ANL-94/44
Supplement 1

TECHNOLOGY DEVELOPMENT GOALS FOR AUTOMOTIVE FUEL CELL POWER SYSTEMS

Final Report
Contract No. 22822402

Prepared by:

Directed Technologies, Inc.
Arlington, VA

Prepared for:

Electrochemical Technology Program
Chemical Technology Division
Argonne National Laboratory
Argonne, IL

July 1995

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Final Report, Appendix B-2
to Contract No. 22822402

HYDROGEN vs. METHANOL: A COMPARATIVE ASSESSMENT FOR FUEL CELL ELECTRIC VEHICLES

Prepared by:

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July 1995

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FUEL CELLS IN TRANSPORTATION

FOREWORD

This report completes the documentation of work performed by Directed Technologies, Inc. under Argonne National Laboratory Contract No. 22822402, Technology Development Goals for Automotive Fuel Cell Power Systems. The objective of the work was to review the status of fuel cell and related technologies and assess the technology gap between the current status and the projected requirements for fuel cell-powered vehicles.

Specifically, conceptual designs for several types of fuel cell-powered light-duty vehicles were developed and propulsion system requirements determined for several performance levels. The status of proton-exchange-membrane fuel cell, hydrogen storage, and power augmentation technologies was assessed to determine the feasibility of designing fuel cell propulsion systems which are comparable to current internal combustion engines. The results of this study were reported earlier in Argonne National Laboratory Report No. ANL-94/44. A task to evaluate and compare hydrogen and methanol energy carriers for fuel cell vehicles was added to the contract later; these results are reported here.

This work was undertaken in support of the U.S. Department of Energy, Energy Efficiency and Renewable Energy, Office of Transportation Technologies, which is developing fuel cell technologies for transportation applications. In related programs, direct hydrogen proton-exchange-membrane fuel cell propulsion systems for light-duty vehicles are being developed under the government/industry Partnership for a New Generation of Vehicles. Walter F. Podolski of the Chemical Technology Division was the project manager at Argonne National Laboratory. Sandy Thomas was the project manager at Directed Technologies, Inc.

Walter F. Podolski
Electrochemical Technology Program
Argonne National Laboratory

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Glossary of Abbreviations

BPEV = battery powered electric vehicle
BTU = British thermal unit
CF = capacity factor
CRF = capital recovery factor
CO = carbon monoxide
CO_2 = carbon dioxide
DOE = (U.S.) Department of Energy
DTI = Directed Technologies, Inc.
FCEV = fuel cell electric vehicle
FUDS = federal urban driving schedule
GJ = gigajoules (10^9 joules)
HHV = higher heating value
ICE = internal combustion engine
IFC = International Fuel Cells
kWh = kilowatt-hour
LHV = lower heating value
MBTU = million BTUs
MW = megawatts
NG = natural gas
O&M = operation and maintenance
PEM = proton exchange membrane (fuel cell)
PV = photovoltaics
SCF = standard cubic feet
TCF = thousand cubic feet
tpd = ton per day

Conversion Factors

1 BTU = 1,054.8 joules
1 kWh = 3.6 megajoules = 3,413 BTUs
1 GJ = 10^9 joules = 0.948 MBTUs

Heats of Combustion

	Gases (BTU/ft^3)[1]		Liquids (BTU/gallon)	
	Hydrogen	Natural Gas	Methanol	Gasoline
Higher Heating Value	318.1	1,012	64,250	124,800
Lower Heating Value	268.6	913.0	56,800	115,000

[1]at 70°F and 1 atmosphere.

Abstract

Directed Technologies, Inc. has previously submitted a detailed technical assessment and concept design for a mid-size, five-passenger fuel cell electric vehicle (FCEV), under contract to the Argonne National Laboratory. As a supplement to that contract, DTI has reviewed the literature and conducted a preliminary evaluation of two energy carriers for the FCEV: hydrogen and methanol. This report compares the estimated fuel efficiency, cost of producing and delivering the fuel, and the resultant life cycle costs of the FCEV when fueled directly by hydrogen and when fueled by methanol with on-board reforming to produce the required hydrogen-rich gas for the fuel cell. This work will be supplemented and expanded under the Ford contract with the Department of Energy to develop the FCEV and its fuel infrastructure.

Introduction

Directed Technologies, Inc. has completed a conceptual design of a mid-size fuel cell electric vehicle (FCEV) under contract to the Argonne National Laboratory. We designed this 5-passenger vehicle to have the same range, acceleration and other creature comforts as a conventional gasoline powered vehicle so as to be acceptable to most American drivers. The final report[2] published in August 1994 defines all necessary power system components including the fuel cell stack, air compressors, hydrogen storage, peak power augmentation, and the electric motor and controller. The report demonstrates that the projected weight and cost of a direct hydrogen FCEV in mass production could be comparable to the weight and cost of the equivalent gasoline powered vehicle.

The primary FCEV design assumed that hydrogen would be stored on-board the vehicle as a compressed gas at 5,000 psi. As a supplement to that work, this report analyzes the alternative of using methanol as the on-board fuel, with an on-board reformer to chemically convert methanol into a hydrogen-rich gas mixture to drive the fuel cell stack. We analyze the fuel efficiency, cost and vehicle life cycle costs for the two alternative fuels.

Fuel Efficiency

The DTI FCEV concept design was based on a 5-passenger Ford Taurus which has a fuel efficiency of about 19 mpg on gasoline, consuming about 6,050 BTU of gasoline per mile (LHV) on the Federal Urban Driving Schedule (FUDS). Keeping the same range as the gasoline powered Taurus (342 miles on FUDS), a FCEV would require about 15 pounds of hydrogen, assuming projected PEM fuel cell performance. This corresponds to an energy consumption of about 2,260 BTU/mile (LHV), or 2.68 times more energy efficient than the gasoline ICE vehicle, based on the lower heating value of both fuels, or 2.45 times more efficient based on higher heating values.[3]

If such a FCEV were powered by methanol, the system energy efficiency could be decreased due to four factors: reduced efficiency in producing methanol from natural gas

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[2]Brian D. James, George N. Baum, and Ira F. Kuhn, Jr., Technology Development Goals for Automotive Fuel Cell Power Systems, Final Report No. ANL-94/44, August 1994.

[3]DeLuchi (U. of California-Davis, Institute of Transportation Studies) has estimated that fuel cell vehicles would be about 2.76 times more energy efficient than gasoline-powered vehicles, based on the higher heating value of both fuels, which corresponds to a LHV efficiency ratio of 3.02, indicating that our estimate of 2.68 may be conservative.

compared to producing hydrogen from natural gas; the inefficiency of the on-board methanol reformer; the reduced efficiency of the fuel cell itself as a result of the output hydrogen gas stream (the reformate) containing other gases, primarily carbon dioxide; and the increase in vehicle weight due to the reformer. The Allison Division of General Motors has estimated that a methanol reformer would have an energy efficiency of about 77% (LHV) in converting methanol into hydrogen, assuming the use of nine heat exchangers in the fuel cell/reformer system to make optimum use of the fuel cell system reject heat.[4] They do not specify the expected fuel cell performance drop due to reformate compared to pure hydrogen. That is, the gas delivered to the fuel cell from a methanol steam reformer would nominally contain 75% hydrogen and 25% carbon dioxide, although in practice the mixture has even less hydrogen, typically 63% hydrogen, 22% carbon dioxide, 11% water and 4% nitrogen.[5] Partial oxidation reformers have even less hydrogen, approximately 48%.

Dilution of hydrogen by CO_2 does not reduce fuel cell efficiency, since the hydrogen (anode) chemical kinetics are fast compared to the oxygen (cathode) kinetics. The cathode reactions therefore limit fuel cell performance, and hydrogen concentrations can decrease to 50% without degrading fuel cell output power.[6]

While CO_2 dilution does not affect fuel cell efficiency per se, the CO_2 does form CO at the anode, and CO poisons the anode catalyst at very low concentrations. For example, Wilson et al. at the Los Alamos National Laboratory have measured a 50 percent drop in fuel cell output power for a low platinum (0.14 mg/cm^2) membrane with CO concentrations of 5 ppm.[7] Much of this degradation can be reversed by purging the hydrogen anode with low concentrations of oxygen or air, usually one or two per cent which is below the four percent lower flammability limit for hydrogen and oxygen/air mixtures, but some permanent degradation remains.

Wilson et al. have also measured the affects of adding 25% CO_2 to the hydrogen input gas stream, to simulate the reformate gas from an on-board methanol reformer. They have concluded

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[4]Research and Development of PEM Fuel System for Transportation Applications: Initial Conceptual Design Report, Allison Gas Turbine Division, General Motors Corporation, Department of Energy Report No. DOE/CH/10435-01, February 1994.

[5]R. Kumar, S. Ahmed, M. Krumpelt, and K.M. Myles, "Reformers for the Production of Hydrogen from Methanol and Alternative Fuels for Fuel Cell Powered Vehicles," Argonne National Laboratory Report No. ANL-92/31, August 1992, p. 16.

[6]J.C. Amphlett, R.F. Mann and B.A. Peppley, "On Board Hydrogen Purification for Steam Reformer Fuel Cell Vehicle Power Plants," Hydrogen Energy Progress X: Proceedings of the 10th World Hydrogen Energy Conference, Cocoa Beach, Florida, June 1994, p. 1681.

[7]Mahlon S. Wilson, Charles R. Derouin, Judith A. Valerio and Shimshon Gottesfeld, "Electrocatalysis Issues in Polymer Electrolyte Fuel Cells," IECEC Meeting, Atlanta, Georgia, August 1993, p. 1.1203.

through a series of tests that CO is created at the anode from CO_2 in sufficient quantity to poison the catalyst.[8] Scaling from their fuel cell polarization (current vs. voltage) curves, we estimate a fuel cell peak power drop of approximately 22% due to this effect. Again, the degradation can be partially reversed by a two percent air bleed, but the power loss is still 7% after air purging.

The Los Alamos team has discovered that adding ruthenium to the conventional platinum catalyst will retard the formation of CO from CO_2, cutting the power loss from 22 percent down to 7 percent. With air purging, the irreversible loss drops to the four to five percent range. Since ruthenium costs less than platinum, this modification should not increase fuel cell cost, and cell stack performance based on limited data looks similar.

We will assume here that production fuel cells for use with methanol reformate use platinum and ruthenium catalysts, but not air purging to minimize the effects of CO_2. The peak power will drop by roughly seven percent relative to operation on pure hydrogen.[9] To compensate, we assume that the total active area of the fuel cell system is increased by seven percent, which adds to the final cost.

Although increasing cell area restores the power loss, the peak power point is now shifted to lower cell voltage, which reduces efficiency. That is, the voltage efficiency for a PEM fuel cell is given by the ratio of the cell operating voltage and 1.23 volts. If the peak power with hydrogen occurs at 0.5 volts/cell and with methanol reformate at 0.45 volts/cell, then the voltage efficiency at peak power decreases from 40.6% to 36.5%, a drop of 10 percent. But an automotive fuel cell usually operates well below peak power. The efficiencies at lower power levels (higher voltages) decrease by lesser amounts, approaching zero decrease as the power goes to zero. We assume that the average efficiency loss due to the CO_2 is five percent averaged over the driving cycle.

The 10 percent drop in voltage at peak power will also require additional cells in the stack to maintain the required voltage for the electric motor. The stack voltage will be at its lowest level at the maximum power point, so the full 10 percent voltage drop must be restored by adding 10 percent more cells to the stack. This will increase power by 10 percent at a given current density. Since we assumed that the total active area (number of cells times the area per cell) had to be increased by only seven percent to restore the full peak power, this means that each cell for the methanol reformate would be slightly smaller to maintain equal power levels for hydrogen and methanol fuels.

The added reformer weight would also decrease vehicle efficiency. According to the Allison design, the combined methanol fuel tank and fuel cell/reformer system would weigh 780 pounds, compared to the DTI estimate of 660 pounds initially for a compressed hydrogen tank

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[8]Private communication with Shimshon Gottesfeld, May 30, 1995.

[9]The Allison/GM design assumes *better* fuel cell performance operating on reformate than DTI assumed for the direct hydrogen fuel cell stack (0.7 volts/cell at 1 amp/cm^2 for GM vs. 0.6 volts/cell for DTI/Ford). Equivalent fuel cell stacks would presumably have on the order of seven percent lower peak power output operating on reformate relative to hydrogen.

and fuel cell system, dropping to 415 pounds by 2004 in production. If the Allison estimate of 780 pounds is representative of the production system, then the extra 365 pounds would reduce vehicle fuel economy, all else being equal. Due to the uncertainty of these weight estimates, however, we neglect the weight penalty here.

The net on-board efficiency drop for methanol compared to hydrogen is then 73.2% -- 77% reformer efficiency combined with the five percent loss due to lower cell voltage with CO_2. The methanol powered FCEV would then consume about 3,090 BTU/mile (LHV) based on the DTI estimate of 2.68 times greater energy efficiency for the direct hydrogen system compared to the gasoline ICE equivalent performance vehicle.

To estimate total carbon dioxide emissions, we must also compare total energy system efficiency from the initial source (crude oil or natural gas well) to the vehicle. In this case, methanol suffers another efficiency drop, since converting natural gas to methanol is less efficient (71%-HHV) than converting natural gas to hydrogen (90%).[10] The final fuel efficiency values are summarized in Table 1, assuming 90% oil refinery efficiency in producing gasoline from crude oil and 90% efficiency in producing natural gas, and assuming that gasoline ultimately creates 0.0705 gram of CO_2 per BTU of gasoline and natural gas generates 0.0528 g/BTU.[11] From a total energy system perspective, methanol requires 73% more natural gas than hydrogen per mile traveled in a FCEV, and therefore will cause the emission of 73% more CO_2 than hydrogen from the same feedstock.

From a total fuel system infrastructure perspective, there will also be auxiliary emissions such as gasoline emissions from the tanker truck required to transport the methanol, and from electricity required to compress the hydrogen. The average U.S. utility emits about 620 grams of CO_2 per kWh produced.[12] Ogden et al. have estimated that an on-site hydrogen compressor would consume about 18.9 kWh of electricity per MBTU of hydrogen compressed to 8,000 psi.[13] Electricity to compress the hydrogen would add about 27 g/mile of CO_2 emissions at the power

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[10]Eric D. Larson & Ryan E. Katofsky, "Production of Methanol and Hydrogen from Biomass," Princeton University, Report PU/CEES No. 271, July 1992, pgs. 214 &217. Efficiency is defined as the ratio of hydrogen energy out of the steam reformer plant divided by natural gas energy in, both in higher heating value. Note that this is *not* thermal efficiency. Including electricity consumed in the plants, the total thermal efficiencies are estimated at 84.8% for hydrogen production and 67.5% for methanol production.

[11]"Emissions of Greenhouse Gases in the United States," Energy Information Administration Report No. DOE/EIA-0573, September 1993, p. 15.

[12]Ibid., EIA, p. 74: in 1991, U.S. utilities emitted 473.6 million metric tons of carbon (1.64 billion metric tons of CO^2) and produced 2.8×10^{12} kWh of electricity.

[13]Joan M. Ogden, E. Dennis, Margaret Steinbugler, and John W. Strohbehn, "Hydrogen Energy Systems Studies," Princeton University, NREL Contract No. XR-11265-2 draft final report, January 18, 1995, Table 13.

plant, raising the total for the hydrogen FCEV to 174 g/mile. But methanol and gasoline tanker trucks also emit pollution. DeLuchi estimated that methanol distribution added 18 grams/mile of CO_2-equivalent emissions, assuming 2.2 times higher FCEV efficiency (compared to our estimate of 2.68 on a LHV basis).[14] In any case, the methanol FCEV would still generate 47% to 57% more total CO_2 than the hydrogen FCEV.

Table 1. Fuel Efficiencies & CO_2 Emissions for Hydrogen-FCEV, Methanol-FCEV and Gasoline-ICE Vehicles

	Gasoline-ICE	Methanol-FCEV	Hydrogen-FCEV
On-Board Energy Consumed by the Vehicle (BTU/mile-LHV)[15]	6,050	3,090	2,260
Primary Energy Consumption (BTU/mile)	6,722 (oil)	4,835 (NG)	2,790 (NG)
Direct Carbon Dioxide Emissions[16] (grams/mile)	474	255	147
Other Emissions (grams/mile)[17]	-	18	27
Total Carbon Dioxide Emissions (grams/mile)	474	273	174

On-board methanol reforming will also generate some minute ozone precursor emissions, estimated at 0.002 g/mile of volatile organic compounds (VOCs) and 0.001 g/mile of nitrous oxides (NOx),[18] disqualifying methanol from the zero emission vehicle (ZEV) category. However, regulated emissions will still be extremely low, well below the California ultra-low emission vehicle (ULEV) requirements of less than 0.04 g/mile VOC and 0.2g/mile NOx.

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[14]M.A. DeLuchi, "Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity," Argonne National Laboratory report ANL/ESD/TM-22, Vol. 2, November 1993, p. B-25.

[15]Based on the Federal Urban Driving Schedule (FUDS) estimates for a mid-size automobile.

[16]Direct CO_2 emissions include emissions from the vehicle (in the case of gasoline and methanol) as well as emissions from the upstream fuel production plants (the only emissions from the hydrogen FCEV.)

[17]Other emissions refer to those from the tanker truck used to deliver the methanol and from the electricity used to compress the hydrogen.

[18]"Energy, Economic, and Environmental Benefits of Fuel Cell Vehicles," U.S. Department of Energy fact sheet DE93000001, November 1992.

For a given fuel feedstock cost, methanol production will generally be more expensive than hydrogen production. In the conventional two-step process of generating methanol from natural gas by steam reformation, hydrogen and carbon monoxide are formed in the first high temperature catalytic reaction and must then be converted in a second, lower temperature catalytic reaction to form methanol. But if hydrogen is the desired output, then the carbon monoxide in the first catalytic reaction can be efficiently converted to more hydrogen by the water shift reaction ($CO + H_20 = H_2 + CO_2$), eliminating the second exothermic methanol reactor.

This hydrogen production process is more efficient and requires less capital equipment than the two-step methanol production process, even though the hydrogen plant requires the water shift reaction plus a gas cleanup process such as pressure swing adsorption (PSA). Williams et. al. attribute the lower methanol efficiency to the waste heat generated in the methanol synthesis step -- methanol production is more exothermic than the water shift reaction plus PSA needed to produce clean hydrogen.[19] Katofsky shows that the capital costs for a large (657 MW) methanol plant are about 1.57 times more per unit energy produced than the costs for a large (414 MW) hydrogen plant. The natural gas feedstock costs 1.25 times more, due to the lower efficiency of a methanol plant (71% vs.90%- HHV). For natural gas selling at $2/GJ[20], methanol at the plant gate will cost about 1.39 times more than hydrogen per unit energy ($6.7/GJ vs. $4.82/GJ for hydrogen.)[21]

Imported Methanol Costs. However, the cost of natural gas can be significantly less for methanol than for hydrogen, since methanol can be produced overseas and economically shipped to the U.S. in large tankers, an impractical option for hydrogen. During the Bush administration, methanol was emphasized as an alternative fuel for internal combustion engines, based partially on somewhat lower emissions of deleterious gases when burned in an ICE, and based on the prospects of inexpensive imported methanol. The EPA estimated that half of all U.S. transportation needs could be supplied from natural gas that is either flared or reinjected into oil wells to boost oil production in other parts of the world.[22] This unmarketable natural gas costs

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[19]Robert H. Williams, Eric D. Larson, Ryan E. Katofsky & Jeff Chen, "Methanol and Hydrogen from Biomass for Transportation," submitted to Energy for Sustainable Development, January, 1995, p. 13.

[20]All dollars in this report are 1995 U.S. dollars unless otherwise noted.

[21]Ryan E. Katofsky, "The Production of Fluid Fuels from Biomass," Princeton University Report PU/CEES No. 279, June 1993.

[22]"Analysis of the Economic and Environmental Effects of Methanol as an Automotive Fuel," Environmental Protection Agency, Special Report, Office of Mobile Sources, September 1989.

between \$0.50 and \$1.00/GJ,[23] compared to U.S. domestic prices[24] (1994) of:

Wellhead	\$1.71/GJ
Electric Utility	2.44
Industrial	2.84
City Gate	2.88
Commercial	4.97
Residential	5.99

Therefore an overseas methanol plant can operate with fuel feedstock costs 2.5 to 5 times lower than a domestic hydrogen steam reforming plant, assuming industrial price natural gas. EPA estimates that methanol transportation by tanker for delivery to the U.S. would add about 4 to 5 cents per gallon, about \$0.5/GJ, or a small fraction of the cost differential between domestic and flared natural gas. They also referenced a Bechtel analysis of six very large, 10,000 ton per day (2.7 GW_{out}) methanol plants located overseas, in Canada, Alaska and the U.S. Gulf.[25] The plants outside the U.S. could deliver methanol to a U.S. port at a cost of about 35 cents/gallon (\$5.16/GJ). This is equivalent to gasoline at 68 cents/gallon on an energy basis (HHV), or close to the wholesale cost of gasoline.

Some analysts have suggested that cheap imported methanol might be used to produce hydrogen locally for transportation applications. The methanol would be trucked to an on-site reformer to generate hydrogen at the dispensing station, avoiding the costs of transporting gaseous hydrogen. But with "cheap" methanol costing \$5.16/GJ, it would be very difficult to compete with local methane steam reformers producing hydrogen from domestic natural gas selling at \$2.84/GJ for industrial users. The methanol reformer would operate near 200°C, giving it a potential advantage over methane reformers above 450°C, but it seems doubtful that the methanol reformer could overcome this current 2 to 1 feedstock cost advantage of domestic natural gas.

<u>Fuel Cost vs. Plant Size</u>. When FCEVs are initially introduced, there will not be sufficient market pull to justify building large, 2.7-GW methanol plants at a cost estimated at a billion dollars each in Trinidad and up to \$1.5 billion in Australia and Alaska. We need to determine how the price of methanol and hydrogen scales with smaller plant sizes that would be expected in the early days of FCEV deployment. We would also like to know if alternative domestic fuel sources might provide economic feedstock for FCEV hydrogen.

The estimated costs of hydrogen and methanol as a function of the plant size are shown in

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[23]Natural gas prices are usually quoted in \$/TCF -- dollars per thousand cubic feet; since one cubic foot contains about 1012 BTUs of energy (HHV), and since 1 MBTU = 1.055 GJ, the values in \$/TCF, \$/GJ, and \$/MBTU are almost equal: \$1/TCF = \$0.988/MBTU = \$0.937/GJ.

[24]"Monthly Energy Review," Energy Information Administration, March 1995, p.125.

[25]"California Fuel Methanol Cost Study," Bechtel, Inc. January 1989.

Tables 2 and 3. The hydrogen estimates are listed in terms of plant sizes necessary to meet four different FCEV refueling options: a 250-car fleet, a 500-car/day refueling station, a 30 ton/day regional plant serving 10 large stations via pipeline, and a 300-ton/day plant supplying hydrogen to 100 large refueling stations through hydrogen pipelines. All cost data have are based on capital recovery factors of 15.1% per year and plant capacity factors of 90%. The annual costs are divided by the energy content of the annual hydrogen production in GJ (HHV) to determine the \$/GJ cost of hydrogen.

The most costly plant shown in Table 2, a 100,000 SCF/day plant (430 kW_{out} - HHV), would produce enough hydrogen by DTI estimates to fuel about 50 cars per day.[26] Assuming that fleet vehicles travel an average of 18,000 miles per year, each vehicle would be refueled (3/4 tank) about once every 5 days. This plant could therefore provide fuel for a 250-car fleet, which would be more than adequate for early FCEV demonstration projects. It would produce hydrogen at costs above \$25/GJ according to Ogden et al.. This estimate is based on scaling down very large steam methane reformers, and does not include reductions due to building multiple units.

The second row of Table 2 shows the potential cost of hydrogen utilizing the front end of a commercial stationary phosphoric acid fuel cell system that includes a small natural gas reformer. This trailer-mounted unit manufactured by International Fuel Cells (IFC), a division of Hamilton Standard, would produce over 150,000 SCF/day, more than enough for a 250-car fleet operation. More than 60 of these PC-25 fuel cells systems have been sold around the world. The entire fuel cell system delivers 200 KW_e and sells for \$600,000. Based on this firm commercial experience, we conservatively estimate that the reformer section (plus gas clean-up) would cost no more than \$320,000. It could produce hydrogen at \$6.90/GJ, assuming industrial natural gas at \$2.84/GJ. This hydrogen would be competitive with gasoline at about 90 cents/gallon on an energy equivalent basis, or just above the wholesale price of gasoline, a very promising result. With the 2.68 times higher efficiency of the FCEV (LHV) compared to a gasoline ICE vehicle, hydrogen from the PC-25 reformer would be equivalent to gasoline at only 34 cents/gallon for the same vehicle range. However, we must still add the costs of compressing and storing the hydrogen, discussed below.

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[26]Ogden et al. assumes more advanced vehicles with lower drag coefficients, lower rolling resistance, and less weight so each vehicle would consume less hydrogen per mile. In this case, the 100,000 SCF/day plant could serve 80 vehicles per day.

Table 2. Comparison of Hydrogen Production Cost Estimates vs. Plant Output for Steam Methane Reformers

	H2 Output (MW - HHV)	Production	O&M	Natural Gas	Total Cost	Total Cost for P_{NG} = \$2.84/GJ
Fleet (50 cars/day = 250 cars)						
Ogden et al.[27]	0.43	18.5	4.82	$1.17 {*} P_{NG}$	$23.32+1.17 {*} P_{NG}$	26.64
IFC PC-25[28]	0.65	2.93	0.57	$1.20 {*} P_{NG}$	$3.5+1.2 {*} P_{NG}$	6.90
Station (500 cars/day)						
Ogden et al.	4.3	3.7	1.64	$1.17 {*} P_{NG}$	$5.34+1.17 {*} P_{NG}$	8.66
Moore & Nahmias[29]	4.1	7.62	1.39	$1.36 {*} P_{NG}$	$9.01+1.36 {*} P_{NG}$	12.87
Regional Plant (30 tpd)						
Moore & Nahmias	41	4.01	1.81	$1.36 {*} P_{NG}$	$5.82+1.36 {*} P_{NG}$	9.68
Large Central Plant (300 tpd)						
Moore & Nahmias	414	1.62	0.49	$1.36 {*} P_{NG}$	$2.11+1.36 {*} P_{NG}$	5.97
Katofsky[30]	676	1.11	0.87	$1.11 {*} P_{NG}$	$1.98+1.11 {*} P_{NG}$	5.13

(All Costs in U.S. \$/GJ (HHV); P_{NG} is the price of natural gas; capital recovery factor = 15.1%/year; plant capacity factor = 90%)

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[27]Joan M. Ogden, E. Dennis, M. Steinbugler, & J.W. Strohbehn, "Hydrogen Energy System Studies," Princeton University, NREL contract No. XR-11265-2, Draft Final Report, January 1995.

[28]Private communication with Alfred Meyer, June 14, 1995.

[29]Robert B. Moore and Dave Nahmias, "Gaseous Hydrogen Markets and Technologies," Proceedings: Transition Strategies to Hydrogen as an Energy Carrier -- First Annual Meeting of the National Hydrogen Association, Palo Alto, California, Electric Power Research Institute, 1991 (as reported in Katofsky).

[30]Ryan E. Katofsky, "The Production of Fluid Fuels from Biomass," Princeton University, PU/CEES Report No. 279, June 1993.

Table 3 lists methanol cost estimates for large scale steam methane reforming plants. We were not able to locate cost estimates for smaller methanol production plants in this brief study to compare with the on-site hydrogen production cost estimates in Table 2. We presume that small methanol plants would suffer from the same disadvantages of these big plants -- lower efficiency and higher capital cost -- barring any new technology or process that makes methanol production more efficient or less capital intensive.

Table 3. Methanol Production Cost Estimates vs. Plant Size for Methane Steam Reformers[31]

	H_2 Output (MW - HHV)	Production	O&M	Natural Gas	Total	Total for P =\$2.84/GJ
Katofsky	528	2.05	1.1	1.42 P	3.15 + 1.42 P	7.18
Wyman[32]	657	2.4	0.93	1.54 P	3.33 + 1.54 P	7.70
OPPA[33]	2627	2.1	0.37	1.39 P	2.47 + 1.39 P	6.42

(All Costs in U.S. \$/GJ (HHV); P_{NG} is the price of natural gas; capital recovery factor = 15.1%/year; plant capacity factor = 90%)

Alternative Fuel Feedstocks. Both hydrogen and methanol can be manufactured from other hydrocarbons such as coal and biomass, and hydrogen can be produced by electrolyzing water as summarized in Table 4. Natural gas is the least costly option today. Hydrogen produced from coal or biomass would cost about twice as much as natural gas-derived hydrogen for very large plants in the 500 MW_{out} (HHV) range (the only range with comparable data). This assessment assumes that biomass feedstock is 2.9 times more expensive than coal (\$3.75/GJ vs. \$1.29/GJ), indicating that gasifying biomass is much less expensive than gasifying coal to produce hydrogen. Biomass gasification can use lower temperatures and pressures, and biomass contains more hydrogen than coal, providing greater yields.

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[31]Ibid., Katofsky, p. 299.

[32]Charles E. Wyman, Richard L. Bain, Norman D. Hinman, and Don J. Stevens, "Ethanol and Methanol from Cellulosic Biomass," Renewable Energy: Sources for Fuels and Electricity, Edited by T.B. Johansson, H. Kelly, A.K.N. Reddy and R.H. Williams, Island Press, Washington, D.C., 1992.

[33]Office of Policy, Planning, and Analysis, U.S. Department of Energy, "Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Technical Report Three: Methanol Production and Transportation Costs," DOE/PE-0093, November 1989.

Electrolysis. Hydrogen can also be produced by water electrolysis. Using inexpensive off-peak electricity, it might be possible to produce hydrogen at very small scales for early FCEV market demonstrations. DTI has analyzed such a small electrolyzer market entry strategy for the National Renewable Energy Laboratory[34]. We concluded that electrolytic hydrogen could be cost competitive with *fully taxed* gasoline on a per mile basis if off-peak electricity were available at less than 3 to 4.5 cents/kWh and if electrolyzer systems were manufactured in large quantities. That is, the electrolytic hydrogen from very small systems, including home electrolyzers for just two FCEVs, would cost the same per mile as $1.20/gallon gasoline. Furthermore, 71 of the 154 major investor-owned utilities in the U.S. currently offer residential *retail* rates at less than 4.5 cents/kWh, making this a potentially viable approach to providing hydrogen for early demonstration programs.

For the small home electrolyzer, 64% of the capital cost was for the storage system, since a relatively large volume of hydrogen must be stored to provide reliable service for just two FCEVs. For a fleet or public hydrogen dispensing station, less hydrogen needs to be stored since the load fluctuations are less, reducing the cost of storage per unit energy. Assuming that electrolyzer systems can be mass produced at a cost of $300/kW$_{out}$ (LHV), we estimate that electrolytic hydrogen could be produced for $3.28/GJ (HHV) plus 1.33 times the price of off-peak electricity in $/GJ. (Compression and storage will be considered in the next section for hydrogen dispensing stations.)

Fuel Cost vs. Feedstock Cost. Table 4 summarizes methanol and hydrogen production costs as a function of the feedstock cost in $/GJ. The primary sources (natural gas, coal and biomass) are taken from Katofsky[17] for large (500 MW$_{out}$ range) plants, and the electrolysis estimate is based on the DTI analysis for very small scale systems. These costs do not include transportation and compression and storage for hydrogen.

[34]C.E. (Sandy) Thomas & Ira F. Kuhn, Jr., "Electrolytic Hydrogen Production Infrastructure Options Evaluation," draft final report on NREL Subcontract No. ACF-4-1426601, January 1995.

Table 4. Hydrogen and Methanol Production Costs as a Function of Fuel Feedstock Cost

	Hydrogen		Methanol	
	\$/GJ - HHV	Cents/mile	\$/GJ -HHV	Cents/mile
Natural Gas	$1.98 + 1.11 * P_{NG}$	$0.56 + 0.31 * P_{NG}$	$3.15 + 1.42 * P_{NG}$	$1.15 + 0.52 * P_{NG}$
Coal	$6.65 + 1.28 * P_C$	$1.88 + 0.36 * P_C$	$7.62 + 1.54 * P_C$	$2.81 + 0.57 * P_C$
Biomass[35]	$5.07 + 1.28 * P_B$	$1.43 + 0.36 * P_B$	$6.73 + 1.54 * P_B$	$2.47 + 0.57 * P_B$
Electrolysis[36]	$3.28 + 1.33 * P_E$	$0.92 + 0.38 * P_E$	N.A.	--

(P_X = feedstock cost in \$/GJ where NG = natural gas, C = coal, B = biomass, and E = electricity)

Fuel Transportation & Distribution Costs

To determine the final cost to the end-user, we must add the cost of transporting the fuel to the refueling station, and, in the case of hydrogen, we must include the costs of compressing and storing the gas on-site. We assume for this evaluation that hydrogen is stored as a compressed gas on-board the vehicle at a pressure of 5,000 psia. If lower pressure storage systems become cost effective in the future, then the cost of delivered hydrogen will be reduced. We do not include retail markup here, assuming that each fuel would have the same markup. The following costs should therefore be compared with gasoline wholesale prices.

Hydrogen Transportation. Gaseous hydrogen could be produced on-site at "gas stations," manufactured at a central facility and delivered by pipeline, or liquified and shipped by tanker truck. Both liquid and pipeline transportation methods are used today to ship large quantities of hydrogen. Air Products and Chemicals operates over 100 miles of hydrogen pipelines supplying the chemical industry around LaPorte, Texas, with a flow rate of 40 million SCF/day. Praxair also operates hydrogen pipelines in Texas, New Jersey and Indiana, and Germany has had a hydrogen pipeline network operating in the Ruhr Valley since 1938. All major hydrogen suppliers also have a fleet of liquid hydrogen tanker trucks that will deliver liquid hydrogen anywhere in the U.S., and most merchant hydrogen is delivered by truck in the U.S.

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[35]Biomass estimate is for the Battelle Columbus Laboratory indirect biomass gasifier, reported in Katofsky.

[36]Electrolyzer estimate from the DTI evaluation assuming mass production of very small electrolyzer systems, with an annualized capital recovery factor of 0.151 to be consistent with the Katofsky data. Capacity factor is 0.7 (vs. 0.9 for Katofsky) to correspond to the use of off-peak electricity.

Ogden et al. have shown that the cost of liquefying and shipping hydrogen by tanker truck would be higher than the cost of pipeline delivery for every size of hydrogen dispensing station.[37] However, liquid hydrogen could be delivered today, whereas hydrogen pipelines would have to be built to service hydrogen dispensing stations. For a large refueling station (1 million SCF/day), the cost of adding a liquid hydrogen storage tank, liquid pump and vaporizer would be only \$0.63/GJ (capital cost of \$430,000). If we assume that liquid hydrogen could be truck delivered at a price of \$1.07/pound or \$16.58/GJ,[38] then the added station cost of \$0.63/GJ is not significant. Ogden et al. estimates a total cost to the consumer of \$17.5/GJ (excluding station labor), which is equivalent to gasoline at about \$0.93/gallon. This is on the high side to be competitive with wholesale gasoline, but low enough so that liquid hydrogen should be considered an early option in the FCEV program. The three major hydrogen suppliers (Air Products, BOC Gases, and Praxair) are currently under contract with the Ford Motor Company as part of the DOE direct hydrogen PEM fuel cell vehicle program to explore the various options of producing, transporting and dispensing hydrogen for FCEVs. They will provide more detailed analysis of various hydrogen delivery options.

The cost of building a national hydrogen pipeline system similar to the existing natural gas pipeline system would be exorbitant. However, significant hydrogen can be produced locally at on-site reformers, utilizing the existing natural gas and electricity infrastructure to supply the feedstock fuel. No new fuel transportation infrastructure would be required to begin demonstrating and utilizing hydrogen powered FCEVs. The federal government is currently promoting natural gas vehicles (NGVs) to help reduce urban air pollution, indicating that some officials believe that natural gas supplies can support the transportation market at least in the short term. Converting this natural gas to hydrogen at 90% efficiency to power a FCEV with 2.7 times higher energy efficiency than ICE vehicles on gasoline (or 2.2 times higher efficiency compared to a dedicated NGV) would provide nearly twice the range per unit of natural gas consumed in a dedicated NGV, thereby substantially extending the effective supply of natural gas. Similarly, there is excess off-peak electricity available that could be used to produce hydrogen without requiring new electrical generation capacity.

Ogden et al. have also estimated the costs of building hydrogen pipelines. The cost of pipeline transmission per unit energy varies widely, depending on the distance traveled, the pipeline diameter, and the pressure drop along the length of the pipe. The hydrogen flow rate through the pipe is given by:[39]

$$Q = 0.25 \times D^{2.5} \times \left[\frac{P_1^2 - P_2^2}{L} \right]^{0.545} \tag{1}$$

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[37] Ibid., Ogden et. al., Figure 21.

[38] Ibid., Ogden et al., Table 17.

[39] Ibid., Ogden et al., Box 2

where Q = the hydrogen flow rate in million SCF/day,
D = the pipe diameter in cm,
P_1 = the inlet pipe absolute pressure in atmospheres,
P_2 = the outlet pipe absolute pressure in atmospheres, and
L = the pipe length in meters.

Ogden et al. estimated that a 7.62 cm diameter pipe would cost about $182/meter to install. If we assume that a hydrogen transmission pipeline cost scales linearly with diameter and length, then the minimum amortized life cycle cost of the pipeline per unit energy of hydrogen delivered is derived from Equation 1:

$$C_p = \frac{7.8\times 10^{-4}\times L^{1.545}\times (CRF + O\&M)}{D^{1.5}\times CF\times \left(P_1^2 - P_2^2\right)^{0.545}} \tag{2}$$

where C_p = hydrogen pipeline cost in \$/GJ (HHV),
CRF = the capital recovery rate (fraction of capital cost recovered each year),
O&M = the annual operations and maintenance charge as a fraction of capital cost, and
CF = the pipeline capacity factor, or the ratio of average hydrogen flow to the maximum pipeline capacity, and L, D, P_1 and P_2 are as defined above.

Consider now a regional natural gas steam reformer producing 30 tons/day of hydrogen, or an output rate of about 45 MW (HHV). This plant would produce enough hydrogen to supply about 10 large refueling stations, each servicing 500 cars per day with 12 pounds of hydrogen. If we assume that the plant supplies these ten stations spaced 3 miles apart from a single linear pipeline, then the flow rate would average 11.5 MSCF/day at the input end. According to Equation 1, a 12.7 cm (5 inch) diameter pipeline could transfer up to 17.1 MSCF/day, assuming a pressure swing from 500 psia to 200 psia, allowing a 50% surge rate above the average plant output. With 10% capital recovery, 2% annual operating costs, and 90% capacity factor, according to Equation 2, this 30-mile pipeline would add about $.93/GJ to the cost of hydrogen. But this assumes that the pipeline is operating at its maximum flow rate of 17.1 MSCF/day. At the average annual rate of 11.5 MSCF/day, the pipeline cost is $1.38/GJ.[40]

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[40]Technically, the linear pipeline in this example is underutilized as one moves away from the hydrogen production plant, with the last of ten stations receiving only ten percent of the annual flow. We assume that all customers would be charged the average capital recovery rate, just as the price of electricity is constant for all customers of a given class no matter how far they are from the utility generation plant. (If the utility were assured that the linear network of refueling stations was permanent, then the line diameter would be reduced after each station, reducing total costs.)

This cost of transporting gaseous hydrogen is much higher than the cost of shipping gasoline by pipeline. The Energy Information Administration estimates that a 1,500-mile gasoline pipeline costs about 2.2 cents/gallon, or $0.17/GJ.[41] In other words, it costs eight times more to ship hydrogen 30 miles by pipeline than it does to ship gasoline 1,500 miles!

In general, a larger hydrogen reformer plant would have higher transmission costs, since the stations would be farther away. However, if we allow multiple transmission lines radiating outward from this large central plant, the cost per unit energy might not be much greater. For example, a 300 ton/day plant might feed ten pipelines, each reaching out 30 miles in a different direction to feed a large urban area. Again, these issues will be addressed in more detail under the DOE direct hydrogen FCEV program .

Hydrogen Compression and Storage. Unless inexpensive, light weight, and low pressure hydrogen storage systems are developed for FCEVs, the hydrogen must also be compressed and stored at the dispensing station. This will add to the cost, but may be cost effective since hydrogen storage will also act as a buffer to accommodate hydrogen daily or weekly demand surges. Without storage, the reformer would need higher capacity (more capital cost) to follow the hydrogen demand load.

Ogden et al. has estimated the costs for compressing and storing hydrogen on-site at a dispensing station. Their storage cylinder cost estimate for steel tanks is equivalent to about $325/pound of stored hydrogen at 8,000 psi. DTI has estimated that carbon wrapped composite tanks could cost as little as $60/pound of stored hydrogen in very large production runs. Furthermore, 3,600 psi fiber wrapped aluminum tanks are being sold for natural gas vehicles at a price of $100 to $200/pound of hydrogen for relatively small tanks, less than 7 cubic feet actual volume. Cost per pound of stored hydrogen in these tanks falls with increased volume, as shown in Figure 1. For the 15 cubic foot tanks assumed by Ogden et al., the price for carbon wrapped aluminum tanks would be less than $100/pound of hydrogen. Ogden et al. also assumed that electricity would cost 6 cents/kWh. To be consistent with other fuel costs, we use the 1994 industrial rate for electricity: 4.7 cents/kWh. Our assumptions for hydrogen compression and storage are compared with those of Ogden et al. below, showing the various components of hydrogen cost in $/GJ:

	Ogden et al.:	DTI:
Storage cylinder capital:	$1.66/GJ ($325/lb)	$0.51/GJ ($100/lb)
Compressor capital:	0.59	0.59
Compressor O&M	0.02	0.02
Compressor electricity	1.08 (6 c/kWh)	0.85 (4.7 c/kWh)
Total:	$3.35/GJ	$1.97/GJ

Methanol Transportation Costs. Methanol can be shipped in pipes and trucks, much like

[41]Ibid., EIA, p. 77.

gasoline. However, methanol is highly toxic (two teaspoons can be lethal for some, and 10 to 60 teaspoons of methanol will be fatal for most people)[42] and corrosive, requiring special attention to the entire distribution chain. Methanol reportedly dissolves solder, aluminum, rubber and other materials,[43] although Perry's handbook lists methanol as being "satisfactory" for use with rubber.[44] Underground storage tanks must be fabricated from special fiberglass or carbon-based steels. Based on studies of methanol powered ICE vehicles, the total costs for methanol vessels and piping are not significantly higher, but all new fuel handling equipment must be built for methanol -- none of the existing gasoline infrastructure could be used. In this sense, methanol has no significant advantage over hydrogen. In either case, new transportation infrastructure must be built if the fuel is produced at large central plants.

The estimated cost for transporting gasoline from the Gulf to Boston is about 5 cents/gallon, including 2.2 cents for 1,500 miles of pipeline travel, 1.1 cents for 250 miles by barge, 0.2 cents for terminal costs, and 1.5 cents for the gasoline tanker truck traveling 40 miles.[45] If we assume that the extra precautions necessary to handle methanol do not add to the transportation costs, and if we assume that an entire pipeline/barge/tanker truck fleet is built for methanol, then presumably methanol could also be moved by this venue at a cost of 5 cents/gallon. Since methanol has only half the heating value of gasoline, the cost per unit energy would be twice as much as gasoline, or about $0.73/GJ.

Per mile, truck delivery is 25 times more costly than pipeline delivery. To the degree that methanol must be delivered by truck while hydrogen is either produced on-site or delivered by pipeline from a local reformer plant, methanol transportation could be more expensive than hydrogen transportation. For example, if the methanol must be trucked 120 miles, the added cost of $0.66/GJ would bring the total methanol transportation costs equal to the hydrogen 30-mile pipeline cost of $1.38/GJ.

Williams et. al.[46] have used much higher costs for methanol transportation: $1.9/GJ compared to our estimate of $0.73/GJ based on experience with gasoline. Conversely, they

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[42] "Analysis of the Economic and Environmental Effects of Methanol as an Automotive Fuel," Environmental Protection Agency, Office of Mobile Sources, September 1989, p. 72.

[43] "Alternative Motor Vehicle Fuels to Improve Air Quality: Options and Implications for California," California Council for Environmental and Economic Balance, January 1990, p. 11.

[44] Perry's Chemical Engineers' Handbook, Sixth Edition, Edited by Don W. Green, McGraw-Hill, 1984, p. 23-29.

[45] Alternatives to Traditional Transportation Fuels: an Overview, Energy Information Administration, U.S. Department of Energy, DOE/EIA-0585/O, June 1994, p. 77.

[46] Robert H. Williams, Eric D. Larson, Ryan E. Katofsky, & Jeff Chen, "Methanol and Hydrogen from Biomass for Transportation," Princeton University, September 6, 1994 draft prepared for the Bioresources '94 meeting in Bangalore, India.

assumed hydrogen transmission costs of only $0.5/GJ, compared to our estimate of $1.38/GJ based on a 30-mile pipeline. The economic advantage of hydrogen relative to methanol would be increased with the Williams et. al. assumptions.

Total Delivered Cost of Hydrogen and Methanol. The final cost estimates for hydrogen and methanol produced from various feedstocks are summarized in Tables 5 and 6, including the cost of transportation, and, for hydrogen, the cost of compression and storage. The cost of hydrogen is plotted in Figure 2 as a function of production plant output. The most surprising result is that hydrogen produced by the small, 150,000 SCF/day PC-25 reformer by IFC has estimated costs about the same as hydrogen delivered from very large plants. Prior to this study, we had assumed that very large plants would be necessary to bring the cost of hydrogen down, which would have created the typical chicken and egg dilemma: fuel demand in the early days of FCEV development could not justify building a large plant, and FCEVs would not be viable until large hydrogen plants were built. The IFC small scale reformer solves this dilemma: we can build very small reformers at individual fleet locations, literally pulling a trailer up to the facility and plumbing into the natural gas line. The IFC cost data are reliable, since they are based on actual manufacturing experience with the PC-25 stationary fuel cell system, which includes the natural gas reformer. Gas clean up is required to remove carbon dioxide, but we have conservatively estimated a total cost of $320,000 for the reformer and pressure swing adsorption unit, or over half the cost of the PC-25 full system cost ($600,000), which includes the phosphoric acid fuel cell stack and power conditioning equipment.

The delivered cost of methanol is plotted in Figure 3 for very large plants. We have not located any data on smaller methanol plants. Both methanol and hydrogen cost more when derived from biomass or coal at today's energy prices.

The delivered costs of hydrogen and methanol are compared in Figure 4. The data barely overlap, with the hydrogen delivered cost for large plants virtually equal to the methanol costs per unit energy. The cost of hydrogen pipeline transportation, compression and storage assumed here ($3.35/GJ), combined with the low methanol transportation cost ($0.73/GJ) has nearly cancelled the production cost advantage of hydrogen over methanol. The small on-site reformer, which eliminates the $1.38/GJ transportation charge for the pipeline, is competitive with methanol per unit energy.

The costs of hydrogen and methanol per mile are shown in Figure 5, based on 1994 industrial fuel costs. The relative inefficiency of the methanol FCEV (77% reformer efficiency and 5% loss due to reformate effects) restores a 22% cost advantage to hydrogen. We have also plotted the cost per mile for wholesale, retail, and fully taxed gasoline[47], assuming $17/barrel crude oil cost or $1.11/gallon fully taxed gasoline.

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[47]State gasoline taxes vary between 7.5 cents/gallon (Georgia) and 30 cents/gallon (Connecticut) as of 1994. We use the national average tax of 41.3 cents/gallon as reported by the DOE Energy Information Administration, including the federal road tax of 18.4 cents/gallon.

According to this estimate, both hydrogen and methanol from natural gas would be competitive with wholesale gasoline today on a per mile basis. Electrolytic hydrogen is competitive with fully taxed gasoline, as discussed above, while hydrogen from natural gas is less than half the cost of fully taxed gasoline. Normally a comparison between untaxed hydrogen and fully taxed gasoline would not be valid, but there is precedent for not taxing clean fuels like natural gas and electricity for EVs. We assume here that hydrogen would not be subjected to a road excise tax, but that taxes would be gradually increased on the more polluting fuels to make up for any loss to the highway trust fund as a result of widespread use of FCEVs.

Biomass derived hydrogen would be competitive with retail gasoline on a per mile basis, reinforcing previous analyses showing biomass to be the first cost-effective renewable hydrogen source.

Fuel Cost Projections. The future projected costs of industrial fuels are plotted in Figure 6. We have taken the 1990 DOE long range projections[48] and adjusted them to match actual 1995 fuel costs. The biomass data were synthesized from the two data points (1995 and 2010) provided by Katofsky.

The projected costs of methanol and hydrogen per mile are shown in Figure 7, based on the fuel cost estimates of Figure 6. The most interesting result is that natural gas would become more expensive than either coal or biomass after the year 2012.

Finally, the cost per mile for gasoline, electrolytic hydrogen, and photovoltaic (PV) hydrogen are added in Figure 8. The cost of gasoline was scaled from the projected National Energy Strategy crude oil price predictions, based on an historical fit of wholesale and retail gasoline costs to crude oil costs. The NES predicts that crude oil will rise to $56/barrel by the year 2030 (in 1995 $). The electrolytic hydrogen is based on the DTI production analysis (Table 4), plus $1.97/GJ for compression and storage. We have assumed that off-peak electricity is available at 60% of the average industrial electrical rate. For 1994, the average industrial rate was 4.7 cents/kWh, so the we assumed an off-peak rate of 2.8 cents/kWh for Figure 8.

The two PV projections are based on data from Zweibel and Luft[49] (more optimistic curve in Figure 8) and from the "Intensified R&D" scenario of the 1990 Department of Energy Interlaboratory White Paper .[50] We used Williams' projections of the cost of PV electricity in cents/kWh for these two estimates, based on the best solar areas of the U.S. (2,400 kWh/m^2-

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[48]Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results, Technical Annex 2, DOE/S-0086P, 1992, Table B-2

[49]Ken Zweibel and W. Luft, "Flat-Plate, Thin-Film Modules/Arrays," National Renewable Energy Laboratory, November 1993, as reported in Williams (Ref. 51 below).

[50]"The Potential of Renewable Energy: An Interlaboratory White Paper," U.S. Department of Energy Report SERI/TP-260-3674, March 1990.

year).[51] Therefore these are the most optimistic projections for PV electricity. We then added the cost of electrolysis, compression and storage to be consistent with the other data on Figure 8: \$300/kW_{out} electrolyzer system cost in mass production, 0.151 capital recovery factor, 4% of the capital cost for O&M, insurance and taxes, and \$1.97/GJ for compression and storage.

To put these PV projections into perspective, PV electricity now costs about 20 cents/kWh for small systems, which would translate into \$79/GJ hydrogen, or a transportation cost of 22 cents/mile, well off the scale of Figure 8. On the other hand, ENRON and Solarex have announced plans to build a 100 MW plant that would produce amorphous silicon PV modules which they estimate could produce PV electricity at 5.5 cents/kWh. This could produce PV hydrogen at \$25.50/GJ (including compression and storage), or a transportation cost in the FCEV of 7.2 cents/mile. If the ENRON/Solarex project is successful, then they will achieve the PV goals projected for about 2010, bringing PV hydrogen close to being competitive with the projected costs of gasoline.

While these projections are highly speculative, Figure 8 indicates one possible outcome for hydrogen and methanol costs relative to fossil fuels. The exact dates are less important than the trends: as natural gas and particularly oil prices rise in the future, hydrogen and methanol from biomass and coal (and possibly MSW - municipal solid waste) will become more cost competitive. Notice that even electrolytic hydrogen, with electricity derived primarily from coal, becomes competitive with wholesale gasoline by 2000 and with methanol from natural gas by the year 2015. The PV projections indicate that PV hydrogen could compete with fully taxed gasoline in the transportation market before 2010, and with wholesale gasoline by 2015. PV electricity would match off-peak grid electricity (assumed to be 60% of the industrial electrical rate) by 2020 for the optimistic case, or by 2030 under the DOE Interlaboratory White Paper projections.

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[51]Robert H. Williams, "Toward an Energy Industrial Renaissance," Princeton University, prepared for the Institute for Environmental Management-Siemens/KWU Workshop, July 14, 1994.

Table 5. Hydrogen Production, Transmission, Compression and Storage Cost Estimates (All Costs in U.S. $/GJ -HHV)

	H_2 Out (MW - HHV)	Prod. Capital	O&M	Fuel	Transmission	Compr. & Storage	Totals
Natural Gas Feedstock							
Fleet (50/day = 250 cars)							
Ogden et al.	.43	18.50	4.82	$1.17{*}P_{NG}$	0	1.97	$25.29+1.17{*}P_{NG}$
IFC PC-25	.65	2.93	0.57	$1.20{*}P_{NG}$	0	1.97	$5.47+1.2{*}P_{NG}$
Station (500 cars/day)							
Ogden et al.	4.3	3.7	1.64	$1.17{*}P_{NG}$	0	1.97	$7.31+1.17{*}P_{NG}$
Moore & Nahmias	4.1	7.62	1.39	$1.36{*}P_{NG}$	0	1.97	$11.49+1.36{*}P_{NG}$
Regional Plant (30 tpd)							
Moore & Nahmias	41	4.01	1.81	$1.36{*}P_{NG}$	1.38	1.97	$9.17+1.36{*}P_{NG}$
Large Central Plants (300 tpd)							
Moore & Nahmias	414	1.62	0.49	$1.36{*}P_{NG}$	1.38	1.97	$5.46+1.36{*}P_{NG}$
Katofsky	676	1.11	0.87	$1.11{*}P_{NG}$	1.38	1.97	$5.33+1.11{*}P_{NG}$
Coal Feedstock							
Steinberg & Cheng	414	4.71	3.04	$1.68{*}P_C$	1.38	1.97	$11.10+1.68{*}P_C$
Blok et. al.	1095	4.31	1.31	$1.54{*}P_C$	1.38	1.97	$8.97+1.54{*}P_C$
Katofsky	1336	3.92	2.73	$1.28{*}P_C$	1.38	1.97	$10.00+1.28{*}P_C$
Biomass Feedstock							
IGT Gasifier	247	5.2	3.13	$1.48{*}P_B$	1.38	1.97	$11.68+1.48{*}P_B$
BCL Gasifier	301	2.86	2.21	$1.28{*}P_B$	1.38	1.97	$8.42+1.28{*}P_B$
Electrolysis							
DTI	0.003	2.6	0.68	$1.33{*}P_E$	0	1.97	$5.25+1.33{*}P_E$

All data & references from: Ryan E. Katofsky, "The Production of Fluid Fuels from Biomass," Princeton University, PU/CEES Report No. 279, June 1993; *except* Joan M. Ogden, E. Dennis, M. Steinbugler, & J.W. Strohbehn, "Hydrogen Energy System Studies," Princeton University, NREL contract No. XR-11265-2, Draft Final Report, January 1995;IFC data from Alfred Meyer, private communications; and DTI, Ibid.. [P_x = feedstock cost in $/GJ, where NG = natural gas, C = coal, B = biomass, and E = electricity.].

Table 6. Methanol Production and Transportation Costs (U.S.$/GJ)

	H_2 Output (MW - HHV)	Production Capital	O&M	Fuel	Transportation	Totals
Natural Gas Feedstock						
Katofsky	528	2.05	1.1	$1.42*P_{NG}$	0.73	$3.88+1.42*P_{NG}$
Wyman	657	2.4	0.93	$1.54*P_{NG}$	0.73	$4.02+1.54*P_{NG}$
OPPA	2627	2.1	.37	$1.39*P_{NG}$	0.73	$3.2+1.39*P_{NG}$
Coal Feedstock						
Katofsky	1117	5.48	2.14	$1.54*P_C$	0.73	$8.35+1.54*P_C$
Wyman	1314	5.8	2.05	$1.80*P_C$	0.73	$8.58+1.80*P_C$
Biomass Feedstock						
IGT Gasifier	209	7.82	2.83	$1.76*P_B$	0.73	$11.38+1.76*P_B$
BCL Gasifier	248	4.7	2.03	$1.54*P_B$	0.73	$7.46+1.54*P_B$

All data and references from Katofsky, Ibid.

Vehicle Life Cycle Costs

The previous sections have demonstrated that hydrogen can be produced for use in a FCEV at a cost per mile that is less than that of gasoline in an ICE today, and that the economic advantage for hydrogen as a fuel will probably increase over time, based on current projections of increasing fossil fuel costs. Methanol is projected to remain about 22% more expensive than hydrogen per mile traveled in a FCEV, but would also be less expensive than wholesale gasoline.

While some drivers may emphasize fuel costs in choosing between vehicle options, in reality the cost of fuel is typically less than 15% of the total costs of owning and operating an automobile, as illustrated in Figure 9. This figure shows the breakdown of life cycle costs for four different vehicles based on 1995 fuel prices: a gasoline powered internal combustion engine vehicle, a FCEV powered directly by hydrogen, a FCEV with an on-board reformer fueled by methanol, and a battery powered electric vehicle (BPEV). With the cost parameters we have assumed here, the FCEV would be less costly to own and operate than either the conventional ICE vehicle or the BPEV, assuming that all vehicles were mass produced.

These life cycle costs differ in several respects from those reported in the literature, most of which are derived from the work of Mark DeLuchi. He assumed that FCEVs would be considerably more expensive than ICEs, and he also assumed that hydrogen storage would be more expensive than methanol reforming per mile of range, to the degree that the added cost of the on-board storage vessel more than cancelled the lower cost of hydrogen per mile compared to methanol.

DeLuchi assumed that the compressed hydrogen FCEV would cost about $8,000 more than a conventional ICE vehicle, based largely on a very expensive fuel tank.[52] In addition, he assumed that the FCEV would have less range than the ICE (240 miles vs. 380). DTI has shown that a carbon wrapped composite tank could be produced in large quantities for about $60 per pound of stored hydrogen, or about $900 to carry the 15 pounds required for the Taurus-like vehicle, giving it the same range as the gasoline version.

The methanol FCEV eliminates the cost of the high pressure storage system, but adds the cost of an on-board reformer. GM has estimated such a reformer could be mass produced for about $12/kW. Assuming a 60kW fuel cell system, the high volume reformer cost would be $780. In addition, we assumed previously that the fuel cells for the methanol system would have to be about 7% larger to account for lower peak power per unit active area with methanol reformate. That is, the methanol reformate fuel cell would have to be larger to maintain the same peak power as the hydrogen powered cell, and also the peak power cell voltage would be slightly lower, requiring more cells to keep the motor voltage at the rated level. Based on the GM estimate, the fuel cell system would cost about $2,100, so the extra 7% would add $146 to the methanol fuel cell system. The sum of the reformer cost and the extra fuel cell cost ($926) is roughly equivalent to the hydrogen storage tank ($900). We therefore assume that a FCEV with compressed hydrogen storage tanks would cost about the same as the methanol FCEV.

DTI has also estimated the total costs of the FCEV drive train in large volume production would be in the range from $4,000 to $5,000, or about $1,000 per vehicle more expensive than the ICE drive train that typically costs $3,000 to $4,000. We have therefore assumed here that the cost of the FCEV (either methanol or hydrogen powered) would be $1,000 more than the ICE. In effect, the DTI estimate reflects high volume production typical of the automobile industry, while the Princeton/DeLuchi estimates are more representative of early models of the FCEV.

DeLuchi also assumed several different parameters for the FCEV compared to the gasoline ICE that tended to mask the comparison. For example, he assumed that the FCEV would be driven more miles per year, "because they would be more reliable and have lower operating costs," and would have different loan parameters (down payments and interest rates). These assumptions continue in recent Princeton publications, with a 1995 document listing the hydrogen FCEV at $7,100 more than the ICE, and the methanol FCEV at $3,700 more expensive[53]. In addition both FCEV's were driven 14,750 miles per year, while the ICE was driven only 11,000 miles.

We assume here identical cost parameters for the ICE and the FCEV, with the exception of maintenance costs, which we have adapted from DeLuchi's work based on the assumption that the electric vehicles would have fewer moving parts and less maintenance. The basic parameters for Figure 9 are summarized in Tables 7 and 8, along with a comparison of the DTI assumptions with the DeLuchi and recent Princeton assumptions.

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[52]Mark DeLuchi, "Hydrogen Fuel-Cell Vehicles," Research Report UCD-ITS-RR-92-14, Institute of Transportation Studies, University of California, Davis, September 1992.

[53]Robert H. Williams, Eric D. Larson, Ryan E. Katofsky & Jeff Chen, "Methanol and Hydrogen from Biomass for Transportation," submitted to Energy for Sustainable Development, January, 1995.

Table 7. Comparison of Motor Vehicle Parameters

	ICE		H2 FCEV		MeOH FCEV		BPEV	
	DTI	PU	DTI	PU	DTI	PU	DTI	PU
Initial Cost ($)	18,000	18,000	20,000	25,100	20,000	21,700	25,000	27,000[54]
Annual Miles Traveled	11,000	11,000	11,000	14,750	11,000	14,750	11,000	14,200
Car Life in miles	120,000	120,000	120,000	159,000	120,000	159,000	120,000	159,000
Vehicle Range (miles)	340	400	340	250	340	350	340	250
Maintenance Costs ($/yr)	620	381	419	345	419	357	419	312

DTI= Directed Technologies, Inc.
PU=Princeton University

Table 8. Other Vehicle Cost Parameters

Battery Replacement Cost	Battery Life (miles)	Loan Down Payment	Loan Interest Rate	Loan Duration	Collision Insurance (% of cap)	Liability Insurance ($/year)	Inspection Fee (ICE only)	Other annual costs	Real Discount Rate
$4,000	30,000	11%	8%	5 years	1.42%	318	$20	$130	3%

[54]Ibid., Katofsky, p. 305.

From a life cycle cost perspective, there is very little difference between hydrogen and methanol. Since fuel accounts for only 10 to 15% of the life cycle costs, the 22% per mile fuel savings of hydrogen is diluted to a negligible advantage over a methanol powered FCEV.

Finally, we have estimated the life cycle costs for the four vehicles assuming the fuel price projections for 2010. As shown in Figure 10, the relatively large increases in fuel prices has only a modest effect on life cycle costs. All fuel prices increase (in constant, 1995 dollars), but oil rises faster than natural gas or coal, and biomass prices fall. The advantage of hydrogen and methanol over gasoline or BPEV is increased compared to 1995 prices, according to these cost projections. The environmental and national security advantages of utilizing FCEVs are not reflected in any of these cost data.

Conclusions

Based on this preliminary comparative evaluation of hydrogen and methanol as fuels for PEM fuel cell electric vehicles, and pending more detailed evaluation of infrastructure issues under the DOE direct hydrogen FCEV program, we come to these tentative conclusions:

Energy Efficiency & Greenhouse Gas Emissions

* Hydrogen produced from natural gas for use in a FCEV is about 1.7 times more energy efficient than methanol produced from natural gas based on three factors: methane steam reforming to produce hydrogen is more efficient than methanol production (90% vs. 71%), methanol reformation on-board the vehicle is only 77% efficient, and methanol reformate is predicted to reduce fuel cell efficiency by 5%, all on a higher heating value (HHV) basis.

* Methanol FCEVs would generate approximately 50% more CO_2 than hydrogen FCEVs, based on more natural gas consumed minus the power plant emissions resulting from compression of the hydrogen to 8,000 psia. Both FCEV's would create less CO_2 than gasoline ICE's: a hydrogen FCEV would reduce CO_2 63%; a methanol FCEV would reduce CO_2 42% relative to gasoline.

Cost

* A small scale steam methane reformer suitable for a 250-car fleet could produce hydrogen at a cost *below the wholesale price of gasoline* on a per mile basis, using part of an existing commercial product at very low manufacturing rates.

* Capital costs for methanol plants are approximately 1.5 times greater than for the same capacity hydrogen steam methane reforming plants.

* Hydrogen would cost about 40% less than methanol to produce, but delivered methanol and hydrogen would cost about the same per unit energy due to the

added costs of compressing and storing hydrogen.

* Hydrogen would cost about 22% less than methanol per FCEV mile.

* Hydrogen FCEV's have only a slight life cycle cost advantage over methanol FCEV's, since fuel costs are a small fraction of life cycle costs.

Alternative Fuel Feedstocks

* Hydrogen and methanol produced from coal or biomass would cost 50 to 80% more than from natural gas today.

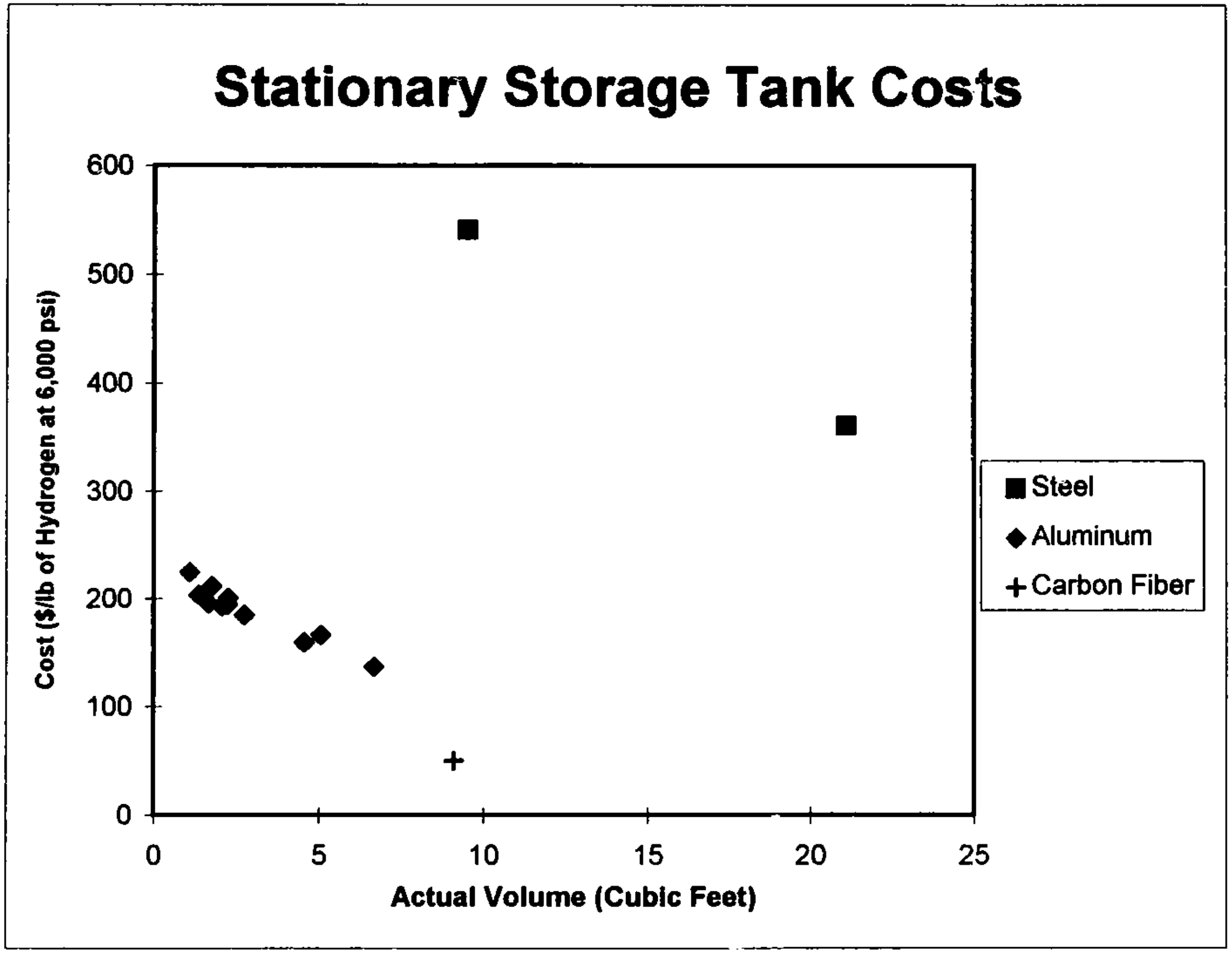
* Based on DOE projections for fossil fuel prices, biomass and coal would become competitive with natural gas as a feedstock for methanol and hydrogen after 2010.

* Electrolytic hydrogen would become competitive with wholesale gasoline by 2000, assuming off-peak electricity at 60% of the industrial rate.

* PV hydrogen would become competitive with fully taxed gasoline per mile driven before 2010, and would become competitive with wholesale gasoline by 2015 according to optimistic PV cost projections.

Either methanol or hydrogen could be a cost-effective energy carrier to support the introduction of FCEVs. Ultimate system efficiency, however, favors direct hydrogen utilization, since methanol is both produced from and must be turned into hydrogen. In addition, hydrogen is the preferred energy carrier for a sustainable energy future based on renewable resources -- producing methanol from PV, wind, geothermal or hydroelectric sources is not practical.

Figure 1

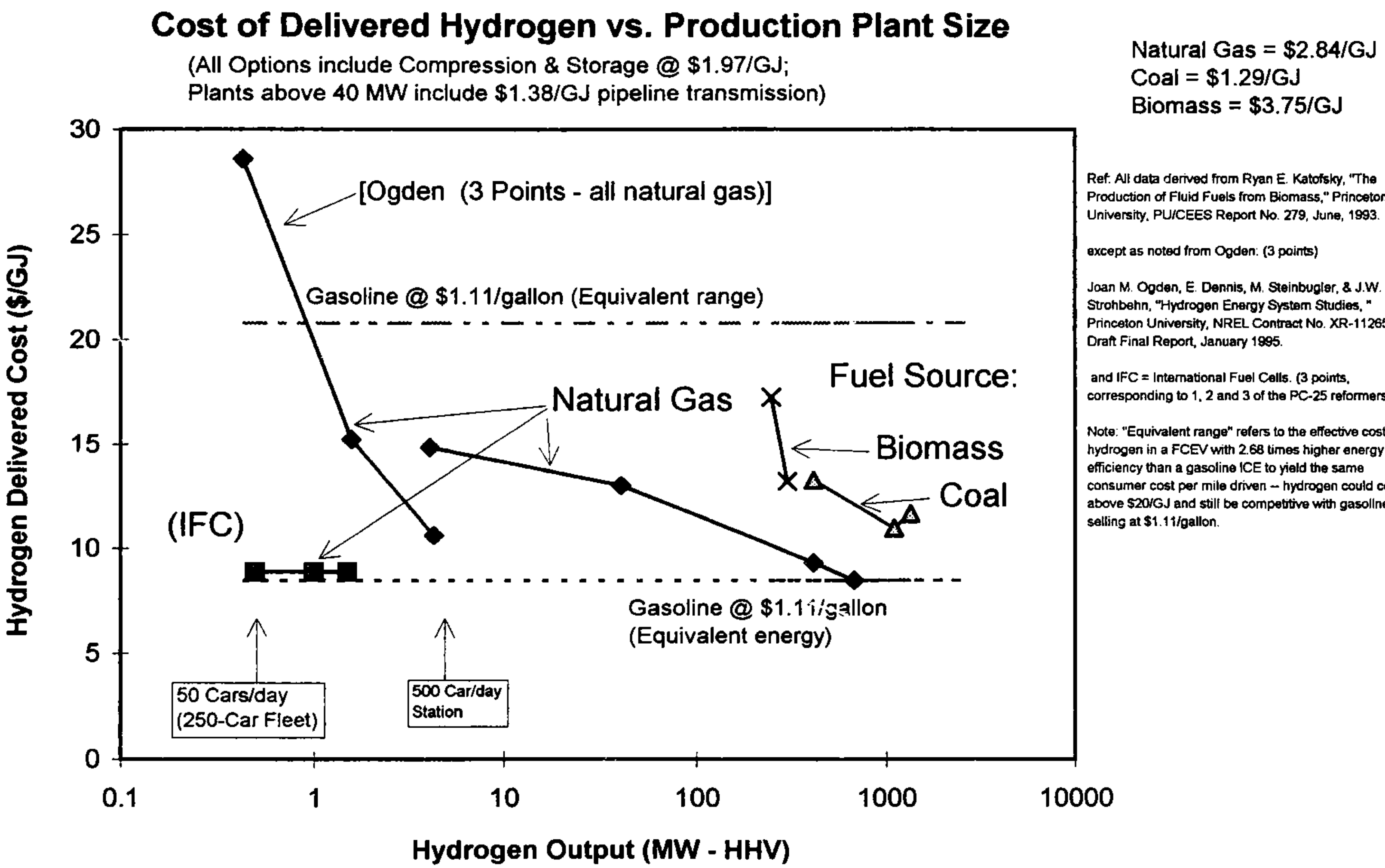


Steel Quote from CP Industries, Inc of McKeesport, Pennsylvania
For 6,000 psi ASME steel tanks, 16 " OD x 1.416" wall.

Aluminum Quote from NGV Systems, Inc of Long Beach, California
For 3,600 psi composite wrapped aluminum cylinders

Carbon Fiber tank is DTI projection for 2004, based on 6,000 psi
carbon fiber wrapped plastic tanks with metalized liner.

Figure 2



Ref: All data derived from Ryan E. Katofsky, "The Production of Fluid Fuels from Biomass," Princeton University, PU/CEES Report No. 279, June, 1993.

except as noted from Ogden: (3 points)

Joan M. Ogden, E. Dennis, M. Steinbugler, & J.W. Strohbehn, "Hydrogen Energy System Studies," Princeton University, NREL Contract No. XR-11265-2, Draft Final Report, January 1995.

and IFC = International Fuel Cells. (3 points, corresponding to 1, 2 and 3 of the PC-25 reformers.)

Note: "Equivalent range" refers to the effective cost of hydrogen in a FCEV with 2.68 times higher energy efficiency than a gasoline ICE to yield the same consumer cost per mile driven -- hydrogen could cost above $20/GJ and still be competitive with gasoline selling at $1.11/gallon.

Figure 3

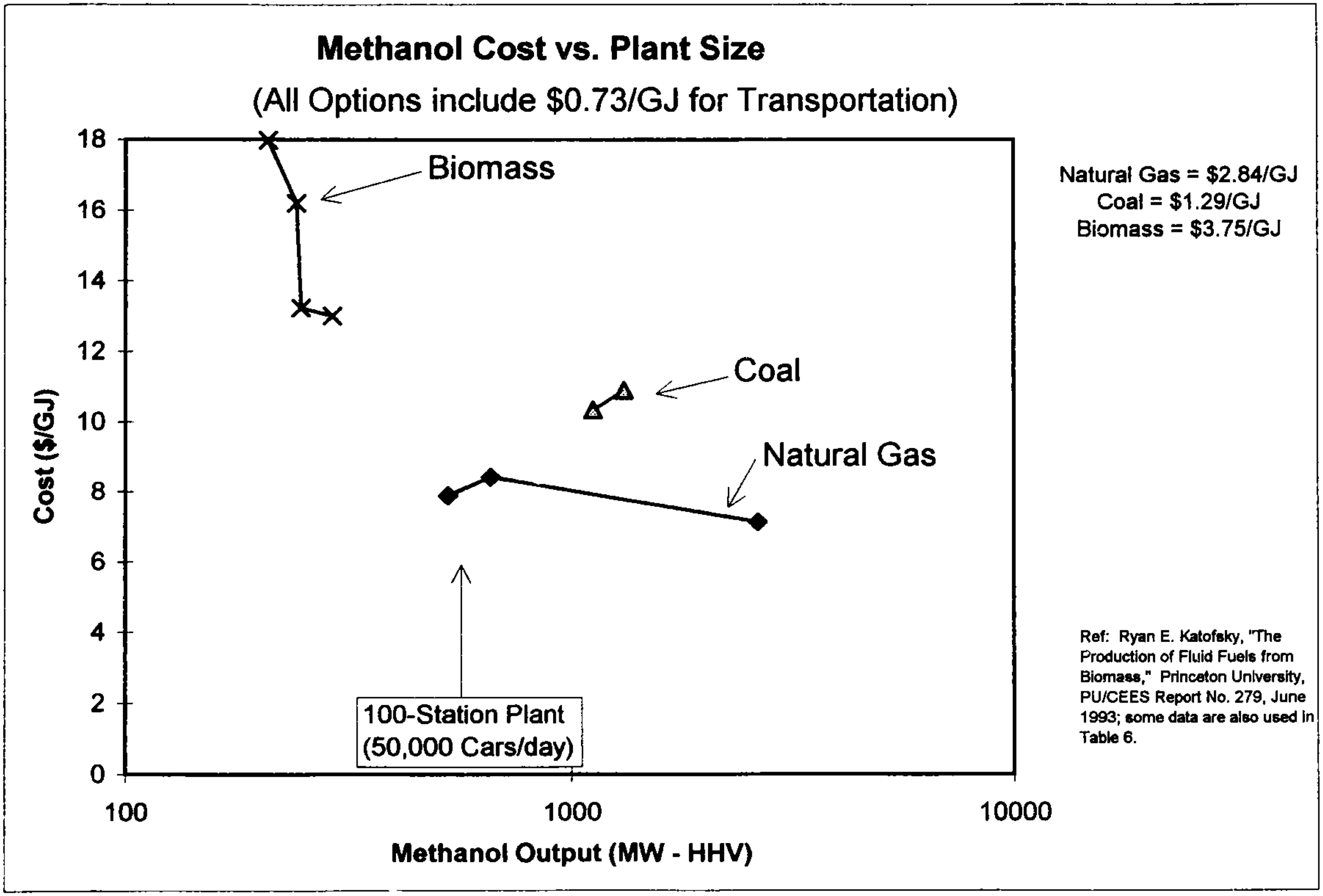

Methanol Cost vs. Plant Size
(All Options include $0.73/GJ for Transportation)
Natural Gas = $2.84/GJ
Coal = $1.29/GJ
Biomass = $3.75/GJ
Biomass
Coal
Natural Gas
100-Station Plant
(50,000 Cars/day)
Cost ($/GJ)
Methanol Output (MW - HHV)
0
2
4
6
8
10
12
14
16
18
100
1000
10000
Ref: Ryan E. Katofsky, "The Production of Fluid Fuels from Biomass," Princeton University, PU/CEES Report No. 279, June 1993; some data are also used in Table 6.

Figure 4

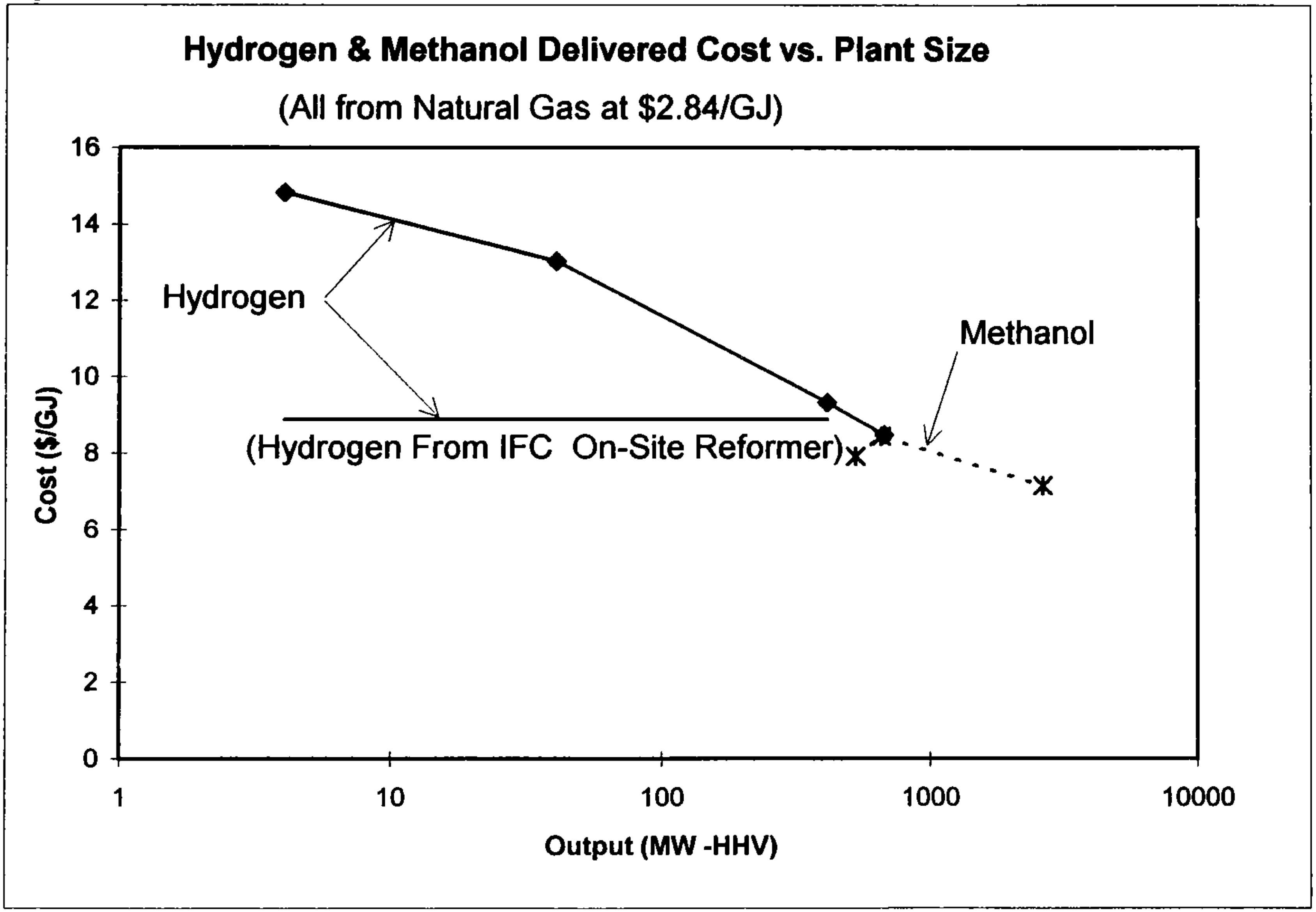
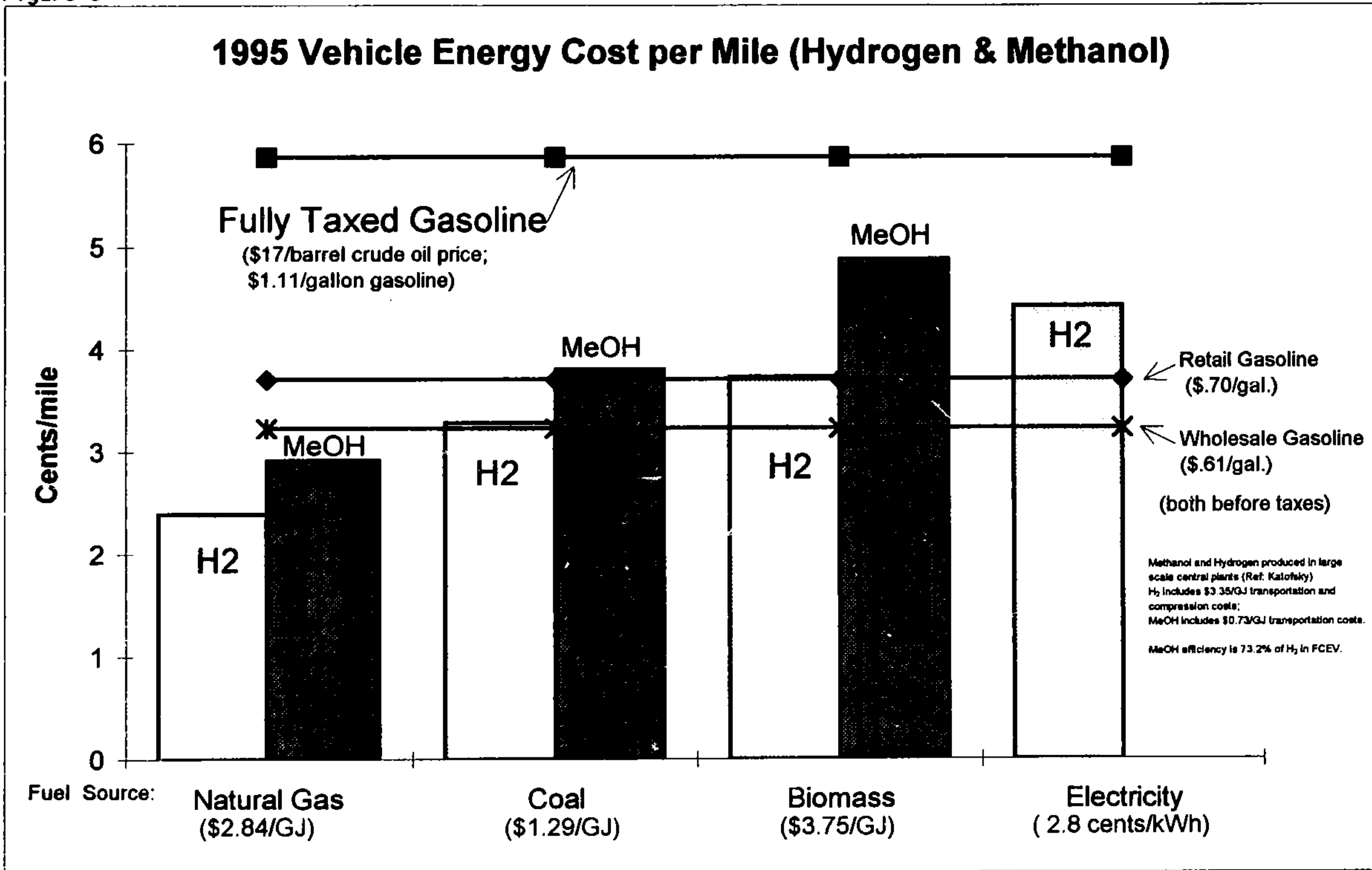

Hydrogen & Methanol Delivered Cost vs. Plant Size
(All from Natural Gas at $2.84/GJ)
Hydrogen
Methanol
(Hydrogen From IFC On-Site Reformer)
Cost ($/GJ)
Output (MW -HHV)
16
14
12
10
8
6
4
2
0
1
10
100
1000
10000

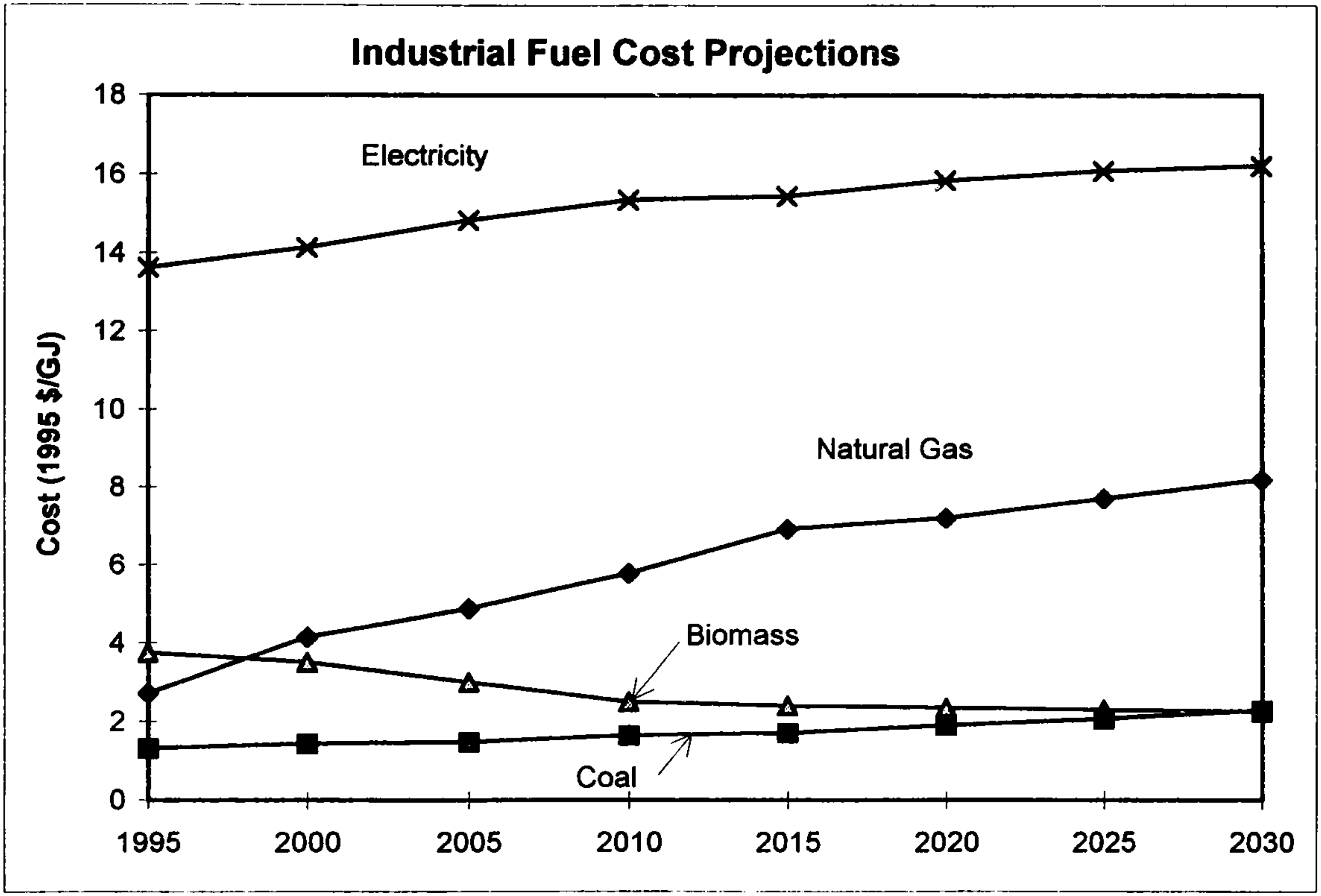
Figure 5



Ref: Ryan E. Katofsky, "The Production of Fluid Fuels from Biomass," Princeton University, PU/CEES Report No. 279, June 1993

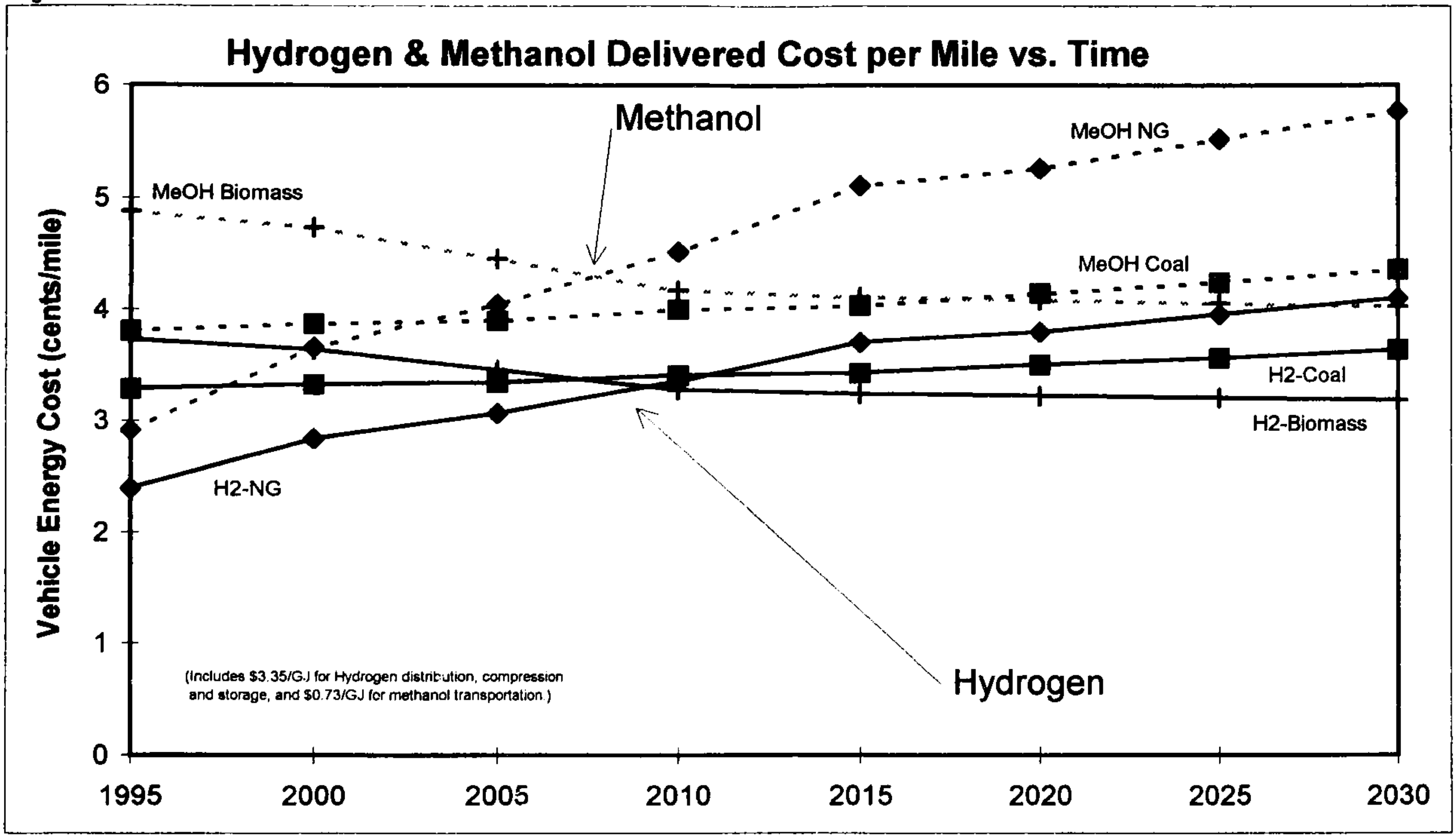
[Gasoline is used in a 19 mpg ICE 5-passenger vehicle; hydrogen and methanol are used in a FCEV with equal range & acceleration, consuming 15 pounds of hydrogen on 342 miles of FUDS driving. The FCEV has 2.68 times greater energy efficiency (LHV) compared to the gasoline vehicle.]

Figure 6



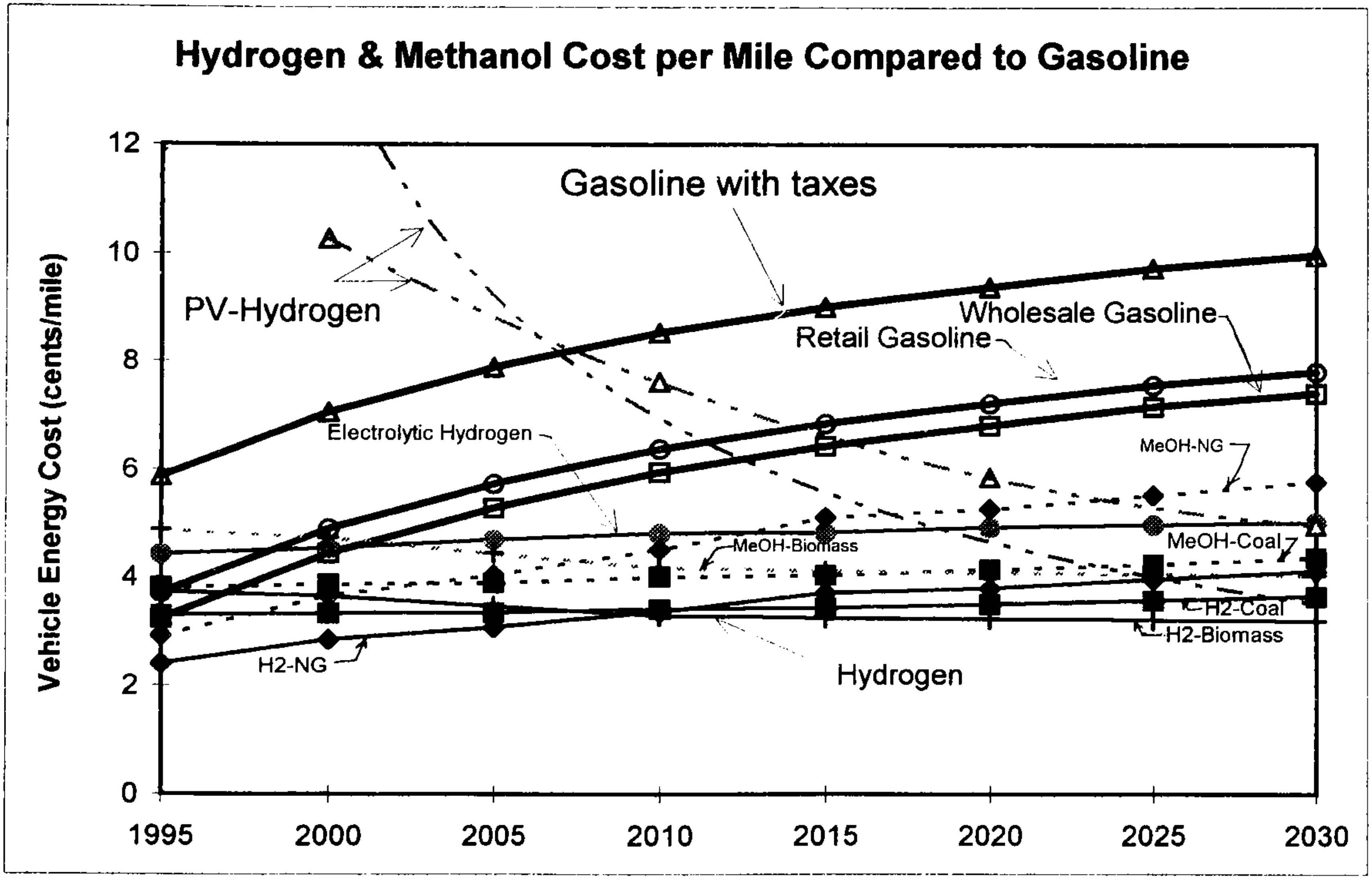
Ref: "Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions, and Results," Technical Annex 2, DOE/S-0086P, 1992, Table B-2.

Figure 7



Ref: "Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions, and Results," Technical Annex 2, DOE/S-0086P, 1992, Table B-2, and Ryan E. Katofsky, "The Production of Fluid Fuels from Biomass," Princeton University, PU/CEES Report No. 279, June 1993.

Figure 8



(Gasoline powers a 19 mpg ICE vehicle; hydrogen and methanol power a FCEV with equal range & acceleration, consuming 15 pounds of hydrogen on 342 miles of FUDS driving.)

Figure 9

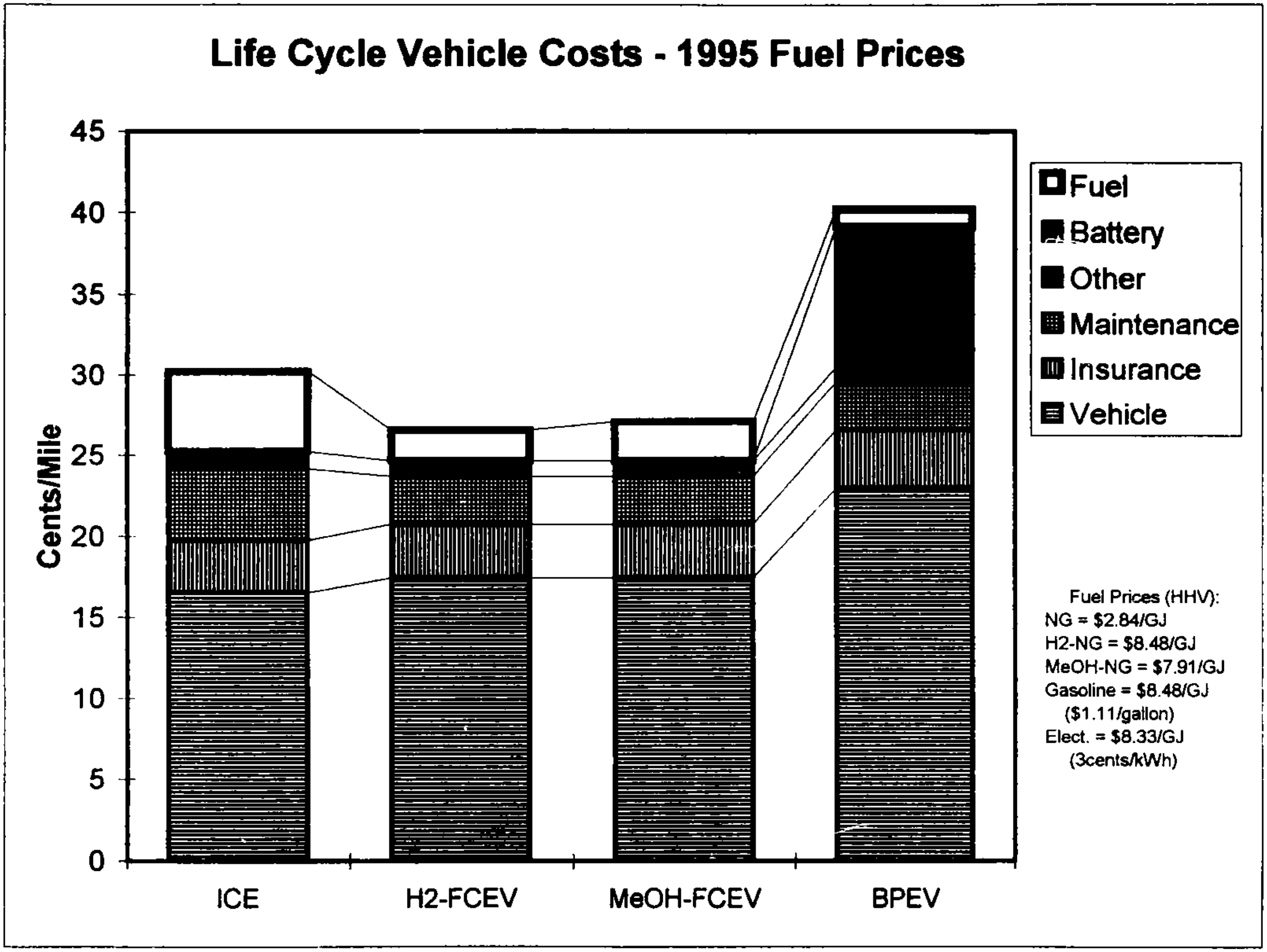
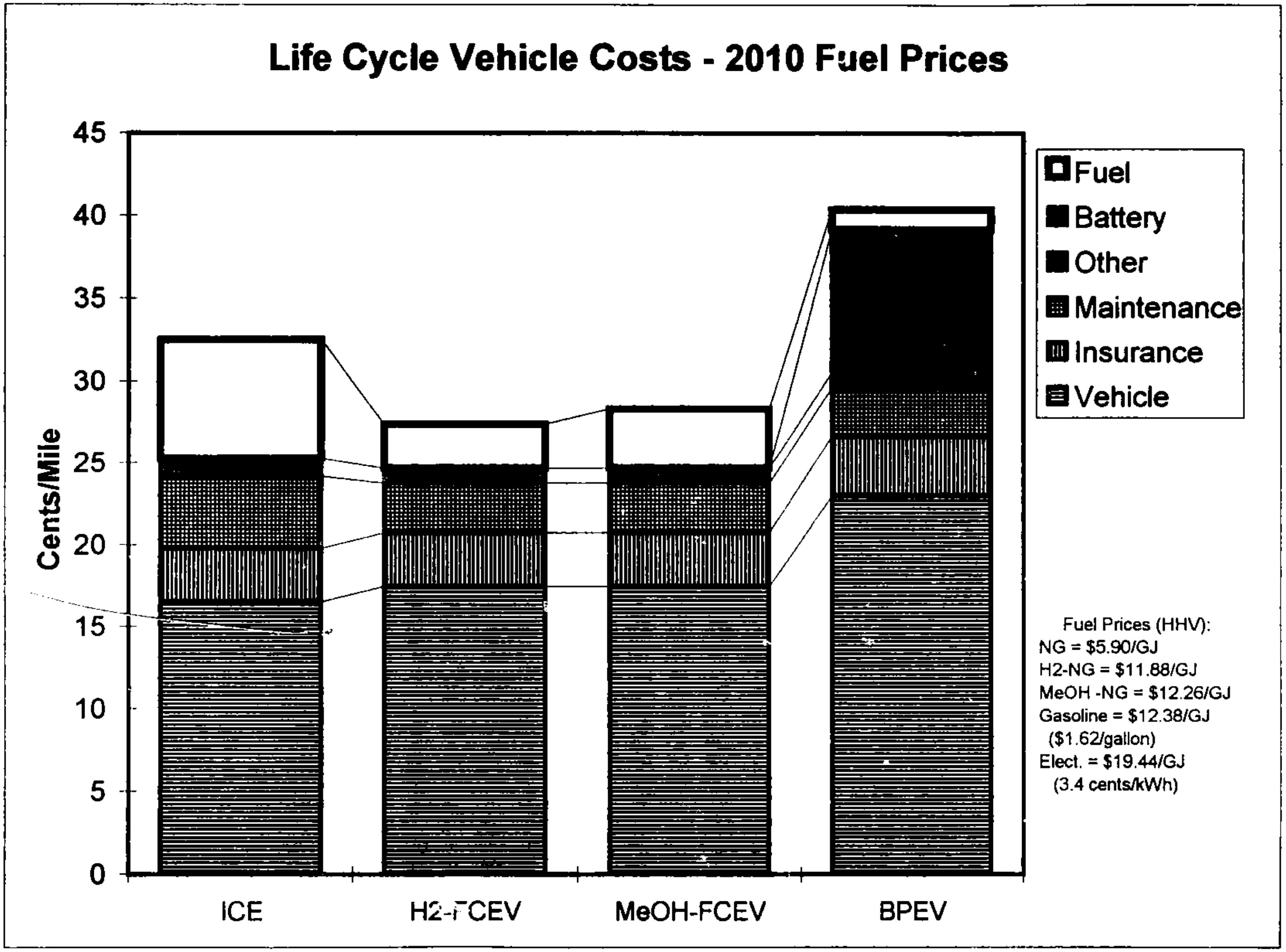

Life Cycle Vehicle Costs - 1995 Fuel Prices
Cents/Mile
45
40
35
30
25
20
15
10
5
0
ICE
H2-FCEV
MeOH-FCEV
BPEV
Fuel
Battery
Other
Maintenance
Insurance
Vehicle
Fuel Prices (HHV):
NG = $2.84/GJ
H2-NG = $8.48/GJ
MeOH-NG = $7.91/GJ
Gasoline = $8.48/GJ
($1.11/gallon)
Elect. = $8.33/GJ
(3cents/kWh)

Figure 10



Life Cycle Vehicle Costs - 2010 Fuel Prices
Cents/Mile
45
40
35
30
25
20
15
10
5
0
ICE
H2-FCEV
MeOH-FCEV
BPEV
Fuel
Battery
Other
Maintenance
Insurance
Vehicle
Fuel Prices (HHV):
NG = $5.90/GJ
H2-NG = $11.88/GJ
MeOH -NG = $12.26/GJ
Gasoline = $12.38/GJ
($1.62/gallon)
Elect. = $19.44/GJ
(3.4 cents/kWh)