES5. Percentage change in fuel-cycle, CO_2-equivalent emissions of greenhouse gases per km of travel relative to reformulated gasoline in ICEVs, circa year-2000.[a]

Feedstock/Fuel	Fuel-cycle CO_2-equivalent emissions (grams/km)	Change in CO_2-equivalent emissions (%)
Internal Combustion Engine Vehicles (ICEVs)		
Coal/methanol	461	+58
Coal/compressed H_2	443	+52
Corn/ethanol (E85)	323	+11
Corn/dedicated ethanol (E100)	310	+6
Natural gas/dedicated methanol (M100)	273	-6
Natural gas/compressed H_2	216	-25
Natural gas/dedicated CNG	215	-26
Biomass/compressed H_2	73	-75
Solar/compressed H_2	52	-82
Biomass/methanol	50	-83
Biomass/ethanol (E85)	35	-88
Biomass/dedicated ethanol (E100)	-27	-109
Battery Powered Electric Vehicles (BPEVs)		
Average US power generating mix	249	-14
Solar power	0	-100
Fuel Cell Electric Vehicles (FCEVs)		
Coal/methanol	211	-27
Coal/compressed H_2	183	-37
Natural gas/methanol	122	-58
Natural gas/compressed H2	89	-69
Biomass/compressed H_2	29	-90
Solar/compressed H_2	20	-93
Biomass/methanol	17	-94
All solar/compressed H_2	0	-100
Petroleum/reformulated gasoline in an ICEV	291	n.a.

(a) See Table 5.12 in text.

hydrogen). The per-kilometer lifecycle costs for the methanol and CNG options would be comparable to those for gasoline/ICEVs, while the costs for the ethanol and hydrogen ICEVs would be 10-15% higher and for the BPEV (with nearly comparable range as the other options) would be 5-10% higher. The commercial development of technology for ethanol production from lignocellulosic biomass would bring lifecycle costs for the ethanol/ICEV to a competitive level with gasoline/ICEVs.

The subsequent introduction of fuel cell vehicles operating on methanol or hydrogen from natural gas would both eliminate tailpipe emissions and substantially reduce greenhouse gas emissions (because of the higher efficiency of FCEVs), while perhaps *reducing* the per-km lifecycle cost of transportation relative to the gasoline/ICEV. The technologies presently being emphasized for FCEVs (based on the proton exchange membrane fuel cell) would be better suited to the use of hydrogen or on-board-reformed methanol than to the use of on-board-reformed ethanol or natural gas.

Further reductions in greenhouse gas emissions would be accomplished through the production of methanol or hydrogen fuels from renewable energy sources. Despite relatively high retail prices for renewable fuels, the per-km lifecycle cost of renewable/FCEVs would be close to, or lower than, the costs for gasoline/ICEVs. With either methanol or hydrogen made from renewable resources, it would ultimately be possible to reduce pollutant and greenhouse gas emissions to near zero. The high efficiency of the FCEV greatly facilitates providing transportation energy needs from renewable resources because they are land or capital intensive. Methanol production requires a carbon source; thus biomass grown in ecologically sustainable ways is the only viable renewable source for this fuel. Hydrogen can be produced thermochemically from biomass or electrolytically from wind or solar resources. At large-scale, biomass is the lowest-cost option for renewable hydrogen (by a factor of two). The resource potentials of wind and solar energy are much larger than of biomass, though potential biomass resources are substantial enough to provide a large (if not full) share of future transportation energy needs.

For BPEVs tailpipe emissions would be zero. Greenhouse gas and other emissions could be reduced through greater use of renewable fuels by electric utilities. Ultimately, it will be possible to produce and use renewable electricity on a large scale with very little emission of greenhouse gases and no tailpipe emissions. However, the long recharging time of BPEVs and their higher projected costs relative to methanol or hydrogen FCEVs may limit their market.

In summary, it appears that in the long term it would be possible to meet US demands for transportation fuels from domestic renewable resources--biomass, wind and solar energy. Greenhouse gas and pollutant emissions could be greatly reduced or even eliminated. The delivered cost of renewable transportation fuels would probably be higher than the cost of gasoline or compressed natural gas. (Biomass derived fuels would be less expensive than electrolytic hydrogen, although the biomass resource potential is more limited than for wind or solar.) However, the lifecycle costs of transportation with renewable fuels might be comparable to that of current gasoline ICEVs, and would also compete with other long term options (e.g. synthetic fuels from coal or nuclear sources.) Fuel cell vehicles would be particularly attractive, as they would combine cost-competitiveness with zero emissions and consumer appeal (long range, fast refueling time). Energy carriers which can be used in low-temperature fuel cell vehicles (methanol and hydrogen) may ultimately become the fuels of choice for general purpose light duty vehicles in the US.

Research, Development and Demonstration Challenges

The details of how renewable transportation fuels might be introduced are not clear at this time. What is clear, however, is that there are technological hurdles to overcome before commercial realization of a transition from today's transportation system to one based entirely (or nearly entirely) on renewable resources. Table ES6 and the discussion below briefly summarizes these key research and development challenges.

Production of fuels from renewable resources

Development of biomass gasifiers for methanol and hydrogen production. Biomass gasifiers that would be suitable for methanol or hydrogen production are under active commercial demonstration. The most promising gasifier designs (indirectly-heated systems) are in a somewhat earlier state of development. In any case, with a continued R&D effort, suitable gasifier technologies could be commercially available before the end of the century.

Development of large-scale biomass energy plantations. Cost reductions projected for the next decade should bring costs of biomass grown on dedicated energy plantations into commercial viability. The commercial implementation of plantations might occur in parallel with this, either on especially good sites and/or where the biomass would be produced for use in electric power generation. Ecological guidelines for establishing plantations must be developed as well during this process. By the middle of the first decade of the 21st century, large-scale biomass plantations may be commercially operating in the US and able to provide feedstocks for transportation fuels production.

Development of enzymatic hydrolysis for ethanol production from biomass. Ethanol can be made from corn, but doing so is economically and energetically unattractive. On the other hand the production of ethanol by enzymatic hydrolysis of lignocellulosic biomass is promising. This technology has been proven in the laboratory. Pilot-scale demonstration is now planned. Additionally, a commercial-scale demonstration is needed before the technology can be considered commercially ready.

Development of electrolytic hydrogen systems using intermittent power. Electrolysis is a comme2rcially available technology. Electrolysis using intermittent PV and wind electricity are currently being researched. There appear to be no serious problems in commercializing electrolyzers for use with wind or solar power over the next ten to twenty years, though optimization for intermittent operation is one issue requiring special attention. For electrolytic hydrogen production, reducing the cost of wind and solar electricity is also important.

Production of electricity from renewable resources

Development of biomass gasifier/gas turbine technology. This technology is now operating at pilot scale, and several commercial-scale demonstrations are at various stages of development. Thus, the technology is likely to be commercially ready before the year 2000. The technology promises baseload electricity production costs at modest scale that will be competitive with electricity from large central-station coal and nuclear plants.

Development of biomass gasifier/fuel cell technology. Molten carbonate or solid oxide fuel cells fueled with gasified biomass are in the conceptual design stage, although analogous systems for coal have been the focus of R&D efforts. Molten carbonate and solid oxide fuel cells fueled with natural gas are in the demonstration phase. These might be commercialized by early in the next century.

Development of low cost PV and wind power. Rapid progress is occurring in both PV and wind technologies. It is likely that economically attractive intermittent power from wind might be available around the year 2000 and from solar PV systems in the early part of the next century.

Transmission and distribution of fuels and electricity

Integration of intermittent renewable electricity resources into utility grids. This has already been done on a small scale by a number of utilities and is being evaluated further. A recent study discussed in this report indicates that it should be possible for an electric utility in the post-2000 time period to supply large quantities of electricity from a mix of renewable sources with little or no increase in the cost of production compared to a conventional fossil-based utility, and with significant reductions in greenhouse gas emissions.

Development of recharging systems for BPEVs. Existing utility grids could be modified for home recharging of electric vehicles. The primary changes required would be addition of higher capacity distribution and residential circuits. In remote sites, battery powered electric vehicles might be recharged from stand-alone PV systems.

Development of hydrogen infrastructure. Development of hydrogen as a transportation fuel poses special problems, as no widespread infrastructure exists today for distributing hydrogen to consumers. Technologies for distributing, compressing, and storing hydrogen are well known and commercially available. The main issue here is system design. It would be possible to demonstrate hydrogen refueling station technology (based on small-scale steam reforming of natural gas or electrolysis to produce hydrogen at the point of use) within the next few years. The development of an infrastructure for hydrogen distribution from large centralized facilities will require a larger, longer-term commitment to hydrogen fuel, but poses no major R&D hurdles.

Vehicle technologies

Reducing emissions from ICEVs. With ICEV technology, the major R&D challenges are in reducing emissions, both by improving emission control and improving fuel quality. With methanol/ICEVs, formaldehyde is of special concern. With ethanol/ICEVs, acetaldehyde emissions are of concern. With hydrogen/ ICEVs, the main concern is reduction

1.0. INTRODUCTION

Despite significant reductions in tailpipe emissions over the past two decades, motor vehicles still account for 30 to 70% of all urban air pollutants (USEPA, 1992) and up to 30% of emissions of carbon dioxide related to energy use (DeLuchi, 1991). In most countries of the world, ground transportation uses petroleum based fuels exclusively, and is hence vulnerable to supply and price volatility of the world oil market. Environmental and energy supply concerns are motivating a search for lower-polluting and more widely produced alternatives to petroleum transportation fuels and to internal combustion engines.

There are many possible options for automotive transportation. Some major options now under consideration are sketched in Figure 1, where the primary energy source, the intermediate energy carrier, and the vehicle technology are shown. (Renewable-energy pathways are shown as solid lines.) To address environmental and energy supply problems posed by our current transportation system, the most attractive combinations are those where fuels could be *(1)* produced economically on a large scale from domestic resources and *(2)* produced and used with minimal emissions of criteria air pollutants (NO_x, CO, unburned hydrocarbons, particulates, SO_x) and greenhouse gases.

If transportation fuels were derived from renewable sources (solar, wind, hydropower, biomass), emissions of greenhouse gases would be largely eliminated. In the United States, as in many areas of the world, potential renewable energy resources are vast, and could ultimately meet foreseeable transportation energy demands (Ogden and Nitsch, 1993). If renewable fuels were used in zero or near zero emission vehicles (e.g. battery powered electric vehicles or fuel cell electric vehicles), emissions of local pollutants would be eliminated or greatly reduced.

We review here the prospects for and R&D challenges facing renewable transportation systems. We consider several renewable fuels which could be used with very low pollution (methanol, ethanol, electricity, and hydrogen). First, we review the status of technologies for producing and delivering these fuels. We then outline the status of alternative vehicle technologies (internal combustion engine vehicles, battery powered electric vehicles, and fuel cell electric vehicles) and discuss the performance, economics, and emissions characteristics of alternative light-duty vehicles using renewable fuels. Finally, we sketch possible transition paths from the current petroleum/internal combustion engine vehicle (ICEV) based transportation systems toward ultimate use of renewable fuels in zero or near-zero emission vehicles.

2.0. TECHNOLOGIES FOR THE PRODUCTION AND DELIVERY OF RENEWABLE TRANSPORTATION FUELS

A variety of transportation fuels can be produced from renewable resources. Here we describe the technologies for producing and delivering four of the most promising energy carriers that have the potential for being used with zero or near zero pollution: methanol, ethanol, hydrogen and electricity. The renewable energy resources we consider are wind, hydropower, solar, and biomass. The technologies we describe are at various stages of development, and we discuss the main research and development challenges to commercializing each.

2.1. PRODUCTION OF BIOMASS ENERGY FEEDSTOCKS

Ethanol, methanol, hydrogen, and electricity can all be produced from renewable biomass energy sources. A key element in the successful commercialization of such technologies is the sustainable production of economically viable biomass feedstocks. For biomass-energy resources to be large enough to be able to play an important role in the transportation-energy future of the country will require the production of biomass on dedicated farms. (See Section 3.2.) At present there are no biomass plantations dedicated to the production of energy feedstocks operating commercially in the US. There are three major challenges to developing such systems in the future: *(1)* presently unfavorable economics; *(2)* uncertain environmental impacts of large-scale biomass-energy production; and *(3)* the long lead times (especially for woody crops) between establishing an energy farm and seeing the revenues from the first harvest. On the positive side, the first large-scale biomass-energy plantations are likely to be established within the decade to fuel electricity generating plants, thereby providing a jump-start on plantations for transportation fuels.

Over the next decade or so, the cost of biomass production is anticipated to fall to below \$2.5/GJ (in most parts of the US), or half the cost with today's technology. Cost reductions are anticipated as a result of improved plantation management, improved land productivity, and improved harvesting methods (Fig. 2.1.1).

The potential ecosystem impacts of large-scale biomass-energy plantations have only recently begun to be explored (US Congress, 1993; Beyea et al, 1991; Cook et al, 1991). No definitive guidelines have been developed for establishing and maintaining ecologically acceptable plantations. Key issues that are not well understood and that must be addressed by such guidelines include nutrient cycling, soil quality and erosion, species selection, hydrology, biodiversity impacts, and landscape design. Large-scale field studies, perhaps undertaken with commercial demonstration efforts, are required to collect the data needed for developing ecological guidelines. The inherently long time-scales associated with such field studies might be reduced somewhat if effective ecosystem modeling capability can be developed.

Woody biomass energy crops will typically require from 3 to 10 years from planting to first harvest. This could potentially create a situation in which the biomass farmer must manage without revenues for several years. On the other hand, the owners of biomass conversion facilities may be reluctant to make the large capital investments associated with conversion plants without a demonstrated, secure, long-term supply of biomass. Novel institutional arrangements may be needed to deal with this situation. Considering that the capital cost for a fluid fuel production facility will be five to seven times the investment needed to establish the plantations to feed the facility,[1] institutional arrangements may be conceivable whereby the facility owner also finances the establishment cost and initial revenue requirements of the farmer.

The first biomass plantations established in the US are likely to be for fueling electric power generation, because advanced technology for MW-scale electricity production from biomass that would be competitive with coal and nuclear electricity generation is closer to--and moving more rapidly toward--commercial readiness than transportation fuels production technology. [See (USDOE, 1992) and Section 2.3.1.5 below]. Thus, the technology for cost-

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[1] For a facility rated to convert 1650 dry tonnes of biomass per day to methanol (hydrogen), the estimated capital requirement is $144 million ($144 million)--see later discussion in this section. If the biomass feedstocks are grown on land with an average annual yield of 15 dry tonnes per hectare, and the establishment cost per hectare is $1000, the total establishment cost would be $36 million.

competitive, ecologically acceptable biomass plantations is likely to be developed (and implemented to an initial degree) independently of, and perhaps sooner than, transportation fuels production technologies.

2.2. ALCOHOL FUELS FROM BIOMASS

2.2.1. Ethanol

Two varieties of ethanol are produced from biomass today: anhydrous ethanol (100% ethanol) and hydrous ethanol (containing about 5% water). Anhydrous ethanol can be blended with gasoline up to a maximum ethanol content of 20% to boost the octane rating (World Bank, 1980). Hydrous ethanol cannot be blended with gasoline in conventional internal combustion engines (ICEs), but can be used alone as a fuel (neat fuel) or in a variable mixture with gasoline in ICEs specifically designed for these purposes (Office of Mobile Sources, 1990). Ethanol can be produced from a variety of biomass crops, including starch-laden crops like corn, sugar-laden crops like sugarcane, or lignocellulosic feedstocks like wood or grasses. Brazil is the world's largest producer and consumer (some 12 billion liters per year) of ethanol in vehicles, with ethanol from sugarcane accounting for 30 to 40% of its transportation fuel needs. Corn and lignocellulose are the feedstocks that are most commonly considered for ethanol production in the United States.

2.2.1.1. Ethanol from Corn

The United States is the world's major producer of ethanol from corn, with a reported production in 1992 of 3.3 billion liters of anhydrous ethanol for use in a 10% blend with gasoline (FMWA, 1993). This corresponds to about 8% of total gasoline use in the US.

Technology. Two-thirds of US ethanol is produced using a wet milling process and one-third using a dry-milling process (Wyman, et al., 1993). In dry milling, the corn kernels are ground and then cooked in water to gelatinize the starch. Enzymes (amylases) are added to convert the starch to glucose, which is then fermented by yeasts. Carbon dioxide released during fermentation can be recovered for sale as a byproduct. The remaining ethanol-water mixture is distilled to produce 100% ethanol. A solid byproduct of distillation, called DDGS (distiller's dried grains and solubles), is sold for cattle feed. Typically, one dry tonne of corn will yield 458 liters of ethanol, 380 kg of DDGS, and 340 kg of CO_2. In wet milling, insoluble protein, fiber, and some solids are separated from the starch before it is converted to sugars and fermented. The yields per tonne of dry corn from this process are typically 440 liters of ethanol, 330 kg of CO_2, 275 kg of corn glutten (a cattle feed ingredient), 70 kg of corn glutten meal (a poultry feed ingredient), and 37 kg of corn oil (for human consumption).

A significant amount of energy is consumed in making ethanol from corn. The ethanol product contains about 60% of the energy originally in the corn, but processing requires external energy input. If the by-products of ethanol production (like CO_2 and DDGS) are appropriately charged for the share of energy input their production requires, the net fraction of input corn energy converted to ethanol is estimated to be 37% (Wyman, et al, 1993). If the energy inputs required to grow the corn (fertilizers, herbicides, machinery fuel, etc.) are incorporated into this energy balance, the net fraction of the input corn energy converted to ethanol is estimated to be from -2% to +11% (Wyman et al, 1993). This energy balance does not take credit for the corn stover (field residue), approximately one tonne of which is produced per tonne of corn harvested (Benson and Pearce, 1987). The stover energy exceeds the external energy required at a corn-to-ethanol plant, so the net energy fraction might improve considerably if the portion of the stover that can be removed from the field without agronomic impacts were used for generating process energy.

Economics. The cost of corn-derived ethanol depends sensitively on the cost of corn. Corn cost fluctuates considerably from year to year due to changes in weather, input costs, agricultural policy, and other factors; over the three-year period, 1984-1986, the "net cost of corn" to ethanol producers (the cost of corn minus credits for sale of by-products) ranged from -\$1.4 to \$87/dry tonne (-\$0.03 to \$1.87/bushel) (Wyman et al., 1993). The total cost of ethanol production at a large wet-milling plant for corn with a net cost per dry tonne of \$0, \$50, \$100, and \$150 (0-\$3.2/bushel) would be about \$10.3, \$15.3, \$20.2, \$25.3/GJ, respectively (Larson, 1993).[2] With no cost for the corn, ethanol would be competitive as a gasoline octane booster with oil at about \$22/bbl, while for corn costing \$100/dry tonne

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[2] All costs in this report are expressed in constant 1991\$ using US GDP deflators. Table 1 gives basic assumptions used in cost assessments presented in this report.

($2.1/bushel), the oil price would need to be close to $40/bbl (Table 2.2.1).[3] As a neat fuel (100% ethanol), the break-even per barrel oil prices would be considerably higher (Table 2.2.1). To encourage ethanol use in the US despite the unfavorable economics, the gasoline excise tax is reduced by 1.6 cents per liter for ethanol-blended gasoline (Office of Mobile Sources, 1990). In effect, this provides a subsidy of about $0.16/liter ($6.6/GJ), which significantly improves ethanol production economics.

2.2.1.2. Ethanol from Lignocellulose

The high cost of corn ethanol has motivated efforts to convert lower-cost biomass, primarily woody and herbaceous materials, into ethanol. These feedstocks are less costly largely because they do not compete as food crops. However, the same reason that they are not considered for animal or human consumption (indigestibility), makes them more difficult (and to date more costly) to convert into ethanol. Advances in biotechnology may change this outlook.

Fundamentals. Woody and herbaceous biomass, referred to generally as lignocellulose, consists of three components: cellulose (about 50%), hemicellulose (25%), and lignin (25%). Cellulose is a crystalline lattice of long chains of glucose molecules. Its crystallinity makes it difficult to unbundle into simple sugars. Once they are produced, however, the sugars are easily fermented into ethanol. Hemicellulose consists of polymers of 5-carbon sugars, such as xylose. Hemicellulose is easily broken down into simple xylose sugars, but these are difficult to ferment. Lignin is made up of phenols, not sugars, and for practical purposes is unfermentable to ethanol.

A number of alternative process routes have been tested or proposed for converting lignocellulose into ethanol (Wright, 1988a). Most proposed processes involve separate processing of cellulose, hemicellulose, and lignin (Fig. 2.2.1a). After separation, the cellulose is treated in either an acid or enzyme-catalyzed hydrolysis (adding water) process to convert it into fermentable glucose. Pretreatment breaks the hemicellulose down into sugars that are separated out. The lignin is also removed. The xylose is typically either converted into

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[3] These estimates assume distribution and filling station costs of 13 cents/gallon and 8 cents/gallon, respectively.

furfural, a saleable by-product, or combined with the lignin and used as fuel for meeting on-site energy needs. (Recently, progress has been made toward fermenting xylose sugars, as discussed later.) Distillation of the fermentation products produces ethanol. Depending on the production process, different by-products are co-produced with the ethanol, the most highly valued of which are furfural and electricity.

Hydrolysis of cellulose has traditionally been done with the help of acids. Enzyme-catalyzed hydrolysis is a more recent development.

2.2.1.2.1. Acid hydrolysis

Acid hydrolysis of cellulose is a commercial technology (Wright et al, 1985), with installations built as long ago as the 1930s. However, the technology is far from large-scale economic viability at present. Much R&D effort has been aimed at improving the low yields (55% to 75% of the cellulose) achievable with currently available technology based on dilute sulfuric acid (Wright, 1988a). This acid will attack and degrade some of the product sugars in the hydrolysis step so that they cannot be fermented, thereby reducing overall yield. A number of different acids and/or reactor configurations have been explored (Wyman et al, 1993; Wright et al, 1985; Bergeron et al, 1989; Bulls et al, 1991). Large amounts of inexpensive acids, e.g. concentrated H_2SO_4, or smaller amounts of more costly acids, e.g. HF, can improve yield. Low-cost recovery and reuse of the acids is necessary to keep production costs down, however (Wright et al, 1985). Recycling of acids is challenging, because of their corrosive nature, and it has yet to be proven commercially viable.

The estimated total cost of producing ethanol by different proposed acid hydrolysis processes is high ($15-$20/GJ) (Larson, 1991). The potential for cost reduction is limited because the maximum overall efficiency of converting energy in the biomass feedstock by acid hydrolysis is only about 30%.

Ethanol produced by the dilute-H_2SO_4 process becomes considerably more attractive economically when furfural production from the hemicellulose fraction is maximized (Bergeron et al, 1989; Bulls et al, 1991), and the revenues from the sale of furfural are credited against the cost of ethanol production (Larson, 1991). The size of furfural markets is small compared to the volume that would be produced by a large-scale fuel-ethanol industry, however, so that in the long-term furfural revenues will not provide the basis for economic sustainability of an acid hydrolysis ethanol industry.

By-product electricity could be another potentially important revenue source to off-set ethanol costs. The amounts of exportable electricity co-produced in process configurations proposed to date are small, but this situation might change if more advanced cogeneration technologies, like gas turbines, are considered. No such evaluations have been reported in the literature.

Unless world oil prices rise considerably (to $40/barrel or more), ethanol from acid hydrolysis appears to be an unpromising technology, particularly in light of promising developments in enzymatic hydrolysis.

2.2.1.2.2. Enzymatic hydrolysis

Enzymatic hydrolysis of cellulose has been under development for about two decades. Advances that have been made in the technology specifically and in biotechnology more generally suggest economically-competitive commercial systems could be developed by early next century.

In enzymatic hydrolysis, biological enzymes take the place of acid in the hydrolysis step. Enzymes typically act only to break down the cellulose and do not attack the product sugars. Thus, in principle, yields near 100% from cellulose can be achieved. A feedstock pretreatment step is required since biomass is naturally resistant to enzyme attack. The most promising of several options for pretreatment appears to be treatment by a dilute acid (Wright, 1988b), in which the hemicellulose is converted to xylose sugars that are separated out, leaving a porous material of cellulose and lignin that can more readily be attacked by enzymes (Wyman et al, 1993). A number of bacteria and yeasts have been identified and tested as catalyzers of cellulose hydrolysis, and several variants of the basic process have been proposed. Researchers have focussed most on three process configurations.

In the separate hydrolysis and fermentation (SHF) of cellulose, distinct operations produce enzymes, hydrolyze cellulose, and ferment glucose (Fig. 2.2.1a). The presence of glucose produced during hydrolysis slows or stops enzymes typically used in SHF processes. This end-product inhibition limits glucose yields and hydrolysis reaction rates and leads to higher enzyme consumption, all of which increase cost. Some enzymes have been identified which are less susceptable to end-product inhibition, but the improvement in overall economics of the SHF process are relatively modest (Wright, 1988a).

Simultaneous saccharification and fermentation (SSF) involves a more promising modification, wherein glucose is continually removed by simultaneously hydrolyzing and fermenting in the same reactor (Fig. 2.2.1b). Economics are substantially improved over SHF processes because more complete hydrolysis of cellulose occurs, at faster rates, and in one rather than two reactor vessels (Wright et al, 1988b). This currently appears to be the most promising route to achieving reasonable economics in converting cellulose to ethanol.

The single most important factor that can further improve the SSF process is xylose fermentation. Xylose contains 30% to 60% of total fermentable sugars in biomass (Wright, 1989), but yeasts and bacteria used in SSF processes cannot ferment xylose sugars to ethanol. Recent research has identified alternative yeasts, bacteria, fungi, and enzymes that can ferment xylose (Hinman et al, 1989). Integrating xylose fermentation with SSF cellulose fermentation (Fig. 2.2.1b) promises significant reductions in the cost for ethanol from biomass (Lynd et al, 1991). Projected total biomass energy conversion efficiency to ethanol with improved xylose fermentation is about 64% (Wyman et al, 1993). If projected capital cost and performance projections for SSF with xylose fermentation are realized in practice, hydrous ethanol from enzymatic hydrolysis would cost about \$9.1/GJ to produce (Table 2.2.1a). Used in an ICE, the delivered price of this ethanol (\$11.5/GJ) would be competitive with gasoline when oil prices are above \$25/barrel (Table 2.2.1). One-third of the delivered cost would be due to feedstock (with biomass costing \$2.5/GJ). Improvements in conversion efficiencies (feedstock energy to ethanol energy) beyond the projected 64% would lead to further decreases in ethanol cost.

A second factor that would improve SSF process economics is the efficient use of the lignin fraction for electricity production. Stone and Lynd (1993) indicate that electrical energy equivalent to 12% of the ethanol energy could be generated in excess of onsite needs at an advanced SSF facility. They suggest that the sale of this electricity could help improve the overall economics of the process.

There have been some efforts to combine enzyme production, cellulose hydrolysis and glucose fermentation in a single reactor--direct microbial conversion (DMC) (Fig. 2.2.1c) (Wyman et al, 1993; Bull, 1990). In limited efforts to date, ethanol yields have been lower than for the SHF or SSF processes, and a number of undesired products in addition to ethanol have been produced.

2.2.1.3. Research and development challenges to commercializing ethanol

Essentially all of the progress in enzymatic hydrolysis technology has been achieved at the laboratory scale. For biomass-derived ethanol production to become a commercial and cost-competitive technology will require pilot and commercial-scale demonstrations, followed by actual commercial installations that can meet projected costs for advanced enzymatic hydrolysis processes (Fig. 2.2.2). To demonstrate the long-term sustainable production of ethanol will require a demonstration of the full fuel cycle, including production of the biomass on ecologically acceptable, dedicated energy plantations.

The combined demonstration of plantation biomass production and advanced technology for conversion to fluid fuel may be more important in the case of ethanol than methanol or hydrogen. As discussed in detail below, the latter two are produced via thermochemical (high-temperature) processes, unlike ethanol. Enzymatic processes in general are typically quite particular about the feedstock on which they act. On the other hand, thermochemical processes are relatively insensitive to the mix of input biomass feedstocks. This distinction between tolerable feedstocks may have implications for the mix of species that can be grown on the plantations (US Congress, 1993). Mixed species plantations, which thermochemical processes are likely to be better suited to than biological processes, may be ecologically preferred.

2.2.2. Methanol

Methanol production from biomass involves processing that is similar to the well-studied production of methanol from coal (Probstein and Hicks, 1982; Office of Policy, Planning and Analysis, 1989). Thermochemical gasification is followed by a series of downstream steps using commercially-established technology similar to that used to make methanol from natural gas, the predominant feedstock used today. A number of analyses have examined the thermodynamics and costs of producing methanol from biomass considering a variety of gasifier designs (Larson et al., 1994; Wyman et al, 1993; Katofsky, 1993; Stevens, 1991; Office of Policy, Planning and Analysis, 1990; Kosstrin and Himmelblau, 1985).

2.2.2.1 Technology

The production of methanol (CH_3OH) (Fig. 2.2.3) begins with gasification. A number of developmental gasifiers were operated in the late-1970s/early-1980s with methanol production in mind (Larson et al, 1989; Wyman et al, 1993; Katofsky, 1993; Office of Policy, Planning and Analysis, 1990; Beenackers and van Swaaij, 1985; Brecheret et al, 1980; Mundo and Wehner, 1979). Most efforts were abandoned when oil prices fell in the mid 1980s. Most work was focussed on pressurized-versions of fluidized-bed gasifiers (Fig. 2.2.4a and 2.2.4b), because pressurization reduces the cost of downstream processing equipment. Oxygen must be used as the gasifying agent to eliminate dilution of the product gas with nitrogen. Since oxygen plants have strong capital cost scale economies, most proposals for biomass-to-methanol facilities have involved large plants (typically 1500 dry tonnes/day or more of input biomass). More recently, indirectly-heated gasifiers (Fig. 2.2.4c and 2.2.4d) have been proposed (Larson et al., 1994; Wyman et al, 1993; Katofsky, 1993). These would produce a nitrogen-free gas without using oxygen, and thus might be built economically at smaller scale.

After gasification, the gas is cooled and then quenched to remove particulates and other contaminants. The gas then undergoes a series of catalyzed reactions to adjust the carbon-to-hydrogen ratio to the level needed for effective conversion into methanol. These steps are essentially those used to make methanol from natural gas (CH_4). These reactions begin with reforming hydrocarbons (mainly methane) in the gas into carbon monoxide (CO) and hydrogen (H_2) via catalytic reaction with steam. The H_2:CO ratio is then adjusted to the desired level in a "shift" reactor, wherein steam is added to produce one mole of H_2 from each mole of CO via the water-gas shift reaction: $CO + H_2O = CO_2 + H_2$. For methanol, only some of the CO leaving the reformer is shifted to H_2, with the goal of a gas with a molar ratio of H_2 to CO of two. Carbon dioxide and water vapor are then separated out, and the remaining gas is compressed and fed to a methanol synthesis reactor, wherein CO and H_2 combine over a catalyst to form methanol. Overall conversion of carbon monoxide to methanol is typically in excess of 98%.

The ratio of methanol energy produced to feedstock biomass energy input (defined here as the energy conversion ratio) ranges from 57% to 65% at a thermally-integrated facility,[4] with the higher conversion resulting from indirectly-heated gasification (Table 2.2.2). Some external input of electricity is required in the process. Assuming biomass is used to generate the needed electricity and counting this additional biomass as part of the feedstock input defines the thermal efficiency of the process. Thermal efficiencies for methanol production are slightly lower than the energy conversion ratios (Table 2.2.2).

Most methanol used today comes from natural gas. Coal is also receiving attention as a feedstock for the longer term. Conversion efficiencies are slightly higher with coal and significantly higher with natural gas as feedstocks (Table 2.2.2). If consideration of feedstocks for methanol production is restricted to renewable ones, biomass is the only viable option.

2.2.2.2. Economics

A number of studies have estimated the cost of methanol production from biomass (Larson et al., 1994; Wyman et al, 1993; Katofsky, 1993; Office of Policy, Planning and Analysis, 1990; Kosstrin and Himmelblau, 1985; Brecheret et al, 1980; Mundo and Wehner, 1979).

In a large production facility (about 400 MW biomass input [1700 dry tonnes/day]), the cost of methanol from biomass ranges from about \$10.9/GJ with indirectly heated gasification, to \$13.8/GJ with directly-heated gasification (Larson et al., 1994), assuming a feedstock cost of \$2.5/GJ. The higher cost for the direct gasification process is due primarily to the lower conversion efficiency and the requirement for oxygen for gasification. The lower of the costs for biomass methanol is about 10% higher than the cost of methanol from coal

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[4] Thermally-integrated refers to the fact that waste heat is recovered to the greatest extent possible and used to meet heating requirements elsewhere in the process.

and about 45% higher than the cost from natural gas (Table 2.2.3). The costs of methanol from smaller-scale biomass conversion facilities would be higher than for the scale considered here.

Being a liquid fuel, methanol would carry distribution and retailing costs that are approximately the same per unit volume as gasoline. Including these costs, we estimate the total, low-end cost of biomass-derived methanol delivered to end users would be \$14.0/GJ.

2.2.2.3. Methanol from municipal solid waste

Municipal solid waste is a potentially interesting feedstock for producing methanol. Landfills in some regions of the US, especially the Northeast, are approaching capacity. Even with ambitious recycling programs, the volume of MSW to be landfilled or otherwise utilized is large. Methanol can be made from MSW using technology that is similar to that described above for biomass. An important difference is that some pre-processing of the feedstock is required to remove non-reactive materials (metals, glass, etc.). The pre-processing step requires energy, thereby reducing the thermal efficiency of fuels production compared to biomass, and is relatively costly, contributing to increased capital costs compared to a biomass processing facility. Also, very thorough cleaning of the gasification products is required both to protect downstream processing equipment and to prevent air emissions of pollutants like dioxins. This will also increase costs, but gas cleanup will be simpler and less costly with gasification than with MSW incineration, the present state-of-the-art technology for thermochemical conversion of MSW: gas volumes after gasification are 1/3 to 1/5 of those for incineration because the gas is undiluted by combustion air, and the higher concentrations of contaminants that accompanies smaller gas volumes makes their removal easier.

The higher capital costs and lower thermal efficiency of MSW relative to biomass conversion would be offset by the lower--typically negative--cost of the feedstock. Tipping fees paid to landfills today range from \$20 to \$100 per tonne of MSW. Such tipping fees paid to a gasification facility would correspond to a feedstock cost of -\$2 to -\$10 per GJ. Based on some preliminary cost estimates for methanol production from MSW (CEES work in progress) for a tipping of about \$50 per tonne of MSW, methanol could be produced at a cost comparable to that for methanol production from natural gas costing \$3/GJ (Fig. 2.2.5).

Tipping fees are higher than this in some regions of the US (Fig. 2.2.5).

2.2.2.4. Research and development challenges to commercialization

Achieving the lowest costs for producing methanol from biomass requires the commercialization of suitable biomass gasification technology. (All unit processes downstream of the gasifier would use technology that is already commercially established.) In particular, either indirectly-heated gasifiers or oxygen-blown gasifiers are needed. With both of these, the gas that is produced is not diluted by nitrogen, so that the size of downstream processing equipment is not prohibitively large. Also, pressurization is desirable, since this further reduces the size of downstream equipment and also reduces gas compression costs.

The only commercial biomass gasifiers are fluidized-bed systems operating at atmospheric pressure using air. The bubbling-bed (Fig. 2.2.4a) was the first fluidized-bed design developed. The circulating fluidized-bed (CFB) (Fig. 2.2.4b), is an increasingly popular commercial variant. In a fluid-bed, biomass is fed continuously into a bed consisting of an inert material such as sand. Air is injected from below to keep the bed fluidized. Turbulence in the bed leads to excellent heat and mass transfer, producing relatively uniform temperatures everywhere and relatively fast reaction kinetics. The high reaction rates allow for relatively high specific throughput capabilities, especially for the CFB design.

A number of pressurized, oxygen-blown biomass gasifiers were operated in the late 1970s and early 1980s with the goal of developing them for methanol production. These efforts included laboratory/pilot and demonstration-scale units: the Institute of Gas Technology's (IGTs) Renugas (USA), Studsvik's MINO (Sweden), Creusot-Loire's unit (France), and the Biosyn gasifier (Canada) (See Fig. 2.2.6.) Among these, only the IGT effort has been carried on. The emphasis now with the IGT gasifier, however, is on pressurized air-blown gasification for use in integrated gasifier/gas turbine electric power generation (see Section 2.3.1.5.2). In fact, this is the emphasis for most other gasifier development activities as well, including Tampella and Ahlstrom (Fig. 2.2.6). Because there is significant previous experience with pressurized oxygen-blown gasification, however, the development of commercial-scale, pressurized oxygen-blown gasifiers would not be especially difficult.

However, the most favorable economics of methanol production appear to be associated with indirectly-heated gasifiers, with which there is much less experience. Indirectly-heated gasifiers are designed specifically to take advantage of the higher thermochemical reactivity of biomass compared to coal (Wyman et al, 1993; Larson et al., 1994; Katofsky, 1993). In these designs, biomass is heated by an inert heat carrying material like sand (Fig. 2.2.4c) or through a heat exchanger (Fig. 2.2.4d). Steam is injected with most designs to promote gasification reactions and/or act as a carrier gas. The indirect designs rely on the high reactivity of the feedstock to compensate for the generally lower operating temperatures that can be achieved using indirect heating. A primary attraction of the indirect design is that it produces a gas undiluted by nitrogen without using costly oxygen. Two indirectly-heated gasifiers are under development in the US today, one by the Battelle Columbus Laboratory (BCL) and one by the MTCI company (Fig. 2.2.6).

Even assuming the commercial availability of indirectly-heated biomass gasifiers, the cost of methanol production would be significantly higher than methanol production from natural gas (Tables 2.2.3), until gas prices rise substantially. One option for producing much lower cost methanol from biomass would be to produce it from municipal solid waste in areas where tipping fees are relatively high (Fig. 2.2.5). The key required development for methanol production from MSW is also the gasifier. Converting MSW into refuse-derived-fuel (RDF) by removing major non-combustible components and sizing the remaining material, thus making it suitable for gasification, is already practiced commercially. Other gasifier technologies under development, such as the Thermoselect gasifier (Riegel and Runyon, 1993), would take raw MSW into the gasifier, with non-gasified components being rejected as a molten slag. An additional R&D issue with MSW or RDF gasification is the fate of toxic components of the feed. Preliminary data from a pilot-scale Thermoselect gasifier, including an extensive gas quenching and cleaning train, suggest that air emissions from such a facility would be dramatically lower than EPA standards for MSW incinerators (Lutzke and Wehde, 1993). Treatment systems would be required to deal with toxic materials from the waste water stream.

2.3. ELECTRICITY

Electricity can be produced from a variety of renewable resources, including solar, wind, hydro power and biomass. Here we briefly review these technologies, estimate current and projected costs for electricity production, as well as the delivered cost of electricity as a transportation fuel. For more details, the reader is referred to the chapters on renewable electric technologies in Johansson et al. (1993) and the references therein.

2.3.1. Technologies for Producing Electricity from Renewables

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. How intermittent sources might be used to meet transportation demand is discussed in Section 2.3.2.

2.3.1.0. 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 nighttime charging of battery powered electric vehicles. The cost of baseload hydropower is estimated to about 3-5 cents/kWh (Moreira and Poole, 1993). Off-peak hydro power could be available for as little as 2-4 cents/kWh (Stuart, 1991).

2.3.1.1. Geothermal power

Geothermal power has been developed in a few sites around the world. The potential exists for low cost electricity which might be used for hydrogen production during off-peak hours.

2.3.1.2. 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 $1200/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, 1993) (Table 2.3.1).

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 12.8 cents/kWhAC (Table 2.3.1). [At an "excellent" site (with a wind power density of 500 Watts/m^2) the cost of electricity would be about 9.2 cents/kwh.] Recent operating experience and design studies have indicated that advanced airfoils, innovative drive controls, drive train 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 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 at a good site should fall to 8.3 cents/kWh for a good site and 5.6 cents/kWh for an excellent site. In the longer term, electricity costs could reach 4.3 to 5.9 cents/kWh. Wind technology is modular, with little economy of scale beyond typical wind turbine sizes of (50-300 kW).

2.3.1.3. Solar thermal electricity

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 (Idaho, 1990; DeLaquil, 1991; DeLaquil et.al., 1992; USDOE, 1990a) (Table 2.3.2).

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 $3000-3800/kW, and produce electricity at a cost of 14-20 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 9-13 cents/kWh (Table 2.3.2).

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% in the early part of the next century. 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 11-22 cents/kWh. In the near term, capital costs could drop to perhaps $2000-3000/kW, resulting in an electricity cost of 7- 13 cents/kWh. In the longer term, with higher capacity factor and more storage, the electricity cost could drop to 6.2-8.7 cents/kWh.

Parabolic dishes achieve 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 18-41 cents/kWh. In the longer term, costs of $1250-2000/kW and 7-13 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).

2.3.1.4. Solar photovoltaic electricity

Solar photovoltaic (PV) technologies, which convert sunlight directly into electricity, are advancing rapidly (Zweibel, 1990; Kelly, 1993; 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 achieved 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% efficient (Zweibel, 1990; Zweibel and Barnett, 1993) -- but less costly to manufacture (Table 2.3.3a).

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 commercial 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. A number of estimates of the balance of system costs for the latter are shown in Table 2.3.3b.

Large (>5 MW) PV systems today cost about $4000-9000/kW installed and produce PV electricity for 18 to 43 cents/kWh (Table 2.3.3c). 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 AC electricity costs of 9-17 cents/kWh. By the early part of the next century, with further improvements in solar cell technology and balance of system design, thin-film solar-cell or concentrator systems could cost $500-1100/kW, with AC electricity costs of 3.5-6.2 cents/kWh (Table 2.3.3c).

2.3.1.5. Biomass electricity production

For MW-scale electricity production from biomass, the boiler/steam turbine is state-of-the-art technology. Gasifier/gas turbines are approaching commercial status. In the longer term, gasifier/fuel cells are a potentially interesting technology.

2.3.1.5.1. Steam turbines

Biomass power plants operating today use the steam-Rankine cycle, a technology initially introduced into commercial use about 100 years ago. Biomass is burned in a boiler producing pressurized steam, which is expanded through a turbine to produce electricity. In the production of power only, a fully-condensing turbine is used, while in the production of electricity and heat (cogeneration), a condensing-extraction or back-pressure turbine is used (Fig. 2.3.1).

In general, the higher the peak pressure and temperature of the steam, the more efficient, sophisticated, and costly the cycle. Biomass-rankine plants operate with far more modest steam conditions than used in large, modern electric-utility coal-fired rankine systems. California has approximately 100 operating biomass plants. Most of these operate with a steam pressure and temperature of about 6 MPa and 480°C (Turnbull, 1991), compared to steam pressures of 10 to 24 MPa and temperatures of 510°C to 537°C in utility coal plants (Combustion Engineering, 1981).

Biomass plants use modest steam conditions primarily because of the strong scale-dependence of the capital cost ($/kW) of steam turbine systems--a principal reason coal and nuclear steam-electric plants are built big (500-1000 MW_e). If bio-electric plants were as large as these, fuel transport costs would be prohibitive. To help minimize the dependence of unit cost on scale, vendors use lower grade steels in the boiler tubes of small-scale steam-electric plants and make other modifications that reduce cost, but also require more modest steam temperatures and pressures, thereby leading to reduced efficiency. Plants in California operate with efficiences of 14% to 18%, compared to 35% for a modern coal plant. The best biomass plants today have efficiencies of 20-25%.

Such low efficiencies explain the reliance of existing biomass power industries on low, zero, or negative cost biomass (primarily residues of agro- and forest product-industry operations). There are still significant untapped supplies of low-cost biomass feedstocks available in many regions of the world, for which the economics of steam-rankine systems will be favorable. Thus, for the next 5-10 years the steam-rankine technology will continue to be the dominant biomass-fired power generating technology. As low-cost feedstocks become more fully utilized, higher cost feedstocks, such as plantation biomass, will be required. With such fuels, steam turbine technology will be less competitive than some alternatives discussed below.

The costs of steam-rankine systems vary widely depending on the level of sophistication. A typical installed capital cost for a 25 MW unit is $1600 to $2100/kW (Turnbull, 1991; Electric Power Research Institute, 1986). With characteristic O&M costs for the US, the total cost of electricity production at a stand-alone power plant is in the range of 7.4 to 9.1 cents/kWh, assuming a fuel cost of $2.5/GJ and a 75% capacity factor (Williams and Larson, 1993). For a cogeneration operation, where some credit is received for process steam production, electricity costs would be somewhat lower. For comparison, the estimated cost of electricity from a large new coal-fired power plant in the US is about 4.5 to 6 c/kWh for a coal price of $1.8/GJ (Williams and Larson, 1993).

2.3.1.5.2. Gas turbines

Gas turbines fueled by gasified biomass are of interest for power generation in the range of 5 to 100 MW_e.[5] In contrast to steam-cycle technology, the unit capital costs of Brayton-cycle (gas turbine) systems are relatively insensitive to scale (Williams and Larson, 1989), so that from a capital cost perspective the gas turbine is a good candidate for modest-scale biomass conversion. The gas turbine is also a good candidate for achieving higher thermodynamic efficiency because the peak cycle temperature--the key parameter determining rankine or brayton-cycle efficiency--of modern gas turbines (about 1260°C for the best gas turbine on the market) is far higher than that for steam turbines (about 540°C) (Williams and Larson, 1989).

Various biomass-gasifier/gas turbine configurations are projected to have biomass-to-electricity efficiencies of 35 to 40% (HHV) or more than double those of Rankine-cycle systems. Gas turbines are today limited to using clean fuels like natural gas or distillate fuel, but biomass-fueled systems are likely to be commercially available by the late 1990s.

Technology. A biomass-gasifier/gas turbine (BIG/GT) system uses a pressurized, air-blown reactor, the hot (900°C) products of which are partially cooled and then cleaned (using

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[5] Gas from anaerobic digestion can also be used in a gas turbine (Hanagudu, 1993), but this option has received very little attention to date.

a ceramic or sintered-metal filter) before being burned in an efficient gas turbine power cycle such as a combined cycle (Fig. 2.3.2) (Williams and Larson, 1989 and 1993). Pressurized gasification avoids energy losses associated with compressing the product gas, and cleanup at 300-400°C avoids cost and efficiency penalties of a wet scrubbing process that would reduce economic attractiveness.[6] An added complication with pressurization is feeding fuel against pressure (Miles and Miles, 1986).

The gas quality requirements for gas turbines are relatively strict to protect the turbine blades. Gas contaminants of most concern are particulates, which can erode turbine blades, and alkali vapors, which corrode blades. There appears to be a basic understanding of the means for adequately cleaning gases for gas turbine applications (Larson et al, 1989; Kurkela et al, 1991), though this has not yet been proven commercially.

Economics. Biomass-gasifier/gas turbines are characterized by high conversion efficiencies and low expected unit capital costs ($/kW) in the 5-100 MW_e size range (Larson and Williams, 1990; Elliott and Booth, 1990; Larson et al, 1991; Elliot, 1993a). The expected performance and costs compare very favorably with direct-combustion steam-turbine systems in cogeneration applications (Table 2.3.4[7]). Competitive capital costs are expected after the construction of five to ten commercial-scale units (Fig. 2.3.3). For an installed capital cost of $1500/kW and a fuel cost of $2.5/GJ, a BIG/GT operating at 40% efficiency would produce electricity at a cost of 4.5 cents/kWh (utility financing) to 5.9 cents/kWh (private financing).

While the economics of BIG/GT power generation appear attractive enough that plantation-biomass is a feasible fuel, initial BIG/GT applications are likely to be at industrial sites where biomass processing residues are readily available today, such as at cane sugar processing mills and mills in the forest products industry. Biomass-fired steam-turbine

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[6] Recently, an atmospheric-pressure gasifier with a separate tar cracking reactor has been proposed as an economic option for gas turbine applications up to about 50 MW_e (Blackadder et al, 1993). Overall efficiency would be lower than with pressurized gasification, but this may be offset by reduced capital costs and greater ease of operation.

[7] This table shows performance and capital cost estimates for biomass-gasifier/steam-injected gas turbines (BIG/STIGs). This particular gas turbine cycle would have an efficiency comparable to or somewhat lower than biomass-gasifier/gas turbine combined cycle (BIG/GTCC) technology (shown in Fig. 2.3.2). Also, capital costs for BIG/STIGs in the size ranges shown in the table would probably be lower than BIG/GTCCs (Williams and Larson, 1989).

cogeneration systems are typically used in these industries today to meet on-site steam and electricity needs. With much higher electrical efficiencies, BIG/GTs could produce 2 to 3 times as much electricity as needed onsite (Larson et al, 1991; Ogden et al, 1990a; Larson, 1992a). The excess could be sold to utilities. Because BIG/GTs would produce less steam than steam-turbines (Table 2.3.4), steam use efficiency would generally need to be improved in a factory to enable BIG/GT systems to meet on-site steam needs. This will often be possible (Ogden et al, 1990a and 1990b; Larson, 1992a), because most mills using biomass residues for fuel are intentionally designed to be somewhat inefficient so as to consume all of the biomass and thus avoid waste disposal problems.

Commercial status. Biomass-gasifier/gas turbines are likely to be commercially available by the late-1990s, because a number of development efforts are in progress (Williams and Larson, 1993). A 6 MW_e combined cycle pilot plant will start-up in June 1993 in Southern Sweden (Skog, 1993). The project is a joint-venture effort of Sydkraft, the second largest Swedish utility, and Ahlstrom, a Finnish gasifier manufacturer. A 25 MW_e combined cycle commercial demonstration supported by a $30 million grant from the Global Environment Facility is ongoing in the Northeast of Brazil (Elliott, 1993b). Engineering and pre-erection hardware development will be completed by mid-1994. The project is led by the Alternative Resources Division of the Hydroelectric Company of Sao Francisco, the utility that serves Northeast Brazil. The US Department of Energy recently launched a new initiative to develop BIG/GT technology, a major initial step of which is the testing of a pilot-scale pressurized fluidized bed gasifier in Hawaii using bagasse (50 tonnes/day input) (Lau et al, 1993). Construction is scheduled to start in 1993. A similar pressurized gasifier development effort is being pursued by Sweden's largest electric utility, Vattenfall, together with a Finnish gasifier manufacturer, Tampella (Bodlund et al, 1993; Lindman, 1993). Also in the US, the Vermont Department of Public Service, in cooperation with in-state electric utilities, is exploring possibilities for a commercial demonstration of BIG/GT technology fueled by wood chips derived from forest management operations (Sedano, 1993). Finally, the Finnish electric utility, Imatran Voima Oy (IVO), has begun development of a modified BIG/GT cycle designed specifically to take advantage of the moisture in wet feedstocks, including wood and peat (McKeough and Kurkela, 1993). Commercialization of the cycle is targeted for the late 1990s.

2.3.1.5.3 Fuel cells

The generation of technology beyond gas turbines for producing power from biomass is likely to be the fuel cell. A fuel cell resembles a battery: an anode and cathode are separated by an ion-conducting electrolyte. Unlike batteries, however, the electrodes in a fuel cell catalyze reactions involving a hydrogen-rich gas provided continuously to the cell (Appleby, 1988; Blomen, 1989). The gas reacts at the anode, and the resulting electrons are directed through an external circuit. In certain types of fuel cells, such as the polymer electrolyte and phosphoric acid fuel cells, the positive ions pass through the electrolyte; in other types of fuel cells, however, the electrolyte transports negative oxide (solid oxide fuel cells) or carbonate (molten carbonate fuel cells) ions.

Fuel cells are named according to their electrolyte. For power generation, the most promising fuel cell technologies include the molten-carbonate fuel cell (MCFC) (Energy Resources Corporation, 1991) and the solid oxide fuel cell (SOFC) (Westinghouse, 1992). These operate at high temperature: 650°C for the MCFC and 1000°C for the SOFC. The high quality waste heat from these systems can be recovered, e.g. using a Rankine steam turbine system, to increase electrical output and efficiency. Unlike other fuel cells, both of these designs are tolerant of carbon monoxide and carbon dioxide in the fuel stream, which makes them suitable for use with gasified biomass. Fuel cells are also modular (larger outputs are achieved by stacking additional cells in parallel), so that relatively modest sized systems (of the order of 10 MW_e) may not have unit costs much greater than much larger systems. Gas cleanup requirements for fuel cells may be more stringent than for gas turbines.

While almost no attention has been given to coupling biomass gasifiers with fuel cells, there has been considerable attention paid to coal gasifier/fuel cell systems (George and Mayfield, 1990). A coal gasifier/MCFC with steam turbine bottoming cycle is estimated to be able to produce electricity with an efficiency between 40 and 45%. Coal to busbar efficiencies in excess of 55% might be reached by 2020 (Douglas, 1990). Similar efficiencies can probably be reached using biomass as fuel (Williams and Larson, 1993).

2.3.2. Delivered Costs of Renewable Electricity for Transportation

The cost of producing electricity from renewables is summarized in Table 2.3.5. In the near term (1990s) off-peak hydropower would offer the lowest renewable electricity costs. By the year 2000, the cost of wind power could be about 5-8 cents/kWh, and in the longer term, both solar PV and wind look attractive (Table 2.3.5), offering costs for intermittent electricity in the range 3-6 cents/kWhAC. With current steam turbine technology, the cost of electricity from biomass would be 7-9 cents/kWh. With biomass gasifier gas turbine systems now under development, the cost of electricity production is estimated to be 4.5-6 cents/kWh.

It is important to reiterate that solar and wind costs are for intermittent electricity only, with no storage included. These costs are not directly comparable to the cost of electricity from a biomass, 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).

How could renewables be used to meet electric-vehicle transportation energy demands? How much would electricity cost, as delivered to a battery powered electric vehicle?

Most likely renewable sources would be integrated into an electric utility system. Recent studies have shown that a significant fraction (from 25-90% of the total demand) could be met with renewable sources (Kelly and Weinberg 1993). In Kelly and Weinberg's study based on data from the Pacific Gas and Electric Company, it was found that intermittent renewables could account for up to 30-50% of the total electricity production with little increase in the total cost of electricity to the consumer. The electricity production cost was about 5-6 cents/kWh (Fig. 2.3.4). The delivered cost of electricity to residential customers would be about 7-8 cents/kWh.

For a future utility system largely dependent on renewables, emissions of greenhouse gases and other pollutants would be greatly reduced. The reduction in emissions of carbon dioxide per kWh are shown in Figure 2.3.4 for scenarios including 30% and 50% penetration of intermittent renewables in the utility power mix.

Where and when recharging takes place would influence the delivered cost of electricity for transportation. It is likely that many electric vehicles will be recharged at home during the off-peak (nighttime) hours. In this case, the type of generating system used to meet this off-peak demand will determine the cost and emissions. This will depend strongly on the utility's power mix. For Kelly and Weinberg's study based on Pacific Gas & Electric data, the average cost of residential electricity would be 7-8 cents/kWh. If off-peak rates were based on less costly generating systems such as hydropower, it might be possible to offer reduced prices.

Another option for electric vehicle recharging is stand-alone solar PV charging, operating during the day (while a car was parked at work, for example or at a commuter station). For this case, some battery storage would probably be needed at the PV charging station for use on cloudy days. This would add several cents per kWh to the cost of PV electricity. The cost of electricity from small PV recharging stations would be higher than the cost of residential electricity from a renewables intensive utility. Stand-alone systems might be used in settings where daytime recharging is desirable or home charging is not feasible.

2.4. HYDROGEN

2.4.1. Technologies for Producing Hydrogen from Renewables

In this section, we describe technologies for producing hydrogen from renewable resources. There are many possible methods for renewable hydrogen production. 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 the economic assumptions given in Table 1. In the case of hydrogen produced from biomass, natural gas or coal, we have assumed that the production plant will be owned by an industrial entity such as an oil company or independent fuel producer. The economic assumptions are appropriate for industrial ownership. In the case of electrolytic hydrogen, the hydrogen plant might be owned by an electric or gas utility, an oil company or an independent fuel producer. We have shown electrolytic hydrogen costs for two sets of economic assumptions, one corresponding to electric utility costing practice, the other to industrial ownership.

2.4.1.1. 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 2.4.1 shows a solar photovoltaic electrolytic hydrogen system.

2.4.1.1.1. Solar electric sources

Technologies for producing electricity from renewables are reviewed in the previous section. For electrolytic hydrogen production, we consider intermittent or off-peak sources. We do not consider electrolysis using biomass-derived electricity, because hydrogen can be produced from biomass via thermochemical gasification at a much lower cost than via electrolysis, as we discuss in Section 2.4.1.2.

2.4.1.1.2. 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).

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 rated at only 10 to 100 kW of capacity 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 2.4.1.

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. Advances in proton exchange membrane fuel cell technology might also lead to lower costs for SPE electrolyzers. 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. Solid oxide electrolysis is another promising laboratory technology. 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. This is an area needed further research, especially the lifetimes of electrodes under intermittent operation must be further investigated. 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 Table 2.4.2).

2.4.1.1.3. Solar-electrolytic hydrogen systems

In Tables 2.4.3-2.4.6 we describe post-2000 solar electrolytic hydrogen systems based on wind, PV, solar thermal electric and hydropower. Levelized costs are shown there assuming either utility or industrial financing, with the latter yielding higher costs. The calculated production cost of hydrogen from PV would be $13-21/GJ (utility financing), equivalent in energy terms to about $1.7-2.8/gallon of gasoline (Table 2.4.3). Wind-electrolytic hydrogen is estimated to cost $16-30/GJ (Table 2.4.4). For comparison, hydrogen from off-peak hydropower costing 2-4 cents/kWh would cost $14-20/GJ (Table 2.4.5), and hydrogen from solar-thermal electricity, based on post-2000 projections, would cost $24-33/GJ (Table 2.4.6).

2.4.1.2. Hydrogen from biomass via gasification

Hydrogen can be produced from biomass using processing similar to that for methanol production (see Section 2.2.2). The thermodynamics and costs of producing hydrogen from biomass have received less attention than those for methanol production, although some work has been done (Larson et al., 1994; Katofsky, 1993; Takahashi, 1989).

The major differences between hydrogen and methanol production are that with hydrogen, as much of the CO leaving the reformer as possible is shifted to H_2 (Fig. 2.2.3). The gas from the shift reactor then enters a pressure swing adsorption (PSA) unit, wherein all gas components except H_2 are physically adsorbed and separated out. Up to 97% of the hydrogen fed to a PSA can be recovered as final product with purity greater than 99.9%. Because with hydrogen production there is not an exothermic process step analogous to methanol synthesis, the energy ratios and thermal efficiencies for hydrogen production are higher than for methanol (Table 2.2.2). The higher of the biomass-hydrogen production efficiency (for indirectly-heated gasification) is slightly lower than with coal, and significantly lower than with natural gas (Table 2.2.2).

Because of the simpler processing equipment and higher thermodynamic efficiency, the cost of hydrogen production from biomass is lower than that for methanol production. In a large production facility (about 400 MW biomass input [1700 dry tonnes/day]), the cost of hydrogen is about 20% lower than for methanol. (Compare Table 2.4.7 and Table 2.2.3.) Hydrogen from biomass costs about as much as hydrogen from coal, but about 50% more than the cost of hydrogen from natural gas (Table 2.4.7). Among renewable energy sources, biomass would be the least costly source of hydrogen at the relatively large scale considered here. As for methanol from biomass, the costs of hydrogen from smaller-scale biomass conversion facilities would be higher than for the scale considered here.

Hydrogen, like methanol, can also be produced from municipal solid waste. Based on preliminary cost estimates, a tipping fee of about $40/tonne would make MSW-derived hydrogen competitive with hydrogen from natural gas costing $3/GJ (Fig. 2.2.5).

2.4.2. Summary: Hydrogen Costs from Renewables and Comparisons to Fossil Sources

The cost of producing hydrogen from various renewable and fossil sources is summarized in Table 2.4.8 and Figure 2.4.2 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 $8.2-10.7/GJ to produce (assuming biomass costs 2-4 $/GJ), making it the least expensive method of renewable hydrogen production (Larson et al., 1994; Katofsky, 1993; DeLuchi et al., 1991b; Phillips, 1990). Electrolytic hydrogen costs would be for wind $16-30/GJ, solar PV $13-21/GJ and off-peak hydropower $14-20/GJ. Electrolytic hydrogen would cost about twice as much as hydrogen from biomass. 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 -- the cost advantage of hydrogen from biomass over PV or wind electrolysis would be reduced or possibly eliminated.

Projected costs for renewable hydrogen would be comparable to those of hydrogen produced from fossil feedstocks (Figure 2.4.2). At large scale, hydrogen from steam reforming of natural gas would cost $5-10/GJ (assuming natural gas prices of $2-6/GJ). At smaller scale (0.5 million scf/day or 200 GJ/day), steam reforming would cost about $11-17/GJ, approximately competitive with electrolysis powered by off-peak or PV (assuming that post-2000 goals for PV are met). Coal gasification plants would also exhibit strong scale economies. For large plant sizes, hydrogen from coal would cost about $8.6-13/GJ (for coal costing $1.5/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.

For electrolytic hydrogen 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.

As an example, the sensitivity of the cost of PV electrolytic hydrogen to changes in the PV and electrolyzer parameters is shown in Figure 2.4.3. The PV efficiency is the single most important factor in reducing the cost of PV hydrogen. 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).

For wind systems, it may be possible to reduce system costs, if the system were designed to produce DC power to drive an electrolyzer, rather than to produce AC power for the grid.[8]

For biomass hydrogen, feedstock costs are the largest single component of the hydrogen cost (Table 2.4.7). Target costs for biomass grown in short-rotation plantations on good quality agricultural land is the US are below $2.5/GJ (Perlack and Ranney, 1987).

2.4.3. Technologies for Delivering Hydrogen Transportation Fuel

2.4.3.1. Developing an infrastructure for hydrogen delivery

One of the key issues for development of hydrogen as a transportation fuel is that no large scale hydrogen delivery system currently exists. This is unlike the situation for gasoline, electricity or natural gas, where widespread distribution systems are already in place. Moreover, developing an infrastructure would be more difficult for hydrogen (which must be transported as a compressed gas or a cryogenic liquid) than for liquid fuels like methanol or ethanol, which can be transported and delivered to the consumer using systems similar to that for gasoline.

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[8] Costs might be further reduced by increasing the capacity utilization of the electrolyzer through an increase in the capacity factor of the wind farm. Increasing the wind farm capacity factor would entail increased capital costs, but these might be compensated for by the more effective utilization of the electrolyzer capacity. A related idea is described by Cavallo (1994).

The components making up a hydrogen energy infrastructure have already been developed. Technologies for storing, compressing, and transporting hydrogen are well known, and are used in the chemical industry today. The present hydrogen distribution system in the US consists of a few hundred miles of industrial pipeline plus fleets of trucks delivering liquid hydrogen or compressed hydrogen gas. Although about 1 EJ/year of hydrogen is produced in the United States, most of this is produced and used onsite for petroleum refining and methanol and ammonia production. Merchant hydrogen (hydrogen which is distributed) amounts to only about 0.5% of the total.

Ultimately, the large scale use of renewable hydrogen as a fuel would require the development of much larger hydrogen transmission and distribution systems. [Projected 2010 US demand for light duty vehicles, assuming hydrogen fuel cell electric vehicles were used,[9] would be about 5 EJ/year (Ogden and DeLuchi, 1993), an energy flow about 1000 times larger than the current merchant hydrogen system.]

In the near term, it is likely that hydrogen will be produced from natural gas, which is presently the least expensive source. There are several ways that the existing natural gas infrastructure could be used to bring hydrogen to consumers. First, it is possible to produce hydrogen from steam reforming of natural gas, even at relatively small scale. Hydrogen might be produced onsite for use in fleet vehicles, using small scale reformers. Alternatively, hydrogen might be blended at concentrations of up to 15-20% by volume into the existing natural gas system and separated out at the point of use. Beyond 15-20% concentrations of hydrogen, changes in the distribution and retailing systems would be required due to the differing physical characteristics of hydrogen compared to natural gas.

Another option for onsite hydrogen production is electrolysis. Here the electricity distribution system could be used to bring off-peak power to the electrolyzer. Alternatively, stand-alone PV hydrogen systems could be used.

In the longer term, as the demand for hydrogen fuel increased, central hydrogen production plants might be built, with a gaseous pipeline distribution system similar to that

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[9] Fuel cell electric vehicles (FCEVs) would be considerably more efficient that internal combustion engine vehicles. FCEVs are discussed at length in Section 4 of this report.

for natural gas.

2.4.3.2. Delivered cost of hydrogen transportation fuel

Here we estimate the cost of delivering gaseous hydrogen for use in vehicles. We assume that hydrogen is stored onboard the vehicle as a compressed gas at 8000 psia. (Hydrogen could also be stored as a cryogenic liquid or as a metal hydride. Compressed gas storage is chosen because of its simplicity, and because high pressure cylinders are commercially available, similar to those used for compressed natural gas vehicles.) The delivered cost includes the cost of hydrogen production, hydrogen compression and storage at the production site (which would be necessary to level the output of PV or wind electrolyzers), pipeline transmission (if required), local distribution costs and filling station costs.

We consider several cases:

* First, we estimate the cost of onsite hydrogen production from 1) steam reforming of natural gas, 2) electrolysis using off-peak power and 3) PV electrolysis. The hydrogen production system produces 0.5 million scf of hydrogen per day, supplying 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 refueling equipment \$2.5/GJ, so that delivery adds a total of about \$6/GJ to the cost of hydrogen. See Table 2.4.9a.

* Second we consider a "city supply" hydrogen system which produces about 50 million scf/day of hydrogen, enough to fuel a fleet of 300,000 fuel cell passenger cars. Here hydrogen is produced in a central plant. We consider various production methods using renewable resources: PV or wind electrolysis or biomass gasification. For electrolysis using intermittent power, hydrogen is compressed to 750 psia and stored in underground rock caverns to level the plant output. Here scale economies reduce compression costs to \$1.4/GJ and storage costs to \$1.0/GJ. Compression and storage would not be required for the biomass hydrogen plants, which would produce hydrogen at 1000 psia and would operate continuously. Hydrogen is fed into a city gas network and piped a short distance to about

100 filling stations for passenger cars. Local distribution costs \$0.5/GJ, and compression, storage, and refueling equipment at a service station costs \$4.4/GJ. Thus, with electrolysis using intermittent power, compression, storage and local delivery adds a total of about \$7/GJ. See Table 2.4.9b.

* Finally we consider a 75 GW "solar export" PV hydrogen system producing 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 \$7/GJ to the hydrogen cost. Because there are good to excellent local resources for renewable hydrogen production in most regions of the United States, such a system might not be used here. In Europe, however, long distance pipeline transport of hydrogen might be desirable (Ogden and Nitsch, 1993).

For hydrogen produced at small scale for onsite use, the total delivered cost of electrolytic hydrogen from PV or off-peak power would be about \$17-25/GJ (a cost of energy equivalent to about \$2.4-3.6/gallon of gasoline). The delivered cost of hydrogen from small scale steam reforming would be slightly less, about \$17-20/GJ. See Table 2.4.9a.

For biomass hydrogen produced in a "city supply" system, delivered costs would be \$13-16/GJ (equivalent to \$1.7-2.0/gallon gasoline). At this scale, the cost of hydrogen from steam reforming of natural gas would be somewhat less than for biomass, about \$9-14/GJ. The delivered cost of electrolytic hydrogen from PV or off-peak power would be about \$19-26/GJ, about twice that of hydrogen from biomass or natural gas (Figure 2.4.2).

3.0. POTENTIAL RENEWABLE ENERGY RESOURCES FOR TRANSPORTATION

Unlike fossil fuels, which are unevenly distributed throughout the world, renewable transportation fuels (methanol, ethanol, hydrogen, electricity) could be produced in many regions. Using one or more indigenous renewable resources, it would be possible, in principle, to produce large quantities of hydrogen or electricity in most parts of the world (Table 3.1). However, the contributions of various renewable sources to future transportation energy supply will depend not only on the potential resource base (Table 3.1), but on the land area and water required (Table 3.2), as well as other environmental effects of large scale renewable energy development and production.

3.1. BIOMASS RESOURCES FOR FLUID TRANSPORTATION FUELS

3.1.1. Potential Biomass Resources

Photosynthesis around the world produces 220 billion dry tonnes of new biomass annually (Hall, 1989), the energy equivalent of ten times present global primary energy use.[10] Less than 1.5% of this is currently used for energy. In the US, biomass accounts for about 4% (or 3 EJ) of primary energy consumption. Production of biomass for energy could be increased considerably through greater use of existing resources and/or more extensive development of managed biomass-energy plantations. The three largest potential sources of biomass for energy are residues (agricultural, industrial, and municipal), natural forests, and plantations. Hall, et al. (1993) provide a comprehensive global assessment of these resources.

For the United States, Fig. 3.1, based on work at the Oak Ridge National Laboratory (Fulkerson et al, 1989; Ranney and Cushman, 1991), gives estimates of the present and future potential sustainable supply of biomass energy by resource category. For each of the five categories shown there, the estimates of potential sustainable resource capability are tempered by factors that would likely reduce the technically sustainable potential. In total, the tempered sustainable US biomass energy resource estimated in Fig. 3.1 is approximately 18 EJ per year.

3.1.1.1. Residues

Residues concentrated at industrial sites are currently the most common commercially used biomass source, but some residues cannot be used for energy: in some cases collection and transport costs would be prohibitive; in other cases, agronomic considerations dictate that residues be recycled to the land (Pimentel et al, 1981). In still other cases, there will be competing non-energy uses for residues. One waste resource that is likely to have few

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[10] The higher heating value of a dry tonne of biomass ranges from about 15 GJ (for some industrial waste streams) to about 20 GJ (for many woody biomass species).

competing uses is municipal solid waste (MSW). Some 1.8 EJ of MSW is landfilled annually in the US each year, and a similar level is projected for the year 2000, even with an ambitious recycling program (Franklin Associates, 1992).

3.1.1.2. Commercially-logged natural forests

Commercially-logged natural forests in temperate regions produce much more biomass annually than is removed for economic purposes (US Congress, 1980). Much of the unharvested "overgrowth" is of too low quality for traditional forest product markets, but is suitable for energy use. Removal of such biomass can increase the yields of the remaining high quality wood. However, there are strong ecological arguments, like loss of biodiversity (Beyea et al, 1991; Cook et al, 1991), which argue against extensive use of existing forests to provide biomass energy in the future.

3.1.1.3. Plantations

Plantations represent the single largest potential source of biomass energy. At present, there exist an estimated 100 million hectares of industrial tree plantations worldwide, about 25 million of which are considered fast-growing plantations (Bazett, 1993). About half the world's area of fast-growing plantations is in the Southeastern US.[11] Most of these plantations are dedicated to industrial products other than energy. For comparison, cropland and forests/woodlands globally occupy approximately 1.5 and 4.1 billion hectares, respectively. As suggested in Fig. 3.1, the land area that can be devoted to energy plantations in the future will depend largely on the economics of competing uses and on how well environmental concerns can be addressed (US Congress, 1993).

In the United States, large amounts of surplus cropland might be available for energy as a consequence of rising farm productivities. Some 33 million hectares of cropland are idle in the US today. For the Midwestern US, one study estimates that some 32 million hectares will be idle and available for energy crops in the year 2000 time frame (Brower, et al, 1993). For the US as a whole, the Dept. of Agriculture projects that some 52 million hectares will be

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[11] Conifer plantations, which are considered border-line fast-growing.

idled by 2030 (US Dept. of Agriculture, 1990).[12]

The cost of producing biomass on plantations will vary by location. At present in the US, the cost of producing woody biomass on good agricultural land using short-rotation intensive culture techniques (5 years between cuts) is in the range of $4 to $5 per GJ (1990 $), depending on geographic location. With advances in biotechnology and agronomic practices, costs are expected to fall to the neighborhood of $1.8 to $2.4 per GJ (Fig. 2.1.1). Given these cost projections, we take $2.5/GJ as a baseline delivered cost of biomass in subsequent calculations in this report.

Finally, to be an important energy source, biomass from plantations must contain much more energy than is required in production. Energy inputs include fertilizers, herbicides, pesticides, and energy for harvest and transport machinery. A recent energy balance assessment for woody-crop and herbaceous plantations in the US (Turhollow and Perlack, 1991) indicates an energy output/input ratio of about 16 for woody crops using today's plantation technology and about 20 with advances expected over the next 20 years. For switchgrass, the output/input ratio at present is about 11 and is expected to increase to about 13 over the next 20 years.

3.1.2. Potential Impact of Biomass Energy Resources

Aside from increasing the sustainable supply of biomass, a major prerequisite for biomass (and other renewable energy resources) to play more important energy roles than is possible today is the availability of technologies for converting the biomass efficiently and cost-effectively into more convenient energy forms, namely fluid fuels (gases and liquids) and electricity (US Congress, 1992; Larson, 1991), and for using these energy carriers as efficiently as possible in providing desired energy services.

This point is illustrated in Fig. 3.2, which shows three estimates for the total amount of primary biomass energy that would be required to displace the 1990 level of gasoline used in passenger vehicles in the US. The three estimates correspond to the use of three sets of

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[12] Energy plantations feeding economically competitive biomass conversion facilities might provide an attractive use for surplus cropland, while simultaneously helping to eliminate the system of farm subsidies used to control agricultural production.

conversion and end-use technologies, including existing technologies and those that may become available and be economically viable within 10 to 20 years. For comparison, an estimate of the sustainable level of biomass production (based on Fig. 3.1) is also shown. For reference, the 1990 level of gasoline use in passenger cars is also shown (US Dept. of Energy, 1992).

In Fig. 3.2, the "current technology" case assumes use of biomass-derived methanol [55% conversion efficiency (Katofsky, 1993)] for cars with a gasoline-equivalent fuel economy of 9.4 liters/100 km [20% higher than the 1990 average for cars in the US (Energy Information Administration, 1992) because of the engine efficiency gain that accompanies the higher compression ratios achievable with methanol]. "Near-term technology" assumes use of methanol from biomass [with an improved conversion efficiency of 63% (Katofsky, 1993)] and a car with improved fuel economy [6.9 lit/100 km (DeLuchi et al, 1991c)]. "Fuel cells" assumes use of hydrogen derived from biomass [69% conversion efficiency (Katofsky, 1993)] in a fuel-cell vehicle with a gasoline-equivalent fuel economy of 3.1 lit/100 km (Ogden and Nitsch, 1993). Fuel cell vehicles are discussed at length in Section 4.

What is apparent from Fig. 3.2 is that biomass does not have the potential to play a significant role in the US transportation energy system unless advanced conversion and end-use technologies are employed. If such systems are considered, then biomass has the potential for meeting a large fraction of US transportation energy needs. The use of other renewable energy resources would benefit from the use of efficient end-use systems.

3.2. ELECTRICITY AND ELECTROLYTIC HYDROGEN

3.2.1. FROM HYDROPOWER

In theory, the technically useable global potential for electricity or electrolytic hydrogen from hydropower could be significant - about 19,400 TWh of electricity or 56 EJ of hydrogen per year (Moreira et.al. 1993). However, hydropower systems require large amounts of land and water (Table 3.2), and can have adverse environmental and social impacts (Moreira et. al., 1993). Moreover, resources are geographically limited to good sites (many of which are already developed). These factors will limit hydropower to a small fraction of the technically useable potential, and thus the global contribution of hydro to a future energy system will probably not be large. Still, because of its low cost, off-peak hydropower at existing sites might offer an opportunities to help launch off-peak electricity or electrolytic hydrogen as an energy carrier.

3.2.2 FROM THE WIND

Wind power is a large and widely distributed resource, that would require less land and much less water than biomass (see Tables 3.1 and 3.2). In practice, only a fraction of the global wind potential of almost 500,000 TWh/yr of electricity or 1200 EJ per year of hydrogen (see Table 3.2) could be developed, however, because of rugged terrain and competing uses for land (Grubb and Meyer, 1993). [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 potential for producing electricity for export or electrolytic hydrogen would be large.

For example, 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 area 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.

3.2.4. FROM SOLAR PV

Although PV electricity or hydrogen would be relatively expensive, it would be by far the most widely available and least constrained renewable resource. PV electricity or 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 3.2). 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.

The water requirements for electrolytic hydrogen production are modest, especially compared to those for biomass hydrogen production (Table 3.2). 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).]

3.3. RENEWABLE FUELS POTENTIAL IN THE UNITED STATES

Figure 3.3 summarizes the potential for renewable hydrogen to meet US transportation energy needs. The potential hydrogen production by renewable resource are compared to the energy requirement for all light duty vehicle travel projected for 2010 in the US, assuming that these vehicles are *(1)* hydrogen internal combustion engine vehicles or *(2)* fuel cell electric vehicles. 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 (Ogden and DeLuchi 1993).

Land and water requirements would be relatively modest (Figure 3.4). 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 3.4 shows hydrogen production systems as large centralized areas, in practice, many small systems would be built.

In summary, there are large potential resources for renewable fuels production in the

US. It will be possible in principle to supply foreseeable US demands for transportation fuel using renewable resources. Biomass (for the production of methanol or hydrogen) could conceivably meet all transportation energy needs if implemented together with high-efficiency vehicle technology (FCEVs). Land or water constraints would probably arise with less efficient vehicle technology. Wind and, especially, solar resources are much larger and it would be possible to produce electricity or electrolytic hydrogen in most areas of the US. Although wind- or solar-derived fuels would not be resource-constrained, high vehicle efficiencies would also be desirable with these fuels to help offset the high capital intensity of producing them.

4.0. ALTERNATIVE VEHICLE TECHNOLOGIES

At present the vast majority of light duty vehicles use gasoline powered internal combustion engines. The tailpipe emissions of pollutants per vehicle have been greatly reduced in the past two decades through the use of improved gasoline additives, catalysts and controls. However, the *total* emissions of most pollutants have stayed about the same, because of the rapidly increasing number of vehicle miles travelled.

Vehicle miles travelled are projected to continue to increase markedly over the next 30 to 50 years. Thus, to impact air quality in the longer term, tailpipe emissions must be greatly reduced as compared to present levels.

The 1990 amendments to the Clean Air Act require significant reductions in tailpipe emissions from motor vehicles (EPA, 1990). In addition, EPA is likely to tighten the test procedure for evaporative emissions. In California, progressively stricter air quality regulations have been enacted, requiring the introduction of transitional low emission vehicles (TLEVs), low emission vehicles (LEVs), ultra low emission vehicles (ULEVs) and zero emissions vehicles (ZEVs) (Table 4.1).

In this section, we briefly discuss vehicle options for reducing vehicle emissions. We consider *(1)* improvements in emission control systems for ICEVS, *(2)* using new fuels in ICEVs (reformulated gasoline, compressed natural gas, methanol, ethanol, hydrogen), *(3)* battery powered electric vehicles, *(4)* hybrid vehicles, and *(5)* fuel cell electric vehicles (using methanol or hydrogen).

We discuss alternative vehicle technologies considering *(1)* the current status of each vehicle technology, *(2)* emissions characteristics, *(3)* cost and performance of vehicles, and *(4)* major RD&D hurdles for each vehicle technology.

4.1. IMPROVED EMISSION CONTROL IN IC ENGINE VEHICLES

To meet increasingly strict emissions standards, better catalytic converters and better controls on emissions equipment and engines are being developed.

Electrically heated catalysts or catalysts placed close to the engine (and thus designated "close-coupled" catalysts) will reduce emissions from the "cold-start" phase of the driving cycle. In current vehicles, it takes several minutes for the exhaust gases from the engine to warm the catalytic converter to its effective operating temperature. During the "cold start" phase, the catalyst is nearly inactive, and emissions are very high. If the catalyst is electrically heated before the engine actually starts, or is placed nearer to the engine, emissions from the cold start phase (which now account for most of the emissions during a typical 7-mile trip) will be greatly reduced. Improved and larger catalysts also will increase the durability and effectiveness of catalytic converters.

Current vehicles also have high emissions during acceleration and whenever the emission control system does not function properly. Smarter on-board emission controls and smarter fuel- and engine-control algorithms, together with new systems that monitor the emission control system and diagnose and report or correct problems, will reduce these sources of emissions.

To meet the new "Tier I" standards of the amended Clean Air Act (Table 4.1a), vehicles in the year 2000 will have onboard refueling controls, improved fuel metering and ignition, a larger or additional or close-coupled catalytic converter, and a larger evaporative emissions canister. Not surprisingly, there is some disagreement about the cost of these changes. The EPA estimates that the Clean Air Act Amendments will add $150 (Walsh, 1992) to $200 (Schaefer, 1991) to the price of a new vehicle. Sierra Research (1994) analyzed cost data provided by auto manufactures and concluded that the Tier 1 standards will add $144 to the price of a vehicle (sales-weighted average of estimates for cars and light trucks). The auto manufacturers themselves estimated that Tier 1 will cost $273/vehicle (sales weighted average of estimates for cars and light trucks) (Sierra Research, 1994). And the Automotive Consulting group (ACG) states that "the Clean Air Act alone is expected to cost consumers an additional $1,000 per vehicle in emissions controls" (ACG News, 1992, p. 3).

It will cost even more to reduce emissions from gasoline vehicles further, beyond what is required by Tier I of the Clean Air Act Amendments. Sierra Research (1994) estimated that the stricter Tier 2 standards (which are half of the Tier-1 standards, and will be implemented only if the EPA deems them necessary) would cost $634 per vehicle (sales-weighted average of estimates for cars and light trucks, relative to 1993 Federal vehicle); the auto manufacturers themselves estimated that Tier 2 would cost $1,013/vehicle (sales-weighted average of estimates for cars and light trucks, relative to 1993 Federal vehicle) (Sierra Research, 1994).

And there is yet even more uncertainty concerning the cost of meeting California's "Low-Emission Vehicle" standards. Table 4.1b compares estimates by the California Air Resources Board, Sierra Research, and automobile manufacturers, of the cost of going beyond Federal Tier-1 standards and meeting CARB's LEV standards.

CARB (1994a) assumes that to meet ULEV standards, gasoline vehicles will have to use dual oxygen sensors, adaptive transient control, sequential fuel injection, improved fuel preparation, improved washcoats on catalytic converters, more catalyst material (mainly palladium), double-wall exhaust pipes, air injection, and electrically heated catalysts. (Some of these items will be used in vehicles meeting the Tier-I standards, and some of them will cost little or nothing extra.) Generally, Sierra Research and the auto manufacturers assumed that vehicles would need more modifications and equipment than did CARB, and that these would be more expensive than estimated by CARB.

The cost and effectiveness of proposed emissions control equipment for gasoline ICEVs is still not well known. The question remains how far gasoline ICEV technology can be pushed to reduce emissions. However, it seems clear that to lower emissions to meet future standards, ICEVs will become more complex and costly.

4.2. INTERNAL COMBUSTION ENGINE VEHICLES WITH NEW FUELS

Internal combustion engine vehicles have been developed for use with alternative fuels such as reformulated gasoline, ethanol, methanol, compressed natural gas and hydrogen. Ethanol, methanol, and natural gas vehicles are commercially available today. Demonstration hydrogen IC engine vehicles have been built by Daimler-Benz, BMW and Mazda, and have been tested in small fleets.

4.2.1. Reformulated Gasoline

Gasoline is being reformulated to have a lower vapor pressure (which will reduce evaporative emissions of hydrocarbons), and to result in lower emissions of "reactive" hydrocarbons (the more reactive a hydrocarbon, the more it contributes to the formation of ozone). Gasoline consists of a large number of different molecular compounds, ranging from very light near-gaseous hydrocarbon molecules to heavy complex molecules. In practice, no two quantities of gasoline are identical; in fact, refiners purposefully create different gasolines for summer and winter, and for certain regions. Reformulated gasoline is gasoline that has been modified to have lower emissions of hydrocarbons, benzene, and other pollutants.

Reformulated gasoline was first proposed as an alternative fuel in the U.S. in summer 1989 in response to the growing pressure for cleaner-burning fuels, in particular the July proposal by President Bush to require the sale of alternative fuel vehicles in the nine most polluted cities of the country. In Fall 1989 in southern California, ARCO became the first oil supplier to market a gasoline reformulated for lower emissions. They reformulated leaded gasoline in part by blending in MTBE, an oxygenated derivative of methanol.

Most of the major oil and automobile companies in the U.S. shortly thereafter initiated a jointly funded multi-million dollar study to analyze the emission impacts of various reformulated blends (later expanded to include methanol and CNG) from current and future motor vehicles. Phase I of this program ended in 1993, after more than 2,200 emission tests using 29 fuel compositions in 53 vehicles (Auto/Oil Air Quality Improvement Research Program, 1993). The key findings of Phase I were that: lowering the RVP (Reid Vapor Pressure, a measure of volatility) of fuel reduces evaporative emissions and ozone formation; lowering the sulfur content of fuel decreases exhaust emissions of toxics and ozone formation; lowering the olefin content of fuel reduces ozone formation; lowering the T90 point (an index of boiling range) reduces ozone and exhaust HC emissions; lowering the aromatic content of fuel reduces emissions of toxics; and adding oxygenate to fuel reduces CO emissions. Most of the reformulations reduced emissions 10-30% (relative to conventional gasoline). It was estimated that it would cost manufacturers 7.0 to 11.6 cents/gallon (1989$) to make a gasoline with 10% aromatics, 15% MTBE, 5% olefins and a 280°F T90, and 2.1-4.6 cents/gallon to reduce sulfur to 50 ppm (Auto/Oil Air Quality Improvement Research Program, 1993).

In summary, the results of the Auto/Oil Phase I research program indicate that gasoline reformulation will provide modest emission benefits at best, at a cost of up to $0.15/gallon.

4.2.2. Methanol in ICEVs [much of this section is from Sperling and DeLuchi (1993)]

In the mid-to late 1980s, methanol was the most widely promoted alternative transportation fuel in the United States (Gray and Alson, 1985; DOE, 1988; McNutt and Ecklund, 1986), but that popularity was recent. Throughout the 1970s and early 1980s, the preferred option for replacing petroleum was petroleumlike "synthetic fuels" made from coal and oil shale. In the 1970s government and industry studies consistently rated methanol below synthetic fuels (Bechtold, 1987; Kant et al., 1974; Stanford Research Institute [SRI], 1976). Methanol was considered an inferior option partly because it was thought that natural gas was in short supply, and thus that methanol would have to be made from coal. The main argument against methanol, though, was that it was too different from petroleum; it would require new or modified distribution systems and vehicles, whereas synthetic crude could simply be added to natural crude at refineries, helping oil companies maintain the usefulness of present investments and insulating consumers from change (SRI, 1976).

In the early 1980s, perceptions began to shift, motivated by three new insights: first, the cost of manufacturing petroleum-like fuels was greater than had been anticipated; second, natural gas was more abundant than had been thought; third, petroleum-like synthetic fuels did not help reduce persistent urban air pollution. The cost problem became salient as world petroleum prices stabilized and then dropped in the 1980s, and as feasibility studies by project sponsors for the US Synthetic Fuels Corporation began to show that the cost of producing refined shale oil and petroleum-like liquids from coal would be $60-100 per oil-equivalent barrel in first and second generation plants (U. S. Synthetic Fuels Corporation, 1985).

At the same time, it was becoming evident that much more natural gas (NG) existed than had been recognized. Although estimates of U.S. and worldwide NG reserves began to be revised sharply upward in 1979, this revision was not widely noted until several years later. The changed perception of NG availability was crucial, because methanol can be manufactured much more cheaply and cleanly from NG than from coal -- and also much more cheaply than any transportation fuel made from coal, oil shale, or biomass (Sperling, 1988). The combination of higher-than-expected costs for synfuels and greater-than-expected supplies of natural gas made methanol more attractive.

The potential air pollution benefits further confirmed methanol's attractiveness. These benefits first gained attention in the early 1980s in California. A landmark study prepared for the California Energy Commission (CEC) (Acurex, 1982) concluded that, given the state's high priority on reducing air pollution, the most attractive use of coal, then thought to be the most promising future source of portable fuel, was to convert it to methanol for the transportation and electric utility sectors. Although this study was not widely circulated, it laid the basis for the CEC's aggressive organizational commitment to methanol. The CEC proved to be the most influential advocate of methanol until the late 1980s, the major justification being air quality (Smith et al., 1984; Three-Agency Methanol Task Force, 1986). By 1985, air quality had become a primary issue nationwide, and interest in methanol began to surge.

Methanol emissions summary. Methanol use promises two air quality benefits over gasoline: lower ozone forming potential in many areas, and, if M100[13] is used, no (or very, very small) emissions of benzene or other polycyclic aromatic hydrocarbons. Methanol also is cleaner than diesel fuel and is beginning to be used in some trucks and buses to meet stringent new emission standards. Methanol thus will help reduce exposure to ozone and toxic air pollutants in many urban areas.

Methanol use will reduce emissions of most toxic compounds (with the probable exception of formaldehyde; but see Table 5.11, note b). The extent of the ozone reduction (and even of the reduction in emissions of toxic compounds) depends in part on the course of development of catalysts and emission control strategies designed specifically to reduce

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[13] M100 refers to 100% methanol as compared to a methanol blend such as M85 (85% methanol, 15% gasoline).

emissions of methanol and formaldehyde. Preliminary research is promising. If methanol vehicles can use lean burn and still meet tight new NO_x standards, then they should emit less CO than gasoline vehicles, too. It will be difficult for lean-burn methanol vehicles to meet the new US NO_x standard, but easy for them to meet the new European standards.

Based on the state-of-the art in methanol vehicle technology, and assuming resolution of some outstanding issues (such as cold start, and catalyst life), we believe that methanol vehicles will have lower emissions of reactive hydrocarbons, and so will reduce ozone formation in areas that are not NO_x limited. However, we expect that in the US, methanol vehicles will be operated stoichiometrically with a high compression ratio, and so will have similar CO and NO_x emissions to gasoline vehicles. In countries that do not adopt the US NO_x standard, lean-burn should work, and reduce CO and perhaps NO_x emissions relative to gasoline vehicles.

4.2.3. Ethanol in ICEVs

Internal combustion engine vehicles fueled with ethanol are used on a large scale in Brazil as a result of the PROALCOOL program initiated in the mid 1970s (Goldemberg et al., 1993). Today, some 12 billion liters of ethanol are used annually there in vehicles, most of which are designed to operate on 100% ethanol. The primary motivation behind this program was energy supply security in the face of rising oil prices in the 1970s. In the US, about 3 billion liters of ethanol are produced annually and blended as an oxygenate into gasoline in some parts of the country.

Ethanol IC engine technology is similar in many respects to gasoline IC engines. Thus, the cost of ethanol ICEVs is comparable to that of gasoline ICEVs in mass production.

Generally, emissions from ethanol vehicles are expected to be similar to emissions from methanol vehicles, except that acetaldehyde will be elevated rather than formaldehyde. The technical issues for ethanol vehicles, like those for methanol vehicles, have largely been solved.

4.2.4. Natural Gas in ICEVs [much of this section is from Sperling and DeLuchi (1993)]

Currently, large numbers of CNG vehicles are operating in Italy, Argentina, New Zealand, Canada, and elsewhere. All are retrofitted gasoline-powered vehicles. About 300,000 vehicles have been operating since the 1950s in Italy, mostly in fleet use. Governments in the remaining three countries initiated major CNG programs in the 1980s. In New Zealand, about 110,000 vehicles were converted to CNG, representing roughly 10% of gasoline use. When the country shifted much of its economy from the public to private sector in the late 1980s, the government withdrew the substantial subsidies it had offered to consumers and market penetration stagnated at the 10% level. The federal and provincial Canadian governments and local gas utilities offered major incentives to fuel suppliers and consumers beginning in the mid 1980s; by 1988 about 15,000 vehicles were operating on CNG, about half by households and half by fleet operators. In Argentina conversions began in 1984 and reached a peak in the early 1990s; today, there are over 200,000 natural gas vehicles and nearly 400 refueling stations in Argentina (Clean Fuels Report, September 1993a). There are tens of thousands more converted vehicles in the United States, Europe, and elsewhere. Mexico City Plans to convert all public transportation vehicles to natural gas, and Japan's Ministry of International Trade is aiming to have 200,000 in operation in Japan by the year 2000 (Keller, 1993). Many transit fleets in the U.S. are converting to natural gas (Clean Fuels Report, 1993b), because the use of natural gas in buses reduces NO_x emissions and nearly eliminates particulate emissions -- the two most serious pollutants emitted by diesel buses. The Natural Gas Vehicle Coalition, the Gas Research Institute, and the Freedonia Group forecast have projected independtly that there will be at least 1 million NGVs on the road in the U.S. at the turn of the century (Clean Fuels Report, 1993c).

Natural gas vehicle technology. Internal combustion engines may be readily adapted to operate on CNG. They may be retrofitted, as are all but about a few tens of the 700,000 or so CNG vehicles currently operating worldwide, at a cost of about $1500-2000 per vehicle. The major change is the addition of one or more pressurized tanks for compressed natural gas (CNG) storage, additional fuel lines for the gaseous fuel, and a gaseous fuel mixer or injector in the engine. A far superior vehicle is one designed specifically for natural gas and not burdened by redundant fuel systems. A vehicle dedicated to and optimized for natural gas generally has lower emissions than gasoline vehicles, slightly greater energy efficiency because of the higher octane number of natural gas, and similar power. Such a vehicle would cost about $900 more (under mass production) because of the more costly fuel tanks, but would not have cold start problems. It would also have a shorter driving range or reduced trunk space because of the much lower volumetric energy density of gaseous fuels. Natural gas can also be liquefied and stored in insulated containers. LNG light-duty vehicles have received comparatively little attention to date and are not discussed further here. (Interest in LNG heavy-duty vehicles is growing.)

Methane can be stored in carbon skeletal networks called adsorbents. The potential advantage of adsorption is that a given energy density can be attained at a pressure lower than that required to compress natural gas by itself to the same volumetric energy density. For example, an adsorbent at less than 60 bar can attain the same volumetric energy density as CNG at over 100 bar (Lin and Huff, 1993). This form of storage, although not yet commercially viable, may lower the cost and bulk of storing natural gas, and may make low-pressure home compression viable. Research is aimed at increasing the capacity of adsorbents, reducing the amount and effect of contaminants, reducing cost, managing heat production, and maintaining safety. In the United States, the Gas Research Institute is sponsoring R&D work aimed at commercializing adsorbents.

Costs. In countries with domestic supplies of natural gas, the main incentive to switch from gasoline to natural gas is lower fuel cost. NG vehicles also may have slightly lower maintenance costs than liquid fuel vehicles. However, the vehicles themselves cost more than gasoline (or methanol) vehicles with comparable range and performance (about $1000 more), because of the relatively expensive high-pressure fuel storage equipment. This higher up-front cost is partially compensated for by lower back-end costs: the storage systems probably will have a high salvage value, and the use of natural gas may increase the life of the engine, and hence increase the resale value of the vehicle.

Based on an exhaustive review of the literature, and a detailed accounting of all costs, including land, site preparation, hook-up to the gas main, energy needed to compress gas from pipeline pressure to 207 bar, etc., we estimate that the cost of compression and retailing is about $2.6 per GJ (DeLuchi et al., 1988; see also J. H. Cann, 1988). In the 2000 to 2010 time frame, natural gas prices to electric utilities in the US are projected to be in the range of $2.8/GJ to $4.0/GJ (EIA, 1994). For a gas price of $3.0/GJ, the estimated retail price of CNG would be around $7.3/GJ before taxes.

Emissions summary. CNG vehicles can emit much less carbon monoxide (CO) than gasoline or methanol vehicles, because CNG mixes better with air than do liquid fuels, and does not have to be enriched (as much) for engine start-up. However, the magnitude of the CO reduction (and, perhaps, whether or not there is any reduction at all) will be determined by NO_x control: if the engine has to be run slightly rich to control NO_x, there will be little or no reduction in CO; if it can be run slightly lean, there will be a reduction. CNG vehicles will emit similar or possibly higher levels of nitrogen oxides than gasoline vehicles and methanol vehicles. CNG vehicles will emit fewer non-methane organic gases and unregulated pollutants than will gasoline or methanol vehicles, and are expected to lower ozone levels slightly more than will methanol vehicles.

CNG vehicles thus offer significant air quality benefits at modest cost. CNG could be provided to consumers at centralized filling stations, via the existing natural gas distribution network. It is unlikely that methane would be used in fuel cell vehicles, because of the high temperatures required for onboard reforming, which implies a larger energy penalty for reforming (compared to more easily reformed fuels like methanol) and hence a lower system efficiency and a higher fuel and fuel-storage cost per mile. A more costly reforming system is likely to be involved due to the higher temperatures and the heat-recovery and heat-management systems would be commensurately more sophisticated.[14] Methane fuel cell vehicles are thus likely to have higher lifecycle costs than hydrogen or methanol fuel cell vehicles, unless methane is inexpensive in the future. However, because the refueling systems and storage systems would be similar for CNG and for hydrogen, CNG vehicles can be seen as a step toward eventual use of hydrogen.

4.2.5. Hydrogen in ICEVs

Hydrogen has been successfully demonstrated in experimental automobiles, busses, trucks and airplanes (Buchner and Povel, 1982; Stewart, 1984; Buchner, 1984; Brewer, 1986; Feucht et al., 1988; Furhama, 1988; Protosenko, 1988; DeLuchi, 1989; Gruenfelder and Schucan, 1989; Mazda, 1992; Swain, 1993; Lynch, 1993). With the exception of a handful of fuel cell electric vehicles (discussed below), all experimental hydrogen vehicles to date have used internal combustion engines (mostly modified gasoline or diesel engines).

Serious work on hydrogen began in the 1930s when Rudolph Erren in Germany converted over one thousand internal combustion engine vehicles to run on hydrogen and hydrogen blends (Hoffmann, 1981). A resurgence of interest occurred in the 1960s and 1970s, as Japan, Germany, and the United States began funding hydrogen research programs. Today several automotive manufacturers including Daimler-Benz, BMW and Mazda have

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[14] In the longer term, if solid oxide fuel cells are developed for transportation, methane might provide some advantages as a fuel because of the high fuel cell operating temperatures--700-1000°C. To date, the most promising fuel cell is the proton exchange membrane, which operates at about 100°C.

developed prototype hydrogen internal combustion engine vehicles.

Perhaps the largest technical challenge facing hydrogen ICEVs is fuel storage. A variety of methods have been tried or proposed (Table 4.2), including compressed gas storage, metal hydrides, and liquid hydrogen. Because hydrogen storage systems are much bulkier, heavier and more expensive than those for liquid fuels, hydrogen ICEVs might have a shorter range than gasoline ICEVs. Also, the first cost of these vehicles would be higher than for other ICEV options because of the cost of storage.

Emissions. The tailpipe emissions from hydrogen internal combustion engine vehicles are much lower than those from a comparable gasoline powered vehicle. Emissions of carbon monoxide, hydrocarbons, and particulates are essentially eliminated (traces of these gases are emitted from combustion of lubricating oils in the engine). The only pollutant of concern is NO_x, which is formed, as in all internal-combustion engines, from nitrogen taken from the air during combustion. Hydrogen vehicles probably will be able to meet any NO_x standard a gasoline vehicle can meet. In principle, an ultra-lean hydrogen engine could produce very little NO_x, but no hydrogen vehicles have been designed for minimum NO_x to prove this potential on the road.

From tests performed to date, and from basic knowledge of engine emissions, we draw several conclusions about emissions from hydrogen IC engine vehicles:

1) An optimized hydrogen vehicle, without a reduction catalyst, probably could meet the current U.S. NO_x standard (0.6 gm/km), and the new EEC NO_x standards (0.86 gm/km to 1.4 gm/km, depending on engine size). An optimized, low-NO_x hydrogen vehicle probably will use some form of combustion cooling, such as EGR (exhaust gas recirculation), water injection (or use of a very cold fuel like liquid hydrogen), combined with lean operation. It should be noted that none of the experiments performed to date focussed primarily on NO_x emission control, and that researchers anticipate being able to further reduce NO_x levels from hydrogen vehicles.

It is not clear, however, what will have to be done for hydrogen vehicles to meet the new 0.25 gm/km US NO_x standard, and the more stringent "phase II" 0.125 gm/km NO_x standard of the Clean Air Act. In principle, hydrogen vehicles can have near-zero NO_x emissions, if they can operate satisfactorily in ultra-lean regimes (Das, 1990; Wolpers et al., 1988). Ultra-lean operation can reduce the temperature in the combustion chamber to below the threshold value for NO_x formation. In addition, the absence of hydrocarbon radicals in a hydrogen engine will greatly reduce the formation of "prompt" NO_x in the flame zone (Wolpers et al., 1988).

However, it is difficult to generalize from this theoretical potential to real-world operation and drive cycles. Lean-burn hydrogen vehicles likely will use fuel enrichment under load to provide power for acceleration, and this enrichment will increase NO_x emissions. The use of a high compression ratio, to compensate for the volumetric power loss with hydrogen also will increase NO_x emissions. Finally, unstable combustion in ultra-lean mixtures may prevent full exploitation of this technique. Optimized, low-NO_x, high-performance hydrogen ICE vehicles need to be built and tested to address these issues. If a lean burn strategy is not attractive, a reduction catalyst can be used. The use of such a pollution control device would be something of a disappointment, though, since a major attraction of hydrogen is the promise of pollution-free operation. In addition, it is not clear how the absence of reactive hydrocarbons in the exhaust stream would affect the performance of a reduction catalyst.

2) If oil combustion is kept within normal limits, emissions of hydrocarbons (HC) and CO from hydrogen vehicles are roughly an order of magnitude lower than HC and CO from properly-maintained, relatively new, catalyst-equipped gasoline vehicles, and in fact are near zero.

3) Hydrogen vehicles emit or produce little, if any, ozone, particulates, sulfates, sulfur oxides, aldehydes, benzene, or other toxic and carcinogenic compounds commonly found in the exhaust of petroleum-fuel vehicles.

4) Dual-fuel operation with hydrogen and gasoline or diesel fuel can substantially reduce emissions of all regulated pollutants. The addition of only small amounts of hydrogen--as little as 5%-10% by mass--has reduced CO, HC, and NO_x emissions (see DeLuchi, 1989).

In sum, properly functioning, advanced, lean-burn hydrogen engines will produce some NO_x, but little else. The use of hydrogen would provide significant reductions in transportation-related ozone and CO. (It is also worth noting that fuel-cycle greenhouse gas emissions could be lowered by up to two or more orders of magnitude, depending on the oil consumption of the engine and the source of energy used to produce the hydrogen.)

The efficiency of hydrogen internal combustion engine vehicles is probably somewhat higher than that of a comparable gasoline powered ICEV. Efficiency gains of 25-30% typically are reported in the literature.

Summary. Of the various alternative fuels which could be used in ICEVs hydrogen offers by far the greatest reduction in tailpipe emissions. The first cost of hydrogen ICEVs is likely to be higher than for other ICEV alternatives, however. The technology is not as developed as that for CNG, methanol and ethanol ICEVs. And, importantly, a widespread infrastructure for delivering hydrogen does not exist.

4.3. BATTERY POWERED ELECTRIC VEHICLES

Interest in electric vehicles has surged and ebbed several times. Although most reports and statements emphasize methanol and CNG as a replacement for gasoline and diesel fuel, there is increasing awareness of the potential for advanced BPEVs to provide substantial air quality and petroleum conservation benefits.

4.3.1. Electric vehicle technology and performance

Electric vehicles were relatively common at the turn of the 20th century. However, by 1920, improvements in BPEV technology had lagged so far behind the development of the internal combustion engine that BPEVs became practically extinct (Hamilton, 1980). With the resurgence of interest in BPEVs in the 1960s came promises of breakthroughs that were to make BPEVs as economical and high-performing as internal combustion engine vehicles. But a decade later the promised BPEV had still not materialized.

The efforts of the past decade have not produced any dramatic breakthroughs. However, over that period the technology of BPEV batteries and power trains has developed incrementally, and the cumulative result is substantial. For example, advances in microelectronics have resulted in low-cost, light-weight dc-to-ac inverters, which make it attractive to use ac rather than dc motors. With the improved inverters the entire ac system is cheaper, more compact, more reliable, easier to maintain, more efficient, and more adaptable to regenerative braking than the dc systems that have been used in virtually all BPEVs to date. Similarly, the development of advanced batteries has progressed to the point where successful commercialization depends not so much on major technical or scientific breakthroughs as on successful design, manufacturing and quality control. In the near term, the major automobile manufacturers are planning to use advanced lead/acid, nickel/iron, nickel/cadmium, sodium/sulfur, or nickel/metal-hydride batteries; in the longer term, lithium batteries are especially promising (IEA, 1993).

Advanced BPEVs now under development, and projected to be commercially available in 2000, are expected to offer considerably better range and performance than state-of-the art BPEVs from the 1980s. Without sacrificing seating or cargo capacity, passenger vehicles and vans are projected to have urban ranges of up to 250 km, high top speeds and acceptable acceleration, and low energy consumption (IEA, 1993). With these characteristics, BPEVs would be attractive as second vehicles in most multi-car households (Lunde, 1980; Horowitz and Hummon, 1987) and as vans in most urban fleets (Berg, 1985; Brunner and Wood, 1988). As personal vehicles become more specialized and consumer expectations regarding multipurpose usage of vehicles continue to diminish, BPEVs may even become acceptable as primary commuter cars.

4.3.2. Battery Powered Electric Vehicle Emissions

A principal attraction of electric vehicles is the promise of improved urban air quality. If EVs use solar power, then they will be essentially nonpolluting. But even if they were to consume electricity generated in a combination of power plants using coal, natural gas, oil, hydroelectric power, nuclear power, and solar power, they would still provide a major reduction in emissions (Wang et al., 1989; Dowlatabadi et al., 1990). First, non-methane organic gases (NMOGs) and CO emissions will be not just reduced -- but essentially eliminated, regardless of the fuel mix used by power plants, and assuming no HC or CO controls on power plants (but strict controls on ICE vehicles). Second, if there are strict controls on power plants, NO_x emissions probably will be reduced. (It should be kept in mind, too, that it is considerably easier to monitor power-plant emissions, to ensure compliance with the NO_x standard, than to monitor vehicular emissions.)

The combination of no HC emissions and low NO_x emissions from power plants will greatly reduce, and in some cases eliminate, ozone formation due to highway vehicles (Dowlatabadi et al., 1990). The exact ozone benefit will depend on the magnitude and timing of NO_x emissions from power plants in relation to the magnitude and timing of HC emissions from other sources in the air basin. Nighttime NO_x emissions from rural power plants will have a different effect on ozone than daytime NO_x emissions in urban areas. A recent modeling of the air quality benefits of EVs predicts that an EV penetration of 15% will reduce total ozone concentrations by about 4-8% (this is the reduction in total urban ozone, not the reduction in per-mile emissions from vehicles) in US ozone-nonattainment areas, and will reduce exposure to high levels of ozone by 35% (Dowlatabadi et al., 1990).

The effect of EV use on SO_x emissions will vary from region to region, depending largely on the amount of coal-fired capacity and the extent of use of low-sulfur coal or flue-gas desulfurization. However, the new US Clean Air Act Amendments place a cap on sulfur emissions, which arguably suggests that there will be no net increase in SO_x emissions due to the use of EVs -- emissions will be at the level of the cap, whether EVs are used or not. In any event, it is important to note that gasoline vehicles are a very minor source of SO_x emissions, which means that EV use in aggregate will not change SO_x levels significantly one way or the other.

EVs will in most cases increase emissions per-kilometer of PM, but light-duty gasoline vehicles are a completely insignificant source of PM (tailpipe emissions of PM from gasoline vehicles account for less than one-half of one-percent of total PM emissions), and so this increase is of little consequence.

In sum, EV use will eliminate CO and HC emissions on a per-km basis and probably reduce NO_x emissions relative to gasoline vehicles meeting future stringent emission standards. SO_x emissions may increase or decrease; PM will increase. Since the light-duty transportation sector is a major source of HC, CO, and NO_x emissions, but a very minor source of SO_x and especially PM, a large decrease in HC, CO, and NO_x emissions from light-duty highway vehicles would have a greater impact on urban air quality than would a moderate increase in PM emissions. As a result, regardless of the feedstock used for electricity generation, EVs will tend to improve urban air quality significantly.

4.4 HYBRID VEHICLES [This section is abbreviated from Burke and Sperling (1994), with their permission.]

4.4.1. Introduction

A hybrid vehicle is a combination of an electric motor and internal combustion engine in a single vehicle. The underlying motivation for hybrid vehicles is to extend the range beyond what batteries by themselves can provide. By combining two propulsion systems and associated energy storage units, hybrid vehicles are inherently more complex than either pure battery-powered EVs or internal combustion engine ICE) vehicles. However, they have the very important advantages of not only longer driving range (per charge) than pure battery EVs, but less pollution and energy consumption than internal combustion engine (ICE) vehicles.

4.4.2. Recent research and development

Since 1980, a wide variety of hybrid vehicles have been built and tested. Some of these vehicles have worked very well, suggesting that hybrid vehicles with attractive performance, low petroleum usage, and low exhaust emissions could be developed. Interest in hybrid vehicles jumped in late 1993 with the announcement of funding for two major collaborations. The U.S. DOE signed a five-year $138 million development agreement with General Motors and a $122 million agreement with Ford to design and build pre-production hybrid prototypes that could be marketed in less than ten years. The DOE-GM hybrid vehicle program emphasizes the use of a ceramic gas turbine engine as the primary power source, with an electric motor and batteries for peak power. The DOE-Ford program had not been formalized as this report went to press. The primary objective in both programs is to improve the fuel economy of full-size cars by at least 50% compared to current gasoline-powered cars and to reduce emissions to California's "ultra-low" level.

Considerable work remains before an advanced marketable hybrid vehicle can be built. The problem is not availability of key components; they are already commercially available or in advanced stages of development. Rather, the challenge is to integrate them into a unit that provides extended range, suitable power, good performance, and low emissions at acceptable cost.

4.4.3. Hybrid designs

Hybrid vehicles fill the range of vehicle options between pure battery-powered electric vehicles and conventional ICE vehicles. At the end of the spectrum closest to pure electric vehicles is the range-extender hybrid. It would operate in an all-electric ZEV mode most of the time, but would have a small engine to "limp home" (or to a recharging station) when the batteries are nearly discharged. It would utilize a powerful electric motor (50 to 100 kw) to provide an all-electric range of perhaps 50 miles. The small engine (5 to 10 kw) would extend the range an additional 50 miles but at a top speed of only about 55 mph. As batteries are improved, the all-electric ZEV range could be extended or, alternatively, the battery pack shrunk.

A second option is the multi-purpose hybrid. This hybrid vehicle would also have a ZEV capability of about 50 miles, but would have a much larger engine (25-40 kW) available for high speed and long distance travel. Because this hybrid, like the range-extender, would operate in an all-electric ZEV mode most of the time, it could have near zero tailpipe emissions and petroleum consumption. Unlike the range-extender hybrid, though, the multi purpose hybrid could directly substitute for a conventional ICE gasoline-powered vehicle. Because the multi-purpose hybrid has a large engine, its emissions and petroleum use would be substantial when operating in the (non-ZEV) hybrid mode.

Next along the spectrum is the near-ICE hybrid. It most closely resembles a conventional ICE vehicle, and also provides multi-purpose capability. All the energy to power this hybrid would come from gasoline (or other chemical fuel) stored onboard the vehicle); it would not use any "wall-plug" electricity. The engine would act as a generator, creating electricity for the electric motor, with excess electricity stored in an onboard battery (or flywheel or ultracapacitor). Because the engine would be running most of the time, but at a near constant speed, emissions and gasoline use would be much lower than for a comparable ICE car. But since the vehicle would rarely if ever operate in an all-electric mode (with electricity only from the battery), it could not in any way be considered a ZEV (even if fueled with hydrogen). Also, if gasoline were its only source of energy, near-ICE hybrids would consume much more petroleum than the other hybrids.

4.4.4. Peak-power for hybrids

Hybrid vehicle will have an electrical peak-power device, to allow the ICE to operate at near constant speed at relatively low power. However, a major issue with current-technology peak-power devices is the life of batteries. Shifting the responsibility for rapidly fluctuating power demands from the engine to the electric motor sharply reduces the engine's energy use and emissions, but at the cost of shortening the life of the batteries. Today's lead-acid batteries, and most batteries expected to be commercially available in the near future, are designed for daily recharges when the battery is nearly depleted; they are not designed to withstand tens or hundreds of charging and discharging cycles each day. New peak-power devices would be needed that are designed to have very high power density (power per unit weight) and to withstand a very large number of shallow, rapid charge/discharge cycles.

Future ICE-electric hybrids, as well pure electrics (including fuel cells), will have the option of meeting peak power needs in a more efficient and inexpensive manner -- with high energy density capacitors (often referred to as ultracapacitors) or flywheels (Table 4.4). By the early 21st century it is possible that enough progress will have been made that the battery pack in a near-ICE hybrid could be replaced with ultracapacitors for only about $500 to $1000. These ultracapacitors would be not only several times less expensive than the batteries they replace, but would last much longer.

4.4.5. Energy and environmental benefits of hybrids

The energy and pollution benefits of hybrids could be substantial. Unfortunately, credible analyses of emissions and energy use do not exist. The problem is that previous studies of hybrid vehicle emissions and energy use have not adequately accounted for the following methodological and data problems: 1) large variations in possible hybrid designs, 2) uncertainty regarding percent of time the hybrid's internal combustion engine will actually be used, and 3) lack of appropriate tests for measuring emissions and fuel economy of hybrid vehicles. Qualitatively, however, it is reasonable to expect that the pollution and energy benefits of shifting peak power demand away from the engine and to the motor are substantial. First, by eliminating the need to respond to occasional power bursts, the engine can be downsized by 3/4 or more to provide only the average, not peak, power needed by the vehicle. This downsized engine will have higher energy efficiency because large gasoline-powered engines are inefficient when operated at the low power conditions typical of conventional ICE car use. Small engines exist for industrial, motorcycle, and marine applications, though they would need to be re-engineered for hybrid applications where minimum fuel consumption and low emissions are critical.

Second, it is far easier to reduce emissions when an engine operates at constant speed and power. Indeed, recent evidence indicates that most pollution from new gasoline engines is emitted during hard accelerations and decelerations. Third, constant (or near-constant) engine speed greatly enhances the feasibility and attractiveness of more energy-efficient types of internal combustion engines, especially gas turbines and two-stroke engines, creating the potential for still greater energy efficiency . (If hydrogen is used instead of gasoline, the efficiency can be higher yet.) With emission control technology on the hybrid's engine of similar sophistication to that on gasoline cars, virtually any hybrid vehicle should easily qualify for California's "ultra-low emission" category (Table 4.1a).

It is not clear, however, just how far NO_x emissions can be reduced. Moreover, it is important to keep in mind that emissions from the production and distribution of crude oil and gasoline will remain substantial: on a per mile basis, these "upstream" emissions will exceed emissions from the power plants that supply all-battery electric vehicles, and probably exceed emissions from hybrid vehicles themselves. Of course, the use of a clean renewable energy source, such as solar hydrogen, would virtually eliminate upstream emissions.)

Despite this potential for very low emissions, one can question whether the emissions will actually be so low in practice. This skepticism centers on two concerns: 1) the engine might be operated more in real-world conditions than indicated by the simulations (and laboratory emissions tests); and 2) in-use emissions from the engine tend to be much higher than indicated in simulation and lab tests.

In summary, hybrids provide the opportunity for greatly reduced emissions, but more experience is needed in real world conditions to know whether results from computer simulations and laboratory tests will be fully realized, and to create appropriate procedures and computer models for testing and predicting emissions.

4.4.6. Costs

As with battery-powered vehicles, the economics of hybrids will be dominated by the batteries. Battery cost can be reduced by limiting the electric range of the vehicle and using peak-power devices such as ultracapacitors. The use of a peak-power device would permit substantial downsizing of batteries. The peak-power device, by smoothing charge and discharge demands on the battery, would also greatly extend battery life and thus further reduce costs.

Engines will be a relatively small cost item for hybrids. The engine in the hybrid vehicle would be much smaller than in a conventional vehicle of the same performance and hence its cost should be less.

While detailed cost analyses of hybrids have not been conducted, it appears likely, based on the cost analysis for pure electric vehicles presented section 5 of this report, that the cost of hybrid vehicles in mass production after extensive product engineering and testing should be similar to that of comparable conventional gasoline-powered vehicles. Ultimately, hybrid vehicle costs will depend upon how far and fast manufacturing costs drop and to what extent energy and environmental externalities are accounted for in vehicle and fuel pricing.

4.5. FUEL CELL ELECTRIC VEHICLES

Recently there has been a growing interest in fuel cell vehicles, spurred in part by the emerging market for zero emission vehicles, and partly by recent advances in fuel cell technology. Fuel cell vehicles are of interest because they could potentially combine the best attributes of electric battery vehicles -- zero (or near zero) emissions, high efficiency, quiet operation and long life -- with the long range and fast refueling time of internal combustion engine vehicles.

Fuel cells are electrochemical devices which convert the chemical energy in a fuel (hydrogen is preferred) and oxidant (usually oxygen in air) directly into electrical energy. Like batteries, fuel cells are electrochemical devices. However, in a battery, the electricity-producing reactants are regenerated in the battery during recharging; in a fuel cell the reactants are continuously supplied from an external source (a hydrogen storage tank plus air).

Unlike heat engines, the efficiency of a fuel cell (electrical output divided fuel input) is not limited by the Carnot cycle. Theoretical efficiencies of about 80% are possible for hydrogen-oxygen fuel cells, with practical efficiencies for hydrogen-air fuel cells of 45-60%. This is considerably higher than an internal combustion engine vehicle. Fuel cell vehicles would probably be 2 to 3 times as energy efficient as gasoline powered ICEVs over a typical driving cycle.

Several types of fuel cells are now under development: proton exchange membrane (PEM), phosphoric acid (PAFC), alkaline (AFC), molten carbonate (MCFC) and solid oxide (SOFC). Table 4.3 shows characteristics of fuel cells which might be used for transportation applications. Of these options, many researchers believe that PEM fuel cells, which should be commercially available within a few years, are best suited for use in highway vehicles in the near term. As compared to other types of fuel cells, PEM fuel cells have the advantages of high energy density, quick start-up time, and the potential to reach low cost in mass production. Most fuel cell vehicle demonstration programs today are planning to use PEM fuel cells.

In a PEM fuel cell, hydrogen is delivered to the anode, and oxygen (or air) to the cathode. The anode and cathode are separated by a thin membrane, which conducts protons, but not electrons. At the anode, hydrogen separates into hydrogen ions and electrons in the presence of a platinum catalyst. The electrons move through an external circuit, driving the motor. The hydrogen ions are conducted through the membrane, where they combine with the returning electrons and oxygen to form water. The water is removed from the cell. The reactions at each electrode are:[15]

$$\text{Anode: } H_2 \xrightarrow[\text{catalyst}]{} 2\,H^+ + 2\,e^-$$

$$\text{Cathode: } 2\,H^+ + 1/2\,O_2 + 2\,e^- \xrightarrow[\text{catalyst}]{} H_2O$$

Overall the fuel cell combines hydrogen and oxygen to produce electricity, heat and water.

PEM fuel cells require hydrogen as a fuel. Hydrogen could be stored directly onboard

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[15] Other fuel cells operate differently. For example, in a solid-oxide fuel cell, the electrolyte transports the negative oxide ions.

the vehicle or produced onboard via reforming of a hydrogen carrier such as methanol, ethanol or methane. Of these, methanol is the easiest to reform onboard the vehicle, because relatively modest temperatures are needed (300°C or less). Ethanol and methane require higher temperatures, which implies a larger energy penalty for reforming and hence a lower system efficiency and a higher fuel and fuel-storage cost per mile. A more costly reforming system is likely to be involved due to the higher temperatures and the heat-recovery and heat-management systems would be commensurately more sophisticated. For these reasons, ethanol or methane fuel cell vehicles are likely to have higher lifecycle costs than a methanol fuel cell vehicle, unless ethanol or methane is considerably less expensive than methanol. We consider only hydrogen and methanol as fuels for fuel cell vehicles.[16] Because the platinum catalyst is poisoned by CO, hydrogen for PEM fuel cells must contain no more than a few ppm of CO. (This imposes stringent clean-up standards on hydrogen produced via reforming.)

A number of experimental fuel cell vehicles are now under development. Ballard Technologies of Canada recently started demonstration runs of a hydrogen PEM fuel cell bus running on compressed hydrogen gas. In the US, the Department of Energy is supporting a demonstration phosphoric-acid fuel cell bus due to start operating in 1994, and is also involved in a joint project with GM and other industrial partners to demonstrate a methanol PEM fuel cell automobile (with on-board reforming) by 1996. The DOE is also planning to develop and demonstrate a PEM fuel cell light-duty vehicle with on-board hydrogen storage. Energy Partners in Florida has recently unveiled its prototype "Green Car," a hydrogen powered PEM fuel cell automobile. The Ford Motor Company is also studying the prospects for fuel cell vehicles. In Japan, Mazda has been involved in the development of hydrogen internal combustion engine vehicles, and is now researching hydrogen fuel cell vehicles. In Europe, the building of the European Eureka Fuel Cell Bus by four companies is expected to be completed in late 1994. The bus will use an alkaline fuel cell, nickel-cadmium battery, and liquid hydrogen fuel. Also, the European Community is sponsoring a fuel cell bus with a PEM fuel cell, lead-acid battery, and liquid hydrogen storage scheduled for testing in 1994. In Germany, Siemens has been developing PEM fuel cells for transportation. Daimler-Benz unveiled a van running on a hydrogen-fed PEM fuel cell in April 1994, and is pursuing further development of PEM fuel cell vehicles in a joint effort with Ballard.

A sketch of a fuel cell vehicle is shown in Figure 4.4.1. The fuel cell vehicle is an

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[16] In the longer term, if solid oxide fuel cells are developed for transportation, methane or ethanol might provide some advantages as fuels because of the high operating temperatures--700-1000°C.

electric drive vehicle that uses a fuel cell system in place of (or, in some designs, in parallel with) a rechargeable storage battery.

The electric drive train has three major parts: 1) an electric traction motor, 2) an electronics package including a motor controller, dc to ac inverter and dc to dc converter, 3) a transmission.

The fuel cell system consists of 1) the fuel cell stack, which produces the electricity, 2) an air compressor to provide pressurized air to the fuel cell, 3) a cooling system to maintain the proper operating temperature, 4) a water management system to keep the PEM membrane saturated and to remove water as it is created at the cathode. If the fuel is stored as methanol, a reformer is needed on the vehicle to convert methanol to hydrogen.

With hydrogen various types of hydrogen storage could be considered (Table 4.2). In this study, we have chosen to focus our analysis on compressed hydrogen gas storage, because of its relative simplicity. Moreover, compressed gas storage would allow the hydrogen vehicle to be refueled in a few minutes, while the refueling operation for other hydrogen storage systems would be longer.

In theory, all the power demands in a FCEV can be provided by a fuel cell alone. However, fuel cell vehicles may be least costly, when the fuel cell is sized to meet the "baseload" power requirement, and a peak power device is added to meet peak demands for acceleration. The peak power device could be a storage battery, an ultracapacitor or a flywheel (Table 4.4). Since most vehicles spend the vast majority of the drive cycle at low load, where the fuel cell alone would be adequate, the peak power device could have a low storage capacity, coupled with a high power density.

The cost of a fuel cell vehicle is likely to be greater than that for a gasoline powered vehicle, but comparable or less than that for a battery powered electric vehicle. The main cost drivers for the fuel cell vehicle are the fuel cell itself, the peak power device, the hydrogen storage system (for hydrogen FCEVs) and the reformer (for methanol FCEVs).

Although the successful development and eventual commercialization of fuel cell vehicles does not depend on technical "breakthroughs," in the way that battery development has been supposed to, it does require the resolution of many design and engineering challenges, and success is by no means guaranteed. Important issues are summarized below [see DeLuchi (1992) for more details].

1) Development of PEM fuel cells. Here issues include:

a) reducing the cost and improving the performance of the membrane without compromising its mechanical properties or making it more sensitive to impurities in the gas streams. At present, the cost of the membrane is the single largest contributor to the cost of the PEM fuel cell. Current costs for the advanced experimental membranes are about \$1000/kg, largely because these materials are custom manufactured in small quantities. It is likely that the cost of the membrane will decrease to the neighborhood of \$10/kg when mass produced. Table 4.5 shows our estimates of the cost contribution of the membrane in the future.

b) mass producing large-area fuel cell stacks with low platinum catalyst loadings. Platinum requirements have been greatly reduced in small-area laboratory fuel cells. It should be possible to do this for large area fuel cell stacks as well.

c) finding a simple and effective way to keep the membrane moist, while still removing product water at the cathode

d) reducing the size and energy consumption of the air compression system

e) reducing the weight, bulk and cost of the fuel cell stack components and assembly.

A reasonable cost goal for PEM fuel cells is \$100/kW or less,[17] which would make PEM FCEVs competitive with gasoline ICEVs, as discussed in detail in Section 5. Table 4.5 shows estimates we have used in our baseline analysis in Section 5 for the cost of various components of the fuel cell. Clearly, bringing down the cost of the membrane and the balance of the fuel-cell stack, is a high priority for PEM fuel cells.

2) Development of low-cost, compact, simple and reliable fuel cell system auxiliaries.

3) Development of electric drive trains designed for long-range, high power and rapid transient operation.

4) Development of control systems for FCEVs, which can coordinate the use of fuel cell and peak power devices.

5) Development of batteries or other peak power devices suitable for use in fuel cell vehicles.

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[17] General Motors has projected a cost of \$50/kW (including a reformer) (General Motors, 1993).

The characteristics needed are different than those for battery-only powered electric vehicles.
6) For hydrogen fuel cell vehicles, development of lightweight, low cost, high pressure compressed gas cylinders for onboard hydrogen storage.
7) For methanol fuel cell vehicles, the development of onboard reformers with rapid response time. Methanol reformers today have long warm up times and cannot follow rapid load changes.

4.6. THE IMPACT OF THE ZEV MANDATE ON THE FUTURE OF HYBRIDS AND HYDROGEN ICEVs [This section is abbreviated from Burke and Sperling (1994), with their permission.]

In striving to enter the marketplace, hybrid vehicles face the same start-up problems of other electric propulsion technologies (namely pure battery or fuel-cell electric vehicles. They utilize new technologies -- motors, power electronics, traction batteries, ultracapacitors -- that are not currently produced in high volume for the automotive market. Hybrid vehicles, like pure electrics, will be unfamiliar to vehicle producers, dealers, maintenance shops, and consumers. Hydrogen ICEVs will face different but equally daunting obstacles, because of the high cost and complexity of most forms of hydrogen storage, and the high cost and unavailability of hydrogen fuel. Automakers will not produce hybrids or hydrogen ICEVs on their own; incentives (or mandates) will be necessary, as with pure electrics, to entice automakers to produce the vehicles and for consumers to buy them.

Unfortunately, those incentives are not likely in the near term, mostly due to the peculiarities of the present regulatory process. For the reasons below, hybrids and hydrogen ICEVs are middling options in the unfortunate position of not being the leading contender in satisfying either regulators nor automakers. (Of course, this could change if present policies were to change.)

First, hybrids vehicles and hydrogen ICEVs, though potentially very low-polluting, do not qualify as ZEVs -- not even hydrogen-fueled hybrids will qualify. This is a critical point, because the ZEV mandate dwarfs all other automaker motivations to produce any kind of vehicle that uses a radically different propulsion system (electric drive) or fuel (hydrogen). If there were no ZEV mandate, automakers surely would show virtually no interest in producing battery EVs or fuel cell EVs. Second, automakers continue to believe that they can meet even ULEV standards without having to use hydrogen. A CNG vehicle already has certified to ULEV standards (Clean Fuels Report, 1994), and many feel that at least small gasoline ICEVs will be able to meet ULEV standards. Thus, automakers again have no incentive to produce hybrids or hydrogen ICEVs. Third, the stagnation of CAFE standards has reduced pressure on automakers to seek dramatic improvements in energy efficiency. Automakers can easily meet the standards without resorting to new energy technologies such as hybrid vehicles or hydrogen ICEVs. Fourth, manufacturers of heavy-duty engines can meet the new truck and bus emission standards with natural gas, methanol, and even advanced diesel fuels and engines; they do not need to use hydrogen or hybrid technology.

In the present regulatory scheme, then, there is no niche for hybrids or hydrogen ICEVs. The net effect of these regulatory circumstances is virtually to eliminate until at least the end of this decade any incentive to produce hybrids or hydrogen ICEVs.

But hybrids and hydrogen ICEVs remain a middling option in the long term as well (unless the regulatory situation changes). As batteries improve, hybrids will find it difficult to compete in the small car market against batteries. More formidable will be the challenge posed by fuel cells. Whatever progress is made in improving and commercializing hybrid and hydrogen ICEV technology will likely be stalled early in the next century --first by anticipation, then by head-to-head competition with fuel cell vehicles. Simpler, cleaner, more energy efficient, and potentially less expensive, fuel cells -- which do qualify as ZEVs -- may be the decisive blow against ICE-battery hybrids and hydrogen ICEVs.

5.0 QUANTITATIVE COMPARISONS OF PROJECTED COSTS AND EMISSIONS FOR ALTERNATIVE PRIMARY ENERGY/INTERMEDIATE FUEL/VEHICLE SYSTEMS

We summarize and compare here alternative primary energy/intermediate energy carrier/vehicle combinations and their projected costs and performance. In particular, we review projected delivered fuel costs, performance and cost of alternative vehicles, per-kilometer lifecycle cost of transportation, and emissions of tail-pipe pollutants, as well as full fuel-cycle greenhouse gas emissions. Our analysis relies on detailed vehicle cost models described elsewhere (DeLuchi 1991 and 1992; DeLuchi and Sperling, 1993; and updates thereof).

The cost results presented here do not assume any major technological breakthroughs, but they do assume that cost of technologies in question reflect commercial maturity. Since many of these are far from commercial maturity today, we also examine the sensitivity of costs to the key uncertainties associated with developing the technologies to commercial maturity. Section 6 considers possible technology and infrastructure development times that might be involved until the large-scale commercial implementation of various systems.

We examine vehicles using an internal combustion engine or an electric motor as the prime mover. For the ICEVs, we consider for fuels reformulated gasoline, ethanol, methanol, compressed natural gas, and hydrogen (from various sources). For the electric vehicles, we consider battery-power and fuel cells operating on hydrogen or on-board-reformed methanol.

5.1. PROJECTED DELIVERED FUEL COSTS

We consider eight primary energy sources: oil, natural gas, coal, biomass, nuclear energy, solar insolation, and wind energy. Table 5.1a summarizes the baseline primary energy costs we have assumed for the analysis in this section. (In Section 5.3, we examine the sensitivity of total transportation costs to our assumed fuel costs.) Our gasoline cost estimate ($1.18/gallon, before taxes) assumes a crude oil price of $26.4/bbl, which is somewhat below the year-2010 reference case projection of the EIA (Table 5.1b). For natural gas and coal, we assume prices of $3/GJ and $1.75/GJ, respectively, reflecting EIA reference case projections for delivered costs of these fuels to utilities between 2000 and 2010 (Table 5.1b). For biomass, we assume a delivered feedstock cost of $2.5/GJ, corresponding to projected costs for dedicated energy crops produced on good quality agricultural land in the US (see earlier discussion). For corn, we assume a "net cost" of $1/bushel. For nuclear electricity, we assume a cost of 5.3 cents per kWh, as estimated for a post-2000 advanced ligh-water reactor (Electric Power Research Institute, 1989). Wind and PV electricity (without storage) are assumed to cost 4.7 and 3.8 cents per kWh, respectively.

Figure 5.1 (and Table 5.1a) show the estimated retail prices for transportation fuels produced from various primary sources, disaggregated by major cost component.

Reformulated gasoline costs \$8.95/GJ at the gas pump. Methanol ranges in cost from \$10.6/GJ when made from natural gas to between \$13 and \$14/GJ when made from coal or biomass. Ethanol from corn at close to \$19/GJ is the most expensive of the hydrocarbon fuels, while ethanol from lignocellulosic biomass is projected to be the least costly renewable fuel (\$112.5/GJ). Compressed natural gas at \$7.3/GJ is the least costly of all fuels shown in Fig. 5.1. Hydrogen from natural gas is about as costly as methanol from gas, while hydrogen from coal and from biomass are approximately equal in price (\$13.6-13.9/GJ). Electrolytic hydrogen is considerably more costly than other hydrogen sources, with PV-hydrogen (\$24.5/GJ) the least costly of the three electrolytic sources shown.

Off-peak electricity delivered to the home for recharging battery powered electric vehicles is assumed to cost 6 cents/kWh. The projected average residential electricity price supplied by a conventional (fossil-dependent) utility in the year 2000 is 8 cents/kWh (\$23/GJ). A renewables-intensive utility in the post-2000 period would supply residential electricity for roughly this price.

5.2. PROJECTED COST AND PERFORMANCE OF ALTERNATIVE VEHICLES

5.2.1. Characteristics of ICEVs

Table 5.2 summarizes baseline characteristics of ICEVs we assume in our analysis. The reference gasoline vehicle is a year-2000 version of the 1990 Ford Taurus. The other vehicles are "built" hypothetically from this (DeLuchi, 1992 and unpublished updates).

The travel range of these ICEVs ranges from a high of about 600 km for a gasoline vehicle down to 320 km for a compressed-hydrogen gas vehicle. The volumetric energy density of methanol is roughly half that of gasoline, which contributes to the 20% lower range for the methanol vehicle relative to gasoline. The lower energy density is compensated by a larger fuel storage volume and the higher fuel economy (through higher compression ratio) achievable with methanol. The range for the ethanol vehicle is greater than for methanol because ethanol has an energy density about 25% greater than methanol. The CNG range is assumed to be less than that of the methanol vehicle because CNG at 3000 psi has roughly half the energy density of methanol.

The lifetimes for all vehicles are assumed to be the same, except for the CNG vehicle. A CNG vehicle's lifetime is assumed to be slightly longer than that of a gasoline vehicle because some (largely anecdotal) evidence suggests that CNG might cause less engine wear than gasoline.

The weights of liquid-fueled vehicles (gasoline, methanol, ethanol, and liquid H_2) are all comparable -- about 1400 kg. The gas-fueled vehicles (CNG and compressed H_2) are somewhat heavier because of the weight of compressed gas cylinders.

The drag coefficients are assumed to be the same for all vehicles except hydrogen-fueled system. The very low energy storage density of the latter demands a more streamlined design in order to achieve a reasonably acceptable driving range.

5.2.2. Characteristics of EVs

Table 5.3 summarizes the baseline characteristics of EVs we assume in our analysis and compares them against the baseline gasoline/ICEV. The table shows characteristics for BPEVs with three different travel ranges and for FCEVs fueled by methanol with on-board reforming or by compressed hydrogen gas. Two travel ranges are shown for the hydrogen FCEV.

For all EVs except the methanol-FCEV, the travel ranges are substantially lower than with the gasoline ICEV due to lower energy storage densities. Also, the maximum power delivered to the wheels is lower. However, because an electric motor can provide full torque at very low rpm, at low vehicle speeds it will perform better than a (larger) gasoline engine.[18] The projected lifetimes of all EVs is 25% longer than for the gasoline/ICEV due largely to the fewer moving parts in EVs. All EVs would have relatively bulky systems for

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[18] Because the modeled FCEV has worse high-end performance but better around-town-performance than the baseline gasoline ICEV, we assume that in general consumers would not reject the modeled FCEVs because of "poor" performance. (Also, the greater reliability and quieter drive of electric vehicles might further compensate for the assumed lower top-end performance.) In any case, we assumed a lower peak performance for the FCEV because of cost, not because of technical limitations. Those who were willing to pay for higher performance would be able to buy it. But an FCEV with the same top-end performance as a gasoline ICEV clearly would have better all around performance, and hence in our view would make for an unfair comparison.

delivering electricity to the drive motor. The methanol FCEV would require an especially large volume because of the on-board reformer that is required for delivering hydrogen to the fuel cell.

The total vehicle weight of all EVs (except for the long-range--400 km--BPEV) would be lower than for the gasoline ICEV as would the drag coefficient (for all EVs). The lower weight and greater streamlining help offset the relatively lower energy storage density in EVs and thereby achieve reasonable travel ranges. The biggest factor, however, in achieving reasonable travel ranges is the high efficiency of the EVs, as reflected in the very low gasoline-equivalent liters per 100 km. The BPEVs would be the most efficient in converting on-board energy into travel kilometers. The methanol FCEV would be the least efficient of the EVs primarily because of losses associated with on-board fuel reforming.

5.3. PROJECTED LIFECYCLE COSTS OF ALTERNATIVE FUELS/VEHICLES

5.3.1. Baseline Costs[19]

Tables 5.4 and 5.5 summarize calculated retail vehicle price, fuel price, and total lifecycle costs per km for the ICEV and EV options considered here. The retail fuel prices correspond to those shown in Table 5.1. The ethanol, methanol, and hydrogen fuel costs assume production from biomass. The electricity price assumed for BPEVs, 6 cents/kWh, corresponds to the assumed off-peak price to residential customers.

The full retail price of all liquid-fueled ICEVs are comparable (Table 5.4). The CNG vehicle cost is about $1500 higher. The hydrogen ICEV is more than $6000 higher (Table 5.4). The hydrogen/ICEV is much more costly principally because of the relatively expensive storage equipment involved. The retail prices for EVs (Table 5.5) are also higher due

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[19] The reader should not view the base-case cost analysis as an attempt at a definitive cost projection, but rather as a scenario analysis -- an "if-then" statement -- or as a parametric analysis. For example, as shown below, the base-case assumptions for FCEVs result in life-cycle cost comparable to the lifecycle cost of gasoline ICEVs at a projected post-2000 oil price. But this does not mean that we are confidently predicting the economic success of fuel cell vehicles. Rather, it means either: a) that if our assumptions are correct, then solar-hydrogen FCEVs will be economically competitive with gasoline ICEVs; or b) that one way to make fuel cell vehicles economically competitive is to realize the set of cost specifications used here. (Of course, as discussed below, there are many other combinations of assumptions that produce a lifecycle cost equal to or lower than the base-case lifecycle cost, as well as many sets of assumptions that produce a higher lifecycle cost.)

primarily to the cost of batteries with the BPEVs and to the cost of fuel storage and fuel cell systems in the FCEVs. While prices for the longest range BPEV and hydrogen/FCEV would be a few thousand dollars higher than their shorter range counterparts, the price for the methanol/FCEV, which would provide the longest range of any of the EVs, would be comparable to the BPEV and hydrogen/FCEV vehicles with less than half the range.

Ownership and operating costs can be combined and expressed as a total cost per kilometer over the life of a vehicle by amortizing the initial cost at an appropriate interest rate, adjusting for salvage values and vehicle life, and adding periodic costs such as maintenance, fuel, insurance, and registration. Tables 5.4 and 5.5. show this total levelized lifecycle cost per km of travel for each ICEV and EV (including vehicle and fuel taxes). (We do not include externality costs, such as costs of emissions, in our estimates.) The baseline gasoline vehicle costs 21.0 cents/km. Among ICEVs (Table 5.4), the CNG vehicle gives a slightly lower cost, while methanol and ethanol give slightly higher costs. The hydrogen/ICEV would be the most expensive (17% higher than the gasoline/ICEV). Among the EVs (Table 5.5.), the 160-km and 240-km BPEVs would have costs close to the 21.0 cents/km of the gasoline ICEV, while the 400-km BPEV would cost slightly more (22.4 cents/km). With lifecycle costs of 19.6 to 20.1 cents/km, the methanol and hydrogen FCEVs would have the lowest lifecycle costs among all the ICEV and EV options we consider here.

Table 5.4 and 5.5. also give lifecycle costs in terms of the breakeven gasoline price. This is the retail price of gasoline (including taxes) at which the lifecycle cost per km of the gasoline/ICEV would be the same as that of the alternative vehicle under consideration. (For comparison, the gasoline price [including taxes] assumed for the baseline gasoline/ICEV is $1.49/gallon.) For the ICEV options (Table 5.4), the breakeven price ranges from $1.3/gallon for the CNG vehicle up to nearly $3/gallon for the compressed H_2 vehicle. For the EV options (Table 5.5), the breakeven price for the 400-km BPEV is the highest ($2.1/gallon), and the price for the methanol FCEV is the lowest ($0.9/gallon). Among all the options considered here, the breakeven gasoline price would be substantially lower than the assumed baseline gasoline price only for the three FCEV options shown in Table 5.5.

Tables 5.6 and 5.7 give disaggregated lifecycle costs corresponding to the total costs shown in Tables 5.4 and 5.5, respectively. Figure 5.2 and 5.3 show disaggregated lifecycle costs considering several primary energy sources for the production of methanol, ethanol, hydrogen, and electricity. The lifecycle costs vary accordingly. However, the lifecycle costs are not terribly sensitive to the assumed fuel source (cost--see Table 5.1), especially for the highly efficient electric vehicles. Notable in Fig. 5.2, which shows costs for alternative ICEVs, is that the gasoline, methanol, ethanol, and CNG ICEVs are comparable in cost (21-22 cents per km) and represent the lowest-cost options. Hydrogen-fueled ICEVs are the most costly--about 25% more than the gasoline vehicle in the highest cost case. The costs for EVs (Fig. 5.3) are shown in Fig. 5.3 for the methanol/FCEV and for the 400-km range BPEV and hydrogen/FCEV. All the FCEV options shown would be less costly than the reference gasoline/ICEV. The BPEV would be would have a slightly higher cost. The total lifecycle cost for all options varies by 2.4 cents per km or less for all EV options compared to the gasoline/ICEV.[20]

5.3.2. Sensitivities of Lifecycle Costs to Uncertainties

Many of the important cost parameters are very uncertain. Although as mentioned above we do not assume any major technological breakthroughs, and generally have *not* used the lowest cost estimates available for major components, we do assume that the key battery, fuel cell, and hydrogen storage technologies will be developed successfully, and that mass production will greatly reduce costs to levels that are being targeted or estimated by industry analysts and others. As shown in Tables 5.8 (for ICEVs) and 5.9 (for EVs), if our estimate of one of several important cost parameters is overly optimistic, then the lifecycle cost and break-even gasoline price could increase substantially. On the other hand, our baseline cases are not the only ones for which the alternative fuels and vehicles (especially FCEVs) would be competitive with gasoline ICEVs.

The apparent cost-competitiveness of several of the EV options warrants additional discussion of the sensitivity of EV costs to several parameters (Table 5.9). Parameters that we have varied in our analysis include the cost of the fuel cell, of the battery, of hydrogen

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[20] Note that a cost differential of 2 cents/km translates into an annual cost difference in the neighborhood of $300 (= $0.02/km x 16,000 km/yr).

storage, and of the fuel. We also consider lifetime and efficiency of the EV, and the interest rate used to amortize capital costs.

If batteries or FCEV-fuel storage costs 30% more than in our baseline analysis, the breakeven gasoline price would be up to $1/gallon higher than for gasoline/ICEVs. The breakeven gasoline price for the FCEVs would also increase, but not as substantially, and FCEVs would still be competitive with gasoline/ICEVs. If batteries or FCEV-fuel storage cost 30% less, the breakeven price would drop by up to nearly $1/gallon from the baseline cases for the BPEVs, and they would be very competitive with gasoline/ICEVs; the FCEVs would have breakeven gasoline prices of $0.5 to $0.6 per gallon.[21] If fuel cells cost 50% more than in our baseline cases, breakeven gasoline prices would increase, but not above the gasoline price ($1.49/gallon) we assume for the post-2000 period. If the fuel cell costs 50% less, the breakeven gasoline is below $0.72/gallon in the highest-cost case. Assumptions about financial parameters, such as the interest rate or the percentage of people taking out a loan to buy the vehicle, are less important but not trivial. If our efficiency estimate of the electric powertrain relative to the ICE powertrain--is overly optimistic, then the breakeven gasoline prices for both the FCEV and BPEV would be substantially higher--up to $3.2/gallon for the 400-km range BPEV and up to $2.2/gallon for the costliest FCEV. With electricity (for BPEVs) or fuels (for FCEVs) costing 50% more per GJ than in baseline values, there would be remarkably little impact on lifecycle costs because of the high efficiencies of EVs. On the other hand, the assumed vehicle lifetimes have an important impact on costs.

Most importantly, any combination of two to four of the higher-cost cases in Table 5.9 would result in a much higher vehicle lifecycle cost than in the corresponding base case.[22] This would make the FCEV options economically unattractive. (The BPEV (400-km range) baseline vehicle is already somewhat unattractive.) On the other hand, the baseline FCEV

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[21] The successful development of H-Power's iron oxidation/reduction system for hydrogen storage (see Table 4.2) could lower the cost of hydrogen storage by nearly an order of magnitude, which would dramatically reduce the breakeven gasoline price for hydrogen/FCEVs.

[22] Although not reflected explicitly in Table 5.9, the maximum performance and driving cycle of the FCEV and BPEV also are quite important: a high-power, long-range FCEV or BPEV used mainly in highway driving would have a much higher lifecycle cost than the vehicle assumed for the base-case analysis.

costs are not the only ones for which FCEVs are competitive with gasoline/ICEVs. In fact, there are many other favorable scenarios. And if several of the favorable cases were combined, the hydrogen FCEV would have a lower lifecycle cost than the gasoline ICEV at any conceivable future gasoline price, and the BPEV with a long driving range would be attractive at current gasoline prices.[23]

A comparison of hydrogen FCEVs and hydrogen ICEVs is also informative. In order for hydrogen ICEVs to have a lower lifecycle cost than hydrogen FCEVs, one must combine very optimistic assumptions for ICEVs, with pessimistic assumptions about FCEVs. In any of our hydrogen/FCEV sensitivity analyses involving reductions or increases in the value of an individual parameter (Table 5.9), the FCEV has a substantially lower lifecycle cost than the lowest-cost hydrogen\ICEVs case shown in Table 5.8.

In summary, there is a good deal of uncertainty in our cost analysis. Nevertheless, two conclusions are fairly robust. First, there are many scenarios--some involving cost values higher than we assumed in our baseline cases-- in which FCEVs have a lower lifecycle cost than gasoline/ICEVs. Second, in most scenarios FCEVs have a lower lifecycle cost than BPEVs and hydrogen ICEVs. (The second conclusion is robust because there is less uncertainty in comparing FCEVs with BPEVs or hydrogen/ICEVs than with gasoline ICEVs, because hydrogen FCEVs will be more like BPEVs and hydrogen/ICEVs.) Of course these conclusions assume the successful development of fuel-cell vehicles. The critical technology in the FCEV is the fuel cell itself. Because the development of the fuel cell has lagged the development of the other components of FCEVs (batteries, electric drivetrains, and even hydrogen storage systems), its cost and performance cannot yet be characterized as well. We have assumed that high specific power and high net energy efficiency can be achieved at relatively low total cost. Fuel cell technology must progress steadily over the next decade in order to realize these assumptions. The peak-power device and the hydrogen storage system in the FCEV also must be developed further to reach the cost and performance levels assumed here.

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[23] The lifecycle cost of the BPEV is particularly sensitive to changes in parameters that affect the lifecycle cost of the battery. These parameters include the OEM (original equipment manufacturer) battery cost, the driving range, the ratio of the retail-level price to the OEM cost, and the battery life.

5.4. PROJECTED EMISSIONS FROM ALTERNATIVE VEHICLES

A major driver for the development of alternative fuel and vehicle systems is improved environmental characteristics. Here we quantify the environmental performance of a range of feedstock/fuel/vehicle options. Specifically, we estimate the emissions of criteria pollutants per km of travel and the full fuel-cycle greenhouse gas emissions per km of travel. For these analyses, we assume that all vehicles would use advanced engines and drivetrains, would be optimized to run on the particular fuel considered (with a couple of exceptions[24]), and would (at a minimum) meet the in-use emissions standards mandated by the 1990 amendments to the US Clean Air Act.

5.4.1. Criteria and Toxic Air Pollutants

The estimated emissions of criteria urban air pollutants--NMOG (non-methane organic gases), CO (carbon monoxide), NO_x (nitrogen oxides), SO_x (sulfur oxides), and PM (particulate matter) are presented in Table 5.10 in terms of percentage changes relative to the baseline year-2000 ICEV using reformulated gasoline.[25] Table 5.11 gives changes in additional toxic pollutants. Our emissions estimates are only approximations, intended to be indicative of relative emissions potential. The actual emissions from any vehicle will depend on the particular characteristics of the engine and emission control systems and on the composition of the fuel and could differ substantially from these estimates. Except for BPEVs, the emissions estimates here exclude emissions associated with the production of the

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[24] Exceptions to this are the "flexible-fuel" vehicles (FFVs) designed to run on any mixture of gasoline and alcohol, but optimized for neither. Similarly, dual-fuel gasoline/CNG vehicles can run on gasoline or CNG (but not mixtures), and likewise are not optimized for either.

[25] The percentage changes in emissions are based on reported gram/kilometer emissions from gasoline and alternative-fuel vehicles (AFVs) driven on a dynamometer according to the standard drive cycle for emissions testing (the Federal Test Procedure--FTP). However, it is now recognized that the FTP does not represent how people drive in the real world. People accelerate harder, stop faster, rev their engines more, and do other things differently than in the FTP. These differences cause emissions from gasoline ICEVs driven in the real world to be considerably higher than emissions from gasoline ICEVs driven on a dynamometer according to the FTP. It is possible that these differences also could *differentially* affect emissions from AFVs; that is, the percentage differences in emissions between real-world AFVs and real-world gasoline ICEVs might not be the same as the percentage differences between AFVs and gasoline ICEVs tested according to the FTP. Unfortunately, there are no data on real-world emissions of AFVs compared to real-world emissions of gasoline ICEVs. As a result, analysts by default have had to assume that the FTP-derived percentages represent the unknown real-world percentages.

fuel.

Relative to emissions from the gasoline/ICEV, emissions of most or all criteria pollutants are expected to be lower for ICEVs running on methanol, ethanol, and CNG and substantially lower for the hydrogen/ICEV and all EVs, except for the BPEV running on electricity produced assuming the average mix of US utility power generation. For that BPEV case, the SO_x and PM emissions would be substantially higher than for the gasoline/ICEV. The non-negligible amount of NMOG emitted from the methanol/FCEV is due to evaporation of methanol during storage, distribution and handling.

A number of toxic non-criteria emissions are relatively high with alcohol fuels used in ICEVs. In contrast, dedicated CNG/ICEVs show reductions in all toxic pollutants except formaldehyde. Toxic pollutant emissions are essentially zero for all EVs (Table 5.11).

5.4.2. Greenhouse Gases

The greenhouse gases we have considered include CO_2, CH_4, N_2O, CO, NO_2 and NMOG emitted over the entire fuel production and use cycle (excluding the manufacture of vehicles and equipment). We have converted emissions of gases other than CO_2 into CO_2-equivalents by multiplying mass emissions of each by an appropriate global warming potential.[26] Our calculations use an updated version of the greenhouse-gas emissions model documented in DeLuchi (1991a). Table 5.12 shows the results of our calculations.

With ICEVs, only coal/methanol, coal/hydrogen, and corn/ethanol would lead to increased equivalent-CO_2 emissions relative to gasoline. The increase would be particularly large with coal/methanol and coal/hydrogen. Natural gas-derived fuels would lead to reductions that are small (6%) for methanol and larger for CNG (26%) and compressed hydrogen (25%). When renewable fuels are considered, the CO_2 emissions fall dramatically with ICEVs: 75% for biomass/hydrogen, 82% for solar/hydrogen, 83% for biomass methanol,

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[26] The assumed global warming potentials are 21 for CH_4, 270 for N_2O, 2 for CO, 4 for NO_2, and 5 for NMOC (revision of data in DeLuchi, 1991).

and 109% for biomass ethanol.[27]

BPEVs give only a modest equivalent-CO_2 emissions reduction (14%) when the average projected year-2000 US electricity generating mix is considered. Emissions fall to zero considering a full solar-powered electricity production.

For FCEVs, the high efficiencies lead to greater reductions in equivalent-CO_2 emissions than for ICEVs using the same feedstock/fuel. The changes in emissions where fossil fuels are concerned would be particularly large: coal/methanol would give a 27% reduction in emissions, compared to a 58% increase for the ICEV; natural gas/methanol gives a 58% reduction compared to a 6% reduction with the ICEV; and natural gas/hydrogen gives a 69% reduction compared to a 25% reduction with the ICEV. With fuels derived from renewable sources, the reductions in equivalent-CO_2 emissions from FCEVs would be larger than for corresponding ICEVs, but the differences would not be as large as with the fossil fuels because the reductions with renewable fuels in ICEVs are themselves substantial. Thus, for example, biomass/methanol in a FCEV gives a 94% reduction compared to 83% with the ICEV.

6.0. TRANSITION STRATEGIES TOWARD USING RENEWABLE FUELS IN ZERO OR NEAR ZERO-EMISSION VEHICLES

With preceding material as background, we speculate here on possible paths for achieving large-scale commercial penetration of renewable fuels in zero or near-zero emission vehicles in the US. In these discussions, we consider the relative state of development of various key technologies and their projected long-term commercial costs and environmental performance. For clarity we have limited ourselves, with one or two exceptions, to separate discussions by energy carrier: methanol, ethanol, hydrogen, and electricity. For each energy

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[27] The 90% reduction would be with a flexible fuel vehicle using E85. The 110% reduction would be with a dedicated E100 vehicle, which would be more efficient than the E85 vehicle. The greater-than-100% result for the E100 vehicle is due to the fact that an advanced biomass-to-ethanol facility would produce ethanol, meet all onsite energy needs, and generate excess (saleable) electricity from byproducts of the incoming biomass feedstock. In the greenhouse gas emissions calculations here, we have taken a CO_2 credit for this electricity based on ethanol production energy balances presented by Stone and Lynd (1993). We assume the electricity would have otherwise been generated elsewhere from fossil fuels. This CO_2 credit is larger than the total actual emissions from the ethanol fuel cycle.

carrier, we have identified several plausible transition pathways, and we discuss the factors that may determine which of these would be developed. As will be evident from our discussions, the evolution of the US transportation system toward full use of renewables in clean vehicles could take very different directions. The direction followed will depend in large part on the relative importance placed by policy makers on key energy and environmental issues, including urban air quality, greenhouse gas emissions, and energy security. One premise of our discussions is that policy decisions will be driven by the prospect of major cost and/or environmental benefits. Only where it is clear there are such benefits can large-scale changes in our transportation system be expected.

6.1. ETHANOL

Among potentially renewable fuels, ethanol is the only one that is presently produced commercially on a large scale in the US for use as a 10% blend with gasoline in conventional ICEVs. About 3 billion liters of ethanol are made annually in the US today, all from corn. Ethanol from corn does not compete on an economic basis with gasoline, but federal subsidies of about \$0.16/liter (\$6.6/GJ) are paid to support continued ethanol production from corn.

Ethanol, as presently used and as might be used in the future in ICEVs, provides relatively little reduction in criteria pollutants compared to other alternative fuels considered here. With the 10%/90% ethanol/gasoline blend criteria pollutants are reduced somewhat over use of reformulated gasoline. More substantial emissions reductions are possible with an engine that is designed either for 100% ethanol (E100) or for accommodating variable mixtures of ethanol and gasoline, up to 85% ethanol (E85). Pure ethanol vehicles (E100) are expected to have emissions of criteria pollutants similar to dedicated methanol (M100) vehicles (see Table 5.10 for the latter), although few tests have been done in the US to determine this. Emissions of NMOG from a flexible fuel ethanol vehicle burning E85 would be less than from a gasoline/ICEV (Fig. 6.1), but greater than from a flexible fuel vehicle burning M85. Other criteria pollutant emissions would be similar for the E85 and M85 vehicles.

The emissions of fuel-cycle greenhouse gases from ethanol vehicles varies greatly depending on the feedstock from which the ethanol is produced. Using corn, the emissions are 5 to 10% greater per km of travel than with reformulated gasoline, due largely to the need for fossil fuel use in the production of the ethanol. On the other hand, if ethanol is made from biomass, emissions are reduced between 88 and 109% (Fig. 6.1).

In principle, near-zero emissions of both criteria pollutants and greenhouse gas emissions are achievable with ethanol if it can be used in fuel cell vehicles. With present FCEV developments targeting the PEM fuel cell, which operates at about 100°C, ethanol is not a promising fuel. The primary reason for this is that reforming of ethanol to hydrogen requires temperatures in excess of 350°C--preferably in excess of 500°C (Garcia and Laborde, 1991). The mismatch between ethanol reformer and fuel cell operating temperature means there would be efficiency penalties and operational complexities not foreseen for fuel cell vehicles operating on methanol, which has a much lower reforming temperature (250°C or less), or on pure hydrogen. If higher temperature fuel cells, such as the solid oxide fuel cell (up to 1000°C operating temperature) are ultimately developed for vehicle applications, then a much wider variety of fuels, including ethanol, could be considered. At present the focus of development efforts with the solid oxide and other high temperature fuel cells is stationary electric power generation.

With ethanol used in ICEVs, the per-km cost of ethanol-based transportation relative to gasoline is determined primarily by the relative cost of delivered fuel, because the first cost and lifetimes of the vehicles are comparable. If the federal subsidy for corn-ethanol were removed, corn/ethanol/ICEVs would not be economically competitive with gasoline/ICEVs (Fig. 6.1). On the other hand, if cost projections for biomass-ethanol are commercially realized, biomass-ethanol/ICEVs would have lifecycle costs only slightly higher than for gasoline/ICEVs (Fig. 6.1).

6.1.1. Research and Development Challenges in the Ethanol Path

There are three key research and development challenges facing a transition to large-scale biomass-based ethanol production and use.

(1) Commercial development of large-scale, dedicated biomass plantations (see Section 2.1). The R&D effort needed to develop biomass energy plantation technology that is economically competitive is expected to require at least a decade (see Section 2.1).

Developing guidelines for environmentally sustainable plantations may require about the same kind of effort, although there has been relatively little work done in this area to date. Even with the availability of competitive and environmentally acceptable plantation technology, putting in place the infrastructure for producing and delivering large quantities of biomass to conversion facilities would require some time. Aside from the time needed to encourage farmers to switch from food to energy crops, woody-tree plantations would require a minimum of about 5 years from planting to first harvest. Perennial crops such switchgrass would shorten this time. In any case, it appears that it will be well into the first decade of the 21st century before large-scale, commercial biomass energy production can be expected. Biomass plantations are required in the long term for any biomass-based energy system (ethanol, methanol, hydrogen, electricity). A potential complication for ethanol production is that the enzymes involved in the most promising conversion process--enzymatic hydrolysis--may require a very homogeneous feedstock to achieve projected performance; hence, biomass produced more-or-less in monoculture may be required, the ecological impacts of which are uncertain at best (US Congress, 1993).

(2) Commercial realization of efficient, low-cost enzymatic hydrolysis processes. The technology needed to achieve the low cost projections for ethanol from biomass -- advanced enzymatic hydrolysis -- has been demonstrated only in the laboratory. A considerable effort is thus required to bring the technology to commercial readiness.

(3) Development of FCEVs utilizing high-temperature fuel cells. Resource constraints and modest-to-poor emissions benefits of ethanol/ICEVs may ultimately relegate this combination to a backseat in future US transportation systems. [The unfavorable energetics of ethanol production from corn (reflected in increased greenhouse gas emissions relative to gasoline) and the high production cost, make this an especially unattractive option for the long term.] If ethanol use is limited to ICEVs, and assuming all transportation in the US continues to be based on ICEVs, it is unlikely that biomass feedstocks could be provided for ethanol production in quantities sufficient to meet a significant share of US transportation needs. The much higher efficiency of FCEVs is required for biomass to play a significant role in the US (see Fig. 3.2.2) and to achieve zero or near-zero emissions. The development of high-temperature fuel cells for vehicles would improve the outlook for ethanol FCEVs, due

to the high temperature required for reforming ethanol.

6.2. METHANOL

Technological options for producing and using methanol are numerous. Methanol can be made from natural gas, coal, or biomass and it can be used in either ICEVs or FCEVs. This multiplicity of sources and vehicle technologies must be considered a characteristic favoring methanol as a fossil-to-clean renewables transition energy carrier. Furthermore, methanol has the character of our present transportation fuel (i.e. liquid, not gas, under normal ICEV operating conditions), which could facilitate a move from the present vehicle technology toward cleaner vehicles. An important limitation of methanol is that it requires a carbon source. Biomass is the only viable renewable source of carbon. As has been discussed earlier (see Fig. 3.2), if highly efficient vehicle technology (FCEVs) were used, the potential biomass energy production in the US would be more than sufficient to meet transportation energy needs. On the other hand, developing the full biomass energy potential of the US will be challenging, as it will involve changes in land use in the US on the scale of millions of hectares.

Our discussion here of transitions toward renewable, clean methanol transportation system begins with a focus on options for ICEVs, as the methanol/ICEV technology is already commercially implemented to a limited extent.

6.2.1. Methanol in ICEVs

Methanol is already produced today at large scale from (low-cost) natural gas. Methanol vehicles operate commercially to a limited extent in the US, mainly in California and federal government fleets. Methanol finds limited use in transportation, despite delivered costs that are directly competitive with gasoline on an energy basis. One important reason is that urban air pollution benefits are not large. In particular, emissions of CO and NO_x--two key criteria pollutants--from methanol ICEVs are not sufficiently below those of gasoline/ICEVs to drive wholesale switching from gasoline to methanol (Fig. 6.2). Furthermore, emission of some toxic, but unregulated pollutants, most notably formaldehyde and benzene, are considerably higher from ICEVs using methanol rather than gasoline.[28] Moreover, fuel-cycle greenhouse gas emissions benefits are negligible with methanol/natural gas/ICEVs compared to gasoline/ICEVs (Fig. 6.2).

The technology for methanol production from coal is also commercially available. Furthermore, coal resources are the largest of any fossil fuel, and coal costs are the lowest among fossil fuels. There has not been any significant commercial production of methanol from coal, however, because of the high capital cost of coal-methanol production: with coal costing $1.75/GJ, the price of natural gas would need to reach $4.7/GJ before /methanol from coal becomes competitive with that from natural gas. Even if methanol production costs were to be competitive, the environmental characteristics of coal/methanol/ICEV vehicles would not be attractive relative to natural gas/methanol/ICEVs. Emissions of criteria pollutants from coal/methanol/ICEVs would be comparable to those for natural gas/methanol/ICEVs, but fuel-cycle greenhouse gas emissions would be substantially higher--more than 50% higher than for gasoline/ICEVs (Fig. 6.2).

A third feedstock option for methanol production is biomass. Importantly, if biomass production cost targets are achieved, the lifecycle cost of transportation with biomass/methanol/ICEVs would be about the same as for coal/methanol/ICEVs (Fig. 6.2). And, the former would provide significant greenhouse gas emission reductions, though emissions of criteria pollutants would not be different than with methanol from other sources.

6.2.2. Methanol in FCEVs

Major environmental benefits would accompany a shift from methanol/ICEVs to methanol FCEVs. With natural gas and (especially) biomass as feedstocks, reductions in greenhouse gas emissions would be very substantial. Emissions of criteria pollutants would be reduced nearly to zero. (See Fig. 6.2.) Furthermore, if fuel production cost and vehicle capital and operating cost targets are realized, the total lifecycle costs for FCEV options

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[28] Methanol vehicles have high tailpipe emissions of formaldehyde because this compound is the first oxidation production of methanol. Note, however, that the atmospheric formaldehyde concentration is determined not only be direct emissions, but also be emissions of formaldehyde precursors that react in the atmosphere to form formaldehyde. Thus, even though methanol vehicles directly emit more formaldehyde than do gasoline vehicles, they might not cause a large increase in the atmospheric concentration, because they emit less formaldehyde precursors.

would be roughly comparable, regardless of the feedstock. The lifecycle costs would be somewhat lower than for gasoline/ICEVs and for methanol/ICEVs.

6.2.3. Research and Development Challenges to the Methanol Path

Before large-scale production of methanol from biomass can be done commercially, three key technological developments are required.

(1) Commercial-scale demonstration of one or more biomass gasifiers suitable for methanol production. Extensive work was done to develop biomass gasifiers for methanol production in the 1970s and early 1980s, so that the commercial demonstration of a suitable biomass gasifier should not require more than about 5 years to undertake. This conclusion is supported by the pace of ongoing commercial-scale fluidized-bed gasifier demonstration projects (see Section 2.2.2.4). Advanced gasifier designs, such as indirectly-heated units, may improve the economics of methanol production significantly over the more traditional designs developed in the 1970s and 1980s. The commercial development of such advanced designs will require a somewhat longer time scale than five years, because they have not received as much effort as the fluidized-bed designs did in the 1980s. In any case, it appears that biomass-to-methanol conversion technology could be commercially ready by about the year 2000.

(2) Commercial-scale demonstration of environmentally acceptable and economically viable production of biomass on dedicated energy plantations. The challenge of developing large-scale commercial biomass energy plantations has been discussed earlier (Sections 6.1.1 and 2.1). A decade or more will be required for this to happen. However, the character of methanol production technology offers the possibility of establishing commercial methanol production before plantations are commercially operating. Methanol production (like hydrogen production) is a thermochemical (high-temperature process) and is thus more tolerant of diversity in feedstocks than biological processes (like enzymatic hydrolysis). Thus, mixed-feedstocks are suitable for methanol production. Two possibilities are interesting, both involving feedstocks that are already produced today. One option is the use of residues produced by the forest products industry, which today is the largest organized user of biomass energy in the US. Forest residues associated with annual wood harvests for the industry

contain some 1.3 EJ (Larson, 1992).[29] These are presently unused for any industrial activity. Some of these residues must be left onsite to maintain long-term soil productivity. Some could be available for other uses. The cost of recovering residues might be relatively low if integrated with the harvest of the industrial wood. A second feedstock stream is municipal solid waste (MSW). This source, amounting to about 1.8 EJ per year (after recycling) (Franklin, 1992), is especially attractive because of its negative cost. The gasification technology needed for MSW is essentially the same as that needed for biomass.

(3) The development of methanol FCEV technology. In our analysis, we have considered methanol/FCEVs with on-board reformers to convert methanol into hydrogen. The reformer technology and its integration into the vehicle is a key requirement for commercialization of methanol/FCEVs that is different from requirements for hydrogen/ FCEVs. The latter are discussed in Section 6.3.1.3.

Work is also ongoing on direct use of methanol in fuel cells. The technical challenges with direct methanol fuel cells appear significantly greater than for hydrogen fuel cells. For additional discussion of direct methanol fuel cells, see Hammett and Troughton (1992), Kjar and Yde-Andersen (1991), and Leger and Lamy (1990).

6.3. HYDROGEN

Here we consider transition paths toward use of renewable hydrogen in fuel cell vehicles. First we summarize the status of relevant hydrogen production, delivery and vehicle technologies. Then various possible transition paths are discussed.

6.3.1. Summary: Status of Hydrogen Technologies

6.3.1.1. Hydrogen production technologies

The technologies for producing hydrogen from natural gas (via steam reforming) are already commercial and are widely used in the petroleum refining and chemical process industries today. Development of low cost small scale reformers would facilitate the production of hydrogen for vehicle fleets. Hydrogen could also be produced via gasification

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[29] Excluding roots, stumps, small branches, needles and leaves.

of coal or biomass. As discussed in Section 6.2, the main technological advances needed for biomass hydrogen production are the development of the biomass gasifier and the development of low cost biomass supplies. Electrolysis is another well known, commercial technology for hydrogen production. For electrolytic hydrogen production from intermittent renewable electricity, the main requirement is reducing the cost of electricity from wind and solar. Another issue for wind and PV hydrogen is the optimization of electrolyzers for intermittent operation.

6.3.1.2. Hydrogen transmission and distribution technologies

Development of hydrogen as a transportation fuel poses special issues, because, at present, no widespread infrastructure for delivering hydrogen to consumers exists. There would be no major technical problems in building such an infrastructure. The required technologies (hydrogen compressors, hydrogen storage, hydrogen pipelines) are well known and are already used in the chemical industries. Instead, the question is what steps might be needed to develop a hydrogen infrastructure (and who would do the development). There are several possibilities for bringing hydrogen to consumers.

1) Centralized production of hydrogen and distribution via a) truck delivery of compressed hydrogen gas or liquid hydrogen (this is how most hydrogen is distributed today), or b) a gaseous hydrogen pipeline transmission and distribution system, similar to that used for natural gas today.

2) Distributed production of hydrogen, at the refueling site via small scale steam reforming of natural gas or electrolysis. (Hydrogen production from gasification of municipal solid waste might be done at modest scale at an urban waste processing facility, where vehicles would go to be refueled.)

Because of the difficulty of building a hydrogen pipeline distribution system, it is likely that the first stages of hydrogen use would depend on truck-delivered hydrogen. Next, the existing natural gas or electricity infrastructures might be used. In this case, hydrogen would be produced at the site of use from steam reforming of natural gas or via electrolysis in areas where low-cost off-peak or intermittent electricity was available. Another possibility which could be considered is stand-alone fuel production, via PV electrolysis. This might be particularly suitable in areas far from either natural gas or electric lines. In the longer term, hydrogen distribution systems would be built to bring hydrogen from centralized hydrogen production plants to local refueling stations. And eventually hydrogen might be transmitted long distances via pipelines.

The development of a hydrogen infrastructure will be influenced by which types of hydrogen supply are most attractive in a given situation. Centralized production with a hydrogen distribution system will be desirable for hydrogen production from natural gas, biomass or coal, since all these benefit strongly from economies of scale. Distributed production (which might be preferred in the initial stages of hydrogen use or in areas far from a natural gas or electric grid) favors hydrogen production technologies such as electrolysis (either grid connected or stand alone) and small scale steam reforming of natural gas.

6.3.1.3. Hydrogen vehicle technologies

A number of experimental hydrogen internal combustion engine vehicles have been built, and small demonstration fleets have been tested by BMW and Daimler Benz. It is likely that fleets of hydrogen ICEVs could be ready by 1998 or sooner. Several manufacturers with hydrogen R&D programs (Daimler-Benz and Mazda) have shown an interest in introducing their hydrogen ICEVs in the California markets.

Hydrogen fuel cell vehicles are in an earlier stage of development than hydrogen ICEVs. The first experimental fuel cell vehicles based on PEM fuel cells are now being built. To date, only one prototype based on a PEMFC has been demonstrated: the Ballard bus, which uses compressed hydrogen storage. Over the next few years several other fuel cell vehicles are expected to be on the road. Small demonstration fleets of fuel cell vehicles might be ready by 1998, though large scale penetration of hydrogen fuel cell vehicles would probably not occur until the early decades of the next century. (After the first experimental vehicles are built and tested, a period of small scale (5-50 vehicle) demonstration fleet testing might be done. This would probably take 3 to 5 years. Beyond this point, fleets of several hundred to several thousand vehicles might be tested, again over a period of perhaps 3 to 5 years. If these tests are successful, commercialization and mass production of fuel cell vehicles might begin.) Because of their high efficiency, fuel cell vehicles would ease the supply requirements for hydrogen. This is particularly important for renewable supplies, which tend to be land and/or capital intensive, and would also reduce the amount of infrastructure building required to serve a given number of vehicles.

Onboard hydrogen storage is an important issue for hydrogen vehicles. We believe that compressed gaseous hydrogen storage will be preferred for several reasons: *(1)* hydrogen pressure cylinders can be refueled in a few minutes; *(2)* the technology could be developed in the near term, based on existing industrial hydrogen technology and storage cylinders for CNG vehicles; *(3)* experience with CNG vehicle refueling systems would be applicable to the development of gaseous hydrogen refueling systems; *(4)* the difficulties of liquid hydrogen (high energy requirement for liquefaction, handling a cryogenic liquid) would be avoided. Compared to liquid hydrogen, compressed gas hydrogen storage has the drawback of having relatively low energy density. For hydrogen ICEVs, this would limit the vehicle's range, but with fuel cell vehicles, this would not be as much of a problem, because of the vehicle's high efficiency.

6.3.2. Transition Paths Toward Use of Hydrogen Transportation Fuel

As a reference case, we consider a transition path built on the following progression: *Step 1*, hydrogen is produced from natural gas and used in hydrogen ICEVs; *Step 2*, hydrogen FCEVs are introduced--hydrogen is produced from natural gas and used in hydrogen FCEVs; *Step 3*, biomass hydrogen supplies are introduced--hydrogen is produced from biomass and used in hydrogen FCEVs; *Step 4*, solar and wind electrolytic hydrogen supplies are introduced--hydrogen is produced from PV or wind electrolysis and used in hydrogen FCEVs.

This path assumes that the lowest cost hydrogen source (natural gas) would be used first. This would also involve the least change in infrastructure since hydrogen could be produced at the point of use from natural gas. Hydrogen ICEVs could be employed in the next few years, so that step 1 might take place by the year 2000.

A progression toward more efficient, lower emission fuel cell vehicles, and renewable supplies then takes place, driven by environmental concerns, and possibly rising natural gas prices. Where it is available, biomass hydrogen could be less expensive than electrolytic hydrogen, so that it is assumed that biomass hydrogen is introduced first, followed by solar and wind hydrogen, when biomass supplies were committed. (This progression might be different depending on the availability of biomass supplies, and on the state of the hydrogen infrastructure.)[30]

We also discuss the technical challenges which must be met at each step. Quantitatively, the effect of taking each step is expressed in terms of the emissions of pollutants and greenhouse gases, the delivered fuel cost, and the lifecycle cost of transportation (Fig. 6.3.1).

6.3.2.1. *Step 1*: Hydrogen from natural gas used in ICEVs

Initially, hydrogen would be produced from natural gas and used in hydrogen ICEVs. At very low demand levels (for the first test fleets of 5 to 50 vehicles), hydrogen might be delivered by truck. As the demand increased, and fleets of 300-1000 vehicles were introduced, small scale reforming of natural gas would become the least costly way of providing hydrogen. The delivered cost of hydrogen from onsite production via small scale reforming of natural gas would be about $17-20/GJ. If demand grew enough to justify building a large steam reforming plant with a local distribution system, the delivered cost of hydrogen might drop to $11-17/GJ (for natural gas prices of $2-6/GJ).

The lifecycle cost of transportation would be increased somewhat with this option as compared to the lifecycle cost for gasoline or CNG vehicles. However, a much larger reduction of both criteria pollutants and greenhouse gases would be realized. With natural gas feedstock for hydrogen production, the emissions of greenhouse gases would be reduced by over 40% as compared to gasoline ICEVs.

The main technical issues in taking this first step would be development of a hydrogen refueling station based on small scale reforming of natural gas. Although some systems engineering would be needed, this could be done with existing technology, and could be built

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[30] In the long term, electrolytic hydrogen from nuclear power is also a possibility. Nuclear hydrogen would cost about as much as hydrogen from wind or PV sources (Table 5.1) and would face the difficulties nuclear power faces today in the US. We do not consider the nuclear option in our discussion in this section.

within the next few years, Automotive manufacturers such as Daimler-Benz and Mazda have indicated readiness to produce hydrogen ICEVs for the California market.

The motivations for step 1 would be to improve urban air quality, to reduce greenhouse gas emissions, and, most importantly, to gain experience with hydrogen refueling and storage in preparation for the introduction of hydrogen fuel cell electric vehicles.

6.3.2.2. *Step 2*: Hydrogen from natural gas in FCEVs

The next step in the development of hydrogen transportation fuel might be the introduction of hydrogen fuel cell vehicles. Depending on the progress in fuel cell vehicle technologies, this could occur in the early part of the next century.

As in step 1, the delivered fuel cost for hydrogen from natural gas would be about $17-20/GJ for onsite production and $11-17/GJ for large scale hydrogen production with pipeline distribution.

Assuming that long term goals for fuel cells are met, and that hydrogen FCEVs are mass produced, the lifecycle cost of transportation might be approximately comparable to that for gasoline ICEVs and somewhat less than with hydrogen ICEVs.

With the introduction of FCEVs, another significant reduction in emissions would result. Hydrogen FCEVs would be true ZEVs with zero vehicular emissions, and the fuel cycle emissions of greenhouse gases would fall by over 70% as compared with gasoline ICEVs.

The primary technical hurdle in making step 2 is the development of hydrogen fuel cell vehicles. The first experimental hydrogen FCEVs are now being built and tested. It is difficult to predict how long it would take to optimize, field test, commercialize and mass produce FCEVs. Even with rapid technical progress, this may not occur until the first few decades of the next century.

The main motivations for taking step two are the compelling benefits of fuel cell vehicles. Fuel cell vehicles would mean further improvements in air quality (elimination of all vehicular emissions and greenhouse gas reductions). Because the efficiency of hydrogen FCEVs would be more than twice that of hydrogen ICEVs, their introduction would also ease future supply concerns (paving the way for renewable supplies to play a larger role) and improve the economics and range of hydrogen vehicles.

6.3.2.3. *Step 3*: Hydrogen from biomass in FCEVs

The next step might be introduction of renewable hydrogen sources. Assuming that biomass is available, this would be the least costly renewable source of hydrogen. The delivered fuel cost for biomass hydrogen would be about $14-17/GJ. To compete with natural gas hydrogen, a gas price in excess of $6/GJ would be required. Even if natural gas prices were not at this level, higher-cost hydrogen from biomass would yield roughly the same transportation lifecycle cost as hydrogen from natural gas, because fuel costs are a relatively small part of the total lifecycle cost.

As in step 2, with FCEVs, vehicular emissions would be zero. With the introduction of biomass supplies, the emissions of greenhouse gases would be reduced by 90% as compared to gasoline ICEVs.

The main technical issues in making step 3 are the development of biomass gasifiers, and the development of low cost biomass supplies. These issues are discussed in Section 6.2.3. Because biomass hydrogen production facilities would exhibit considerable economies of scale, biomass hydrogen might not be introduced until a gaseous hydrogen pipeline distribution system was in place.

The main motivations for step 3 would be concerns about global warming, and possibly cost and security constraints on natural gas. In addition, the development of biomass plantations might have macro-economic and social benefits, in that agricultural subsidies paid to effectively keep cropland idle might be reduced and the land would be productively used.

6.3.2.4. *Step 4*: Hydrogen from solar or wind in FCEVs

Biomass supplies would be able to meet a significant fraction of the US demand for transportation fuels, if highly efficient fuel cell vehicles were used. However, in certain areas, biomass may not be available, or it might be difficult or costly to develop a hydrogen distribution system for biomass hydrogen. In this case electrolytic hydrogen from wind or solar PV might be used. In addition, solar and wind electrolytic hydrogen would have some environmental advantages over biomass-hydrogen (lower land and water requirements).

The delivered fuel cost would be higher with PV or wind hydrogen, about twice that of biomass hydrogen. However, greenhouse gas emissions would be slightly lower, and lifecycle costs would be only slightly higher than with biomass hydrogen. Because PV and wind resources are much larger and more widely available than biomass, this might be preferred in some areas of the US.

In the long term, if solar electricity and hydrogen were used, it would be possible to essentially eliminate both urban regional air pollutant emissions and greenhouse gases.

Because electricity is the largest contributor to the cost of electrolytic hydrogen, it is highly desirable to reduce the cost of renewable electricity. We have estimated costs for PV and wind hydrogen based on post-2000 projections for these technologies, and assuming that these technologies are mass produced. This might occur by the early part of the next century. Based on these projections, the delivered fuel cost for PV hydrogen would be about twice that for biomass hydrogen, and the lifecycle cost of transportation would be 1-2 cents/km greater. (With double the fuel cost, the breakeven gasoline price would be $1.8/gallon instead of $1.1/gallon.)

A primary motivation for taking step 4 would be energy supply concerns, and in some cases the attractions of distributed fuel production, as compared to extending or building a hydrogen distribution infrastructure. Also, solar and wind hydrogen may be environmentally preferred to biomass hydrogen because of lower land and water-use intensities.

6.3.3. Other Transition Paths

6.3.3.1. Coal hydrogen

Given that coal supplies in many regions of the world are vast and low in cost, there may be pressure to use these for transportation. The environmental problems with coal, especially its contribution to greenhouse warming, makes this an undesirable option. Moreover, natural gas supplies are likely to be sufficient to carry the transition from our present transportation system to one based on renewable fuels and FCEVs in the long term. *If* coal use were to be considered, then a transition path might be something along the following lines: *Step 1*, hydrogen is produced from natural gas and used in hydrogen ICEVs; *Step 2*, natural gas/hydrogen FCEVs are introduced; *Step 3*, coal hydrogen/FCEVs are introduced; *Step 4*, renewable hydrogen/FCEVs are introduced.

As an intermediate step between natural gas and renewable energy sources, hydrogen might be produced from coal. This might occur in the unlikely case that natural gas supplies became scarce before biomass, PV or wind hydrogen systems are commercialized.[31] With hydrogen ICEVs or FCEVs vehicular emissions would be reduced to near zero or zero. The economics would be similar to using hydrogen from biomass. However, making hydrogen from coal would lead to a significant increase in greenhouse gas emissions relative to natural gas/hydrogen/FCEVs (Fig. 6.3.2). Thus, the use of coal would be desirable only if avoiding global warming is not a high priority.

6.3.3.2. An early role for electrolytic hydrogen

We have assumed that initially hydrogen would be produced via small scale steam reforming of natural gas. However, depending on the size of the demand and the availability of a distribution infrastructure, electrolytic hydrogen might compete with hydrogen from natural gas. For demands smaller than about 0.5 million scf/day (enough for a fleet of several hundred to 1000 vehicles), the delivered cost for electrolytic hydrogen might compete with that of hydrogen from natural gas, if off-peak or intermittent renewable power were available at 2-5 cents/kWh. Once a city-scale hydrogen distribution network was established, centralized production of hydrogen (from natural gas or biomass) would be less expensive.

However, electrolytic hydrogen might get an earlier start for small scale demands in areas far from the electricity grid or natural gas pipeline network. Moreover, small small-scale PV or wind hydrogen might continue to be used in the longer term in such areas.

6.3.4. Who Would Develop Hydrogen as a Transportation Fuel?

A number of automobile manufacturers have built experimental hydrogen/ICEVs. Companies such as GM, Mazda, and Daimler-Benz are now working on hydrogen FCEVs,

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[31] Natural gas is plentiful today and likely to remain so for a long time. Moreover, natural gas demand by FCEVs will be modest, partly because FCEVs will be so efficient, and partly because natural gas is likely to be a transition fuel only. By the time FCEVs are ready to be fully commercialized and mass-produced, a biomass-hydrogen or PV-hydrogen infrastructure could be available, so that there would be no reason to use natural gas as the primary feedstock.

and there is a good chance that these low polluting, efficient vehicles could be ready by the early part of the next century. The question remains as to where the hydrogen would come from.

It is interesting to speculate about who would undertake the development needed to produce and deliver hydrogen as a transportation fuel. Possibilities include:

1) Present industrial hydrogen production companies
2) Gas utilities
3) Electric utilities
4) Oil companies
5) Independent fuel producers (either at small scale at the refueling site or at a large, centralized plant)

In very early stages of demand, present industrial hydrogen producers might be best positioned to deliver small quantities of hydrogen to refueling sites. As demand increased, truck delivery would no longer compete with onsite production. Hydrogen production companies would have to either build hydrogen lines to refueling sites or work with local distribution gas utilities to adapt their delivery systems.

Gas utilities might be attracted by the prospect of serving many onsite reforming units at hydrogen refueling stations. Because a large centralized hydrogen producer might be able to "bypass" the gas utility, (e.g. obtain a more favorable natural gas rate directly from the pipeline carrier), local gas utilities might favor distributed hydrogen production (which would mean adding customers) rather than centralized (which would not). This approach would also delay expense and difficulty involved in changing the distribution system to hydrogen. In the longer term, if a large demand for hydrogen transportation fuel evolved, gas utilities might convert natural gas lines to hydrogen or even build dedicated hydrogen distribution lines in parallel with natural gas lines along utility rights of way. Blending hydrogen with natural gas is another possibility.

Similarly, electric utilities might find markets for small scale onsite electrolysis using off-peak power attractive.

Oil companies already produce large quantities of hydrogen for refining operations. These companies might be key players in developing large scale hydrogen production facilities from natural gas, biomass or coal. (For biomass, this might also involve companies presently involved in commercial plantations, e.g. the forest products industry.) Many oil companies also own natural gas pipeline and distribution systems. Where possible, vertical integration might facilitate development of a hydrogen infrastructure. Moreover, long experience with transportation fuels might work in the oil companies' favor.

Finally, independent fuel producers making hydrogen at or near the point of use would be the least constrained by infrastructure considerations. Technologies exist now for using natural gas or electricity to make hydrogen at small scale. As costs for PV electricity decrease, stand-alone hydrogen production from PV would be increasingly attractive. The drawback is that hydrogen might ultimately cost more from distributed production systems than from centralized systems.

6.4. ELECTRICITY

Electricity can be produced from a variety of renewable sources (biomass, wind, solar, hydro). As discussed in Section 2.3.2, the cost of producing electricity in a "renewables-intensive utility" in the post-2000 time frame may be comparable to that for a conventional utility. Assuming that battery powered electric vehicles are recharged from the grid, a transition toward use of renewable electricity as a transportation fuel would take place as the utility's generating mix became more dependent on renewables.

The primary technical issues involved in a transition toward renewable/BPEV transportation are development of renewable electric technologies (see Section 2.3 for details), their integration into a utility grid, and the development of battery powered electric vehicles (see Section 4.3) and their recharging systems.

In Figure 6.4, we show the effect of changing from a conventional to a renewables intensive utility. The cost of electricity is essentially the same, as is the lifecycle cost of transportation. In both cases, vehicular emissions are zero, although emissions at the power plant are non-negligible for the conventional utility. The emissions of greenhouse gases are reduced by almost 100% with a renewables intensive utility.

With battery powered electric vehicles run on renewable electricity, it would be possible to produce and use energy with essentially zero fuelcycle emissions.

7.0 TOWARD RENEWABLE TRANSPORTATION FUELS AND TECHNOLOGIES

This report has reviewed the current state-of-the-art and projected developments in technologies for producing and delivering transportation fuels and for using these fuels in vehicles. Our discussions have emphasized alternative transportation systems based on renewable energy resources (water, sun, wind, and biomass) fueling either internal combustion engine vehicles (ICEVs), battery-powered electric vehicles (BPEVs), or fuel cell electric vehicles (FCEVs). For fuel supply, we have concentrated on ethanol, methanol, electricity, and hydrogen, all of which have the potential for being used with significantly reduced emissions of pollutants and greenhouse gases compared to gasoline/ICEVs, and for being produced renewably on a large scale from domestic resources. Within this set of fuels and vehicle technologies, there are a multiplicity of plausible scenarios for a transition from the present gasoline/ICEV transportation system to one based entirely (or nearly entirely) on one or more renewable fuels.

We have discussed the technological hurdles associated with a number of the transition scenarios. Research and development efforts of varying levels are addressing most of these hurdles, but it is difficult to draw firm conclusions as to the time scales that will be involved until key technologies are commercialized. The rate of technological development and hence the transition strategies that are ultimately commercially implemented may depend most importantly on the degree to which air quality, global warming and energy security are prominent public policy concerns over the next few decade or two.

7.1. SUMMARY OF EMISSIONS AND COSTS

While the timing of a transition from our fossil-fuel transportation system to a renewably-fueled one is uncertain, the benefits of various incremental steps and their costs (if our projections are realized commercially) in the transition are fairly clear. By way of summarizing our key baseline, analytical results in this report, we review these benefits and costs here. For additional detail, the reader is referred to earlier sections of the report.

Early initial steps could be the introduction of BPEVs and/or ICEVs operating on compressed natural gas, methanol or hydrogen made from natural gas, or ethanol made from corn. Reductions in pollutant emissions would be modest (ethanol and methanol) to significant (CNG) to dramatic (hydrogen and BPEV[32]). Reductions in greenhouse gas emissions would be nil (ethanol) to slight (methanol and BPEV) to significant (CNG and hydrogen). The lifecycle costs for the CNG option would be below that for gasoline/ICEVs, the per-km lifecycle cost for the ethanol and methanol ICEVs would be slightly higher, and for the BPEV (with nearly comparable range as the other options) would be 5-10% higher.

The subsequent introduction of fuel cell vehicles operating on methanol or hydrogen from natural gas would both eliminate vehicular emissions and substantially reduce greenhouse gas emissions (because of the higher efficiency of FCEVs), while perhaps *reducing* the per-km lifecycle cost of transportation relative to the gasoline/ICEV. The technologies presently being emphasized for FCEVs would not be able to use ethanol or methane for fuel.

Further reductions in greenhouse gas emissions associated with FCEVs would be accomplished through the production of methanol or hydrogen fuels from renewable energy sources. The retail price of these fuels made from renewable sources would be significantly higher than the projected retail gasoline price we have assumed. However, the per-km lifecycle cost of renewable/FCEVs would still be close to the costs for gasoline/ICEVs. With either methanol or hydrogen made from renewable resources, it would ultimately be possible to reduce pollutant and greenhouse gas emissions to near zero. Methanol production requires a carbon source; thus biomass is the only viable renewable source for this fuel. Hydrogen can be produced thermochemically from biomass or electrolytically from wind or solar resources. At large-scale, biomass is the lowest-cost option for renewable hydrogen (by a factor of two). The high efficiency of the FCEV greatly facilitates providing transportation energy needs from renewable resources because renewable resources are land and/or capital intensive. The resource potentials of wind and solar energy are much larger than of biomass, though potential biomass resources are substantial enough to provide a large (if not full) share of future transportation energy needs.

For BPEVs vehicular emissions would be zero. Greenhouse gas and other emissions

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[32] Emissions with the BPEV would be lower for all except SO_x and PM (emitted at the power plant, but charged as an emission from the vehicle).

could be reduced through greater use of renewable fuels by electric utilities. Ultimately, it will be possible to produce and use renewable electricity on a large scale with very little emission of greenhouse gases and no vehicular emissions. However, the long recharging time of BPEVs and their higher projected costs relative to methanol or hydrogen FCEVs may limit their market.

In summary, it appears that in the long term it would be possible to meet US demands for transportation fuels from domestic renewable resources--biomass, wind and solar energy. Greenhouse gas and pollutant emissions could be greatly reduced or even eliminated. The delivered cost of renewable transportation fuels would probably be higher than the cost of gasoline or compressed natural gas. (Biomass derived fuels would be less expensive than electrolytic hydrogen, although the biomass resource potential is more limited than for wind or solar.) However, the lifecycle costs of transportation with renewable fuels might be comparable to that of current gasoline ICEVs, and would also compete with other long term options (e.g. synthetic fuels from coal or nuclear sources.) Fuel cell vehicles would be particularly attractive, as they would combine cost-competitiveness with zero emissions and consumer appeal (long range, fast refueling time). Energy carriers which can be used in low-temperature fuel cell vehicles (methanol and hydrogen) may ultimately become the fuels of choice for general purpose light duty (and heavy-duty) vehicles in the US.

7.2. RESEARCH AND DEVELOPMENT CHALLENGES

The details of how renewable transportation fuels might be introduced are not clear at this time. What is clear, however, is that there are technological hurdles to overcome before commercial realization of a transition from today's transportation system to one based entirely (or nearly entirely) on renewable resources. We briefly summarize these key research and development challenges (discussed in detail elsewhere in this report). See also Table 7.1.

7.2.1. Production of Fuels from Renewable Resources

Development of biomass gasifiers for methanol and hydrogen production. Biomass gasifiers that would be suitable for methanol or hydrogen production are under active commercial demonstration. The most promising gasifier designs (indirectly-heated systems) are in a somewhat earlier state of development. In any case, with a continued R&D effort, suitable gasifier technologies could be commercially available before the end of the century.

Development of large-scale biomass energy plantations. Cost reductions projected for the next decade should bring costs of biomass grown on dedicated energy plantations into commercial viability. The commercial implementation of plantations might occur in parallel with this, either on especially good sites and/or where the biomass would be produced for use in electric power generation. Ecological guidelines for establishing plantations must be developed as well during this process. By the middle of the first decade of the 21st century, large-scale biomass plantations may be commercially operating in the US and able to provide feedstocks for transportation fuels production.

Development of enzymatic hydrolysis for ethanol production from biomass. This technology has been proven in the laboratory. Pilot-scale demonstration is now planned. Additionally, a commercial-scale demonstration is needed before the technology can be considered commercially ready.

Development of electrolysis systems for use with intermittent power. Electrolysis is a commercially available technology. Electrolysis using intermittent PV and wind electricity are currently being researched. There appear to be no serious problems in commercializing electrolyzers optimized for use with wind or solar power over the next ten to twenty years.

7.2.2. Production of Electricity from Renewable Resources

Development of biomass gasifier/gas turbine technology. This technology is now operating at pilot scale, and several commercial-scale demonstrations are at various stages of development. The technology is likely to be commercially ready within about five years.

Development of biomass gasifier/fuel cell technology. Molten carbonate or solid oxide fuel cells fueled with gasified biomass are in the conceptual design stage, although analogous systems for coal have been the focus of R&D efforts. Molten carbonate and solid oxide fuel cells fueled with natural gas are in the demonstration phase. These might be commercialized by early in the next century.

Development of low cost PV and wind power. Rapid progress is occurring in both PV and wind technologies. It is likely that low-cost intermittent power from wind might be available around the year 2000 and from low-cost PV power in the early part of the next century.

7.2.3. Transmission and distribution of fuels and electricity

Integration of intermittent renewable electricity resources into utility grids. This has already been done on a small scale by a number of utilities and is being evaluated.

Development of hydrogen infrastructure. Technologies for distributing, compressing, and storing hydrogen are well known and commercially available. The main issue here is system design. It would be possible to demonstrate hydrogen refueling station technology (based on small-scale steam reforming of natural gas or electrolysis) within the next few years. The development of an infrastructure for hydrogen distribution from large centralized facilities will require a larger, longer-term commitment to hydrogen fuel, but poses no major R&D hurdles.

7.2.4. Vehicle technologies

Reduction of emissions from ICEVs. With ICEV technology, the major R&D challenges are in reducing emissions. With methanol/ICEVs, formaldehyde is of special concern. With ethanol/ICEVs, acetaldehyde emissions are of concern. With hydrogen/ICEVs or hybrid vehicles, the main challenge is to demonstrate near-ZEV NO_x emissions.

Development of low cost, high energy density onboard hydrogen storage. Storage of hydrogen will be one of the most costly components of future hydrogen vehicles. Because of the simplicity and long-range of compressed hydrogen gas (compared to liquid hydrogen or hydride systems), this storage option appears to be the most promising. Building on the experience with compressed natural gas vehicles, onboard hydrogen cylinders might be introduced over the next few years.

Development of low-cost, long-lived batteries for electric vehicles. This goal is being actively pursued at present with a large public/private research, development and demonstration program.

Development of methanol and hydrogen fuel cell vehicles. The key requirements here are: the development of low-cost, compact, high performance PEM stacks; the development of efficient, simple, compact fuel-cell auxiliary systems; the development of fast-starting, efficient onboard reformers; and the integration of the stack, auxiliaries, reformer, and peak-power device. The first experimental fuel cell vehicles are now being built and tested. With rapid technical progress, it might be possible to do small fleet tests around the year 2000, with larger tests over the following decade and subsequent full-scale commercial implementation. A longer term challenge is to develop other fuel cell technologies, such as the solid oxide fuel cell, to commercial viability.

Table 1. Conversion factors and economic assumptions.

EJ = Exajoule (10^{18} Joules) = 0.95 Quadrillion BTU's

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

1 million standard cubic feet H_2/day = 28,300 Nm^3 H_2/day = 362 GJ/day (higher heating value)

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/year

Economic assumptions

All costs are given in average 1991 US dollars.

For electricity production, levelized costs were calculated in constant 1991 dollars assuming (EPRI 1986):

Real discount rate = 6.2%
Corporate income tax rate = 38%
Annual insurance = 0.5% of installed capital cost
Annual property taxes = 1.5% of installed capital cost

For fuels production (methanol, ethanol, hydrogen produced from biomass, natural gas or coal) we use assumptions similar to those used in the oil industry:

Real discount rate = 9.9% for equity
Real discount rate = 6.2% for debt
Debt to equity ratio = 30%
Corporate income tax rate = 44%
Annual insurance = 0.5% of installed capital cost
Annual property taxes = 1.5% of installed capital cost

In the case of electrolytic hydrogen, the producer might be an electric or gas utility, an oil company or an independent fuel producer. We give fuel costs for both sets of economic assumptions.

All fuel costs are based on the higher heating value of the fuel.

Table 2.2.1. Required price of alcohol fuels (that would be used in internal combustion engines) to compete with retail price of gasoline.

Crude oil price ($/bbl)	*Retail gasoline price*[a]		*Required methanol price*[b]		*Required hydrous ethanol price*[c]		*Required anhydrous ethanol price*[d]	
	($/gal)	*($/liter)*	*($/liter)*	*($/GJ, HHV)*	*($/liter)*	*($/GJ, HHV)*	*($/liter)*	*($/GJ, HHV)*
20	0.89	0.24	0.14	7.7	0.~~20~~.18	~~9.1~~ 8.2	0.28	11.9
25	1.12	0.30	0.18	9.9	0.~~25~~.23	~~11.4~~ 10.5	0.35	14.9
30	1.34	0.35	0.21	11.6	0.~~29~~.27	~~13.2~~ 12.3	0.41	17.5
35	1.56	0.41	0.25	13.8	~~0.34~~.32	~~15.5~~ 14.6	0.48	20.5
40	1.79	0.47	0.28	15.5	~~0.39~~.36	~~17.7~~ 16.4	0.55	23.5
45	2.01	0.53	0.32	17.7	~~0.44~~.41	~~20.0~~ 18.7	0.61	26.0

(a) Assuming the per-barrel (42 gallons) retail price of reformulated gasoline is 1.87 times the per-barrel crude oil price.

(b) On a per-liter basis, methanol has about half the heating value of gasoline, but because methanol can be used in engines with higher compression ratios, methanol-engine efficiency would be about 15-20% higher. Thus, the calculation here assumes 1 liter of methanol as a neat fuel is worth 0.6 liters of gasoline (Wyman et al, 1993).

(c) On a per-liter basis, ethanol has about ~~63~~ 60% of the heating value of gasoline, but ethanol engines can operate more efficiently due to higher compression ratio. Thus, the calculation here assumes 1 liter of hydrous ethanol as a neat fuel is worth ~~0.84~~ 0.77 liters of gasoline ~~(Goldemberg et al, 1993; Wyman and Hinman, 1989)~~. The distribution and retailing fraction of the total price is about 21 cents/gallon (5.5 cents/liter), or $2.5/GJ.

(d) Assumes 1 liter of anhydrous ethanol is worth 1.16 liters of gasoline when used as an octane-boosting additive (US Congress, 1979). Other studies (Office of Mobile Sources, 1990; Comisao Nacional Energi, 1987) suggest that a liter of anhydrous ethanol is worth somewhat less than 1.16 liters of gasoline. The distribution and retailing fraction of the total price is about 21 cents/gallon (5.5 cents/liter), or $2.35/GJ.

Table 2.2.1a. Estimated commercial production costs (in 1991$) for ethanol from cellulosic biomass.[a]

	Reference Plant	Larger Plant	Advanced Technology
Feedstock input capacity			
Dry tonnes per day	1745	9090	2727
GJ per hour	1461	7613	2284
Output production capacity[b]			
Million liters per year	215.3	1078.8	494.7
GJ per hour	590	2956	1355
Annual feed and output			
Feed (10^6 GJ per year)	11.52	60.02	18.01
Product output (10^6 GJ per year)	4.65	23.30	10.69
Installed Equipment Costs (10^6 1991$)			
Feed handling	7.50	29.93	11.92
Prehydrolysis	24.45	97.20	39.43
Xylose fermentation	6.53	26.09	4.12
Cellulase production	2.82	11.27	1.49
SSF fermentation	23.43	93.57	11.48
Ethanol purification	4.05	11.62	5.62
Offsite tankage	3.30	8.03	9.86
Environmental systems	4.32	12.39	3.38
Utilities/auxiliaries	62.48	179.36	54.14
Subtotal	138.88	469.45	141.45
Contingencies	27.77	93.89	153.44
Owners costs, fees, profits	13.89	46.95	14.15
Startup	6.94	23.47	7.07
Total Capital Requirement (10^6 $)	187.48	633.77	190.96
Working Capital (10^6 $)	13.89	46.95	14.15
Land (10^6 $)	2.21	14.68	3.69
Variable Operating Costs (10^6 $ per year)			
Feed[c]	28.80	150.05	45.01
Catalysts and chemicals	10.03	50.16	16.09
Electricity (credit)[d]	-5.24	-27.29	-4.54
Subtotal	33.59	172.92	56.56
Fixed Operating Costs			
Labor	1.72	3.45	1.54
Maintenance	4.17	14.08	4.24
General Overhead	3.83	11.40	3.76
Direct Overhead	0.78	1.55	0.69
Subtotal	10.50	30.48	10.24
Total Operating Costs (10^6 $ per year)	44.09	203.40	66.80
PRODUCTION COST ($ per GJ of methanol)			
Capital[e]	6.43	4.37	2.86
Labor & maintenance	4.42	3.46	2.46
Electricity credit	-1.13	-1.17	-0.43
Feedstock	6.19	6.44	4.21
TOTAL PRODUCTION COST	15.91	13.10	9.10
Distribution cost ($/GJ)	1.5	1.5	1.5
Refueling station cost ($/GJ)	0.9	0.9	0.9
Delivered retail price ($/GJ)	18.3	15.5	11.5

Notes to Table 2.2.1a:

(a) Equipment capital costs and costs for catalysts and chemicals are based on Wyman, et al. (1993). Contingencies, owners costs, startup, working capital, land, labor, maintenance, general overhead, and direct overhead are calculated on the same basis as for the methanol cost estimates shown in Table 2.2.3.

(b) Based on yields (in liters of ethanol per dry tonne of biomass) of 338, 325, and 497 for the reference, larger, and advanced technology plants (Wyman et al., 1993).

(c) Assuming a levelized cost for delivered biomass chips of $2.5/GJ.

(d) Electricity is produced as a byproduct at a rate of 22.53, 23.42, and 8.5 kWh/GJ of ethanol for the reference, larger, and advanced technology plants, respectively (Wyman et al., 1993). The assumed selling price is 5 cents per kWh.

(e) Annual capital charge rate of 15.1% is assumed, based on average financial parameters for major US corporations during the period 1984-1988 (9.91% real rate of return on equity, 6.2% real rate of return on debt, a 30% debt fraction, a 44% corporate income tax), a property and insurance rate of 1.5% per year, and a 25-year plant life. For land and working capital, the annual capital charge rate is taken to be 9.91% per year, the corporate discount rate.

Table 2.2.2. Energy balances for methanol and hydrogen production from biomass, with comparisons to production from natural gas and from coal.[a]

	Fuel input (MW)	*Product output (MW)*	*Net external electricity use (MW)*	*Net external heating (MW)*	*Net external cooling (MW)*[b]	*Energy conversion ratio (HHV)*[c]	*Thermal efficiency (HHV)*[d]
Methanol							
Biomass (direct heating)[e]	368.2	208.4	7.0	0	0	0.57	0.54
Biomass (indirect heating)[f]	371.6	225.3	7.3	0	0	0.61	0.58
Coal[g]	1718.8	1115.9	39.3	0	188.3	0.65	0.61
Natural gas	750.0	527.9	13.8	0	137.5	0.70	0.67
Hydrogen							
Biomass (direct heating)[e]	368.2	246.2	26.1	0	0	0.67	0.56
Biomass (indirect heating)[f]	371.6	272.1	21.3	0	0	0.73	0.64
Coal[g]	1718.8	1330.1	133.3	40.9	199.4	0.77	0.64
Natural gas	750.0	672.7	19.8	0	27.2	0.90	0.84

(a) From Larson, et al (1994). See also Katofsky (1993).

(b) No external cooling is required in the biomass cases, because the drying of biomass from its incoming moisture content (50%) to its moisture content entering the gasifier (20%), provides a low-temperature heat sink that is not available in the fossil fuel cases.

(c) The energy conversion ratio is the higher heating value of the energy contained in the product divided by the higher heating value of the energy in the input feedstock.

(d) The thermal efficiency is the higher heating value of the energy contained in the product divided by the higher heating value of all energy inputs to the process, assuming that all external energy requirements are provided using the same type of fuel as the feedstock.

(e) Based on using an oxygen-blown, pressurized, bubbling fluidized-bed gasifier under development by the Institue of Gas Technology in the US.

(f) Based on using a twin circulating fluidized-bed gasifier being developed by the Battelle-Columbus Laboratory in the US.

(g) Based on using Shell's dry-feed, entrained-bed gasifier.

Table 2.2.3. Estimated production costs (in 1991$) for methanol from biomass, natural gas, and coal.

FEEDSTOCK →	BIOMASS				N. GAS	COAL
PROCESS →	IGT gasifier	MTCI gasifier	BCL gasifier	Shell gasifier	Steam reforming	Shell gasifier
Feedstock input capacity						
Dry tonnes per day	1650	1650	1650	1650	1224	5000
GJ per hour	1325	1334	1337	1325	2700	6188
Output production capacity[a]						
Tonnes per day	794	869	857	950	2012	4254
GJ per hour	750	821	810	897	1901	4018
Annual feed and output						
Feed (10^6 GJ per year)	10.45	10.52	10.54	10.45	21.29	48.79
Product output (10^6 GJ per year)	5.91	6.46	6.39	7.07	14.98	31.68
Installed Equipment Costs (10^6 $)						
Feed preparation, including drying[b]	17.32	13.21	13.17	38.78	0.00	67.96
Gasifier[c]	29.74	33.73	12.72	29.74	0.00	120.06
High temperature gas cooling[d]	0.00	0.00	0.00	39.67	0.00	113.27
Oxygen plant[e]	21.56	0.00	0.00	28.77	0.00	95.42
Reformer feed compressor[f]	0.00	15.94	11.88	0.00	0.00	0.00
Reformer[g]	21.39	0.00	17.20	0.00	50.00	0.00
Shift reactor[h]	1.98	0.00	2.00	0.00	0.00	0.00
CO_2 removal[i]	20.20	15.38	14.34	22.05	0.00	59.50
Sulfur removal (acid gas scrub)[j]	0.00	0.00	0.00	0.00	0.00	36.25
Methanol synthesis & purification[k]	35.86	38.05	37.78	40.36	66.25	108.54
Utilities/auxiliaries[l]	37.01	29.08	27.27	49.84	29.06	150.25
Subtotal	185.06	145.40	136.36	249.21	145.30	751.25
Contingencies[m]	37.01	29.08	27.27	49.84	29.06	150.25
Owners costs, fees, profits[m]	18.51	14.54	13.64	24.92	14.53	75.12
Startup[n]	9.25	7.27	6.82	12.46	7.27	37.56
Total Capital Requirement (10^6 $)	249.83	196.28	184.08	336.43	196.16	1014.18
Working Capital[m] (10^6 $)	18.51	14.54	13.64	24.92	14.53	75.12
Land[o] (10^6 $)	2.08	2.08	2.08	2.08	4.26	7.40
Variable Operating Costs (10^6 $ per year)						
Feed[p]	26.12	26.29	26.40	26.12	63.86	85.43
Catalysts and chemicals[q]	1.67	0.67	2.24	0.67	2.58	10.87
Purchased energy[r]	2.76	4.48	2.89	4.89	5.44	13.87
Subtotal	30.55	31.43	31.53	31.67	71.88	110.17
Fixed Operating Costs						
Labor[s]	1.08	1.08	1.08	1.08	1.00	3.14
Maintenance[t]	5.55	4.36	4.09	7.48	4.36	22.54
General Overhead	4.31	3.54	3.36	5.56	3.48	16.69
Direct Overhead	0.49	0.49	0.49	0.49	0.45	1.41
Subtotal	11.43	9.47	9.03	14.61	9.29	43.77
Total Operating Costs (10^6 $ per year)	41.98	40.91	40.56	46.28	81.17	153.94
PRODUCTION COST ($ per GJ of methanol)						
Capital[u]	6.73	4.84	4.59	7.56	2.10	5.10
Labor & maintenance	2.22	1.57	1.76	2.16	0.79	1.73
Purchased energy	0.47	0.69	0.45	0.69	0.36	0.44
Feedstock	4.42	4.07	4.13	3.69	4.26	2.70
TOTAL PRODUCTION COST	13.83	11.16	10.93	14.11	7.52	9.95
Distribution cost ($/GJ)	1.91	1.91	1.91	1.91	1.91	1.91
Refueling station cost ($/GJ)	1.18	1.18	1.18	1.18	1.18	1.18
Delivered retail price ($/GJ)	16.92	14.25	14.02	17.20	10.61	13.04

Notes to Table 2.2.3:

(a) Based on process energy ratios given in Table 2.

(b) Feed preparation costs include drying (and pulverizing for the Shell gasifier cases). Costs are scaled from other estimates according to feed capacity (dry tonne per day, dtpd) raised to the 0.7 power. The other estimates are as follows: for IGT, $18.5 million for 1814 dtpd (OPPA, 1990); for BCL, $7.51 million for 740 dtpd (Breault and Morgan, 1992); Shell-biomass, $41.44 million for 1814 dtpd (OPPA, 1990); Shell-coal, $94.3 million for 7982 dtpd (OPPA, 1989). For the MTCI case, the cost is assumed to be the same as for IGT.

(c) Gasifier costs are scaled from other estimates according to feed capacity (dry tonne per day, dtpd) raised to the 0.7 power. The other estimates are as follows: for IGT, $31.78 million for 1814 dtpd (OPPA, 1990); for MTCI, $3.78 million for 72.5 dtpd (MTCI, 1994), which is for a pressurized reactor (no adjustment is made for the lower pressure unit considered here); for BCL, $7.25 million for 740 dtpd (Breault and Morgan, 1992); Shell-coal, $166.6 million for 7982 dtpd (OPPA, 1989). The Shell-gasifier with biomass is assumed to cost the same as the IGT gasifier, because both are pressurized and the lower cost associated with the higher throughput of an entrained-bed design is assumed to be offset by the higher cost associated with higher temperature operation.

(d) For the coal case, the cost of the high-temperature gas cooling system (plus the shift reactor) is scaled from an estimate of $157.1 million for a plant with a coal feed rate of 7982 dry tonnes per day (OPPA, 1989). A 0.7 power scaling factor is assumed. For the biomass case, the cost is scaled (using 0.7 factor) from that for the coal case according to the heat removal rate in the gas cooler: 215.6 MW in the coal case and 48.2 MW in the biomass case.

(e) The cost for oxygen plants (in million 1991$) is assumed to be $0.260x(tO_2pd)^{0.712}$, where tO_2pd is the plant capacity in tonnes of 99.5% purity oxygen per day. This is based on estimates of the cost of 95% purity oxygen plants sold by the Air Products Company for use in integrated coal-gasifier/gas turbine facilities (Brown et al., 1987). The plants produce O_2 at 3.7 MPa and include 20 minutes of gaseous oxygen storage. For plant sizes of 1000 tO_2pd or larger, the use of dual trains is assumed, each providing 50% of the capacity. Methanol or hydrogen production requires an O_2 purity of 99.5% (or higher). It is assumed that capital cost increases by 15% to produce O_2 of 99.5% purity instead of 95% purity (Klosek et al., 1986).

(f) Compressor cost is assumed to be $900 per kW of required capacity. There is no reformer in the MTCI case. The cost here refers to the cost of the compressor used to raise the pressure of the syngas before it enters the methanol synthesis loop.

(g) The reformer cost includes costs for boiler feedwater pumps, steam drum, induced-draft and forced-draft fans, all internal heat exchangers, including exchangers to cool the reformate to ambient temperature, desulfurizing vessels, local piping, controls, instrumentation, analyzers, initial catalyst charge and water treating equipment. For the natural gas case, the cost is based on an estimate of Moore (1994). For the other cases, the reformer cost is scaled (using 0.57 power) according to the total heat exchange duty of the reformer, including all preheating, after-cooling, and steam raising associated with the reformer. The total duty in the natural gas case is 767.8 MW.

(h) No shift reactor is required with natural gas or with the MTCI biomass gasifier. For the Shell gasifier cases with biomass and with coal, the shift reactor costs are included in the cost of high temperature gas cooling equipment. For the IGT and BCL gasifier cases, the shift reactor cost is scaled according to the volume flow of $H_2 + CO$, assuming a baseline cost of $9.02 million for a flow rate of 8819 kmol/hour and a scaling factor of 0.65 (Moore, 1994).

(i) For Union Carbide's SELEXOL process, leaving approximately 2% CO_2 in the exit gas. Costs are scaled according to volume of CO_2 removal raised to the 0.7 power. The baseline estimate is $14.3 million for 810 kmol/hour of CO_2 removal Epps (1991).

(j) H_2S recovery is required with the coal system. This cost has been scaled using a 0.7 power factor according to the feed rate of dry coal from a baseline cost of $50.3 million for a coal feed rate of 7982 tonnes per day.

(k) Estimated cost with the ICI low-pressure methanol synthesis process, including the make-up compressor, recycle compressor, and synthesis loop equipment. A cost estimate of $66.25 million is assumed for a facility with production capacity of 2012 tonnes per day (Moore, 1994). The costs for other capacities have been scaled using a 0.66 power factor (Mansfield, 1991).

(l) Assumed to be 25% of the sum of other installed hardware costs (Wyman et al., 1993; Moore, 1994).

(m) The following percent of installed equipment costs (given by Wyman et al., 1993 for methanol production) are adopted here: contingencies, 20%; owners costs, fees and profit, 10%; working capital, 10%.

(n) Startup costs are assumed to be 5% of installed hardware costs.

(o) The following costs for land, developed from estimates of Wyman et al. (1993), are assumed: for biomass and coal facilities, land cost (in million 1991\$) is 423x(tpd)$^{1.147}$, where tpd is the dry feed capacity in tonnes per day; for the natural gas case the land cost (in 1991\$) is assumed to be \$0.18 per GJ/yr of natural gas feed capacity.

(p) Assuming levelized costs for delivered feedstocks of \$2.5/GJ for biomass chips, \$3.0/GJ for natural gas, and \$1.75/GJ for coal.

(q) The costs for catalysts and chemicals for the IGT, BCL, and Shell-coal are those estimated by Wyman et al (1993) scaled linearly by production rate. The costs for the MTCI and Shell-biomass cases are scaled according to the cost estimated by Wyman et al. for a biomass case using the Koppers-Totzek entrained bed gasifier, which requires no reforming.

(r) Electricity is the only required external energy input. A cost of 5 cents per kWh is assumed. See Table 2 for quantities.

(s) Labor costs are based on Wyman et al. (1993). For natural gas, Wyman's estimate is used directly. For solid feedstocks, the following relationship for annual labor costs was derived from two BCL cases of different capacities considered by Wyman, et al: $10^6\$ = 889x(dtpd)^{0.959}$, where dtpd is the plant feed rate in dry tonnes per day.

(t) Based on Wyman, et al. (1993), maintenance is assumed to be 3% of installed hardware costs, general overhead is 65% of labor and maintenance, and direct overhead is assumed to be 45% of labor.

(u) Annual capital charge rate of 15.1% is assumed, based on average financial parameters for major US corporations during the period 1984-1988 (9.91% real rate of return on equity, 6.2% real rate of return on debt, a 30% debt fraction, a 44% corporate income tax), a property and insurance rate of 1.5% per year, and a 25-year plant life. For land and working capital, the annual capital charge rate is taken to be 9.91% per year, the corporate discount rate.

Table 2.3.1. Cost and performance of wind power technologies

	1990[a]	near-term[b]	post-2000[c]
Total installed cost (\$/kWp)	1200	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)	1.6	1.1	0.6
Rent on land (cents/kWhAC)	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[d]			
Wind power density = 350 W/^{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)[e]			
Wind power density = 350 W/m^2	12.8	8.3	5.9
Wind power density = 500 W/m^2	9.2	5.6	4.3
Wind power density = 700 W/m^2	-	4.5	3.2

Notes to Table 2.3.1.

(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 1991 US dollars using the economic assumptions in Table 1.

Table 2.3.2. Cost and performance of solar thermal electric technologies.[a,b]

	Parabolic trough systems		
	1990	near term	post 2000
Capital cost ($/kW)	3000-3800	2400-3000	2000-2400
Peak Capacity (MWe)	80	80	160
Annual energy efficiency solar mode	13-17%	13-17%	13-17%
Method for enhanced load matching	-- Natural-gas firing --		
Fraction of kWh from gas	25%	25%	25%
Solar capacity factor	22-25%	18-26%	22-27%
O&M cost (cents/kWh)	2.0-2.7	1.6-2.4	1.3-2.0
System lifetime (years)	30	30	30
AC electricity cost (cents/kWhAC)	**14.1-19.7**	**11.0-18.7**	**8.7-12.5**
	Central receiver systems near term post 2000		
Capital cost ($/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 (cents/kWh)	1.3-1.9	0.8-1.6	0.5-0.8
System lifetime (years)	30	30	30
AC electricity cost (cents/kWhAC)	**10.5-21.8**	**7.4-13.4**	**6.2-8.7**
	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 (cents/kWh)	2.5-5.0	2.0-3.0	1.5-2.5
System lifetime (years)	30	30	30
AC electricity cost (cents/kWhAC)[c]	**18-41**	**11.0-24**	**6.6-13.2**

Notes to Table 2.3.2.

(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 2.2 cents/kWh. NG = natural gas.

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

(c) Levelized electricity costs are calculated in constant 1991 US dollars using the economic assumptions of Table 1 and assuming a Southwestern US location.

Table 2.3.3a. Cost and performance of solar photovoltaic modules.

	PV module efficiency			PV module manufacturing cost ($/square meter)		
Solar PV Technology	1990	near term	post 2000	1990	near term	post 2000
Flat plate modules						
Thin Films						
Amorphous silicon[a]	6%	8-10%	12-18%	100	70	30-55
CuInSE$_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 2.3.3b. Area-related Balance of System Costs for Large Fixed Flat plate PV Systems (all costs are adjusted to 1991 dollars and given in $\$/m^2$).[a]

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

Notes to Table 2.3.3b.

(a) In some studies only some elements of the balance of system cost were estimated.

(b) Includes the cost of the DC interface to the power conditioning unit.

(c) See Bechtel (1983).

(d) See Carmichael et.al. (1982).

(e) See Martin Marietta (1984).

(f) See Levy, et al. (1984).

(g) See Stranix and Firester (1982).

(h) See Noel, et.al. (1985).

(i) See USDOE (May 1987).

(j) See Bechtel (1987); Noel, et al. (1985).

(k) See Matlin (1989, 1990) and Candelario, et.al. (1991).

(l) See Zweibel (1990).

(m) See (J. Ogden and K. Happe, 1993).

Table 2.3.3c. Cost and performance of solar photovoltaic systems.[a,b]

	1990	near term	post 2000
Balance of system costs ($\$/\mathrm{m}^2$)			
Fixed, flat plate	50-80	40-55	40
1-axis tracking		75	75
2-axis tracking		125	100
Balance of system efficiency[c]	80%	85%	85%
System lifetime (years)	30	30	30
Annual O&M costs			
Fixes, flat plate ($\$/\mathrm{m}^2/\mathrm{yr}$)	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)		
Flat plate systems			
Thin films	4.1-4.6	1.7-3.7	0.7-1.3
Polycrystalline	3.8-6.0		1.9-3.4
Crystalline	5.9-9.4		1.9-3.4
Concentrator systems (2-axis tracking)	4.5-7.6	2.1	1.3
	Cost of AC electricity, $/kWh-AC[d]		
Flat plate			
Thin films	0.198-0.266	0.085-0.174	0.035-0.062
Polycrystalline	0.195-0.260		0.089-0.158
Crystalline	0.274-0.430		0.087-0.150
Concentrator (2-axis tracking)	0.17-0.31	0.102	0.065
	Cost of DC electricity, $/kWh-DC[e]		
Flat plate			
Thin films	0.180-0.246	0.073-0.158	0.025-0.050
Polycrystalline	0.177-0.240		0.077-0.138
Crystalline	0.255-0.403		0.074-0.136
Concentrator (2-axis tracking)[f]	0.155-0.291	0.089	0.054

Notes to Table 2.3.3c.

(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 AC electricity (in $/kwhAC) in the Southwestern US, with average annual insolation of 271 Watts/m^2.

(e) For electrolytic hydrogen production DC power would be needed. If DC power were produced instead of AC power, the power conditioning equipment could be eliminated, saving $150/kW. The balance of system efficiency for a DC system would be 89% rather than 85% because of energy losses in the inverter which is assumed to be 96% efficient. The cost of AC power is typically $0.006-0.01/kwh greater than the cost of DC power.

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

Table 2.3.4. Performance and capital cost estimates of biomass cogeneration systems (Williams and Larson, 1993).

	Performance in cogeneration mode				*Performance for maximum electric power production*		*Installed capital cost*
	Electricity		*Maximum steam output*				
	MW_e	*efficiency (% HHV)*	*kg/hour*	*efficiency (% HHV)*	MW_e	*efficiency (% HHV)*	*1991$/kW*
15% moisture content fuel							
BIG/ISTIG[a]							
LM-8000	97	37.9	76,200	25.4	111.2	42.9	945
BIG/STIG[b]							
LM-5000	39	31.3	47,700	30.0	51.5	35.6	1,215
LM-1600	15	29.8	21,800	33.8	20	33.0	1,495
LM-38	4	29.1	5,700	32.4	5.4	33.1	1,995
50% moisture content fuel							
BIG/STIG[b]	38.3	29.5	47,700	28.9	50.8	33.5	1,320
CEST[c]	37	10.0	319,000	52.1	77	20.9	1,640

(a) BIG/ISTIG is a biomass-integrated-gasifier/intercooled steam-injected gas turbine. The installed cost (in 1991$/kW) as a function of plant capacity is estimated to be $2665 \cdot (MW_e)^{-0.22}$

(b) BIG/STIG is a biomass-integrated-gasifier/steam-injected gas turbine. In the case with 15% moisture content, the installed cost (in 1991$/kW) is estimated to be $2888 \cdot (MW_e)^{-0.22}$. In the case with 50% moisture content fuel, the capital cost includes the cost of a dryer.

(c) CEST is a condensing-extraction steam turbine. The installed cost (in 1991$/kW) is estimated to be $6600 \cdot (MW_e)^{-0.32}$.

Table 2.3.5. Current and projected costs for commercially produced solar electricity (cents/kWh).[a]

Technology	1991	Near term	Post 2000
Wind (700 W/m^2)	--	4.5	3.2
(500 W/m^2)	9.2	5.6	4.3
(350 W/m^2)	12.8	8.3	5.9
Solar thermal electric (SW US)	12-17	11-18	6.2-8.6
Solar PV (SW US)	20-43	9-17	2.5-5.0(DC) 3.5-6.2(AC)
Hydropower (Off-peak)	2-4	2-4	2-4
Biomass			
Steam turbine	7-9	7-9	7-9
Gasifier/gas turbine	5.3-6.9		4.5-6.0

(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 1991 US dollars for the economic assumptions in Table 1. (See Tables 2.3.1-2.3.4 for details.) For wind power the annual average wind power density at hub height is shown in parentheses.

Table 2.4.1. Advanced alkaline electrolyzers

Electrolyzer Type	Bipolar[a]		Unipolar[b]	
	Present	Future	Present	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) (LHV)	 73% 62%	 90% 76%	 73% 62%	 90% 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: ($/kW AC) (including rectifier, building)	650	330	650	400
Capital costs for DC plant ($/kW)			515	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 $650/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 2.4.2. Solar electrolysis experiments.[a]

COUNTRY	EXPERIMENTER	TYPE OF EXPERIMENT	REF.
CANADA	Electrolyzer, Inc.	10 kW PV/electrolysis system	(Stuart 1992)
CHINA	Jiotang University	Small PV electrolysis experiment	(Chen 1992))
FINLAND	Helsinki University	2 kW PV electrolysis experiment	(Kaurenen 1992)
FORMER SOVIET UNION	Azerbajian Academy of Science	100 W PV electrolysis experiment	(Selamov 1992)
	KVANT, Mocsow	6 kW stand alone PV electrolysis system	(Bortmikov 1992)
GERMANY	DLR, Stuttgart	10 kW PV electrolysis system	(Winter 1989
	Solar Wasserstoff Bayern	270 kW PV electrolysis system	(Szyszka 1992)
	Fraunhofer Institute	2.1 kW PV electrolysis system	(Ledjeff 1990)
	KFA, Julich	Electrolyzers for intermittent operation	(Divisek 1991)
SAUDI ARABIA	Saudi Gov't./DLR Stuttgart	2 kW PV electrolysis experiment underway, 350 kW experiment being built	(Steeb 1992)
SPAIN	Instituto Nacional Aerospacial Energy Lab	8.5 kW PV electrolysis system	(Garcia Conde 1992)
SWITZERLAND	Paul Scherrer Institute	PEM electrolyzer experiments	(Stucki 1991)
UNITED STATES	Humboldt State Univ.	10 kW PV electrolysis experiment	(Lehmann 1992)
	Florida Solar Energy Center	PV electrolysis experiments with unipolar electrolyzers	(Collier 1992)
	U. California Riverside/SCAQMD	10 kW PV electrolysis system	(Norbeck 1993)

(a) All electrolyzers are alkaline technology unless otherwise noted.

Table 2.4.3. 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	\$0.5m^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	negligible	
Solar Resource		
Annual average insolation[c]	271 watts/m^2	
Land area required in SW U.S.		
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 performance 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
Utility economics:		
Levelized cost of DC electricity (cents/kWh)	2.5	5.0
Levelized cost of PV hydrogen (\$/GJ)	13.0	21.4
Industrial economics:		
Levelized cost of DC electricity (cents/kWh)	3.5	7.1
Levelized cost of PV hydrogen (\$/GJ)	17.8	29.6

Notes to Table 2.4.3.

(a) Projected efficiencies and manufacturing costs for thin-film PV modules are from Carlson (1990) and 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 2.4.4. 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 unipolor 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/kWAC in	
Rectifier efficiency	96%	
Installed AC plant capital cost @ max. operating cur. density	$371/kWACin	
Electrolyzer annual O&M cost	2% of capital cost	
Electrolyzer	20 years	
Wind resource		
Annual average wind power density W/m^2 (power per unit of area swept by turbine)	700	350
Energy costs:		
Utility economics:		
Levelized cost of wind electricity (cents/kWh)	3.2	5.9
Levelized cost of wind hydrogen ($/GJ)	16.1	29.6
Industrial economics:		
Levelized cost of wind electricity (cents/kWh)	4.1	7.9
Levelized cost of wind hydrogen ($/GJ)	20.9	39.3

(a) Costs and performance for wind systems are from Cohen et. al. (1989), Lucas et.al. (1990), Hock et. al. (1990), SERI (1990), and 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 2.4.5. Post-2000 hydropower electrolytic hydrogen system parameters

Off-Peak Hydropower[a,b]		
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	$371/kWACin	
Electrolyzer annual O&M cost	2% of capital cost	
Electrolyzer lifetime	20 years	
Energy Costs		
Off-peak electricity cost (cents/kWh)	2	4
Utility economics: Levelized cost of electrolytic hydrogen ($/GJ)	13.6	20.5
Industrial economics: Levelized cost of electrolytic hydrogen ($/GJ)	15.6	22.4

(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).

Table 2.4.6. Post-2000 solar thermal electric/electrolytic hydrogen system parameters

Central receiver system[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%	
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	$371/kWACin	
Electrolyzer annual O&M cost	2% of capital cost	
Electrolyzer lifetime	20 years	
Solar resource		
Annual average insolation (W/m^2) (Southwestern U.S.)	270 W/m^2	
Energy Costs		
System capital cost ($/kW)	2900	3500
Utility economics:		
Levelized cost of solar electricity (cents/kWh)	6.2	8.6
Levelized cost of solar hydrogen ($/GJ)	24	33
Industrial economics:		
Levelized cost of solar electricity (cents/kWh)	8.6	12.1
Levelized cost of solar hydrogen ($/GJ)	34	46

(a) Costs and performance for solar thermal electric systems are from Table 2.3.2.

(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 2.4.7. Estimated production costs of hydrogen from natural gas, biomass, and coal (in 1991$).

FEEDSTOCK →	BIOMASS				N. GAS	COAL
PROCESS →	IGT gasifier	MTCI gasifier	BCL gasifier	Shell gasifier	Steam reforming	Shell gasifier
Feedstock in input capacity						
Dry tonnes per day	1650	1650	1650	1650	1224	5000
GJ per hour	1325	1334	1337	1325	2700	6188
Output production capacity[a]						
Million Nm^3 per day	1.69	1.93	1.87	1.99	4.62	9.13
GJ per hour	886	1013	979	1045	2423	4790
Annual feed and output						
Feed (10^6 GJ per year)	10.45	10.52	10.54	10.45	21.29	48.79
Product output (10^6 GJ per year)	6.99	7.98	7.72	8.24	19.10	37.76
Installed Equipment Costs (10^6 $)						
Feed preparation[b]	17.32	13.21	13.17	38.78	0.00	67.96
Gasifier[b]	29.74	33.73	12.72	29.74	0.00	120.06
High temperature gas cooling[c]	0.00	0.00	0.00	39.67	0.00	113.27
Oxygen plant[b]	21.56	0.00	0.00	28.77	0.00	95.42
Reformer feed compressor[b]	0.00	14.99	11.88	0.00	0.00	0.00
Reformer[d]	22.45	0.00	18.38	0.00	43.91	0.00
Shift reactors[b]	4.70	5.10	5.01	3.10	9.02	7.28
Sulfur removal[b]	0.00	0.00	0.00	0.00	0.00	36.25
PSA recycle compressor[e]	3.66	4.82	2.43	1.61	7.11	16.43
PSA (with CO_2 removal)[f]	14.50	16.02	15.63	16.40	30.82	51.39
Hydrogen compressor[d]	2.53	5.31	5.82	4.23	9.64	19.22
Utilities/auxiliaries[b]	29.12	23.30	21.26	40.57	25.13	131.82
Subtotal	145.58	116.49	106.29	202.86	125.63	659.09
Contingencies[b]	29.12	23.30	21.26	40.57	25.13	131.82
Owners costs, fees, profits[b]	14.56	11.65	10.63	20.29	12.56	65.91
Startup[b]	7.28	5.82	5.31	10.14	6.28	32.95
Total Capital Requirement (10^6 $)	196.53	157.26	143.50	273.86	169.60	889.77
Working Capital[b] (10^6 $)	14.56	11.65	10.63	20.29	12.56	65.91
Land[b] (10^6 $)	2.08	2.08	2.08	2.08	4.26	7.40
Variable Operating Costs						
Feed[b]	26.12	26.29	27.40	26.12	63.86	85.43
Catalysts and chemicals[b]	1.67	0.67	2.24	0.67	2.58	10.87
Purchased energy[g]	10.31	13.68	8.39	11.17	7.82	57.19
Subtotal	38.09	40.64	37.02	37.96	74.25	153.49
Fixed Operating Costs[b]						
Labor	1.08	1.08	1.08	1.08	1.00	3.14
Maintenance	4.37	3.49	3.19	6.09	3.77	19.77
General Overhead	3.54	2.98	2.78	4.66	3.10	14.89
Direct Overhead	0.49	0.49	0.49	0.49	0.45	1.41
Subtotal	9.48	8.04	7.54	12.32	8.32	39.21
Total Operating Costs (10^6 $ per year)	47.57	48.68	44.56	50.27	82.57	192.70
PRODUCTION COSTS ($ per GJ H_2)						
Capital[b]	4.48	3.15	2.97	5.29	1.43	3.75
Labor & maintenance	1.60	1.09	1.27	1.58	0.57	1.45
Purchased energy	1.48	1.71	1.08	1.36	0.41	1.51
Feedstock	3.74	3.29	3.42	3.17	3.35	2.26
TOTAL PRODUCTION COST ($/GJ)	11.29	9.24	8.73	11.40	5.76	8.97
Distribution cost ($/GJ)	0.50	0.50	0.50	0.50	0.50	0.50
Refueling station cost ($/GJ)	4.43	4.43	4.43	4.43	4.43	4.43
Delivered retail price ($/GJ)	16.22	14.17	13.66	16.33	10.69	13.90

Notes to Table 2.4.7:

(a) Based on the process energy ratios in Table 3.

(b) The basis for the cost estimate for this item is the same as with methanol production. See corresponding note to Table 4.

(c) For the Shell gasifier cases, this item includes the high temperature gas cooling and the shift reactors. The gas cooling costs are the same as for the corresponding methanol production cases, but additional shift reactor capacity is needed for hydrogen production. Thus, the costs estimated for the methanol case (Table 4) have been increased by an amount representing the added cost of the additional shift reactor capacity. The cost of the additional shift reactor capacity has been estimated by scaling according to incremental volume flow of H_2 + CO using a 0.65 power factor and assuming a baseline cost of $9.02 million for a flow of 8819 kmol/hour (Moore, 1994).

(d) The reformer cost includes costs for boiler feedwater pumps, steam drum, induced-draft and forced-draft fans, all internal heat exchangers, including exchangers to cool the reformate to ambient temperature, desulfurizing vessels, local piping, controls, instrumentation, analyzers, initial catalyst charge and water treating equipment. For the natural gas case, the cost is based on an estimate of Moore (1994). For the other cases, the reformer cost is scaled (using 0.57 power) according to the total heat exchange duty of the reformer, including all preheating, after-cooling, and steam raising associated with the reformer. The total duty in the natural gas case is 560.13 MW.

(e) Compressors are assumed to cost $900 per kW of capacity.

(f) Assuming use of the "Gemini-9" pressure swing adsorption system from Air Products, Inc., which removes CO_2 and H_2O in a first bed and produces a fuel gas of 99.999% purity H_2 out of a second bed. The estimated cost for the natural gas case is $30.82 million for a hydrogen production rate of 8474 kmol/hour (Moore, 1994). For the other cases, cost are scaled according to the hydrogen production rate raised to the 0.7 power. The cost excludes the recycle compressor.

(g) For external electricity input, a cost of 5 cents per kWh is assumed. External heat input is charged at $4/GJ. Quantities are given in Table 3.

Table 2.4.8 Current and projected production costs of hydrogen ($/GJ)[a]

	1991	Near Term	Post 2000
Renewable sources			
Hydrogen from biomass gasification[b]			
Large plant (50 million scf/day)			8.2-10.7
Electrolytic hydrogen (for plants producing 0.5 million scf/day (180 GJ)[c] from: (assuming utility economics)			
Solar PV (SW US)	64-138	29-57	13-21
Wind (700 W/m^2)			16
(500 W/m^2)	42	26	20
(350 W/m^2)	60	39	30
Solar thermal (S.W. US)	60-79	45-75	24-33
Off peak hydroelectricity[d]	14-20	14-20	14-20
Electrolytic hydrogen (for plants producing 0.5 million scf/day (180 GJ)[c] from: (assuming industrial economics)			
Solar PV (SW US)			18-30
Wind (700 W/m^2)			21
(350 W/m^2)			39
Solar thermal (S.W. US)			34-46
Off peak hydroelectricity[d]			16-22
Fossil sources			
Hydrogen from steam reforming of natural gas			
Large plant (100 million scf/day)[e]	4.2-6.4	4.2-6.4	6.4-8.6
Small plant (0.5 million scf/day)[f]	11.1-13.8	11.1-13.8	13.8-16.5
Hydrogen from coal gasification			
Large plant (100 million scf/day)[e]	8.6	8.6	8.6
Medium plant (25 million scf/day)[g]	13	13	13
Nuclear Sources[h]			
Electrolytic hydrogen			
utility economics	34.2		19.4
industrial economics	45.2		25.0

Notes to Table 2.4.8.

(a) Levelized hydrogen production costs are given in constant 1989 US dollars.

(b) Assuming that the biomass feedstock costs $2 to 4 per GJ.

(c) A hydrogen plant producing 180 GJ/day could provide enough energy to fuel about 1000 fuel cell fleet automobiles, each traveling 48,000 km/yr.

(d) Assuming that off-peak hydroelectricity at existing sites costs 2 to 4 cents per kWh.

(e) Costs for hyrogen from steam reforming for a large scale plant are from (Katofsky 1993), 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. Costs for hydrogen from coal gasification from a large sized plant are from (Katofsky 1993) assuming coal costs $1.5/GJ.

(f) Costs for hyrogen from steam reforming for a small scale plant are from (Fein 1981), 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.

(g) Costs for hyrogen from steam reforming for a small scale plant are from (Fein 1981), 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.

(h) See Williams (1993).

Table 2.4.9a. Delivered cost of solar hydrogen from small plants c.2000[a,b]

	Electrolysis 10 MWp			Steam reforming of natural gas	
	PV	Wind	Hydro		
Capital costs (10^6\$)					
Power system	5-11	8.5	--	2.1	Reformer
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 sta.
TOTAL	9-15	6.3	6.3	3.6	TOTAL
Contributions to hydrogen cost($/GJ)					
Power system	7-14	13.6	--	5.0	Plant capital
Electrolyzer	4.4	5.9	5.2	2.3	O&M
Compression	2.3	2.3	1.1	0.8	Compression
Hydrogen Storage	1.4	1.4	1.4	1.4	Storage
Filling Station	2.5	2.5	2.5	2.5	Filling sta.
				5.4-8.1	Natural gas[c]
Total cost of hydrogen to consumer					
($/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	
Land used by power system (hectares)	12-19	47-160			
Energy delivered	70,000 to 90,000 GJ per year				
Vehicles fueled[d]	1200	1200	1600	1000	

(a) Costs and performance for PV and wind electrolysis systems are taken from Tables 2.3.4 and 2.3.2. Costs are given in 1991$. 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) It is assumed that hydrogen is compressed from electrolyzer pressure (14.7 psia) or steam reformer pressure (1000 psia) to an intermediate storage pressure of 1250 psia. The filling station serves 300 vehicles/day. For refueling, a second compressor raises the hydrogen pressure to 8600 psia for storage in a small array of "cascade tanks". The vehicles (which have gaseous hydrogen storage at 8000 psia) are refueled by connecting them directly to the cascade storage.

(c) It is assumed that natural gas costs $4-6/GJ.

(d) Fuel cell fleet vehicles with an efficiency equivalent to 60 miles per gallon gasoline, driven 48,000 km/yr.

Table 2.4.9b. Delivered cost of Hydrogen Based on Post-2000 Projections.[a]

	Demonstration 10MWp		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 ($/GJ)						
Power System	7.0-14.2	12.8	7.0-14.2	12.8	8.2-10.7	7.0-14.2
Electrolyzer	4.5	6.4	4.5	6.4		4.5
Compression	2.4	2.2	1.4	1.4		1.4
Hydrogen storage	1.4	1.6	1.0	1.0		0.3
Pipeline (1000 mi)	--	--	--	--		0.4
Local Distribution	--	--	0.5	0.5	0.5	0.5
Filling Station[b]	2.5	2.5	4.4	4.4	4.4	4.4
Cost of hydrogen to consumer at filling station						
($/GJ)	17.8-25.0	25.5	18.8-26.0	26.5	13.1-15.6	18.5-25.7
($/GAL.GASO.)	2.32-3.27	3.34	2.45-3.39	3.46	1.71-2.03	2.42-3.35
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 (GJ)	66,000	76,000	5×10^6	7×10^6	7×10^6	5×10^8
Vehicles fueled	1000[c]		300,000[d]			30 million[d]

Notes to Table 2.4.9b.

(a) Costs and performance for PV and wind electrolysis systems are taken from Tables 2.4.3,5. Hydrogen costs are based on the higher heating value.

(b) For the "demonstration project systems, it is assumed that hydrogen is compressed from electrolyzer pressure (14.7 psia) to an intermediate storage pressure of 1250 psia. The filling station serves 300 vehicles/day. For refueling, a second compressor raises the hydrogen pressure to 8600 psia for storage in a small array of "cascade tanks". The vehicles (which have gaseous hydrogen storage at 8000 psia) are refueled by connecting them directly to the cascade storage. For "city scale" and "solar export" systems, it is assumed that the hydrogen is available at 50 psia from a local distribution system, and is then compressed to 8600 psia for storage in "cascades". As shown the "filling station" cost is higher at city than at small scale. This is true because compresssor and storage systems at small scale are counted separately, since they serve two purposes (1) leveling the plant output for intermittent systems and 2) as storage for the refueling system.

(c) For fleet vehicles with efficiency equivalent to 60 mpg gasoline, driven 48,000 km per year.

(d) For passenger vehicles with efficiency equivalent to 60 mpg gasoline, driven 16,000 km per year.

Table 3.1. Potential Resources for Renewable Electricity and Hydrogen Production.[a]

	Electricity from			Biomass Produced on Area Equiv. to 10% of Forest, Woods, Cropland
	Technically Useable Hydro	Total Wind Potential	PV on 1% Land Area	
Region	**TWh/yr[b]**	**TWh/yr[c]**	**TWh/yr[d]**	**TWh/yr[e]**
Africa	3,140	106,000	45,500	3,700
Asia	5,340	32,000	36,600	4,200
Australia	390	30,000	16,700	1,000
N. America	3,120	139,000	33,400	3,400
S/C America	3,780	54,000	27,400	4,900
Europe & former USSR	3,620	147,000	46,200	4,900
World	19,390	498,000	205,900	23,000

	Electrolytic Hydrogen From			Biomass Produced on Area Equiv. to 10% of Forest, Woods, Cropland
	Technically Useable Hydro	Total Wind Potential	PV on 1% Land Area	
Region	**EJ H_2/yr[b]**	**EJ H_2/yr[c]**	**EJ H_2/yr[d]**	**EJ H_2/yr[e]**
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

(a) The potential resource is the technically useable resource subject to environmental and land area constraints as indicated.

(b) Estimates for technically useable hydroelectricity production are from Table 2 of Moreira et.al (1993). For electrolytic hydrogen, it is assumed that the electrolyzer efficiency is 79%.

(c) Estimates for wind electricity production are from Table 10 of Grubb and Meyer (1993). For electrolytic hydrogen, it is assumed that the electrolyzer efficiency is 79%, and that the coupling efficiency is 94%.

(d) It is assumed that the PV system has an efficiency of 15%, the electrolyzer an efficiency of 80%, and that the coulping efficiency for PV electrolysis is 96%. Average insolation values for each region are used to ompute electricity and hydrogen production.

(e) It is assumed that a 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 69% (Katofsky, 1993). It is assumed that biomass is converted to electricity in a biomass gasifier/gas turbine system at 40% efficiency.

Table 3.2. 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:

	Projected US light-duty vehicles in 2010 if run on fuel cells (4.8 EJ)[f]	Present			Projected world non-electric fuel demand (IPCC)[g]	
From:		U.S. Oil Use (34 EJ)	World Oil Use (115 EJ)	World Fossil Fuel Use (300 EJ)	2025 (286 EJ)	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 (48 continguous states) = 7.8 million km^2

Notes to Table 3.2.

(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 69%. 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., 1993).

(f) The total energy use for US light duty vehicles in the year 2010 is estimated to be 14.5 EJ/yr (EIA, 1993). Assuming that hydrogen fuel cell vehicles have three times the energy efficiency of gasoline ICEVs, the demand for hydrogen energy would be 4.8 EJ/yr.

(g) Projections are from the IPCC accelerated policy scenario (IPCC 1990).

Table 4.1a. Emission standards (grams/mile) for light-duty motor vehicles.[a]

Pollutant[c]	Emission Standard[b]					
	Federal 1993 Standard	Federal CAAA, Tier 1 1994 MY[d]	Federal CAAA, Tier 2 (if needed)	CARB TLEV 1994 MY	CARB LEV 1997 MY	CARB ULEV 1997 MY
HC	0.41	0.25	0.125	0.125	0.075	0.040
CO	3.40	3.40	1.70	3.40	3.40	1.70
NO_x	1.00	0.40	0.20	0.40	0.20	0.20

(a) Source: Davis and Strang (1993); Sierra Research (1994)

(b) CAAA = Clean Air Act Amendments of 1990
MY = model year
CARB = California Air Resources Board
TLEV = transitional low-emission vehicle
LEV = low-emission vehicle
ULEV = ultra-low emission vehicle

(c) HC = hydrocarbons (California regulates nonmethane organic gases, not hydrocarbons)
CO = carbon monoxide
NO_x = nitrogen oxides

Table 4.1b. Projected average increase in consumer price per vehicle to go beyond Tier 1 emission standards specified by the Clean Air Act Amendments of 1990 and meet California's TLEV, LEV and ULEV emissions standards.[a]

Estimate of:	TLEV (transitional low-emission vehicle)	LEV (low-emission vehicle)	ULEV (ultra-low emission vehicle)
California Air Resources Board (1994a)	$34.61 (MC)	$84.96 (MC)	$165.54 (MC)
	$56.13 (RPE)	$112.10 (RPE)	$203.49 (RPE)
Sierra Research (1994)	$346 (RPE)	$906 (RPE)	$1331 (RPE)
Automobile manufacturers (Sierra Research, 1994)	$599 (RPE)	$1479 (RPE)	$2230 (RPE)

(a) MC = manufacturing cost; RPE = retail price equivalent.

Table 4.2. Characteristics of hydrogen storage systems.

Storage system	Installed fuel-system energy density[a] (MJ/liter)	(MJ/kg)	Container cost[b] ($-OEM/GJ)	Refueling time[c] (minutes)	Station cost[d] ($/GJ)
Gasoline tank[e]	32.4	34.0	20	2-3	0.6
H-Power iron oxidation/reduction[f]	5.8?	5.0?	500?	?	3?
Carbon-wrapped alum. cyl. (8000 psi)[g]	3.4	7.0	4000	3-5	4-6
Liquid hydrogen[h]	5.0	15.0	1000-2000	5+	3.5-5-(11)
Cryoadsorption[i]	2.1	6.3	2000-4000	5	4-5
Thermocooled pressure vessel[j]	2.5	8.2	4000+?	5+	5+(8+)
FeTi metal hydride[k]	2.4	1-2	3300-5500	20-30	3-4
Organic liquid hydride[l]	0.5	1.0	?	6-10	?

(a) Weight and volume of container, fuel, and auxiliaries.

(b) Cost to the original equipment manufacturer (OEM) per GJ of storage capacity.

(c) Time to deliver fuel, not including time to pull in, pull out, or pay.

(d) The full owning and operating cost of the station. The cost of hydrogen is not included here.

(e) Energy density was calculated assuming that an empty gasoline tank weighs 12-kg, and that the ratio of the outside displacement of a tank to its inner capacity is 1.075:1. The estimate of the cost of the tank is based on data from the American Council for an Energy-Efficient Economy (ACEEE, 1990).

(f) H-Power, a company located in New Jersey, is seeking a patent on a reduced-iron/oxidized-iron (oxidation/reduction) hydrogen-generation system (Werth, 1992). The process begins with iron oxide (Fe_3O_4) and a reducing gas (H_2 or CO), offboard the vehicle. The reducing gas and the iron oxide are reacted at high temperature (about 800 to 1,100o C if hydrogen is used) to produce reduced iron and steam: $Fe_3O_4 + 4H_2 \longrightarrow 3Fe + 4H_2O(g)$. If pure hydrogen is used as the reducing gas, the reaction requires an external source of heat; if enough CO is added, no external heat source is needed, because the reaction becomes exothermic. The reduced iron is transferred to the vehicle, and stored onboard, as a powder, in metal tubes.

To produce hydrogen fuel onboard the vehicle, the iron-reduction reaction is reversed: steam or hot water (over 50°C) is reacted with the reduced iron to produce hydrogen and iron-oxide. This hydrogen-generation (iron-oxidation) reaction takes place between 25°C and 900°C. However, below about 500°C, a catalyst, probably a noble metal, is required. Generally, the necessary reaction energy can be supplied by some combination of a catalyst and external heat. At 25°C, one would need a very good and effective (and presumably costly) catalyst, but no external heat; above 500°C, no catalyst would be needed. The balance between the use of a catalyst and the use of external heat will be determined by overall cost, complexity, and performance. The catalyst may be alloyed with the metal, mixed with the water, or introduced in other ways. The fuel cycle is completed when the oxidized iron is removed from the vehicle to undergo the initial reduction (regeneration) reaction. (Details are in Werth, 1992).

Madeda (1991) of H-Power gives the following performance specifications for this system: 22.66 Wh-electricity per in^3 of storage, and 366 wh-electricity per lb of storage, assuming 50% hydrogen-to-power efficiency on a LHV basis (42% HHV basis). This translates into 11.7 MJ/L and 6.8 MJ/kg. These values refer to the actual iron (Fe) storage media only, and do not include metal tubes, steam and water lines, fuel lines, pumps (if any), separators, preheaters (if any), insulation, or the overall enclosure. We assume that the overall system volumetic energy density is half of the energy density of the iron "storage media" alone, and that the overall weight energy density is 3/4 of the energy density of the iron alone.

The iron-material cost of the system isonly 15 cents/kWh, but the entire selling cost of the system (tubes, steam lines, catalyst, enclosure, etc.. probably will be several times higher than this. We assume that it would cost $200 to $300 to manufacture the system (recall that a noble-metal catalyst might be used), or about $500 at the retail level.

The refueling time depends on details which have not yet been worked out. The developers believe that refueling can be done very quickly. Because the station would not have compressors or coolers, the station mark-up should be less than the markup for CH2, LH2, or cyroadsorbed hydrogen. We assume a cost slightly lower than that for hydride refueling.

(g) One of us (DeLuchi) commissioned a consultant to the pressure-vessel industry to estimate the weight, size, and cost of ultra-high-pressure carbon-wrapped containers for vehicular use (Price, 1991). Based on his results, we calculated the energy density and cost of the containers alone (no auxiliaries), and then assumed that the auxiliaries reduce the energy density values by 5%. The energy density values for 9000 psi are 7.0 MJ/kg and 3.6 MJ/L, and the values for 6000 psi are 6.8 MJ/kg 32.8 MJ/L. The estimate of refueling time is mine; no ultra-high-pressure fast refueling systems have been built.

(h) DeLuchi (1989) reports a range of 3 to 5 MJ/liter for LH2 systems, including the pump, but not including the other auxiliaries. Collier et al. (1991) report 9 to 25 MJ/kg and 2-5 MJ/l for LH2 systems (it is not clear if this includes the pump, plumbing, preheater, and so on). Peschka (1987) reports a goal of 37 MJ/kg, probably for the tank alone.

According to Iwatani (n.d.), the 100-liter tank in the Musashi-8 weighs 60 kg when full (16.7 MJ/kg). However, the tank also has a pump, motor, heat exchanger, and gas storage bottles, which are not included in the energy-density figures just cited. Adiagram in Furuhama et al. (1990) indicates that their small 80-liter tank has a 191-liter outer displacement including the pump (but no other auxiliaries), resulting in 3.7 MJ/L.

We assume that including all auxiliaries would reduce these energy density values by 10%.

BMW has developed two LH2 versions of its model 745i, one using external mixture formation, and the othe using direct injection. The tank in the external-mixture vehicle operates at 2.5 bar, has a boil off rate of 2.0%/day, has a capacity of 130 liters and weighs 80 kg full (16.3 MJ/kg). The tank in the direct-injection vehicle operates at 2.0 bar and has a capacity of 45-liters and weighs 45 kg full (10.0 MJ/kg) (Strobl, 1987).

Takiguchi et al. (1987) give the following data for the tank in the Musashi-7 vehicle: 155-l capacity, 90-kg when full (17.1 MJ/kg), and 280-liter outer displacement (5.56 MJ/liter). The tank is double-walled stainless steel, and operates at 2.5 bar. It also has an 8-L pressurized-H2 storage tank, a motor for the injection pump, an oil tank for the lubricating oil for the motor, and a heat exchanger to vaporize the fuel. Assuming that these total 30 liters and 20 kg, the total storage system specifications, including all auxiliaries, would be 14 MJ/kg and 5.0 MJ/liter.

The estimates of the tank cost and the station cost are based on data in DeLuchi (1989). (Reister and Strobl (1992) have stated that a dual-fuel LH2/gasoline vehicle would cost aroud 30-40% more to manufacture than a conventional gasoline vehicle, under mass production.) The estimate of the station mark-up in parantheses includes the cost of liquefying hydrogen (about $6/GJ); the other estimate does not.

According to Strobl (1987), the BMW LH2 tanks can be refilled in 5 minutes when they are cold (Strobl, 1987). If the tanks and the refueling lines are warm, they have to be cooled first with liquid nitrogen, and this is a very time consuming process. However, Reister and Strobl (1992) state that "once suitable components and the process technology have been developed, the entire refueling process will probably take less than 10 minutes (compared with the previous 1 hour) with virtually negligible energy losses" (p. 6). It is not clear if the "entire refueling process" in this case includes precooling.

(i) Young (1990) estimates 1.92 MJ/l and 6.83 MJ/kg (including fuel) for a carbon adsoprtion system storing hydrogen at 55 atm and 150 K. In another paper from the same research group, Amankwah et al. (1990) estimate 7.2 MJ/kg and 2.4 MJ/l (they assume kevlar-wrapped tanks). However, the system needs active cooling system to maintain the low temperature. We assume that including such auxiliaries would reduce these energy-density values by 15%.

The refueling station would require a compressor, refrigerator, and vacuum pump. We used Amankwah et al.'s (1990) estimate of the station cost, except that we assumed $0.07/kWh for electricity. We estimated the cost of the container based on statements in Amankwah et al. (1990) that indicate that the vessel would cost a bit more than an LH2 vessel, but less than half as much as a hydride system. The refueling time is our estimate.

(j) Krepec et al. (1990) estimate that a combination of low-temperature and high-pressure storage, with no carbon adsorption, would provide 9.45 MJ/kg and 2.84 MJ/l at 300 bar and 100 K, and 5.67 MJ/kg and 1.61 MJ/L at 300 bar and 200 K. The system also would require a pressure regulator, pre-heater, and a gas accumulator, which we assume would reduce the tank-only figures above by 15%.

The refueling station would be complex and probably expensive, because it would store and deliver both LH2 and high-pressure gas. Refueling would be a two-step process: first deliver LH2, then deliver high-pressure gaseous hydrogen. This suggests that the refueling time and the refueling mark-up would be at least as high as for LH2 sytems. The station mark-up estimate in parentheses accounts for the extra cost of liquefying half of the hydrogen delivered to the vehicle.

(k) DeLuchi (1989) reports 2-5 MJ/liter and 1-2 MJ/kg for various hydrides, excluding auxiliaries. Collier et al. (1991) estimate that conventional hydrides contain 1-3 MJ/kg and 0.5-5 MJ/L. They have a research goal of 7 MJ/kg and 5 MJ/l. We assume that the auxiliaries (heat exchanger, piping, pressure regulators, etc.) reduce these values by 15%.

Hama et al. (1988) describe a lanthium-nickel-aluminum (LaNi0.5Al0.1) hydride that weighs 663 kg, displaces 201 liters, and contains 7.1 kg of hydrogen. In addition, it has an 18-liter exhaust heat exchanger, a voluminous pressure reduction device, and associated electronic controls. If the size and weight of the auxiliaries could be reduced somewhat, the total system would contain 4.2 MJ/l and about 1.4 MJ/kg.

Lanyin et al. (1990) described an advanced TiFe hydride that contains about 2.1% hydrogen by weight. The total system energy density probably is about 2.3 MJ/kg.

The estimate of the cost of the hydride is based on data in DeLuchi (1989). (Magnesium hydrides would be several times less expensive than FeTi hydrides, but they are not yet suitable for vehicular applications, because of their high dissociation temperature.) The service-station mark up was calculated using the refueling station model described in DeLuchi (1992), with input parameters set for hydrogen at 50 bar.

(l) In this system methylcyclohexane (MCH), a liquid, would be carried on board the vehicle and dehydrogenated by an onboard reformer to produce hydrogen and toluene. The system would be very bulky and heavy for several reasons: 1) the effective volumetric and mass density of hydrogen in MCH is low; 2) two large tanks would be needed -- one for the MCH, and one for the toluene; and 3) the reformer itself would be large and heavy, even assuming major improvements over the current models. Based on data in Gruenenfelder and Schucan (1989) and Taube et al. (1985), we estimate that an advanced system storing 0.66 GJ of hydrogen and providing 55-kW of would weigh 675 kg and displace 1230 liters installed. The system would have to be further improved by an order of magnitude to be attractive in light-duty applications. (Note, though, that it may be attractive in heavy-duty vehicles, which can accomodate much more weight and bulk.) We estimated the refueling time by assuming that MCH would be delivered and toluene removed simultaneously, and that the gal/min delivery rate would the same as with gasoline.

Table 4.3 Characteristics of fuel cells for transportation.[a]

Type of fuel cell	Status[b] (1991)	Specific power[c] (kW/kg)	(kW/1)	Operating temp. (^{o}C)	Contami-nated by	Start-up time
Phosphoric Acid	CA	0.12	0.16	150-250		long
Alkaline	CA	1.49	1.47	65-220	CO, CO_2	long
Proton exchange membrane	E	1.33	1.20	25-100	CO	short
Monolithic solid oxide	L	8.3	4.0	700-1000		long

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

(b) CA = commercially available, E = experimental, L = laboratory.

(c) Specific power includes only the fuel cell stack, but no auxiliaries.

Table 4.4. Characteristics of batteries and peak-power devices for EVs.[a]

Battery type (developers)	Status[b] (1991)	Energy density (3-hour rate)[c]		Power density (at 80% DoD)[d]		Energy effic.[e]	Life[f]
		(Wh/kg)	(wh/l)	(W/kg)	(W/l)	(%)	(cycles)
Bipolar sealed lead/acid[g] (GNB)	CA	32*	52*	250*	400*	n.s.	short
Nickel/cadmium[h] (Saft)	CA	57*	115*	160*	322*	n.s.	2000
Nickel/iron[i] (Eagle-Picher)	PC	50*	113*	80*	181*	58*	1100
Sodium/sulfur[j] (Powerplex & CSPL)	PC	105	120	150	171	91*	600
Bipolar lithium/disulfide for BPEV[j] (ANL)	L	142	257	319	577	high	1000+
Bipolar lithium/disulfide for FCEV[j] (ANL)	L	110	188	657	1130	high	1000+
Lithium/polymer electrolyte[k] (IREQ)	L	128	129	201	202	77	?
Bipolar lithium/polymer[l]	L	170	221	380	494	n.s.	n.s.
Zinc-air battery[m] (Electric Fuel)	PC	260*	341*	113*	148*	n.s.	n.s.
Nickel metal-hydride[n] (Ovonic)	PC	80*	215*	175*	470*	high	1000+*
Ultra-capacitor[o] (various developers)	L	13	48	>10000*	>28000*	80-95*	120000*
Ultra-capacitor[p] (US DOE development goals)	L	>15	>37.5	>1600	>4000	>90	n.s.
Composite flywheel[q] (LLNL)	L	37	33	306-818	269-718	96	long?

(a) Numbers marked with an asterisk are measured performance of a module or battery. All others are projections or modeling results. n.s. =

(b) CA = commercially-available batteries; PC = pre-commercial battery prototypes; L = laboratory cells.

(c) The discharge rate was not specified for the lithium/disulfide battery, the ultracapacitors, or the flywheel. The discharge rate for the zinc/air battery was 5 hours at a constant current.

(d) DoD= depth of dishcarge. Typically, the power density is based on a peak-power pulse of 15 to 30 seconds at 80% depth of discharge. Exceptions are noted below.

(e) Efficiency is defined as the amount of electrical energy output from the battery terminals divided by the amount of electrical energy input to the battery from the charger. The total amount of electrical energy (expresed in joules) input to the battery is equal to the number of electrons (expressed in coulombs) input multiplied by the electrical potential energy per electron (expressed in volts). Given this simple representation, one can see that there are two ways in which electrical energy might be "lost" within the battery, and not end up at the battery terminals as electrical energy: electrons might be "lost" from the electricity-producing electrochemical pathways, or energy per electron might be reduced. The successful transfer of charge is represented by a measure called the "coulombic efficiency;" the loss of energy per electron is related to the internal resistance of the battery. One also can count in the efficiency expression any use of energy necessary to maintain the operating temperature of the battery. However, we do not count this energy here (except in the case of the low-temperature lithium/polymer battery, because so little is required; see note k). However, we do account for battery heating in the cost analysis. Note too that batteries are less efficient when discharged in an actual driving cycle than when dishcarged during a contsant-current discharge test. We make rough estimates of this effect.

(f) The number of cycles to 80% depth of discharge, until the battery performance falls to a certain level, unless noted otherwise. The lifetime in actual use is likely to be less than the lifetime measured in the laboratory. Burke (1991b) notes that "field experience with lead-acid batteries in vehicles and the limited laboratory data available show that battery life on the FUDS or SFUDS is much shorter than that found from constant-current discharge testing" (p. 19). We account for this in the cost analysis.

(g) From Burke and Dowgiallo (1990). The USDOE (1991a) shows 30 wh/kg and 48 wh/l. Burke and Dowgiallo (1990) state that the 12-volt side-by-side bipolar GNB battery tested at Idaho National Engineering Lab is "commercially available," but we presume that it is not commercially available in electric-vehicle pack sizes. The peak-power figures shown are for a 10-second pulse at a 80% DoD.The power density was very strongly dependent on the DoD: for a 10-second pulse at 50% DoD, the power density was 400 W/kg. However, the USDOE (1991a) reported only 67 W/kg for a 15-second pulse at 50% DoD, for the same kind of battery, from the same manufacturer, tested at the same facility (Idaho National Engineering Laboratory). Thus, either the power density is extraordinarily sensitive to the length of the pulse, or the battery does not perform consistently. The efficiency of the battery was not specified (n.s.); the battery has relatively high coulombic efficiency (USDOE, 1991a); but also a very high internal resistance (Burke and Dowgiallo, 1990).

(h) From EPRI (1990). The life-cycle numbers are projections. DeLuca et al. (1991) report test results of 55 Wh/kg (3-hr rate), 104 Wh/l (3-hr rate), and 191 W/kg (@50% DoD) for Ni/Cd batteries. (Note that the DeLuca et al. W/kg results are at 50% DoD, whereas the EPRI results are at 80% DoD.) See also Cornu (1990).

(i) From EPRI (1990), except for the estimates of battery efficiency, which are from DeLuca et al. (1991), and the indication of pre-commercial status for sodium/sulfur, which is based on CSPL's (1991) statements that the commercialization of sodium/sulfur batteries already is being planned. DeLuca et al. (1991) report test results of 51 Wh/kg, 118 Wh/l, and 112 W/kg for Ni/Fe batteries, and 81 Wh/kg (3-hr rate), 83 Wh/l (3-hr rate), and 152 W/kg (@50% DoD) for the ABB Na/S battery. (Note that the DeLuca et al. W/kg results are at 50% DoD, whereas the EPRI results are at 80% DoD.) The life-cycle numbers for both batteries are projections. See also Dustmann (1990). CSPL = Chloride Silent Power Limited.

The efficiency estimate shown for sodium/sulfurdoes not account for the potentially substantial amount of energy required to maintain the operating temperature of the battery. If this heating energy were deducted, the battery efficiency probably would be 75% or less. (See note i for a sample calculation of the amount of energy required to maintain a lithium/iron-sulfide battery.) Also, the indicated efficiency apparently was measured at constant-current charge and discharge. The efficiency over a standard-driving cycle discharge would be lower. Thus, the overall in-use efficiency of the battery might be between 60% and 75%. (The efficiency of the nickel/iron also probably would be lower in-use than shown here.)

(j) The estimates of energy density and power density are mid-range values from battery-modeling exercise reported by Nelson and Kaun (1991). The BPEV case refers to a battery designed to supply the full driving range and power in a BPEV; the FCEV case refers to a battery designed to supply only the peak power in an FCEV. The battery probably would be very efficient, because the coulombic efficiency of the cells thus far exceeds 98%, and the internal resistance is very low (Kaun et al., 1991).

However, the battery also may require a substantial amount of energy to maintain its operating temperature of at least 400o C. Although the battery would generate more than enough heat to maintain its temperature when the vehicle was being used, it would lose at least 150 Watts when the vehicle was idle. It might be possible to design the battery to tolerate a temperature drop of 50o C or so, but if the battery remained idle after reaching this lowest tolerable temperature, the temperature would have to be maintained by a heating system. The developers of the battery hope to limit the heat loss to 150 Watts, presumably for a relatively large battery. If the battery typically remained idle for no more than two days in a complete charge/dishcarge cycle, and could cool for 12 hours before heating was required, then 36 hrs x 150 Watts = 5.4 kWh of energy -- about 10% of the total stored energy of a large battery -- would be required to offset the heat loss (assuming 100%-efficient resistive heating). However, a greater percentage of the stored energy would be required to maintain the temperature of a smaller battery, because of the higher surface-to-volume ratio. Moreover, if the heat loss was greater than 150 Watts (a sodium/sulfur battery tested at Argonne National Lab used a 176-Watt heater to maintain a temperature below that of Li/S batteries), or if the battery remained idle for longer than two days, or if the allowable cool-down period was less than 12 hours, then still more energy would be required for heating. It is not difficult to imagine that a small battery, such as might be used to provide peak-power in an FCEV, might consume 50% of its energy to maintain its temperature over several days.

The estimate of cycle life is based on EPRI (1990; 1000+); Kaun et al. (1990; 1000-2000); and Kaun et al. (1991; 1000). ANL = Argonne National Laboratory.

(k) From Belanger et al. (1990). All the estimates are based on a "conceptual batttery design," for the DOE's IDSEP urban-fleet van. A graph in the source projects that about 52 kWh hours will be available at a 3-hour discharge rate. At 80% depth of discharge, the battery will provide an 82-kW pulse for 20 seconds. The concept battery weighs 407 kg and displaces 404 liters. These figures apparently are based on 1990 cell performances. See also EPRI (1990). The authors also project that the battery can be manufactured for $100 to $150/kWh.

The efficiency estimate is the projected round-trip energy efficiency, including energy lost to maintain the 80o C operating temperature. (Because the operating temperature of this battery is much less than the temperature of the high-temperature batteries, Na/S and Li/S, much less energy is required to maintain its temperature.) The authors actually project 1000 to 2000 cycles over 5 to 6 years, based on 1990 cell performances. However, they have defined "end of life" differently, and more leniently, than have other researchers. The battery they describe actually loses 6% of its capacity per year, which is a relatively high loss rate. IREQ = Research Institute of Hydro-Quebec in Canada.

(l) Projections for a 90-kW, 40-kWh advanced battery, in 1998 (Neslon, 1992).

(m) From Harats et al. (1992). The energy densities shown here are equal to the total energy (based on consumption of 100% of the zinc fuel; 5-hour constant-current discharge) in a 12-cell module divided by the mass or volume of the complete system, including all auxiliaries (such as CO2 scrubbing equipment). The power densities are based on 30-second high-current discharges down to 71% fuel consumption (i.e., they are for up to 71% "depth of discharge"); at greater than 71% fuel consumption, the peak-power declines. In this battery design the zinc slurry is static, so there are no circulation pumps or storage tanks. The battery has a higher power density than other zinc/air batteries (Appleyard, 1992; Cheiky et al., 1991; *Modern Battery Technology*, 1991) because it does not have a bifunctional air electrode. That the air electrode is not bifunctional means that the battery is mechanically rechargeable only (not electrically rechargeable). The battery would be "recharged" by replacing cassettes of spent zinc fuel with cassettes of electrochemically regenerated fuel; the electrochemical regeneration would occur off-board the vehicle, perhaps at a central facility. Although the life of the batttery was not specified, the elimination of the bifunctional air electrode, and the constant replenishment of the spent zinc with fresh zinc, suggests the possibility of a long life.

(n) Data are from Ovshinsky (1993). The author states that 80 Wh/kg and 215 Wh/l have been achieved in prototype cells, and that 150 Wh/kg is being sought. Venkatesan et al. (1991) state that energy efficiency is "exceptional". Because the battery operates between -20o C and 60o C, it will not require extra energy for heating. The battery has been cycled over 1000 times to 100% DoD. The batteries are sealed and maintenance-free, and can be charged as quickly as one hour.

(o) The energy densities are performances projected by Pinnacle Research in 1992 (Burke, 1992). Kaschmitter (1992) projects 20-30 wh/kg for a carbon aerogel ultracapacitor being developed at Lawrence Livermore National Laboratory. Presently available devices have an energy density of 1-10 Wh/kg and 1-12 Wh/liter (Burke and Dowgiallo, 1992; Burke, 1992; Burke, 1991a). The power densities are results of testing by Pinnacle Research (Burke, 1992). The efficiency and life-cycle estimates are from Burke (1992, 1991a). A Japanese ultracapacitor showed only 20% degradation in capacity after 120,000 charge/discharge cycles (15- to 30-second cycles between 100% and 50% of initial voltage). A Pinnacle Research ultracapacitor failed after 120,000 cycles (Burke, 1991a). Capacitors are commercially available for many applications, but ultracapacitors for electric vehicles are not yet commercially available (Burke, 1991a). See also Trippe and Blank (1992).

(p) From Burke and Dowgiallo (1992).

(q) The performance values are from conceptual designs of a gimbaled electromechanical battery: a flywheel (or rotor) consisting of six shells of carbon-fiber composite material, wrapped around a permanent-magnent motor/generator (Comfort et al., 1992). The system stores 12 kWh and can be recharged in 15 minutes. The power densities are based on the ability to accelerate or decelerate at 0.34g between 0 and 60 mph. The high end of the range assumes that the rotor is operating at maximum speed; the low end assumes 3/8 of maximum speed. The turnaround efficiency of 0.96 is based on a predicted motor-generator efficiency of 0.98. The flywheel (rotor) has a design lifetime of 10 years or 120,000 miles. The rotor operates at 54,000 to 144,000 rpm. LLNL = Lawrence Livermore National Laboratory.

Table 4.5. Breakdown of PEM fuel cell and related systems for an FCEV assumed in this report.[a]

Input assumptions	
Membrane price ($/sq ft)	6.2
Total membrane area/active membrane area	1.1
Catalyst price ($ per troy ounce)	780
Total catalyst loading (milligrams per cm^2)	0.100
Calculated results	
Fuel cell calendar life (years)	10.1
Hours of vehicle use sustained by fuel cell	7,067
Net efficiency of fuel cell and auxiliary system (GJ-electricity-to-power train/GJ-fuel, higher heating value basis)	0.458
Power density (mW/cm^2)	688
Fuel cell component and system costs	
Cost of catalyst ($/kW)	3.65
Cost of membrane ($/kW)	10.73
Cost of other materials ($/kW)	15.10
Cost of flow field ($/kW)	0.90
Total materials cost for fuel cell system, including auxiliaries, but excluding fuel cell electronics ($-OEM/kW)	40.77
Total labor cost for fuel cell system, excluding fuel cell electronics ($-OEM/kW)	18.11
Volume of fuel cell stack and associated water, heat, and air auxiliaries (ft^3)	3
Weight of fuel cell stack and associated auxiliaries (kg)	57
Total retail price per kW of fuel cell system, including electronics and sales tax ($/kW)	118.19
Total retail price of fuel cell system, including sales tax ($)	2,954

(a) Source: Updated (unpublished) version of model documented in DeLuchi (1992).

Table 5.1a. Summary of baseline delivered retail fuel prices we assume in subsequent economic analyses.[a]

			Components of delivered fuel cost ($/GJ)				Delivered cost to consumer ($/GJ)
Transport fuel	Feedstock/ electricity source	Feedstock/ electricity cost	Production	Storage	Distribution	Filling station	
Methanol	Biomass	$2.5/GJ	10.4	0	1.9	1.2	14.0
Methanol	Natural gas	$3.0/GJ	7.5	0	1.9	1.2	10.6
Methanol	Coal	$1.75/GJ	10.0	0	1.9	1.2	13.1
Ethanol	Biomass	$2.5/GJ	9.1	0	1.5	0.9	11.5
Ethanol	Corn	$1/bushel[b]	16.3	0	1.5	0.9	18.7
Hydrogen	Biomass	$2.5/GJ	8.7	0	0.5	4.4	13.6
Hydrogen	PV	3.8 c/kWh	17.2	2.4	0.5	4.4	24.5
Hydrogen	Wind	4.7 c/kWh	22.8	2.4	0.5	4.4	30.1
Hydrogen	Natural gas	$3/GJ	5.8	0	0.5	4.4	10.7
Hydrogen	Coal	$1.75/GJ	9.0	0	0.5	4.4	13.9
Hydrogen	Nuclear	5.3 c/kWh	21.2	0	0.5	4.4	26.1
CNG	Natural gas	$3/GJ	3.0	0	1.7	2.6	7.3
Reform. gasoline	Crude oil	$26.4/bbl	7.34 (97 c/gal)	0 (0 c/gal)	0.99 (13 c/gal)	0.61 (8 c/gal)	$8.95/GJ ($1.18/gal)
Utility residential electricity rates for recharging battery-powered electric vehicles							
Off-peak power							6 c/kWh
Conventional utility, 1993							7.5 c/kWh
Conventional utility, 2000							8 c/kWh
Renewables-intensive utility (post 2000)[c]		6.4 c/kWh					7.9 c/kWh

(a) Details of these estimates are discussed in the text and elswhere (tables and figures).

(b) This is the "net cost" of corn, i.e. the actual cost per bushel minus credits for sale of byproducts produced with the ethanol.

(c) Source: Kelly and Weinberg, 1993. (Case 10 shown in Fig. 2.3.4.)

Table 5.1b. US Dept. of Energy projections for fossil energy prices in 1991 dollars.[a]

	1990	2000			2010		
		low	reference	high	low	reference	high
World oil price ($/barrel)	22.57	15.00	20.14	23.48	19.58	27.37	33.15
Transportation motor fuel[b]							
$/GJ	9.46	8.90	9.91	10.72	9.89	11.46	12.58
$/gallon	1.25	1.17	1.31	1.41	1.30	1.51	1.66
Delivered natural gas ($/GJ)							
Commercial sector	4.86	5.73	5.87	5.94	6.84	7.07	7.13
Industrial sector	3.36	3.53	3.74	3.94	4.49	4.79	5.13
Electric utilities	2.39	2.65	2.83	2.98	3.80	3.97	4.08
Delivered steam coal ($/GJ)							
Industrial sector	1.59	1.61	1.65	1.69	1.78	1.86	1.88
Electric utilities	1.52	1.56	1.58	1.60	1.79	1.87	1.90
Delivered electricity (c/kWh)							
Residential sector	8.3	8.3	8.5	8.5	9.3	9.5	9.6
Commercial sector	7.5	7.3	7.4	7.5	7.7	7.9	8.0
Industrial sector	5.1	5.0	5.0	5.1	5.3	5.4	5.4

(a) Projected prices under the reference, low, and high oil price scenarios (EIA, 1994).

(b) Including federal and state taxes.

Table 5.2. Characteristics of ICEVs in the analyses.[a]

Item	Gasoline	MeOH	EtOH	CNG	Liquid H2	Hydride H2	Compressed H2
Energy storage system	metal tank	metal tank	metal tank	high-pressure vessel	cryo-genic dewar	fe/ti hydride	C-over aluminum vessel[b]
Driving range (km)	640[c]	483	563	402	402	241	322
Max. power to wheels (kW)	101	n.e.	n.e.	n.e.	n.e.	n.e.	n.e.
Vehicle life (km)[d]	193,080	193,080	193,080	202,734	193,080	193,080	193,080
Volume of complete fuel storage system (liters)	63	83	74	n.e.	n.e.	n.e.	n.e.
Weight of complete vehicle (kg)[e]	1,415	1,406	1,402	1,524	1,361	1,745	1,517
Coefficient of drag	0.28	0.28	0.28	0.28	0.24	0.24	0.24
Fuel economy* (HHV, gasoline-equivalent mpg)[f]	25.8	29.1	29.0	27.6	32.0	27.5	29.9
Fuel economy* (gasoline-equivalent liters/100 km)	9.1	8.1	8.1	8.5	7.4	8.6	7.9

(a) The gasoline vehicle is a year-2000 version of the 1990 Ford Taurus. The other vehicles are "built" hypothetically from this. n.e. = not estimated. Fe/Ti = iron/titanium hydride. The vehicle life and the coefficient of drag are input directly into the model; the other parameters are calculated by the model.

(b) Carbon-wrapped aluminum ultra-high pressure vessel, storing hydrogen at 550 bar. As one increases the storage pressure the bulk of the storage system decreases but the cost increases. We have chosen 550 bar because a tradeoff analysis indicated that it represents a good balancing of these two opposing tendencies.

(c) The 1990 Ford Taurus has a 16.0-gallon gasoline tank (1990 Market Data Book, 1990). If in the year 2000 the tank were the same size and the vehicle got about 25 mpg in use, the drving range would be about 400 miles, or 640 km.

(d) We assume that natural-gas vehicles would have a slightly longer life than gasoline ICEVs.

(e) Inlcuding one passenger and fuel to 40% of tank capacity.

(f) Gasoline-equivalent fuel economy in miles/gallon is calculated as the mile/million-Btu fuel economy of the alternative vehicle in combined city and highway driving in the year 2000, divided by 125,000 Btu/gallon-gasoline (34,830 kj/liter). We use the higher heating value of hydrogen and methanol. (On a lower heating value basis, the gasoline-equivalent fuel economy for hydrogen vehicles is 1.092 times higher than the higher-heating value basis. It is 1.054 times higher for methanol vehicles.) The mpg fuel economy of the baseline gasoline ICEV is calculated from a detailed set of input parameters, including vehicle weight, powertrain efficiency, aerodynamic drag, the amount of city vs. highway driving, and other factors.

The mi/million-Btu fuel economy of each of the alternative-fuel ICEVs is calculated as: the mi/million BTU fuel-economy of the gasoline vehicle multiplied by an engine thermal efficiency factor and a weight factor. The thermal efficiency factor is the ratio of the efficiency of the engine in the alternative-fuel vehicle to the efficiency of the engine in the gasoline vehicle. The weight factor is the percentage difference in weight between the alternative-fuel vehicle and the gasoline vehicle multiplied by the percentage change in fuel economy per one percent change in weight. The relative weight and thermal efficiency of alternative-fuel vehicles has been analyzed elsewhere (DeLuchi, 1991), taking into account the effect of the 1990 Clean Air Act Amendments. We use those estimates here. For example, we assume that the hydride/hydrogen engine would have a higher compression ratio than would the gasoline engine and would operate at a very high air-to-fuel ratio (but still meet the 0.25 g/km NO_x standard), and that as a result of these two factors would be about 20% more thermally efficient than the gasoline engine. However, the considerable extra weight of the hydride storage system would reduce the overall fuel-efficiency advantage. The LH_2 vehicle would have two efficiency advantages over the hydride vehicle: the low temperature of the liquid hydrogen would reduce heat loss and improve thermal efficiency, and the LH_2 storage system would weigh only slightly more than the gasoline storage tank. (Note, though, that these assumptions of very high efficiency and very low NO_x emissions might be optimistic.)

The fuel economy estimate shown in the table is given in terms of hydrogen delivered to the motorist, and does not account for boil-off losses of hydrogen upstream. Assuming that 3% of the hydrogen would be lost at each of three transfer points in the hydrogen distribution system, then the gasoline-equivalent mpg, expressed in terms of hydrogen produced at the LH_2 facility, would be 8.7% lower than shown here ($1-0.97^3$).

Table 5.3. Characteristics of EVs in the analyses.[a]

Item	Gasoline *(640 km range)*	BPEV *(160 km range)*	BPEV *(240 km range)*	BPEV *(400 km range)*	FCEV Methanol *(560 km range)*	FCEV Hydrogen *(240 km range)*	FCEV Hydrogen *(400 km range)*
Energy storage system	metal tank	bipolar Li/S	bipolar Li/S	bipolar Li/S	metal tank	carbon/Al tank	carbon/Al tank
Battery type	---	as above	as above	as above	bipolar Li/S	bipolar Li/S	bipolar Li/S
Gross power of fuel cell (kW)[b]	n.a.	n.a.	n.a.	n.a.	25	25	25
Max. power at wheels (kW)[c]	101	72	76	86	76	71	76
Vehicle life (km)[d]	193,080	241,350	241,350	241,350	241,350	241,350	241,350
Volume of fuel storage and fuel cell system (lit)[e]	63	118	157	240	301	224	310
Weight of whole vehicle (kg)	1,415	1,227	1,325	1,525	1,328	1,232	1,311
Drag coefficient[f]	0.28	0.23	0.23	0.23	0.23	0.23	0.23
Fuel economy[g] (HHV, gasoline-equivalent mpg)	25.8	124.2	119.9	111.1	61.5	74.5	71.6
Fuel economy (gasoline-equivalent liters/100 km)	9.1	1.9	2.0	2.1	3.8	3.2	3.3

(a) The FCEVs and BPEVs are based on the year-2000 Ford Taurus (the gasoline/ICEV shown here). The vehicle lifetimes and drag coefficients are input directly into the model; the other parameters are calculated by the model. Li/S = lithium/sulfide. See also notes to Table 5.2.

(b) This is the gross maximum power output of the fuel cell; the power requirement of the auxiliaries is deducted from this to determine the net power available to the drivetrain from the fuel cell. By trial-and-error runs of the cost model we find the combination of gross maximum fuel-cell power and maximum battery power that result in the lowest life cycle cost per km, subject to constraints on battery size and performance.

(c) We calculate the peak power of the EV and FCEV motor given the peak power of the ICE, the desired high-end acceleration of the EV relative to the high-end acceleration of the ICEV, and the mass, drag, and rolling resistance of the EV and ICEV. In the base case, we assume that the ratio of the maximum acceleration of the EV at 60 mph to the maximum acceleration of the ICEV at 60 mph is 0.80:1.00. Note, though, that the EVs would perform better than the ICEVs at low speeds.

(d) We assume that EVs will have a longer life than ICEVs (DeLuchi, 1992).

(e) The sum of the volume of the energy storage system (the battery, the methanol tank, the gasoline tank, or the hydrogen containers), the fuel cell, and the methanol reformer. If the volumetric power density of the fuel cell could be reduced to 0.04 ft^3/kW, as specified by Lemons (1990) and projected by Appleby (1990) and Meyer (1989), and if the hydrogen-storage pressure were increased to 10,000 psi, the total system volume would be reduced by about 20%, and lifecycle costs would increase slightly.

(f) The coefficient of drag is assumed to be lower for EVs than for gasoline ICEVs because of the higher value of improving the efficiency of EVs, due in turn to the higher cost of energy storage.

(g) Gasoline-equivalent fuel economy in miles/gallon is calculated as the mile/million-Btu fuel economy of the alternative vehicle in combined city and highway driving in the year 2000, divided by 125,000 Btu/gallon-gasoline (34,830 kj/liter). We use the higher heating value of hydrogen and methanol, and count electricity consumption at the outlet at 3413 Btu/kWh. (On a lower heating value basis, the gasoline-equivalent fuel economy for hydrogen vehicles is 1.092 times higher than the higher-heating value basis. It is 1.054 times higher for methanol vehicles.) The mpg fuel economy of the baseline gasoline ICEV and the mi/million Btu fuel economy of the FCEVs and BPEVs are calculated from a detailed set of input parameters, including vehicle weight, powertrain efficiency, aerodynamic drag, the amount of city vs. highway driving, and other factors.

An electric powertrain, consisting of the motor, controller, and transmission, is at least 6 times more efficient than an ICE powertrain, in combined city/highway driving (after accounting for regenerative braking). PEM fuel cells are about 45% efficient (after accounting for the energy consumption of auxiliaries); hence, the fuel cell/electric motor system would be almost 3 times as efficient as the ICE, before accounting for differences in vehicle weight and aerodynamic drag. The explanation of the calculation of the efficiency of the BPEV would follow the explanation for the FCEV, except that the efficiency of the battery and recharging system (up to 80%, not counting the energy required to heat a high-temperature battery) would be substitituted for the efficiency of the fuel cell. However, the BPEV also would be much heavier than the fuel cell vehicle.

Table 5.4. Summary of baseline cost results (in 1991$) from the analysis of ICEV systems.[a]

Item	Gasoline	MeOH	EtOH	CNG	Liquid H2	Hydride H2	Compressed H2
Fuel retail price, excluding taxes *($/gal. gasoline equiv.)*[b]	1.18	1.85	1.52	0.96	3.63	1.54	1.79
($/GJ$_{HHV}$)	8.95	14.0	11.5	7.30	27.53	11.68	13.6
Full retail price of vehicle, incl. taxes ($)[c]	17,976	17,912	17,903	19,483	20,230	24,208	24,550
Levelized annual maintenance cost ($/year)	396	392	392	370	392	392	392
Total lifecycle cost[d] (cents per km)	21.01	22.32	21.38	20.45	26.28	24.41	24.57
Breakeven gasoline price ($ per gallon)[e]	n.a.	2.04	1.64	1.26	3.69	2.91	2.97

(a) The cost estimates for the gasoline ICEV are detailed in DeLuchi (1992). The cost estimates for the alternative-fuel ICEVs are based primarily on data summarized in Sperling and DeLuchi (1992). n.a. = not applicable.

(b) Dollars per gasoline-equivalent gallon is calculated as: the $/million-Btu (HHV) price of the fuel to the motorist, ***excluding*** Federal, state, and local taxes ($0.31/gallon in the US), multiplied by 0.125 million Btu/gallon-gasoline. Note that this gasoline equivalence is defined in terms of energy delivered to the vehicle, and hence does not account for the efficiency with which the vehicle uses that energy. The estimate of the cost of gasoline assumes a world oil price of $26.40/bbl and reformulated gasoline (15 cents/gallon more than conventional gasoline). The gasoline- equivalent price for liquid H_2 accounts for boil-off losses (3% at each of three transfer points).

(c) Including sales tax, dealer costs, and shipping costs.

(d) Includes Federal, state, and local taxes of 0.78 cents per km for all vehicles.

(e) The retail price of gasoline (including Federal and state taxes in the US, which in 1991 amounted to $0.31/gallon) at which the life-cycle consumer cost-per-km of the alternative-fuel vehicle would equal that of the gasoline vehicle. To compare these figures with gasoline costs in other countries, subtract the $0.31/gallon US total tax assumed here and divide by 3.7854 to obtain $/liter pre-tax breakeven gasoline price.

Table 5.5. Summary of baseline cost results (in 1991$) from the analysis of EV systems.[a]

Item	Gasoline *(640 km range)*	BPEV *(160 km range)*	BPEV *(250 km range)*	BPEV *(400 km range)*	FCEV Methanol *(560 km range)*	FCEV Hydrogen *(250 km range)*	FCEV Hydrogen *(400 km range)*
Fuel retail price, excl. taxes *($/gal. gasoline equiv.)*[b]	1.18	2.20	2.20	2.20	1.85	1.79	1.79
($/GJ)	8.95	6 c/kWh	6 c/kWh	6 c/kWh	14.0	13.6	13.6
Full retail price of vehicle, incl. taxes ($)[c]	17,976	20,409	21,179	26,210	21,709	22,530	25,091
Levelized annual maintenance cost ($ per year)	396	336	336	336	389	376	376
Total lifecycle cost[d] (cents/km)	21.01	21.08	21.15	22.41	19.58	19.64	20.09
Breakeven gasoline price ($ per gallon)[e]	n.a.	1.52	1.55	2.07	0.89	0.92	1.11

(a) The results for the EVs and the gasoline ICEV are based on the analysis detailed by DeLuchi (1992). n.a. = not applicable.

(b) Dollars per gasoline-equivalent gallon is calculated as: the $/million-Btu (HHV) price of the fuel to the motorist, excluding Federal, state, and local taxes ($0.31/gallon in the US), multiplied by 0.125 million Btu/gallon-gasoline. Note that this gasoline equivalence is defined in terms of energy delivered to the vehicle, and hence does not account for the efficiency with which the vehicle uses that energy. The estimate of the cost of gasoline assumes a world oil price of $26.40/bbl and reformulated gasoline (15 cents/gallon more than conventional gasoline). For the BPEV, the gasoline-equivalent fuel price is calculated assuming that off-peak electricity costs 6 cents/kWh.

The methanol and hydrogen prices are from Tables 2.2.2 and 2.4.7, respectively, corresponding to production of these fuels from biomass.

(c) Including sales tax, dealer costs, and shipping costs.

(d) Includes Federal, state, and local taxes of 0.78 cents per km for all vehicles.

(e) The retail price of gasoline (including Federal and state taxes in the US, which in 1991 amounted to $0.31/gallon) at which the life-cycle consumer cost-per-km of the alternative-fuel vehicle would equal that of the gasoline vehicle. To compare these figures with gasoline costs in other countries, subtract the $0.31/gallon US total tax assumed here and divide by 3.7854 to obtain $/liter pre-tax breakeven gasoline price.

Table 5.6. Disaggregated lifecycle costs (cents per km, 1991$) for alternative ICEVs.[a]

Item	Gasoline	Methanol	Ethanol	CNG	Liquid H_2	Hydride H_2	Compressed H_2
Base vehicle	11.60	11.51	11.50	11.26	11.52	11.94	11.85
Fuel, excl. retail taxes	2.83	4.18	3.25	2.16	7.05	3.47	3.72
Fuel storage system	in vehicle	0.05	0.05	0.49	1.10	2.09	2.26
Insurance (function of VMT and vehicle value)[b]	2.31	2.31	2.31	2.35	2.47	2.56	2.56
Maintenance and repairs[c]	2.22	2.22	2.22	2.14	2.19	2.19	2.19
Oil	0.07	0.07	0.07	0.03	0.05	0.05	0.05
Replacement tires (function of VMT and vehicle weight)[d]	0.26	0.26	0.26	0.26	0.26	0.39	0.27
Parking and tolls (assumed same for all vehicles)	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Registration fee[e]	0.29	0.29	0.29	0.32	0.28	0.36	0.31
Inspection and maintenance fee[f]	0.29	0.29	0.29	0.30	0.22	0.22	0.22
Fuel taxes[g]	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Accessories (assumed same for all vehicles)	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Total lifecycle cost (cents per km)	21.01	22.32	21.38	20.45	26.28	24.41	24.57

(a) Calculated from the input data and formulae in DeLuchi (1992; updated). n. a. = not applicable. Vehicle characteristics and cost parameters as in Tables 5.2 and 5.4.

(b) The insurance cost per km is calculated as a function of the km driven per year, the value of the vehicle, the amount of the deductible, and the number of years that insurance against collision damage is carried. If an alternative-fuel ICEV is more expensive than the baseline gasoline ICEV, then it will have a higher insurance cost per km.

(c) Natural gas vehicles might have slightly lower maintenance and repair costs than have gasoline vehicles.

(d) The cost program of DeLuchi (1992) estimates the present value of all tire replacement costs, and then amortizes this present value on a monthly basis. Since the present value of replacement costs is a function of the number of replacements and the time of occurrence, it is necessary to estimate differences in tire replacement intervals. Although tire wear is a function of vehicle weight, road conditions, and driving patterns, we assume that the only difference in the rate of tire wear between alternative-fuel ICEVs and gasoline ICEVs would be due to vehicle weight. In the cost program, tire life for the alternative-fuel ICEV is estimated relative to tire life for the reference gasoline vehicle in proportion to the relative weight of the alternative ICEV. We have assumed that, near the end of the life of the vehicle, the driver will replace the tires only if he or she expects to get at least 20% of the tire life out of the new set before the vehicle is scrapped.

(e) We assume that the vehicle registration fee is a function of vehicle weight, as it is now in most states.

(f) We assume that the inspection of an ICEV covers safety and emissions. Since a hydrogen ICEV probably will have a simpler emission control system than will a gasoline vehicle, the part of the inspection concerned with emissions could be simplified, and the inspection fee be reduced accordingly.

(g) We assume that all vehicles are taxed so that total revenues per mile are the same, and equal to the revenues generated from the current national-average state-plus-Federal gasoline tax of $0.31/gallon.

Table 5.7. Disaggregated lifecycle costs (cents per km, 1991$) for alternative EVs.[a]

Item	Gasoline	BPEV *(160 km range)*	BPEV *(250 km range)*	BPEV *(400 km range)*	FCEV Methanol *(560 km range)*	FCEV Hydrogen *(250 km range)*	FCEV Hydrogen *(400 km range)*
Purchased electricity[b]	0	1.14	1.21	1.36	0	0	0
Base vehicle, excl. battery, fuel cell, and H_2 storage[c]	11.60	7.51	7.73	8.25	7.76	7.60	7.82
Battery and tray and auxiliaries	0	6.67	6.38	6.71	1.89	2.43	2.06
Fuel, excl. retail taxes[d]	2.83	0	0	0	2.03	1.59	1.67
Fuel storage system	in vehicle	0	0	0	0.02	0.58	1.00
Fuel cell system, including reformer, if any	0	0	0	0	1.86	1.51	1.53
Home recharging station	0	0.04	0.04	0.04	0	0	0
Insurance (function of VMT and vehicle value)[e]	2.31	2.73	2.78	2.91	2.79	2.77	2.84
Maintenance and repairs[f]	2.22	1.41	1.41	1.41	1.63	1.58	1.58
Oil	0.07	0	0	0	0	0	0
Replacement tires (function of VMT and vehicle weight)[g]	0.26	0.22	0.22	0.32	0.22	0.22	0.22
Parking and tolls (assumed same for all vehicles)	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Registration fee (function of vehicle weight)[h]	0.29	0.19	0.21	0.24	0.21	0.19	0.20
Inspection and maintenance fee[i]	0.29	0.03	0.03	0.03	0.03	0.03	0.03
Fuel taxes[j]	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Accessories (assumed same for all vehicles)	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Total lifecycle cost (cents per km)	21.01	21.08	21.15	22.41	19.58	19.64	20.09

(a) Calculated from the input data and formulae in DeLuchi (1992; updated). n. a. = not applicable. Vehicle characteristics and cost parameters as in Tables 5.3 and 5.5.

(b) In the base case, this includes electricity bought to heat the battery when the vehicle is idle, as well as electricity bought to recharge the battery. (In the base case, the peak-power battery in the FCEV is recharged from the outlet). In the scenario analyses, I consider a case in which hydrogen (via the fuel cell) is used to heat and recharge the battery in the FCEV (to the extent that regenerative braking does not). It is costly to use hydrogen for these purposes, but it does liberate the vehicle from plug-in recharging.

(c) The amortized initial cost of cost of the EVs (excluding the battery, the fuel cell, and the fuel storage system, which are treated separately), is less than the amortized initial cost of the ICEV, because the EVs have both a lower initial cost (excluding the components listed above) and a longer life.

(d) If fuel is used to heat the battery, the tax on that fuel is included.

(e) The insurance cost per km is calculated as a function of the km driven per year, the value of the vehicle, the amount of the deductible, and the number of years that insurance against collision damage is carried. Because the complete EVs (i.e., with the battery, fuel cell, and fuel storage system) of this analysis are more expensive than the baseline gasoline ICEV, and are assumed to be driven more km per year, they have a higher insurance cost per km.

(f) EVs are expected to have lower maintenance costs than ICEVs (DeLuchi, 1992).

(g) The cost program estimates the present value of all tire replacement costs, and then amortizes this present value on a monthly basis. Since the present value of replacement costs is a function of the number of replacements and the time of occurrence, it is necessary to estimate differences in tire replacement intervals for EVs and ICEVs. Although tire wear is a function of vehicle weight, road conditions, and driving patterns, I assume that the only difference in the rate of tire wear between EVs and ICEVs would be due to vehicle weight. In the cost program, tire life for the EV is estimated relative to tire life for the reference gasoline vehicle in proportion to the relative weight of the EV. I have assumed that, near the end of the life of the vehicle, the driver will replace the tires only if he or she expects to get at least 20% of the tire life out of the new set before the vehicle is scrapped. In the base case, it turns out that the lifecycle tire cost is higher for the FCEV than for the ICEV, even though the FCEV weighs less, because the last tire purchase for the FCEV falls much closer to the end of the FCEV's life than the does the last tire purchase for the ICE relative to the ICEV's life (recall that the FCEV has a longer life). Hence, there are fewer miles over which to amortize the last purchase, and so the cost per km is higher.

(h) We assume that the vehicle registration fee is a function of vehicle weight, as it is now in most states.

(i) We assume that the inspection of an ICEV covers safety and emissions. Since EVs do not have emission controls, the part of the inspection concerned with emissions could be eliminated, and the inspection fee be reduced accordingly.

(j) We assume that all vehicles are taxed so that total revenues per mile are the same, and equal to the revenues generated from the 1991 national-average state-plus-Federal gasoline tax of $0.31/gallon.

Table 5.8. Sensitivity of ICEV lifecycle costs and breakeven gasoline prices to important cost parameters.[a]

	Gas-oline	MeOH	EtOH	CNG	Liquid H2	Hydride H2	Comp. H2
Base case:							
cents per km	21.01	22.32	21.38	20.45	26.28	24.41	24.57
$ per gallon	n.a.	2.04	1.64	1.26	3.69	2.91	2.97
Fuel tanks cost 30% less per kg:							
cents per km	21.01	22.29	21.36	20.30	25.96	23.77	24.55
$ per gallon	n.a.	2.02	1.64	1.19	3.55	2.64	2.97
Fuel tanks cost 30% more per kg:							
cents per km	21.01	22.33	21.39	20.50	26.61	25.03	25.24
$ per gallon	n.a.	2.04	1.65	1.28	3.82	3.17	3.25
Fuel costs 50% more per GJ:							
cents per km	21.01	24.41	23.00	21.58	29.81	26.13	25.77
$ per gallon	n.a.	2.91	2.32	1.73	5.16	3.62	3.47
Real interest rate = 10%:[b]							
cents per km	23.19	24.48	23.55	23.00	28.80	27.46	27.70
$ per gallon	n.a.	2.03	1.64	1.41	3.83	3.27	3.37
All engines with same efficiency:[c]							
cents per km	21.01	22.87	21.72	20.82	27.89	25.74	25.87
$ per gallon	n.a.	2.24	1.79	1.41	4.36	3.46	3.52
tanks 30% ↑, fuel 50% ↑, same engine efficiencies:[d]							
cents per km	21.01	25.17	23.53	22.21	32.48	28.60	28.90
$ per gallon	n.a.	3.22	2.54	1.99	6.27	4.65	4.78

(a) In each scenario, only the parameters named change from their base-case values, except that any variables linked to the parameter(s) of interest change automatically (e.g., the cost of the fuel tank and the weight of the vehicle are linked to the thermal efficiency of the engine: if the efficiency of the engine is less, the fuel tank must be bigger, heavier, and more costly in order to provide a given range). The rows labeled "cents/km" show the lifecycle cost. The rows labeled "$/gallon" show the breakeven gasoline price, i.e. the retail price of gasoline (including $0.31/gallon federal, state, and local taxes) at which the full lifecycle cost per km of the gasoline vehicle would equal the full lifecycle cost of the alternative-fuel vehicle.

(b) In the base case, the real rate of interest earned by consumers is assumed equal to the long-run, average after-tax, real rate of interest paid on high-yield savings accounts -- about 3.6% per year. However, consumers often behave as if they have a much higher implicit discount rate when they purchase new cars.

(c) All engines are assumed to have the same GJ/km brake fuel efficiency.

(d) This case combines the three individually higher cases analyzed above.

Table 5.9. Sensitivity of EV lifecycle costs and breakeven gasoline prices to important cost parameters.[a]

	Gasoline *(640 km range)*	BPEV *(160 km range)*	BPEV *(250 km range)*	BPEV *(400 km range)*	FCEV Methanol *(560 km range)*	FCEV Hydrogen *(250 km range)*	FCEV Hydrogen *(400 km range)*
Base case cents per km	21.01	21.08	21.15	22.41	19.58	19.64	20.09
$ per gallon	n.a.	1.52	1.55	2.07	0.89	0.92	1.11
Batteries/tanks cost 30% ↓ per kg cents per km	21.01	18.89	19.02	20.04	18.89	18.57	18.96
$ per gallon	n.a.	0.61	0.66	1.09	0.61	0.47	0.64
Batteries/tanks cost 30% ↑ per kg cents per km	21.01	23.25	23.33	24.93	20.30	20.65	21.20
$ per gallon	n.a.	2.42	2.46	3.12	1.19	1.34	1.57
Fuel cell costs 50% ↓ cents per km	21.01	21.08	21.15	22.41	18.52	18.73	19.17
$ per gallon	n.a.	1.52	1.55	2.07	0.45	0.54	0.72
Fuel cell costs 50% ↑ cents per km	21.01	21.08	21.15	22.41	20.69	20.50	20.97
$ per gallon	n.a.	1.52	1.55	2.07	1.36	1.28	1.47
10% interest rate[b] cents per km	23.19	22.52	23.20	24.64	22.06	21.49	22.63
$ per gallon	n.a.	1.21	1.49	2.09	1.02	0.78	1.26
EVs are 20% less efficient cents per km	21.01	22.77	23.18	25.07	22.12	21.68	22.80
$ per gallon	n.a.	2.22	2.39	3.18	1.95	1.77	2.24
BPEV and FCEV fuels 50% ↑ per GJ: cents per km	21.01	21.62	21.75	23.12	20.54	20.33	20.84
$ per gallon	n.a.	1.74	1.80	2.37	1.29	1.21	1.42
EVs have 50% ↑ life[c] cents per km	21.01	20.02	20.10	21.34	18.29	18.37	18.81
$ per gallon	n.a.	1.08	1.11	1.63	0.36	0.39	0.57
EVs life = ICEV life[c] cents per km	21.01	22.79	22.92	24.22	21.78	21.69	22.20
$ per gallon	n.a.	2.23	2.29	2.83	1.81	1.77	1.99

(a) In each scenario, only the parameters named change from their base-case values, except that any variables linked to the parameter(s) of interest change automatically (e.g., the cost of the fuel tank and the weight of the vehicle are linked to the thermal efficiency of the engine: if the efficiency of the engine is less, the fuel tank must be bigger, heavier, and more costly in order to provide a given range). The rows labeled "cents/km" show the lifecycle cost. The rows labeled "$/gallon" show the breakeven gasoline price, i.e. the retail price of gasoline (including $0.31/gallon federal, state, and local taxes) at which the full lifecycle cost per km of the gasoline vehicle would equal the full lifecycle cost of the alternative-fuel vehicle.

(b) In the base case, the real rate of interest earned by consumers is assumed equal to the long-run, average after-tax, real rate of interest paid on high-yield savings accounts -- about 3.6% per year. However, consumers often behave as if they have a much higher implicit discount rate when they purchase new cars, so a 10% real interest rate is considered here.

(c) In the base case, we assume that an EV is driven 25% more miles over its lifetime than is an ICEV (see DeLuchi, 1992 for rationale). This assumption is important because it reduces the amortized initial cost of the vehicle. In these two sensitivity cases, we test a more favorable and a less favorable assumption.

Table 5.10. Percentage change in grams per km emissions of criteria pollutants from alternative-fuel light-duty vehicles relative to comparable gasoline vehicles, circa 2000.[a]

Fuel/Vehicle	NMOG *(evap.)*	Criteria Pollutants				
		NMOG *(tailpipe)*	CO[b]	NO_x[b]	SO_x[c]	PM
ICEVs						
flex.fuel methanol (M85)	-58 to -67	-50 to -58	0 to -10	0 to -10	up to -100	less
dedicated methanol (M100)	-81 to -92	-66 to -77	-10 to -30	0 to -20	up to -100	less
dual fuel CNG	-100	-87 to -93	-20 to -40	0	up to -100	less
dedicated CNG	-100	-89 to -95	-30 to -50	0 to -10	up to -100	less
flexible fuel ethanol (E85)	-36 to -49	-23 to -36	0 to -10	0 to -10	up to -100	less
dedicated hydrogen[d]	-100	-?? to -99	-?? to -99	0 to ??	up to -100	to -100
EVs						
BPEV/US power mix[e]	-100	-94 to -99	-95 to -99	-60 to -80	more	more
BPEV/solar power	-100	-100	-100	-100	-100	-100
FCEV/methanol[f]	-?? to -99	-100	-?? to -99	-?? to -99	up to -100	-100
FCEV/hydrogen		-100	-100	-100	-100	-100

(a) The percentage changes in emissions are based on reported gram/kilometer emissions from gasoline and alternative-fuel vehicles (AFVs) driven on a dynamometer according to the standard drive cycle for emissions testing (the Federal Test Procedure--FTP). However, it is now recognized that the FTP does not represent how people drive in the real world. People accelerate harder, stop faster, rev their engines more, and do other things differently than in the FTP. These differences cause emissions from gasoline ICEVs driven in the real world to be considerably higher than emissions from gasoline ICEVs driven on a dynamomter according to the FTP. It is possible that these differences also could *differentially* affect emissions from AFVs; that is, the percentage differences in emissions between real-world AFVs and real-world gasoline ICEVs might not be the same as the percentage differences between AFVs and gasoline ICEVs tested according to the FTP. Unfortunately, there are no data on real-world emissions of AFVs compared to real-world emissions of gasoline ICEVs. As a result, analysts by default have had to assume that the FTP-derived percentages represent the unknown real-world percentages.

The range of emission changes for the national BPEVs and for all of the ICEVs except the hydrogen ICEV, and for all pollutants except SOx and PM, are from Wang et al. (1993), who compiled and analyzed a large data base on emissions from alternative fuel vehicles.

FFV M85 = flexible-fuel vehicle (which can use any mixture of methanol, ethanol, and gasoline) running on 85% methanol and 15% gasoline; dedicated M100 = single-fuel vehicle optimized for methanol, running on 100% methanol; FFV E85 = flexible-fuel vehicle (which can use any mixture of ethanol, methanol, and gasoline) running on 85% ethanol and 15% gasoline; Dual-fuel CNG = dual-fuel vehicle with a both a gasoline tank and a CNG tank on board, running on compressed natural gas (CNG); dedicated CNG = single-fuel vehicle optimized for compressed natural gas (CNG); dedicated hydrogen = single-fuel vehicle optimized to run on hydrogen; national BPEV = battery-powered electric vehicle using national-average mix of power plants; solar BPEV = battery-powered electric vehicle using electricity generated from solar power plants; methanol FCEV = fuel-cell electric vehicle using methanol and a reformer; hydrogen FCEV = fuel-cell vehicle storing hydrogen on board.

NMOG evap. = evaporative emissions of non-methane organic gases from the fuel tank, fuel lines, and engine (methane is excluded from this measure because it is relatively unreactive and contributes little to the formation of ozone); NMOG tailpipe = exhaust emissions of non-methane organic gases; CO = carbon monoxide; NOx = nitrogen oxides; SOx = sulfur oxides; PM = particulate matter (from the exhaust, not from the tires or roadway).

(b) CO emissions depend very strongly on the ratio of air to fuel. Generally, the higher, or "leaner," this ratio -- that is, the greater the amount of oxygen -- the lower the CO emissions. All alternative-fuel engines can burn leaner mixtures than gasoline engines can, and therefore have the potential to reduce CO emissions considerably. However, the new "Tier-I" NOx standard of the Clean Air Act of 1990 (0.25 g/km, or 0.4 g/mi) might preclude the use of lean-burn engines, except perhaps in hydrogen vehicles (see note below). Certainly, the Tier-II NOx standard of 0.2 g/mi is very likely to preclude the use of lean burn: the National Academy of Sciences (1992) has concluded that a NOx standard of 0.2 g/mi would preclude the use of lean-burn for all except the lightest gasoline-powered cars and trucks. Thus, alternative-fuel vehicles are likely to provide only modest reductions in emissions of CO.

(c) SO_x emissions are proportional to the sulfur content of the fuel. Methanol, ethanol, CNG, and hydrogen contain little or no sulfur.

(d) Hydrogen ICEVs emit a small amount of CO and NMOCs due to combustion of the lubricating oil, and may emit a very small amount of particulates. NO_x emissions are difficult to characterize, because hydrogen vehicles built and tested to date have shown a wide range of NO_x emissions (Sperling and DeLuchi, 1993). A hydrogen engine can be designed to operate at a very high air-to-fuel ratio (i.e, very "lean"), and as long as such an engine actually operates very lean, it has very low NO_x emissions, because of the reduced temperature due to the excess air. But if the air/fuel mixture is enriched to stoichiometric, so that the engine operates at full power then engine-out NO_x emissions increase substantially. Overall, such a scheme (lean-burn at part load, stoichiometric at full load and no NO_x reduction catalyst) probably would result in NO_x emissions comparable to those from a gasoline vehicle equipped with a 3-way catalytic converter. (For example, see the FTP test results in Withalm and Gelse, 1986). To achieve a considerable reduction in NOx emissions relative to emissions from a well-controlled gasoline vehicle, the hydrogen vehicle either would have to be restricted to very lean operation (meaning that the full power of the engine would never be exploited), or else equipped with a NO_x reduction catalyst for full-load operation.

(e) Recently, the US DOE (1993) analyzed the impact of EVs in 101 cities in 6 regions of the U.S. and found that EVs would nearly eliminate VOC and CO emissions, greatly reduce TSP emissions (e.g., by about 80% in most cases), decrease emissions of NO_x and CO_2 (except in the two least favorable cases for EVs), and greatly increase SO_x emissions. The report compared ICEV tailpipe with EV powerplant emissions; it did not include petroleum-refinery emissions.

(f) A methanol FCEV would have no tailpipe emissions of NMOCs, but the storage, distribution, and transfer of methanol would produce a small amount of evaporative emissions of methanol (DeLuchi, 1991; DeLuchi et al., 1992). The methanol reformer, which would convert methanol into hydrogen and CO and then shift the CO to CO_2, would emit small amounts of CO and NO_x. Data and statements in Patil (1992a), Zegers (1990), Patil et al. (1990), Kevala (1990), and Werbos (1987) indicate that these emissions would be on the order of 1% or less of the emissions from a gasoline ICEV. For example, Patil (1992a) and Huff (1992) report 0.002 g/mi HC, less than 2 ppm CO, and 0.001 g/mi NO_x. However, most estimates of emissions from methanol reformers appear to apply to steady-state operation. For example, the data or statements in Kevala (1990), Patil et al. (1990), Patil (1992a) and Huff (1992) apparently refer to the benchtop system being developed for the Georgetown Bus, and according to Christ (1993), that system was tested at full power. Emissions from transient operation, warm-up, or malfunctioning could be substantially higher. The PEM fuel cell itself would not produce any NO_x, because of its extremely low operating temperature.

Table 5.11. Percentage change in grams per km emissions of toxic air pollutants from alternative-fuel light-duty vehicles relative to comparable gasoline vehicles, circa 2000.[a]

Fuel/Vehicle		Toxic Air Pollutants			
	benzene *(evap.)*	benzene *(tailpipe)*	formaldehyde	acetaldehyde	1,3-butadiene
ICEVs					
flex.fuel methanol (M85)[b]	+152 to +215	-83 to -86	+245 to +314	-70 to -75	-77 to -81
dedicated meth. (M100)[b]	- 53 to +18	-87 to -92	+107 to +211	-78 to -85	-83 to -89
dual fuel CNG	-100	-98 to -99	+22 to +114	-54 to -74	-96 to -98
dedicated CNG	-100	-98 to -99	-8 to +83	-61 to -80	-97 to -98
flex. fuel ethanol (E85)[c]	+152 to +215	-91 to -93	+27 to +53	+740 to +909	-77 to -81
dedicated hydrogen[d]	-100	?? to -99	?? to -99	?? to -99	?? to -99
EVs					
BPEV/US power mix	-100	-100	-87 to -97	-100	-100
BPEV/solar power	-100	-100	-100	-100	-100
FCEV/methanol[e]	up to -100	up to -100	up to -100	up to -100	up to -100
FCEV/hydrogen	-100	-100	-100	-100	-100

(a) FFV M85 = flexible-fuel vehicle (which can use any mixture of methanol, ethanol, and gasoline) running on 85% methanol and 15% gasoline; dedicated M100 = single-fuel vehicle optimized for methanol, running on 100% methanol; FFV E85 = flexible-fuel vehicle (which can use any mixture of ethanol, methanol, and gasoline) running on 85% ethanol and 15% gasoline; Dual-fuel CNG = dual-fuel vehicle with a both a gasoline tank and a CNG tank on board, running on compressed natural gas (CNG); dedicated CNG = single-fuel vehicle optimized for compressed natural gas (CNG); dedicated hydrogen = single-fuel vehicle optimized to run on hydrogen; national BPEV = battery-powered electric vehicle using national-average mix of power plants; solar BPEV = battery-powered electric vehicle using electricity generated from solar power plants; methanol FCEV = fuel-cell electric vehicle using methanol and a reformer; hydrogen FCEV = fuel-cell vehicle storing hydrogen on board.

(b) Methanol vehicles have high tailpipe emissions of formaldehyde because formaldehyde is the first oxidation product of methanol. Note, though, that the concentration of formaldehyde in the atmosphere is determined not only by direct emissions of formaldehyde, but also by emissions of formaldehyde "precursors" that through atmospheric chemistry react to form formaldehyde. Methanol vehicles produce relatively small amounts of these formaldehyde precursors. Thus, even though methanol vehicles directly emit more formaldehyde than do gasoline vehicles, they might not cause a large increase in the atmospheric concentration of formaldehyde, because they emit less of the compounds that are transformed into formaldehyde.

(c) Ethanol vehicles have high tailpipe emissions of acetaldehyde because acetaldehyde is the first oxidation product of ethanol. However, even though ethanol vehicles directly emit more acetaldehyde than do gasoline vehicles, they might not cause a large increase in the atmospheric concentration of acetaldehyde, because they might emit less of the compounds that are transformed into acetaldehyde. (See note above regarding methanol and formaldehyde. Whereas it has been shown that methanol vehicles produce less formaldehyde precursors than do gasoline vehicles, we are not aware that it has not been shown that ethanol vehicles produce less acetaldehyde precursors than do gasoline vehicles.)

(d) The combustion of lubricating oil in a hydrogen ICEV might produce small amounts of toxic air pollutants.

(e) Very small amounts of toxic air pollutants might be emitted from the evaporation of methanol or from the methanol reformer.

Table 5.12. Percentage change in fuel-cycle, CO_2-equivalent emissions of greenhouse gases per km of travel relative to reformulated gasoline in ICEVs, circa 2000.

Feedstock/Fuel	Fuel-cycle CO_2-equivalent emissions (grams/km)[a]	Change in CO_2-equivalent emissions (%)[b]
Internal Combustion Engine Vehicles (ICEVs)		
Coal/methanol[c]	461	+58
Coal/compressed H_2[d]	443	+52
Corn/ethanol (E85)[e]	323	+11
Corn/dedicated ethanol (E100)[f]	310	+6
Natural gas/dedicated methanol (M100)[g]	273	-6
Natural gas/compressed H_2[h]	216	-25
Natural gas/dedicated CNG[i]	215	-26
Biomass/compressed H_2[j]	73	-75
Solar/compressed H_2[k]	52	-82
Biomass/methanol[l]	50	-83
Biomass/ethanol (E85)[e]	35	-88
Biomass/dedicated ethanol (E100)[m]	-27	-109
Battery Powered Electric Vehicles (BPEVs)		
Average US power generating mix[n]	249	-14
Solar power[o]	0	-100
Fuel Cell Electric Vehicles (FCEVs)		
Coal/methanol[c]	211	-27
Coal/compressed H_2[d]	183	-37
Natural gas/methanol[g]	122	-58
Natural gas/compressed H_2[h]	89	-69
Biomass/compressed H_2[j]	29	-90
Solar/compressed H_2[k]	20	-93
Biomass/methanol[l]	17	-94
All solar/compressed H_2[p]	0	-100
Petroleum/reformulated gasoline in an ICEV[q]	291	n.a.

(a) This is the sum of emissions of CO_2,CH_4, N_2O, CO, NO_2, and NMOCs from the entire fuel-production and use cycle (excluding the manufacture of vehicles and equipment), per km of travel, and are relative to the total g/km emissions for the gasoline vehicle shown at the bottom. All the results shown are from unpublished runs of an updated version of the greenhouse-gas emissions model documented in DeLuchi (1991). In these runs all the vehicles were specified to have the same total energy consumption as in the cost and performance analysis presented in this report. Emissions of gases other than CO_2 have been converted to an "equivalent" amount of CO_2, by multiplying mass emissions of each gas by the following "global warming potentials": CH_4, 21; N_2O, 270; CO, 2; NO_2, 4; NMOCs, 5. The resultant CO_2 equivalents of these gases have been added to actual CO_2 emissions, to produce an aggregate measure of greenhouse-gas emissions.

(b) The percentage changes are with respect to the emissions of the baseline reformulated-gasoline vehicle emissions shown at the bottom of the table.

(c) The energy efficiency of converting coal to methanol is assumed to be 0.618 (Katofsky, 1993).

(d) The energy efficiency of converting coal to hydrogen is assumed to be 0.63 (Katofsky, 1993).

(e) Assumes use of 85% ethanol mixed with 15% gasoline in a "flexible-fuel" vehicle that can burn any mixture of alcohol and gasoline. We assume that the E85 flexible-fuel vehicle is 5% more efficient than the comparable dedicated gasoline/ICEV. The dedicated ethanol/ICEV (E100) is assumed to be 12% more efficient than the gasoline/ICEV because it can be optimized to run on ethanol, whereas the flexible-fuel vehicle cannot.

(f) Assuming a relatively high productivity of 440 liters of ethanol produced per metric tonne of corn. Coal is the process fuel at the corn-to-ethanol plant, and an emissions credit is given for the production of byproducts at the plant.

(g) The energy efficiency of converting natural gas to methanol is assumed to be 0.675 (Katofsky, 1993).

(h) Hydrogen is made at the refueling site from natural gas delivered by pipeline, and then compressed to 8400 psi for delivery to vehicles. The compressor uses electricity generated from the projected national mix of power sources in the U.S. in the year 2000 (EIA, 1991). Steam-reforming of natural gas to produce hydrogen is assumed to be 84.8% efficient (Katofsky, 1993).

(i) Natural gas is compressed to 3000 psi for delivery to vehicles with high-pressure tanks.

(j) Hydrogen is made in centralized biomass-gasification plants with an energy efficiency of 0.686 (Katofsky, 1993), then compressed for pipeline transport using bio-electricity generated at the biomass plant. At the station hydrogen is compressed to 8400 psi for delivery to vehicles by a compressor using the projected year-2000 US mix of power sources (EIA, 1991).

(k) Hydrogen is produced from water using solar power, delivered by pipeline to the service station, and then compressed to 8400 psi for delivery to high-pressure tanks on board vehicles. The hydrogen compressor at the refueling station runs off electricity generated from the projected national mix of power sources in the US in the year 2000 (EIA, 1991).

(l) The energy efficiency of converting biomass to methanol is assumed to be 0.628 (Katofsky, 1993).

(m) Stone and Lynd (1993) show a "state-of-the-art" energy-flow diagram for ethanol production from biomass in which one unit of biomass energy produces 0.4 units of ethanol energy and 0.032 units of electrical energy for sale, and a "futuristic" diagram in which one unit of biomass energy produces 0.52 units of ethanol energy and 0.068 units of electrical energy for sale. Thus, for every energy unit of ethanol produced by the "state-of-the-art" process, 2.5 units of biomass are required as input, and 0.08 units of electricity are coproduced. For every energy unit of ethanol produced by the "futuristic" process, 1.9 units of biomass are required as input, and 0.12 units of electricity are coproduced. Our calculations assume the energy balance of the "futuristic" process. The emissions displaced by the sale of the excess electricity are counted as a credit against actual emissions from the biomass-to-ethanol fuel-cycle. The emissions credit from the sale of the excess electricity exceeds actual emissions from the rest of the fuel-cycle (which includes an emissions credit for photosynthesis); hence the reduction in emissions with respect to reformulated gasoline is greater than 100%.

(n) BPEVs are recharged at night using the extra electricity generated specifically to meet the EV demand (see DeLuchi, 1991 for details). The BPEV has a 150-mile range.

(o) This BPEV is recharged from 100% solar power.

(p) The hydrogen compressor at the station runs on solar power.

(q) Projected greenhouse gas emissions for a year-2000 light-duty vehicle operating on reformulated gasoline (DeLuchi, 1991).

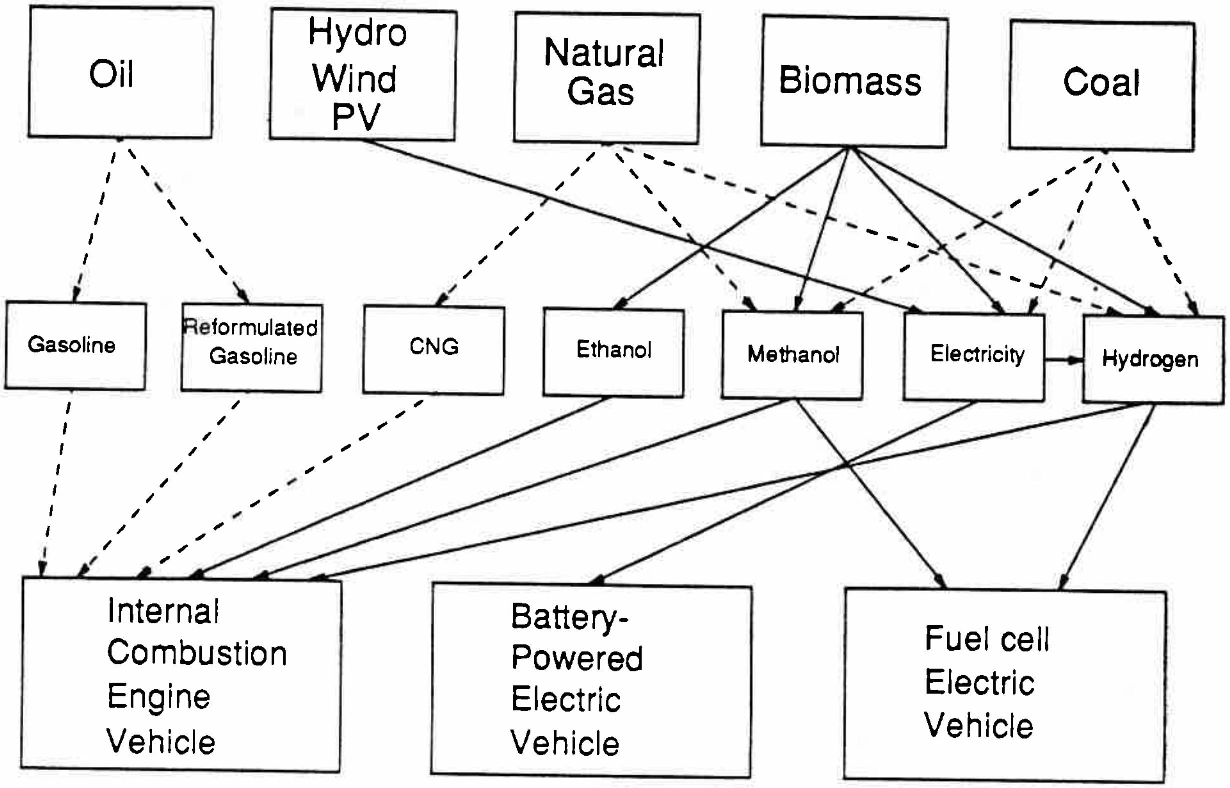


Figure 1. Alternatives for production and use of transportation fuels. Primary energy sources are represented in the top row, with the intermediate transportation fuel in the second row and the vehicle technology in the third row. The diagram does not represent all possibilities, but does include all that are considered in this report.

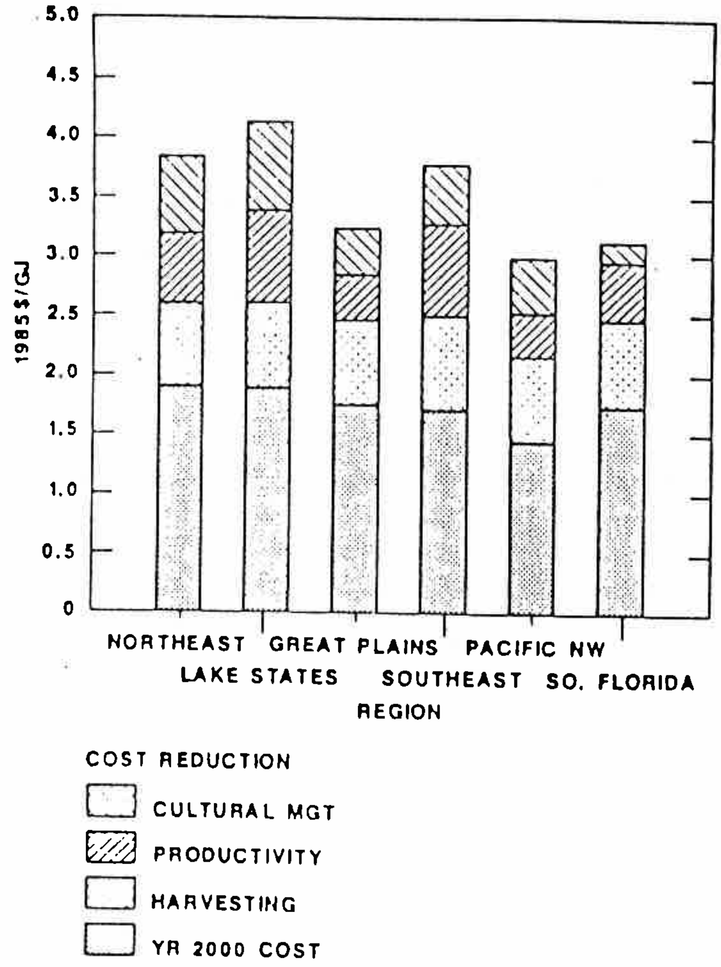


Figure 2.1.1. Delivered cost of biomass from short-rotation intensive-culture woody biomass energy plantations in different regions of the US, as estimated by researchers at the Oak Ridge National Laboratory (Perlack and Ranney, 1987). The full height of each bar is the estimated costs based on present understanding and technology. The lowest-most segment of each bar is the cost projected (under optimistic assumptions) that will be achieved by about the year 2000. To estimate costs in 1991 dollars, multiply the 1985$ costs shown in this figure by 1.25 (US GNP deflator from 1985 to 1991).

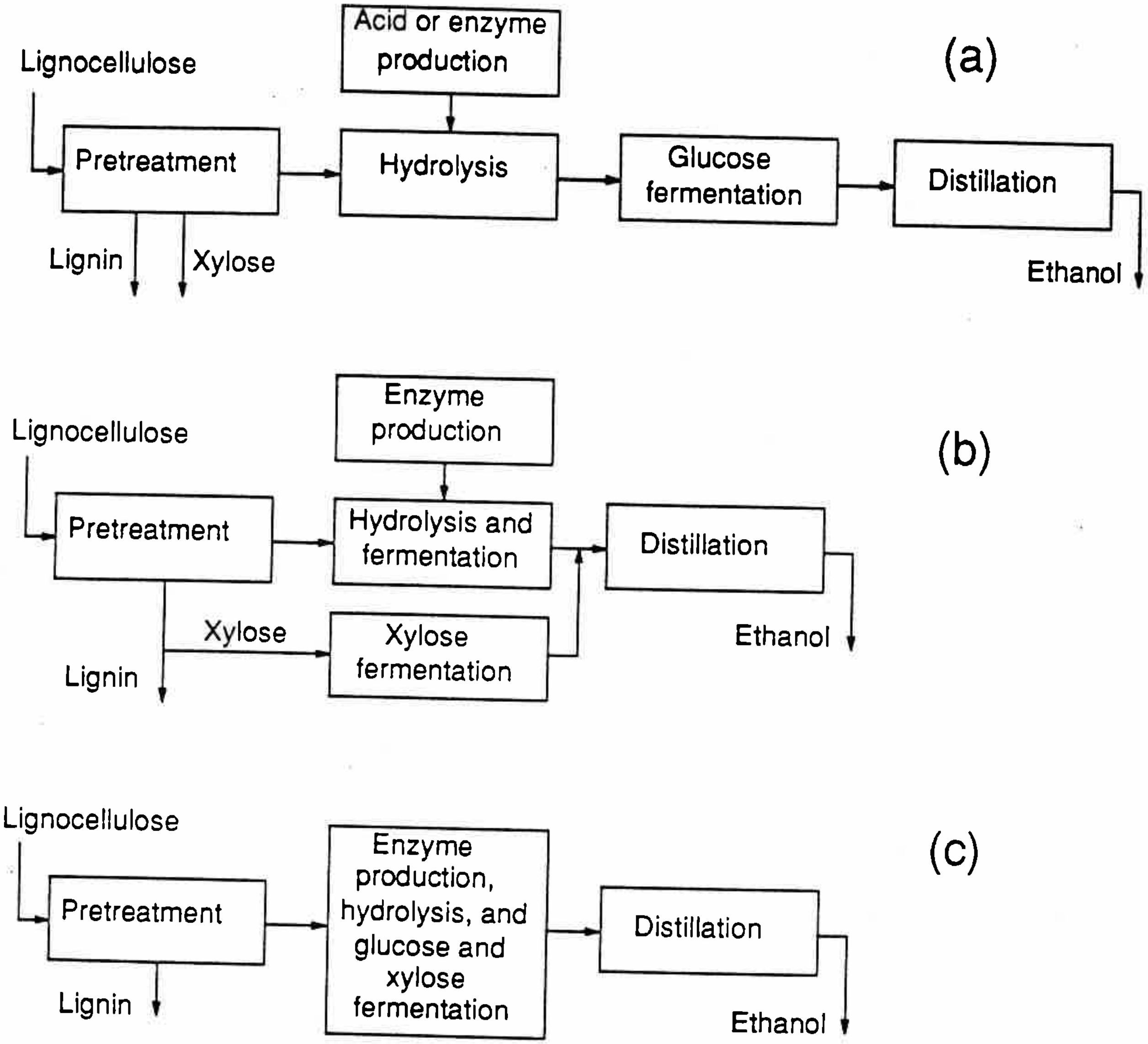


Figure 2.2.1. Alternative production routes for ethanol from lignocellulosic biomass: (a) separate hydrolysis and fermentation (SSF), using either acid or enzyme-catalyzed hydrolysis; (b) simultaneous saccharification and fermentation (SSF), with additional xylose fermentation; (c) direct microbial conversion (DMC).

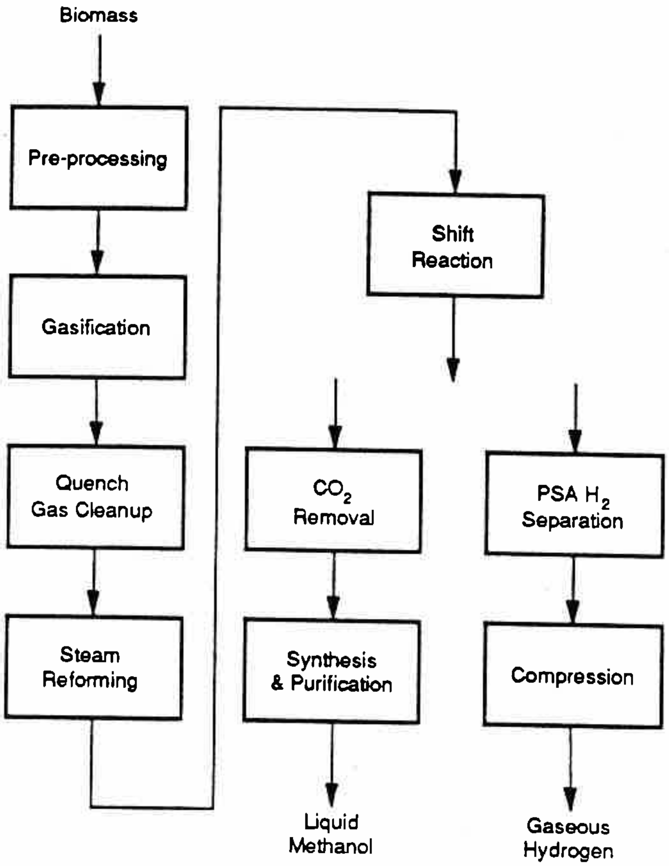
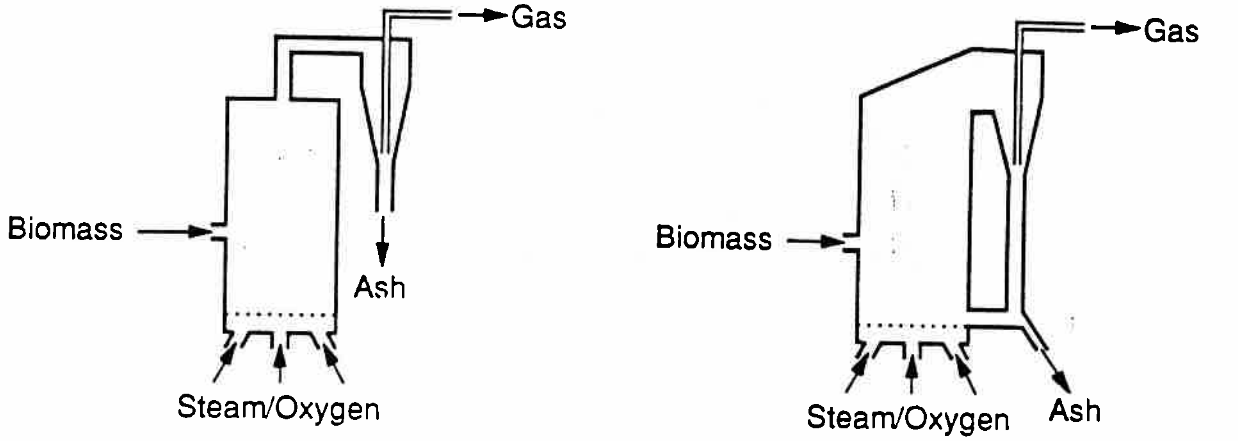
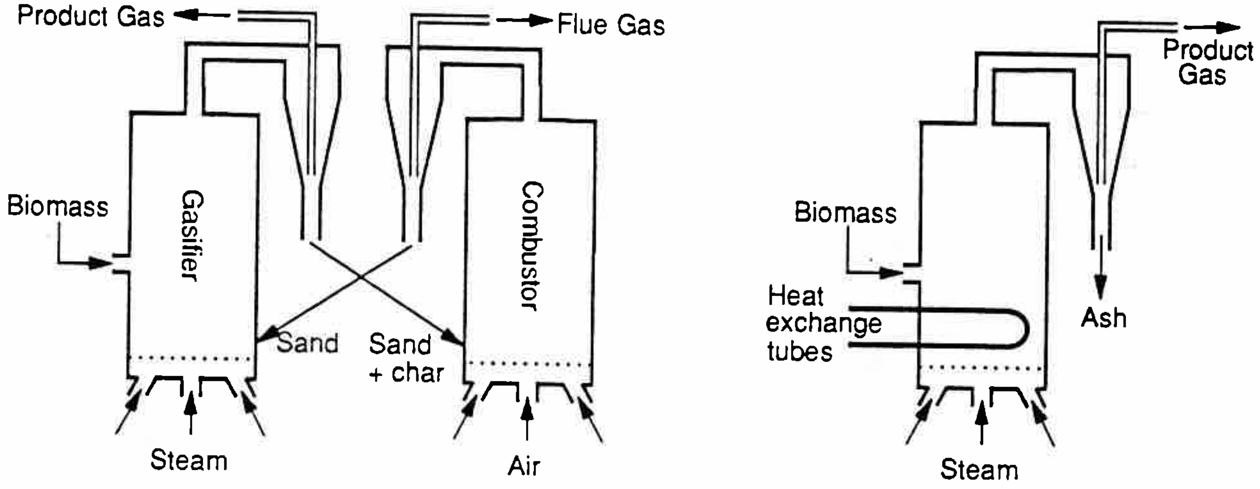


Figure 2.2.3. Thermochemical processing steps in the production of methanol or hydrogen from biomass (Katofsky, 1993). PSA stands for pressure swing adsorption.

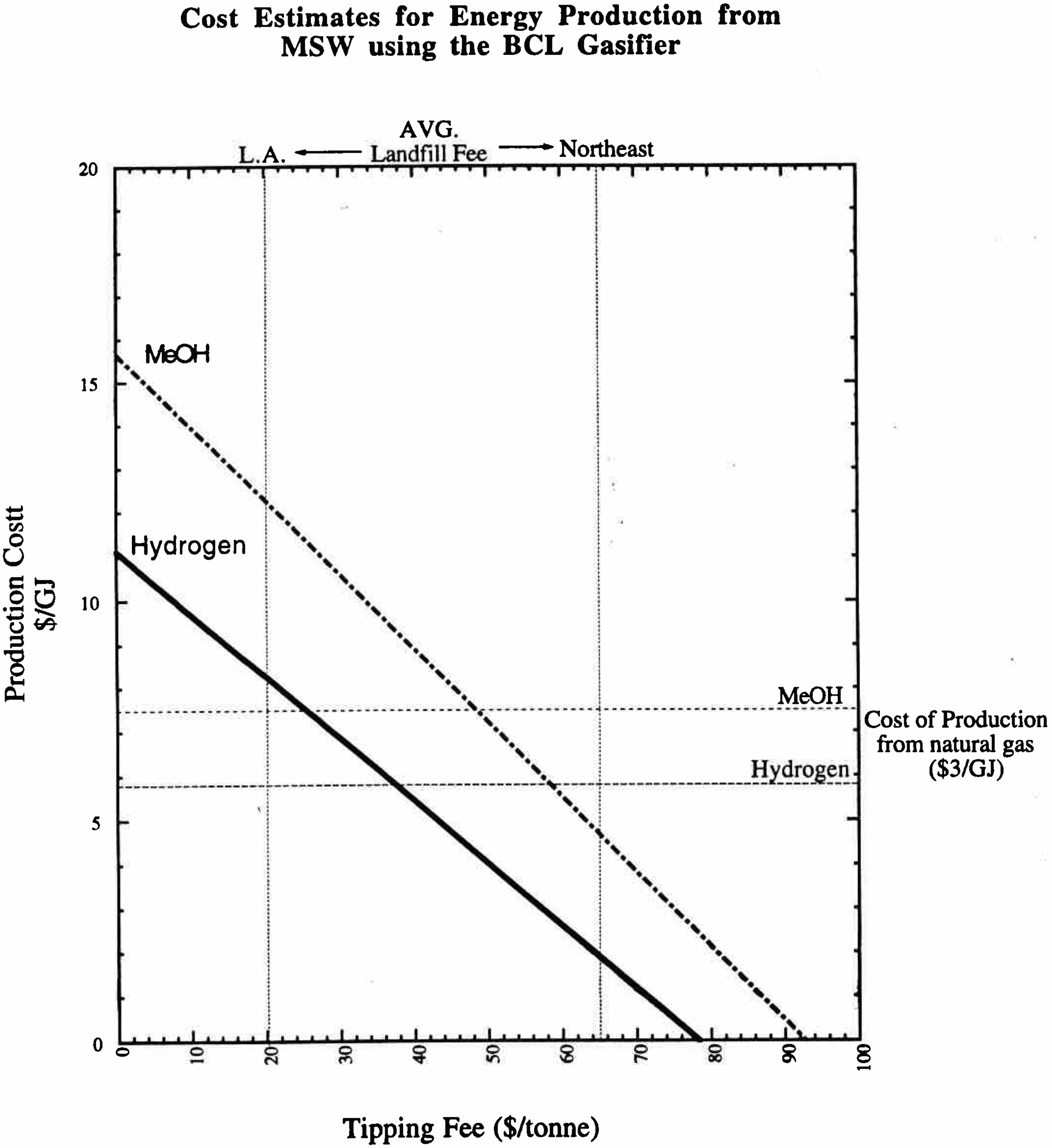


(a) bubbling fluidized-bed gasifier (b) circulating fluidized-bed gasifier



(c) indirectly heated gasifier (BCL) (d) indirectly-heated gasifier (MTCI)

Figure. 2.2.4 Alternative designs for thermochemical gasification of biomass: (a) bubbling fluidized-bed and (b) circulating fluidized-bed designs (Williams and Larson, 1993) common for large-scale applications; and indirectly-heated biomass gasifier designs under development in the US (Katofsky, 1993). In the twin fluidized-bed reactor design (c), pyrolytic gasification is driven by heat from circulating sand. The sand and char are separated from the product gas and sent to a char combustor where the sand is heated again. An alternative design (d), uses an in-bed heat exchanger to provide the heat for pyrolysis and char gasification. In both designs steam acts as a fluidizing gas.



Cost Estimates for Energy Production from MSW using the BCL Gasifier

Figure 2.2.5. Preliminary estimates (based on work in progress at the CEES) of the cost of producing liquid methanol and compressed hydrogen gas from municipal solid waste feedstocks. Costs fall with increasing tipping fees (the fees paid to the conversion facility for the right to leave MSW with the facility.) For comparison, the estimated cost of delivering methanol and hydrogen from natural gas costing $3/GJ is indicated, as are average tipping fees paid to landfills in the Los Angeles area and the Northeastern region of the US. (A capital charge rate of 15.1%/year is assumed in all costs.)

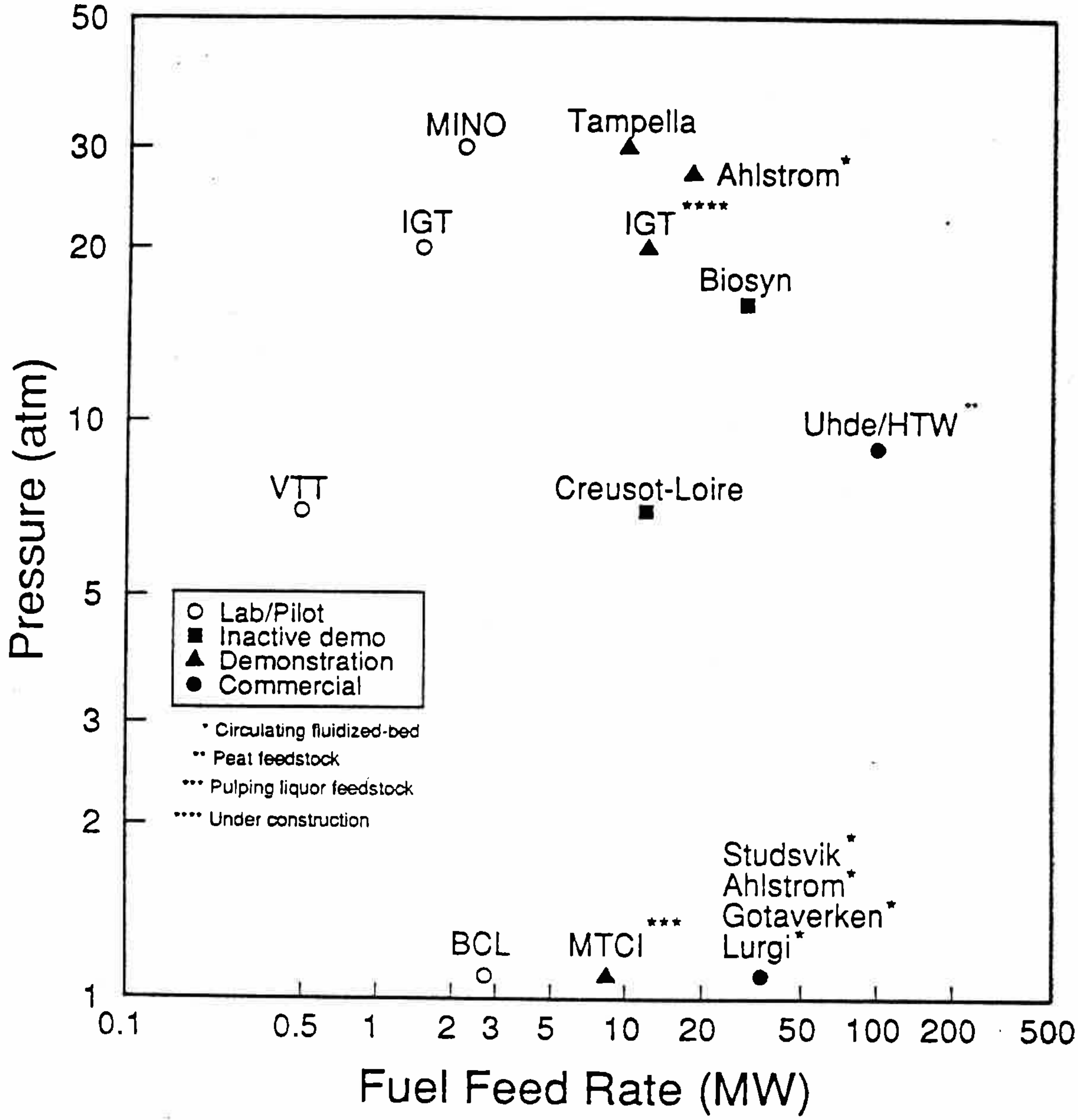


Figure 2.2.6. Status of biomass gasifier technologies worldwide. Only in the case of the commercial circulating fluidized-bed gasifiers has more than a single unit been built. MINO is the technology developed by the Studsvik company in Sweden. IGT is the Institute of Gas Technology. Tampella and Ahlstrom are Finnish companies. VTT is a the Technical Research Center of Finland. Cruesot-Loire was a French company. Biosyn was a Canadian company. Uhde is a German company with a license to the HTW (High Temperature Winkler) gasification technology. Lurgi is another German company. Gotaverken is a Swedish company. BCL is the Battelle Columbus Laboratory in Ohio, and MTCI is a US company based in Columbia, Maryland.

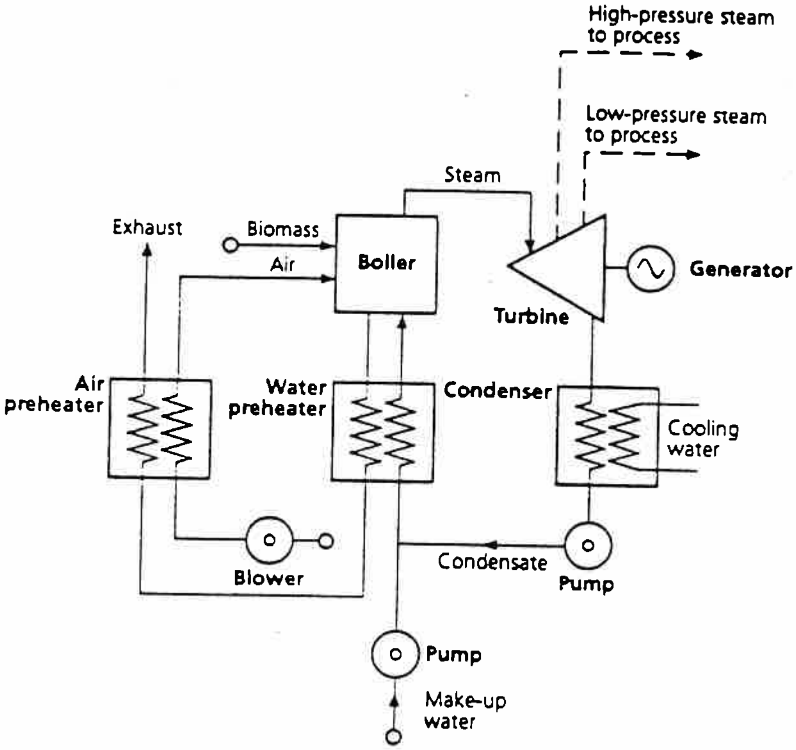


Figure 2.3.1. A biomass-fired steam-turbine system. In the production of power only, all steam is expanded through the turbine to sub-atmospheric pressure, condensed, and recycled to the boiler. In a cogeneration application (combined heat and electricity production), some steam would be extracted from the turbine (dashed lines) for heating use before it is eventually returned to the boiler. In this case, the steam turbine is a condensing-extraction turbine. In a cogeneration plant using a back-pressure steam turbine (not shown), all steam is expanded through the turbine, but exits above atmospheric pressure. Instead of passing to a condenser, the steam is used for heating, e.g. in an industrial process, where it condenses and is returned to the boiler.

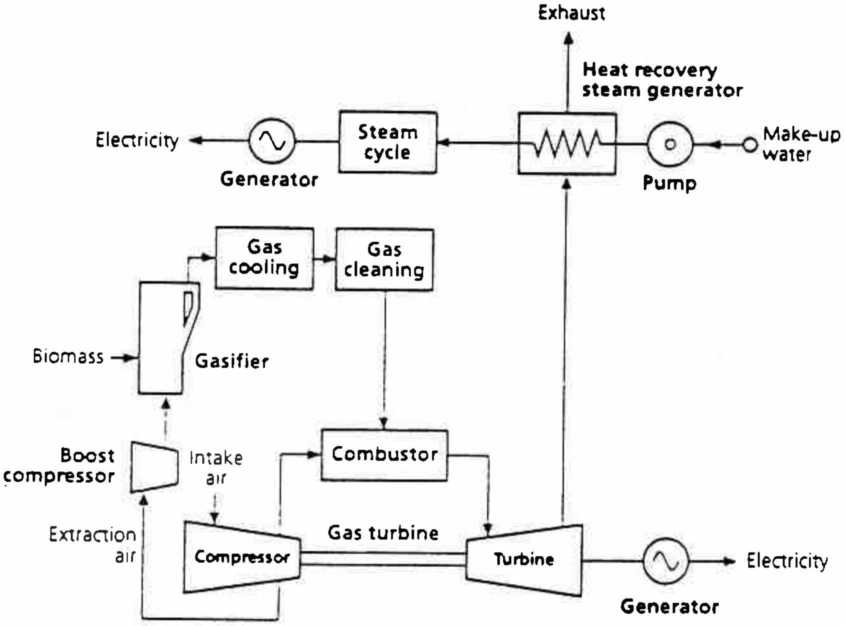


Figure 2.3.2. A biomass-gasifier/gas-turbine combined cycle. Dried biomass is gasified in a pressurized circulating fluidized-bed reactor in air extracted from the gas turbine compressor. The product gas leaves the gasifier at about 900°C. It is cooled to 350-400°C (primarily to condense out alkali vapors), passed through a particulate filter, and then burned in a gas turbine combustor. The hot exhaust of the turbine raises steam in a heat recovery steam generator, and the steam is used in a condensing steam turbine like the one described in Fig. 2.3.1.

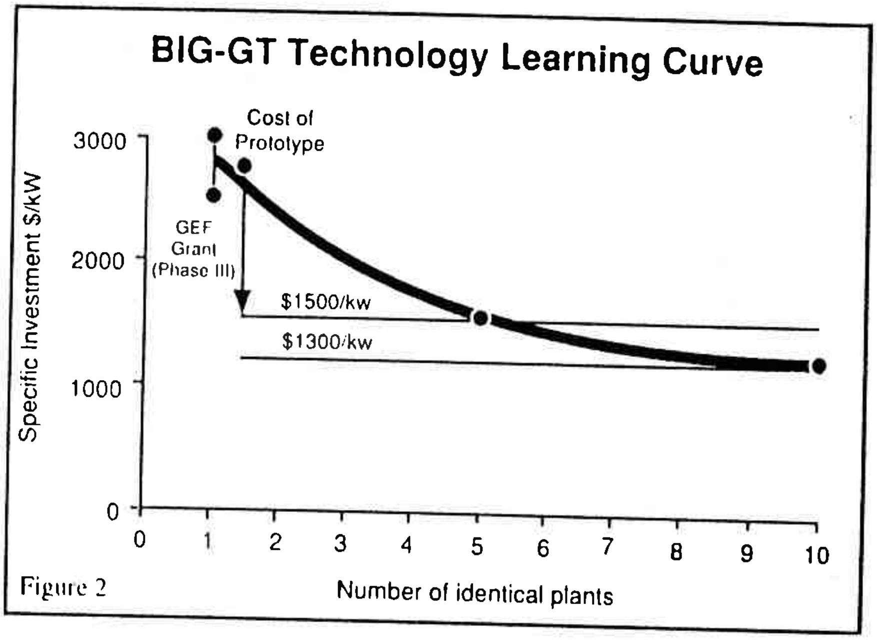


Figure 2

Figure 2.3.3. Cost learning curve for biomass-gasifier/gas-turbine combined cycle technology suggested by analysts at the Shell International Petroleum Company (Elliot and Booth, 1993).

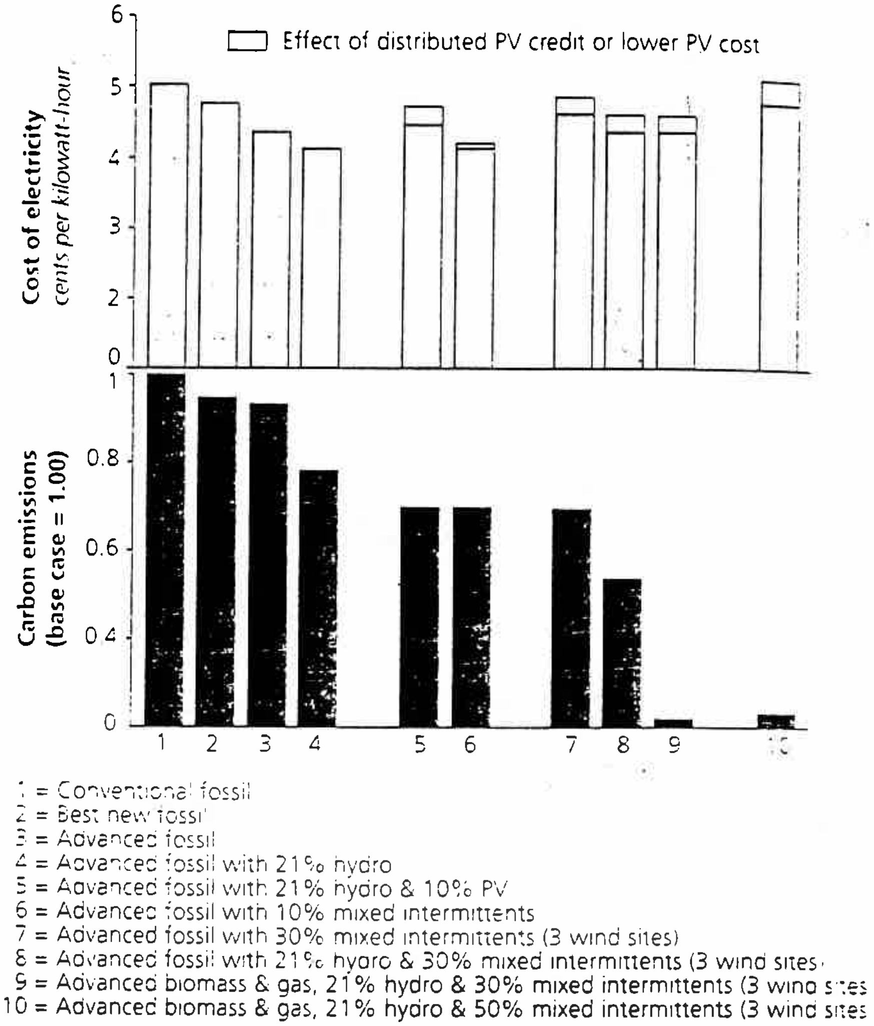


Figure 2.3.4. This figure (from Kelly and Weinberg, 1993) shows the average cost of meeting the annual electricity demands of the Pacific Gas and Electric Utility in northern California in 1989 (top) and the CO_2 emissions as a fraction of the emissions from the reference case (bottom) for 10 different portfolios of generating equipment. The upper segment of bars 4 through 10 represents the magnitude of the transmission and distribution savings that can be realized by distributed photovoltaic systems. In this analysis, this distributed credit was valued at $80 per kilowatt-year for the installed photovoltaic capacity and includes credits for transmission and distribution capital costs, distribution losses, and 10 percent of the reliability credit computed for the one real case in which a detailed reliability study has been conducted. The upper bar segment can also represent the effect on overall electricity cost of lowering the cost of installed photovoltaic capacity from $1800 per kW to $900 per kW if no distributed credit is applied.

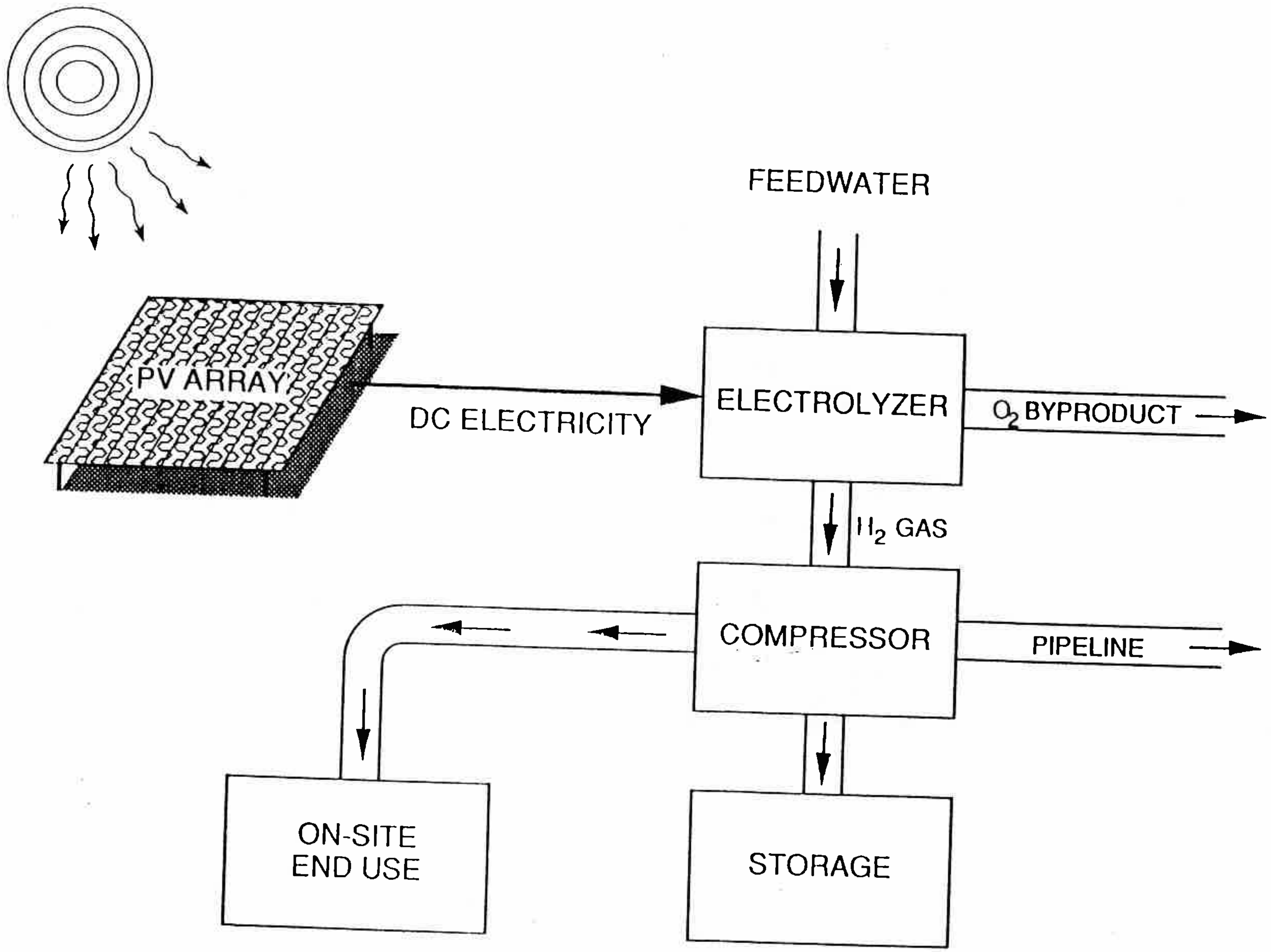


Figure 2.4.1. A solar photovoltaic/electrolytic hydrogen system. A solar photovoltaic array is connected directly to an electrolyzer, which splits water into hydrogen and oxygen. Hydrogen is compressed for onsite use, storage or transmission to remote users.

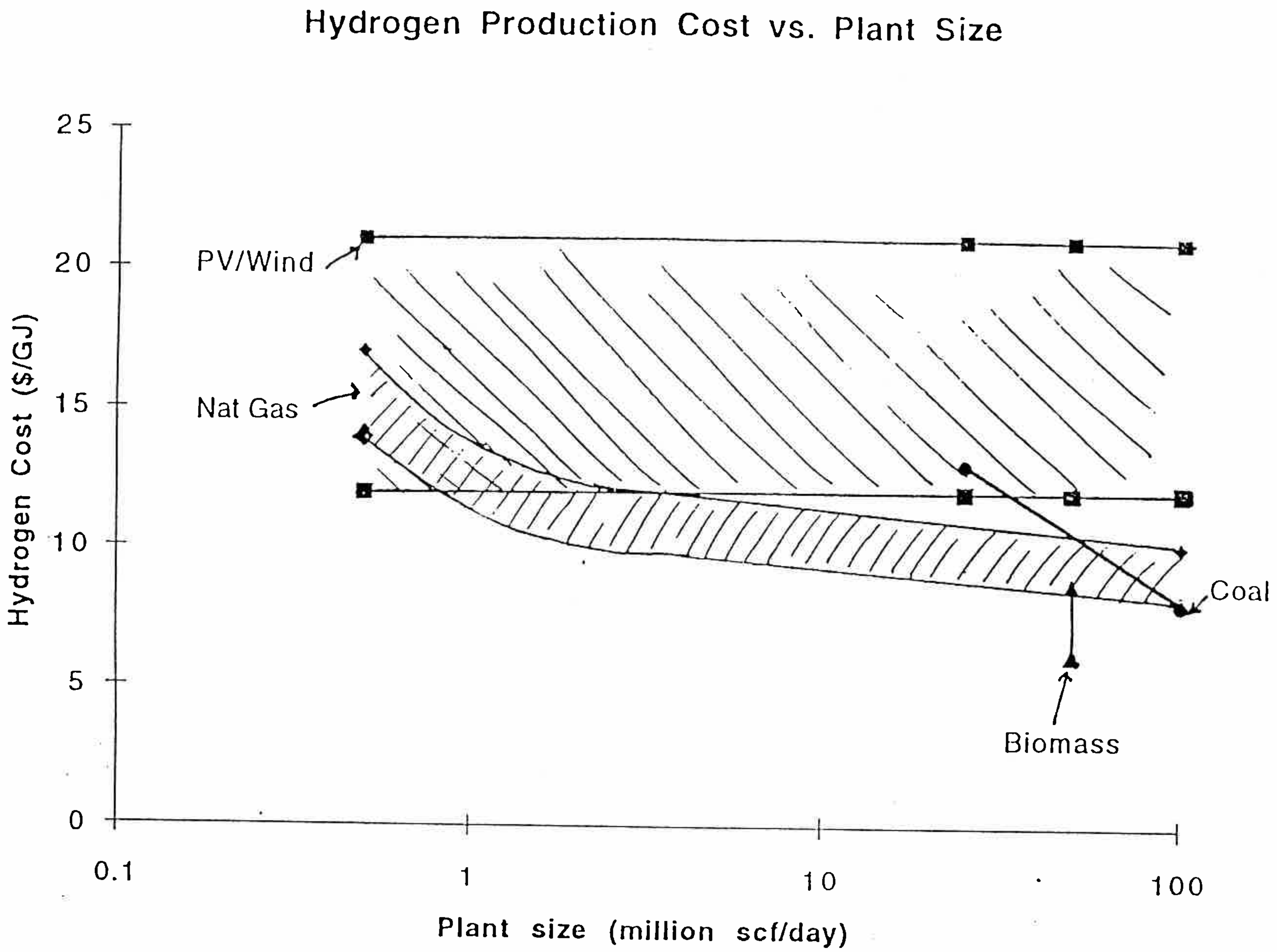
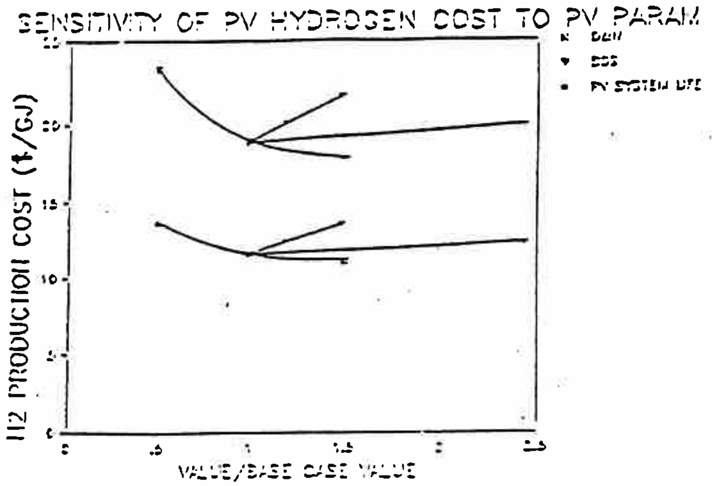
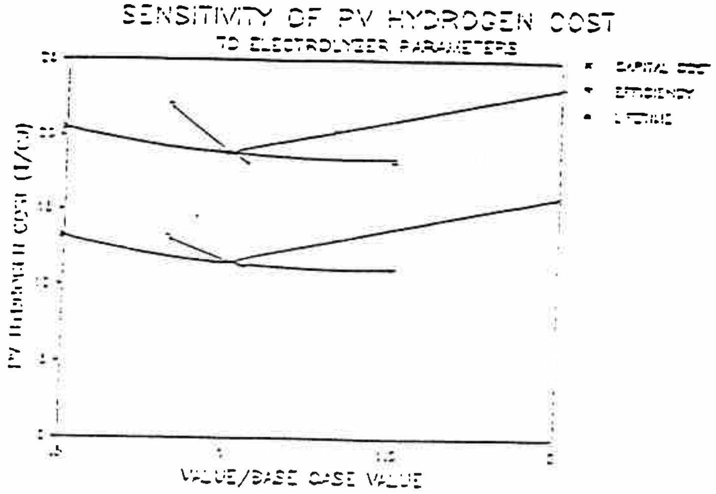


Figure 2.4.2. Hydrogen production cost vs. hydrogen plant size. The hydrogen production cost in $/GJ is shown for various hydrogen production technologies as a function plant size , given in standard cubic feet of hydrogen produced per day.





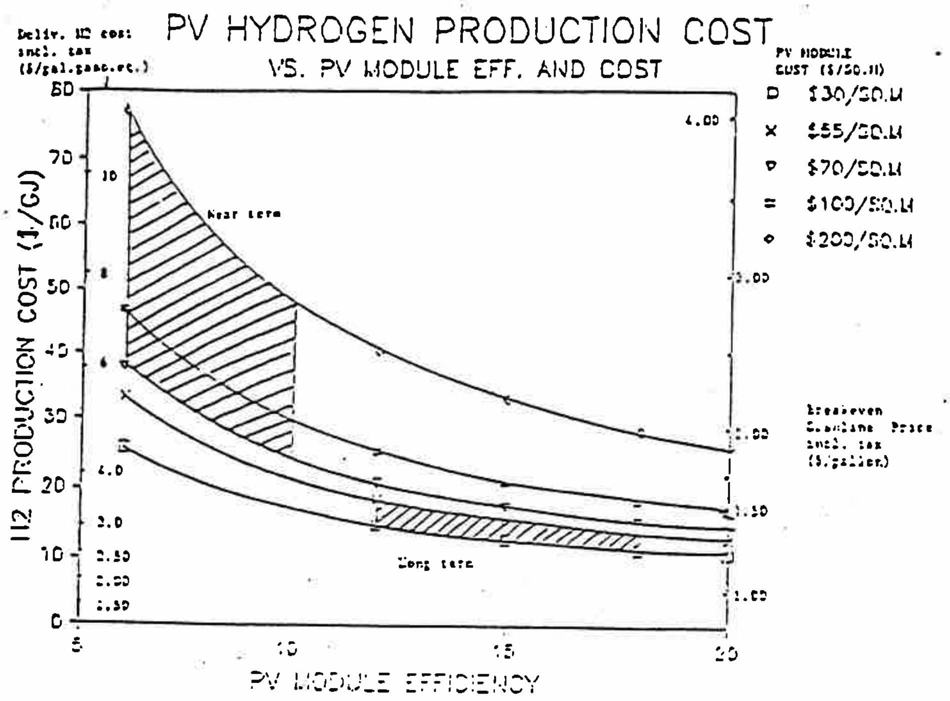


Figure 2.4.3. Sensitivity of PV hydrogen cost to PV and electrolyzer parameters. These graphs indicate how the cost of PV hydrogen varies with PV efficiency, module cost, balance of system cost, operation and maintenance costs, and PV system lifetime. The sensitivity to electrolyzer parameters (electrolyzer capital cost, lifetime and efficiency) is also shown.

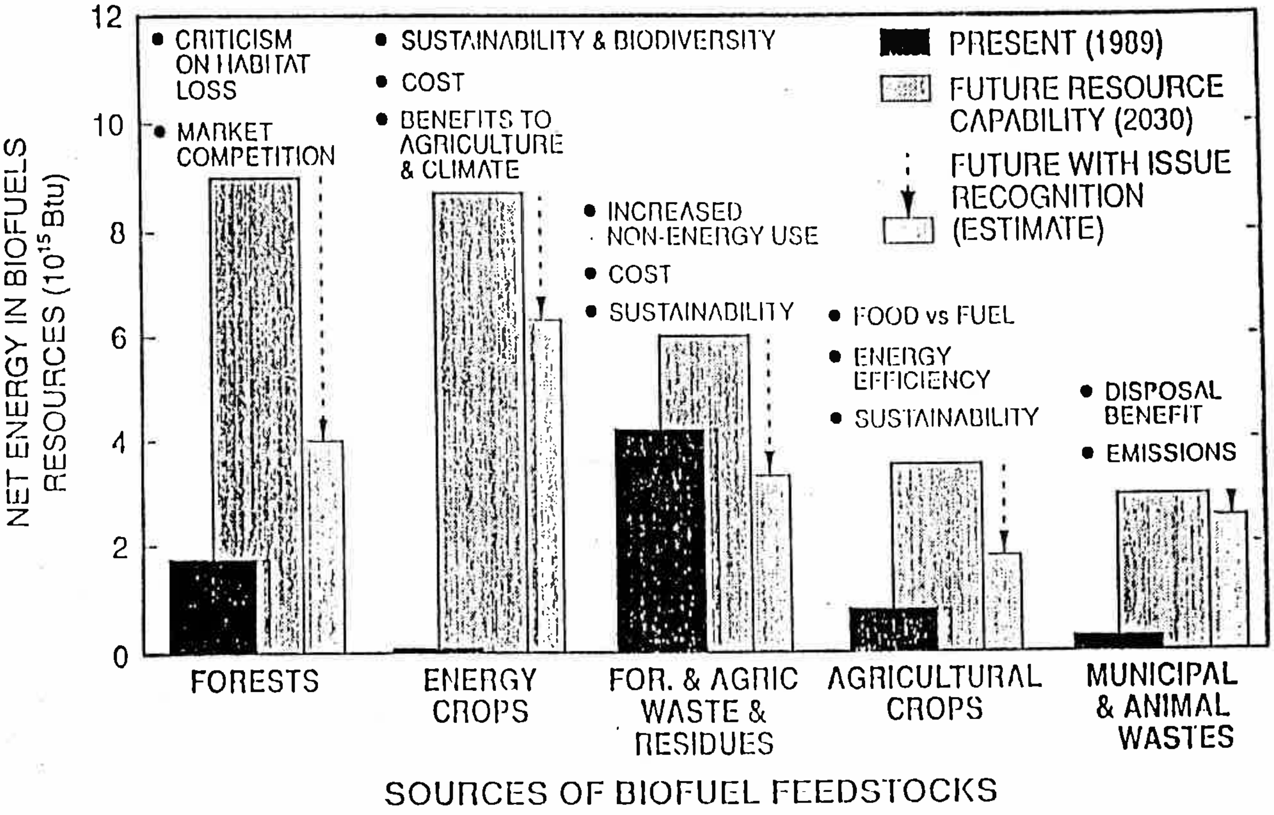


Figure 3.1. Alternative sources of biomass energy, as estimated by researchers at the Oak Ridge National Laboratory (Fulkerson et al, 1989; Ranney and Cushman, 1991).

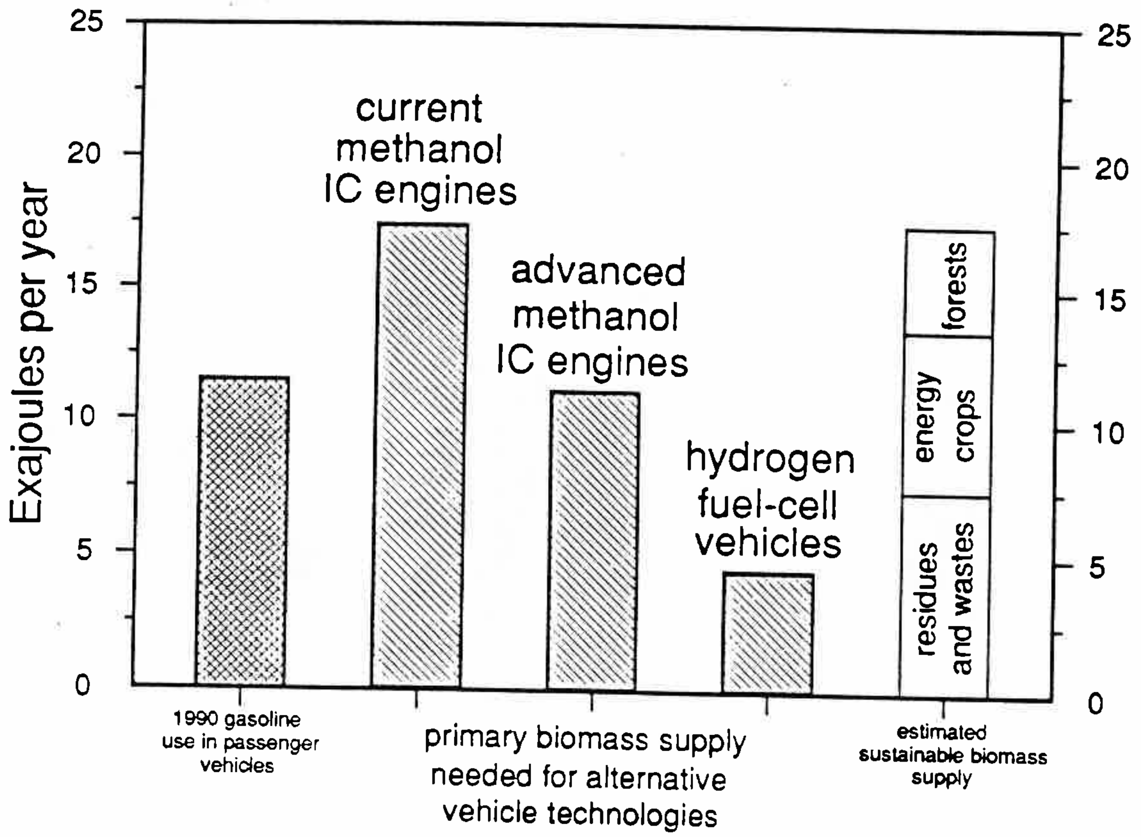


Figure 3.2. This figure shows the primary biomass energy supply required to provide the same passenger vehicle miles of travel as in 1990 in the US. The left-hand bar indicates total gasoline consumed for this purpose in 1990. The three middle bars correspond to three levels of biomass fuels production technology and vehicle technology. These are described in detail in the text. The right-most bar shows the estimated potential sustainable biomass supplies in the US, based on Fig. 3.1.

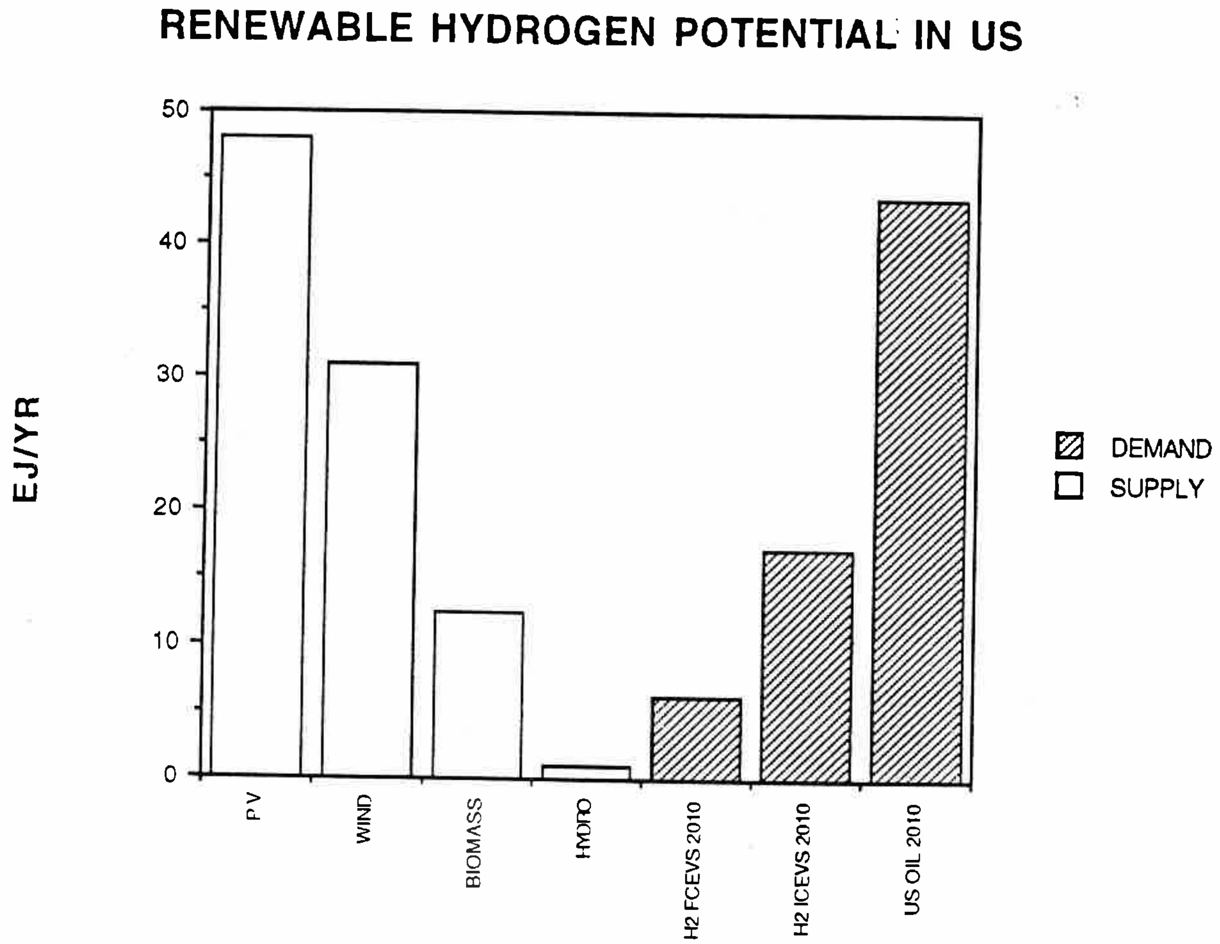


Figure 3.3. Renewable hydrogen potential in the US. The potential US hydrogen supply derived from PV, wind, biomass and hydropower is shown. This is compared to the projected 2010 demand for motor gasoline (assumed to be used in light duty vehicles) if gasoline ICEVs were used, and if hydrogen FCEVs were used. The demand for hydrogen FCEVs is assumed to be 1/3 that for gasoline ICEVs. The projected US oil use in 2010 is also shown.

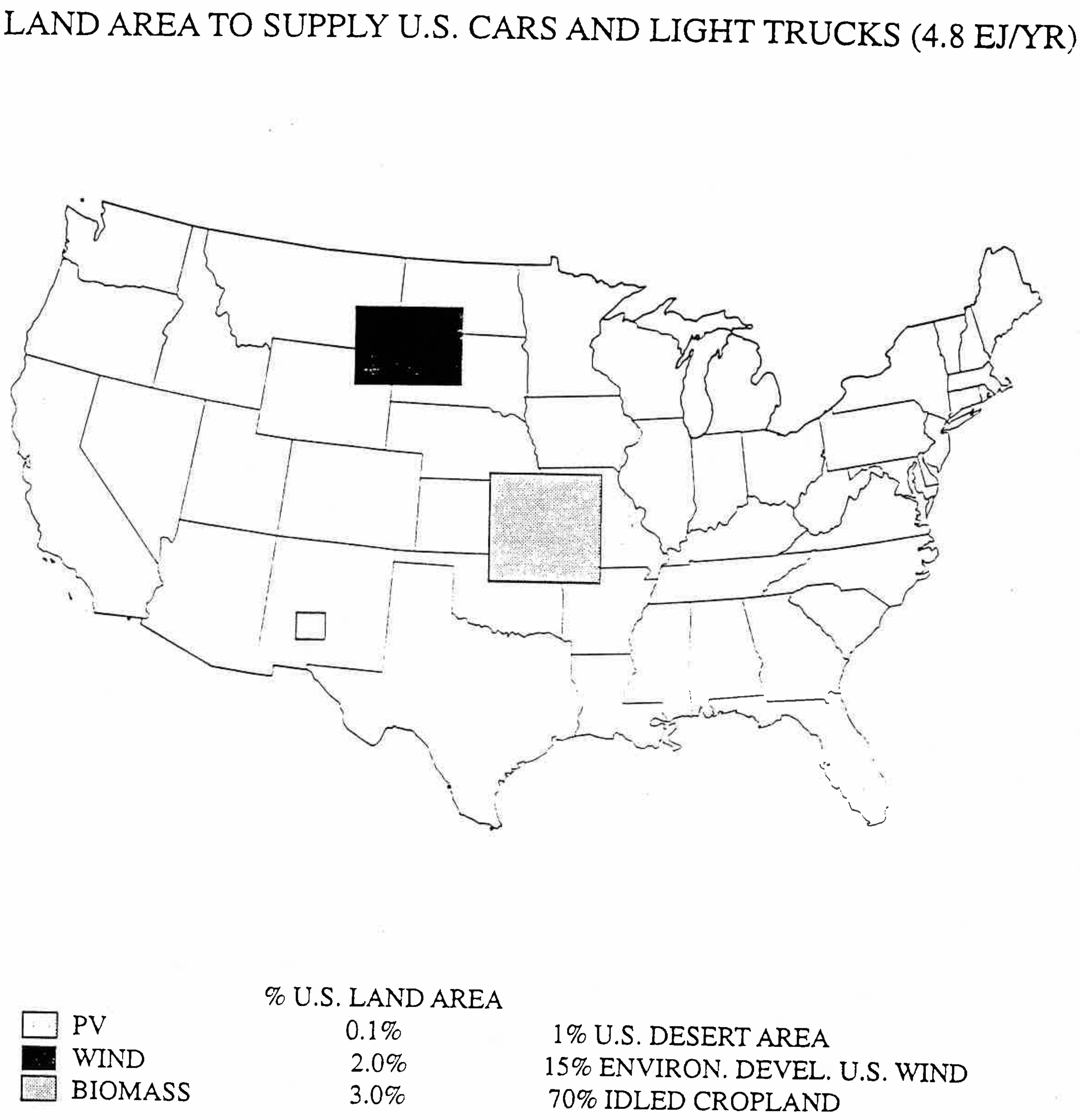


Figure 3.4. Land area with various supply options needed to supply hydrogen to US cars and light trucks, at 2010 driving levels, assuming that hydrogen fuel cell vehicles are used. It is assumed that 4.8 EJ of hydrogen per year would be needed, and that PV, wind and biomass land use are as shown in Table 3.2.

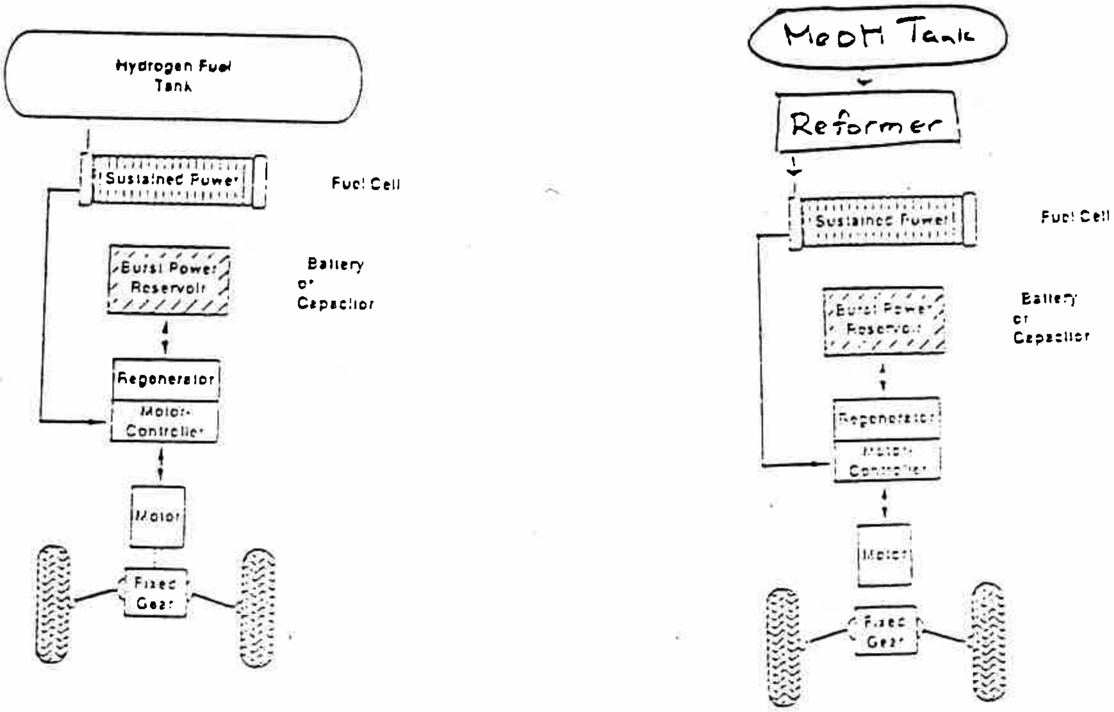


Figure 4.4.1. Fuel cell vehicles. Two alternative configurations for fuel cell electric vehicles are shown, one with compressed hydrogen gas storage, the other with methanol storage and onboard reforming to produce hydrogen.

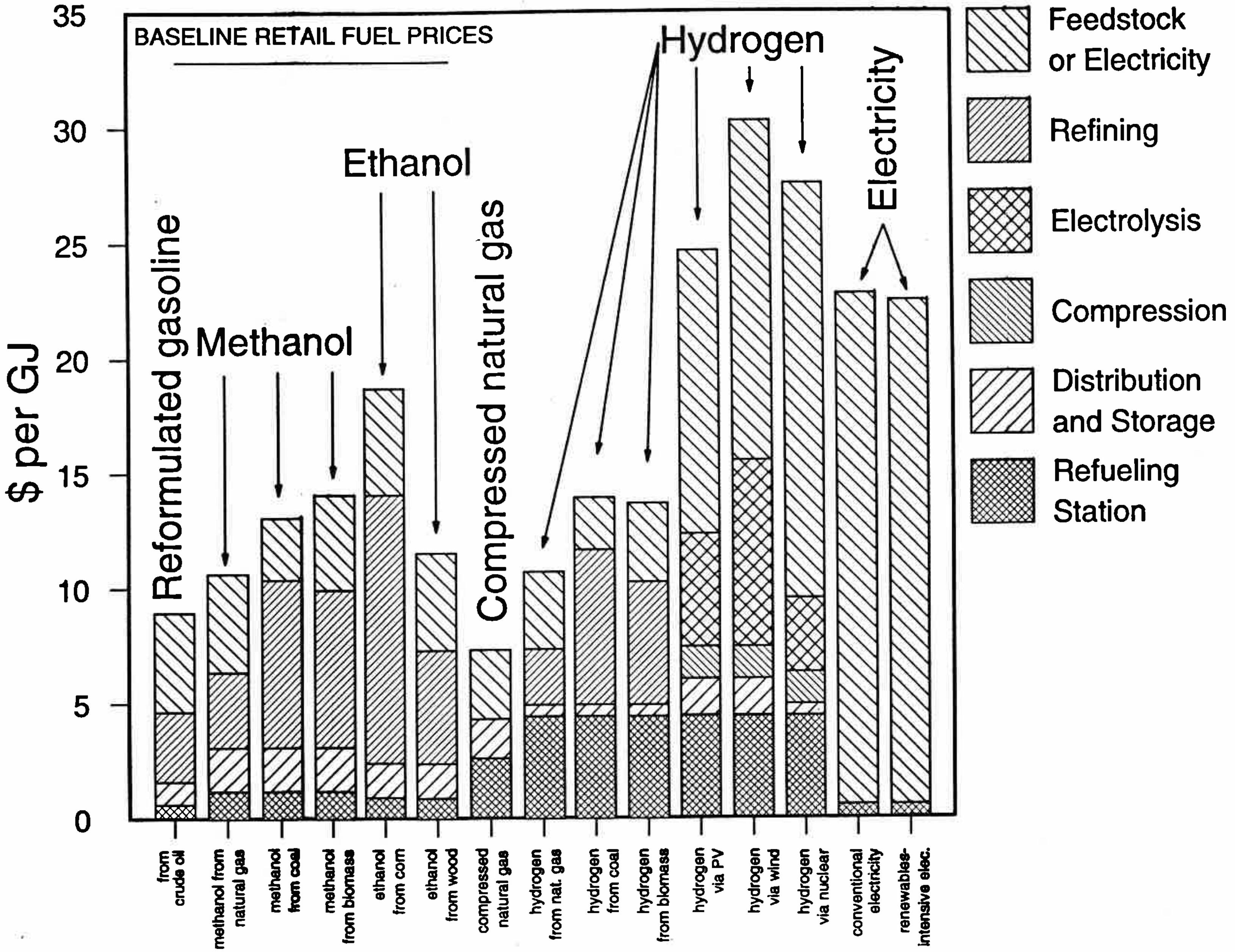


Figure 5.1. Baseline delivered cost of fuels we have estimated for the analysis presented in this study. See Table 5.1a and earlier detailed tables.

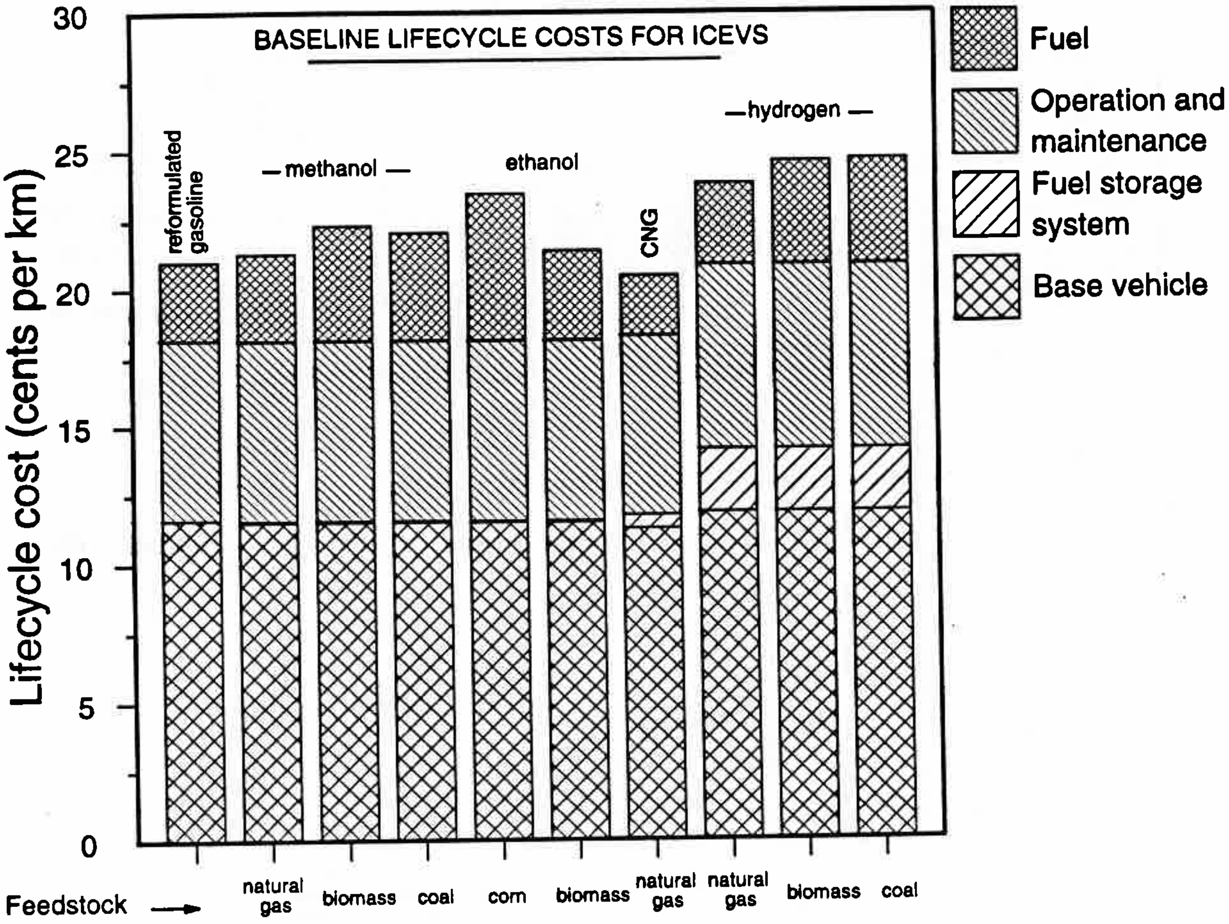


Figure 5.2. Baseline lifecycle costs of ICEV travel calculated assuming the indicated combination of feedstock and fuel. Details are shown in Table 5.6.

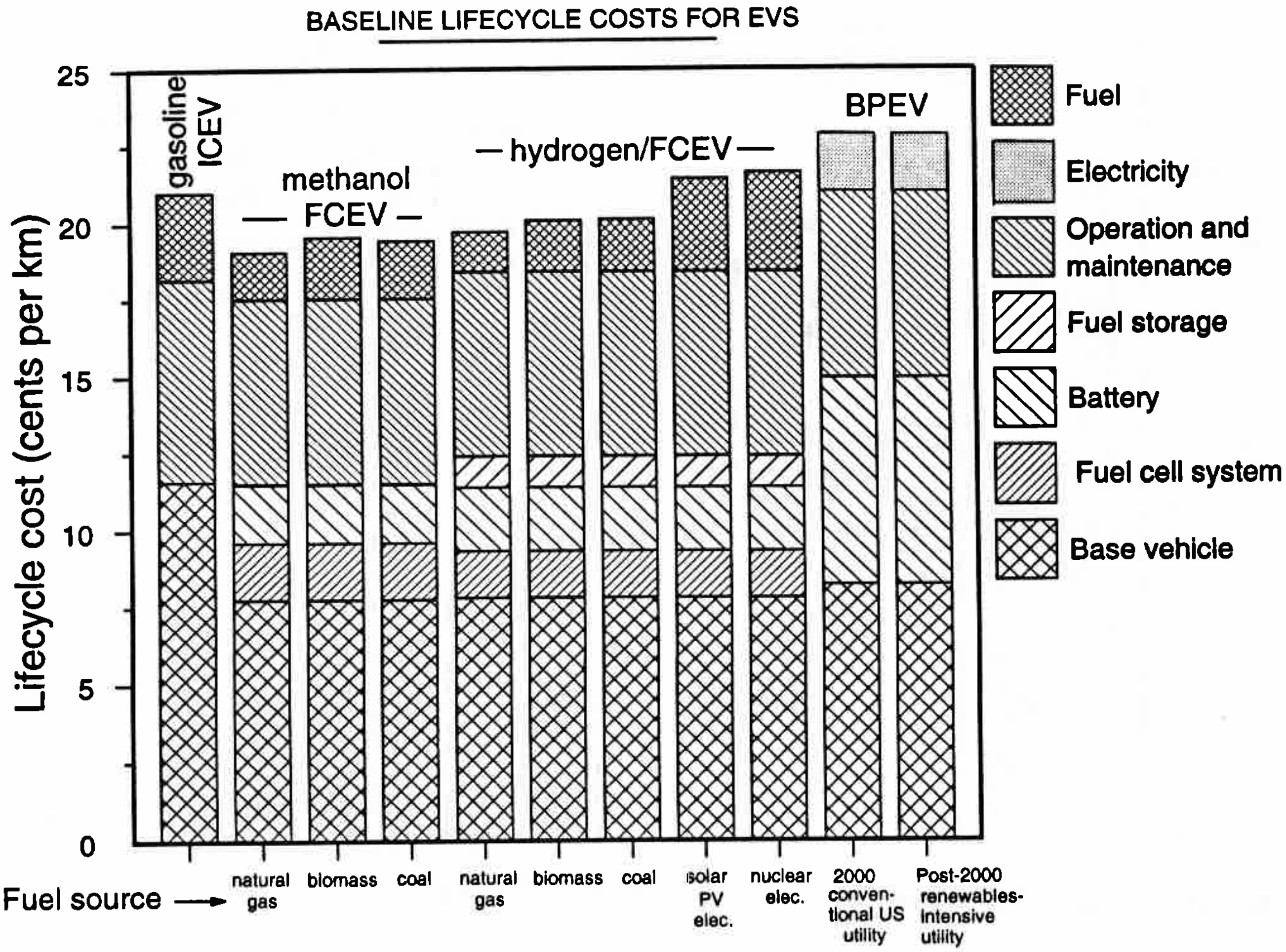


Figure 5.3. Baseline lifecycle costs of EV travel calculated assuming use of alternative sources of electricity (for BPEVs) or the indicated combination of feedstock and fuel (for FCEVs). Details are shown in Table 5.7.

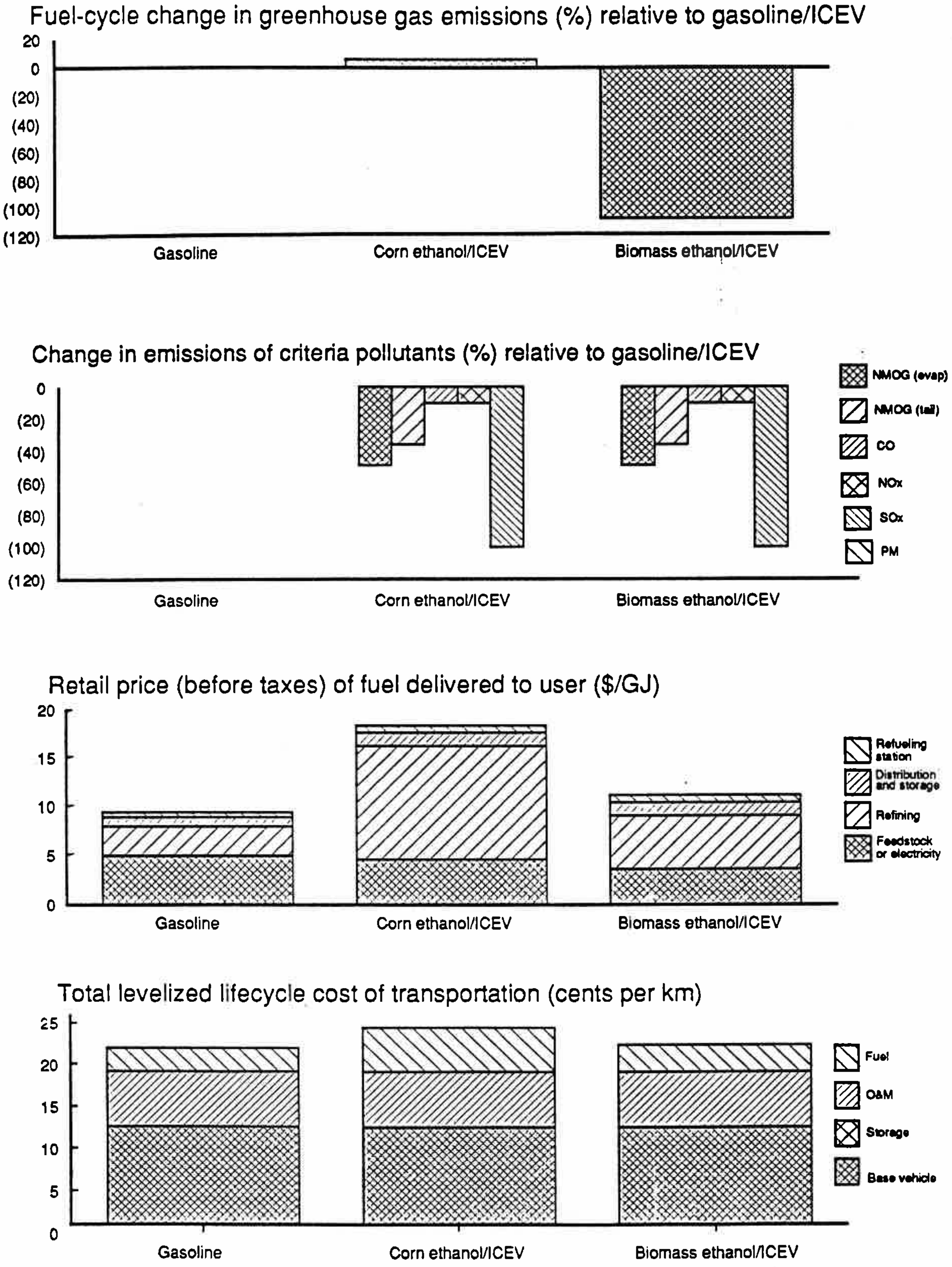


Figure 6.1. *Ethanol Options*. Comparison of emissions of greenhouse gases, criteria pollutants, delivered fuel costs (baseline case), and lifecycle transportation costs (base case) for ethanol vehicle options with ethanol produced from corn or lignocellulosic biomass. The numbers for criteria pollutants are the lower estimates given in Table 5.10 for a flexible-fuel vehicle using E85. The greenhouse gas emissions are for a dedicated ethanol (E100) vehicle. For comparison, our baseline gasoline/ICEV estimates are shown for comparison.

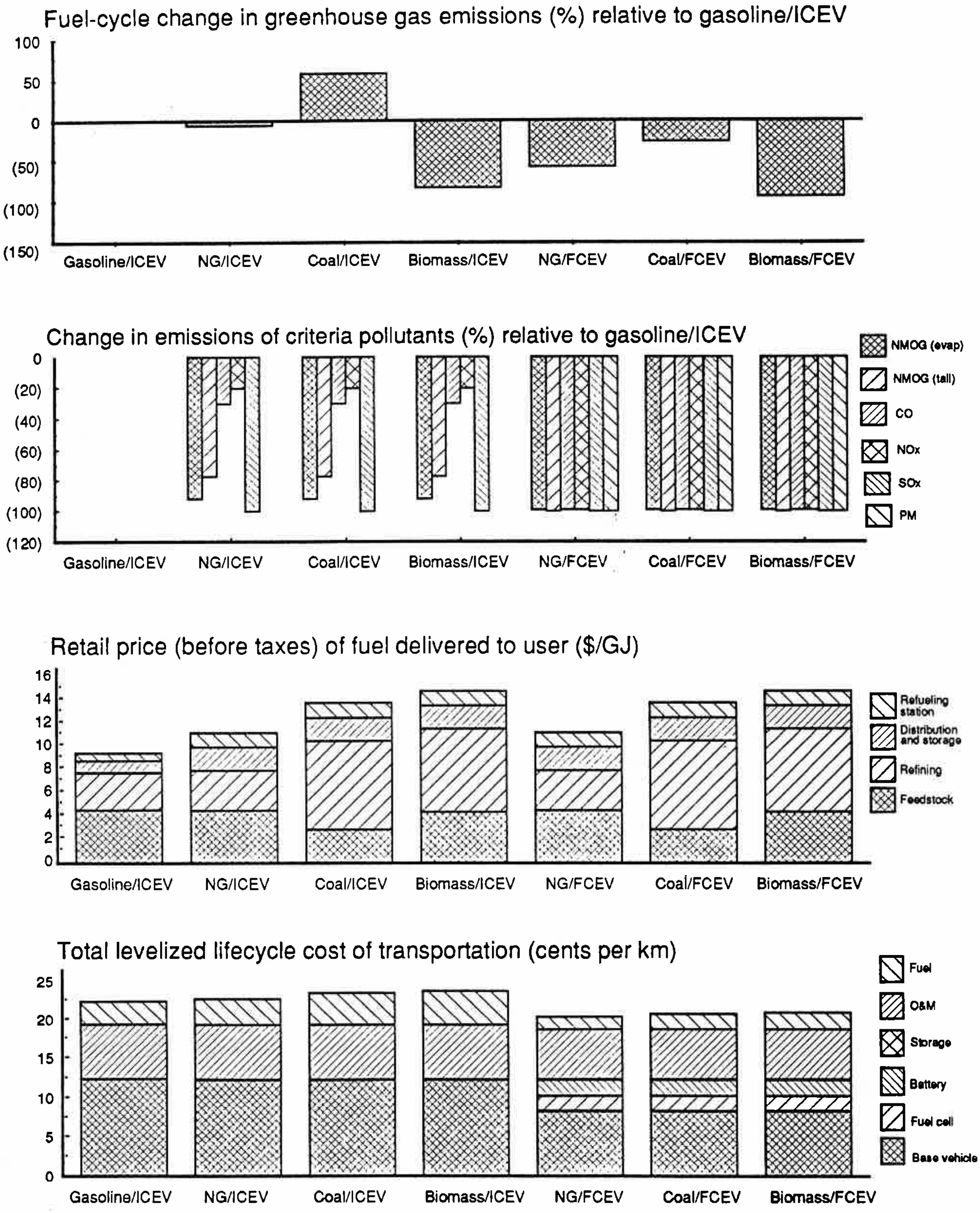
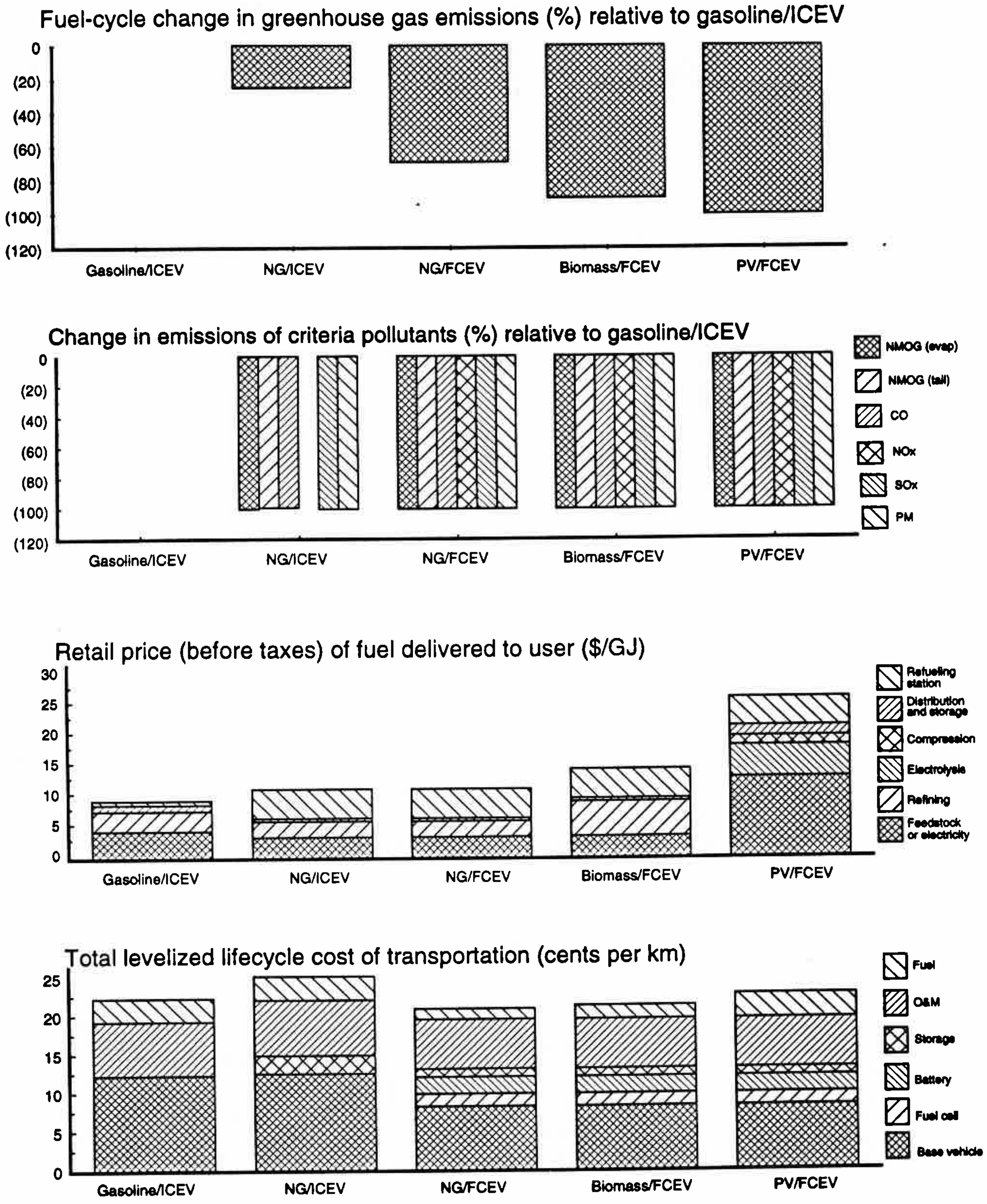
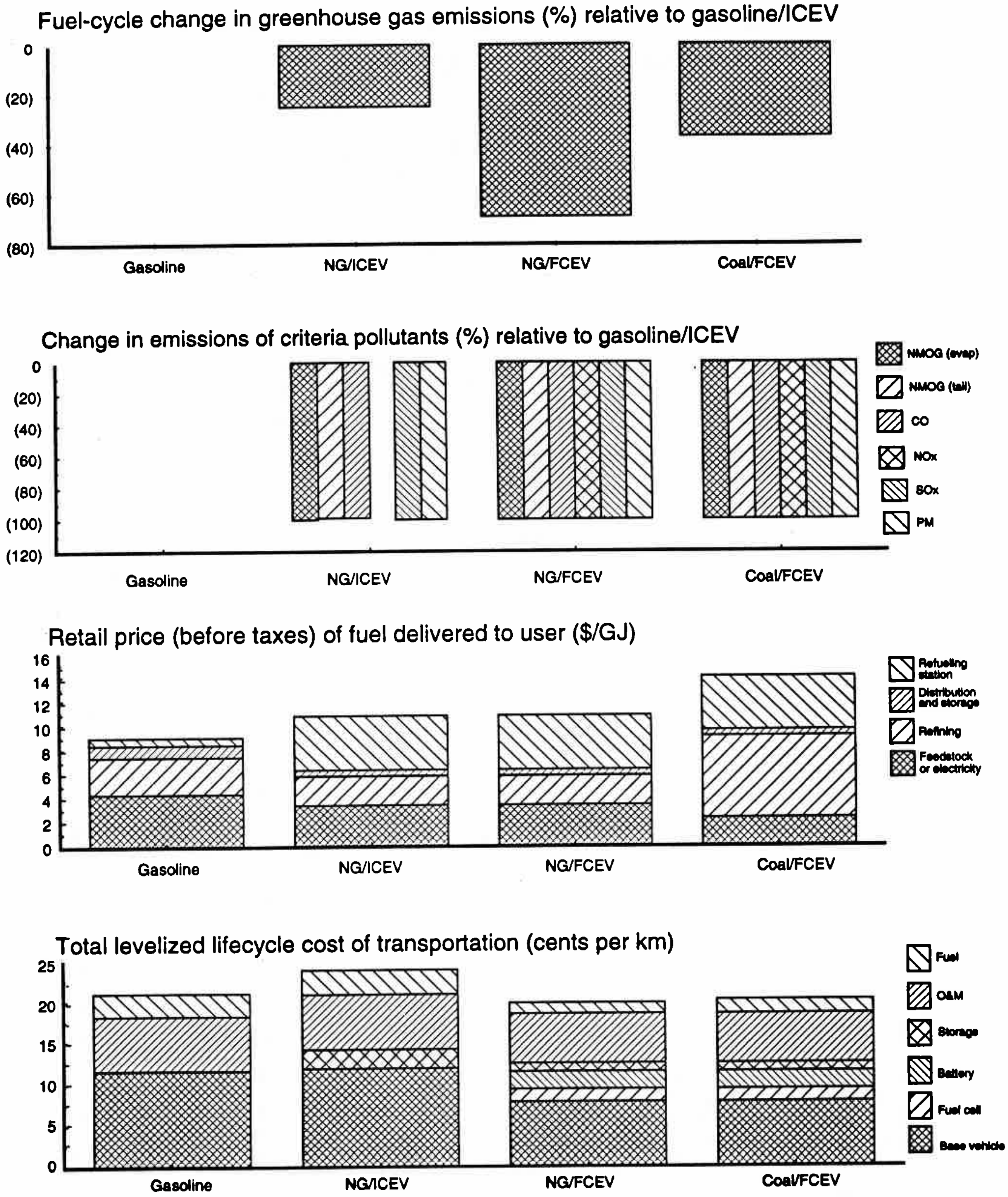


Figure 6.2. *Methanol Options*. Comparison of emissions of greenhouse gases, criteria pollutants, delivered fuel costs (baseline case), and lifecycle transportation costs (base case) for dedicated-methanol ICEV and FCEV options with methanol produced from natural gas, coal or biomass. The numbers for criteria pollutants are the lower estimates given in Table 5.10. For comparison, our baseline gasoline/ICEV estimates are shown for comparison.



Figuure 6.3.1. *Renewable Hydrogen Option.* Comparison of emissions of greenhouse gases, criteria pollutants, delivered fuel costs (baseline case), and lifecycle transportation costs (base case) for hydrogen ICEV and FCEV options with hydrogen produced from natural gas, biomass, or PV electricity. The numbers for criteria pollutants are the lower estimates given in Table 5.10. Our baseline gasoline/ICEV estimates are shown for comparison.



Fuel-cycle change in greenhouse gas emissions (%) relative to gasoline/ICEV

Change in emissions of criteria pollutants (%) relative to gasoline/ICEV

Retail price (before taxes) of fuel delivered to user ($/GJ)

Total levelized lifecycle cost of transportation (cents per km)

Figure 6.3.2. *Coal Hydrogen Option.* Comparison of emissions of greenhouse gases, criteria pollutants, delivered fuel costs (baseline case), and lifecycle transportation costs (base case) for hydrogen ICEV and FCEV options with hydrogen produced from natural gas or coal. The numbers for criteria pollutants are the lower estimates given in Table 5.10. Our baseline gasoline/ICEV estimates are shown for comparison.

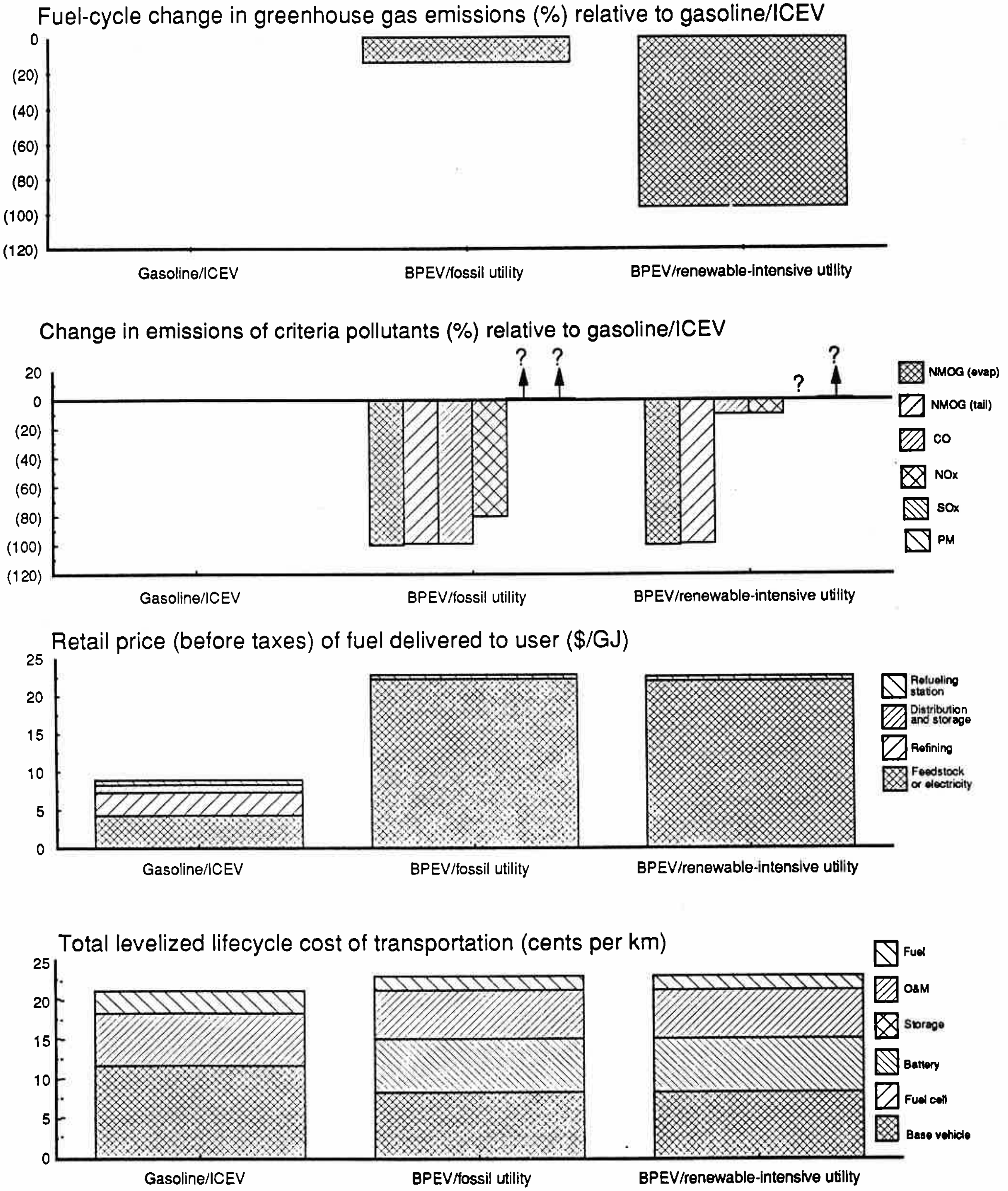


Figure 6.4. *Battery Powered Electric Vehicles*. Comparison of emissions of greenhouse gases, criteria pollutants, delivered fuel costs (baseline case), and lifecycle transportation costs (base case) for BPEVs, with electricity produced by a conventional fossil-intensive utility and by a post-2000 renewable-intensive utility (see Table 5.1a). The numbers for criteria pollutants are the lower estimates given in Table 5.10. Our baseline gasoline/ICEV estimates are shown for comparison.

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