HYDROGEN AND THE REVOLUTION IN AMORPHOUS SILICON SOLAR CELL TECHNOLOGY

Joan M. Ogden
Robert H. Williams

PU/CEES Report No. 231

February 15, 1989

Center for Energy and Environmental Studies
Princeton University
Princeton, New Jersey 08544
USA

TABLE OF CONTENTS PAGE

I. INTRODUCTION 1

A. THE EMERGING FOSSIL FUEL CRISIS 3
  1. Urban Air Pollution 4
  2. Regional Air Pollution 11
  3. Global Air Pollution: the Greenhouse Effect 14
B. THE HYDROGEN ECONOMY REVISITED 18
  1. Hydrogen as an Alternative to Fossil Fuels 18
  2. The Prospects for Hydrogen Derived Using a-Si Solar Cells 22
C. THE TRANSITION TO A HYDROGEN ECONOMY 23

II. THE COMING OF AGE OF PHOTOVOLTAIC POWER 26

A. BACKGROUND 26
B. THE AMORPHOUS SILICON SOLAR CELL 27
C. IMPLICATIONS FOR THE FUTURE OF PHOTOVOLTAIC POWER 34
D. IMPLICATIONS FOR SOLAR HYDROGEN 38

III. DESIGNING A PV HYDROGEN ENERGY SYSTEM 43

A. FINDING SITES FOR PV HYDROGEN PRODUCTION 43
B. DESIGNING THE ELECTRICITY PRODUCTION SYSTEM 44
C. THE ELECTROLYTIC PRODUCTION OF HYDROGEN 51
D. HYDROGEN STORAGE 55
E. COMPRESSORS AND PIPELINES 55
F. THE COST OF DELIVERED HYDROGEN 57

IV. COMPARING HYDROGEN TO OTHER SYNTHETIC FUELS 60

A. PV HYDROGEN AND NUCLEAR ELECTROLYTIC HYDROGEN 61
B. PV HYDROGEN AND ELECTROLYTIC HYDROGEN FROM OTHER RENEWABLE SOURCES 63
C. PV HYDROGEN AND BIOMASS-DERIVED FLUID FUELS 65
D. PV HYDROGEN AND SYNTHETIC FOSSIL FUELS 73
E. HYDROGEN SAFETY 75

V. PV HYDROGEN AS A REPLACEMENT FOR OIL 81

A. PV HYDROGEN AS A FUEL FOR TRANSPORTATION 81
B. PV HYDROGEN AS AN AUTOMOTIVE FUEL 81
  1. The Storage Challenge 81
  2. Engines for Hydrogen-Powered Cars 91
  3. A Hydrogen Fuel Distribution System 92
  4. Economics of Cars Fueled with Hydrogen 92
    a. Alternative Fuel Costs 92
    b. Consumer Costs for Cars with Alternative Fuels 92
    c. The National Cost of Alternative Transport Fuels 95
  5. What About Trucks, Busses, Trains, Ships and Planes? 97
  6. Environmental Problems and Alternative Fuels 98

VI. THE GASEOUS FUELS MARKETS 102

A. THE ECONOMIC CHALLENGE FOR PV HYDROGEN IN GASEOUS FUELS MARKETS 102
B. PV HYDROGEN FOR RESIDENTIAL HEATING 102
C. PV HYDROGEN FOR INDUSTRY 113
  1. Hydrogen for Industrial Heat and Power 113
  2. Hydrogen as a Chemical Feedstock 114
D. SUMMARY 114

VII. A POSSIBLE PATH TOWARD LARGE-SCALE USE OF PV HYDROGEN 116

A. A DEVELOPMENT PATH FOR PV HYDROGEN IN THE US 117
  1. PV Hydrogen for Chemical Markets 117
  2. PV Hydrogen as a Transportation Fuel 125
    a. Getting Started: a Hydrogen-based Transport System for Phoenix? 125
    b. A Nationwide Hydrogen Transport System 132
  3. Hydrogen for Residential Space and Water Heating 133
  4. Parallels with Development of PV Electricity 134
B. POLICY ISSUES 136
  1. Policies Aimed at Coping with Externalities 137
    a. Reducing Local Air Pollution 137
    b. Reducing Oil Import Dependency 137
    c. Reducing Greenhouse Emissions 137
  2. Promoting Improved Energy End-Use Efficiency 138
  3. Policies Targetting PV Hydrogen Development 139
    a. Continued R&D to Improve the Efficiency and Lifetime of a-Si Solar Cells and to Reduce their Manufacturing Cost 139
    b. Development of Low-cost BOS Designs for Large Amorphous Silicon-based PV Systems 141
    c. Research on PV Hydrogen Systems Designs 142
    d. Continued Research on Hydrogen End-Use Systems 142
    e. Government Procurement 143
C. CONCLUSION 143

NOTES AND REFERENCES

TABLES

CHAPTER 1

1. Automotive Emissions (in grams/mile) 8

CHAPTER 2

2. Estimated Amorphous Silicon Solar Module Production Cost for a Factory Producing 10 MW_p per Year of 6 Percent Efficient Solar Modules 33

3. Cost and Efficiency Projections for Amorphous Silicon Solar Cells 35

4. Potential Markets for Photovoltaic Electricity 36

CHAPTER 3

5. The Solar Resource in Various Cities 46

6. Area-Related Balance of System Costs for PV Systems 48

7. Projected Cost of PV Hydrogen and PV Electricity in the Southwest 52

CHAPTER 4

8. Estimated Costs for Alternative Sources of Electrolytic Hydrogen 64

9. Projected Production Costs for Synthetic Liquid and Gaseous Fuels 66

10. Land Use Requirements for PV Hydrogen, Biomass and Coal Synfuels 68

11. Desert Areas of the World by Continent 70

12. Water Requirements for PV Hydrogen and Biomass Energy Systems 72

CHAPTER 5

13. Oil Consumption in the US Transportation Sector in 1983 83

14. Energy Storage in Automotive Fuels 85

15. Delivered Cost of Automotive Fuels c. 2000 93

16. The Automobile Fuel Bill of the United States 96

17. CO_2 Emissions for Alternative Automotive Fuels 99

CHAPTER 6

18. World Natural Gas Consumption in 1983 103

19. Delivered Prices of Residential Heating Fuels 106

20. Cost and Performance of Natural Gas, Hydrogen and Electric Heating Systems for Conventional and Super-insulated Houses in New Jersey 110

CHAPTER 7

21. Alternative Scenarios for Automotive Emissions in Phoenix 128

22. Potential Markets for PV Electricity and PV Hydrogen 135

FIGURES

CHAPTER 1

1. Trends in NOx and VOCs emissions in the United States from all sources, normalized to 1976 emissions levels 6

2. Emissions trends in the United States from all sources 7

3. Carbon dioxide Emissions from the processing and use of various fuels 12

4. Estimated temperature history of the northern hemisphere for the last 850,000 years 16

5. A solar photovoltaic electrolytic hydrogen system 21

CHAPTER 2

6. Progress in amorphous silicon solar cell technology 30

7. Estimated cost versus production volume for amorphous silicon solar modules 32

CHAPTER 3

8. Cost of PV hydrogen as a function of PV electricity cost 45

9. Cost of PV electricity vs. solar module and BOS costs for 10% and and 15% efficient systems 50

10. Cost of electrolytic hydrogen vs. plant size and DC electricity cost 53

11. The US natural gas pipeline system 58

CHAPTER 4

12. The land area needed to produce hydrogen equivalent to US consumption of oil, natural gas, and coal 69

CHAPTER 5

13. Hydrogen-powered motor vehicles 82

14. Prototype super-mpg automobiles 87

15. A gaseous storage system for an automobile 89

16. Operating cost of automobiles as a function of fuel economy for various fuels 94

17. CO_2 emissions from automobiles with alternative fuels as a function of fuel economy 100

CHAPTER 6

18. The Northern Energy Home 109

19. Levelized annual cost for residential space and water heating 112

CHAPTER 7

20. Cost of hydrogen production using various methods as a function of daily hydrogen production 118

21. The cost of owning and operating a car versus fuel economy 140

BOXES

CHAPTER 2

1. MINING THE EARTH'S CRUST FOR ENERGY : NUCLEAR VS. a-Si SOLAR CELLS 28

2. KEY TECHNICAL ASSUMPTIONS RELATING TO AMORPHOUS SILICON SOLAR CELLS 39

CHAPTER 4

3. IS HYDROGEN SAFE? 77

CHAPTER 5

4. THE REVOLUTION IN AUTOMOTIVE FUEL ECONOMY 86

5. METAL HYDRIDE STORAGE FOR AUTOMOBILES 90

CHAPTER 7

6 PRESENT USES OF HYDROGEN 119

7. HYDROGEN PRODUCTION METHODS AND COSTS 122

8. PV HYDROGEN FOR CHEMICAL MARKETS 123

9. HYDROGEN FUEL AND AUTOMOTIVE EMISSIONS 126

CHAPTER 1. INTRODUCTION

February 14, 1989

A. THE EMERGING FOSSIL FUEL CRISIS

The oil crises of the 1970s are fading into history. While their root cause remains--the fact that the remaining global oil resources are concentrated in the Middle East--the world oil market is no longer being manipulated by Middle East oil producers and will probably not be under their control again for at least a few more years, owing to successful oil conservation efforts by industrial countries and increased oil production by non-OPEC producers.

But a new energy crisis is rapidly unfolding--a crisis that may make the oil crises of the 1970s, by comparison, seem like minor irritants on our energy system. The emerging crisis relates not to issues of energy supply but to a complex web of environmental problems caused by the use of fossil fuels that not only endangers the quality of life in modern society but also jeopardizes continued global development. Deteriorating urban air quality, crop losses, the acidification of lakes and forests, and a changing global climate are interrelated consequences of fossil fuel use that are making fossil fuel pollution front page news[1] and a target for possible farrreaching environmental control policies.

1. Urban Air Pollution

By far the most familiar and easy to grasp air pollution problem is urban air pollution. Urban air pollution can often be seen and smelled, and its adverse effects on human health and property are fairly well-understood. Since the passage of the Clean Air Act in 1970, ambient levels of air-borne lead and carbon monoxide have been reduced, but the urban air pollution problem is far from solved; in 1987 over 130 million Americans lived in areas where ozone levels in photochemical smog exceeded federal air quality standards.[2] Exposure to levels of ozone in excess of the present federal standard (0.12 parts per million) can cause acute respiratory symptoms and has been implicated in the onset of respiratory disease.[3] Recent studies have raised concern that chronic exposures to lower ozone levels (in the range 0.08 to 0.12 parts per million) may lead to permanent lung damage.[4]

When the Clean Air Act was passed in 1970, the final deadline for compliance with ozone standards was set for 1975. In 1977, with 78 areas still out of compliance, the deadline was pushed ahead to 1982. By 1983, ozone standards had been relaxed from 0.08 ppm to 0.12 ppm, but many areas were unable to meet even these less stringent standards and obtained deadline extensions to December 31, 1987. Twenty days before the end of 1987, the deadline was extended again to August 31, 1988.[5] Early in 1988, the Environmental Protection Agency projected that some 68 cities would again fail to meet the extended deadline[6]. The summer of 1988 brought a stifling combination of heat, sun and stagnant weather patterns (which a few scientists see as early symptoms of the greenhouse effect[7]) driving ozone pollution in many US cities to the highest levels this decade[8]. It now appears that many more than 68 cities were out of compliance in 1988.

Ozone is formed when nitrogen oxides (NOx) and volatile organic compounds (VOCs) react in the presence of sunlight. One of the difficulties in reducing ozone is the variety of NOx and VOC sources which must be controlled (*).

---

* NOx is a product of combustion at high flame temperatures in power plants and motor vehicles. VOCs are emitted as unburned hydrocarbons in car exhaust, gasoline pump vapors and fumes from solvents in paints and other chemicals.

Motor vehicles are large sources of both NOx and VOCs (*). Since 1970, progressively stricter emissions standards for vehicles have been implemented, and for automobiles, the actual NOx and VOC emissions per mile travelled decreased four-fold between 1972 and 1988[10]. Yet, because of the growing number of autos, the less stringent standards for heavier vehicles and the increased number of vehicle miles travelled, aggregate NOx emissions from all vehicles has stayed essentially constant (Figure 1), and VOC emissions have decreased only slightly. Model calculations carried out by the Environmental Protection Agency indicate that both VOC and NOx levels could increase sharply over the next few decades, if emissions from both mobile and stationary sources are not reduced (Figure 2).

Control of emissions from motor vehicles must be an important part of an overall ozone control strategy. In the near term much could be accomplished by instituting tougher vehicle emissions standards. If emissions standards for motor vehicles advanced in federal legislation now under consideration (S. 1894, adopted by the Senate Environment and Public Works Committee in 1987) were met, total US emissions of NOx and VOCs from all sources could be stabilized or even decreased slightly over the next couple of decades.[11]

For automobiles, meeting the proposed standards in practice would require a three-fold reduction in the average actual in-use emissions. (This is shown in Table 1, which lists the average certified emissions from 1987 gasoline powered automobiles, the actual in-use emissions for 1986 cars, the current 1988 standards for automotive emissions, and proposed standards now under

---

* In 1985, motor vehicles contributed an estimated 45% of the NOx and of 34% of the VOCs emitted in the US. In some cities the fractions from mobile sources were even higher[9].

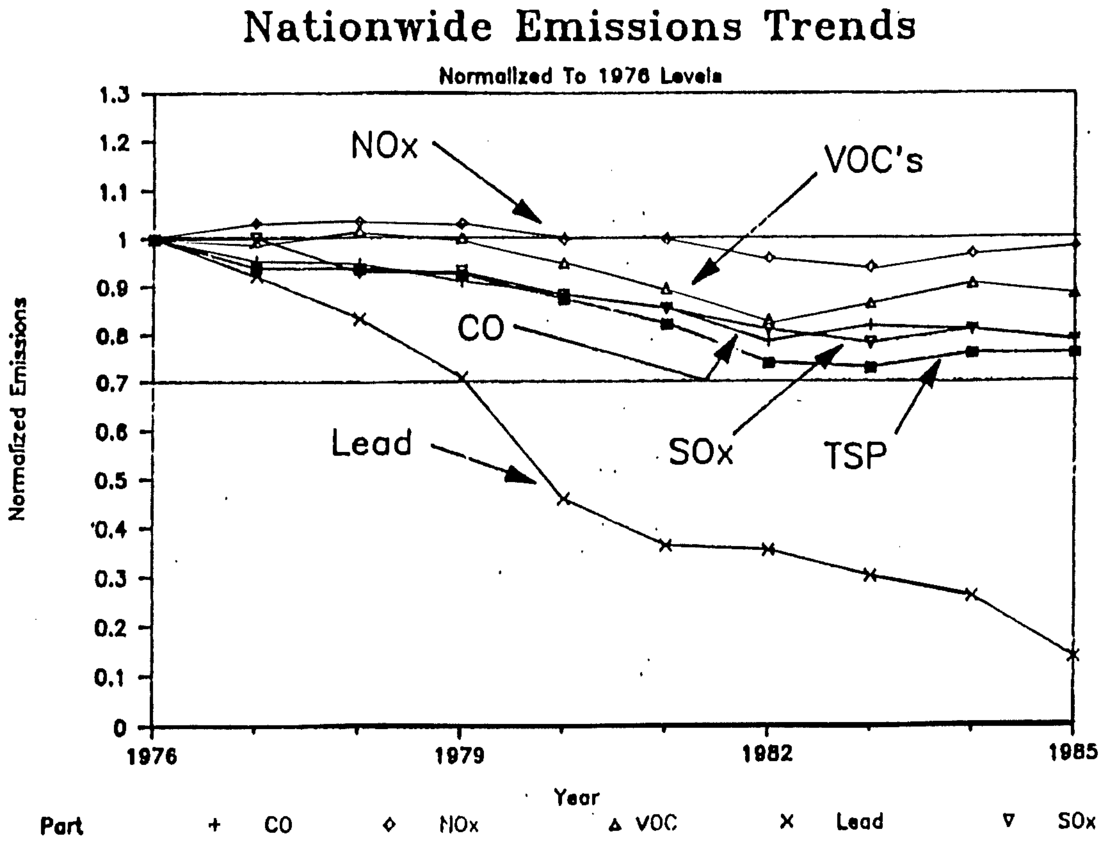


Figure 1.

Trends in NOx and VOCs emissions from all sources, normalized to the 1976 emissions levels.

Source: Michael P. Walsh, "Pollution on Wheels," Report to the American Lung Association, February 11, 1988.

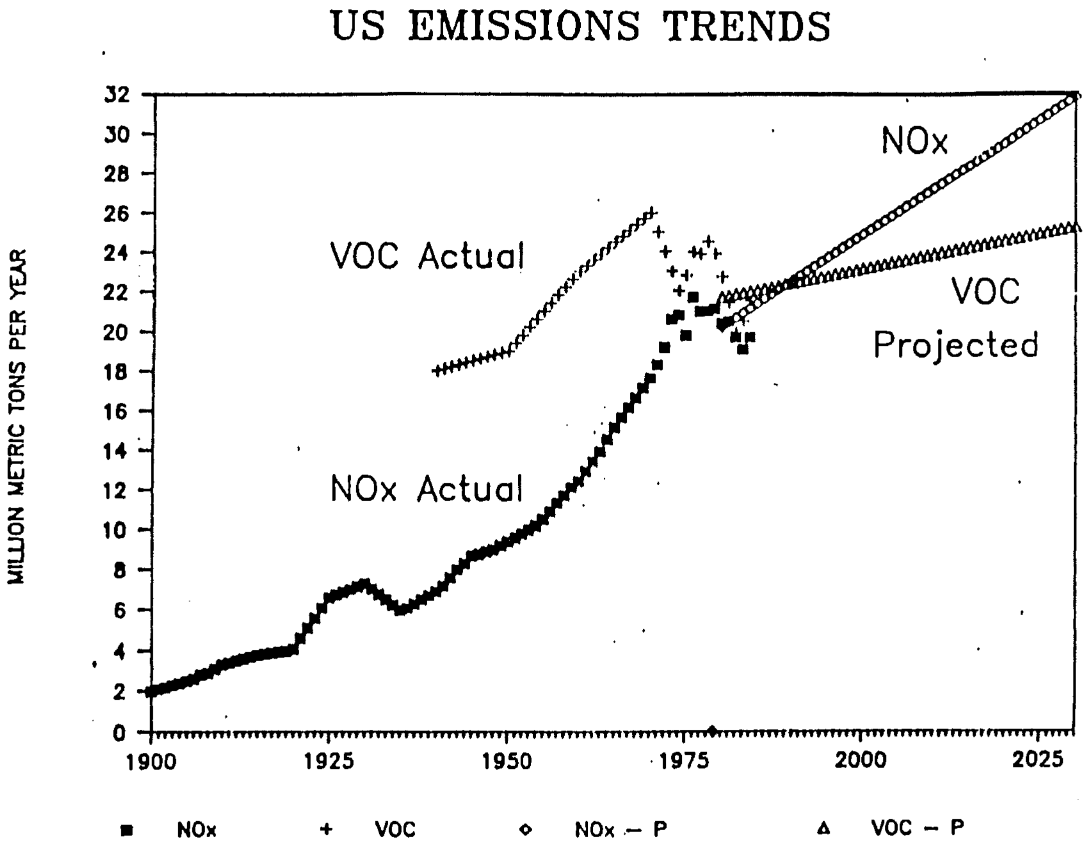


Figure 2.

Trends in air pollutant emission from all sources in the United States.

Historical data and EPA projections are shown.

Source: Michael P. Walsh, "Pollution on Wheels," Report to the American Lung Association, February 11, 1988.

Table 1. Automotive Emissions (in grams/mile)

	AVERAGE EMISSIONS		EMISSIONS STANDARDS	
	Certified (1987)	Actual (1986)	1988	Proposed
Automobiles				
Carbon Monoxide	1.91	10.0	3.4	3.4
Hydrocarbons (VOCs)	0.20	0.8	0.41	0.25
Nitrogen Oxides	0.37	1.2	1.0	0.4
Particulates	-	-	0.2	0.08

Source: Michael P. Walsh, "Pollution on Wheels," Report to the American Lung Association, February 11, 1988.

consideration by Congress (*).)

While major changes in current practice would be required to meet the proposed standards, so doing would be technically feasible. If vehicles in routine use could be made to operate much closer to the levels certified for new cars in 1987 through improved maintenance and rigorously enforced inspection programs, the proposed emissions standards could be met (Table 1). Improvements in automotive fuel economy would also reduce emissions per mile.

But tighter emissions controls alone will not be enough to bring all metropolitan regions into compliance with the ozone standards. Even with tough emissions controls on both mobile and stationary pollution sources, the Los Angeles-Long Beach, California, consolidated metropolitan statistical area [for which the "design" value of ozone concentration (**), 1983-1985, was 0.36 ppm or three times the federal standard] would be unable to comply with the ambient air quality standards for ozone.[12] And other rapidly growing metropolitan areas (e.g. Phoenix) would be in compliance for at most a few years, before the burgeoning vehicular population would once again convert these regions into nonattainment areas.

Such considerations have prompted interest in alternative cleaner transport fuels as a strategy for coping with the urban air pollution problem.

---

* The certified emissions level is the average for new cars as measured for a idealized standardized driving cycle. The actual in-use level is the measured value for cars in the field under real operating conditions. The actual in-use emissions from 1986 cars are several times higher than the certified emissions, because cars are not operated precisely as modeled in the standardized driving cycles used for testing purposes and because few cars are maintained in optimum condition.

** The design value is a measure of the highest daily maximum 1-hour average ozone concentration in an area; specifically, it is the fourth highest of all the daily peak 1-hour average ozone concentrations observed within the area over the most recent three-year period. Areas with design values of 0.13 ppm or higher are violating the ozone standard.

Both the proposed Senate bill (S. 1894) and a House air pollution control bill (H.R. 3054) mandate the use of "alternative" motor fuel in some ozone nonattainment areas. The alternative fuel most often considered for ozone is methanol (either 100% or "neat" methanol, or a blend of at least 85% methanol and up to 15% gasoline). From an air quality perspective a major attraction of methanol is that it reacts much more slowly in the atmosphere and consequently produces less ozone than the VOCs emitted from the combustion and evaporation of gasoline. One study estimates that, per mile travelled, substituting methanol for gasoline is 30% to 90% as effective in reducing ozone concentrations as completely eliminating emissions from gasoline-fueled vehicles.[13]

Perhaps the most ambitious alternative fuels plan advanced to date is the long-range plan announced June 30, 1988, by the California South Coast Air Quality Management District, aimed at bringing the greater Los Angeles area into compliance with the federal standards for ozone.[14] This ambitious plan, which is subject to EPA approval, proposes phasing out petroleum fuels in favor of alternative fuels in both industrial and transport applications. In the transport sector the plan calls for converting 40% of passenger cars and 70% of trucks to alternative fuels, mainly methanol.

Complementing the emphasis given to alternative fuels in proposals such as the above mentioned environmental legislation and the proposed South Coast Air Quality Management District plan for ozone compliance is the significant push given to alternative transport fuels in the Alternative Motor Fuels Act of 1988. This new law gives a powerful incentive to car manufacturers to produce vehicles capable of using alternative fuels by significantly relaxing the fuel economy standards for such vehicles. For vehicles that use gasoline-alcohol blends the law's fuel economy standard requires that the only fuel that has be counted in determining compliance is the conventional fuel component (gasoline).

While emphasizing methanol as a transport fuel may indeed help mitigate the urban air quality problem, a shift to methanol could significantly exacerbate another important environmental problem: the global greenhouse warming associated with the buildup in the atmosphere of carbon dioxide from the burning of fossil fuels (see below). In the initial phases of a "methanol economy" for transport, methanol would be derived from natural gas, and carbon dioxide emissions would be comparable to those arising from use of gasoline as fuel. But because global natural gas resources are probably not much more abundant than global oil resources,[15] in a matter of decades a methanol economy would have to shift its base from natural gas to abundant low-quality feedstocks such as coal. If the transport sector were operated on methanol derived from coal, carbon dioxide emissions per unit of useful energy derived would be roughly twice as large as for gasoline (Figure 3). Thus while a shift to methanol might help solve the urban air pollution problem, it would exacerabate the global greenhouse problem.

2. Regional Air Pollution

In the 1960s and early 1970s concerns about deteriorating air quality were focussed largely on local air pollutants arising from local sources. In this period many polluting utilities sought to address pollution concerns by building tall stacks for their fossil fuel power plants to disperse the offending pollutants over a wide area.

But it is now recognized that "dilution is not the solution to pollution," because certain dispersed pollutants are now known to cause major damage over wide areas. The problem has grown to the point that the transnational

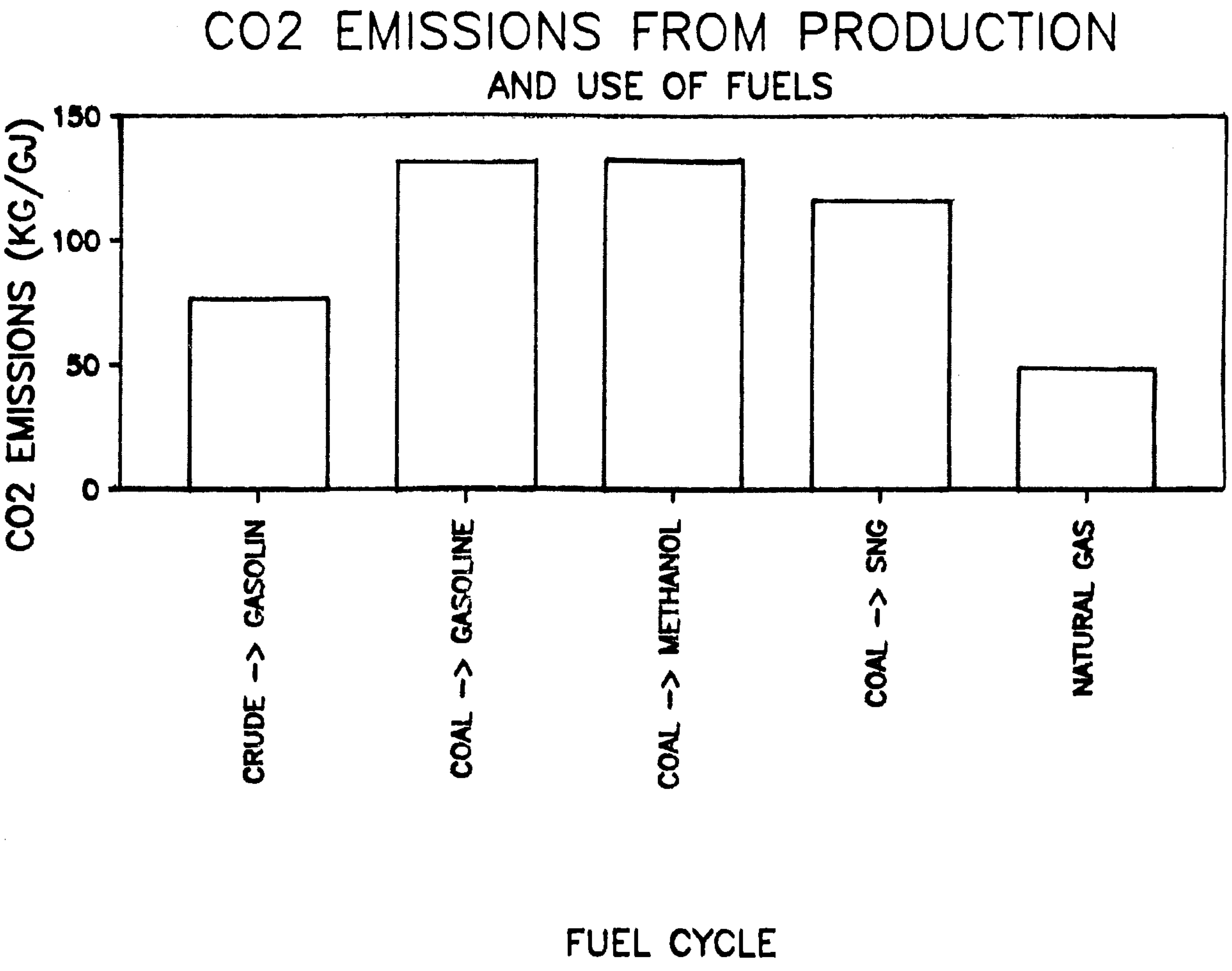


Figure 3.

CO_2 emissions from the processing and use of various fuels, in kilograms of CO_2 released per Gigajoule (GJ) of fuel energy used.

Here it is assumed that crude oil is refined to give gasoline and Diesel fuel with 10% refinery losses; coal is converted to synthetic natural gas via the Lurgi dry ash process; coal is converted to methanol via the Texaco gasifier process; coal is converted to gasoline plus liquid propane gas plus synthetic natural gas via the SRC-II process.

transport of air pollutants has become a matter of international dispute. The most discussed form of regional pollution involves the deposition on lakes, farmland, and forests, of acidic air pollutants, largely due to the emissions of nitrogen oxides and sulfur oxides from the combustion of fossil fuels in road transport and stationary power plants. This acid deposition (*) has raised the acidity of some lakes in the Northeastern United States and Southeastern Canada. Declines in fish and insect populations and loss of species diversity, which are directly correlated with acidification, have been observed in these lakes.[16]

Acid deposition combined with other air pollutants (such as ozone or heavy metals), and climatic stresses (such as the drought, hot summers and cold winters of the past few years) may be a factor in the observed decline of forests in the northeastern US and Canada.[17,18] In the United States, the red spruce forests on the upper slopes of the Appalachians, where the acid deposition is greatest, have been declining since the 1960s. On the highest mountains the red spruce forests have already died, and some scientists fear for the lower elevation hardwood forests (**). To paraphrase one scientist, the Appalachian high forests may be the coal-miner's canary.[19]

Ozone pollution is not only directly hazardous to human health, the focus of concern regarding urban air pollution, but also it can harm crops and forests. Concentrations as low as 0.04 to 0.06 parts per million, which are typical mean levels in many rural areas in the eastern US, can seriously

---

* Acid deposition is often referred to as "acid rain." Acid deposition is a more appropriate term, however, because the acidic pollutants involved are deposited in a variety of forms--dry, as well as in rain, snow, and fog.

** In Vermont, New York and Canada air pollution, acid deposition, heat and drought are thought to have weakened the sugar maples, allowing infestation by previously harmless insect parasites.

reduce crop yields (*). Ozone may also be a factor contributing to the decline of forests in the US, Canada, and Europe (**).

While there are considerable uncertainties regarding the extent of damage caused by acid deposition and other long-range pollutants, there is already a considerable body of scientific evidence showing that the long-range pollutants caused by the burning of fossil fuels, often acting in concert with climatic stresses (that may also be related to the burning of fossil fuels, through the greenhouse effect), are significantly altering the ecology of lakes and reducing the productivity of farmland and forests.[20]

3. Global Air Pollution: the Greenhouse Effect

The use of fossil fuels is leading to global as well as local and regional air pollution problems. The combustion of fossil fuels leads to the release of carbon dioxide and its accumulation in the atmosphere. While carbon dioxide is a colorless, odorless gas that causes no direct damage to human health and is not directly disruptive of the local or regional ecology, its buildup in the atmosphere can change the global climate through the so-called greenhouse effect--characterized by a global warming, changes in precipitation patterns throughout the world, and a rise in the sea level, among other effects.[23]

Though uncertainties remain regarding the timing, severity, and the distribution of the the consequences of the greenhouse effect, a scientific consensus has developed regarding the seriousness of the problem if the buildup

---

* Wheat, soybeans and cotton are particularly sensitive to ozone pollution. At concentrations of 0.06 ppm, wheat yields can be reduced by as much as 51%, cotton by 16-35%, and soybeans by 5-24%.[21]

** Ozone is thought to be a principal cause of the decline of Ponderosa and Jeffrey pines in California forests, and of white pines in the eastern US. Ozone may also be a contributing factor in the dieback of red spruce forests on the high slopes of the Applachians, and the decline of sugar maples in New England, New York and Canada.[22]

of carbon dioxide in the atmosphere continues. The scientific concern has been reinforced in the in the public's mind by the record temperatures (and associated drought, forest fires, and heightened air pollution) and intense hurricane activity experienced during the summer and fall of 1988. While it is premature to allocate responsibility to the greenhouse effect for these events, which may well merely natural variations in the climate, experts do see these events as a foretaste of what would happen in the US as the greenhouse effect worsens.[24]

Most global energy studies project large increases in fossil fuel consumption over the next several decades.[25] What do such projections imply for future carbon dioxide level in the atmosphere? Consider the 1981 global energy study of the International Institute for Applied Systems Analysis (IIASA). The IIASA study, which is typical, projected that fossil fuel use would increase between 1.8-fold and 3-fold, 1980-2030.[26] For the IIASA scenarios the carbon dioxide level would increase from 1.25 times the pre-industrial level in 1984 to the range 1.55 to 1.65 times the pre-industrial level by 2030.[27] Climatic modelers believe that increasing the atmospheric carbon dioxide level to twice the pre-industrial level will increase the average global surface temperature by 1.5 to 4.5°C,[28] so that with the IIASA scenarios the equilibrium average surface heating resulting from CO_2 released to the atmosphere by 2030 would be 60-70% of the heating arising with a doubling of atmospheric carbon dioxide.[29] The actual surface heating would probably be about twice as large, owing to the simultaneous build-up of other greenhouse gases (especially chlorofluorocarbons, ozone, methane, nitrous oxide) (*) associated with man's activities.[30] Thus in just a few decades time

---

* Emissions of ozone, methane, and nitrous oxide are partly due to the use of fossil fuels.

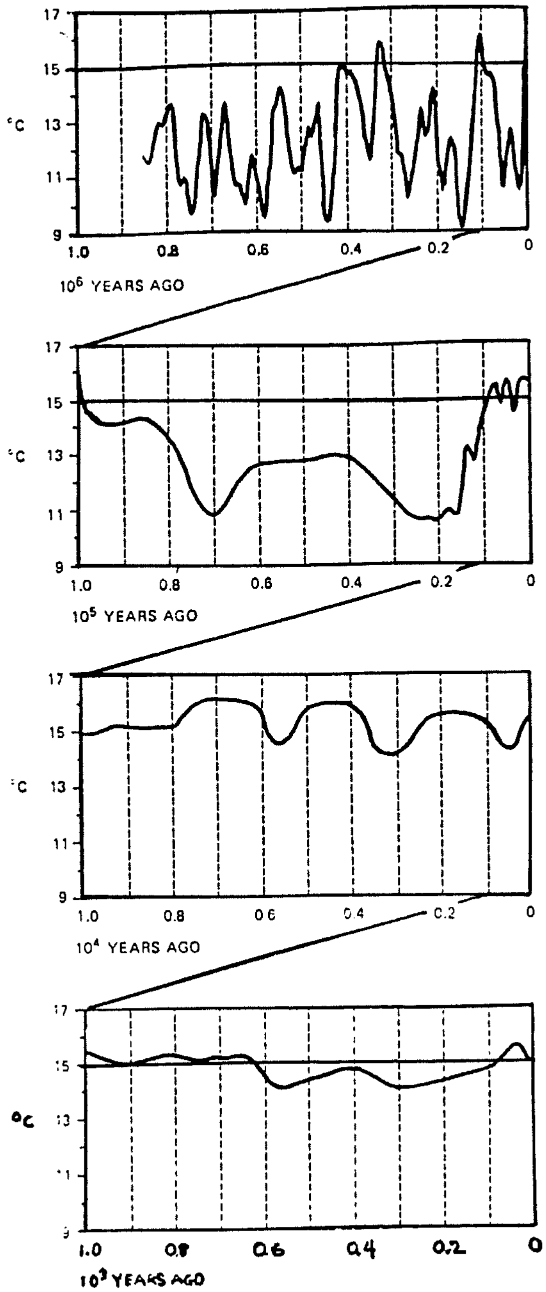


Figure 4.

An estimated temperature history of the Northern hemisphere for the last 850,000 years.

The panels are shown at the same temperature scale. The top panel illustrates the past 1,000,000 years, the second panel the last 100,000 years, the third panel the last 10,000 years and the fourth panel the last 1000 years. The data shown are average surface air temperatures for various locations, most of which are over land. Because the data are inhomogenous in space and time (they were taken from a number of different localities and refer to different eras), these graphs do not represent a true hemispheric or global temperature average. They are however indicative of the range of local average surface temperatures experienced.

Source: W.C. Clark, editor, Carbon Dioxide Review 1982, Clarendon Press, Oxford University Press, New York, 1982.

man's activities could lead to an increase in the global temperature of 2 °C or more, which would make the surface temperature hotter than it probably has been during the last 850,000 years (Figure 4), with farreaching implications for a wide range of human activities and the global ecology.[31]

Despite the fact that energy is a necessary input to all human activity, the extent of the greenhouse warming need not be as great as is indicated by the IIASA and related projections. Because of ongoing structural shifts in the economies of the industrialized countries toward less energy-intensive economic activities, energy demand in these countries (which account for half of the increment in global energy demand projected in the IIASA study) will probably grow much less rapidly than projected in the IIASA study.[32] Moreover, there are many cost-effective opportunities for making more efficient use of energy. Taking into account both ongoing structural changes in industrialized countries and cost-effective opportunities for using energy more efficiently in both industrialized and developing countries, it has been shown that global economic goals could be met over the next several decades with little increase in global energy use.[33] For developing countries this emphasis on energy efficiency would be not just an option but a necessary condition for meeting development goals, because continued emphasis on supply expansion is becoming constrained by rapidly growing capital requirements that are becoming unaffordable, and because emphasis on improved energy efficiency is the most promising way of avoiding these capital expenditure constraints.[34]

While emphasis on the efficient use of energy could lead to a stabilization in the overall level of fossil fuel use globally over the next several decades, this strategy alone would not solve the greenhouse problem. With global fossil use held constant, the atmospheric carbon dioxide level in the atmosphere by 2020 would still be some 40% higher than the preindustrial level, and the committed global heating from carbon dioxide at that time would still be about half as much as with a doubling of the carbon dioxide level.[35]

It may be both necessary and desirable to reduce fossil fuel use globally by 50% or more in the coming decades in order to stabilize the atmospheric level of carbon dioxide and limit the adverse consequences of the greenhouse warming. The urgency of doing so was reflected, for example, in the deliberations of the World Conference on The Changing Atmosphere: Implications for Global Security, held in Toronto, June 27-30, 1988, hosted by the Canadian government with the support of the United Nations Environment Program and the World Meteorological Organization. The final formal policy statement of this historic conference set a target of reducing annual global carbon dioxide emissions 20% by the year 2005 through improved energy efficiency and shifts in the energy supply mix.[36]

It appears that a shift to fuels that do not contribute to the greenhouse warming will be a necessary complement to emphasis on improved energy efficiency in coping with the greenhouse problem.

B. THE HYDROGEN ECONOMY REVISITED

1. Hydrogen as an Alternative to Fossil Fuels

One way to avoid the greenhouse problem would be to shift our energy economy from fossil fuels to hydrogen. Hydrogen is a high-quality fuel that could replace oil and natural gas for transportation, heating and power applications. When hydrogen is burned the primary combustion product is water vapor with traces of NOx (*).

Much of the hydrogen used in industry today is derived from natural gas. Of course, use of hydrogen derived from fossil fuel would not help cope with the greenhouse problem. If a fossil fuel is the feedstock, carbon dioxide would be released to the atmosphere during production, if not during combustion. But hydrogen can also be made without using fossil fuels--e.g. through the electrolysis of water using electricity from solar, wind, hydropower or nuclear sources.

Because of its environmental benefits, a large-scale hydrogen energy system or "hydrogen economy" based on non-fossil fuel feedstocks has long been seen as an ideal solution to man's energy needs.[37] But, thus far, the hydrogen economy has remained an elusive dream for the distant future because no widely available source of electricity has been yet been developed that is sufficiently inexpensive to enable electrolytic hydrogen to compete economically with carbon-based fuels.

The prospects for a nuclear power-based hydrogen economy looked bright in the 1960s, when it was thought that nuclear power would soon become "too cheap to meter." But the promise of low cost nuclear power has not materialized. In fact, nuclear power has priced itself out of the electric power market in the United States, and, worldwide, nuclear power is the focus of much public concern, as a result of the accidents at Three Mile Island and Chernobyl, anxieties

---

* There is no carbon monoxide, carbon dioxide, sulfur dioxide, VOCs, or particulate matter produced in the combustion of hydrogen. When hydrogen is burned in air at high temperatures, however, nitrogen oxides are formed. But when only one pollutant is formed in combustion, its control is far easier than would be the case where multiple pollutants must be controlled simultaneously--e.g. in a gasoline- or diesel-fired internal combustion engine. Hence NOx emissions can be controlled with various techniques to very low levels in hydrogen-fueled engines. With hydrogen fuel cells that may one day be practical commercial devices, even NOx emissions would be negligible.

about the unsolved problems of nuclear waste disposal, and the possibilities for the proliferation of nuclear weapons-usable materials diverted from nuclear power fuel cycles. Moreover, even if the hoped-for improved economics of a born-again nuclear industry could be realized, the resulting nuclear electricity would not be cheap enough to make the derived hydrogen an economically attractive alternative to carbon-based fuels (see Chapter 4).

What about renewable sources of electricity--hydroelectric, wind and photovoltaic sources? Low-cost hydrogen can be produced at many existing hydroelectric sites, but global hydroelectric resources are too limited for the potential quantities of hydrogen produced this way to have much of a global impact in replacing fossil fuels,[38] and new hydroelectric supplies are generally much more costly than the low-cost supplies already developed.[39] Wind energy resources are similarly limited in global extent[40], and wind-based hydrogen would would also be quite costly (see Chapter 4).

The photovoltaic (PV) resource is much less geographically constrained than hydro- and wind-power: PV power can be produced in any sunny region. A system for producing hydrogen from PV power is sketched in Figure 5. A PV array converts sunlight into DC electricity (*), which powers an electrolyzer, spliting water into its constituent elements hydrogen and oxygen. A compressor pressurizes the hydrogen for storage, onsite use or pipeline transport to distant markets. PV hydrogen can in principle be produced in quantitities sufficient to allow it to substitute for fossil fuel on a very large scale.

PV hydrogen systems were studied intensively in the 1970s. Research indicated that it would be technically feasible to produce PV hydrogen and use

---

* Hydrogen production also represents an attractive early market for PV power, because conversion to hydrogen provides a means of storing the solar energy for use when the sun is not shining.

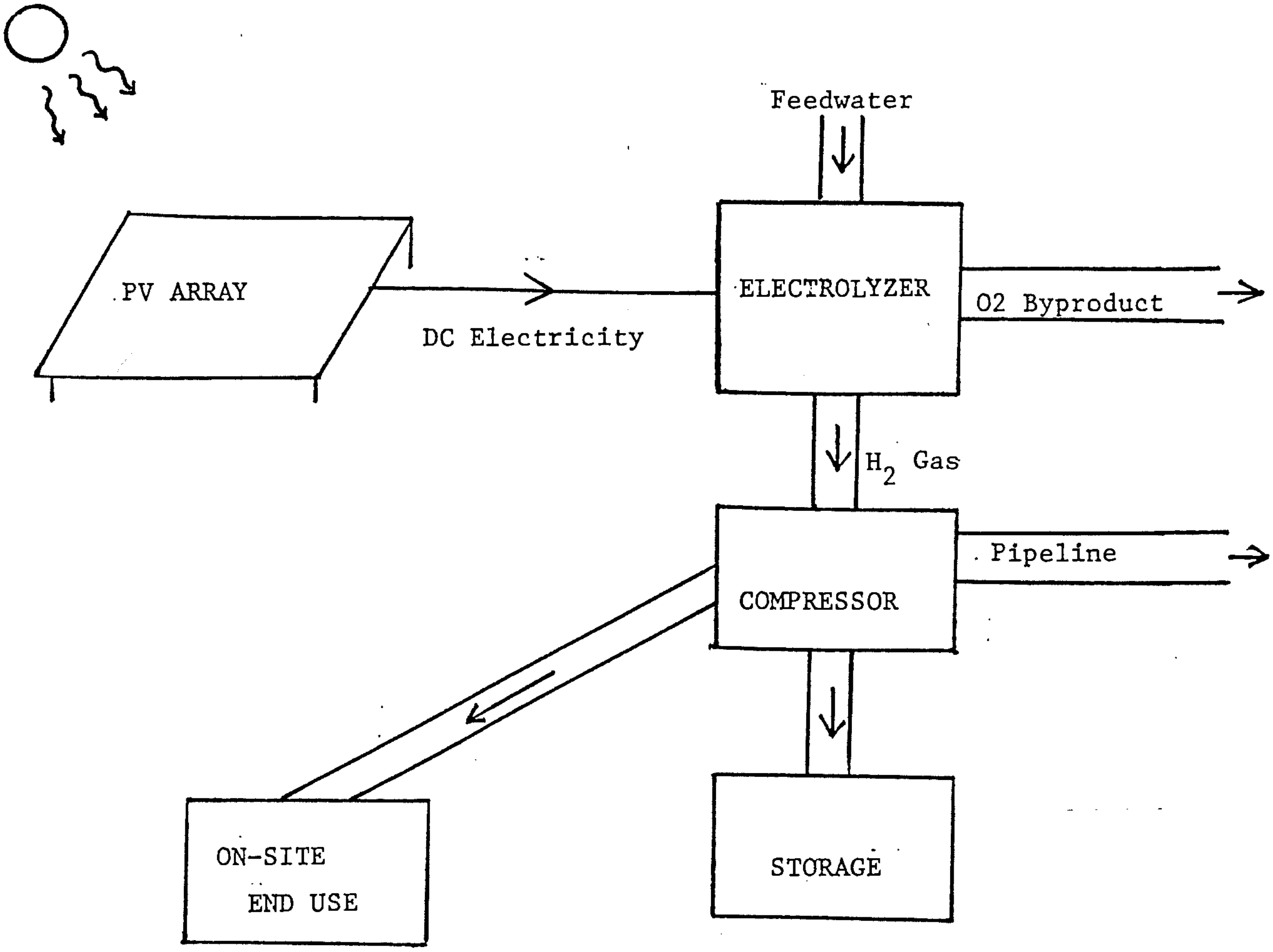


Figure 5. A solar photovoltaic electrolytic hydrogen system.

it for transport, heating and power. However, economic assessments published in the early 1980s concluded that solar cells, and therefore PV electricity, would probably always be too expensive for PV hydrogen to compete with other fuels. This conclusion, based largely on late 1970s projections for the eventual cost and efficiency of solar cells, has remained the "conventional wisdom" regarding PV hydrogen.

2. The Prospects for PV Hydrogen Derived Using a-Si Solar Cells

While relatively little attention has been paid to PV hydrogen (outside of West Germany) since the early 1980s, there has been a revolution in the development of new, inexpensive solar cell materials. Particularly rapid progress is being made for amorphous silicon (a-Si) solar cells--a technology that did not exist even in the heads of theoretical physicists before the mid-1970s. Over the last few years there have been continuing dramatic increases in the efficiency and reductions in the costs of amorphous silicon solar cells--trends which are expected to continue for the foreseeable future. It now appears that solar cells and PV electricity may turn out to be much less expensive than was thought possible just a few years ago (see Chapter 2).

The development of low-cost amorphous silicon solar cells has profound implications for PV hydrogen. As we will show, if PV industry projections for amorphous silicon are achieved, PV hydrogen could become roughly cost competitive with synthetic fuels from coal or other sources by the early part of the next century (see Chapter 4). At that time it would probably cost the consumer about as much to use low-polluting PV hydrogen as to use coal-based synthetic fuels or electricity from coal or nuclear sources (see Chapters 5 and 6). When one considers the clean air and greenhouse benefits of PV hydrogen relative to fossil fuels and the opportunity to gain these benefits without incurring the various risks associated with large-scale nuclear power development, PV hydrogen looks even more cost-effective.

This outlook for solar hydrogen, which contradicts the accepted view, is largely unfamiliar to energy planners for several reasons. First, amorphous silicon solar cell technology has emerged only recently. In the early 1980s, when the last major assessments of PV hydrogen were completed, amorphous silicon solar cells were still only laboratory curiosities, and it was thought that commercial PV power would require crystalline devices, which are inherently much more costly than amorphous silicion devices. Second, low world oil prices have tended to keep energy issues off the agenda of public policy debates during the last few years, so that policymakers and the public generally are unaware of the spectacular progress being made in the PV industry. And third, even within the PV R&D community, efforts have been focussed on the nearer term PV electricity markets rather than longer-term PV hydrogen markets.

C. THE TRANSITION TO A HYDROGEN ECONOMY

How and when might a transition to a PV hydrogen economy begin in the United States? As we shall show, a hydrogen economy stands the best chances of succeeding if hydrogen serves energy-efficient end-use technologies. Thus a precondition for a successful transition to a hydrogen economy appears to be emphasis in the near term on reducing fossil fuel use through improvements in the efficiency of fossil fuel energy use.

The transition to hydrogen as an energy carrier could probably begin in the latter part of this century with small local energy systems located in the sunny Southwest, where the cost of delivered PV hydrogen would be the most favorable.

Initial applications of hydrogen as an energy carrier will probably be in the transport sector (see Chapter 5), for several reasons.

- Transportation fuels are the most expensive fossil fuels, and PV hydrogen would be better able to compete on a fuel cost basis. As will be shown in later chapters, the cost of hydrogen produced in the Southwestern US could be comparable to other liquid synthetic fuels by the year 2000.
- Hydrogen-powered cars could probably be commercialized over the next decade. Experimental hydrogen-powered cars have already been built, and automobile manufacturers in Germany and Japan are currently developing hydrogen cars.
- In several urban areas of the Southwest, there are already severe air pollution problems associated with automotive emissions. In some areas, pollution is projected to become even worse because of population expansion. These air pollution problems have focussed attention on the use of alternative transport fuels as an air pollution control strategy. This situation provides a favorable context for introducing hydrogen as a low-polluting transport fuel.
- There is likely to be increasingly strong political pressure to develop demonstration projects to address the greenhouse warming problem that can be in place within a decade. The modular nature of PV hydrogen technology makes it well-suited to low-cost, near-term demonstrations.

Initially, perhaps over the next 5-10 years, fleet vehicles in some Southwestern city could be converted to hydrogen, derived not from PV sources but produced instead off-peak at some low-cost coal-fired or hydropower plant in the region (*). If this demonstration effort were to succeed, then by the turn of the century cost-effective PV hydrogen systems could provide additional hydrogen supplies as the demand for hydrogen starts to grow.

Automotive fleets as an initial market would have the advantage that they could be centrally fuelled and maintained, which would minimize the initial investment in a fuel distribution system. The first hydrogen fleets might belong to utilities, which would probably have some experience with PV systems,

---

* As in the case of coal-derived methanol, hydrogen derived from coal this way would improve local air pollution problems but exacerbate the greenhouse problem. But the amount of hydrogen produced would be miniscule. The purpose of using this source of hydrogen would be to get an early demonstration of the use of hydrogen as an automotive fuel before PV hydrogen is commercially ready.

or to the city or state government, or police.

Because both PV systems and electrolysis systems have little economy of scale above sizes of perhaps 5-10 MW, the initial investments in these hydrogen/PV systems would be small. Capacity would have to be added only in small increments, as the demand increased.

Once the technology became established for fleets, the local utility could begin to offer hydrogen fuel for private automobiles. In order to interest consumers, it would be important to have multi-fuel capable vehicles, which could use other fuels in areas where hydrogen would not yet be available.

If local hydrogen transport systems came to be viewed as an attractive way to cope with the problem of urban air pollution in the Southwest, cities in the Northeast and the Midwest might decide to convert to hydrogen as well. If 10% of fleet vehicles in the US converted to hydrogen, this would be enough demand to justify building a pipeline to bring hydrogen from the Southwest to the Northeast. Hydrogen-powered transport would then follow a similar pattern in northern cities, first as a fuel for fleets and then for private vehicles.

Once pipelines were built and hydrogen was established as a transportation fuel, it might find other uses as well. For example, hydrogen could be used for residential space and water heating in the Northeast (see Chapter 6).

A switch to hydrogen fuel would take many decades to complete, but it seems that significant initial benefits from hydrogen as a low-polluting alternative to fossil fuels could be realized beginning around the turn of the century.

CHAPTER 2. THE COMING OF AGE OF PHOTOVOLTAIC POWER

February 15, 1989

A. BACKGROUND

The prospect that low-polluting PV hydrogen could begin to be used as a transport fuel by the turn of the century is not rooted in any dramatic developments relating to hydrogen. Rather it is a direct result of advances relating to PV technology, which involves the direct conversion of sunlight into electrcity using solar cells, and in particular a result of rapid progress being made in amorphous silicon (a-Si) solar cell technology.

Compared to other methods of electric generation, PV conversion of sunlight into electricity is exceptionally clean and quiet, with no moving parts and no pollution. The "fuel" is free and inexhaustible sunlight, and solar PV cells can be made mostly of silicon, a raw material which is plentiful and easily available from silicon dioxide in sand.

Until recently, the solar cell was considered an "exotic" power source, too expensive for all but a few specialized applications such as space craft, navigation buoys and remote weather stations. In the last few years, this picture has been radically changed by the development of new solar cell materials, that not only require much less raw material and energy to manufacture but are amenable to inexpensive mass production techniques.

Before about 1980, the only commercially available solar cells were made of high-grade single-crystal silicon, using a time-consuming, material- and energy-intensive crystal growing process.[41] In the early 1970s crystalline silicon solar cells cost about $120 per peak Watt.[42,43] Such high costs were tolerable for space power, but they implied that terrestrial power applications were but a dream. The cost of electricity from solar cells costing $120 per peak watt would be more than $5 per kilowatt-hour (kWh);[44,45] for comparison, the cost of electricity from new coal and nuclear power plants is some $0.05 to $0.07 per kWh.[46]

Despite the challenges posed by single crystal silicon technology, improved manufacturing techniques have enabled prices to be cut to about $5 per peak Watt ($5/Wp). This price, however, is still too high for large-scale use.

In the early 1980s the industry began marketing solar cells made of polycrystalline silicon, a less expensive (but somewhat less efficient) material composed of many small crystallites.[47] Polycrystalline cells (which accounted for about one fifth of the solar cell capacity manufactured in 1986[48]) now cost about $3 per peak watt to manufacture and sell for about $5 per peak watt. While improvements in efficiency and manufacturing techniques may eventually reduce the production costs of crystalline and polycrystalline cells to about $1-2 per peak watt,[49,50] it is a new technology, the amorphous silicon solar cell, which offers the most promise for reducing solar cell costs to the levels required for the large scale development of photovoltaic power.

B. THE AMORPHOUS SILICON SOLAR CELL

In the mid-1970s it was discovered that thin films of amorphous silicon could be used to convert sunlight directly into electricity. Only 1 micron thick, amorphous thin films use much less raw material than crystalline solar cells, which are typically 100-200 microns thick. In fact, so little material is required for the active layer of a-Si cells that the amount of electricity that can be extracted from a gram of silicon over the life of a solar cell is comparable to the amount that could be extracted from a gram of uranium used in a plutonium fast breeder reactor! Of course silicon is far more abundant than uranium in the earth's crust (Box 1).

Another attractive feature of a-Si cells is that, instead of the

Box 1. MINING THE EARTH'S CRUST FOR ENERGY: NUCLEAR VS. a-Si SOLAR CELLS

The allure of nuclear power is the enormous amount of energy released in the fissioning of nuclear fuel. If one day breeder reactors were to become the dominant technology for nuclear power it would be feasible (with repeated fuel recycling) to fission about half the mass contained in the nuclear fuel. If the energy released in fission were converted to electricity at 33% efficiency, some 3800 kWh could be obtained from a single gram of uranium or thorium "feedstock"--nearly half the electricity consumed in a year by the average US household. This is so large that it would mean consideration might be given to "mining the rocks" for uranium and thorium fuel. Even though the the combined concentration of uranium and thorium in the crust averages just 50 parts per million, the amount of electricity that could be extracted from a tonne of this crust material would be equivalent to that which could be obtained by burning 70 tonnes of coal.

How does amorphous silicon solar cell technology compare? Even though the energy released in the fissioning of a single uranium nucleus is 100 million times greater than the "energy released" when a photon is absorbed in amorphous silicon, a uranium atom can fission only once, whereas a silicon solar cell can repeatedly absorb photons and convert solar energy into electricity. An amorphous silicon solar cell contains an amorphous silicon layer about 1 micron thick, amounting to some 3 grams per square meter of cell area. A 15% efficient PV system operated in the Southwest US, where the insolation averages about 250 Watts per square meter, would thus produce about 3300 kWh per gram of silicon over the expected thirty year PV system life--about the same as the amount of electricity from a gram of nuclear feedstock using breeder reactors.

But silicon is more than 5000 times more abundant than uranium and thorium in the earth's crust. In fact, it accounts for about half the mass of ordinary sand. The amount of electricity that could be produced from amorphous silicon cells using a tonne of sand is equivalent to what could be produced by burning more than a half a million tonnes of coal.

painstaking crystal growing and cutting process, production of amorphous silicon solar cells involves a simpler process of depositing silicon vapor on an inexpensive substrate such as glass, plastic or stainless steel. Because of the speed with which vapor deposition can be done, the ease with which electrical connections can be made, and lower energy and material requirements, amorphous modules can be mass produced much more quickly and cheaply than crystalline modules.[51]

Progress in amorphous silicon technology has been rapid. While the first cells produced in 1976 were only 1 percent efficient, efficiencies have increased at a steady rate, reaching in 1987 almost 14 percent for small area laboratory cells and almost 12 percent for larger area laboratory modules (Figure 6, top). One of the leading scientists involved in a-Si PV development projects that an efficiency of 18% will be achieved in the laboratory in 1990.[52]

Manufacturers in Japan, the US, and Europe were quick to recognize the potential of amorphous silicon as an inexpensive solar cell material. In a mere ten years the a-Si solar cell has grown from a laboratory device to a commercial product (*), for which production has steadily increased (Figure 6, bottom), reaching 11.9 MW or 41 percent of the total worldwide PV market in 1987.[53]

Present indications are that this rapid growth will continue. Chronar

---

* A key event in the early development of a-Si solar cells was the Japanese creation of the solar calculator market. Initially too expensive and inefficient to compete with crystalline silicon for the established PV power markets, amorphous silicon found a niche by replacing calculator and watch batteries. A-Si solar cells have now expanded beyond these initial consumer electronics markets into other applications including solar powered battery chargers for vehicles, outdoor lights and electric fences and remote power systems and utility power plants providing peak power during the daytime.

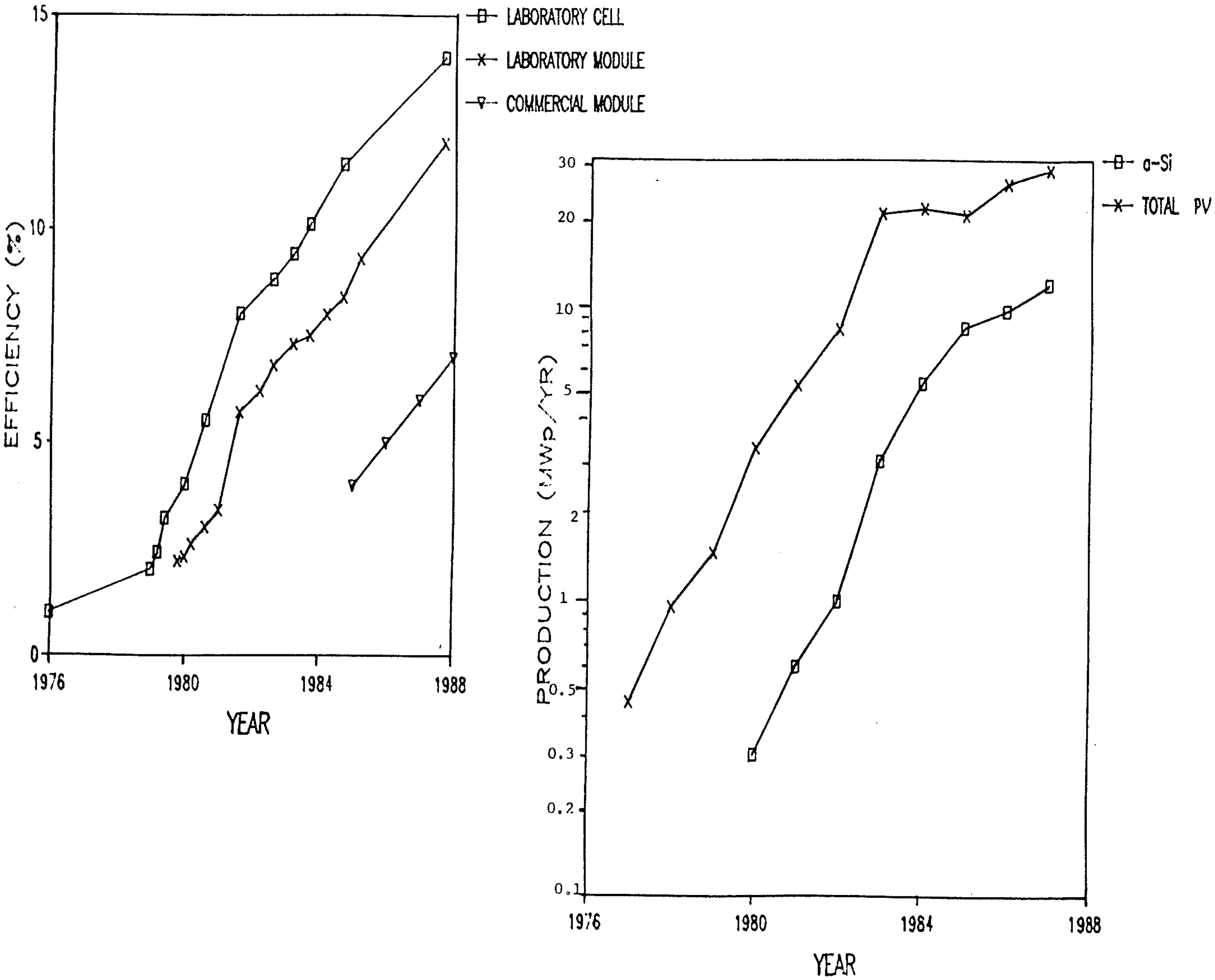


Figure 6.

Progress in amorphous silicon solar cell technology.

The trends in the efficiency of amorphous silicon (a-Si) small-area laboratory cells (typically 1 cm x 1 cm in size), larger area laboratory modules (≥ 100 square centimeters), and commercially available modules are shown vs. calendar year in the top graph.

The bottom graph shows the total annual PV production volume and the annual production of amorphous silicon solar modules in megawatts of peak power manufactured per year.

Sources: Y. Kuwano, SANYO, private communications, 1985; Z Erol Smith, private communications, 1987; D. Carlson, Solarex, private communications, 1987; Photovoltaic Insider's Report, February 1987 and January 1988.

Corporation of Princeton, NJ, plans to start construction on a 10 MW per year a-Si solar cell factory toward the end of 1988[54] and has recently announced plans to build a 50 MW amorphous silicon power plant in California[55]. Solarex, of Newtown, Pennsylvania, will have a 1 MW per year, fully computer-integrated-manufacturing line operating in 1989 and is planning to build a 10 MW per year production facility in the early 1990s [56]. Arco Solar, Inc., of Chatsworth, California, is building a manufacturing facility in Camarillo, California, capable of producing 5 MW per year and is designing a separate plant capable of 70 MW of yearly production [57].

Today a-Si solar cells are manufactured in relatively small factories, with about 1 MW per year production capacity, at costs of about $1.5-1.6 per peak watt for 5-7% efficient modules.[58] Amorphous silicon solar cells are already less expensive than other solar cell technologies, costing only about half as much per peak watt as polycrystalline cells and one third as much as single crystalline cells. Production costs of a-Si solar cells are expected to decline even further as the scale of plant production increases. These trends are illustrated by a range of recent projections by various solar cell manufacturers and researchers (Figure 7).

Both Chronar's and Solarex's 10 MW per year plants and Arco Solar's proposed 70 MW per year plant are expected to produce 6% efficient cells for a cost in the $1 per peak Watt range,[59] according projections made by these companies (e.g. Table 2). The cost of 5% efficient solar modules for the 50 MW Chronar power plant is expected to be $1.25 per peak Watt [60]. As amorphous silicon continues to move into the potentially vast electric power market, competition between photovoltaic manufacturers in the US, Japan and Europe is expected to set a fierce pace of innovation.

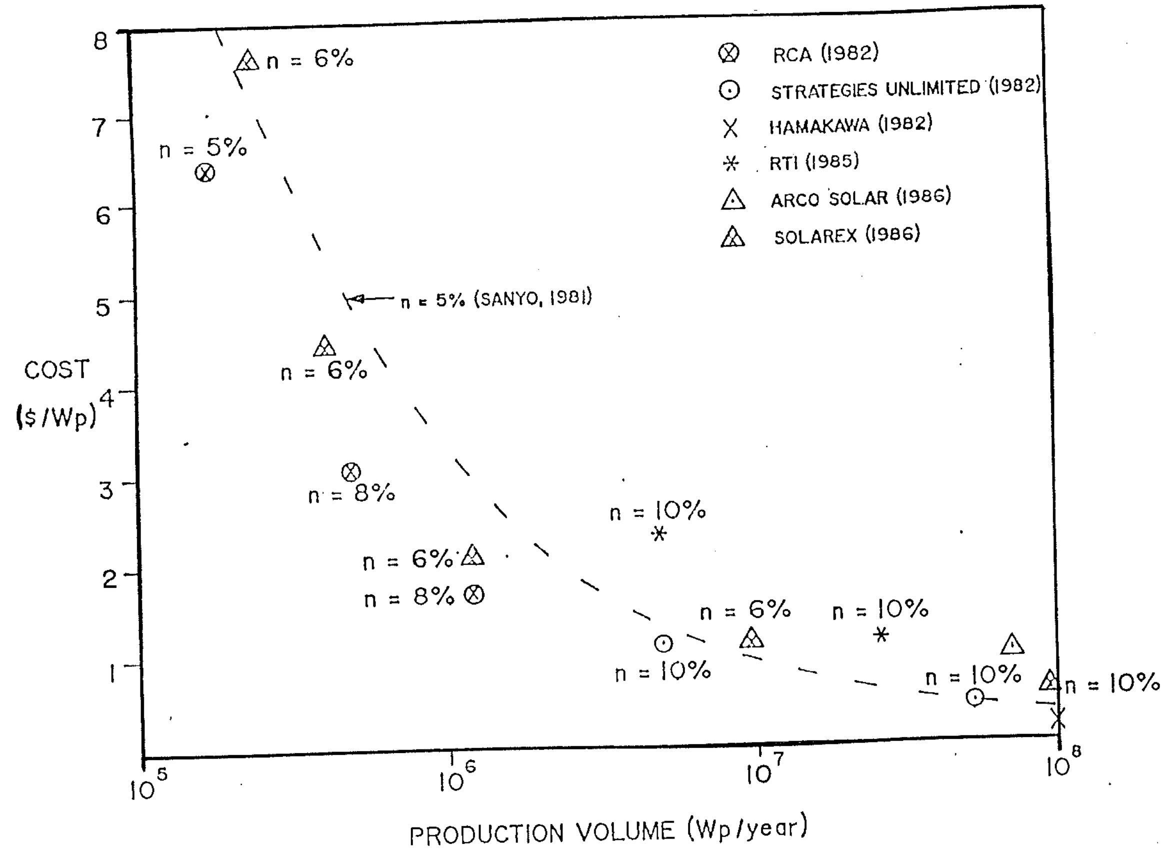


Figure 7.

Estimated cost versus production volume for amorphous silicon solar cell modules, based on recent projections by various manufacturers and researchers.

Source: David E. Carlson (General Manager, Thin Film Division, Solarex, New Town, Pennsylvania), "Low-Cost Power from Thin-Film Photovoltaics," paper prepared for the Vattenfall Electricity Congress, Goteburg, Sweden, May 30-June 1, 1989.

Table 2. Estimated Amorphous Silicon Solar Module Production Cost for a Factory Producing 10 MW_p per Year of 6 Percent Efficient Solar Modules (a).

	Dollars per W_p
Equipment Depreciation (b)	0.41
Direct Materials (c)	0.46
Direct Labor and Fringe Benefits (d)	0.16
Indirect Labor (e)	0.07
Indirect Expenses	0.06
Total	1.16

---

[a] For a factory planned by Solarex.

[b] For a five-year depreciation period and a capital cost for equipment (computer integrated manufacturing) in a 20,000 square foot facility estimated to be $16,500,000.

[c] For 1 foot x 4 foot modules produced with an overall yield of 84%. The following is a breakdown of the materials cost:

Material	Cost ($ per Wp)
Glass (chemically strengthened)	0.23
Silane	0.07
Encapsulant	0.04
Frame	0.03
Diborane, phosphine	0.03
Stannic chloride	0.02
Wire, other process gases	0.02
Aluminum	0.02
Total	0.46

[d] 83 direct employees, 5 day work week, 2.5 shifts per day.

[e] 17 indirect employees.

Although the eventual efficiencies and costs of amorphous silicon solar cells cannot be forecast with certainty, it seems almost sure that commercial module efficiencies of 10% and 13% will be achieved for single-layer and multi-layer (*) cells, respectively, in the near term (1990-1995). In the longer term, it is likely that "practical limit" efficiencies of 12-14% will be achieved for single-layer amorphous silicon modules, while efficiencies of 18-20% percent are likely for multi-layer modules. By the turn of the century, PV module efficiencies of 12-18% (corresponding to PV system efficiencies of 10-15%) and costs of $0.20-0.40/Wp may well be achieved, if manufacturers' projections are realized (Table 3). The technical basis of these cost and efficiency projections, which are the basic PV assumptions underlying our PV hydrogen analysis set forth in later chapters, is examined in Box 2.

To give a brief indication of how these manufacturing cost reductions might be achieved, consider possible improvements on the Solarex design for a 10 MWp per year production facility that could be built with present technology, producing 6% efficient cells costing $1.16 per Wp (Table 2, Box 2).

For amorphous silicon solar cells the cost per unit area is not expected to change much with the efficiency, because the active materials in the cell account for only a few percent of the total cost (Table 2), and because improvements in efficency will be achieved largely by fine tuning the composition of the active materials--adjusting the thickness of the active layer, adjusting the amounts of dopants, adding additional layers that use different parts of the solar spectrum, adjusting the alloy composition of the cells used in different layers, etc. Accordingly, the cost for 12% efficient cells, which are expected to commercially available by 1995, should be about $0.58 per Wp (Table B.2.1). A further reduction in the cost of 12% efficient cells to about $0.47 per Wp could be achieved simply by expanding the scale of production tenfold from 20 MWp to 200 MWp per year. Most of the gains would be realized through the economies of scale with regard to labor requirements.

A-Si PV technology would be sufficiently mature with 12% efficient modules that it would probably be justifiable to extend the depreciation period for the PV production facility from 5 years (assumed for the 10 MW per year case producing 6% efficient cells shown in Table 2) to 10 years--thereby reducing the cost of cells further to $0.37 per Wp (Table B.2.1).

There are also various possibilities for reducing the materials costs associated with cell manufacture. First, with a larger production facility it becomes feasible to couple a PV production facility to a dedicated float glass production plant. Plant integration together with reductions in silane gas losses in a-Si cell processing, elimination of the the need for chemically strengthening the glass, and reductions in module framing costs could collectively cut materials costs in half and thus reduce the total cost of cells to $0.25 per Wp (Table B.2.1). Even further cost reductions could be acheived with commercial cell efficiencies higher than 12% [e.g. to $0.16 per Wp with 18% efficient cells (Table B.2.1)].

C. THE IMPLICATIONS FOR THE FUTURE OF PHOTOVOLTAIC POWER

What are the implications of these advances for stationary power generation? Table 4 shows markets for PV electricity, with the "breakeven" solar module price needed to compete with existing sources of electricity. In recent years, the drop in prices (to current levels of about $4-5/Wp) has

---

* Multi-layer cells are made by depositing several thin film layers, with each layer tuned to absorb a different part of the solar spectrum. Multi-layer cells are more efficient than single layer cells, because they utilize more of the sun's spectrum.

Table 3. Cost and Efficiency Projections for Amorphous Silicon Solar Cells

	Single layer	Multi-layer
Efficiency:		
1987 small area cell (best laboratory results for 1 cm^2 device)	12% (a)	14% (b)
1987 submodule (laboratory module with area of about 1000 cm^2)	8-9% (a)	12% (b)
1987 commercial module (typical, mass-produced)	5-7% (c)	
Projected 1990-1995 module	10% (d)	13% (d)
Practical limit	12-14% (e)	18-20% (e)
Costs (in $ per peak Watt):		
1988 Module manufacturing cost	1.5-1.6 (f) [for 6-7% efficient modules (f)]	
Projected 1990s module manufacturing cost	0.6-1.2 (g) [for 6-12% efficient modules (g)]	
Projected 2000 module manufacturing cost	0.2-0.4 (g) [for 10-15% PV array efficiency]	

---

[a] D.E. Carlson, Solarex, quoted in Photovoltaic Insider's Report, December 1987, p. 4.

[b] D.L. Morel, ARCO Solar, quoted in PVIR, December 1987, p. 4.

[c] PVIR, May 1987, p. 1.

[d] Four US manufacturers of a-Si solar cells (Chronar, Solarex, Spire and 3-M) are in a cost-shared program with the US Department of Energy to produce modules of these efficiencies by 1990, PVIR, February 1987, p.2.

[e] D.E. Carlson, Solarex, private communication, 1987.

[f] For a plant producing 1.3-1.4 MWp per year. S. Kaplan, Chronar Corp., private communications, 1988. 1988 prices are about $4-5 per peak watt.

[g] D. E. Carlson, based on estimates by amorphous silicon solar cell manufacturers for factories producing 10-200 MW$_p$ of solar cells per year.

Table 4. Potential Markets for Photovoltaic Electricity

Market	Breakeven Solar Module Price ($ per peak Watt)(c)	Potential Market Size Total (MWp)	Annual (MWp/year)
Corrosion protection (a)	20-100 (d)		
Buoys (a)	60 (d)		
Consumer products: calculators, watches, etc. (a)	10 (d)		9 (e)
Remote water pumping (a)	4-7 (d)	2,000 (f)	100 (b)
Diesel generator replacement, remote power (a)	5 (d)	10,000 (g)	500 (b)
US Utility electric peaking	2-3 (d)	50,000 (Total US Peaking)	2,500 (b)
Daytime power for grid-connected residences in US (h)	0.7-1.5	100,000	5,000 (b)
US Utility electric baseload (with storage) (i)	0.15-0.45	600,000 (Total US Baseload)	30,000 (b)

---

[a] Currently commercial markets. The total PV market in 1987 was about 29 MW.

[b] The annual potential market was estimated by dividing the total potential market by 20 years commercialization time.

[c] Breakeven PV prices were estimated assuming 10% efficient PV systems, and balance of systems costs of $33-100 per square meter, depending on system size.

[d] P.D. Maycock and E. N. Stirewalt, The Photovoltaic Revolution, Rodale Press, NY, NY, 1985.

[e] Estimated size of 1986 consumer products market for solar cells, Photovoltaic Insider's Report, July 1987, p. 2.

[f] Assuming that 2 million 1 kW water pumping systems are installed.

[g] Assuming that 2 million remote sites acquire 5 kW PV systems for communications, refrigeration and lighting.

[h] Assuming that the PV systems must compete with residential grid power costing $0.06/kwh, and that 50 million residences acquire 2 kW PV systems.

[i] Assuming that baseload PV electricity with storage costs $0.08/kwhAC.

permitted PV power to move beyond small, highly specialized markets such as emergency telephone power packs, lights for navigation buoys, and consumer electronic products, into water pumping and small-scale power-generating applications. In sunny areas not served by central station power sources, such as remote military bases, research stations and rural areas in developing countries,[61] PV power has become competitive with the small Diesel generators now used to generate electric power.

With the expected near term (1990-1995) production costs of amorphous silicon solar modules in the range \$0.6-1.2/Wp, amorphous silicon PV arrays could start replacing oil and gas-fired generators for utility electric peaking applications sometime in the 1990s. (Chronar's planned 50 MW plant will essentially be a peaking plant, the electricity from which will be sold to Southern California Edison.) In the US, utility peaking will very likely be the most important near term PV market,[62] followed by daytime power generation on residential rooftops (Table 4).

While these markets will be important for the PV industry, the resulting impact on the overall energy supply situation, while locally significant, will be small on a global scale.[63] In order for PV power to make major inroads into the electric power market, it would be necessary to make PV electricity available on demand, which means that PV power must not only become very cheap but also that inexpensive methods must be found for storing electricity for use when the sun doesn't shine.[64,65]

As shown in the next chapter, it is likely that DC electricity produced in the Southwestern US could cost as little as \$0.02-0.035/kwhDC by the year 2000, if goals for amorphous silicon solar cells are achieved. If PV DC electricity could be produced for say \$0.02/kWhDC, then PV baseload power could cost less than \$0.05/kwhAC, with advanced batteries or underground pumped hydro storage systems, making it competitive with baseload power from coal-fired and nuclear power plants.

However, to reach such low electricity costs with PV would require not only the achievement of technological goals (15% efficient PV systems, balance of systems costs of \$33/m^2 and PV modules costing \$0.20/Wp), but also the right location, e.g. one with a good solar resource. (It would be neccessary to locate a baseload PV system relatively near the demand, because electricity is very expensive to transmit over long distances with present technology.) In much of the US, the insolation is simply too low to reach these costs.

Even in sunny areas where storage technologies could be developed, the overall potential impact of PV electricity would be limited by the restricted role of electricity in the overall energy economy. Electricity consumption accounts for only about 10 percent of global energy use, and electricity production for only about 1/4 of all fossil fuel use.

D. THE IMPLICATIONS FOR SOLAR HYDROGEN

PV technology could have a much larger impact in reducing fossil fuel use, if economical ways could be found for making synthetic fluid fuels with solar cells as direct substitutes for oil and gas, which account for 2/3 of global fossil fuel use.

As many have pointed out, hydrogen produced by splitting water via PV-powered electrolysis could replace oil and natural gas in virtually all their present uses [66]. Making hydrogen this way provides a means of storing the solar energy for when the sun doesn't shine, and the hydrogen produced in sunny areas can be transported long distances to remote markets at much lower costs than electricity. And PV hydrogen has obvious environmental advantages.

But how much would PV hydrogen cost as compared to other options? In the next chapter, we describe a detailed technical/economic design for a PV hydrogen energy system, with the aim of addressing this question. Assuming that goals for amorphous silicon solar cell technology (Box 2) are met, we estimate how much it would cost to produce and deliver PV hydrogen fuel. We then compare the cost of PV hydrogen and various other synthetic fuels, and some environmental aspects of using each fuel.

Box 2. KEY TECHNICAL ASSUMPTIONS RELATING TO AMORPHOUS SILICON SOLAR CELLS

Our analysis of the prospects for PV hydrogen is based on the assumption that the cost and performance goals for amorphous silicon solar cells near the turn of the century will be realized. Here we review the technical basis for these goals.

Assumption #1:<u>Amorphous silicon PV modules will have stable efficiencies of 12-18%</u>

While today's commercially available single layer amorphous silicon modules have modest conversion efficiencies of about 5-7%, efficiencies achieved in the laboratory with small-area, multi-layer cells have exceeded 13%. To date, efficiencies achieved in the laboratory have been realized in commercial modules some 5-6 years later (Figure 6a), but this time lag is expected to shorten in the future, as manufacturers move toward computer-integrated manufacturing of a-Si cells, resulting in a generally higher level of quality control in production than in the laboratory--a phenomenon that has occurred for a variety of products in the semiconductor industry.[67] By the early to mid-1990s, efficiencies for commercial modules are expected to be 10% (for single-layered cells) and 13% (for multi-layer cells).[68] One of the leading scientists in amorphous silicon solar cells projects that efficiencies of 18% will be achieved in the laboratory in 1990.* By the year 2000, commercial modules approaching the "practical limit" values of 12-14% for single layer solar cells and 18-20% for multi-layer cells may well become available.[69,70,71]

One problem that plagued the early development of amorphous silicon solar cells is that the cells experience an initial loss of efficiency (known as the Staebler-Wronski effect[72]) when exposed to light. While the Staebler-Wronski effect is not yet fully understood theoretically, the problem has been largely solved in practice. The initial efficiency degradation can be completely reversed by reheating the cells to their annealing temperature (about 200°C) for a few minutes. At typical outdoor solar cell operating temperatures of 50-60 °C some annealing takes place, which tends to counterbalance the Staebler-Wronski effect.[73] Also, making single layer cells thinner and using multiple layers tends to retard the initial loss of efficiency. Single-layered and multi-layered modules can now be made that stabilize, after a few months exposure to sunlight, at about 80% and 90% of their initial efficiencies, respectively.[74]

On the basis of these results, we assume that stabilized solar module efficiencies of 12-18% will be reached around the turn of the century. We further assume that the efficiency of a large PV system is 85% of the individual module efficiency, due to electrical losses in wiring and perhaps to wind-blown dirt or dust on the modules.[75] Thus, a PV system constructed of 12-18% efficient modules would have an overall efficiency of 10.2-15.3%.

---

* David E. Carlson (General Manager, Thin Film Division, Solarex, New Town, Pennsylvania), "Low-Cost Power from Thin-Film Photovoltaics," paper prepared for the Vattenfall Electricity Congress, Goteburg, Sweden, May 30-June 1, 1989

Assumption #2: The production cost of amorphous silicon PV modules will be in the range \$0.2-0.4 per peak Watt.

Today most commercial amorphous silicon solar cells are produced in batch operations in small facilities with production capacities of the order of 1 Megawatt peak per year or less. The current production cost is estimated at \$1.5-1.6 per peak Watt for 6% efficient cells.[76] In larger plants, considerable economies of scale could be realized. According to Dr. E. S. Sabisky, manager of the Amorphous Silicon Research Project, at the Solar Energy Research Institute, in Golden, Colorado:[77]

> "...if today's thin-film amorphous silicon modules of 6-8% efficiency are combined with a 10 megawatt annual production plant, the module cost target of \$1 per peak Watt can be reached..."

Sabisky's prognosis is reflected in the announcement in September 1988 that Chronar, of Trenton, New Jersey, will build a 50 MW plant at a site 60 miles north of Los Angeles for \$125 million.[78] This plant, which will sell the produced electricity to the Southern California Edison Company, represents an enormous scale-up from the largest amorphous silicon facility built to date, a 100 kW generating field operated by Alabama Power Company. The PV modules in this plant are expected to have initial efficiencies of 7 1/2% and guaranteed stabilized efficiencies of 5% and are expected to cost \$1.25 per peak Watt.[79] Similar cost estimates have been projected by other manufacturers and are shown in Figure 7.

In Table B.2.1, we show how costs might evolve from current levels to the range of \$0.2-0.4/Wp. These estimates are based on a detailed cost evaluation by Solarex researchers for a 10 MW per year plant, which would produce 6% efficient modules costing \$1.16 per peak Watt.[80]

Increasing the scale of production from 10 MW to 100 MW per year would lead to savings mainly in labor costs, and the cost of 6% efficient modules would be reduced from \$1.16 to \$0.94 per peak Watt (Table B.2.1).

Increasing the efficiency of thin-film solar cells generally involves fine tuning the deposition process by adding slightly different amounts of dopant or varying slightly the layer thickness and would probably entail little or no increase in the labor and materials costs.[81] Thus, a doubling or a tripling of cell efficiency would probably lead to a two-fold or three-fold reduction in the cost per peak Watt.

Materials costs could also be reduced. For the Solarex design glass accounts for \$0.23 per peak Watt or half of the materials cost. The cost of glass could be reduced \$0.06 per peak Watt, if chemical strengthening were not required. A further reduction in the cost of glass could be realized in large-scale (> 60 MW) facilities, where it would be possible to integrate a float-glass manufacturing plant with an a-Si plant. Recovering silane (SiH_4) gas (the primary feedstock for amorphous silicon deposition) during processing, and reducing module framing costs could further reduce material costs. Researchers at Solarex estimate that the overall cost of materials could potentially be reduced to about \$0.11 per peak Watt through innovations such as these, for 12%

efficient cells produced in a 200 MW per year production facility.

Finally, as the technology matures, the rate of equipment obsolescence will slow, making it possible to increase the equipment depreciation period. The effect of increasing the depreciation period from 5 to 10 years plus the effects of the materials innovations mentioned above are summarized for a 1.67 million square meters per year production facility in the last three columns of Table B. Note that total production costs with such innovations would be in the range $0.16 to $0.25 per peak Watt for 12-18% cells, somewhat lower than the range we assume for our PV hydrogen analysis.

Assumption #3: Amorphous silicon PV modules will have lifetimes of 30 years.

Because amorphous silicon solar cells are a new technology, field tests of more than a few years have not yet been completed. However, present-day commercial modules pass a battery of accelerated environmental tests. These tests are designed to simulate many years of use in a short time by subjecting the solar modules to rapidly varying extremes of light, temperature, humidity, hail impacts, etc. A preliminary judgment (which must be verified by further field testing), based on the results of such tests and expected processing improvements, is that a 30-year lifetime is a reasonable expectation.[82]

Assumption #4: Area-related balance of systems costs will be $33 per square meter for large, fixed, flat-plate amorphous silicon based PV arrays.

Area-related balance of systems (BOS) costs include the support structure holding the PV modules, the array wiring and electrical equipment, land, site preparation and other construction costs. Previous conceptual design studies and analysis of data from experimental PV arrays and demonstration projects indicate that area-related BOS costs of $50 per square meter could be readily achieved with present technology.[83,84] If low-cost support structures using pre-fabricated PV panels were employed, this cost could be reduced to perhaps $37 per square meter. With a low-current, high-voltage electrical design, which is especially well suited to amorphous silicon cells, wiring costs could be reduced to give a total area-related BOS cost of $33 per square meter, as assumed in this study.[85]

Table B.2.1. Production Cost of Amorphous Silicon Solar Cells (\$ per W_p)

Annual Production	5-Year Depreciation						10-Year Depreciation w/Reductions in Materials' Costs[c]		
Million sq. m.	0.167			1.67			1.67		
MWp	10	20	30	100	200	300	100	200	300
Efficiency	6%[a]	12%[a]	18%[b]	6%[a]	12%[a]	18%[b]	6%	12%	18%
Variable Costs									
Direct Labor	0.16	0.08	0.05	0.06	0.03	0.02	0.06	0.03	0.02
Materials	0.46	0.23	0.15	0.46	0.23	0.15	0.22	0.11	0.07
Fixed Costs									
Indirect Labor	0.07	0.035	0.023	0.01	0.005	0.003	0.01	0.005	0.003
Indirect Expenses	0.06	0.03	0.02	0.01	0.005	0.003	0.01	0.005	0.003
Depreciation	0.41	0.205	0.14	0.40	0.20	0.133	0.20	0.10	0.065
Total Cost	1.16	0.58	0.39	0.94	0.47	0.31	0.50	0.25	0.16

---

[a] These estimates were made by Carlson [David E. Carlson (General Manager, Thin Film Division, Solarex, New Town, Pennsylvania), "Low-Cost Power from Thin-Film Photovoltaics," paper prepared for the Vattenfall Electricity Congress, Goteburg, Sweden, May 30-June 1, 1989], based on computer integrated manufacturing technology under development at Solarex, in Newtown, Pennsylvania. In this analysis detailed cost estimates were made for present-day production technology using 6% efficient cells, and these cost estimates were extrapolated to 12% efficient cells, assuming that the costs per unit area will not change as the efficiency is increased.

[b] These cost estimates are obtained by extrapolating Carlson's estimates to 18% efficient cells, with the assumption that the cost per unit area will not change as the efficiency is increased.

[c] Two possibilities for cost reduction are taken into account here: (i) reduced materials costs and (ii) an extended equipment depreciation period. Carlson estimates that the collective effect of the materials cost reduction efforts discussed in the text could be to reduce the cost of materials from \$0.46 per peak Watt for 6% efficient cells manufactured at a rate of 10 MW per year to perhaps \$0.11 per peak Watt for 12% efficient cells produced at a rate of 200 MW per year (D.E. Carlson, "Low-Cost Power from Thin-Film Photovoltaics"). Since the pace of innovation will probably slow as the technology matures, it is assumed here that the depreciation period is doubled from five to ten years.

CHAPTER 3. DESIGNING A PV HYDROGEN ENERGY SYSTEM February 15, 1989

If PV hydrogen is to be economically acceptable as well as environmentally benign, it must provide the consumer with energy services (transport, heating, etc.) at costs comparable to those for alternative synthetic fuels. Here we describe the design of a PV hydrogen system, based on amorphous silicon solar cells, with the aim of understanding better the prospects for making PV hydrogen competitive.

A PV hydrogen system would consist of an array of solar modules that would collect sunlight and convert it into DC electricity, an electrolyzer that would use this electricity to split water into hydrogen and oxygen, a compressor that would compress the produced hydrogen up to the required pressure, a storage unit that would compensate for the temporal variation in sunlight to make the supply of hydrogen conform better to the temporal variation in demand, and, if the production of hydrogen exceeds onsite demand, a pipeline that carries the hydrogen to remote users (Figure 5).

A. FINDING SITES FOR PV HYDROGEN PRODUCTION

We begin with the question of where to locate the plants for producing the electricity and converting it to hydrogen. Would it be better to produce the electricity locally, to avoid the expense of long distance transport? Or should the electricity be produced instead in areas where the amount of available sunshine is greater, making it possible to extract more useful energy from a given solar cell (and thereby reducing the cost of PV electricity)?

The choice is not a difficult one because, even for the DC PV electricity production cost in the range \$0.020 to \$0.035 per kWh expected for sunny areas near the turn of the century, electricity production for electrolysis would still account for over 50% of the cost of hydrogen delivered to consumers a thousand miles from the production site (Figure 8). This means that in all likelihood a PV hydrogen economy would involve locating solar hydrogen systems in sunny areas like the Southwestern United States, where the average solar insolation is typically at least 50% higher than in much of the rest of the country (Table 5) and distributing the produced hydrogen in pipelines to areas with less sunshine.

The cost of transporting hydrogen long distances via pipelines is typically far lower than the cost of transporting the same amount of energy in the form of electricity via transmission lines.[86] While it would not make sense to generate PV electricity in sunny regions for transmission to distant demand areas (at least with present technology*), it would make sense to develop PV hydrogen systems this way, because of the relatively low cost of long distance hydrogen transmission. (As shown in Figure 8, hydrogen transmission costs are a relatively small part of the total cost of hydrogen.)

B. DESIGNING THE PV ELECTRICITY PRODUCTION SYSTEM

Once a site has been selected the next task is to design a PV array that would produce low-cost electricity for electrolytic hydrogen production. Solar cells produce direct current (DC) electricity, which is the form required by electrolyzers. When PV electricity is used to produce hydrogen, rather than electric power for the utility grid, one need not convert first to alternating current (AC). DC electricity from a PV array is less expensive than AC electricity, because no DC to AC conversion equipment is required. Moreover, there is good theoretical and empirical evidence from both the US and Germany

---

* This outlook may one day be changed with superconducting transmission lines.

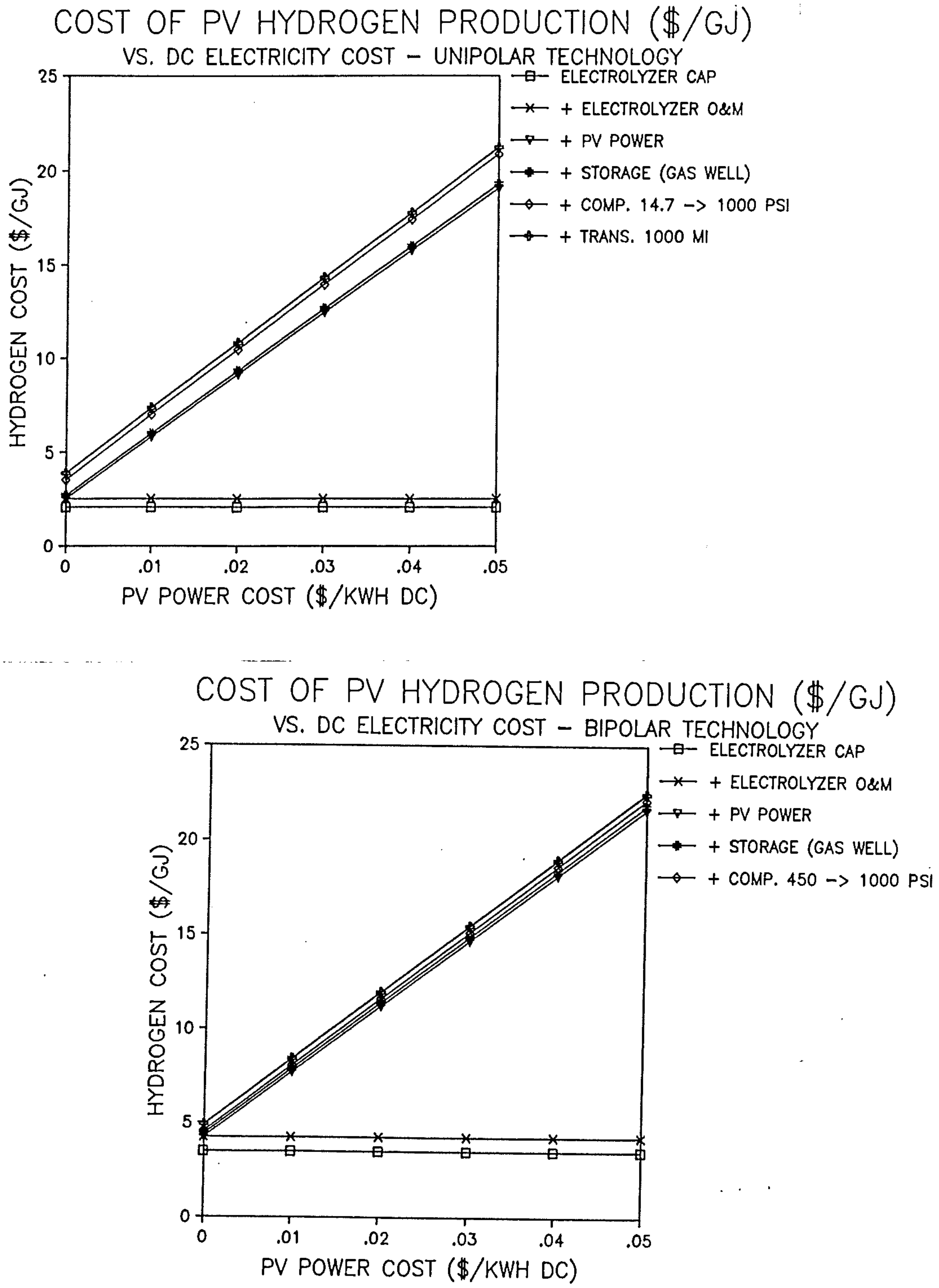


Figure 8.

The production cost of PV hydrogen as a function of DC PV electricity cost for unipolar (top) and bipolar (bottom) electrolyzer technologies.

The hydrogen production cost includes electrolyzer capital costs, operation and maintenance costs, the cost of DC PV electricity, the cost of storage, the cost of compression from electrolyzer pressure (14.7 psia for unipolar technology and 450 psia for bipolar technology) to pipeline pressure of 1000 psia, and the cost for 1000 miles of pipeline transmission.

Table 5. Insolation in US Cities

City	Latitude	Annual Average Insolation (Watts/m^2) Incident on a Flat Plate PV Array Horizontal Surface	 Surface Tilted at Latitude Angle
Albuquerque, NM	35.1 N	236	266
Amarillo, TX	35.2 N	218	241
Atlanta, GA	33.7 N	177	187
Bakersfield, CA	35.4 N	230	245
Boston, MA	42.4 N	145	157
Chicago, IL	41.8 N	160	172
China Lake, CA	35.7 N	241	263
Pueblo, CO	38.3 N	213	241
El Paso, TX	31.8 N	250	271
Las Vegas, NV	36.1 N	245	273
Newark, NJ	40.7 N	153	166
New Orleans, LA	30.0 N	189	198
Phoenix, AZ	33.4 N	246	267
Portland, OR	45.6 N	140	147
Tuscon, AZ	32.2 N	246	267

Source : Jan F. Kreider and Frank Kreith, Solar Heating and Cooling : Active and Passive Design, McGraw-Hill Book Company, New York, NY, (1982).

that a direct connection between the solar array and the electrolyzer works extremely well and obviates the need for expensive DC to DC power-conditioning equipment.[87]

While most of the emphasis to date in PV power development has been on reducing the cost for the PV modules themselves, there has been some effort aimed at developing low-cost designs for the balance of system (BOS). The balance of system includes all the components in the PV system except the modules themselves: e.g., the support structure holding the modules, the electrical wiring and equipment, land and construction. BOS costs from several conceptual design studies (RCA, Sandia/Battelle, EPRI, USDOE) for flat, tilted fixed arrays[88] and field data from ARCO Solar and European Economic Community PV projects are summarized in Table 6. These costs vary from about $47 to some $230 per square meter of collector area.

The BOS cost for a PV system usually has two components--an "area-related" cost and a "power-related" cost. The area-related cost includes all costs which depend directly on the solar collector area (such as the amount of land needed, the size of the support structures needed, the amount of wire needed for the electrical system); the power-related cost includes all components which depend on the total amount of power generated (such as any power conditioning equipment which might be required between the PV array and other parts of the system). In the case of PV hydrogen production, all the BOS costs would be area-related, because no power conditioning equipment would be needed.

The higher the efficiency of the solar modules, the smaller the contribution of area-related BOS costs. The BOS costs would be less with more efficient solar modules, because less land, smaller support structures, and less wire would be needed to produce the same amount of PV power.

Table 6. Area Related Balance of Systems Cost Estimates for PV Arrays

Cost ($\$/m^2$)

	Conceptual Designs			Field Studies	
Component	RCA (a)	Sandia (b)	EPRI (c)	ARCO (d)	EEC (e)
Array support structure	41.2	26.2	46.2	48	30-100
Wire	3.2	12.7	5.65	65 (includes all electrical) $15 subtracted for PCU	
Other DC electric	0.5	14.4	9.2		
Site-prep and cleanup	1.8	2.5	2.8	120 (includes engineering)	
Land (f)	0.2	0.25	0.25	0.25	-
Total BOS cost	47.0	56.1	64	233	50-180

---

[a] J.Stranix and A.H. Firester, "Conceptual Design of a 50MW Central Station Power Plant," RCA Laboratories, Princeton, NJ, 1982.

[b] G.T. Noel, D.C. Carmichael, R.W. Smith, and J.H. Broehl, "Optimization and Modularity Study for Large-Size PV Flat-Panel Array Fields," Batelle-Columbus,18th IEEE PV Spec. Conf.,Las Vegas, Nevada, October 1985.

[c] S.L. Levy and L.E. Stoddard, "Integrated Photovoltaic Central Station Conceptual Designs," EPRI Report AP-3264, June 1984.

[d] G.J.Shushnar, J.H. Caldwell, R.F. Reinoehl, and J.H.Wilson, "ARCO Solar Field Data for Flat Plate PV Arrays", 18th IEEE PV Specialists Conference, Las Vegas, October, 1985.

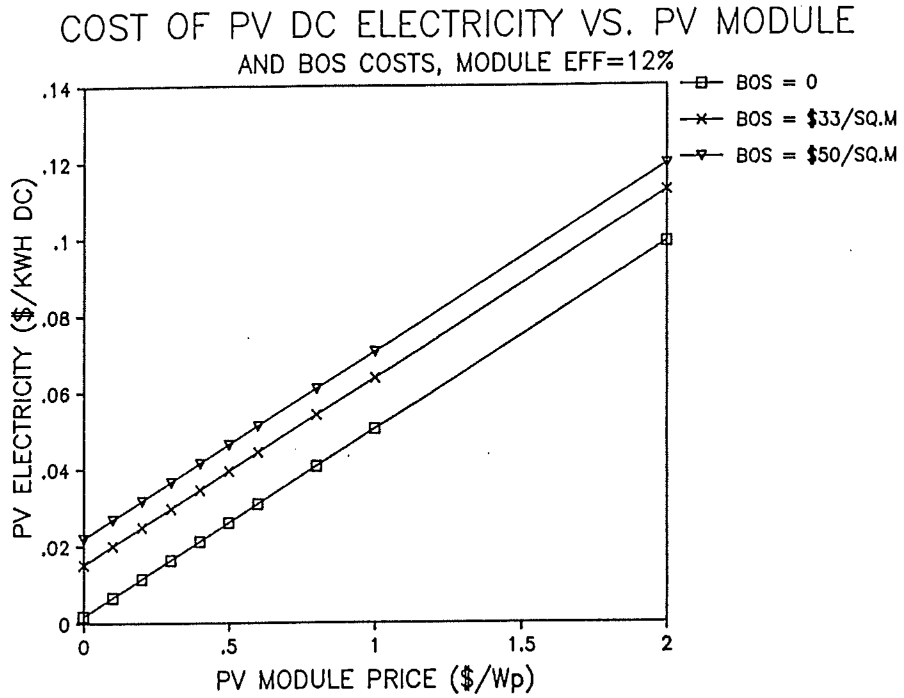
[e] G. Grassi, Commission of the European Communities, DC XII, Brussels, Belgium, 18th Photovoltaic Specialists Conference, Las Vegas, Nevada, October 1985; G. Grassi, P.Paoli, L.Leonardini, E. Vitali, P.Conti, E.Colpizzi, "Low-Cost support Structure for Large Photovoltaic Generators", 18th IEEE Photovoltaics Specialists Conference, October 1985.

[f] For land costing $1000/acre.

A BOS cost of $100 per square meter would add only 25% to the cost of a 10% efficient module at the 1987 price of $5 per Wp. Thus, at present, the highest priority in PV development should still be reducing the module price and increasing solar cell efficiency. But for the period near the turn of the century, when the price of 12-18% modules are expected to be less than $0.50 per Wp, BOS cost reduction efforts will become relatively more important. For example, if the price of 18% modules were $0.40 per Wp, the BOS contribution to the cost would be as just as large at $60 per square meter. Clearly considerable emphasis should be given to finding low-cost BOS designs over the next decade or so.

Fortunately, much can be accomplished simply with "off-the-shelf" components and established construction practices. For the present analysis a design was selected which brings together the best features of the different designs indicated in Table 6, resulting in an estimated BOS cost of $33 per square meter. Most of the savings come from adopting the low-cost Sandia/Battelle design for the collector array structure (which makes use of pre-fabricated panels) and the RCA electrical design (in which the system operates at high voltage and low current, thereby saving on the cost of the more expensive wire needed to carry a higher current, and coincidentally requiring fewer electrical connections).[89] With innovative designs it may be possible to reduce BOS costs further to $20 per square meter or less,[90] but such possibilities are not taken into account in the present analysis.

The cost of DC electricity from an amorphous silicon solar array is plotted as a function of solar module and balance of systems costs for 12% and 18% efficient modules in Figure 9.[91,92] These graphs can be used to estimate the cost of DC electricity in an area with solar insolation conditions



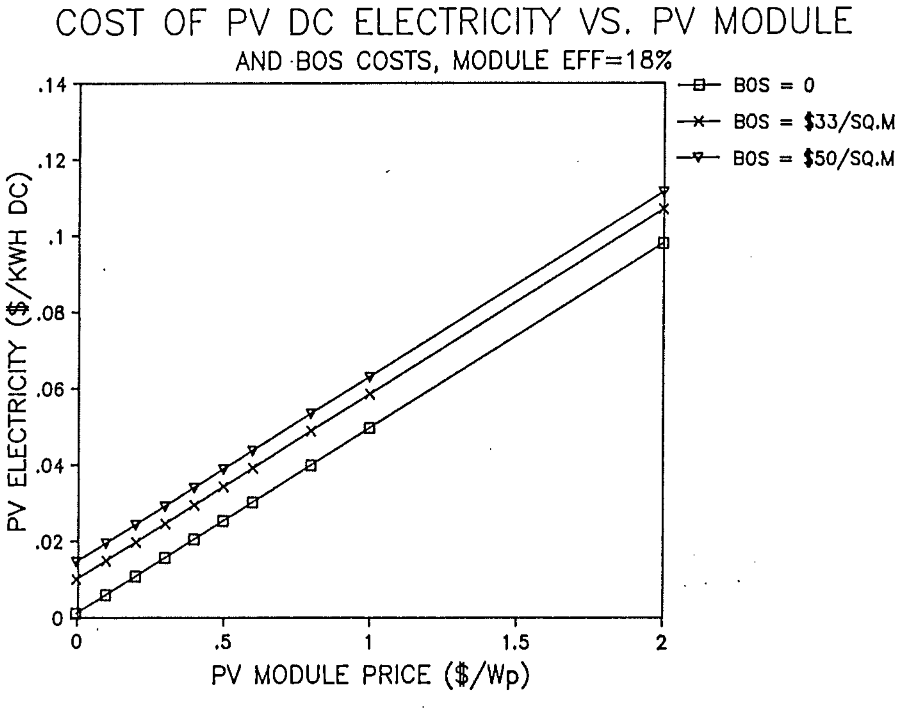


Figure 9.

The cost of DC PV electricity vs. solar module and balance of systems costs.

For a 10% efficient system (top) and a 15% efficient system (bottom) located in the Southwestern US with average insolation of 271 Watts per square meter, assuming a system lifetime of 30 years and an annual operation and maintenance cost of $0.45 per square meter. (See Note 92).

like those in El Paso. (Note, for example, that with a module efficiency of 18%, a BOS cost of \$33 per square meter, and a PV module cost of \$0.40 per Wp, the cost of DC electricity would be about \$0.030 per kWh.) Alternatively, if a certain DC electricity cost is desired, a range of satisfactory PV module and BOS costs can be inferred. (For example, to achieve a DC electricity cost of \$0.025 per kWh with a BOS cost of \$33/m^2 and 18% efficient PV modules, the module cost would have to be \$0.30 per Wp; with 12% efficient modules, the module cost would have to be \$0.20 per Wp).

Table 7 shows the projected cost of DC electricity in the Southwest US as a function of year, based on the projections for amorphous silicon solar technology shown in Table 3. These projections imply that the cost of DC solar electricity should fall from its present value of about \$0.28 per kWh (based on the 1987 solar module selling price of \$5/Wp and efficiency of 5%) to about \$0.044-0.089 per kWh by 1990-1995 (for solar module costs of \$0.6-1.2/Wp for 6-12% efficient modules), and to the range \$0.020-\$0.035 per kWh by 2000, if module costs fall to the range \$0.20-0.40/Wp and PV module efficiencies of 12-18% are achieved.

C. THE ELECTROLYTIC PRODUCTION OF HYDROGEN

The cost of electrolytic hydrogen depends on the capital cost of the electrolyzer plus the cost of the DC electricity needed to run it.[93,94] The cost of hydrogen from a large (>10 MW) electrolyzer is shown in Figure 8, as a function of DC electricity cost. Using PV electricity costs, based on projections for amorphous silicon solar cell technology, we can estimate the projected production cost of PV hydrogen versus calendar year (Table 7).

The cost of hydrogen production for a range of smaller-sized systems is shown in Figure 10. While the cost of electrolytic hydrogen declines with

Table 7. Projected Cost of PV Electricity and PV Hydrogen in the Southwest [a]

				COST OF PRODUCTION		
	PV Module Cost	EFFICIENCY		PV Electricity	PV Hydrogen	
Year	($/Wp)	Module	PV system	($/kwhDC)	($/GJ)	($/gal)[b]
1988	5.0 (price)	5%	4.3%	0.279	95	11.6
	1.6 (cost)	5%	4.3%	0.114	40.2	4.9
1990-1995	1.2	6%	5.1%	0.089	31.8	3.88
	0.6	12%	10.2%	0.044	17.2	2.10
2000	0.4	12%	10.2%	0.035	14.0	1.70
	0.2	18%	15.3%	0.020	9.10	1.11

---

[a] PV electricity and hydrogen production costs are calculated for a PV hydrogen system greater than 5 MW in size, assuming that BOS costs are $\$33/m^2$, system lifetime is 30 years, average annual insolation is 271 Watts/m^2, and annual operation and maintenance costs are $\$0.45/m^2$ A unipolar electrolyzer is used to produce hydrogen at atmospheric pressure. It is assumed that the PV array is directly coupled to the electrolyzer at 93% coupling efficiency. The cost of hydrogen compression, storage, transmission and local distribution are not included. (See Notes 92, 94.)

[b] Cost of equivalent energy expressed in dollars per gallon of gasoline.

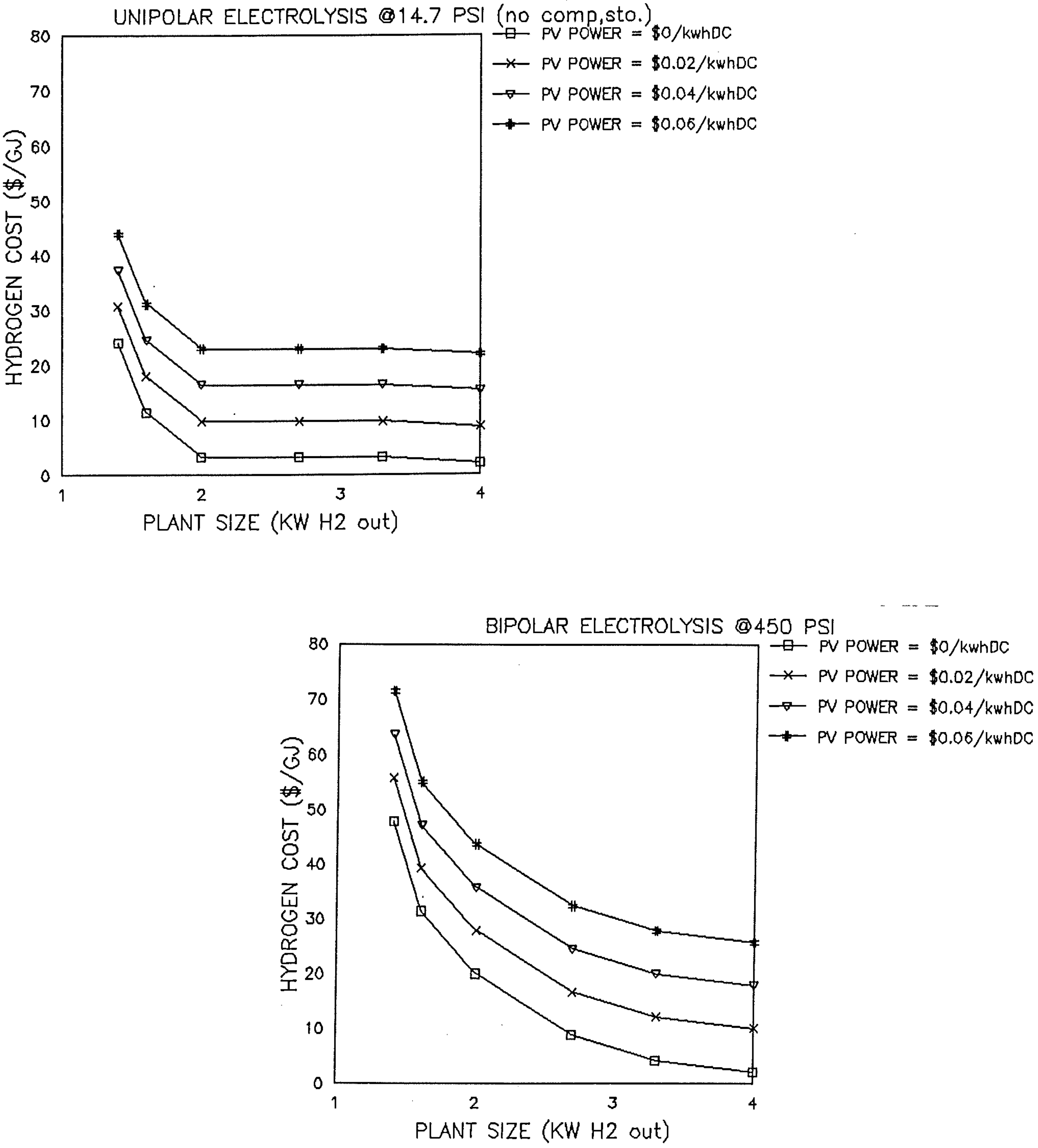


Figure 10.

The cost of electrolytic hydrogen as a function of plant size and DC electricity cost.

For unipolar electrolysis at atmospheric pressure (top) and bipolar electrolysis at 30 atmospheres (bottom).

increasing plant size, there is little economy of scale for hydrogen production rates above about 2 MW.[95] As there are likewise no significant scale economies for PV power production above production levels of some 5-10 MW,[96] hydrogen production operations could be highly modularized, with typical module capacity in the range 5-10 MW and characteristic capital costs of $3-10 million for electrolyzer plus PV equipment (for 12-18% efficient PV modules costing $0.2-0.4/Wp).

If hydrogen is to be produced in the Southwest and transmitted by pipeline to distant markets, two alternative electrolytic strategies could be pursued. One approach would involve first making hydrogen at atmospheric pressure and then compressing the hydrogen up to the high pressure needed to move the gas through the pipeline. The alternative approach would be to carry out the electrolysis at high pressure, thereby reducing dramatically the required amount of compressor work (*). While pressurized electrolyzers lead to savings in compressor work, they tend to be slightly more costly and less efficient. The cost of hydrogen delivered at the end of long pipelines tends to be less with the more efficient, less capital-intensive atmospheric pressure units (compare the top and bottom graphs in Figure 8).

When water is split electrolytically oxygen is produced as well as hydrogen. If this oxygen could be sold in local markets the byproduct credit would be some $1.5-2.2 per GJ of produced hydrogen,[97]--equivalent to $0.20-0.29 per gallon of gasoline. A byproduct credit of this magnitude could be very important in reducing costs. (For 12% efficient modules costing $0.40 per Wp,

---

* In a pressurized electrolyzer the feedwater is brought up to the pressure of the electrolyzer with a water pump. As water is practically incompressible, the amount of work required is negligible. In contrast, hydrogen gas, like other gases, is compressible, requiring considerable compressor work for pressurization.

an oxygen credit of this size would lead to a cost reduction for electrolytic hydrogen from $14.0 to $12.5 per GJ.) As the PV hydrogen industry develops, however, the market for oxygen would saturate and its market price would fall. Nevertheless, byproduct oxygen sales could be important in helping establish the embryonic PV hydrogen industry.

D. HYDROGEN STORAGE

If hydrogen is produced from PV electricity, the average output of the electrolysis plant is only 1/4 of the peak output, as the sun shines only in the daytime. If the produced hydrogen is to be transported long distances in costly pipelines, it would be highly desirable to run those pipelines full, so as to make full use of the pipeline capital investment. Fortunately, it is not costly to store some of the hydrogen produced in the day, so as to level out the quantity of hydrogen delivered to the pipeline. A number of proven storage methods are available for large quantities of hydrogen.[98] For the Southwest, an attractive storage option might be to use depleted natural gas wells. For this option the cost of the storage needed to levelize the hydrogen input to the pipeline would be about $0.20 per GJ, equivalent to about $0.026 per gallon of gasoline.

E. COMPRESSORS AND PIPELINES

To transport hydrogen long distances in pipes requires that the gas be pressurized enough to overcome the frictional drag on the flowing gas. There are two alternative compression strategies that can be pursued. One would be to pressurize the gas moderately at the pipeline inlet and provide a number of booster compressors along the way. The alternative would be to provide a very high pressure at the pipeline inlet to minimize the need for booster compressors. Two considerations suggest that the latter strategy is preferable. First, there are clear scale economies for compressors, so that one large compressor would tend to be less costly than an equivalent number of smaller units. Second, the compressor work at the pipeline inlet could be provided by the low cost power from the PV array, whereas the booster stations in general would have to rely on more costly electricity from other sources.

For the case where gas is transported 1000 miles without the aid of booster compressors, with inlet and exit pipeline pressures of 1000 psia (68 atmospheres) and 300 psia (20 atmospheres) respectively, the total cost of compression would be \$1.2 to \$1.5 per GJ, for PV electricity costing \$0.020 to \$0.035 per kWh.[99] This cost for compressor work is equivalent to gasoline costing \$0.16 to \$0.20 per gallon--a non-trivial cost, but one which is nevertheless only 11-14% of the cost of producing electrolytic hydrogen.

While there are not significant scale economies in hydrogen production at scales greater than 2 MW, there are major scale economies for long-distance hydrogen transport. Here we consider the cost of transporting in a single pipe for 1000 miles hydrogen equivalent to about 1% of total US oil and gas use (16,000 MW). For inlet and exit gas pressures of 1000 and 300 psia, respectively, the required pipe would have to be about 1.6 meters in diameter (63 inches) and installed would cost more than one thousand dollars per linear meter! Despite the fact that 1000 miles of such a pipeline would cost \$1.7 billion, the cost per GJ of delivered hydrogen would be a relatively modest \$0.35 per GJ, equivalent to \$0.05 per gallon of gasoline.[100]

It has been suggested that existing natural gas pipelines might be used for hydrogen transmission. Although natural gas pipelines are not optimized for hydrogen transmission (*), it appears that a relatively small cost penalty would be incurred for the mismatch.[102] As shown in Figure 11, the natural gas pipeline grid in the United States runs primarily from gas wells in the Gulf states and the Southwest. These areas have a good solar resource (Table 5) and are possible sites for PV hydrogen production. At the very least, hydrogen pipelines could be built along existing natural gas pipeline rights of way. As natural gas production in the Gulf states and Southwest falls off, an increasing percentage of PV hydrogen could be mixed in. A similar strategy has already been used by some US utilities, which routinely blend hydrogen rich refinery off-gases with natural gas. In Honolulu, manufactured gas typically contains 10% hydrogen by volume.[103]

F. THE COST OF DELIVERED HYDROGEN

When the costs of atmospheric pressure electrolysis, storage, compression, and pipeline transport for 1000 miles are considered together, the total cost of PV hydrogen at the end of the pipeline can be calculated as a function of the PV DC electricity cost (Figure 8).

The delivered cost of PV hydrogen for a particular service depends on the pressure required and local distribution and delivery costs. As shown in Chapters 5 and 6 (where the economics of PV hydrogen for transport and heating are discussed), if the cost and efficiency goals for PV modules are realized

---

* Problems of hydrogen embrittlement and diffusion, which could be problematic in converting some kinds of gas-handling equipment to hydrogen, would not be serious problems for pipelines.[101] Embrittlement would not be a serious problem under the modest temperature and pressure conditions in pipelines. Compressors, valves, and other flow-modifying parts for which diffusion might be problematic would typically have to be replaced anyway when a pipeline is converted to hydrogen, to accommodate the different fluid characteristics of hydrogen.

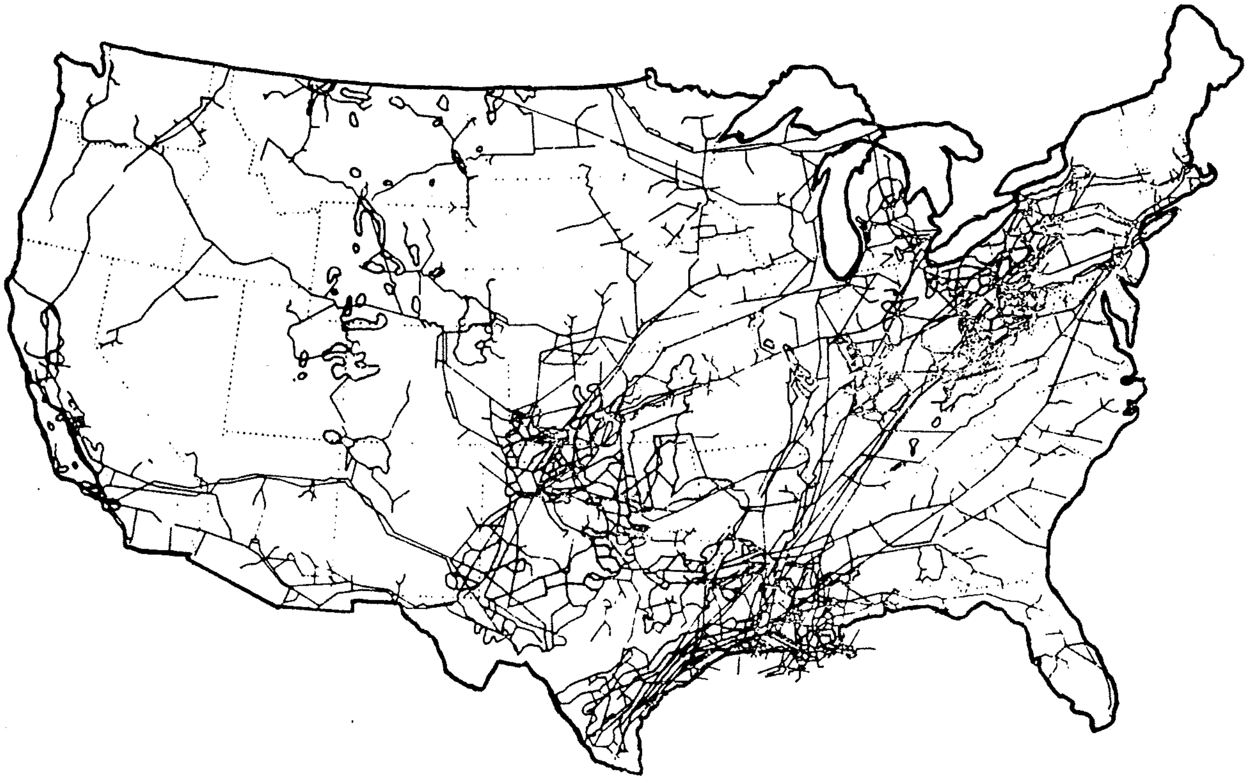


Figure 11.

The US natural gas pipeline system.

<u>Source</u>: W.J.D. Escher, R.W. Foster, R.R. Tison, and J.A. Hanson, "Solar/Hydrogen Systems Assessment," USDOE Report, DOE/JPL-955491, 1980.

(12-18% PV module efficiency and PV module costs of $0.2-0.4/Wp), delivered hydrogen could cost $12.9-18.0/GJ for transport use and $12.5-17.6/GJ for residential use. These costs are not low compared to present energy prices (e.g. the costs of hydrogen for transport are equivalent to gasoline costing $1.57 to $2.19 per gallon of gasoline-equivalent), but, as we shall see (Chapter 4), these costs are comparable to the costs of producing various synthetic fuels that are being considered for development in the time frame of the turn of the century, reflecting concerns about both the prospect of dwindling domestic oil production and the environmental costs of continued reliance on fossil fuels.

CHAPTER 4. COMPARING PV HYDROGEN TO OTHER SYNTHETIC FUELS Feb. 15, 1989

While the PV hydrogen system described in the last chapter would be far less costly than one that would be built today, its ultimate role in the energy economy will depend on how PV hydrogen compares to alternative fuels with which it would compete in the time frame of the turn of the century.

High on the list of criteria by which PV hydrogen will be judged are environmental criteria. In this regard PV hydrogen offers significant air pollution benefits relative to conventional fossil fuels: unlike most fossil fuels, no sulfur oxides, volatile organic compounds, carbon monoxide or particulates would be emitted in hydrogen combustion. While hydrogen-powered engines can produce significant levels of nitrogen oxides, this could be controlled to low levels with various techniques. With hydrogen-powered fuel cells, even NOx emissions would be negligible. Moreover, in the production and combustion of PV hydrogen, there is no release of carbon dioxide and thus no contribution to the greenhouse warming.

However, PV hydrogen is not unique in offering these advantages. For example, hydrogen derived electrolytically from nuclear-, hydro-, or wind-power sources would also result in negligible local, regional, and global air pollution. Moreover, synthetic fuels derived from biomass sources would emit no sulfur oxides and would not contribute to the atmospheric buildup of carbon dioxide, if the biomass were produced renewably. Among the possibilities for synthetic fuel from biomass are ethyl alcohol from sugar cane or corn and methyl alcohol produced from a wide range of cellulosic feedstocks, including wood and urban refuse.[104]

Because PV hydrogen is not unique in offering air pollution benefits, it must offer marked advantages relative to these alternative fuels, its direct economic costs must be acceptable, and it should not pose other serious environmental or safety problems, if it is become the fuel of choice in the future.

A. PV HYDROGEN AND NUCLEAR ELECTOLYTIC HYDROGEN

To the extent that the attractions of PV hydrogen stem from the fact that the energy carrier is hydrogen that is not derived from fossil fuels, PV hydrogen should be compared to other non-fossil fuel sources of hydrogen--e.g. nuclear-based hydrogen systems.

Widespread concern about the greenhouse problem is leading to calls to reconsider the nuclear power option. For example, the Conference Statement of the 1988 World Conference on the The Changing Atmosphere: Implications for Global Security recommended:[105]

> "There is a need to revisit the nuclear power option. If the problems of safety, waste, and nuclear arms proliferation can be solved, nuclear power could have a role to play in lowering CO_2 emissions."

Two of the problems mentioned here, though unsolved, are in principle amenable to technical fixes that could greatly reduce the risks involved: nuclear safety and nuclear waste disposal. There is already considerable interest in some quarters of the nuclear community in fundamentally redesigning nuclear power systems in ways that would make them inherently safe, thus addressing the major public anxiety about nuclear power at present, its safety.[106]

But the nuclear weapons connection to nuclear power is more troubling. Inherent in nuclear technology is the fact that the fissile (*) plutonium produced as a byproduct of reactor operation in uranium-fueled nuclear power plants is also the stuff from which nuclear weapons are made. A present-day

---

* Fissile plutonium is plutonium made up of those isotopes that are fissionable by slow neutrons (e.g. those that mediate the controlled nuclear chain reactions in present-day nuclear power plants).

1000 MW nuclear power plant discharges some 141 kg of fissile plutonium annually in its spent fuel.[107] For comparison, it takes less than 10 kg of fissile plutonium to make a nuclear explosive.

Actually the nuclear weapons link to nuclear power is less troubling for the present generation of nuclear power plants than this juxtaposition of numbers would suggest, because the produced plutonium is locked in the spent fuel of these power plants, where it is protected agains diversion to nuclear weapons use by the intensely radioactive products of nuclear fission. However, the nuclear weapons connection to nuclear power would come into sharp focus if the nuclear power industry were to be reborn, and nuclear power were to come to play a major role in the world energy economy. If nuclear power were developed on a large scale, concerns about limited world supplies of uranium would force a shift from the present generation of nuclear power plants based on "once-through" nuclear fuel cycles to fuel cycles that involve the reprocessing of spent nuclear fuel and the recycling of the recovered plutonium in fresh fuel for both present reactor types and a new generation of plutonium breeder reactors.

Under current plans for this second-generation nuclear power technology some 30,000 kg of fissile plutonium will be circulating in worldwide commerce in hundreds of shipments annually by the year 2000--in trucks, trains, ships, and planes.[108] This scenario, which poses horrific institutional challenges for safeguarding this material against occasional diversion to nuclear weapons purposes, is for a dying nuclear power industry.

For a reborn nuclear industry the institutional challenges would be of a different order. Suppose that concern about the greenhouse problem were to lead to the resurrection of the nuclear power industry and that these efforts led in turn to a nuclear-based hydrogen energy economy that would replace 1/4 of the present global level of fossil fuel use. Such an emphasis on nuclear power would require a global installed nuclear capacity of more than 4200 GW (up from about 300 GW in 1986), a nuclear power generation rate equivalent to more that 2 1/2 times the present level of global electricity generation from all sources, and an annual fissile plutonium discharge rate of more than 4 million kg per year.[109] It is difficult to imagine human institutions capable of safeguarding 100% of these plutonium flows against occasional diversions of tiny but significant fractions to nuclear weapons purposes.

Such a role for nuclear power is unlkely, however, unless it is dictated by political forces that are oblivious to economic considerations, because the economics are not favorable. It would probably not suprise many people to learn that at present nuclear power costs in the United States, electrolytic hydrogen would cost almost twice as much as the high end of the costs targeted here for PV hydrogen in the year 2000 (Table 8). But even if the cost reduction goals for a reborn nuclear industry were met--involving nearly 50% reductions in both capital and O&M costs, the cost of electrolytic hydrogen based on these cost targets would still be about 20% higher than the upper end of the costs targeted for PV hydrogen in the year 2000 (Table 8).*

B. PV HYDROGEN AND ELECTROLYTIC HYDROGEN FROM OTHER RENEWABLE SOURCES

What about other renewable sources of electrolytic hydrogen--e.g. hydroelectric- and wind-based hydrogen? Low-cost hydrogen can be produced at

---

* PV hydrogen would probably still be cheaper even if some of the cost goals for a-Si technology were not met. For example, if the balance of system were to cost $50/m^2 ($50/m^2 is the DOE goal for the year 2000 and has already been achieved in experimental systems in Europe) instead of $33/m^2 or if the a-Si modules were to last not 30 but 15 years, the cost of PV hydrogen would still be in the range $10-18/GJ, compared to $14-24/GJ for nuclear hydrogen (see Table 9).

Table 8. Estimated Costs for Alternative Sources of Electrolytic Hydrogen

	PV[a]		NUCLEAR[b]		HYDROPOWER[c] (GLOBAL AVERAGES)		WIND[d]	
	n=12% $0.4/Wp	n=18% $0.2/Wp	Current	Target	2000L	2000H	LOW	HIGH
ELECTRICITY GENERATION								
System Size (MW)	10	10	1100	1100	-	-	(40 x 2.5)	
Capital Cost ($/kW)	992	564	2970	1620	3260	4000	1340	1580
Plant Life (years)	30	30	30	30	50	50	30	30
Capacity Factor	0.271	0.271	0.566	0.65	0.47	0.47	0.35	0.35
O & M (mills/kWh)	1.9	1.3	12.0	6.5	2.9	2.9	8.7	10.3
Fuel (mills/kwh)	-	-	7.5	7.5	-	-	-	-
Electricity Production Cost (mills/kwh)	34.7	19.8	66.5	36.3	55.4	70.2	43.0	50.8
HYDROGEN PRODUCTION COST[e] ($/GJ)								
Electricity	11.47	6.55	22.91	12.51	19.01	24.18	14.83	17.48
Electrolyzer	2.52	2.52	1.47	1.27	1.76	1.76	2.36	2.36
Total	14.0	9.10	24.4	13.8	20.8	25.9	17.2	19.8

---

[a] See Note 94. (See Table 9 for sensitivity analysis of PV H_2 costs.)

[b] The capital costs indicated for nuclear power are estimates made by the Electric Power Research Institute (EPRI, Technical Assessment Guide 1: Electricity Supply, 1986). The higher value is EPRI's estimate of the cost of a plant that would be ordered in the US at present. The lower value is EPRI's target for "improved conditions" in the United States--resulting from higher construction labor productivity, a shorter construction period, a streamlined licencing process, etc. The "current" capacity factor (56.6%) is the actual average for US nuclear plants in the period 1983-1987; for "target" conditions it is assumed that this increases to 65%. The fuel cost of 0.75 cents per kilowatt hour and the "current" O&M cost are actual average values for nuclear plants in 1986 [Energy Information Administration, "Historical Plant Costs and Annual Production Expenses for Selected Electric Plants, 1986", DOE/EIA-0455(86), May 27, 1988]. The "target" O&M cost is a an value set by EPRI (EPRI, 1986).

[c] The indicated hydro capital costs and capacity factors are global average estimates for the year 2000 (H. K. Schneider and W. Schulz, Investment Requirements of the World Energy Industries 1980-2000, World Energy Conference, 1987). The hydro O&M costs are EPRI estimates for the indicated capacity factor (EPRI, 1986).

[d] For mass-produced 2.5 MW wind turbines configured to produce 100 MW (J. I. Lerner, "A Status Report on Wind Farm Energy Commercialization in the United States, with Emphasis on California," paper presented at the 4th International Solar Forum, Berlin, FRG, October 6-9, 1982). The O&M cost is assumed to be 2% of the initial capital cost per year.

[e] For non-PV electricity sources, unit electrolyzer capital costs are assumed to be 25% higher because of the rectifier, which is assumed to be 96% efficient.

many existing hydroelectric sites, but potential global hydroelectric resources are too limited for the potential quantities of hydrogen produced this way to have much of a global impact in replacing fossil fuels,[110] and new hydroelectric supplies are generally much more costly than the low-cost supplies already developed and also probably much more costly than DC PV electricity based on amorphous silicon near in the time frame near the turn of the century (Table 8).

Electrolytic hydrogen could also be produced from wind power resources. But again good wind sites are quite limited globally and confined largely to the already industrialized world,[111] and hydrogen derived from wind is likely to be considerably more costly that hydrogen derived from PV sources (Table 8).

C. PV HYDROGEN AND BIOMASS-DERIVED FLUID FUELS

In comparing PV hydrogen to biomass-derived fuels, it is noteworthy (Table 9) that the cost estimates for ethanol derived from sugar cane and corn ($8 to $14 per GJ) are in the same range as our cost targets for PV hydrogen ($9 to $14 per GJ). Indeed biomass converted to modern energy carriers has an important role to play as a transitional energy source, especially in developing countries, over the next several decades.[112]

However, for the very long term there are two fundamental constraints that limit the extent of bioenergy development: the low efficiency of photosynthesis and the large water requirements for bioenergy development.

While solar energy can be converted to hydrogen energy using solar cells at an overall efficiency of 8 to 13 percent, the maximum efficiency of photosynthesis is probably about 5.5 percent. In practice the photosynthetic efficiency is closer to 1-4 percent under ideal growing conditions and only 1/6

Table 9. Estimated Production Costs for Synthetic Liquid and Gaseous Fuels[a]

FUEL	SYNFUEL PLANT Plant Size (1000 GJ/day)	Installed Cost ($$10^6$)	($/Wp)	Fuel Production Cost[b] ($/GJ)
Gasoline Derived from Coal	176	5107	2.26	16.2
Methanol Derived from Coal	322	3860	0.93	7.9
	32.2	567	1.37	10.0
Ethanol Derived from				
Sugar cane (Brazil)	2.68	7.7	0.22	8.0
Corn (US)	13	95.2	0.57	14.4
Synthetic Gas Derived from Coal (c)				
High heating value gas	264	1820	0.54	5.7
	88	756	0.67	6.4
	26.4	341	1.00	7.9
Intermediate heating value gas	264	822	0.24	4.0
PV Hydrogen (Southwestern US)				
BOS = $33/m^2, PV System Lifetime = 30 years				
n=18%, $0.2/Wp	0.183[d]	7.8	0.92	9.1
n=12%, $0.2/Wp		9.2	1.10	10.7
n=18%, $0.4/Wp		10.9	1.30	12.3
n=12%, $0.4/Wp		12.3	1.47	14.0
BOS = $50/m^2, PV System Lifetime = 30 years				
n=18%, $0.2/Wp	0.183[d]	7.8	0.92	10.6
n=12%, $0.4/Wp		12.3	1.47	16.3
BOS = $33/m^2, PV System Lifetime = 15 years				
n=18%, $0.2/Wp	0.183[d]	7.8	0.92	10.4
n=12%, $0.4/Wp		12.3	1.47	18.2

---

[a] The cost estimates presented here were derived using a self-consistent set of assumptions to ensure that the cost comparisons for alternative technologies are meaningful. For details see notes 92, 94, and 114.

[b] The production cost includes plant capital, feedstock and operation and maintenance costs, but not the costs of transmission or storage.

[c] For Lurgi Dry Ash process with Western US coal.

[d] This corresponds to a 10.8 MWp PV array coupled to an 84% efficient unipolar electrolyzer, where the coupling efficiency is 93%. The peak PV hydrogen output is 8.4 MW, and the average output is 183 GJ/day for a system located in the Southwestern US, with average insolation of 271 watts per square meter. There should be no significant economies of scale for PV powered electrolyzers above about 5-10 MW.

to 1/2 percent under average conditions.[113] The low photosynthetic efficiency problem is compounded by the fact that conversion of raw biomass to a high quality fluid (e.g. liquid or gaseous) fuel typically involves energy losses in the range 30-50 percent. As a result land use constraints on biomass become formidable at high levels of bioenergy utilization and are much more severe than the land use constraints on PV hydrogen.

To illustrate the problem, consider the land-use requirements for fluid fuels derived at 65% conversion efficiency from biomass grown on energy farms or plantations with a biomass productivity of 40 tonnes of dry biomass per hectare per year. While these are generally considered relatively high values for the conversion efficiency and biomass productivity, the overall efficiency of converting sunlight into fluid fuels this way is only about 3/4 percent for typical solar insolation values. Such a low overall efficiency implies that land use constraints will ultimately limit the extent of bioenergy development. In the US, for example, providing enough bioenergy to equal the present level of of fossil fuel use would require an amount of land comparable to that presently used as cropland or forests (Table 10).

In contrast, the land requirements for PV hydrogen production would be less than 1/10 of those for bioenergy production, so that PV hydrogen does not appear to be land-use constrained, even in densely-populated coundtries (Table 10). Producing hydrogen equivalent to total US oil use would require a collector field in the Southwest of some 64 thousand square kilometers (24 thousand square miles). This is equivalent to 0.5% of total US land use or about 7% of the desert area in the US (Figure 12). Hydrogen equivalent to total world fossil fuel consumption could be produced on a mere 530 thousand square kilometers of arid lands (Table 10), less than two percent of the area of the

Table 10. Land Use Requirements for PV Hydrogen, Biomass and Coal Synfuels

	Fossil Fuel Displaced/Year (Gigajoules)	LAND REQUIRED (hectares)		
		w/PV H2(a)	w/Biomass(b)	w/Coal Synfuels(c)
Fossil Fuel Displaced at the Present US Average Per Capita Consumption Rate	287	0.053	0.72	0.018
US Land Area Per Capita for (d):				
Forests and Woodland		1.1		
Cropland		0.8		
Permanent Pasture		1.0		
Average Land Area per Capita (d) in:				
World		2.62		
Africa		5.02		
Rwanda		0.38		
North America		5.18		
El Salvador		0.35		
Asia		0.92		
Bangladesh		0.13		
Europe		0.96		
Netherlands		0.23		
South America		6.29		
Equador		2.79		

	Fossil Fuel Displaced/Year (Exajoules)	LAND REQUIRED (million hectares)		
		w/PV H2(a)	w/Biomass(b)	w/Coal Synfuels(c)
Fossil Fuel Displaced for the World at the Present Consumption Rate	283	53	670	18
Total World Land in:				
Forests and Woodland (d)		4090		
Cropland (d)		1470		
Permanent Pasture (d)		1350		
Deserts (e)		3140		

---

[a] For PV electricity produced in 15% efficient solar modules and converted to hydrogen at 84% efficiency on tilted collectors requiring a ground area twice as large. For average insolation on tilted collectors of 271 Watts/square meter (250 Watts/square meter on the ground).

[b] For biomass grown @ 40 tonnes of dry biomass (@ 18 GJ/tonne) per hectare per year and converted to fluid fuels at 65% efficiency, on average.

[c] For surface-mined coal (See Note 117).

[d] World Resources Institute, World Resources 1987, Basic Books, Washington, DC, 1987.

[e] M. P. Petrov, Deserts of the World, John Wiley & Sons, 1976.

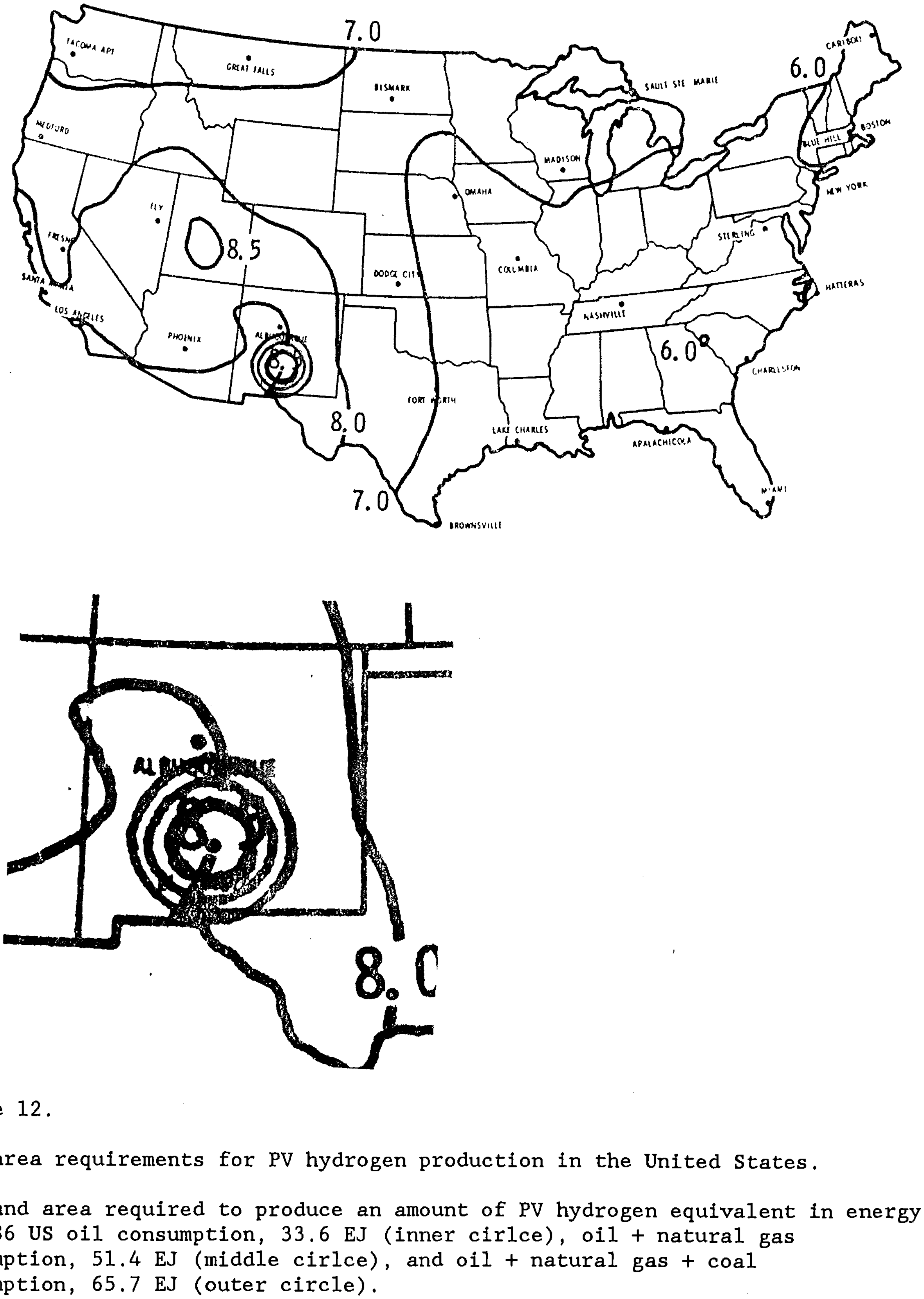


Figure 12.

Land area requirements for PV hydrogen production in the United States.

The land area required to produce an amount of PV hydrogen equivalent in energy to 1986 US oil consumption, 33.6 EJ (inner cirlce), oil + natural gas consumption, 51.4 EJ (middle cirlce), and oil + natural gas + coal consumption, 65.7 EJ (outer circle).

world's deserts (Tables 10 and 11).

Not only is bioenergy development ultimately constrained by land use requirements but also the required land must be in areas with adequate water supplies. Biomass production requires some 300 to 700 tonnes of water (for photosynthesis and transpiration) per tonne of dry biomass produced. Assuming that fluid fuels are produced from biomass at an average efficiency of 65%, the water requirements become some 25,000 to 60,000 liters per GJ of produced biofuel.

In contrast, the consumptive water requirements for electrolysis are a modest 63 liters per GJ of hydrogen produced (*). In producing an amount of hydrogen equivalent in energy to one liter of gasoline, only two liters of water are consumed. For comparison the per capita water use in the US is more than 100 times the per capita level of petroleum consumption (in volumetric terms).[115] Thus, the water requirement for enough hydrogen to replace current petroleum use would be a "drop in the bucket", adding only about 2% to the average per capita water use in the US.

Water requirements are also quite modest compared to precipitation levels in areas where PV hydrogen systems might be located. A typical average insolation value for hot arid regions is some 270 Watts per square meter. If the land area requirements were twice the PV collector area (to prevent significant self-shading), the water requirements for hydrogen production would be some 2 to 3 centimeters per year (Table 12), which is a small fraction of total precipition even in very arid regions. Consequently, PV hydrogen can be produced even in deserts. For example, even though El Paso is in one of the

---

* Assuming that the water required to cool the electrolyzer is recirculated.

Table 11. Desert Areas by Continent (million hectares)

North America		190
Temperate Zone	60	
Subtropical Zone	90	
Tropical Zone	40	
South America		180
Temperate Zone	50	
Subtropical Zone	50	
Tropical Zone	80	
Eurasia		1430
Temperate Zone	590	
Subtropical Zone	470	
Tropical Zone	370	
Africa		1000
Subtropical Zone	110	
Tropical Zone	890	
Australia		340
Subtropical Zone	20	
Tropical Zone	320	
TOTAL		3140

Source: M. P. Petrov, *Deserts of the World*, John Wiley & Sons, 1976.

Table 12. Water Requirements for PV-Hydrogen and Biomass Energy Systems

	Useful Energy Production Rate (GJ/sq.m/year)	Water Requirements (cm of rainfall/year)
Efficiency of PV modules (%) (a)		
10	0.35	2.3
15	0.53	3.4
Biomass Productivity (b) (tonnes/hectare/year)		
10	0.012	30- 70
20	0.023	60-140
30	0.035	90-210
40	0.046	120-280

---

[a] See Note 116.

[b] Biomass production requires for photosynthesis and transpiration some 300 to 700 tonnes of water for each tonne of dry biomass produced. Assuming that fluid fuels are produced from biomass at an average efficiency of 65% (and that the heating value of dry biomass is 18 GJ per tonne), the water requirements become 25,000 to 60,000 liters per GJ of produced biofuel.

dryest areas in the US--with annual rainfall amounting to only 20 centimeters (8 inches)--the water required for electrolysis is only 12 to 17 percent of total precipitation.[116]

Despite the enormous advantages of PV hydrogen over bioenergy with regard to land use and water requirements, biomass offers something that PV hydrogen cannot offer: a source of carbon that is not derived from fossil fuel. Carbon-based fuels will be preferable to hydrogen in some applications--notably some applications where liquid fuels are required. While hydrogen can be liquefied, the use of liquid hydrogn as a fuel is beset by many practical complications (see Chapter 5) because it is a cryogenic fuel. In contrast there are many carbon-based liquid fuels that are easily stored under ambient conditions. Biomass may ultimately become very valued because of it can serve as feedstock for convenient liquid fuels. In this regard an important synergism could develop between biomass and PV hydrogen: the latter could become of source of hydrogen for these biomass-derived liquid fuels, thereby significantly reducing the amount of land and water needed to produce a given amount of liquid fuel.

D. PV HYDROGEN AND SYNTHETIC FOSSIL FUELS

Perhaps the most troubling feature of synthetic fossil fuels is that a shift to these fuels implies a speeding up of the greenhouse warming, because the carbon dioxide emissions per unit of useful energy derived would be much higher than conventional oil and gas--e.g. synthetics from coal would release almost twice as much carbon dioxide per unit of energy consumed as oil and almost three times as much as natural gas (Figure 3). PV hydrogen is thus clearly far more attractive than fossil synthetics with regard to the greenhouse warming. And PV hydrogen is also clearly preferable with regard to local and regional air pollution problems, because, as has already been pointed out, the only pollutant generated in combustion is NOx, the emissions of which can be readily controlled to low levels.

One might think that from a land use perspective fossil systhetics would be enormously preferable to PV hydrogen. But while land use requirements for fossil synthetics are probably less than for PV hydrogen, the advantage is not decisive: the amount of land required to produce synthetic liquid fuels equivalent to current US oil use from the estimated 86 billion tonnes of stripminable coal reserves would average about 8.5 thousand square miles; the amount of land required for the same amount of PV hydrogen is only about three times as large (Table 10).[117]

From a narrow economic perspective PV hydrogen would probably not be decisively preferable to fossil synthetic fuels (Table 9). PV hydrogen would probably be approximately competitive with synthetic liquids from coal (projected to cost \$8-16/GJ), but more expensive than synthetic gases from coal (projected to cost \$4-8/GJ).

The production cost comparisons shown in Table 9, based on detailed systems analysis but no actual field experience, may prove to be biased in favor of synthetic fossil fuels, because the low cost estimates shown there are for very large facilities. In order to achieve favorable production economics for methanol from coal, for example, a facility costing nearly \$4 billion and having a methanol production capacity of some 3700 MW (322 thousand GJ/day) must be constructed. For production at a rate of 37 MW (3.22 thousand GJ/day) the cost of the produced methanol would be larger by 70% (Table 9).

In contrast, because PV arrays and electrolyzers are modular technologies, it would be possible to achieve low PV hydrogen production costs in very small facilities. As pointed out in Chapter 3, PV hydrogen systems could be highly modularized, with typical module capacity in the range 5-10 MW and characteristic capital costs of 5 to 15 million dollars, for 12-18% efficient PV modules costing $0.2-0.4/Wp.

The fact that PV systems are modular means that they can be largely factory-built so that the economies of mass production can be exploited, while synthetic fossil fuel plants will require much field construction, which is inherently more costly. The importance of this difference, though not generally appreciated, was perceptively articulated by John Fisher in 1974 in an analysis of the escalation in nuclear power costs in the decade leading up to the first oil crisis:[118]

> "When measured in constant dollars per kilowatt of capacity, the cost of constructing a nuclear power plant increased by perhaps 50 percent in the past decade... When power plant costs rise an explanation is required, as we expect all power plant costs to decline through the economies of scale and new technology. The environmental movement was responsible for part of the rise in nuclear plant costs, by causing various procedural delays and by requiring additional expensive safeguards to protect against hypothetical accidents. But there appears to be another cause for increasing construction costs, associated with a growing portion of high-cost field construction and a shrinking proportion of low-cost factory construction for the very large power plants now being built... the costs associated with a shift to field from factory can more than offset anticipated economies of scale..."

Fisher pointed out that historically, as the electric utility industry and plant capacity doubled every decade, factory capacity also doubled, as did field construction at each site. Manufacturing and construction costs per kW declined in the factory and in the field, since each of these increased its scale of operations. As long as both activities grew in proportion, the economies of scale produced similar cost reductions in each, and therefore an overall cost reduction, even though the unit cost of field construction was always higher than the unit cost of factory construction. This pattern held until plant size reached about 200 MW. Then, because design engineers felt that scale economies would be much more important for nuclear than for fossil fuel plants, nuclear power plant capacities were built in sizes of the order of 1000 MW--shifting a greater portion of the construction from the factory to the field, upsetting the pattern of the past, with the result that a much larger fraction of the construction was carried out at smaller, less-efficient field locations. Fisher's important insight is that the widely touted economies of scale in power plant construction are illusory because (a) field construction is inherently more costly than factory construction, and (b) with field construction it is never possible to get very far down the "learning curve," in contrast to the situation with factory production.

E. HYDROGEN SAFETY

While hydrogen is clearly preferable to other fluid fuels from an environmental perspective, what about its safety? Everyone remembers the Hindenburg disaster, and this event often conjures up images of hydrogen as an inherently unsafe fuel.

For any fuel, safety is an important concern. Indeed, the very properties that make fluid fuels so useful (e.g. storage of a large amount of readily accessible energy in a small volume), also make them potentially dangerous. Despite the widespread perception that hydrogen is much more dangerous than natural gas or gasoline, this concern is not borne out by the physical properties of the fuel or by many years of industrial and residential experience with hydrogen (see Box 3). Past studies of the relative safety of hydrogen, methane (natural gas) and gasoline have concluded that no one fuel is inherently safer than the others in all aspects. Each fuel demands its own set of precautions, but all three fuels can be (and have been) used safely.

Box 3. IS HYDROGEN SAFE?

What are the hazards of using hydrogen as compared to other commonly used fuels such as natural gas and gasoline?

A COMPARISON OF THE PHYSICAL PROPERTIES OF HYDROGEN, GASOLINE AND METHANE

Some safety-related physical properties of hydrogen, methane (natural gas is typically about 96% methane) and gasoline are listed in Table B.3.1. We focus our comparison on a few significant properties, which are most often mentioned in discussions of hydrogen safety:

Limits of flammability (detonability) in air: The limits of flammability (detonability) indicate the range of mixtures of fuel in air which will sustain a fire (sustain an explosion). Hydrogen will burn (detonate) over a much wider range of concentrations than either methane or gasoline.

While hydrogen's wide range of flammability would seem to be a serious concern, if the fuel concentration built up gradually through a leak, as might occur in residential or indoor industrial settings, the lower flammability limit would be the most relevant parameter, rather than the range of flammability limits. This is true because sources of ignition are often present in residential or industrial environments and a fire would be likely as soon as the fuel to air concentration reached the the lower flammability limit. Hydrogen's lower flammability limit (4% by volume) is not much less than that for methane (5.3%), and is higher than that for gasoline (1%); hydrogen's lower detonability limit is 18.3%, significantly higher than that of methane (6.3%) or gasoline (1.1%). It is obviously important to detect leaks and provide adequate ventilation for all three fuels, when they are used in enclosed spaces.

The range of flammability (detonability) could be of more concern in hydrogen transmission and distrubution systems. It might be neccessary to purge a hydrogen pipeline with an inert gas (nitrogen), prior to commissioning or after a maintenance shutdown in order to avoid flammable (or detonable) hydrogen-air mixtures. This is the current industrial practice with hydrogen handling systems. During normal operation, of course, a hydrogen pipeline or distribution system would be pressurized and air could not leak in.

Minimum energy for ignition: Hydrogen has a significantly lower ignition energy than gasoline or methane (e.g. it ignites more easily that either methane or gasoline). However, the ignition energy for all three fuels is extremely low, and weak thermal sources of ignition (sparks from static electricity, open flames from matches, hot surfaces) would be more than sufficient to ignite flammable mixtures of methane, gasoline or hydrogen.

Buoyant velocity/diffusion velocity in air: Buoyant velocity refers to the rate at which fuels rise in air, diffusion velocity to the rate at which they diffuse through air. Both quantities reflect how quickly fuel vapors would disperse after a leak. Hydrogen is the lightest element, and it rises and disperses very quickly. Methane is also buoyant and disperses quickly, although less so than hydrogen. Gasoline vapors are heavier than air and can linger near a leak even outside. There should be little problem with hydrogen or methane leaks outside (from storage, pipelines or an external automotive tank), as these fuels would tend to disperse before a flammable mixture could build up. This is not true with gasoline, where fumes could reach a hazardous concentration more easily. For indoor use, adequate ventilation (through roof vents) would assure that buoyant hydrogen or methane would not reach flammable concentrations.

Leak rate: Hydrogen gas would have a volumetric leak rate (for example, from a cracked weld or damaged seal) about three times that of methane gas, but less than that of gasoline vapors. Hydrogen also disperses more quickly than methane or gasoline, so that it would be more difficult to reach dangerous concentrations of duel in air. For indoor use, roof vents would be desirable to assure that buoyant hydrogen (or methane) would be eliminated from a closed space in case of a leak. As with natural gas, an odorant would probably be added to hydrogen to aid detection of leaks. Experience in industrial and residential settings has shown that all three fuels can be safely handled, distributed and stored, with minimal leakage.

Materials embrittlement: At high temperatures and pressures (such as those found in hydrogen handling equipment in oil refineries) hydrogen can cause potentially dangerous embrittlement of metal vessels and pipes. However, at the lower temperatures and pressures found in a hydrogen energy system, embrittlement should not be a problem.

Toxicity: Hydrogen and methane are non-toxic, gasoline and gasoline vapors are toxic. All three gases are asphixiants in high concentrations.

RESIDENTIAL EXPERIENCE WITH HYDROGEN

Since the 19th century, hydrogen-rich "town gas" manufactured from coal or wastes has been widely used as a home heating fuel. Many utilities in the United States switched from town gas to natural gas as recently as the 1940's and 50's, when long distance pipelines were built linking gas fields in the Gulf states and the Southwest to the Northeast and Midwest. While it is now rare in the US, town gas is still common in many regions of the world where natural gas is expensive or unavailable. Town gas is typically about half hydrogen and half carbon monoxide (with traces of methane and other combustible gases). The flammability and combustion properties of CO are similar to those of hydrogen, so that the hazard of fire and explosion with town gas would be similar to that of pure hydrogen. The fire hazards associated with residential use of town gas appear to have been acceptable, which is a strong argument that hydrogen could be safely used for residential heating as well.

INDUSTRIAL EXPERIENCE WITH HYDROGEN

Hydrogen has been used routinely in process industries for decades, and safe storage and handling techniques have been developed. Hydrogen pipelines several 100 kilometers in length have been operated in Germany, the US and England, with no undue problems, and utilities have used hydrogen for generator cooling for 50 years. The overall conclusion of past studies is that safety should not be a problem in industrial or utility settings.

CONCLUSIONS

Chemical fuels such as natural gas, gasoline and hydrogen are potentially hazardous and must be treated with respect. No one fuel is safer in all situations. The evidence indicates that all three can be produced, stored, transmitted and handled safely for industrial, residential and transport use. The overwhelming conclusion of past studies is that, while hydrogen safety must be investigated in each individual setting, hydrogen should not be ruled out as a future fuel on safety grounds.

For an excellent and extensive discussion of hydrogen safety issues the reader is referred to the paper by J. Hord.

Sources: J. Hord, "Is Hydrogen a Safe Fuel?", International Journal of Hydrogen Energy, v. 3, pp 157-176, 1978; G.D. Brewer, "Some Environmental and Safety Aspects of Using Hydrogen as a Fuel", International Journal of Hydrogen Energy, v. 3, pp. 461-474, 1978; W. Balthasar, "Safety Aspects in the Use of Hydrogen in Industry and in the Home", in Hydrogen: Energy Vector of the Future, Graham and Trotman, London, 1983; H. Tamm, "Summary of Hydrogen Safety Workshop held at the Fifth World Hydrogen Energy Conference", International Journal of Hydrogen Energy, v. 11, pp.61-66, 1986.

Table B.3.1. Safety-Related Physical Properties of Hydrogen, Methane and Gasoline

	HYDROGEN	METHANE	GASOLINE
Limits of flammability in air (% volume)	4.0-75.0	5.3-15.0	1.0-7.6
Limits of detonability in air (% volume)	18.3-59.0	6.3-13.5	1.1-3.3
Minimum energy for ignition in air (milliJoules)	0.02	0.29	0.24
Diffusion velocity in air (meters per second)	2.0	0.51	0.17
Buoyant velocity in air (meters per second)	1.2-9.0	0.8-6.0	non-buoyant
Leak rate in air (relative to methane)	2.8	1	1.7-3.6 (gasoline vapors)
Toxicity	non-toxic	non-toxic	toxic in concentrations > 500 ppm

SAFETY ASPECT	RELEVANT PHYSICAL CHARACTERISTICS	IMPLICATIONS
Fire/Explosion Hazard		
Leak Rate	Density, absolute viscosity	Hydrogen has a leak rate 2.8 x methane 0.6-7.3 x gasoline
Ignitability	Minimum ignition energy, Flammability/Detonability limits, Buoyant velocity, Diffusion velocity.	All three fuels ignite very easily. Ignition hazard persists longest w/gasoline then with CH_4, H_2.
Physiological Hazard		Gasoline toxic, H_2 and CH_4 non-toxic

---

[a] Adapted from J. Hord, "Is Hydrogen a Safe Fuel?", International Journal of Hydrogen Energy, v. 3, pp 157-176, 1978.

[b] Adapted from G.D. Brewer, "Some Environmental and Safety Aspects of Using Hydrogen as a Fuel", International Journal of Hydrogen Energy, v. 3, pp. 461-474, 1978.

CHAPTER 5. PV HYDROGEN AS A REPLACEMENT FOR OIL

February 15, 1989

A. PV HYDROGEN AS A FUEL FOR TRANSPORTATION

While hydrogen could supplant oil in virtually all its current end uses, transportation markets are particularly interesting for several reasons:

- Transportation is the largest single user of oil, accounting for over half of oil use in the US, and more than one third of oil use worldwide. Widespread use of PV hydrogen as a transport fuel could thus have a large impact in reducing fossil fuel use as a response to the greenhouse problem, as well as in reducing dependence on oil, especially oil from the Middle East.
- In many urban areas of the United States, automobiles are responsible for the majority of NOx and VOCs emissions.[119] Automobiles are also important contributors to regional pollution problems such as acidification of the environment. Switching from gasoline to less polluting transport fuels such as hydrogen could do much to ameliorate these problems, and strategies mandating alternative fuels have been adopted in California.
- Market prices for highly-refined transport fuels (e.g. gasoline and Diesel oil) are the highest prices paid for fluid fuels. Thus, it might be easier for hydrogen (or other synthetic fuels) to compete on a fuel cost basis in transportation markets than in other fluid fuel markets.
- Since both PV arrays and electrolyzers are highly modular with little economy of scale above sizes of 5-10 MW, initial investments in PV hydrogen systems could be small, on the order of a 5-15 million dollars. This contrasts with synthetic fossil fuels such as methanol, where billion dollar investments would be needed to exploit economies of scale.
- Hydrogen-based transport technology could be commercialized relatively soon. Hydrogen-powered internal combustion engines have been extensively researched and experimental hydrogen powered cars and buses have already been built[120] (Figure 13). The viability of a gaseous fuel infrastructure for transportation has been demonstrated in Italy, New Zealand and Canada for vehicles operated on natural gas[121].

B. PV HYDROGEN AS AN AUTOMOTIVE FUEL

Here the analysis is focussed on the prospects for using hydrogen as a transport fuel for the automobile--in part because the automobile dominates transportation energy use (e.g see Table 13 for the US) and in part because if hydrogen could be successfully utilized as a fuels for automobiles, it could also be used in other transport markets where the technical problems of using

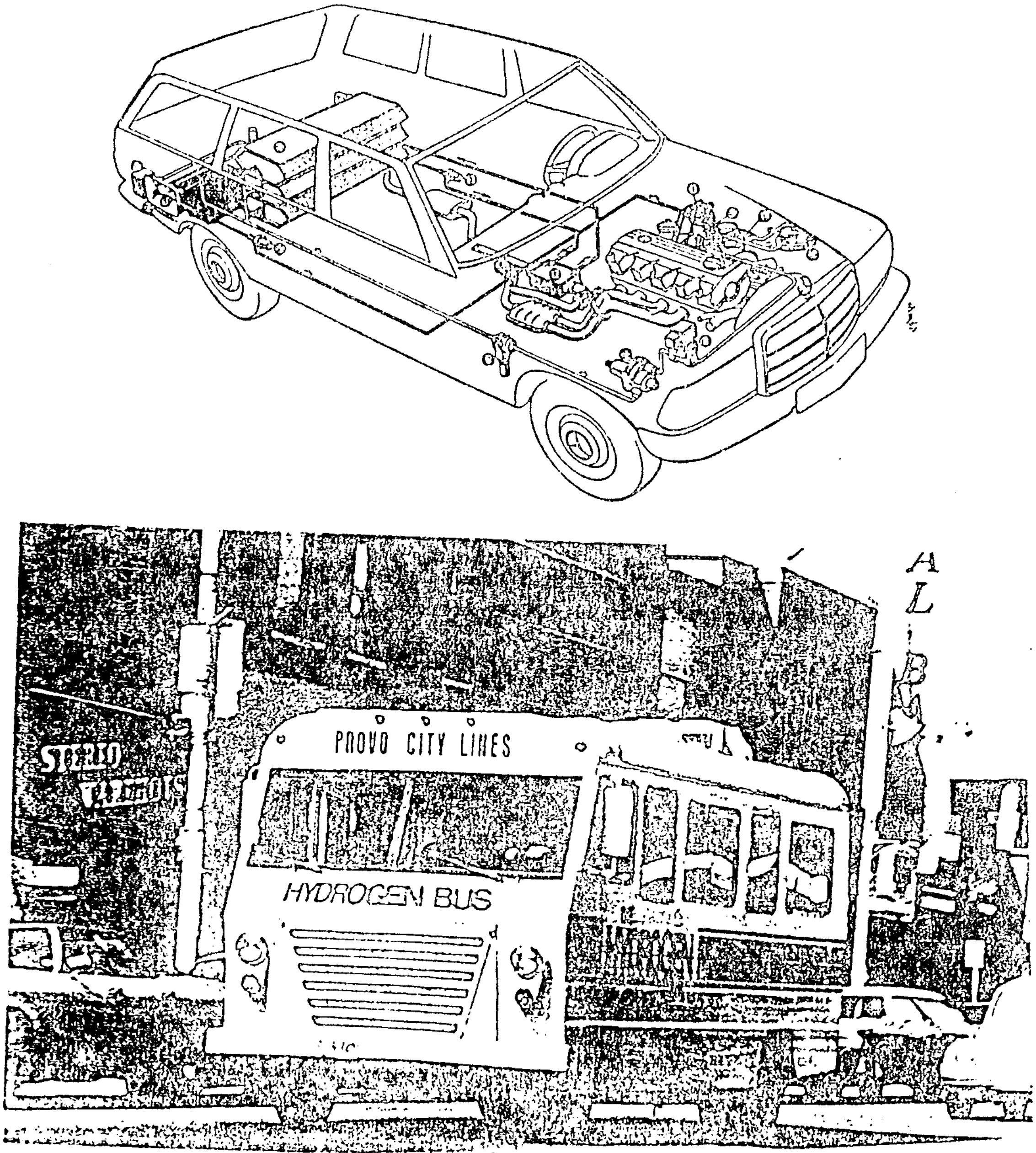


Figure 13.

Hydrogen-powered motor vehicles.

Both the hydrogen-powered car developed by Daimler-Benz Corporation of Stuttgart, West Germany (top) and the hydrogen-powered bus built by Billings Energy Corporation of Provo, Utah (bottom) use onboard metal hydride storage tanks.

Table 13. Oil Consumption in the US Transportation Sector, 1983

TYPE OF TRANSPORT	OIL CONSUMPTION (Exajoules/year)	(% of Total)
Automobiles	9.34	45.4
Motorcycles	0.036	0.2
Trucks	5.95	28.9
Light trucks	2.56	12.5
Other trucks	3.39	16.5
Busses	0.15	0.7
Off-highway equipment (mining, construction, farming)	0.75	3.7
Airplanes	1.58	7.7
Ships	1.26	6.1
Rail	0.61	2.9
Pipeline	0.17	0.8
Military	0.71	3.5
Total	20.6	100

Source: C. M. Hanchey and M. C. Holcomb, Transportation Energy Data Book, Edition 8, Oak Ridge National Laboratory Report, ORNL-6205, November 1985.

hydrogen as fuel are less challenging.

1. The Storage Challenge

Although hydrogen is the lightest fuel in terms of energy per unit weight, it has the lowest energy per unit volume (Table 14), so that storing enough fuel on board for a reasonable travelling range is a major challenge. For example, to store energy equivalent to a 20-gallon tank of gasoline, a storage size typical of 1970's "mid-size cars", would require about 1.4 cubic meters of hydrogen gas compressed to over 160 times atmospheric pressure. For comparison a typical station wagon has a cargo space of only 1 cubic meter, and the average sedan has trunk space of perhaps 0.5 cubic meters.[122] The problem is much more serious for compressed hydrogen than for compressed natural gas (0.4 cubic meters), though less severe than for advanced batteries (2.7 cubic meters).[123]

The low energy density of hydrogen led researchers in the past to view hydrogen-fueled cars as short-range vehicles. However, because it it now practically feasible to improve automotive fuel economy to the range 80 to 100 miles per gallon of gasoline-equivalent fuel (Box 4), limited range is no longer a serious constraint on the use of hydrogen as an automotive fuel. With such high fuel economy it becomes feasible to store enough fuel for a reasonable travelling range without sacrificing passenger room or trunk space, even for very low density fuels.[124]

In order to store enough energy onboard for a reasonable travelling range hydrogen gas must be compressed for storage at high pressure (2000-3000 psia), liquefied and stored cryogenically at very low temperature, or converted to another compound (such as a metal hydride), which is more compact.[125] All these storage options have been explored with experimental vehicles.

Table 14. Energy Storage in Automotive Fuels

	ENERGY DENSITY (a)					
	(GJ/m3)		(MJ/kg)		Density	Type of storage
FUEL	HHV	LHV	HHV	LHV	(kg/m^3)	
Gasoline (b)	34.5	32.3	45.9	43.0	720	metal tank
LPG (100 psi) (c)	25.5	23.6	50.0	46.3	510	pressurized cylinder
CH_4 Gas (2400 psia)	6.16	5.51	55.5	50.0	111	pressurized cylinder
Liquefied CH_4 (d) (-161 oK)	23.9	21.5	43.4	39.1	550	cryogenic dewar
Methanol (b)	18.1	15.9	22.7	19.9	791	metal tank
Ethanol (b)	24.0	21.6	30.2	27.2	790	metal tank
H_2 Gas (2400 psia)	2.09	1.76	142.4	120.2	14.7	pressurized cylinder
Liquefied H2 (b) (-253 ^oK)	9.95	8.4	142.4	120.2	71	cryogenic dewar
Metal hydride (e)	5.8	4.9	2.13	1.80	2706	hydride storage
Electricity (f,g,h)	0.42		0.144 (40 Wh/kg)		2900	lead-acid battery (f) (commercially available)
	0.48		0.191 (53 Wh/kg)		2500	Ni-Fe battery (g) (best laboratory result)
	0.90		0.324 (90 Wh/kg)		2778	Li/metal sulfide battery (EPRI projection) (h)

---

a HHV is the higher heating value of the fuel; LHV, the lower heating value.

b E.M. Goodger, "Liquid Fuels for Transport", Progress in Energy and Combustion Science, Vol. 8, p. 233, 1982.

c Gregory and J.B. Pangborn, "Hydrogen: A Portable Fuel for Military Applications", Proceedings 26th Annual Power Sources Conference, (May 1974); C. M. Hanchey and M. C. Holcomb, Transportation Energy Data Book, Edition 8, Oak Ridge National Laboratory Report, ORNL-6205, 1985.

d Amos Golovoy and Roberta J. Nichols, "Natural Gas Powered Vehicles," ChemTech, p. 359, June 1983.

e H. Buchner, "Hydrogen Use-Transportation Fuel", International Journal of Hydrogen Energy, Vol. 9, p.501, 1984; H. Buchner and R. Povel, "The Daimler-Benz Hydride Vehicle Project", International Journal of Hydrogen Energy, Vol. 7, p. 259-266, 1982.

f B. Sorensen, "Energy Storage", Annual Review of Energy, Vol. 9, pp. 1-29, 1984.

g US Department of Energy, Electric and Hybrid Vehicles Program, 10th Annual Report to Congress, DOE/CE-0179, April 1987.

h "Electric Vehicles", EPRI Energy Researcher, May 1986.

Box 4. THE REVOLUTION IN AUTOMOTIVE FUEL ECONOMY

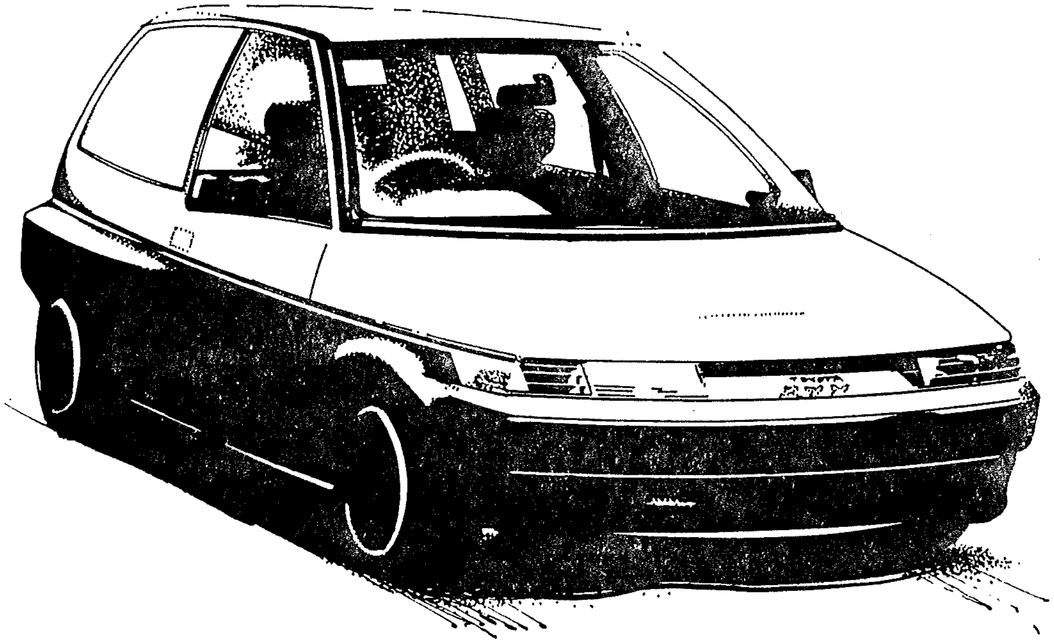
The oil shocks of the 1970s prompted interest in the possibilities for improving automotive fuel economy. As a result of Congressionally mandated fuel economy economy standards the average on-the-road fuel economy of the US automobile fleet increased from 13.5 mpg in 1975 to 18.5 by 1985, and the average fuel economy of cars purchased in the US in 1985 was 23.1 mpg.[126]

The most energy-efficient cars on the market have far higher fuels economies. The 1986 model gasoline-fueled Chevrolet Suzuki Sprint and the 1985 model diesel-fueled Nissan Sentra and Ford Escort are 4-5 passenger cars having average on-the-road fuel economies in the range 54 to 57 mpg.

Moreover, still higher fuel economies have been demonstrated. Volkswagen, Volvo, and Renault have all built prototypes with fuel economies in the range 66 to 70 mpg.[127] The most efficient protype built so far is a 98 mpg 4-5 passenger car introduced by Toyota in 1985 (Figure 14). No exotic technologies are required to achieve such high fuel economies--only the use of lightweight materials, aerodynamic styling to cut air resistance, and the use of proven high efficiency engines and transmissions.

High fuel economy does not necessarily imply sluggish performance that would make highway entry or passing difficult or dangerous. The Volvo LCP 2000 prototype, with a fuel economy of 66 mpg, requires only 11 seconds to accelerate from 0 to 60 mph, compared to 17 seconds for the popular Chevrolet Cavalier with automatic transmission, which has a fuel economy of only 28 mpg.[128]

Also, safety need not be compromised in building lightweight cars. One possibility for making lightweight cars safe is to make them large, offering plenty of "crush-space" in the event of a crash--a strategy proposed in a Battelle Memorial Laboratory design for a 5-6 passenger that would weigh 545 kg and have a fuel economy of 100 mpg.[129] The 69 mpg LCP 2000 built by Volvo is a lightweight (707 kg) prototype engineered to withstand 35-mph (56-km per hour front and side impacts and 30-mph (48-km/hour) rear impacts--thereby meeting stricter standards than do cars currently sold in the United States.[130] Moreover, advanced technology still under development will make it possible to build heavy fuel-efficient cars. For example, an 80 mpg car proposed by Cummins/NASA Lewis researchers--a multifuel-capable, direct injection, adiabatic diesel with turbocompounding--would weigh 1360 kg, approximately the average weight of new cars sold in the US today.[131]



Toyota AXV

Figure 14.

The Toyota AXV, a prototype four- to five-passenger super, fuel-efficient car.

Introduced in in late 1985, the AXV has a fuel economy of 98 mpg on the combined urban/ highway test administered by the US Environmental Protection Agency. High fuel economy is achieved with the systematic application of presently available technologies: low weight (650 kg) from extensive use of plastics and aluminum, low aerodynamic drag (a drag coefficient of 0.26), a direct-injection diesel engine (the kind used in trucks), and a continuously variable transmission.

Source: Toyota press release, October 23, 1985.

At first glance, liquid hydrogen would appear to be the most desirable option for onboard fuel storage, as it has the highest energy content per unit volume of any form of hydrogen (Table 14). However, liquid hydrogen is a cryogenic liquid at a temperature of -423 ^{o}F (-253 ^{o}C), which leads to difficulties in distributing and storing the fuel. As no economically feasible way of piping liquid hydrogen more than one or two miles exists, liquid hydrogen would have to be delivered by cryogenic truck or liquefied at a service station, at a high cost.[132] Moreover, liquid hydrogen is difficult to store for any length of time (up to 6 percent of the energy stored in the tank per day evaporates even from the best automotive-sized dewars) and refuelling losses can be up to 50 percent per transfer.[133] Small onboard cryogenic storage dewars would require bulky layers of extra insulation to retard evaporation losses, making the overall storage volume comparable to that of gas cylinders or hydride tanks.

For cars with fuel economy in the 60-100 mpg range relatively small storage tanks can be used with compressed hydrogen gas. For such fuel economies and a range of 200 miles between fuelings, hydrogen pressurized to 2400 psia could be stored in 3 to 5 standard 50 liter compressed gas cylinders (containing 2 to 3.3 gallons of gasoline-equivalent energy).[134] This is a relatively modest volume, which could be accommodated in the trunk of even a small car. (Roughly 0.20-0.32 cubic meters would be required for 3-5 tanks, or 40-65 percent of the trunk space.) Today's natural gas-powered cars use this kind of storage system (Figure 15).

A serious constraint on the compressed hydrogen gas option even for super-mpg cars is that filling station costs would be quite large. It is very costly (about $3 per GJ or 37 cents per gallon of gasoline-equivalent) to compress a

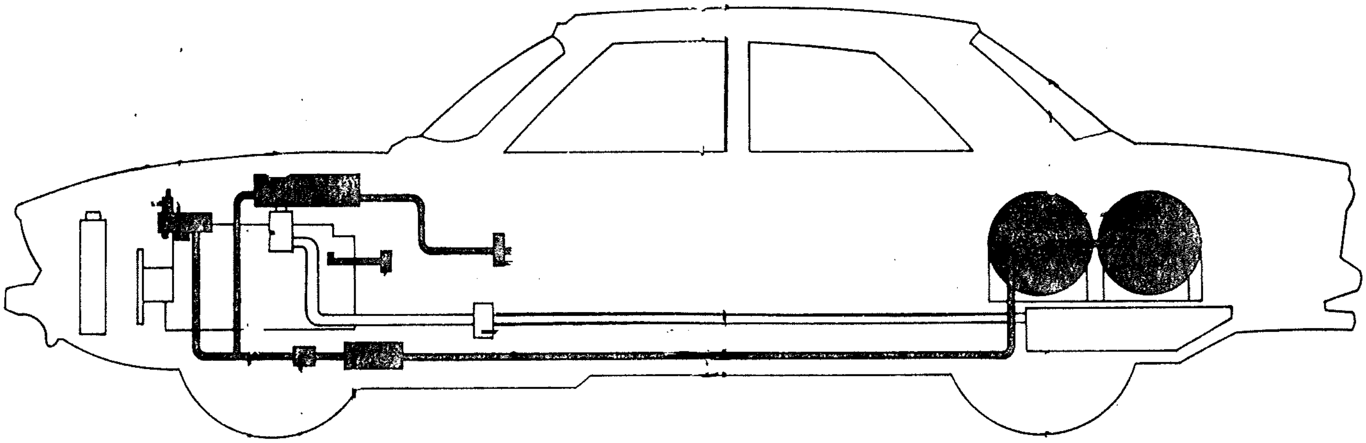


Figure 15.

A natural gas-powered car with compressed gas storage tanks in the trunk.

A similar system could be used for a super-mpg hydrogen car.

Box 5. METAL HYDRIDE STORAGE FOR AUTOMOBILES

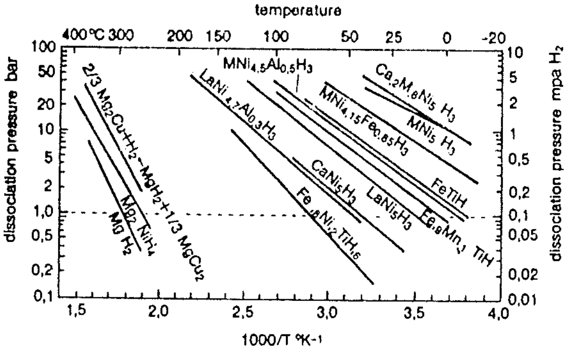
Onboard storage of hydrogen in metal hydrides is a promising option for hydrogen powered automobiles. Hydrogen reacts with many metals (among them iron, titanium, nickel) to form hydrides according to:

$$H_2 + \text{Metal} \dashrightarrow \text{Metal Hydride} + \text{Heat}$$

The reaction is reversible, if heat is added to the hydride:

$$\text{Metal Hydride} + \text{Heat} \dashrightarrow H_2$$

The temperature of heat required to liberate hydrogen depends upon the particular hydride. As shown below, metal hydrides fall into two groups "high-temperature hydrides" (HTHs), where heat at 300-400°C is needed, and "low-temperature hydrides" (LTHs), where the reaction begins when heat at 25-200°C is applied. As the pressure is increased, a higher temperature is required for the reaction.



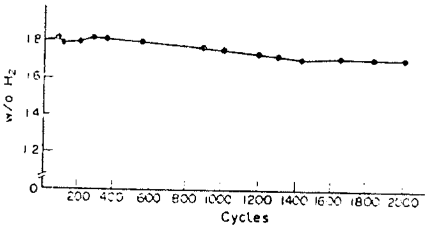


Fig. 15. Cycling behaviour of the $Ti_{0.98}Zr_{0.02}V_{0.43}Fe_{0.09}Cr_{0.05}Mn_{1.5}$-hydride with pure hydrogen (H_2 = 99.999 vol.%)

The HTH's can store about 7-8% of usable hydrogen by weight. The LTH's store about 2% hydrogen by weight. Because the HTH's would have a higher energy density than the LTH's, they would appear to be preferable. However, for automotive applications, it is desirable to produce hydrogen at pressures in the range of 10-50 atmospheres, for injection into the engine, and to use the heat from the engine exhaust, which is generally less than 300°C during typical driving conditions, to liberate the hydrogen. From these two considerations, it can be seen from the figure above that LTH's are more practical to use, even though their energy density is less. With HTH's, extra equipment for providing auxiliary heat would be needed, which would negate their advantage.

The storage tank for the hydride typically adds 15-25% to the weight ot the hydride itself. Energy densities for the combined system (hydride plus tank) are 1.80-1.98 MJ/kg. Hydrides do not degrade appreciably with repeated charging, as shown in the second figure above. After 2000 cycles, the capacity of the material to combine with hydrogen is virtually unchanged. For a car with a 400 km range, 400 charging cycles would be equivalent to 160,000 kilometers, about the lifetime of the car.

Source: H. Buchner, "Hydrogen Use--Transportation Fuel", International Journal of Hydrogen Energy, v. 9, pp. 501-514, 1984.

low energy density fuel from pipeline pressure (150-300 psi) to filling station storage pressure (3600 psi).[135]

Metal hydride storage (Box 5) seems the most promising option for automobiles, one which is being pursued by Daimler-Benz and the Billing Energy Corporation among others (Figure 13). In hydride storage, hydrogen is bound in the metal unless a high temperature is applied to liberate it. Hydrides weigh about as much as compressed gas cylinders for the same amount of energy storage but are about three times more compact.[136] For a 100 mpg car, hydride storage for a range of 320 km would weigh 128 kg and take up 47 liters of space (about as large as a 12 gallon gasoline tank). Moreover, hydride tanks can be shaped like traditional gasoline tanks, and they are easier to fit into a car than pressurized cylinders. The initial cost of hydride storage tanks would be only one third to half that for gaseous storage, and costly high-pressure equipment would not be needed at filling stations.

Liquid organic hydrides are another possibility for onboard storage of hydrogen, one which is being investigated for large vehicles.[137]

2. Engines for Hydrogen-Powered Cars

Conventional spark ignited (S-I) internal combustion engines have been run on hydrogen in a number of prototype vehicles.[138] While hydrogen is not a suitable fuel for Diesel engines, as it does not ignite easily under compression, there are other automotive engines, now under development, that would be as efficient as Diesels and are well suited for use with hydrogen fuel.[139] Most attractive of these appears to be the spark-ignited direct injection (DI) engine, sometimes called a stratified charge engine. Direct injection engines can be used with almost any fuel, and their energy efficiency is almost independent of fuel characteristics.[140] On an energy per kilometer basis, D-I engines operated on hydrogen, gasoline, natural gas or methanol, like Diesel engines run on Diesel fuel, would be about 50 percent more energy-efficient than current spark-ignited, gasoline-powered engines.

3. Hydrogen Fuel Distribution System

The fuel distribution system for metal hydride-fueled cars could involve service stations connected to a gas pipeline, the current practice for natural gas-powered cars. Daimler-Benz researchers estimate that it would take about 10 minutes per hydride storage tank "fill-up" at a delivery pressure of 735 psia. Filling station costs would add perhaps $1.5 per GJ (19 cents per gallon gasoline-equivalent) to the cost of the fuel, an amount comparable to that for compressed natural gas (Table 15).[141]

4. The Economics of Cars Fueled with Hydrogen

How much would it cost to own and operate a car fueled with PV hydrogen compared to the costs for other long-term options such as methanol, electricity, synthetic gasoline, synthetic natural gas, and batteries?

a. Alternative Fuel Costs: Table 15 shows the estimated production costs and delivered costs (including long-distance transmission, local distribution and filling station costs) for various transportation fuels. If the cost and performance goals for PV modules are met (Table 7) PV hydrogen could be delivered to consumers for $12.9 to 18.0 per GJ ($1.57 to $2.19 per gallon of gasoline equivalent), making hydrogen somewhat more costly than methanol or synthetic natural gas derived from coal, but probably less costly than gasoline derived from coal and ethanol derived from corn. (Hydrogen from PV sources would be much less expensive than electrolytic hydrogen from nuclear power, which would have a delivered cost of perhaps $18-28/GJ or $2.20-3.42 per gallon of gasoline equivalent.)

Table 15. Delivered Cost of Automotive Fuels c. 2000 ($/GJ)

	Long Distance Distrib.	Local Distrib.	Filling Station	Total Delivery Cost	Production Cost (a)	Delivered Cost to User	($/gallon gasoline equiv.)
Gasoline from coal	0.54	0.15	0.81	1.50 (b)	16.15	17.65	2.15
Methanol from coal	0.79	0.30	0.93	2.02 (b)	7.89 (c)	9.91	1.21
					10.05 (d)	12.07	1.47
Ethanol							
from corn, US				1.49 (e)	14.41	15.90	1.94
from sugar cane, Brazil					8.05	9.54	1.16
Synthetic natural gas							
from coal	1.10 (f)	0.42 (f)	1.57 (g)	3.09	5.74(h)	8.83	1.08
					7.92(i)	11.00	1.35
PV Hydrogen		0.42 (k)	1.45 (g)				
n=18%, $0.2/Wp	1.92 (j)			3.79	9.10	12.86	1.57
n=12%, $0.2/Wp	2.01 (j)			3.88	10.75	14.63	1.79
n=18%, $0.4/Wp	2.08 (j)			3.95	12.28	16.23	1.98
n=12%, $0.4/Wp	2.14 (j)			4.01	13.96	17.97	2.19

---

[a] See Table 9, Notes 114 and 94.

[b] <u>Source</u>: "Preliminary Perspective on Pure Methanol for Transportation", EPA 460/3-83-003, 1982.

[c] For a methanol synfuel plant producing 322,000 GJ/day (Note 114).

[d] For a methanol synfuel plant producing 32,200 GJ/day (Note 114).

[e] Assumed to be the same per liter as for methanol.

[f] The costs of long distance transmission and local distribution are average values projected for all customers and industrial customers respectively for natural gas in the US in 2000. <u>Source</u>: American Gas Association, Policy Evaluation and Analysis Group, Bulletin AGA-TERA 86-1, January 1986.

[g] See Note 135.

[h] For an SNG synfuel plant producing 264,000 GJ/day (Note 114).

[i] For an SNG synfuel plant producing 26,400 GJ/day (Note 114).

[j] Long distance transmission costs for hydrogen were estimated assuming transmission 1000 miles via pipeline (Note 100).

[k] As hydrogen and natural gas local distribution systems would be similar in size and handle about the same energy flow, we have assumed that hydrogen local distribution costs are the same as for natural gas.

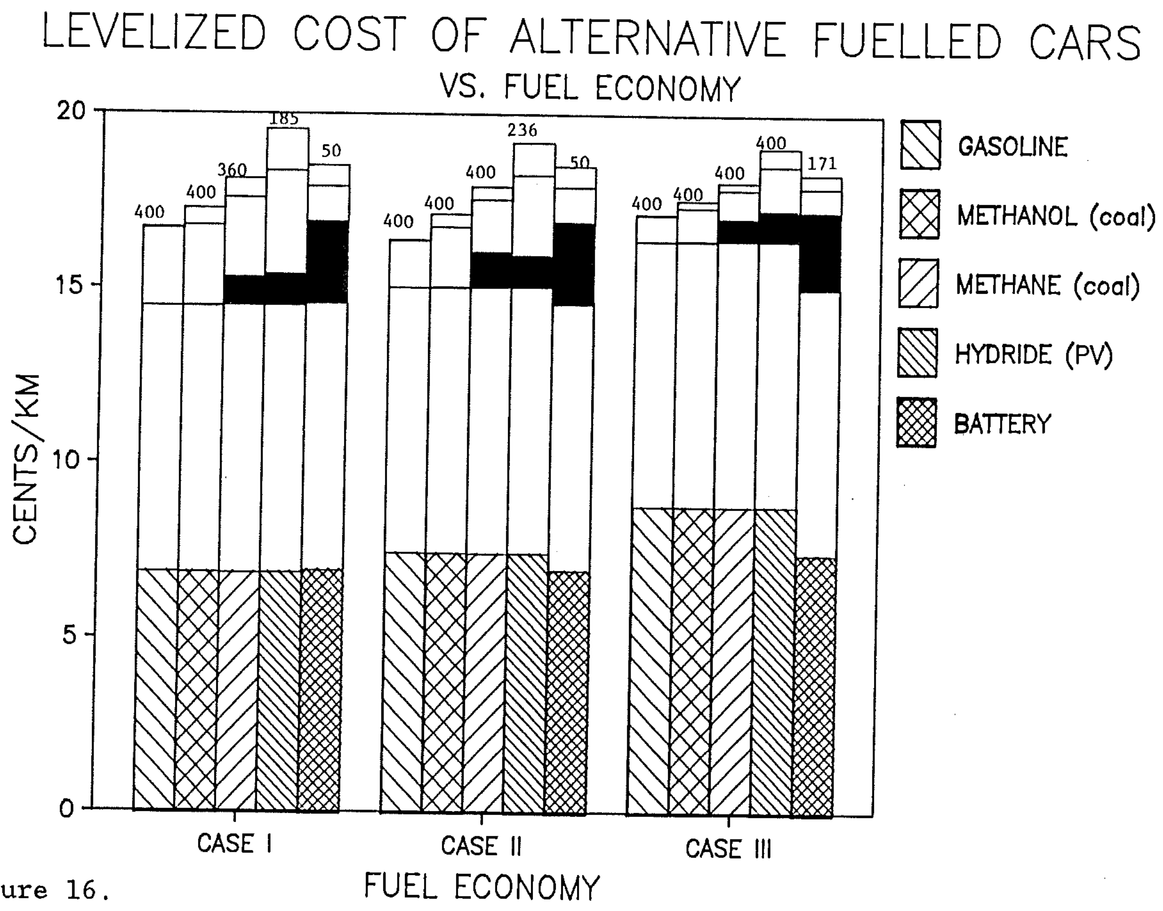


Figure 16.

A comparison of levelized costs for owning and operating cars on various fuels for three levels of automotive fuel economy. The levelized cost in cents per kilometer is shown for automobiles fueled with gasoline, methanol from coal, synthetic natural gas from coal, electricity stored in batteries, and PV hydrogen. Case I is roughly equivalent to a present day sub-compact car with a fuel economy of 30 miles per gallon of gasoline equivalent. Case II is roughly equivalent to a subcompact car with a more efficient engine (Diesel or stratified charge), with fuel economy of 50 mpg gasoline. Case III corresponds to a car with a more efficient engine, aerodynamic styling and a continuously variable transmission. (A detailed description of each case is presented in Note 142.) For each case, the levelized cost has four components: initial capital cost of the vehicle (which is shown in hatched patterns and includes the purchase price of the car, exclusive of extra storage system costs), miscellaneous expenses (shown in white above the initial capital cost of the vehicle, this includes tolls, registration fees, insurance, parking, repairs and maintenance), the storage cost (shown in black and includes any extra cost for a special fuel storage system such as batteries, compressed gas cylinders or hydride tanks), and the fuel cost (shown in white at the tops of the bars). The delivered costs of fuels (from Table 15) are: $8.19/GJ ($1/gallon) for gasoline, $9.91-$12.1/GJ for methanol from coal, $8.83-$11.0/GJ for synthetic natural gas from coal, $0.06-0.10/kwh for electricity, and $12.9-$18.0/GJ for PV hydrogen. The travelling range (in km) for each option is shown at the top of the bar.

b. Consumer Costs for Cars with Alternative Fuels: In comparing the costs of owning and operating cars with alternative fuels, costs other than fuel should be taken into account--the capital cost of the vehicle (including any costs associated with modifications of the vehicle to improve fuel economy and any costs for engine modifications or onboard storage tanks needed to accommodate alternative fuels), and various maintenance costs, tolls, insurance, and parking costs.[142]

Figure 16 shows the total cost per kilometer of owning and operating a car powered by gasoline, methanol from coal, synthetic natural gas from coal, an electric battery, and PV hydrogen--for three levels of fuel economy (corresponding approximately to 30, 50 and 90 mpg of gasoline-equivalent) and the ranges of delivered fuel prices presented in Table 15. This figure shows that the non-fuel costs dominate total costs, even at 30 mpg, and that there is little difference among fuels in the total cost to the consumer of owning and operating a car.

c. The National Cost of Alternative Transport Fuels: There appears to be a relatively small difference in cost to the individual consumer for owning and operating a car with various synthetic transport fuels. However, the aggregate cost to the nation would be different for each option.

Table 16 illustrates how automobile transport fuel costs in the US might evolve as vehicles and fuels change. (For the purposes of this discussion, "automobiles" include light trucks as well as cars.) Specifically, this table shows estimated the annual automotive transport fuel cost c. 2020 with various synthetic fuel options for three levels of fuel economy, corresponding to approximately 30, 50 and 90 miles per gallon of gasoline, in relation to the actual expenditures on gasoline in 1984 and the range of expenditures projected

Table 16. The Automobile Fuel Bill of the United States

	Consumer Fuel Price ($/GJ)	Cost of Automobile Transport Fuel (Billion Dollars per Year)		
Gasoline from crude				
1984 (a)	10.17	125		
2000 I (b)	7.97	103		
2000 II (b)	9.65	118		
2000 III (b)	11.93	137		
		Alternative Scenarios for 2020 (c,d)		
		"30 mpg"	"50 mpg"	"90 mpg"
Gasoline from coal	17.65	153	92	51
Methanol from coal	9.91-12.07	73-89	55-67	30-36
SNG from coal	8.83-11.0	71-89	48-60	26-32
PV Hydrogen				
n=18%, $0.2/Wp	12.86	95	74	41
n=12%, $0.2/Wp	14.63	109	84	47
n=18%, $0.4/Wp	16.23	118	90	50
n=12%, $0.4/Wp	17.97	129	100	56

---

[a] For a total light vehicle energy use of 12.3 EJ per year. *Source*: *Transportation Energy Data Book: Edition 9*, Oak Ridge National Laboratory, ORNL-6325, April 1987.

[b] Alternative USDOE projections for gasoline consumption and prices in the year 2000, with alternative crude oil prices of $26.76/barrel for I, $32.87 for II, and $41.48 for III. *Source*: Energy Information Administration, US Department of Energy, *Annual Energy Outlook with Projections to 2000*, DOE/EIA-0383(86), 1987.

[c] We assume that there will be 235 million adults (aged 16 and over) in the US in 2020, that there will be 0.80 light vehicles per adult, and that each vehicle travels 10,600 miles per year.

[d] Based on fuel costs from Table 15, for three levels of average automotive fleet fuel economy corresponding roughly to 30, 50, and 90 miles per gallon of gasoline equivalent.

for the year 2000 by the US Department of Energy.

It is immediately apparent from Table 16 that increasing automotive fuel economy would lead to dramatic reductions in the annual transport fuel bill of the US, even with many more vehicles on the road and more costly fuels.

5. What about Trucks, Buses, Trains, Ships, and Planes?

Buses, trucks, airplanes, and ships are also large oil users. In the US in 1983 these end uses collectively accounted for 9.3 EJ of oil use, about as much oil as the automobile used (Table 13).

Present levels of fuel economy for these other transport modes probably do not constrain the use of hydrogen a fuel option for these other transport modes, as is the case for the automobile, because with larger vehicles the weight and volume penalties associated with onboard hydrogen storage are not serious,[143] as has been demonstrated for hydrogen-fueled buses (Figure 13).[144]

However, as oil prices rise and shifts are made to more costly synthetic fuels, improvements in fuel economy will become important for economic reasons, and there are substantial opportunities for making such improvements.[145] As in the case of the automobile, the total cost of owning and operating these vehicles becomes less sensitive to fuel choice at higher levels of fuel economy, which again makes it easier to select a fuel on the basis of considerations of external social costs as well as private costs.

While there should be no formidable problems limiting the use of hydrogen in buses, trucks, trains, and ships, the use of hydrogen as an air transport fuel may be more problematic. Because hydrogen is readily burned in jet engines and has almost three times as much energy per unit weight as jet fuel (Table 14), one might think that hydrogen would be attractive for large, long-range aircraft, where the fuel weight is a significant load. But for aircraft use, hydrogen would probably have to be liquefied to save space, and the expense of liquefaction (adding $6-10/GJ to the cost of fuel) would make it more difficult for liquid hydrogen to compete with other synthetic fuels in today's jumbo jets.[146]

6. Environmental Problems and Alternative Synthetic Fuels

While electric cars will have limited appeal because of their limited range, all the fuel-driven cars offer comparable performance at high fuel economy levels, and the total cost of operating cars with these alternative fuels varies little from fuel to fuel. Thus the choice of a transportation fuel for the long term need not be driven by private economic cost considerations alone but might be shaped by considerations of external social costs as well--such as the health risks associated with urban air pollution, the environmental risks due to acid deposition, and the risk of global climate changes due to CO_2 emissions.

As will be shown in Chapter 7, substantial local air quality improvements could be achieved by switching to hydrogen as a transport fuel. Moreover, if hydrogen were produced from PV power, no CO_2 would be emitted in fuel production.

The total CO_2 emissions from various synthetic fuel cycles, including both fuel production and combustion in vehicles, are shown in Table 17 and Figure 17[147]. Here it is seen that if a shift is made from gasoline to fossil fuel-based synthetic fuels, there would be a sharp increase in CO_2 emissions, unless there were a compensating improvement in automotive fuel economy. By shifting to PV hydrogen instead, CO_2 emissions would be eliminated.

This strategy for eliminating CO_2 emissions from automobiles depends on (i) having available automobiles of high fuel economy and (ii) PV hydrogen

Table 17. CO2 Emissions for Alternative Automotive Fuels (a)

	CO2 Emission Rate (kg/km)		
	25 mpg (b)	50 mpg (b)	100 mpg (c)
Crude oil -> Gasoline + Diesel	0.251	0.125	0.063
Natural gas	0.167	0.084	0.042
Coal -> SNG (Lurgi Dry Ash process)	0.394	0.197	0.099
Coal -> Methanol (w/ Texaco gasifier)	0.460	0.230	0.115
Coal -> Gasoline, SNG, LPG (SRC-II process)	0.430	0.215	0.108
PV Hydrogen	0	0	0
PV Electricity -> Battery	0	0	0

---

[a] See Note 147.

[b] Gasoline-equivalent fuel economy.

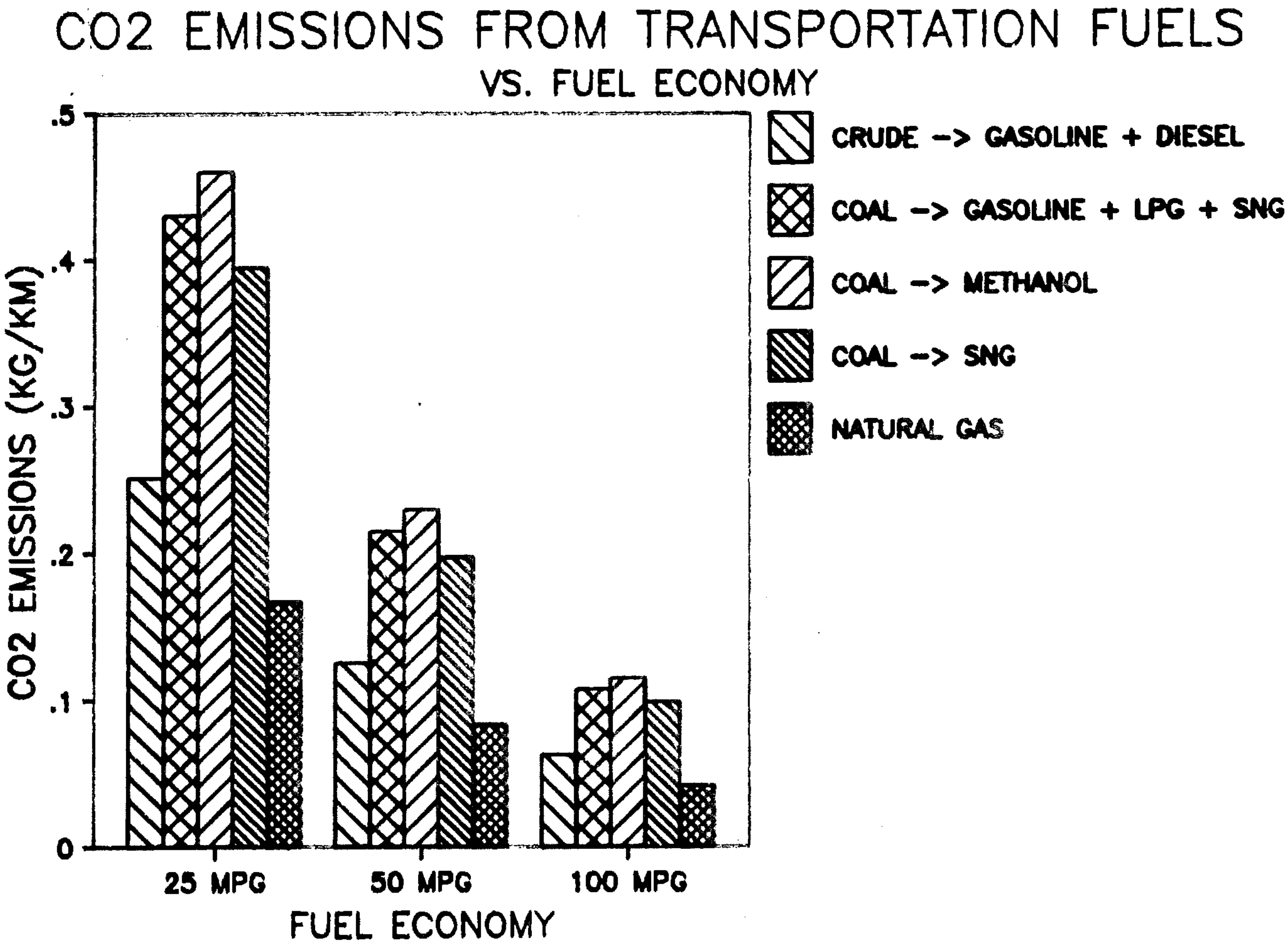


Figure 17.

Automotive CO_2 emissions with various synthetic fuels as a function of automotive fuel economy.

The number of kilograms of CO_2 released in the synthesis and combustion of fuel per kilometer travelled is shown for gasoline from crude oil, gasoline from coal, methanol from coal, and synthetic natural gas from coal. PV hydrogen would release no CO_2 to the atmosphere.

being a more attractive fuel than coal-synthetic fuels. In each instance a new publicy policy may be needed.

In light of the minor role of fuel cost in the overall cost of owning and operating an automobile, and the insensitivity of the overall cost to improved fuel economy levels (Figure 16), it is clear that a public policy promoting fuel economy improvement (e.g. tougher automotive emissions or fuel economy standards or a gas-guzzler tax) is needed to bring about a shift to super fuel-efficient cars.

Also, if the coal-synthetic fuel were less costly than PV hydrogen, a carbon tax might have to be levied on the former, thereby directing the market to choose hydrogen instead.

These public sector interventions would have little impact on the cost of owning and operating the automobile from the consumer's perspective (Figure 16). There might be a national economic penalty associated with choosing hydrogen instead of, say, coal-derived methanol, which may well prove to be less costly. But the penalty would be small and would decline sharply with increasing fuel economy. For example, with methanol costing \$12.1/GJ and hydrogen \$14.6/GJ, the penalty on the national fuel bill in 2020 (Table 16) would decline from \$17 billion at 50 mpg to \$11 billion at 90 mpg, and the total US fuel bill for hydrogen for automobiles would still be less than 40% of that for gasoline in 1984 (Table 16). It would seem that this is a fairly painless strategy for coping with a very serious problem.

CHAPTER 6. GASEOUS FUELS MARKETS

A. THE ECONOMIC CHALLENGE FOR PV HYDROGEN IN GASEOUS FUELS MARKETS

As synthetic natural gas (SNG) made from coal is estimated to cost only \$6 to \$8 per GJ, compared to \$9 to \$14 per GJ for PV hydrogen (Table 9) it would appear to be much harder for PV hydrogen to compete in synthetic gaseous fuels markets than in synthetic liquid fuels markets. However, there are still reasons for considering PV hydrogen in synthetic gaseous fuels markets:

- If the continued use of coal became untenable because of the risks of climatic change associated with the buildup of carbon dioxide in the atmosphere, PV hydrogen could provide an alternative, which is not much more costly than coal-derived gases on an energy-equivalent basis.
- PV-powered electrolysis is inherently modular and there is essentially no economy of scale above about 5-10 MW, while the production costs of coal-derived gases are strongly dependent on the size. For applications where it is not feasible or practical to build large synfuels facilities, PV-based hydrogen may be a competitive synfuel.[148]
- As we shall show, hydrogen has attractive properties that will enable it to compete in some important applications even when its price on an energy-equivalent basis is considerably higher than that of coal-based synfuels.

B. PV HYDROGEN FOR RESIDENTIAL HEATING

To give an indication of the possibilities for using hydrogen in gaseous synfuels markets, the possibilities for using hydrogen for residential space and water heating are discussed here--applications which account for about 7/8 of residential natural gas use at present (Table 18). For these applications hydrogen is compared to synthetic natural gas derived from coal and electricity, the principal alternative energy carriers that might eventually be used to replace natural gas.

Although hydrogen sounds like an exotic choice to most people in the US

Table 18. World Natural Gas Consumption IN 1983 (Exajoules/year)

Market Economies		
United States		
Residential		5.0
Space Heat	3.29	
Water Heat	1.09	
Cooking, other	0.58	
Commercial		2.2
Space Heat	1.44	
Water Heating	0.36	
Cooking	0.16	
Cooling	0.06	
Other	0.13	
Industrial		7.1
Heat and Power	5.87	
Refinery Fuel	0.62	
Chemical Feedstock	0.52	
Electricity generation		3.6
Transportation		0.5
Total		18.6
Other OECD (a)		11.3
Developing Countries (b)		5.8
Centrally Planned Economies		
USSR		17.3
China		0.4
Others		3.2
World		56.5

---

[a] Other OECD Includes Western Europe, Japan, Australia, New Zealand, Canada.

[b] Africa, Southeast Asia, Pakistan, Latin America.

Sources: BP Gas Company, *B.P. Preview of World Gas*, August 1985; American Gas Association, *The Gas Energy Demand Outlook 1984-2000*, 1984; American Gas Association, *Gas Facts*, 1986; US Energy Information Administration, *Annual Energy Outlook, 1984*, DOE/EIA 0383(84), January 1985.

today, hydrogen-rich gases have been used for home heating and cooking for over a hundred years. "Town gas" (a mixture of approximately half hydrogen and half carbon monoxide with traces of methane, which can be derived from coal, wastes or wood), was piped into millions of urban homes in the US earlier in this century, and is still used in parts of Europe, Asia, and South America. In some regions of the US, natural gas did not supplant town gas as a residential fuel until after World War II.

Hydrogen flame burners would be similar to those in today's natural gas heating systems and appliances. The only important difference would be in the size of the burner openings controlling the velocity of the gas flow: hydrogen gas would have to flow three times as fast as natural gas to deliver the same energy flow. In fact, existing natural gas appliances could perhaps be converted to hydrogen use, if the burners and some metering devices were replaced.[149] Because of NOx production, appliances using an open hydrogen flame would have to be vented, as with natural gas flames. The efficiency, cost and performance should be essentially the same as with natural gas appliances.

Catalytic combustion offers the prospect of higher efficiency for gas heaters. In a catalytic heater, fuel gas combines with the oxygen in air at a relatively low temperature in the presence of a catalyst, such as platinum or stainless steel.[150] Instead of a flame, the catalytic reaction produces a radiant glow. Thus, catalytic space heaters are generally used in the room to be warmed, to take advantage of radiant heating.

Catalytic space heaters fueled with natural gas are commercially available for residential use.[151] These units are commonly used to heat a single room. They must be vented to the outside to avoid the buildup of combustion products such as CO_2 and NOx. Even with venting, heating efficiencies of 80-90% are obtained. With hydrogen fuel, catalytic combustion could be carried out at a low enough temperature that there would be negligible NOx production,[152] and the combustion products (mainly water vapor) can be discharged directly into the heated space. As a result, the heating efficiency of hydrogen catalytic burners can be close to 100%! Moreover, the catalytic hydrogen heater can also improve comfort by acting as a humidifier, as well as a heater, providing a relative humidity of 40-50% on cold days.[153] [Alternatively, the steam from combustion could be condensed to make potable (distilled) water, rather than released into the room.[154]]

Researchers in the US, Japan and Europe have already constructed prototype catalytic space heaters and hot water heaters fueled with hydrogen.[155] The costs of hydrogen space heaters should be comparable to those of natural gas catalytic heaters today, and installation costs should be lower, as venting would not be neccessary.[156]

Catalytic hydrogen water heaters would probably cost about 8-20 percent more than today's natural gas-fired storage tank-type heaters, but they would be 50 to 100 percent more energy-efficient![157]

To get a sense of how much the consumer would pay with various alternatives, the annual cost to consumers of residential space and water heating are estimated here for three different energy carriers--PV hydrogen, synthetic natural gas (SNG) derived from coal, and electricity--and for three alternative sets of energy end-use technologies. The residential energy prices assumed in this comparison are shown in Table 19. Three different levels of technology are chosen to illustrate the fact that the competitiveness of hydrogen is strongly dependent on the characteristics of the end-use technologies involved.

Table 19. Delivered Prices for Residential Heating Fuels ($/GJ)

Fuel	Production Cost(a)	Long Distance Distribution	Local Distribution	Delivered Cost to Consumer
Synthetic natural gas from coal	5.79-7.92	1.12(b)	1.50(b)	8.41-10.54
PV Hydrogen			1.50(d)	
n=15%, $0.2/Wp	9.07	1.92(c)		12.49
n=10%, $0.2/Wp	10.75	2.01(c)		14.26
n=15%, $0.4/Wp	12.28	2.08(c)		15.86
n=10%, $0.4/Wp	13.96	2.14(c)		17.60
Electricity				16.67-27.78 (e) ($0.06-0.10/kwh)

---

[a] See Note 114 for SNG from coal and Note 94 for PV hydrogen.

[b] American Gas Association, Policy Evaluation and Analysis Group, Bulletin A.G.A.-TERA 86-1, January 1986.

[c] This estimate is for transmitting hydrogen 1000 miles, with an assumed pipeline inlet pressure of 1000 psia and pipeline outlet pressure of 300 psia (see Note 100).

[d] We assume that the local distribution of natural gas and hydrogen would involve similar systems and that the costs would be the same.

[e] The average residential electricity price projected for the year 2000 is $0.074/kwh. Energy Information Administration, US Department of Energy, Annual Energy Outlook with Projections to 2000, DOE/EIA-0383(86), 1987.

As will be shown, the economics of hydrogen in relation to the alternative energy carriers improves markedly as the efficiency of end-use technologies improves.

The three sets of energy end-use technologies assumed in this comparison are the following:

1. <u>Low First-Cost Technologies for Conventional New Houses</u>: conventional furnaces for natural gas and hydrogen; conventional tank-type water heaters for natural gas and hydrogen; electric resistance space and water heating for electricity.

2. <u>Energy-Efficient Technologies for Conventional New Houses</u>: condensing furnaces (*) for natural gas and hydrogen; tankless water heater (**) for natural gas; catalytic water heater for hydrogen; and heat pumps (***) for space and water heating with electricity.

---

* In a conventional furnace a considerable amount of heat is lost because the exhaust gases are discharged to the atmosphere at a relatively high temperature of 149°C (300°F). In a condensing furnace extra heat is extracted from the exhaust gases before they are discharged to the atmosphere. They are called condensing furnaces because the exhaust is cooled to about 38°C (100°F), which is below the dew point, thereby causing the water vapor in the exhaust to condense and enabling the recovery of its latent heat.

** Unlike conventional storage tank type natural gas-fired water heaters (which store hot water for later use), tankless heaters produce hot water on demand from a heat exchanger (which is usually part of the furnace). As a considerable amount of heat is lost from hot water storage between uses, tankless heaters are much more efficient. Because they are commonly used in conjunction with a central furnace, tankless water heaters would not be used in super-insulated houses that are heated with several in-room space heaters instead of a central furnace.

*** Heat pumps use electricity to transfer heat from one space to another. In the summer, they operate as air-conditioners, moving heat from the indoors to the outdoors; in winter they acts as heaters, extracting heat from the outdoors and transferring it to the living space. As electricity is high-grade energy, this can be done very efficiently; with a heat pump it only takes one GJ of electrical energy to provide two or three GJ of heat energy. This contrasts with electric resistance heaters, where electricity is turned directly into low-grade energy heat, so that one GJ of electrical energy produces only one GJ of heat. Heat pump water heaters operate on a similar principle.

3. Energy-Efficient Technologies for Superinsulated Houses: catalytic space heaters for both natural gas and hydrogen; tank-type water heater for natural gas (a tank-type water heater is used here because tankless units are usually installed in conjunction with a central furnace), catalytic water heater for hydrogen, resistance space heating (*) and heat pump water heater for electricity.

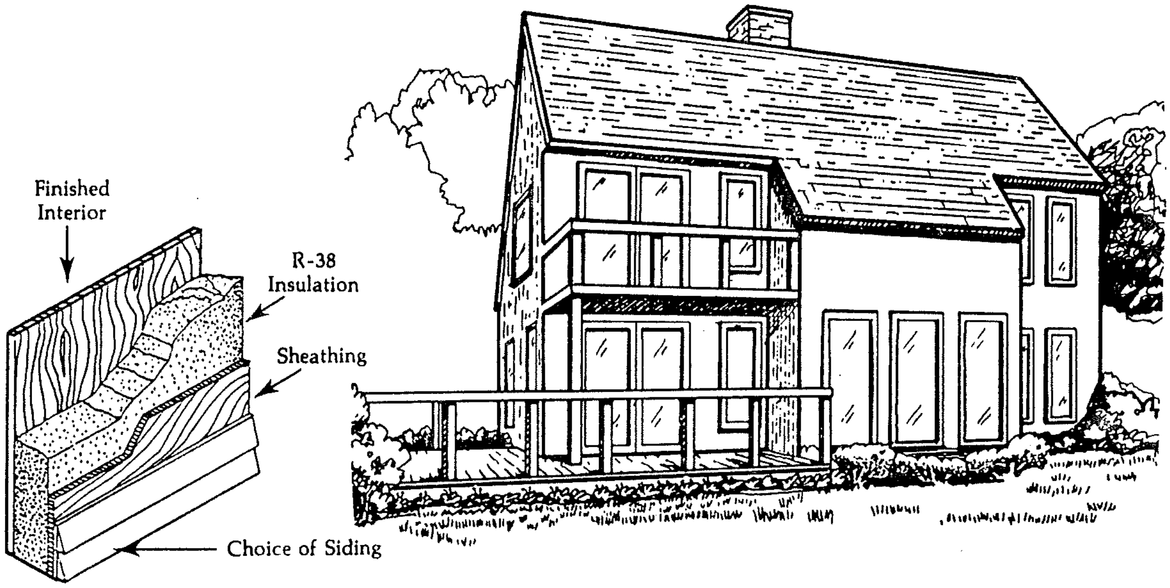
Hydrogen is particularly well-suited for use in houses that are so well insulated that uniform temperatures can be maintained throughout by convective heat flows in the living space from a few well-placed catalytic space heaters--obviating the need for a central furnace and associated ductwork. To illustrate the advantages of hydrogen for such applications two types of houses are considered here--a "conventional" house typical of today's new construction, and a "super-insulated" house, with very low energy use. It is assumed that the houses are located in New Jersey, where the amount of heating required is roughly the US average.

The superinsulated design chosen for this analysis is based on the Northern Energy Home (NEH) offered in a number of popular styles in New England (Figure 18) and assumed here to be equiped with double-glazed windows having "heat mirror" coatings on the glass; the annual space heating requirements for this house would be just 1/8 as large as for a typically constructed new house.[158] It is estimated that the house would cost about $4100 more to build than a house with more typical heat loss characteristics but otherwise having the same general quality.[159]

The size, performance, capital costs and estimated lifetimes of the various end-use technologies considered for each case are summarized in Table 20.[160] The levelized annual cost (in dollars per year) of providing space and

---

* In a superinsulated house the heating load is so small and the heating season so short that it would not be cost-effective to install a heat pump. It is more economical to install a low capital cost resistive heating unit.



Stress-Skin Panel

Northern Energy Home

Figure 18.

Cross-Section of a "Stress-Skin" Panel (Left) Used in a Northern Energy Home (right).

The NEH is constructed by mounting highly insulating 4 feet x 8 feet "stress-skin" panels on a a post-and-beam frame. The factory-assembled panels, containing thick (8-inch) rigid polystyrene insulation, are made to fit together easily for rapid construction. Doors and windows are foam-sealed into the the panels at the factory.

Because of tight construction natural air infiltration is low in the NEH--about 0.15 air changes per hour. For this reason natural air infiltration is supplemented by forced ventilation at a rate of 0.35 air exchanges per hour. The forced ventilation takes place through an air-to-air heat exchanger, in which the warm air being exhausted from the house gives up about 70 percent of its heat to the fresh cold incoming air. For the purposes of heat loss calculations the "effective" ventilation rate is thus 0.15 + [0.35 x (1.0 - 0.70)] = 0.255 air exchanges per hour.

Table 20. COST AND PERFORMANCE OF NATURAL GAS, HYDROGEN AND ELECTRIC HEATING SYSTEMS FOR CONVENTIONAL AND SUPER-INSULATED HOUSES IN NEW JERSEY (a)

		Costs ($)						
	Size	Installed Unit	Ducts	Vents	System Total	Effic. or COP	Life (yr)	O&M ($/yr)
1. Low First-Cost Technologies, Conventional New Houses								
NATURAL GAS:								
Conventional furnace	41 kBTU/h	700	1500	50	2250	0.69	18	25
Tank-type water heater	40 gal	320	-	50	370	0.52	10	5
HYDROGEN:								
Conventonal furnace	43 kBTU/h	700	1500	50	2250	0.65	18	25
Tank-type water heater	40 gal	320	-	50	370	0.49	10	5
ELECTRICITY:								
Resistance space heat	8.28 kW	1100	-	-	1100	0.99	15	15
Resistance water heater	40 gal	300			300	0.85	10	5
2. Energy-Efficient Technologies, Conventional New Houses								
NATURAL GAS:								
Recuperative furnace	29 kBTU/h	2200	1500	50	3750	0.95	20	80
Tankless water heater	40 gal	750	-	50	800	0.78	10	30
HYDROGEN:								
Recuperative furnace	29 kBTU/h	2200	1500	50	3750	0.95	20	80
Catalytic water heater	40 gal	425	-	50	475	0.83	10	5
ELECTRICITY:								
Heat pump	2.87 kW	2700	1500	-	4200	2.85	15	25
Heat pump water heater	40 gal	1550			1550	1.8	10	30
3. Energy-Efficient Technologies, Superinsulated Houses								
NATURAL GAS:								
Tightened building shell					4100			
3 Catalyt. sp. htrs	11.5 kBTU/h	1245	-	-	1245	0.85	15	10
Tank-type water heater	40 gal	320	-	50	370	0.52	10	5
HYDROGEN:								
Tightened building shell					4100			
3 Catalyt. sp. htrs	9.9 kBTU/h	855	-	-	855	0.99	15	10
Catalytic water heater	40 gal	425	-	50	475	0.83	10	5
ELECTRICITY:								
Tightened building shell					4100			
Resistance heaters	2.89 kW	800	-	-	800	0.99	15	15
Heat pump water heater	40 gal	1550	-	-	1550	1.8	10	30

---

[a] The technical characteristics of the space and water heating systems are described in Note 160. The equipment capital and O&M costs are from the Electric Power Research Institute's "TAG Technical Assessment Guide, Volume 2: Electricity End Use, Part I: Residential Electricity Use", EPRI, P-4463-SR, (September 1987), for all but the catalytic heaters; cost estimates for catalytic heaters are from B. Wells, Thermal Systems, Inc., Tumwater, Washington, private communication, 1987.

water heating with each energy carrier and with each set of end-use technologies is shown in Figure 19.[161]

The relative costs for space and water heating with the different energy carriers are roughly what one would expect in the "base case" of low first-cost end-use technologies used in conventional energy houses: SNG systems are the least costly, followed by electricity, with hydrogen coming in last. When energy-efficient end-use technologies are deployed in conventional houses overall costs are reduced for hydrogen and electric systems, though not for SNG systems; and hydrogen fares somewhat better than in the base case in relation to the other energy carriers: when priced at the low end of its estimated cost range, hydrogen-fueled systems would be able provide heat at about the same cost as for electrical systems and SNG systems fueled with SNG priced at the high end of its estimated cost range. But when energy-efficient end-use technologies are deployed in superinsulated houses overall costs drop sharply in all cases--even though superinsulated houses are much more costly to build; and, suprisingly, hydrogen becomes more competitive with the other energy carriers. Using hydrogen is clearly less expensive than using electricity for space and water heating. Even with hydrogen priced at the high end of its estimated cost range, annual space and water heating bills would be about 15 percent less costly than with electrical systems. Hydrogen would be competitive with SNG at the high end of the price range and about 5% less expensive at the low end of the range. This remarkable shift arises because of the capital savings and efficiency improvements that are possible in end-use equipment used with superinsulated housing designs. When hydrogen is used to heat the conventionally constructed house, a complex centralized heating system is required, costing some $3750

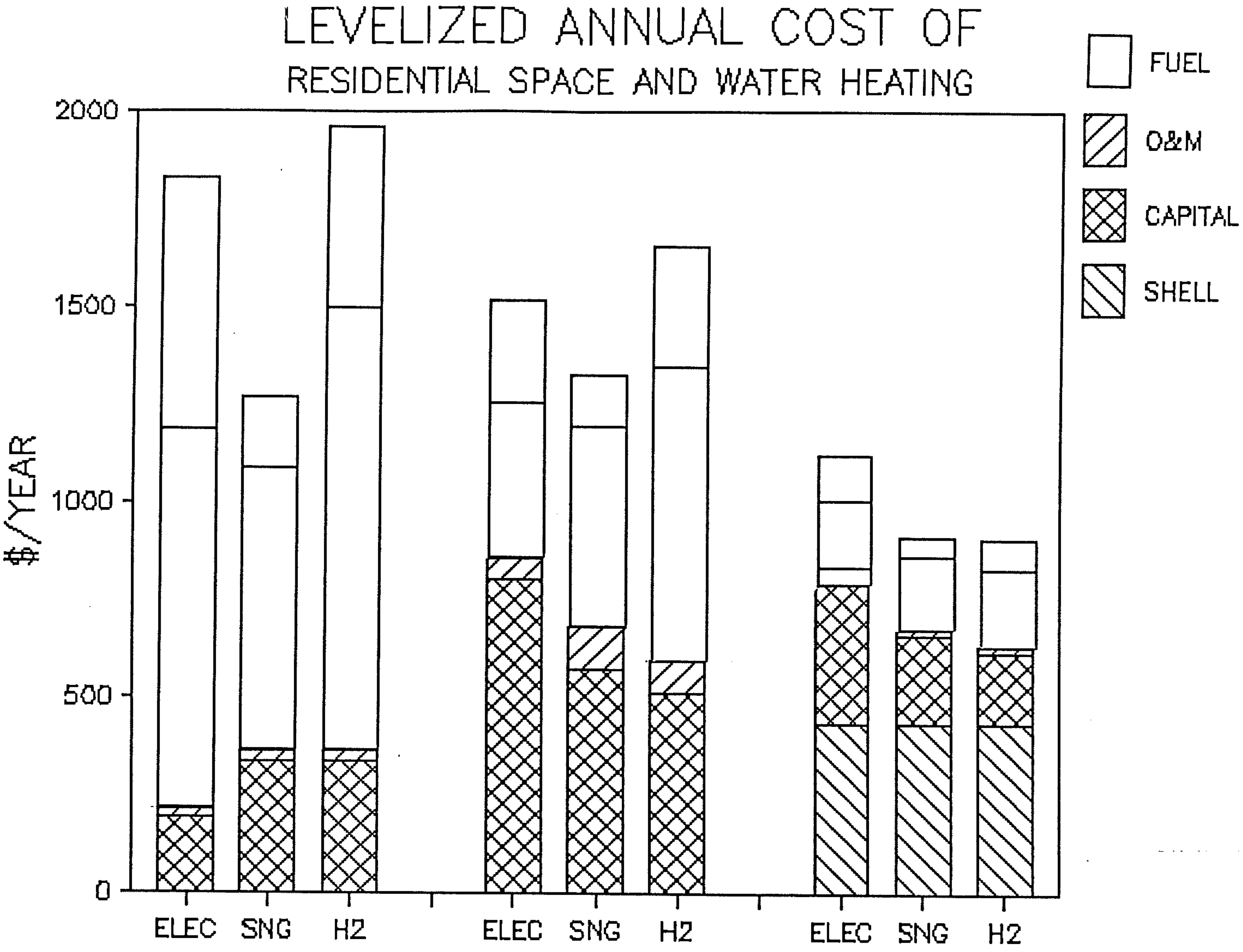


Figure 19.

Levelized costs for residential space and water heating.

The costs are for houses located in New Jersey and heated with electricity, synthetic natural gas from coal, and PV hydrogen for three levels of energy end-use technology. Level I involves low first-cost equipment in conventionally-constructed houses. Level II involves the use of energy-efficient equipment in conventionally-constructed houses. Level III involves the use of energy-efficient equipment in super-insulated houses. The levelized cost has four components: building shell retrofit costs (which apply to the super-insulated house), heating system capital costs, operation and maintenance costs and fuel costs. A range of fuel costs are shown, corresponding to high and low energy prices from Table 19. The energy requirements for space and water heating are presented in Note 158. The assumed capital and O&M costs are presented in Table 20. A ten percent discount rate is assumed for the lifecycle cost calculations (Note 161).

installed. In contrast, when hydrogen is used to heat the superinsulated house it is feasible to meet heating needs with three small space heaters costing just $855. Of course, there is also a large reduction in the capital cost of heating equipment with the SNG system--but the required catalytic heaters are somewhat more costly ($1245 vs. $855) and less efficient (85% vs. 99%) because the SNG units must be vented.

C. PV HYDROGEN FOR INDUSTRY

1. Hydrogen for industrial heat and power

Hydrogen would probably face much tougher competition in the industrial process heat and power generation gaseous fuels markets, which account for about half of natural gas consumption in the US (Table 18), than in residential markets. In these markets the synthetic gaseous fuel of choice may well be gas of intermediate heating value (consisting mainly of carbon monoxide and hydrogen) derived from coal, which can probably be produced at a cost of about $4 per GJ (Table 9), considerably less than the cost of SNG or hydrogen.

As in the residential case, however, the relative production cost may not always be the best indicator of competitive advantage. Industry in the US consumes about 2/5 as much electricity as natural gas, even though electricity is nearly 5 times as costly per GJ. Electricity is preferred and often necessary for many applications, despite its higher price because electricity is a more versatile energy source that is qualitatively quite different from natural gas. Likewise hydrogen differs from natural gas in important ways that may lead industrial users to prefer it in some applications. While it is beyond the scope of the present analysis to explore such opportunities in detail, one example illustrates the possibilities.

Because PV electrolysis can be carried out economically at a small scale, large industrial users in sunny areas might choose to operate their own PV electrolysis units, rather than buy coal gas from the utility. Utility transmission and distribution costs (which could total perhaps \$1.5/GJ to industrial users of synthetic gas) would be saved and a valuable byproduct, oxygen (which is worth perhaps \$1.5-2.2 per GJ of hydrogen[162]), would be produced. (Of course the relative economics of coal gas and PV hydrogen would also depend on the need for storage, the load factor of the process and a host of other factors.)

2. PV hydrogen as a chemical feedstock

Hydrogen is a basic chemical building block, which can be combined with a source of carbon such as coal or biomass to form a myriad of useful compounds. In some chemical processing industries where natural gas (CH_4) is used primarily as a source of hydrogen, hydrogen produced via PV-powered electrolysis may be economically attractive in some applications (see Chapter 7).

D. SUMMARY

Perhaps the most promising potential gaseous fuel market for PV hydrogen is space and water heating in the residential sector, end-uses which in 1980 accounted for about 1/8 of total US energy use (10 EJ). While the PV hydrogen prices projected here for the residential sector would seem to preclude the development of significant residential hydrogen markets, the price of hydrogen is not a good indicator of the market penetration potential. A much better indicator is the lifecycle cost of energy services that would be provided by hydrogen fuel. By focussing on the lifecycle cost it becomes clear that hydrogen offers distinct advantages in terms of energy efficiency and capital equipment requirements that can be readily exploited through emphasis on energy-efficient end-use technologies.

The use of hydrogen for residential heating will probably occur only after hydrogen has become well-established as a transportation fuel. The first PV hydrogen systems in the US will probably be built in the Southwest to serve local transport markets. In much of the Southwest, space heating needs are minor, and there is a crucial need for clean automotive fuels. Thus, it is unlikely that significant residential heating markets will evolve there.

If hydrogen pipelines were built linking PV production facilities to transport markets in the Northeast and Midwest, residential heating markets might develop for hydrogen. If a residential heating market does develop it might be accompanied by a shift of the hydrogen automotive refueling activity from the hydrogen "gas station" to the home, if cost-effective home refuelling systems for hydrogen cars are commercialized.

CHAPTER 7. A POSSIBLE PATH TOWARD LARGE-SCALE USE OF PV HYDROGEN Feb. 15, 1989

Concerns about local, regional and global environmental impacts of fossil fuels, as well as the prospect of declining domestic oil production, are prompting decisionmakers to give increasing attention to less-polluting, domestically-produced fuels (*). Near the turn of the century photovoltaic hydrogen could begin to compete economically in these emerging alternative fuels markets, offering an option that could help meet local and regional air pollution control goals and reduce oil import dependency, without contributing to the global greenhouse warming.

In this chapter, we explore how a PV hydrogen energy system might evolve in the United States. It has often been suggested that the first economically viable markets for PV hydrogen might be niches in present chemical hydrogen markets. We begin with a discussion of these potential near-term "transition" (**) markets for PV hydrogen, which might open during the 1990s as the price of PV modules decreases. Then, a strategy for commercializing PV hydrogen for energy markets is sketched, beginning with transportation. Finally, policies that would facilitate the development of a large-scale PV hydrogen energy economy are suggested.

---

* The most notable actions to date along these lines are the Alternative Motor Fuels Act of 1988 that relaxes the automotive fuel economy standards for cars capable of using alternative fuels and the plans proposed by the California South Coast Air Quality Management District to phase out petroleum in Southern California in favor of alternative fuels, as an air pollution control strategy. To the extent that they would promote a shift to methanol, these actions could exacerbate the greenhouse problem while helping cope with oil import dependency and local air pollution problems. Nevertheless, these actions underscore the gravity of the underlying issues in the minds of decisionmakers.

** An example of a transition market for photovoltaics is the hand-held calculator market, which was the first commercial market for a-Si solar cells.

A. A DEVELOPMENT PATH FOR PV HYDROGEN IN THE US

1. PV Hydrogen for Chemical Markets

Today hydrogen is used primarily in the production of ammonia, methanol and various chemical products and in oil refining (Box 6). Hydrogen can be produced from fossil fuels or via water electrolysis (Box 7). In the United States, at present, steam reforming of natural gas is the least expensive and most widely used method of large-scale hydrogen production (Box 7). Small users generally buy "merchant" hydrogen from suppliers.

Figure 20 shows how the cost of PV hydrogen compares with merchant hydrogen prices and with the cost of hydrogen from steam reforming as a function of hydrogen use per day and DC electricity cost. Within broad limits, the smaller the daily hydrogen demand, the higher the cost of hydrogen to the user. It has been suggested that PV hydrogen might compete first in the higher priced merchant hydrogen markets, and eventually move into larger chemical markets, as the price of PV modules and DC electricity dropped.

Over the next ten to twenty years, it appears there could be significant opportunities for commercialization of PV hydrogen for chemical use (Box 8). For small-volume users of chemical hydrogen located in sunny areas, PV-powered electrolysis could begin to compete with merchant hydrogen or small steam reforming plants sometime in the early to mid-1990s. To supply the entire US merchant hydrogen market would require perhaps 400 MW of PV capacity.

For intermediate-sized chemical users located in sunny regions, PV hydrogen is likely to become competitive in the late 1990s. This market totals perhaps 3000 MW of PV capacity. Large chemical markets would probably open around the same time as energy markets.

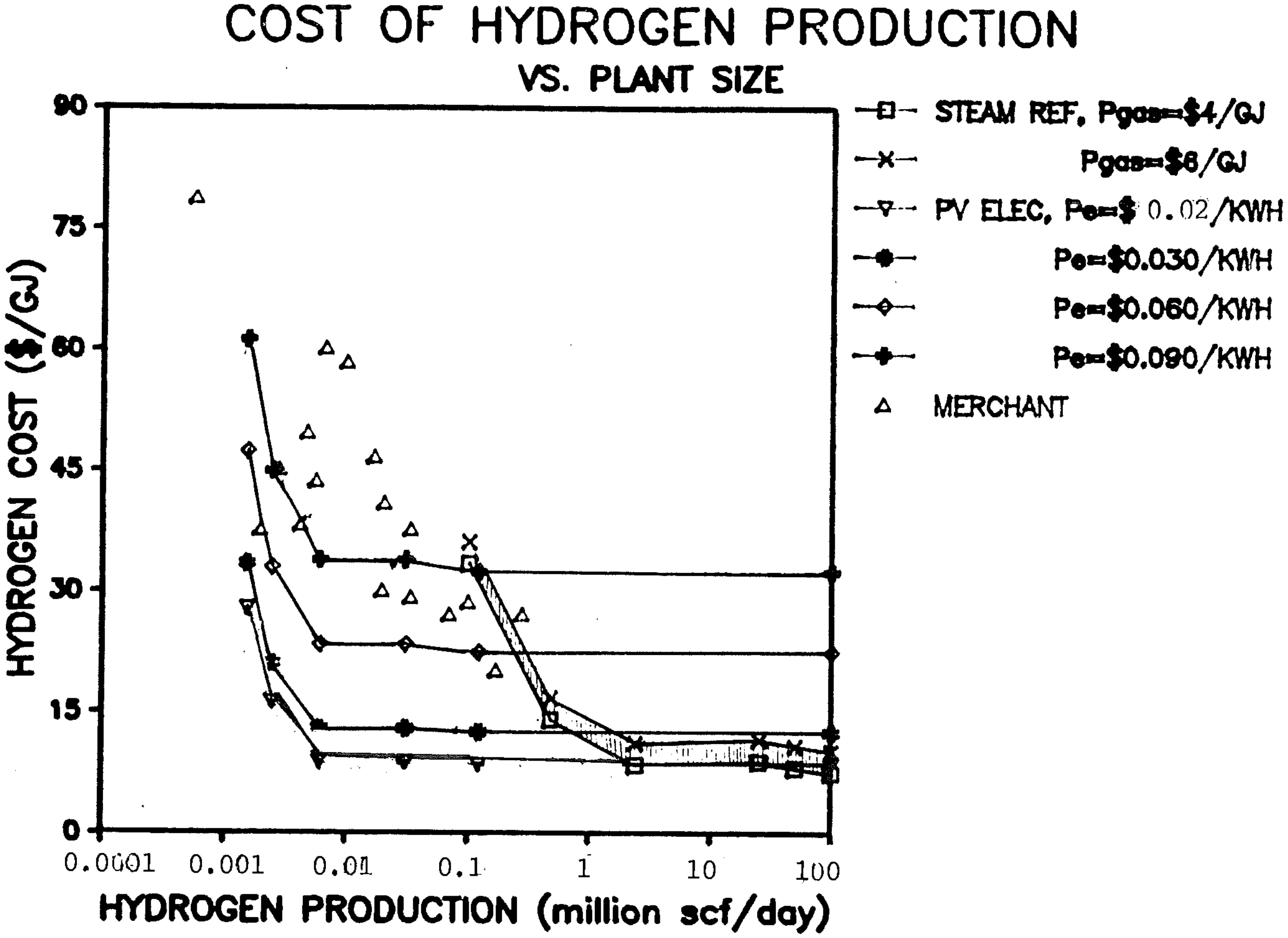


Figure 20.

Costs of hydrogen production using various methods as a function of daily hydrogen production and merchant hydrogen prices versus the volume purchased.

Costs for the steam reforming of natural gas are shown for natural gas prices of $4-6/GJ. Costs for PV electrolytic hydrogen are shown for Southwest US conditions and DC electricity costs of $0.02-0.09/kWh. See Note 164.

The merchant hydrogen prices shown are based on an EPRI survey (see E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Service Territories", EPRI Report, EM-3561, May 1984).

Box 6. PRESENT USES OF HYDROGEN

Today hydrogen is used primarily as a chemical feedstock for ammonia synthesis, oil refining, methanol production, and smaller industrial uses including metals reduction, hydrogenation of fats and oils, electronics, glass production, pharmaceuticals and electric generator cooling. In some areas of the world hydrogen-rich synthetic gases (from coal, wastes or biomass) are burned as fuel.

Hydrogen use worldwide is about 1.4 Exajoules per year, of which 62% is for industrial nonenergy purposes (e.g. the production of ammonia, methanol, and other industrial products), 34% is for indirect energy use (petroleum refining), and 4% is direct energy use (as a component of synthetic fuel gas).[163] Figure B.6.1 shows hydrogen production in various countries as a percentage of total energy use.

The US accounts for about half of global hydrogen consumption, some 0.65 EJ per year--equivalent to almost 1% of total US energy use. Table B.6.1 lists the main uses of hydrogen in the US, the annual demand, the source of hydrogen, and the approximate onsite production cost (Box 7)[164] or price (for "merchant hydrogen" purchased from a supplier).[165]

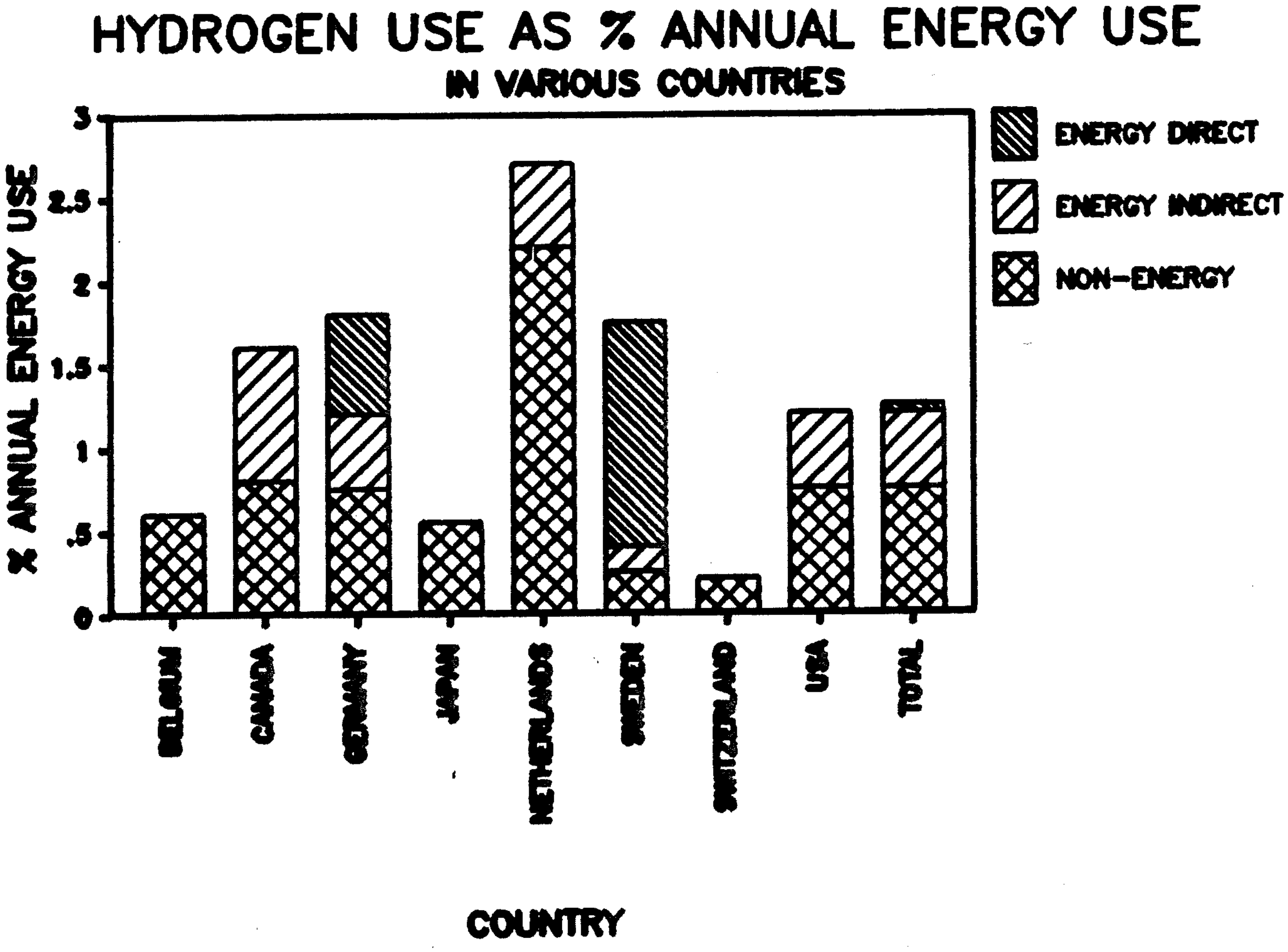


Figure B.6.1.

Annual hydrogen production in various countries as a percentage of total energy use.

Source: W. Balthasar, "Hydrogen Production and Technology: Today, Tomorrow and Beyond", International Journal of Hydrogen Energy, v. 9, p.649-668, 1984.

Table B.6.1. Hydrogen Use in the United States

Use	Annual Hydrogen Demand (EJ/yr)(b)		Hydrogen Production Method (c)	Hydrogen (a) Cost ($/GJ)
LARGE USERS (d)				
Ammonia Synthesis	0.393		Steam Reforming	7.5-10.2
Oil Refining	0.167		75% Recovery (e) from off gas streams 25% Steam Reforming	
Methanol Synthesis	0.0666		Steam Reforming	
SMALL USERS (f)	Total	Merchant		
Misc. Chemical	0.0177	0.0011	Small Reformers	8.5-36
Metals Reduction	0.00360	0.00043	or Merchant	18-100(g)
Hydrogenation of fats and oils	0.00292	0.00026	"	
Electronics	0.00076	0.00076	"	
Float Glass	0.00032	0.00025	"	
Pharmaceutical	0.00022	0.00022	"	
Other Merchant	0.00029	0.00029	"	
Total Small Users	0.0258	0.00327		
TOTAL ALL USERS	0.653	0.00327		

[a] Hydrogen production costs are estimated in Note 164.

[b] The hydrogen energy demand is given on a higher heating value basis.

[c] W. Balthasar, "Hydrogen Production and Technology: Today, Tomorrow and Beyond", International Journal of Hydrogen Energy, v. 9, p.649-668, 1984.

[d] For 1975 hydrogen use in the US. E. Fein and T. Munson, "An Assessment of Non-Fossil Hydrogen", Gas Research Institute Report, GRI 79/0108, December 1980.

[e] C.R. Baker, "Production of Hydrogen for the Commercial Market: Current and Future Trends", American Chemical Society Report, 0-8412-0522-1/80/47-116-047-229, 1980.

[f] For 1977 hydrogen use. R.W Foster, R.R. Tison, W.J.D. Escher, and J.A.Hanson, "Solar/Hydrogen Systems Assessment", DOE/JPL-955492, 1980.

[g] For merchant hydrogen the price rather than the production cost is given. E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Service Territories", EPRI Report, EM-3561, May 1984.

Box 7. HYDROGEN PRODUCTION METHODS AND COSTS (*)

Steam reforming of natural gas: The most widely used method of hydrogen production is steam reforming. A light hydrocarbon such as natural gas or naphtha reacts with steam in the presence of a nickel catalyst to produce hydrogen and carbon monoxide. For natural gas prices in the range $4-6/GJ the production cost of hydrogen by this method would be $7.5-10.2/GJ. Almost all ammonia and methanol plants produce hydrogen by steam reforming.

Partial oxidation of residual oil: In this process, heavy oil is gasified with steam and oxygen. The synthesis gas is processed through several steps to give hydrogen and byproduct sulfur. For a residual oil price of $4-6/GJ ($25-37/bbl) the cost of hydrogen would be about $11.2-13.6/GJ.

Recovery of hydrogen in oil refining: About 75% of the hydrogen required for oil refining is recovered from the end products of other chemical reactions. (The cost of hydrogen recovery depends on the particular plant design, but would often be less than alternate methods of hydrogen production.) The remaining 25% can be produced by steam reforming of natural gas or naphtha or by partial oxidation of oil.[166]

Coal gasification: Rapid partial oxidation of pulverized coal can be used to form hydrogen. For a coal price of $1.78/GJ (which is the average price projected for steam coal in the year 2000)[167] the cost of hydrogen would be $7.9-13.9/GJ. Biomass gasification is another potential source of hydrogen.[168]

Water electrolysis: At present, only about 1% of the world's hydrogen is produced electrolytically.[169] Electrolysis is used in several large scale plants where inexpensive hydroelectricity is available.[170] As shown in Chapter 3, if DC electricity is available at $0.020-0.035/kWh, the cost of large-scale PV powered electrolytic hydrogen production (exclusive of storage, compression or transmission) in the Southwest would be about $9.1-14.0/GJ. For PV electrolysis there is little economy of scale above 5-10 MW (or 0.3-0.6 million scf/day).

---

* Hydrogen production costs are estimated in Note 164.

Box 8. PV HYDROGEN FOR CHEMICAL MARKETS

When could PV hydrogen begin to compete in present chemical markets? This can be inferred from Figure 20, where hydrogen production costs with PV electrolysis (in the Southwest) and steam reforming of natural gas are compared to merchant hydrogen prices for a range of hydrogen production capacities from 0.001 to 100 million standard cubic feet per day (scf/day) (*). The cost of PV powered electrolysis is plotted versus production capacity for several DC electricity costs ranging from \$0.012/kwh to \$0.09/kwh, corresponding to various PV module efficiencies and costs. The cost of steam reforming is plotted for natural gas prices of \$4-6/GJ. Both electrolysis and steam reforming exhibit economies of scale, although these are less severe for electrolysis, because of its modular nature. The prices plotted for merchant hydrogen are based on a recent EPRI survey of small-volume users of hydrogen.[171] Although merchant prices show a wide variation, in general the smaller the volume of hydrogen use, the higher the merchant price paid.

a. The merchant hydrogen market

Because merchant hydrogen customers pay premium prices (\$18-100/GJ) for hydrogen delivered by truck, it has been suggested that electrolytic hydrogen could compete in the merchant hydrogen market in the US.[172] Merchant hydrogen users concerned about reliability of supply and hydrogen purity might have an added incentive to buy their own electrolyzers.[173]

For merchant hydrogen users with demands less than about 0.03 million scf/day (10 GJ/day), PV-powered electrolysis would be competitive for electricity costs of less than about \$0.09/kWhDC. PV electricity could be produced in the Southwestern US for \$0.09/kWhDC using 12% efficient modules with balance of systems (BOS) costs of \$50/m^2 and PV module costs of \$1.4 per peak Watt (Figure 9). This system is within the range of projections for the early to mid-1990s (Table 3). For those merchant hydrogen customers located in sunny areas now paying \$30-80/GJ, PV hydrogen could begin to compete within a very few years (**).

Larger consumers of merchant hydrogen with demands of 0.03-0.3 million scf/day (10-100 GJ/day) pay \$15-30/GJ. PV-powered electrolysis could compete in these markets when electricity costs less than about \$0.06/kWhDC. A 10% efficient PV system with a BOS cost of \$50/m^2 and module cost of \$0.8 per peak

---

* One million scf/day = 339 GJ/day = 56 barrels per day of oil-equivalent.

** Because PV hydrogen technology is new, it may take an usually innovative small company to try this method as a replacement for merchant hydrogen. Large chemical, aerospace, or energy companies, automobile manufacturers or utilities with long-term interests in hydrogen research and development may be the first to exploit chemical market opportunities, as a way of helping finance PV hydrogen demonstration projects. This approach is being taken in Germany, where BMW, GmbH, and various utilities are now building an experimental 600 kW PV hydrogen system, which will supply fuel for BMW's research on hydrogen-powered cars.[174]

Watt could produce electricity at this cost. By the mid-1990s such systems may well be available.

The total US merchant hydrogen market is about 3 million GJ/year. While this is tiny compared to energy markets, about 400 MW of PV capacity would be required to supply all US merchant hydrogen via PV-powered electrolysis. For comparison, in 1987 world production of PV systems was about 30 MW per year.

b. Intermediate-sized chemical markets

Medium-sized chemical users who make their own hydrogen using small natural gas reformers typically pay $12-20/GJ. Figure 21 shows that to compete with small natural gas reformers for this market, with demand levels in the range 0.3 to 1.0 million scf/day (100 to 339 GJ/day), PV electricity must cost less than about $0.03-05/kWhDC. This electricity cost corresponds to 12% efficient modules with BOS costs of $33/m^2 and module costs of $0.3-0.6/Wp. These costs and efficiencies are projected for amorphous silicon solar cells sometime in the late 1990s.

Electrolysis would produce not only hydrogen but also high purity oxygen. Chemical users might be able to sell this oxygen as a byproduct, earning up to $1.5-2.2 per Gigajoule of hydrogen produced. If oxygen could be sold, less stringent PV cost and efficiency goals would be needed to make PV hydrogen competitive with steam reforming.

The hydrogen market for small-volume users is estimated to be some 26 million GJ/year, almost 10 times as large as the merchant hydrogen market. Perhaps 3000 MW of PV capacity would be required to make this much hydrogen every year. Again, this could be a potentially important market for PV hydrogen systems in the mid- to late 1990s.

c. The large chemical markets

Large users (ammonia and methanol plants and oil refineries) produce their own hydrogen (primarily via steam reforming of natural gas) at a cost of $7.5-10.2/GJ.[175]

Thus, in order to compete with hydrogen from large-scale reforming, solar hydrogen would have to cost about $7.5-10.2/GJ. PV hydrogen produced in the Southwestern US could cost $9.1-14.0/GJ for 12-18% efficient PV modules costing $0.20-0.40/Wp. For natural gas prices of $4-6/GJ, steam reforming would probably be a less expensive method of hydrogen production. However, if an oxygen byproduct credit of $1.5/GJ were received, the cost of PV hydrogen would be $7.6-12.5/GJ, making it approximately competitive with reforming. Still, PV hydrogen seems unlikely to compete with steam reforming for large chemical plants until after 2000.

2. PV Hydrogen as a Transportation Fuel

While chemical markets could play a role in the early development of PV hydrogen, the major environmental benefits offered by PV hydrogen would begin to be realized only when PV hydrogen begins to penetrate transportation energy markets. When could the transition to a hydrogen based transportation system begin?

a. Getting started: a hydrogen-based transport system for Phoenix?

A promising strategy for initiating any new technological system would be to identify an initial application where costs would be favorable, where the need would be pressing, and where the system could be introduced in an evolutionary fashion, one small step at a time. To illustrate how this approach might be used to initiate a hydrogen economy a scenario will now be presented showing how a hypothetical PV hydrogen-based transport system might be introduced in Phoenix, Arixona.

By introducing PV hydrogen technology in Phoenix it would be possible to satisfy the cost criterion for this strategy--first, because Phoenix is one of the sunniest areas in the United States (Table 5), making it a good candidate for PV hydrogen production, and second, because by using the hydrogen produced in Phoenix itself, the costs and complications of long-distance hydrogen transport could be deferred.

By locating the initial system in Phoenix the need criterion would also be satisfied, as an alternative transport fuel like hydrogen (Box 9) may be needed to cope with the problem of urban air pollution. In 1987, Phoenix violated federal air quality standards for ozone, carbon monoxide and particulates on 33 days. Much of this pollution was due to cars; passenger vehicles were responsible for a majority of the ozone and particulates and 80% of the carbon

Box 9. HYDROGEN FUEL AND AUTOMOTIVE EMISSIONS

For each car converted from gasoline to hydrogen, CO, particulate and VOCs emissions would be eliminated, and NOx emissions would be reduced. For hydrogen-powered cars with fuel economy typical of today's vehicles (30 mpg gasoline), NOx emissions would be about 0.24 grams/mile (Table B.9.1), which would satisfy the proposed NOx emissions standards of 0.4 grams/mile (Table B.9.2). For more efficient hydrogen-powered cars, corresponding to fuel economy levels of 50 mpg (90 mpg) gasoline, NOx emissions would be reduced to about 1/2 (1/4) the proposed standards (Table B.9.1).

Table B.9.1 Estimated Emissions from Hydrogen Cars (in grams/mile)

	FUEL ECONOMY [a]		
	30 mpg	50 mpg	90 mpg
Carbon Monoxide	0	0	0
Hydrocarbons (VOCs)	0	0	0
Nitrogen Oxides			
w/D-I engine [b]	0.24	0.18	0.10
w/fuel cell [c]	0	0	0
Particulates	0	0	0

[a] Asuming for 30 mpg, 50 mpg, and 90 mpg cars that the fuel energy consumed is 4.14 MJ/mile, 2.45 MJ/mile, and 1.35 MJ/mile, respectively (Note 133).

[b] Assuming a direct-injection engine [at 40% efficiency (LHV basis)] and emissions of 0.3 grams of NO per MJ of engine output power or 0.075 grams per MJ of hydrogen fuel burned. There is experimental evidence that this emissions level can be achieved by operating at an equivalence ratio of 0.55 (P.C.T de Boer, W.J. McLean, and H.S. Homan, "Performance and Emissions of Hydrogen Fuelled Internal Combustion Engines," International Journal of Hydrogen Energy, vol. 1, p. 153, 1976).

[c] For a hydrogen-powered car using a fuel cell coupled to an electric motor, there would be no significant NOx production.

Table B.9.2 Emissions from Gasoline-Powered Cars (in grams/mile)

	AVERAGE EMISSIONS		EMISSIONS STANDARDS	
	Certified (1987)	Actual (1986)	1988	Proposed
Automobiles (below 6000 lb.)				
Carbon Monoxide	1.91	10.0	3.4	3.4
Hydrocarbons (VOCs)	0.20	0.8	0.41	0.25
Nitrogen Oxides	0.37	1.2	1.0	0.4
Particulates	-	-	0.2	0.08

Source: Michael P. Walsh, "Pollution on Wheels", Report to the American Lung Association, February 11, 1988.

monoxide.[176]

Unless automobile emissions are controlled, air pollution in Phoenix could become much worse. The population of the greater Phoenix area is projected to grow from 2 million people in 1985 to 3 million by the year 2000, and 5 million by 2015. During this time, automobile use is projected to increase by more than a factor of three from 38 million vehicle-miles per day in 1985 to 119 vehicle-miles per day in 2015.[177]

By focussing initially on automotive fleet vehicles in Phoenix, the evolutionary criterion for this technological strategy could also be satisfied. The initial demand for hydrogen could be satisfied using low-cost off-peak power from conventional power plants, well before PV hydrogen is commercially ready. This way considerable field experience could be gained with hydrogen-powered vehicles before PV hydrogen is introduced on much larger scales.

Table 21 shows how three alternative courses of action would effect automotive emissions in Phoenix. In Scenario I, emissions levels per car remain fixed at the present average levels, and automotive pollution quickly becomes intolerable. By 2000, emissions from cars increase by about 50%, and by 2015, they triple, implying perhaps a doubling in the rate of ozone production by 2015. This scenario highlights the urgency of new measures aimed at reducing automotive emissions.

Scenario II shows how emissions would evolve if recently proposed automotive emissions standards were implemented (Box 9 and Chapter 1). The proposed standards could be achieved by a combination of a rigorous maintenance

Table 21. Alternative Scenarios for Automotive Emissions in Phoenix

	1985	2000	2015
Demograpic Trends for Phoenix			
Population (millions)	2	3	5
Number of automobiles (millions)	1	1.5	2.5
Automobile-miles per day (millions) (millions)	38	57	119
Total Automotive Emissions (tonnes/day)			
SCENARIO I: No Change in Emissions per Car[a]			
CO	380	570	1190
Hydrocarbons	30.4	45.6	95.2
NOx	45.6	68.4	142.8
SCENARIO II: Proposed Emissions Standards[b]			
CO	380	168	404
Hydrocarbons	30.4	14.3	29.8
NOx	45.6	22.8	47.6
Particulates	-	4.6	9.5
SCENARIO III: Proposed Emissions Standards + Gradual Shift to Hydrogen[c]			
CO	380	147	202
Hydrocarbons	30.4	12.8	14.9
NOx	45.6	21.6	34.5
Particulates	-	4.2	4.8

---

[a] Based on 1986 in-use emissions (Table B.9.2).

[b] Assuming the adoption and enforcement of the proposed standards (Table B.9.2) for the years 2000 and 2015.

[c] Assuming that the proposed standards are adopted and enforced for gasoline cars, that 50% of automotive fleets (4% of all cars but 10.5% of all vehicle miles) are operating on hydrogen by 2000, and that 50% of all cars are operating on hydrogen by 2015. It is also assumed that the fuel use in hydrogen cars averages 4.14 MJ/km (30 mpg) in 2000 and 2.45 MJ/km (50 mpg) in 2015.

and inspection program and improved fuel economy (*). In this scenario automotive emissions fall to about half the present level (**) by the year 2000. But even these measures would provide only temporary relief. By 2015 total automotive emissions return to the troublesome 1988 levels, because of the growing number of cars. Scenario II highlights the importance of switching in the longer term from gasoline to low-polluting fuels such as hydrogen.

In Scenario III, tightened emission standards are combined with a gradual shift to hydrogen cars, to the extent that by the year 2000 half of automotive fleets (60,000 cars, accounting for 4% of all automobiles but over 10% of all automobile miles) are operating on hydrogen, while 50% of all cars in Phoenix are operating on hydrogen by 2015. In this scenario automotive emissions fall to about half the present levels by 2000 and are still well below present levels by the year 2015.

Automotive fleets are a logical target for introducing the hydrogen economy because these cars could be centrally fueled, initially with only a few hydrogen filling stations, thereby avoiding the need for large initial infrastructure costs.

When could conversion to hydrogen fuel begin? In the early to mid 1990s, PV hydrogen production (excluding storage and filling station costs) is

---

* If individual states were to adopt automotive efficiency standards as a way of coping with air pollution, automobile manufacturers might choose to produce more efficient cars routinely, to avoid the complexity of meeting diverse state requirements.

** Present emissions levels from all cars in the Phoenix area are estimated based on average 1986 in-use emissions/mile and the total number of automobile-miles travelled per day in 1985 (Table 21). Emissions levels for gasoline-powered vehicles in 2000 and 2015 are based on assumed emissions standards (Table B.9.2) and projected automobile-miles travelled (Table 21). Emissions levels for hydrogen cars are based on the emissions levels indicated in Table B.9.1.

projected to cost \$18-32/GJ, (equivalent to \$2.1-3.9/gallon of gasoline), which may be too costly to justify a large-scale fleet conversion program. PV hydrogen would not become cost competitive with other alternative fuels such as methanol, until about the year 2000 (Table 7). A less costly source of hydrogen is needed to launch a hydrogen car program before the turn of the century.

As long as the initial fleet of vehicles is not too large, there would be enough low-cost, off-peak power available from conventional coal-fired power plants in Phoenix to serve as an interim source of power for electrolytic hydrogen production. As much as several hundred megawatts of power could be available at \$0.02-0.03/kWh between the hours of 10 pm and 7 am.[178] With power at this cost electrolytic hydrogen could be produced and delivered to the consumer for \$12-16/GJ (*) (equivalent to \$1.5-2/gallon gasoline),[179] which is approximately the cost targeted for PV hydrogen delivered to consumers in a full-blown PV-based hydrogen economy for automobiles (Table 15).

If 480 MW of off-peak power were available, it would be possible to produce enough fuel for 30,000 fleet vehicles, each travelling 100 miles per day [thus accounting for about 5% of automobile miles in Phoenix in 2000 (**)] at an average gasoline-equivalent fuel economy of 30 mpg. At this fuel economy a typical metal hydride car would have a range of 115 miles,[181] so that the fleet cars could be operated during the day and evening and refueled at night.

---

* This cost estimate neglects any credit for byproduct oxygen, which could reduce the cost of the hydrogen by \$1.5-2/GJ.

** In the US at large, about 8% of passenger cars are fleet vehicles.[180] Assuming that the same ratio holds in Phoenix, 30,000 fleet vehicles represents 2% of the number of automobiles projected for Phoenix in 2000. But driven 100 miles a day they would account for 5.3% of the projected number of automobile miles driven per day.

The total capital cost for this initial system would be about $132 million for the for the electrolyzer, hydrogen compressor, gaseous hydrogen storage, and associated refuelling station.[182] This amounts to about $1260 per fleet vehicle served by this system.[183] The cost of the metal hydride storage system would also probably cost about $370 per fleet vehicle.[184]

To put the required investment into perspective, a recent study suggested building an extensive public transportation system for Phoenix at a cost of over $7 billion dollars, as a strategy for coping with the air pollution and congestion challenges associated with the expected population explosion.[185] While the new system would doubtless ease congestion and improve the quality of life for its users, it would reduce the number of automobile-miles travelled by only about 2 to 3 percent and would thus have only a modest impact in improving air quality.

As PV technology develops and PV hydrogen systems become more competitive, PV sources could augment off-peak conventional power as a source for electrolysis. By the year 2000 PV hydrogen could cost about $13-18/GJ[186] (*), about the same as the cost of hydrogen from conventional off-peak power, so that in this time frame perhaps another 30,000 fleet vehicles could be fueled with hydrogen, this time from PV sources. The required installed PV generating capacity would be 655 MW, requiring a land area 2.5 square miles for a 10% efficient PV system or 1.7 square miles for a 15% efficient PV system.

---

* This may be an overestimate, in part because it is based on the assumption that entirely an entirely new hydrogen system would be constructed when PV technology comes of age. Instead, in this initial phase it would be possible to use the same electrolyzer at night with off-peak power and during the day with PV power, cutting the capital costs and improving the utilization factor of the electrolyzer. Also, if there were a market for the byproduct oxygen, the cost of hydrogen could be reduced by $1.5-2/GJ.

In the time frame beyond the year 2000 the use of hydrogen could be extended to the car population at large, provided that these more widely-used vehicles would have a sufficiently high fuel economy fuel that their range is satisfactory to the general user (*) and would be equipped with engines having dual- or multi-fuel capability (e.g. stratified-charge engines). If by 2015 50% of the Phoenix automotive population were fueled with PV hydrogen, the required installed PV generating capacity would be 7.8 GW, and the corresponding land area 30 (20) square miles for 10% (15%) efficient PV systems.

b. A nationwide hydrogen transport system

If initial hydrogen fuelled cars were successful, fleet vehicles in other areas might be converted to hydrogen. In 1985, there were 7.6 million cars in the US in fleets of 10 or more vehicles.[187] These automobiles averaged about 30,000 miles per year. Assuming an average fuel economy of 50 miles per gallon of gasoline equivalent, the energy consumed by a fleet this size would be about 570 million GJ/year. If 10% of US fleet vehicles converted to PV hydrogen, this would entail 57 million GJ/year of hydrogen production (or 7,000 MW of installed PV capacity). At this scale, it would make sense to connect large centralized PV hydrogen facilities in the Southwest to other parts of the country via pipeline.[188] With some changes, existing natural gas pipelines

---

* Here 50 mpg is assumed, so that the range is 236 km (147 miles). For a car driven 10,000 miles per year (the US average), this implies refueling every 5 days, on average. For Phoenix, where the average amount of driving is expected to be over 17,000 miles per car per year in 2015 (Table 21), the average time between refuelings would have to be every 3 days. At 90 mpg, which is both technically and economically feasible (Chapter 5), cars in Phoenix would have to refuel every 5 days. Clearly, higher fuel economy levels would be preferable.

could be used to bring hydrogen to distant markets, or new hydrogen pipelines could be built along existing natural gas rights of way. Wider use by the general public would follow the establishment of the technology by fleet vehicles.

3. Hydrogen for Residential Space and Water Heating

After large-scale development of transport-based PV hydrogen systems is underway, consideration can be given use of hydrogen as a fuel for home space and water heating (Chapter 6). In much of the Southwest, there is little demand for space heating, and water heating could be provided at a lower cost by PV electricity than by hydrogen. Thus, initial use of PV hydrogen in home heating markets would probably begin in colder regions, using hydrogen transported via pipeline from the Southwest. Significant use of hydrogen in the home heating market might follow the establishment of pipelines for transport fuel.

For use in older housing stock, PV hydrogen could be mixed in as a natural gas extender (in mixtures of up to 10-20%, no modification of natural gas appliances or distribution systems would be needed). Conversion to pure hydrogen use in existing homes would involve more extensive retrofits of home heating systems, appliances and local distribution systems (*). However, the best opportunity for introducing hydrogen may be for heating purposes in new super-insulated homes (Chapter 6).

The successful development of inexpensive home refuelling systems for hydrogen-powered cars could enhance the attractiveness of the use of hydrogen for space and water heating purposes. The large hydrogen load required for the

---

* An analogous retrofit was carried out in the 1930s and 40s when many US cities switched from town gas (a CO-hydrogen mixture) to natural gas.

automobile would help justify the expense of building a hydrogen distribution network for residences. And instead of visiting a gas station to refuel, the homeowner could simply attach his car to a small compressor in his garage (*) and fill up with hydrogen piped to his home. With this design the homeowner could save time and probably pay no more for heating his house than with alternative systems for superinsulated houses in the period beyond the turn of the century (Chapter 6).

4. Parallels with Development of PV Electricity

As the price of PV modules comes down, a number of markets will open for PV hydrogen, as well as for PV electricity. Table 22 lists some potential markets for PV electricity and PV hydrogen as a function of the PV module price needed to compete with existing sources of energy.

Not surprisingly, most uses of PV systems in the next decade or two are likely to be for electricity. The first chemical market for PV hydrogen (as a replacement for merchant hydrogen) is likely to open about the same time as the much larger utility peaking market. Rooftop PV systems for residential daytime electricity should become competitive with grid power about the same time as PV hydrogen systems for intermediate-sized chemical users. When PV modules achieve efficiencies of 12-18% and costs of $0.2-0.4/Wp, however, vast energy markets for baseload electricity and hydrogen fuel could open. At this stage, the potential markets for PV hydrogen would be comparable in size to PV electricity markets.

---

* Home refuelling of compressed natural gas-powered cars has been proposed, and small compressors are marketted are commercially available. However, the cost of these systems is still too high ($4000) for this system to be commercially viable.[189]

Table 22. Potential Markets for Photovoltaic Electricity[a] and Hydrogen

Electricity Market	Breakeven Solar Module Price ($ per peak Watt)	Potential Market Size Total (MWp)	Hydrogen Market
Corrosion protection	20-100		
Buoys	60		
Consumer products: calculators, etc.	10	100	
Remote water pumping	4-7	2,000	
Diesel generator replacement, remote power	5	10,000	
US utility electric peaking (Total US peaking)	2-3	50,000	
	1-2	400	Merchant hydrogen
Daytime power for grid connected residences in US	0.7-1.5	100,000	
	0.5-1.0	3,000	Intermediate chemical
	0.20-0.40	4,000	Heating in 2 million super-insulated houses
		7,000	10% of US automotive fleets
		60,000	Large chemical
		600,000	All US home heating
US baseload electric power (with storage)		600,000	
		1,100,000	All US automotive

---

[a] See Table 4 for assumptions about PV electric markets.

The large-scale development of PV electricity would greatly benefit the development of PV hydrogen, as much of the engineering design of PV systems for central station electric generation will be directly applicable to large PV hydrogen systems.

B. POLICY ISSUES

In this book it has been argued that a PV hydrogen-based energy economy would be able to provide energy services at costs comparable to those for alternative fuels in the time frame beyond the turn of the century. While PV hydrogen technology could bring to energy the economies of factory-based mass production, an attractive feature that is rare in energy supply technology today, PV hydrogen would probably not be a decisive winner in the competition with alternative fluid fuels from coal or biomass in this time frame, when alternative technologies are compared in narrow economic terms. However, PV hydrogen would probably be less expensive than electrolytic hydrogen from nuclear power and other electricity sources (Table 8).

The balance is tipped sharply in favor of PV hydrogen over synfuels from coal, however, only when externalities are taken into account--local, regional, and global pollution, as well the security risks of oil import dependency. Accordingly, new public policies are needed to help bring about a transition to a PV hydrogen economy.

While the preparation of a policy blueprint for promoting a PV hydrogen economy is beyond the scope of the present analysis, the following are some of the policy initiatives that would appear to be desirable, if society should decide that the benefits offered by the PV hydrogen economy are worth the effort required to bring it about. The purpose here is to be suggestive rather than comprehensive. However, the order in which the public policy issues are

The large-scale development of PV electricity would greatly benefit the development of PV hydrogen, as much of the engineering design of PV systems for central station electric generation will be directly applicable to large PV hydrogen systems.

B. POLICY ISSUES

In this book it has been argued that a PV hydrogen-based energy economy would be able to provide energy services at costs comparable to those for alternative fuels in the time frame beyond the turn of the century. While PV hydrogen technology could bring to energy the economies of factory-based mass production, an attractive feature that is rare in energy supply technology today, PV hydrogen would probably not be a decisive winner in the competition with alternative fluid fuels from coal or biomass in this time frame, when alternative technologies are compared in narrow economic terms. However, PV hydrogen would be much less expensive than electrolytic hydrogen from nuclear power and other electricity sources (Table 8).

The balance is tipped sharply in favor of PV hydrogen over synfuels from coal, however, only when externalities are taken into account--local, regional, and global pollution, as well the security risks of oil import dependency. Accordingly, new public policies are needed to help bring about a transition to a PV hydrogen economy.

While the preparation of a policy blueprint for promoting a PV hydrogen economy is beyond the scope of the present analysis, the following are some of the policy initiatives that would appear to be desirable, if society should decide that the benefits offered by the PV hydrogen economy are worth the effort required to bring it about. The purpose here is to be suggestive rather than comprehensive. However, the order in which the public policy issues are discussed reflects the authors' views as to appropriate priorities.

1. Policies Aimed at Coping with Externalities

Since society's concerns about the risks of fossil fuel dependency is at the root of society's interest in a PV hydrogen economy, policies directed at reducing these risks head the list of recommended policies.

a. Reducing local air pollution.

In many urban areas of the US ozone pollution resulting from emissions from automobiles and gasoline pumps exceeds federally mandated levels. There is also widespread concern about the acid deposition arising from emissions from power plants and automobiles. Tough policies aimed at limiting these emissions could be framed in ways that would promote the development of clean-burning alternative fuels like hydrogen.

b. Reducing oil import dependency

As domestic oil production in the US is expected to decline for the indefine future, concern about import dependency suggests a tariff on oil imports[190] or an oil products tax[191] as a means of internalizing the societal costs of this dependency. Such a tax on oil would help make alternative fluid fuels more competitive.

c. Reducing greenhouse emissions.

An oil tax by itself would help promote fossil synfuels as well as hydrogen. Thus an oil tax should be complemented by a carbon tax that would help limit CO_2 emissions, while encouraging both energy efficiency and fuel switching to renewable sources such as PV hydrogen.

If society should decide to make hydrogen costing \$15/GJ at the fuel pump competitive with methanol costing $11/GJ, a tax of $4/GJ would be needed (*). Adding $4/GJ to the price of methanol would be equivalent to adding about $2.4/GJ to the cost of coal feedstock--more than doubling the price of coal for synfuel production. But the impact on the consumer would be much more modest--equivalent to a 50 cents per gallon tax on gasoline.

2. Promoting Improved Energy End-Use Efficiency

Hydrogen energy systems tend to be both more practical and more economic when the end-use technologies involved are energy-efficient (Chapters 5 and 6). Thus the broad range of policies needed to implement energy-efficient end-use technologies[192] would be valuable in promoting the development of the hydrogen economy, as well as helping to cope with environmental problems associated with overdependence on fossil fuels before a switch to PV hydrogen can be made.

Since automotive fuel would probably be the major initial energy market for PV hydrogen, and since the low energy density of hydrogen implies the need for high fuel economy in order to provide cars that can run for several days on a single refueling, automotive fuel economy improvement is at the top of the list of conservation measures needed to promote a hydrogen economy.

While a oil tax would help promote fuel economy improvements, it is not likely that an oil tax alone would be adequate to generate the high levels of fuel economy needed for the successful development of hydrogen as an automotive fuel, as the the cost per mile of owning and operating a car tends to be relatively flat as a function of fuel economy, for fuel economies in the range 30 to 90 mpg of gasoline-equivalent, over a wide range of fuel prices (Figure

---

* Producing methanol from coal would release some 37 kg of Carbon per GJ of methanol. The carbon tax required to equalize the cost of methanol and PV hydrogen would be about 11 cents per kilogram of carbon.

21). Thus, with gasoline-fueling, consumers will be largely indifferent to the the level of automotive fuel economy, even with a substantial gasoline tax.

In order to facilitate the transition to the use of PV hydrogen in cars, as well as help reduce the risks of oil import dependency in the period before PV hydrogen is cheap enough to use in automobiles, it would be desirable to complement an oil tax with increases in the federally mandated fuel economy standards or the levy of "gas guzzler" taxes or similar measures.[193]

3. Policies Targeting PV Hydrogen Development

While policies aimed at coping with externalities and promoting efficient end-use technology are the most important steps that need to be taken in promoting a transition to a hydrogen economy, consideration should also be given to initiatives specifically targeting PV hydrogen development. Although there is a high level of ongoing private sector R&D activity in photovoltaic technology, there are areas where progress is not being made as rapidly as is probably socially desirable.

a. Elimination of capital-related taxes on energy systems

Under current practice both corporate income taxes and property taxes on energy systems are assessed as capital charges. As there is no fundamental rationale for this approach to taxation and as it is biased against capital-intensive energy systems such as PV electric and PV hydrogen systems (*), consideration should be given to alternative approaches. It was argued above

---

* In this study corporate income tax and property taxes were neglected, as the analysis was aimed at comparing the costs to society of alternative energy systems. Has these taxes been included as they are presently assessed, the outlook for capital intensive-energy technologies (PV hydrogen and electricity, hydropower, wind power and nuclear) would have been less favorable than indicated as compared to fossil fuel based technologies.

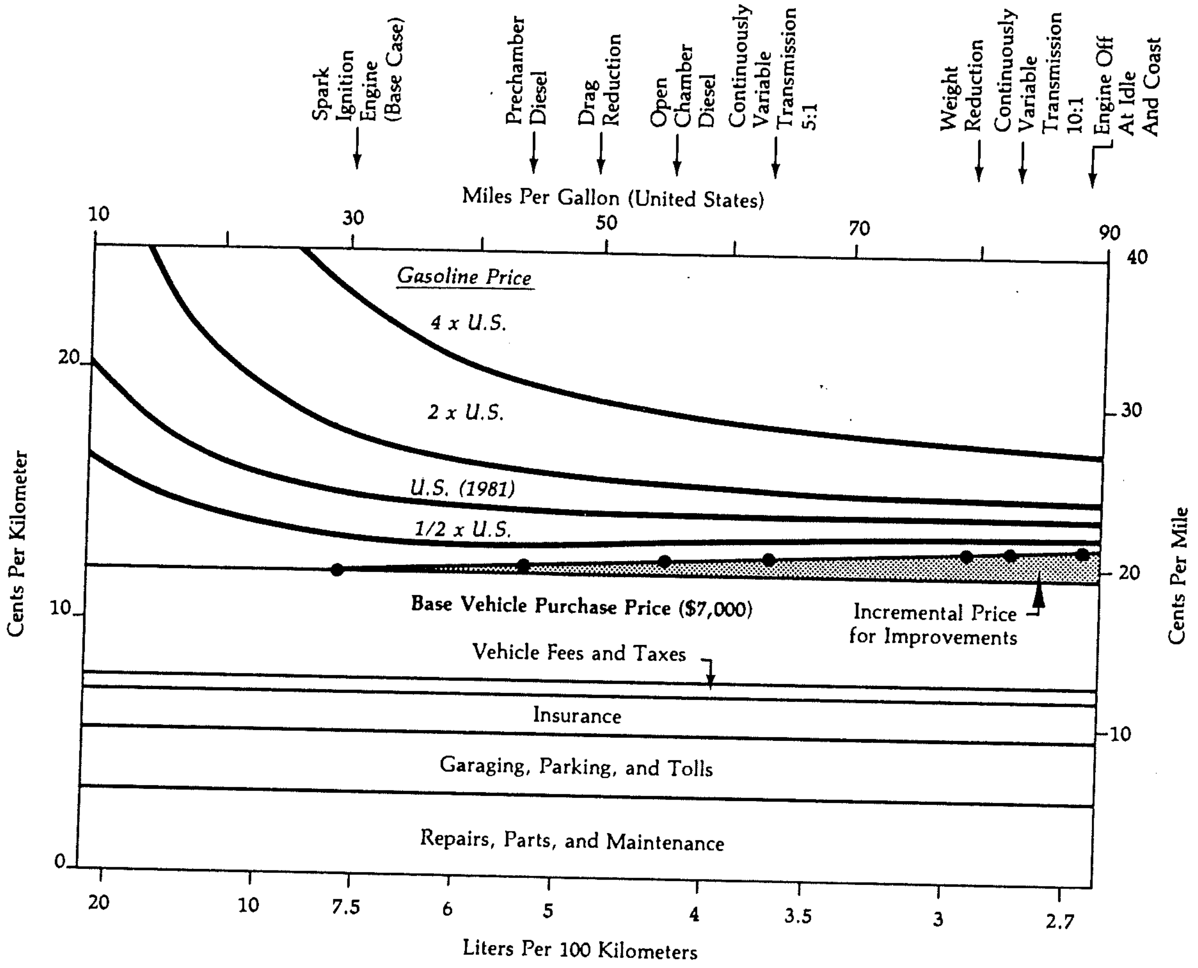


Figure 21.

The cost of driving versus automotive fuel economy.

The indicated energy performance is based on computer simulations of an automobile having various fuel economy improvements added in the sequence shown at the top of the graph. The base car is a 1981 Volkswagen rabbit gasoline verion).

The figure shows that the reduced operating costs associated with various fuel economy improvements are roughly offset by the increased capital costs of these improvements over a wide range of fuel economy.

Source: F. von Hippel and B.G. Levi, "Automotive Fuel Efficiency: the Opportunity and Weakness of Existing Market Incentives," Resources and Conservation, vol. 10, pp. 103-124, 1983.

that a carbon tax on fossil fuels and a tax or tariff on oil should be levied to reflect externalities caused by dependence on fossil fuels and oil imports. If additional taxes are needed on energy to meet revenue requirements of federal state or local governments, consideration should be given to mechanisms that are not biased against particular fuel forms. One possibility would be a tax proportional to the energy content of the energy carrier.

b. Continued research and development to improve the efficiency and lifetime of amorphous silicon solar cells and to reduce their manufacturing cost

Potentially large near-term markets for PV electricity highlight the importance of continued rapid progress relating to the cost and performance of a-Si solar cells. Some specific strategies identified for reducing manufacturing costs are integration of PV module and glass-making facilities, recovery of silane gas in manufacturing, development of low-cost frames for large arrays, automation of production facilities, and the exploitation of economies of scale by expanding factory output from present levels of 1 MWp per year to the range 10-100 MWp/yr (Box 2). If all these steps were taken, 12-18% efficient modules costing $0.2-0.4/Wp could probably become available by the year 2000.

As production costs of a-Si solar cells probably vary inversely with the efficiency, the achievement of a-Si cost targets depends critically on improving the efficiency of commercial a-Si modules from their present values of 5-7% to the range 12-18%. Continued support for research and development to improve efficiency and reduce unit capital costs is crucial.

c. Development of low-cost balance of systems (BOS) designs for large amorphous silicon-based PV systems

The commercialization of the utility peaking market in the 1990s should lead to some optimization of low-cost balance of systems designs for large flat plate PV arrays. At the PV module costs of $1-2/Wp needed for utility PV systems, area-related balance of systems cost will still be a small contributor to the overall DC electricity cost. However, as the costs of PV modules drop to \$0.2-0.4/Wp, reduced balance-of-systems costs will become more important. Using estimates drawn from various conceptual designs for large, flat-plate PV systems, it has been shown here that area-related BOS costs could be reduced from the often quoted figure of \$50/m^2 to perhaps \$33/m^2 (*). Other analysts have estimated that even lower balance of systems costs may be possible with innovative support structures. For 18% efficient PV modules, reducing BOS costs from \$50 to \$33/m^2 corresponds to reducing the PV hydrogen cost by roughly 10% or about \$1/GJ. While not as critical as the reducing the costs and increasing the efficiencies of the solar cells themselves, reducing BOS costs would clearly be helpful to the overall economics of a PV-based hydrogen economy and should be supported.

d. Research on PV hydrogen systems design

Several small (kilowatt-sized) experimental PV hydrogen systems have been built, and a number of conceptual designs for large plants have been carried out. But until the recently proposed 600-kW Solar Wasserstoff project in West Germany,[194] there has been no plan to collect field data on large PV-hydrogen systems.

By the mid- to late-1990s, PV hydrogen systems sited in the Southwestern US could begin to pay their way in chemical hydrogen and oxygen markets. Chemical companies, energy companies, automobile manufacturers and utilities might be more inclined to exploit these markets, if better data on large-sized

---

* These reductions can be achieved by (i) by taking a low-current, high-voltage electrical system design to reduce wire and DC electrical component costs, (ii) by using low-cost pre-fabricated panels to hold the modules, and (iii) by using low-cost support structures.

sized PV hydrogen systems were available. The Solar Wasserstoff project is a potentially important source of such data on solar hydrogen systems. Consideration should be given to supporting one or more similar projects carried out under US conditions and/or in other parts of the world.

e. Continued research on hydrogen end-use systems

Research on hydrogen-powered cars, on space and water heating systems, on low-cost compressors for home car-refuelling systems, and on fuel cells warrant high priority among hydrogen-using technologies because of both the promising economics and the potentially large markets involved. While much work was done in this area in the United States in the 1970s, little is being done today. This is in contrast to the situation in Germany, where Daimler Benz and BMW are developing hydrogen-powered cars and associated hydrogen storages systems, and there is ongoing research on residential use of hydrogen.

f. Government procurement

Since the hydrogen energy economy will probably be initiated through the application of hydrogen to urban fleet vehicles in the Southwestern United States, state or city procurement of hydrogen-powered vehicles could help the early development of local PV hydrogen facilities in sunny areas.

Some fraction of US government auto, bus, truck fleets could also be converted to PV hydrogen, assuring a market for manufacturers of hydrogen-powered vehicles, and providing impetus for investment in a pipeline. A committment to convert 10% of US fleet vehicles to hydrogen would be sufficient to justify building a hydrogen pipeline.

C. CONCLUSION

If amorphous silicon solar cell technology advances as expected, PV electricity would become competitive in increasingly large electricity markets in the 1990s. Smaller, but potentially important chemical markets would also open for PV hydrogen in this period. These small "transition" markets for chemical hydrogen (and oxygen) could prove to be important in helping support the near-term technological development of PV hydrogen systems.

As PV hydrogen technology advances it could begin to compete in energy markets. Concerns about urban air quality, regional air pollution, and the global greenhouse warming represent the most powerful external stimuli affecting the choice between PV hydrogen and alternative fuel technologies, at least through the early part of the century.

Automotive air pollution in the urban environment is perhaps the single most important factor motivating an early shift to PV hydrogen. This shift could be initiated with the introduction of local hydrogen transport systems in Southwestern cities in early to mid-1990s. (If a program to develop a hydrogen powered transport system were implemented, the first hydrogen energy markets might develop before chemical transition markets.)

Initally, the hydrogen required in the Southwest could come from low-cost hydrogen produced from off-peak electricity generated at existing fossil fuel power plants. A shift to PV-based hydrogen could probably begin near the turn of the century.

The hydrogen energy economy could be initiated with automotive fleet vehicles in the Southwest and expand into widespread PV hydrogen use in private cars sometime in the 2000-2015 timeframe. If local hydrogen transport systems in the Southwest were successful in reducing pollution, cities in other parts of the US might decide to adopt hydrogen as a transport fuel. A relatively small, initial demand for hydrogen would justify building the first long-distance pipelines for hydrogen transmission from the Southwest to the

Northeast and Midwest. In Northern cities, hydrogen use would probably be initiated as a fuel for fleet vehicles, and later it could later come into widespread use in private cars, as in the Southwest. If hydrogen became readily available in the North, it might eventually find uses as a fuel for residential space and water heating as well.

While a transition to a hydrogen economy could begin as early as the 1990s, it would take many decades to complete, largely because of capital constraints on the evolution of the energy system.[195] Yet the benefits of making a transition to PV hydrogen are so farreaching, that serious consideration should be given to policy strategies that would hasten its development.

February 15, 1989

NOTES AND REFERENCES - TECHNICAL VERSION

CHAPTER 1

1. United States Department of Energy, Energy Security, A Report to the President of the United States, Washington, DC, March 1987.

2. "Urban Ozone and The Clean Air Act: Problems and Proposals for Change," Staff Paper, Oceans and Environments Program, Office of Technology Assessment, April 1988.

3. Ibid.

4. Philip Shabecoff, "Ozone Pollution Is Found at Peak in Summer Heat," New York Times, July 31, 1988, p.1.

5. "Urban Ozone and The Clean Air Act: Problems and Proposals for Change," Office of Technology Assessment.

6. Shabecoff, op.cit.

7. Philip Shabecoff, "Global Warming Has Begun, Expert Tells Senate," New York Times, June 24, 1988, p.1.

8. Preliminary 1988 EPA Concentrations, July 14, 1988.

9. Michael P. Walsh, "Pollution on Wheels," Report to the American Lung Association, February 11, 1988.

10. Walsh, op.cit.

11. Walsh, op.cit.

12. Walsh, op. cit.

13. U.S. Environmental Protection Agency, "Guidance on Estimating Motor Emission Reductions from the Use of Alternative Fuels and Fuel Blends," EPA Report No. AA-TSS-PA-87-4, Research Triangle Park, North Carolina, January 1988.

14. "Draft 1988: Air Quality Management Plan," California South Coast Air Quality Management District, Southern California Association of Governments, September 1988.

15. C.D. Masters, E.D. Attanasi, W.D. Dietzman, R.F. Meyer, R.W. Mitchell, and D.H. Root, D. H. "World Resources of Crude Oil, Natural Gas, Natural Bitumen, and Shale Oil," paper prepared for the 12th World Petroleum Congress, Houston, Texas, 1987.

16. Committee on the Monitoring and Assessment of Trends in Acid Deposition, National Research Council, Acid Deposition: Long Term Trends, National

Academy Press, Washington, DC, 1986; J.E. White, ed., Acid Rain, The Relationship Between Sources and Receptors, Elsevier, New York, 1988.

17. A.H. Johnson, "Acid Deposition: Trends, Relationships and Effects," Environment, v. 28, No. 4, May 1986, p. 6; "Acid Deposition and Forest Decline," Resource Highlights Pamphlet, Land and Water Resources Center, University of Maine, Orono, January 1984.

18. J.J. MacKenzie and M.T. El-Ashry, Ill Windss: Airborne Pollution's Toll on Trees and Crops, 71 pp., World Resources Institute, Washington, DC, September 1988.

19. Ibid.

20. Ibid.

21. "Urban Ozone and The Clean Air Act : Problems and Proposals for Change," Office of Technology Assessment.

22. Ibid.

23. B. Bolin, B.R. Doos, J. Jaeger, amd R. A. Warrick, The Greenhouse Effect, Climatic Change, and Ecosystems, SCOPE 29, John Wiley & Sons, 1986.

24. Philip Shabecoff, "Global Warming Has Begun, Expert Tells Senate," New York Times, June 24, 1988, p.1.

25. W. Haefele et al., Energy in a Finite World -- A Global Systems Analysis, Ballinger, Cambridge, MA (1981); World Energy Conference. Energy 2000-2020: World Prospects and Regional Stresses, ed. Frisch, J.-R., Graham & Trotman, London (1983); J. A. Edmonds and J. Reilly, "Global Energy Production and Use to the Year 2050," Energy, the International Journal, vol. 8, pp. 419-432, 1983; J. A. Edmonds, J. Reilly, J. R. Trabalka, and D. E. Reichle, "An Analysis of Possible Future Atmospheric Retention of Fossil Fuel CO_2," DOE Report No. DOE/OR/21400-1, Washington, DC, 1984.

26. IIASA study (ref. 25)

27. The IIASA low (L) and high (H) projections (ref. 25) are as follows:

	Fossil Fuel Use (TW-years/year)			Cumulative Fossil Fuel Use, 1980-2030 (TW-years)		Cumulative Carbon Emissions As CO_2 (Gigatonnes)	
	1980	2030L	2030H	Low	High	Low	High
Coal	2.44	6.45	12.00	206.7	299.7	161.2	233.8
Oil	4.18	5.02	6.83	229.5	269.9	144.6	170.0
N. Gas	1.74	3.47	5.97	125.4	171.3	53.9	73.7
Totals	8.36	14.94	24.80	561.6	740.9	359.7	477.5

Here the carbon emissions (as carbon dioxide) are assumed to be 0.78, 0.63, and 0.43 GT per TW-year for coal, oil, and natural gas respectively. If half of the carbon dioxide released from the use of fossil fuels were to stay in the atmosphere, the atmospheric burden of carbon dioxide would increase from 721 GT (340 ppm) in 1980 to the range 901 to 960 GT (425 to 453 ppm) by 2030, up 55 to 65% from the estimated pre-industrial level of 275 ppm.

28. Bolin (ref. 23)

29. If $\triangle T_d$ is the expected equilibrium increase in the surface temperature associated with a doubling of the carbon dioxide concentration, then the equilibrium temperature increase $\triangle T$ resulting from an X-fold increase in the CO_2 level is given by

$$\triangle T = \triangle T_d \times (\ln X) / (\ln 2).$$

For the IIASA scenarios, X = 1.55 to 1.65 by 2030 (see note 27), so that

$$\triangle T = (0.63 \text{ to } 0.72) \times \triangle T_d \text{ by } 2030.$$

30. Bolin (ref. 23)

31. Bolin (ref. 23)

32. R.H. Williams, E.D. Larson, and M.H. Ross, "Materials, Affluence, and Industrial Energy Use," Annual Review of Energy, vol. 12, pp. 99-144, 1987; Energy Demand and Materials Flows in the Economy," Energy, vol. 12, nos, 10/11, pp. 953-967, 1987; E.D. Larson, M.H. Ross, and R.H. Williams, "Beyond the Era of Materials," Scientific American, vol. 254, no. 6, pp. 34-41, June 1986.

33. J. Goldemberg, T.B. Johansson, A.K.N. Reddy, and R.H. Williams, Energy for a Sustainable World, 119 p., World Resources Institute, Washington, DC, September 1987; J. Goldemberg, T.B. Johansson, A.K.N. Reddy, and R.H. Williams, Energy for a Sustainable World, 517 p., Wiley-Eastern, Delhi, 1988; J. Goldemberg, T.B. Johansson, A.K.N. Reddy, and R.H. Williams, Energy for Development, 73 p., World Resources Institute, Washington, DC, September 1987.

34. R.H. Williams, "Are Runaway Energy Capital Costs a Constraint on Development?", paper presented at the International Seminar on the New Era in the World Economy, Fernand Braudel Institute of World Economics, Sao Paulo, Brazil, August 31-September 2, 1988.

35. Fossil fuel use for the global energy future described in Energy for a Sustainable World (ref. 33) is as follows:

	Fossil Fuel Use (TW-years/year)		Cumulative Fossil Fuel Use, 1980-2020 (TW-years)	Cumulative Carbon Emissions As CO_2 (Gigatonnes)
	1980	2020		
Coal	2.44	1.94	87.6	68.3
Oil	4.18	3.21	147.8	93.1
N. Gas	1.74	3.21	99.0	42.6
Totals	8.36	8.36	334.4	204.0

If half of the carbon dioxide released from the use of fossil fuels were to stay in the atmosphere, the atmospheric burden of carbon dioxide would increase from 721 GT (340 ppm) in 1980 to 823 GT (388 ppm) by 2020, up 41% from the estimated pre-industrial level of 275 ppm, and the equilibrium global warming from this much added carbon dioxide would be:

$$\Delta T = \Delta T_d \times (\ln 1.41) / (\ln 2) = 0.5 \times \Delta T_d.$$

36. Conference Statement of the World Conference on The Changing Atmosphere: Implications for Global Security, Toronto, June 27 to 30, 1988.

37. J.B.S. Haldane was the first to suggest electrolytic production of hydrogen fuel from wind power in 1923, and in 1927, A.J. Stuart suggested using hydropower as a source of electricity for hydrogen production. The use of solar power to produce hydrogen was first suggested by J. O'M. Bockris in 1962. (see: J. O'M. Bockris, *Energy Options*, Halsted Press, New York, 1980.)

38. See Appendix A in *Energy for a Sustainable World*, Wiley-Eastern, Delhi, 1988 (ref. 34).

39. H.K. Schneider and W. Schulz, "Investment Requirements of the World Energy Industries 1980-2000," Report prepared for the World Energy Conference Study Group on Long-Term Investment Requirements: Needs, Constraints, and Proposals, World Energy Confernce, London, September 1987.

40. See Appendix A in *Energy for a Sustainable World*, Wiley-Eastern, Delhi, 1988 (ref. 34).

41. When manufacturing single crystal silicon solar cell material, the atoms must be arranged in a precise geometrical "lattice". This is done by inserting a small "seed crystal" into purified molten silicon, then withdrawing and cooling it slowly to preserve the original pattern of the seed. One common method involves producing a cylindrical crystalline ingot, several inches in diameter, which is then sawn into circular wafers. The circular wafers are then positioned and electrically connected to make a solar module. This method is costly, as about half of the material is lost in sawing, and it is time consuming to assemble the modules. A potentially less expensive method of single crystal solar cell mass production involves pulling a continuous rectangular sheet or "web" of single crystal silicon. Material and energy consumption are reduced with this technique.

42. Crystalline silicon solar cells were originally developed as power sources for spacecraft and satellites. In the early 1970's, the cost of cells for space applications was about $120 per peak Watt (in 1986$). During the energy crisis of the mid-1970's, there was growing interest in terrestrial use of photovoltaics, and less expensive manufacturing techniques were developed. As of 1974, solar cells cost about $50 per peak Watt; and by 1976, the cost of solar cells had dropped to about $25 per peak Watt. See D.L. Pulfrey, Photovoltaic Power Production, Van Nostrand Reinhold, New York, (1978).

43. Costs for solar modules are given in $/peak Watt ($/Wp) or sometimes in dollars per square meter ($\$/m^2$) or dollars per square foot. Peak Wattage is the amount of electrical power generated under maximum insolation (sunlight). Under ideal conditions the earth's surface receives a maximum of about 1 kilowatt of solar power per square meter. The cost per unit area and the cost per unit of output are related by:

$$\$/Wp = (\$/m^2)/[(\text{efficiency}) \times (1000\ Wp/m^2)]$$

Production volumes for solar cells are generally given in peak Watts of PV generating capacity produced per year or "Wp/year".

44. In this study the real (inflation-corrected) discount rate is assumed to be 6.1% for all energy production systems and insurance is assume to cost 0.5% of the installed capital cost per year [values recommended by the Electric Power Research Institute for evaluating alternative electric utility investments (Electric Power Research Institute, Technical Assessment Guide, Vol. 1: Electricity Supply--1986, EPRI P-4463-SR, December 1986--henceforth referred to as the 1986 EPRI TAG)]. Corporate income taxes, property taxes and tax incentives are neglected. For consumer systems such as automobiles and home heating systems, a discount rate of 10% is assumed.

45. The contribution of capital to the cost of electricity C_e in $ per kWh is:

$$C_e = (CRF + INS) \times C / Aw,$$

where

C = cost of solar modules in \$ per peak Watt (\$/Wp)
Aw = number of kilowatt hours produced annually per peak Watt of solar array
= 8760 hours/year x [Ia / (1000 Watts/kW)] / Ip
Ia = average insolation (in Watts/m^2)
Ip = peak insolation = 1000 Watts/m^2
CRF = capital recovery factor = $i/[1 - (1 + i)^{-N}]$,
INS = insurance factor = 0.005
i = the discount rate (the cost of capital--the weighted average of the rate of return on debt and the rate of return on equity)
N = expected life of the facility, in years

Assuming N = 30 years, and Ia = 250 Watts/m^2 (appropriate for sunny areas, e.g. the US Southwest), one obtains:

$C_e = \$5.12$ per kWh, for C = \$120 per peak Watt.

This calculation neglects balance of system, indirect costs and operation and maintenance costs.

46. The following are estimates of the costs of producing electricity from new coal or nuclear plants in the United States:

Type	Coal (a)	LWR (b)
Unit Size [MW(e)]	500	1100
Efficiency (Coal-to-Busbar)	34.6	33.4
Unit Capital Cost (1986\$/kW)	1375	2990
Levelized Busbar Cost (1986\$/kWh)		
Capital (c)	0.0189	0.0411
Fuel (d)	0.0181	0.0087
O&M (e)	0.0101	0.0105
TOTAL	0.0471	0.0604

---

[a] For a conventional coal-fired subcritical steam plant with wet limestone flue gas desulfurization, for bituminous coal, East/West Central regions. Unit capital costs, efficiencies, O&M costs, and other plant characteristics are from the 1986 EPRI TAG.

[b] Unit capital costs, efficiencies, and other light water reactor plant characteristics are from the 1986 EPRI TAG.

[c] For a 30 year plant life (so that CRF + INS = 0.0784) and a 65% capacity factor.

[d] For a coal price of \$1.74/GJ--the average price projected by the U.S. Department of Energy for the year 2000 (Energy Information Administration, "Annual Energy Outlook 1987, with Projections to 2000," DOE/EIA-0383(87),

March 28, 1988). For a nuclear fuel cycle cost of \$0.81/GJ, the estimated cost in 1990, according to the EPRI TAG.

e The O&M cost estimate for coal plants is from the 1986 EPRI TAG. That for nuclear plants is the actual US average for nuclear plants in the period 1982-1985, according to Energy Information Administration, "Historical Plant Cost and Anuual Production Expenses for Selected Electric Plants 1985," DOE/EIA-0455(85).

47. Polycrystalline silicon solar cells are manufactured by casting molten silicon into rectangular ingots, which are then sliced and configured into modules. The resulting material is composed of many small adjacent single crystal regions or "crystallites" rather than a single large crystal of silicon. The conversion of sunlight to electricity is less efficient for the polyscrystalline than for single crystal solar cells, but production is faster and the materials and energy costs are lower than for single crystal silicon.

48. In 1986 world production of photovoltaic cells totalled 29.9 MW and was comprised of 12.4 MW single crystal silicon, 6.2 MW polycrystalline silicon, 10.8 MW amorphous silicon, 0.1 MW concentrator cells, and 0.4 MW ribbon type silicon. Japanese manufacturers produced 9 MW (83%) of amorphous silicon solar cells, almost all for the consumer electronics market. In 1986, amorphous silicon modules for power applications were first introduced by several companies, including Chronar in the US and Sanyo in Japan. See Photovoltaic Insiders' Report, Vol. 6, No. 2 (February 1987).

49. Z Erol Smith III, "Amorphous Silicon for Solar Cell Applications: Defect Generation, Annealing, and Equilibrium," Department of Electrical Engineering, Princeton University, 1987.

50. R.A. Whisnant, P.T. Champagne, S.R. Wright, K.C. Brookshire and G.J. Zuckerman, "Comparison of the Required Price for Amorphous Silicon, Dendritic Web, and Czochralski Flate Plate Modules and Conventrators", RTI Associates Report, 1985.

51. Amorphous silicon is vapor deposited from a silicon-bearing gas (silane) on a glass, plastic or stainless steel substrate in a vacuum chamber. The depth and composition of the various layers which make up the solar cell are controlled by adjusting the composition of the gas in the deposition chamber. Solar modules can be configured swiftly and flexibly from these sheets of amorphous silicon. The neccessary electrical connections are made by scribing the amorphous silicon film with a laser and depositing metal conducting paths.

52. D.E. Carlson, "Low-Cost Power from Thin-Film Photovoltaics," paper to be presented at the Vattenfall Symposium on Efficient End Use and New Generation Technology for Electric Utility Planning and Policy, Stockholm 1989.

53. Photovoltaic Insiders' Report, February 1988.

54. S. Kaplan, Chronar Corp., private communications, 1988.

55. M. L. Wald, "Solar Power Plant Planned for California," Business Day Section of The New York Times, September 6, 1988.

56. D.E. Carlson, General Manager, Thin Film Division, Solarex, private communication, 1987.

57. Photovoltaic Insiders' Report, January 1987.

58. S. Kaplan, Chronar Corp., private communication, 1988.

59. Arun Madan, "Amorphous Silicon: from Promise to Practice," IEEE Spectrum, pp. 38-43, September 1986.

60. M.L. Wald, op. cit.

61. Photovoltaic power may prove to be attractive to many developing countries. Not only is sunshine a plentiful resource, but the technology can be readily acquired, owned and operated. Although the manufacture of solar modules requires a factory using a "high-tech" process, the installation of flat plate solar modules requires little specialized knowledge beyond basic construction skills. Experience with PV projects in the US and abroad have shown that maintenance needed on flat plate solar arrays is simple and minimal.

    In the last year or two China, as well as France and Yugoslavia, decided to get into the amorphous silicon manufacturing business, and one US company (Chronar Corporation) specializes in selling "turnkey" amorphous silicon solar cell factories to interested countries. A plant with a production capacity of 1-1.4 MW peak/year costs about $6-7.5 million, a relatively small initial investment for getting into a new energy supply business (S. Kaplan, Chronar Corporation, private communications, 1988.)

62. Photovoltaic power is well-suited for utility peaking service, as the maximum output of a solar array generally occurs at the same time as the maximum electricity demand for air conditioning, on hot, sunny summer days.

63. If the estimated two million remote villages in the world were electrified with 5 kW photovoltaic plants as an alternative to using small diesel generators, the annual oil savings would be about 0.2 EJ or 0.7% of total oil use by developing countries in 1986.

    Installing 40 GW of photovoltaic peaking capacity in the US (equal to the total oil and natural gas fired peaking capacity) could displace up to 1.1 EJ of oil and gas now used for power generation, some 2% of total oil and gas use in the US.

    If 50 million residential users in the US bought 2 kW rooftop PV generators to produce daytime electricity, the electricity produced could displace 2.7 EJ of oil and gas now used for electric power generation, or

5% of total US oil and gas use in 1986. [These savings and the peaking power savings indicated above are not additive, as daytime residential electricity demand is usually a major contributor to the utility system peak demand.]

64. As PV electricity is generated only when the sun shines, a method of electricity storage must be found to provide PV electricity for other times. In general the amount of storage needed depends in complicated ways on the details of the variations of the output of the PV array and of the profile of the electrical load that must be met by the PV system. To give an indication of the potential significance of storage costs, a simple model is constructed here that estimates the cost of baseload electricity from a PV + storage system located in a sunny area, such as the Southwest United States. While this model overestimates the amount of storage that would be needed in practical applications (since in most situations electricity demand tends to be much higher during the period of the day when insolation is the greatest than at other times), this approach permits a ready comparison between PV and alternative systems that can provide baseload electricity.

This model, described below (a), yields the following costs for baseload electricity (in $/kWh AC) for several alternative storage technologies:

Storage Technology		
For DC input PV electricity @	$0.020/kWh	$0.035/kWh
Lead-acid batteries (b,c)	0.074	0.093
Advanced batteries (b,d)	0.047	0.065
Underground pumped storage (b,e)	0.055	0.074
Hydrogen/air turbine (f)	0.072	0.104
Hydrogen/oxygen turbine (g)	0.056	0.081

Comparing these costs to the estimated costs of baseload electricity from new coal and nuclear plants in the US (note 46), it is seen that in sunny areas PV power plus advanced batteries would be competitive with power produced in new coal and nuclear plants for PV DC electricity costs of $0.02 per kWh or less and with current nuclear power for DC electricity costs of $0.035 per kWh or less.

a It is assumed that insolation is constant throughout the daylight hours and that the PV system plus storage produces AC power at a constant average baseload rate, determined by:

$$[(24 - L) \times Pb/npc] + [L \times Pb/ns] = Po \times (24 - L) = 24 \times Pa$$

where

L = hours of storage needed per day
Po = peak DC output of the PV array (in kW)
Pa = annual average DC output of the PV array (in kW)
Pb = annual average level of baseload output of the PV array

+ storage (in kW)
$= (24 \times Pa)/[(24 - L)/npc + L/ns]$
ns = round trip storage efficiency
npc = efficiency of power conditioning unit for electricity not stored

b For batteries and underground pumped storage (for which storage system costs are from the 1986 EPRI TAG) the cost of baseload electricity from the system consisting of the PV array + storage is given by:

$$Cac = (CRF + INS) \times (Cpow \times Ps + Csto \times Es + Cpc \times Pb)/(8760\ hr/yr \times Pb)$$

$$+\ Pe/n + Com \times (L/24)$$

where

Cac = average cost of baseload electricity (in \$/kWh AC)
Cpow = unit capital cost of power equipment for storage system (\$/kW in)
Ps = electrical capacity of storage system (kW of input power)
$= Po - Pb/npc = [Pb/ns]/(24/L - 1)$
Csto = unit capital cost of storage related equipment (in \$/kWh of storage)
Es = capacity of storage (in kWh) = $Pb \times L$
Cpc = unit power conditioning capital cost for electricity not stored (in \$/kW of output)
Pe = cost of DC electricity from PV array (in \$/kWh DC)
n = $Pb/Pa = 24/[(24-L)/npc + L/ns]$
Com = operating and maintenance costs for storage (in \$/kWh AC)

$$Cac = (CRF + INS) \times [Cpow/(24/L - 1)/ns + Csto \times L + Cpc]/8760$$

$$+\ (Pe/24) \times [(24-L)/npc + L/ns] + Com \times (L/24)$$

Assuming that

L = 18 hours
Cpc = \$150/kW (the US DOE target for fixed, flat-plate PV systems in the year 2000),
npc = 0.96,

then:

$$Cac = (CRF + INS) \times [3Cpow/ns + 18Csto + 150]/8760$$

$$+\ Pe \times [0.260 + 0.75/ns] + 0.75 \times Com$$

c For lead-acid batteries:

Cpow = \$120/kW
ns = 0.769
Com = \$0.0051/kWh,
N = 30 years, so that CRF = 0.0734.
Csto = PVf x Cssto,

where

Cssto = cost of a single battery unit = \$242 x $L^{-0.305}$ = \$100/kWh for L = 18 hours, and
PVf = present value factor for batteries that must be purchased every Y years, where
Y = battery life = 2555.5 x $Ncyc^{-1.004}$ = 6.84 years for Ncyc = 365 cyles per year => PVf = 2.5 => Csto = \$250/kWh.

Thus:

Cac = \$0.074/kWh (for Pe = \$0.020/kWh DC) or \$0.093/kWh (for Pe = \$0.035/kWh DC).

d For advanced batteries (sodium-sulfur or zinc-chlorine):

Cpow = \$120/kW
ns = 0.80
Com = \$0.0026/kWh,
N = 30 years so that CRF = 0.0934.
Csto = PVf x Cssto
Cssto = \$130 x $L^{-0.302}$ = \$54/kWh for L = 18 hours,
Y = 3752 x $Ncyc^{-1}$ = 10 years for Ncyc = 365 cycles per year => PVf = 1.86 => Csto = \$100/kWh.

Thus:

Cac = \$0.047/kWh (for Pe = \$0.020/kWh DC) or \$0.065/kWh (for Pe = \$0.035/kWh DC).

e For underground pumped hydro:

Cpow = \$622/kW
Csto = \$31.1/kWh
ns = 0.735
Com = \$0.0048/kWh,
N = 50 years, so that CRF = 0.0643.

Thus,

Cac = \$0.055/kWh (for Pe = \$0.020/kWh DC) or \$0.074/kWh (for Pe = \$0.035/kWh DC).

f When PV energy is stored as hydrogen, electricity can be generated at a later time, as needed, by burning the hydrogen with air in a turbine. The cost of baseload electricity for a PV array + hydrogen/air turbine is given by:

Cac = (CRF + INS) x (Ct x Pb + Cpc x Pb)/(8760 hr/yr x Pb)

+ (L/24) x [Ph/nt x (0.0036 GJ/kWh) + Com] + (24 - L)/24 x Pe/npc

where:

N = 30 years, so that CRF = 0.0734.

Ct = unit capital cost of turbine (in $/kW)
Ph = cost of hydrogen delivered to turbine (in $/GJ)
Com = cost of turbine operating and maintenance costs (in $/kWh)
nt = efficiency of hydrogen/air turbine = 0.50 (HHV basis)
L = 18 hours

Assuming that the capital and O&M costs of a hydrogen powered gas turbine would be similar to these costs for a natural gas-fired unit:

Ct = $400/kW
Pom = $0.004/kWh

As calculated in Chapter 3, hydrogen from a PV powered unipolar electrolyzer located in the Southwest US would cost about $9.07/GJ (for Pe = $0.020/kWhDC) or $13.96/GJ (for Pe = $0.035/kWhDC). Including storage, compression and transmission costs, hydrogen delivered from the pipeline to the turbines would cost:

Ph = $ 10.82/GJ (for Pe = $0.020/kWh DC) or $ 16.02/GJ (for Pe = $0.035/kWh DC).

Thus Cac = $0.072/kWh (for Pe = $0.020/kWh DC) or $0.104/kWh (for Pe = $0.035/kWh DC).

g If electricity is produced near a PV-powered electrolysis plant, it would be possible to store the oxygen, as well as hydrogen for later use in the turbine. For an oxygen-hydrogen powered turbine, the efficiency would be about nt = 0.65 (HHV basis).

The cost of hydrogen would be (including hydrogen compression to 450 psia and storage but not transmission, and neglecting the cost of oxygen compression and storage):

Ph = $ 10.25/GJ (for Pe = $0.020/kWh DC) or $ 15.40/GJ (for Pe = $0.035/kWh DC).

Then assuming as before,

Ct = $400/kW
Com = 0.004/kWh

the cost of electricity would be

Cac = $ 0.056 (for Pe = $0.020/kWh DC) or $ 0.081 (for Pe = $0.035/kWh DC).

65. One new technology under development (Stuart Licht, MIT) is the liquid solar cell that combines the functions of converting solar energy into electricity and storage in a single system. See, for example, "Solar Cells, Mehr Licht," <u>The Economist</u>, pp. 82-83, January 16-22, 1988.

66. For detailed information about the uses of hydrogen see, for example:

K.E. Cox and K.D. Williamson, Hydrogen Its Technology and Implications, five volumes, CRC Press, Boca Raton, Florida, (1979).

T.N. Veziroglu, Hydrogen Energy: Parts A and B, 2 volumes, Plenum Press, New York, (1975).

The International Journal of Hydrogen Energy, started in 1976, is the primary publication of hydrogen energy research community.

See also reports from the Brookhaven National Laboratory hydrogen program (mid-1970s to 1985).

T.N. Veziroglu, ed.,Hydrogen Energy Progress, Proceedings of the World Hydrogen Energy Conferences, Pergamon Press, 1974-1988.

67. Private communications from Sigurd Wagner, Electrical Engineering Department, Princeton University, July 1988.

68. Four US manufacturers (Chronar, Solarex, Arco Solar, and ECD) are in a cost shared program with the US Department of Energy to produce modules of these efficiencies by 1990, PVIR, February 1987.

69. D.E. Carlson, Solarex Thin Films Division, private communications, 1988; D.E. Carlson, "Low-Cost Power from Thin-Film Photovoltaics," paper to be presented at the Vattenfall Symposium on Efficient End Use and New Generation Technology for Electric Utility Planning and Policy, Stockholm 1989.

70. E.A. DeMeo and R.W. Taylor, "Solar Photovoltaic Power Systems: An Electric Utility Perspective," Science, v. 224, April 20, 1984.

71. Private communications from Sigurd Wagner, Electrical Engineering Department, Princeton University, July 1988.

72. D.L. Staebler and C.R. Wronski, Applied Physics Letters, v. 31, p. 292, 1977.

73. D.E. Carlson, "Solar Cells," in Semiconductors and Semimetals, v.21, Part D, ed. J.I. Pankove, Academic Press, NY, p.7, 1984

74. D.E. Carlson, 8th European Photovoltaic Solar Energy Conference, Florence, Italy, May 9-13, 1988.

75. US Dept. of Energy, DOE/CH10093-19, January 1988. Also EPRI, Sandia reports.

76. S. Kaplan, Chronar Corp., private communications, 1988.

77. "$1 per Wp Module Cost Target Seen Obtainable by Early 1990s Without Efficiency Gains," PVIR, p. 4, May 1988.

78. M. L. Wald, op. cit.

79. "Chronar Negotiating to Install 60 MW, $150 Million PV System in Southern California," PVIR, p. 1, September 1988.

80. D.E. Carlson, "Low-Cost Power from Thin-Film Photovoltaics," paper prepared for the Vattenfall Symposium on Efficient End Use and New Generation Technology for Electric Utility Planning and Policy, Stockholm 1989.

81. Private communications from Sigurd Wagner, Electrical Engineering Department, Princeton University, July 1988.

82. D.E. Carlson, General Manager, Thin Film Division, Solarex, private communications, 1988.

83. S.L. Levy and L.E. Stoddard, "Integrated Photovoltaic Central Station Conceptual Designs," EPRI Report AP-3264, June 1984.

84. G.T. Noel, D.C. Carmichael, R.W. Smith, and J.H. Broehl, "Optimization and Modularity Studies for Large-Size, Flat-Panel Array Fields," Battelle-Columbus, 18th IEEE PV Specialists' Conference, Las Vegas, Nevada, October 1985.

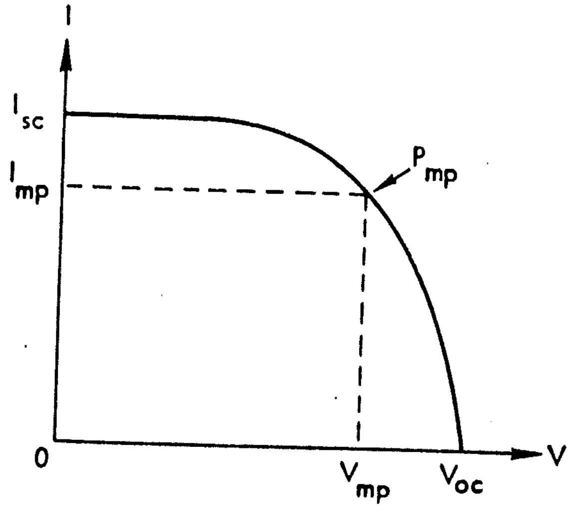
85. See note 89.

86. Hydrogen transmission costs can be less than those of synthetic medium BTU coal gas and comparable to those for natural gas, with optimized pipelines. For a 1000 mile (1600 km) pipeline, the cost of hydrogen transmission is about $0.35/GJ. See Note 100 and D. Christodoulou, " Technology and Economics of the Transmission of Gaseous Fuels Via Pipeline", Princeton University, Department of Mechanical and Aerospace Engineering, Master's Thesis, 1984.

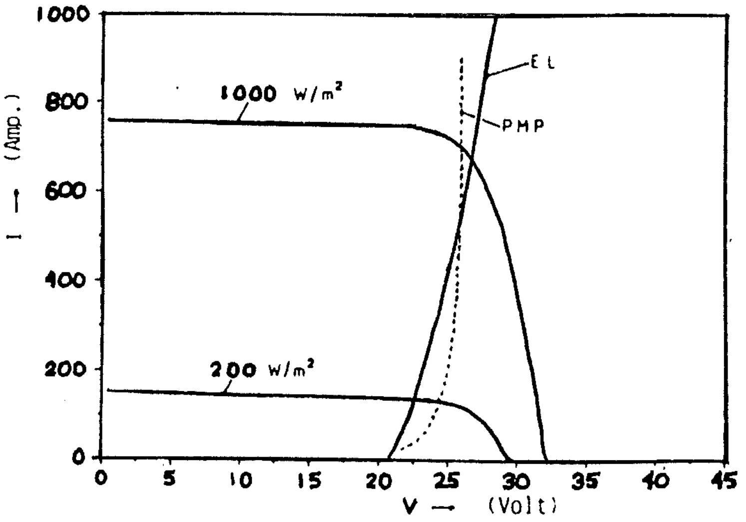
The cost of long-distance DC electrical transmission is about $0.09 to $0.11 per GJ per 100 km for distances longer than about 1000 km. For a 1600 km transmission line, this is a cost of about $1.44 to 1.76/GJ, roughly four times the cost of hydrogen transmission via pipeline. See D. W. Devins, Energy : Its Physical Impact on the Environment, John Wiley and Sons, New York, 1982.

87. The interface between the PV array and the electrolyzer must be considered when calculating the efficiency of a PV hydrogen system. Achieving a good electrical match is neccessary for efficient conversion of sunlight to hydrogen.

The PV array is a variable DC power source, where the output current I and voltage V depend on the physical parameters of the solar cell, the electrical connection pattern, the module temperature and the insolation. The current varies from 0 to Isc (short circuit current) and the voltage from 0 to Voc (open circuit voltage). The maximum power output Pmp and solar energy conversion efficiency occur for Imp and Vmp determined by d(IV)/dI = 0, as shown below:



The electrolyzer is a DC load with its own current-voltage characteristic, which depends on the electrolyzer type, the electrolyte temperature, and the number of electrolysis modules connected in series and parallel. I-V curves for a PV-array and an electrolyzer are shown together below. When the PV array is connected directly to the electrolyzer, the system operating point is the intersection of the two I-V curves. Ideally, the operating point should be near the maximum power point of the PV array for most operating conditions that occur throughout the day, to assure maximum conversion efficiency over the expected range of conditions.



As insolation and temperature change over the course of a day's operation, the maximum power point (PMP) describes a curve in I-V space, as shown above. Typically the temperature lags slightly behind the insolation, giving a curve for the maximum power point as sketched above. If the maximum power point curve followed the electrolyzer characteristic (EL) perfectly, the PV array and the electrolyzer would be perfectly matched. Although a perfect match is not possible, the mismatch can be made quite small if the PV system is designed to operate at the maximum power point for the most likely weather conditions (averaged over a year or more of local insolation and temperature data.) Since the shape of the maximum power curve over the course of a day is relatively close to the shape of the electrolyzer characteristic, this gives a system efficiency which is 90-95% of the ideal efficiency. For a well-matched PV array and electrolyzer, direct connection actually works better than connection with maximum power tracking circuits, which are typically only 90% efficient.

For crystalline solar cells Carpetis found excellent agreement between his model which predicts such a match and PV/electrolysis experiments for which good weather data were available. (C. Carpetis, International Journal of Hydrogen Energy, Vol. 7, p. 287, 1982; C. Carpetis, International Journal of Hydrogen Energy, Vol. 9, p. 969, 1984). Metz and his coworkers at Brookhaven National Laboratory have also done simulations and experiments with solar PV powered electrolysis. Using a model similar to the one used by Carpetis, they found that direct connection of the PV array to the electrolyzer gave a match which was 93% of the ideal (R. W. Leigh, P.D. Metz, and K. Michalek, "Photovoltaic Electrolyzer System Transient Simulation Results", BNL-34081, December 1983; P. D. Metz and M. Piraino, BNL-51940, July 1985).

Although the parameters for amorphous silicon solar cells are somewhat different from those for crystalline silicon cells, the shape of the PV array output curve is quite similar. There should be no special problems in achieving a good direct match between an electrolyzer and an amorphous silicon-based array. The fact that amorphous modules can be configured electrically in a variety of ways during deposition of the thin film material may add extra flexibility in electrical design for small systems. The maximum power point for amorphous silicon is marginally less temperature-sensitive than that for crystalline silicon, so that it may be marginally easier to match the electrolyzer I-V curve with an amorphous silicon-based array.

Since both PV arrays and electrolyzers are modular, a good match should be achievable for any desired voltage/current combination.

88. We have considered only fixed, flat plate arrays, because the experience gained from PV projects to date shows that gains in efficiency possible with tracking and/or concentrating systems are not sufficient to offset the added complexity of construction and maintenance.

Sources: G.T. Noel, D.C. Carmichael, R.W. Smith, and J.H. Broehl, "Optimization and Modularity Study for Large-Size PV Flat-Panel Array Fields", Batelle-Columbus,18th IEEE PV Specialists Conference, Las Vegas, Nevada, October 1985; G.J.Shushnar, J.H. Caldwell, R.F. Reinoehl, and J.H.Wilson, "ARCO Solar Field Data for Large PV Arrays", 18th IEEE PV Specialists Conference, Las Vegas, October 1985.

89. Balance of systems costs for amorphous silicon solar cell flat plate fixed PV arrays are discussed here.

A. Survey of Previous Studies

A large amount of research has been done on balance of systems costs for fixed flat plate arrays. This work is summarized in the following table, after which various studies are described. The terms used as defined as follows:

TERMINOLOGY USED IN PHOTOVOLTAIC ARRAY DESIGN

A module (or "laminate") is an individual PV power unit, typically 2' x 4'in size with peak power output in the 50-100 Watt range. All circuits in the array are made up of modules.

A panel is made up of perhaps 10-40 modules mounted on a common frame and connected electrically. Panels can be either assembled at a remote factory and shipped to the PV array site, assembled at an onsite factory, or constructed in the field.

A source circuit is made up of a number of panels connected electrically. The source circuit includes wiring between the modules, and the wiring between panels.

A subfield (or "building block") is made up of a number of source circuits connected electrically. A subfield size is typically 1-10 MW, and each subfield would have its own power conditioning unit (if needed).

The array support structure refers to the panel frame (on which the individual modules are mounted) and the foundations (e.g. vertical supports with concrete foundations) on which the tilted panels are installed. The panel frame cost can sometimes include electrical parts which are used to connect the individual modules together.

Junction boxes are used to gather panel or module wiring to form a source circuit.

Disconnects (switches and interrupts) are electrical safety devices, which are added at the panel or source circuit level.

DC cabling from source circuit connects source circuits to a DC interface. Each subfield would have one DC interface.

The DC interface would then collect the DC power from the source circuits. For the case of PV hydrogen production, this power would be sent to the electrolyzer. For a utility peaking plant, producing AC power, the DC interface would be connected to a DC to AC power conditioning unit.

BALANCE OF SYSTEM COSTS FOR A DC PV ARRAY

	CONCEPTUAL DESIGNS			FIELD STUDIES	
	EPRI	Sandia/ Battelle	RCA	EEC	ARCO/ SMUD
MODULE CHARACTERISTICS:					
Solar Cell Material	Thin Film	Crystalline Silicon	Amorphous Silicon	Crystalline Silicon	
Efficiency	15%	8%	10%		
Voltage (VDC)	120	5	120		
Current (amps)	1.6	12.8	1.24		
SYSTEM CHARACTERISTICS:					
System Size (MW)	100	100	50	0.03-0.3	5
Sub-field Size (MW)	10	1.5	12.5		
# Modules/Panel	16	16	18		
Panel Voltage (V)	960	20	1000		
Panel Current (amps)	3.2	51.2	2.5		
# Panels/Source Circuit	48	40	40		
Source Circuit Volt.	+/-960	+/-400	+/-1000		
Source Circuit Current (amps)	38.4	30	50		
System Lifetime (yr)	30	30			
SUPPORT STRUCTURE COSTS ($\$/m^2$):					
Panel	35	18.7			
Foundation	9.63	7.6			
Panel Installation	1.70	-			
Total	46.2	26.2	41.2	30-100	48
ELECTRICAL SYSTEM COSTS ($/Wp):					
Source Circuit:					
Wiring	0.0377	0.127	0.0315		
Junction Boxes	-	0.032			
Other DC Electrical:					
DC Bus Disconnects	0.0237	-	0.0054		
Wiring Source Circuit to DC Interface	0.0102	0.085	(incl. above)		
DC Interface	0.0275	0.063	-		
Fault Detection	-	0.032	-		
Total	0.0991	0.296	0.0369	-	$\$65/m^2$
OTHER COSTS ($\$/m^2$):					
Site Preparation + Clean-up	2.81	1.30	1.8		
Land	0.25	0.25	0.25		
Engineering Development	-	-	-	-	120
TOTAL AREA-RELATED COST ($\$/m^2$)	64.1	51.4	46.9	50-180	233

1. US DOE/JPL Studies: Extensive studies of flat-plate module and array design have been carried out by DOE/JPL researchers, in which the costs of various module designs for crystalline silicon, dendritic web and thin film solar cells have been estimated. Commercially available modules have been evaluated for reliability, safety, operating conditions. The goals the USDOE has set for thin-film modules by the late 1990s are 20-year lifetimes, 10% efficiency, and $0.50/Wp cost.

To obtain a levelized electricity cost of $0.15/kwhAC, DOE calculates that for area-related BOS costs of $\$50/m^2$ and power-related BOS costs of $0.15/Wp module costs must be about $\$15\text{-}20/m^2$ for 10% efficient modules and $\$50\text{-}60/m^2$ for 15% efficient modules.

Source: "Photovoltaics: Electricity from Sunlight: Five Year Research Plan," USDOE, DE84-010-679, May 1983.

2. EPRI Studies: EPRI has also estimated the efficiency, module cost, and BOS costs required to give a levelized electricity cost of $0.15/kwhAC. Their estimates are somewhat more optimistic than those of the Department of Energy. For a 10% efficient module (7.5% efficient system), a $\$50/m^2$ area related BOS cost would imply a $\$38/m^2$ module cost, according to their calculations. This study also assumed power related BOS costs of $0.15/Wp for power conditioning.

Source: J.G. Witwer, "Photovoltaic Power Systems Research Evaluation," EPRI Report AP-3351, December 1983.

EPRI has also sponsored detailed conceptual design studies of PV arrays. A conceptual design for a 100 MW power plant was carried out comparing various types of PV arrays, including fixed, flat-plate arrays. Key assumptions in this study were: 15% efficient flate plate modules (two cases were considered: thin film and crystalline silicon modules), 30-year lifetimes, 10 MW subfield (or building block) size, 35^o tilted array. The following are cost estimates for this conceptual design:

Estimated support structure and site costs: ($\$/m^2$)

Panel	35.0 (a)
Foundation/pedestal	9.63
Panel installation	1.70
Subtotal, installed support structure	46.3
Site preparation and clean-up	2.81 (b)
Land	0.25 (c)

Estimated electrical system costs: (d) ($/Wp)

Source circuit	0.0377 (e)
DC bus disconnect	0.0237 (f)
Cabling from source circuit to DC interface	0.0102
DC interface	0.0275
Subtotal	0.0991

a Includes panel structural and electrical components and panel assembly labor.

b $11,400/acre.

c $1000/acre.

d Module type: thin film; module efficiency: 15%; module voltage: 120 VDC; module current: 1.6 amps; module power: 192 watts; 16 modules arranged in an 8′ x 32′ "panel"; power from panel: 960 VDC, 3.2 amps; source circuit: 48 panels; source circuit current: 38.4 amps; source circuit voltage: 960 VDC.

e Interpanel and interarray wiring, installation, labor.

f Safety interrupts and switches.

Source: S.L. Levy and L.E. Stoddard "Integrated Photovoltaic Central Station Conceptual Designs," EPRI Report AP-3264, June 1984.

3. Sandia Laboratories/Battelle Conceptual Design of a 100 MW PV Array, based on crystalline silicon modules: Sandia Laboratories has investigated ways of reducing costs of fixed, flat plate arrays for use in central power station applications. With Battelle-Columbus they carried out a number of specific designs for a 100 MW central station PV array made up of "building blocks" 1 MW and 5 MW in size. Their design requirements were: 30-year equipment lifetime; no plastic or wood structural supports; foundations: concrete or concrete-encased; clear, level site; use of present day construction and installation techniques; flat panels tilted at 35 degrees. PV array costs were estimated for several designs with: 1 or 5 MW array "building blocks;" operating voltages of 400, 800 or 2000 VDC.

Estimated support structure and site costs: ($/$m^2$)

Installed support structure	26
Site preparation and clean-up	1.30
Land (@ $1000/acre)	0.25

Estimated electrical system costs: (a) ($/Wp)

	System	Voltage
	400 VDC	800 VDC
Source circuit (b)	0.12	0.13
Junction box (c)	0.03	0.02
Disconnects (d)	included in junction box	0.08
Cabling and DC interface to power conditioning unit	0.08	0.06
Fault detection	0.07	0.03
Subtotal	0.28	0.28

a Module type: crystalline silicon; module efficiency: 8%; module voltage: 5 VDC; module current: 12.8 amps; module power: 64 Watts; system current: 30 amps.

b Intermodule wiring, wiring to junction box, installation, labor.

c Blocking diodes, varistors, heat sinks, housings.

d Safety interrupts and switches.

Source: G.T. Noel, D.C. Carmichael, R.W. Smith, and J.H. Broehl, "Optimization and Modularity Study for Large-Size PV Flat-Panel Array Fields," Batelle-Columbus, 18th IEEE PV Spec. Conf., Las Vegas, Nevada, October 1985.

4. RCA Conceptual Design of a 50 MW amorphous silicon based PV power plant. RCA has developed a conceptual design of a central station PV array based on amorphous silicon flat plate modules, for flat panels tilted at 30 degrees.

Estimated support structure and site costs: ($/m^2)

Installed support structure	41.2
Site preparation and clean-up	1.8 (a)
Land	0.25 (b)

Estimated electrical system costs: (c) ($/Wp)

Wiring	0.0315
Electrical protection	0.0054 (d)
Subtotal	0.0369

---

a $12,000/acre.

b $1000/acre.

c Module type: amorphous silicon; module voltage: 120 VDC; module current: 1.24 amps; module power: 150 Watts: system voltage: 1000 VDC; system current: 2.5 amps.

d Safety interrupts and switches, fault detection.

Source: J.Stranix and A.H. Firester, "Conceptual Design of a 50MW Central Station Power Plant," RCA Laboratories, Princeton, NJ, 1982.

5. European Economic Community Field Studies of Flat Plate PV Arrays: Dr. Grassi and his colleagues have analyzed the costs of a number of European experimental PV arrays in the 30-300 kW size range. Area-related BOS costs (including the support structure and wiring, but not DC to AC power conditioning equipment) for these projects ranged from $50-180/m^2 with the support structure contributing $30-100/m^2.

Sources: G. Grassi, Commission of the European Communities, DC XII, Brussels, Belgium, 18th Photovoltaic Specialists Conference, Las Vegas, Nevada, October 1985; G. Grassi, P.Paoli, L.Leonardini, E. Vitali, P.Conti, E.Colpizzi, "Low-Cost support Structure for Large Photovoltaic Generators," 18th IEEE Photovoltaics Specialists Conference, October 1985.

6. ARCO Solar Field Experience at the SMUD PV Array: Estimated BOS costs based on cost data from an ARCO solar array at the Sacramento Municipal Utility Demonstration PV project are listed. The costs are quite high, because they include engineering for this first of kind project.

Source: G.J.Shushnar, J.H. Caldwell, R.F. Reinoehl, and J.H.Wilson, "ARCO Solar Field Data for Flat Plate PV Arrays," 18th IEEE PV Specialists Conference, Las Vegas, October, 1985.

B. Synthesis of a Base case BOS Design: Comparison of costs for EPRI, Sandia/Battelle and RCA conceptual designs

It is instructive to compare the BOS costs in the EPRI, Sandia/Battelle and the RCA designs with the goal of adapting the best features of each design for our base case amorphous silicon array.

1. Comparison of array support structure costs: "Array support structure costs" include the cost of the panel structure, the cost of building the foundations to support the panels and the cost of installing the panels. At an estimated \$26/m^2, the Sandia/Battelle support structure costs were considerably lower those in the EPRI design (\$46/m^2) or RCA designs (\$41.2/m^2). Part of the discrepancy comes from EPRI's estimated foundation and panel installation costs of \$11.3/m^2, which are about 50% higher than the \$7.6/m^2 projected by Sandia. But the largest difference was in the panel cost, which was about \$35/m^2 in the EPRI design and only \$18.7/m^2 in the Sandia design. The difference appears to be that the Sandia design assumed that PV panels were pre-assembled at a factory off-site prior to field installation, while the EPRI design relied on assembly of panels at a field site facility, where labor costs were higher. In the RCA design, the cost of off-site vs. onsite panel assembly was not directly addressed.

2. Comparison of electrical system costs: The electrical costs of the system are strongly dependent on the size of the wires used to interconnect the panels into source circuits, which in turn depends upon the panel current. To minimize wiring costs, a low current, high voltage design is preferable. This is evident when the costs of source circuit wiring are compared for the three studies. In the EPRI designs, a panel current of 3.2 amps was selected, with source current wiring costs of \$0.0377/Wp. For the Sandia design, a panel voltage of 51.2 amps was used, and source circuit wiring cost some \$0.127/Wp. In addition, for the Sandia design a junction box costing \$0.032/Wp was required. Thus, the source circuit wiring cost of a high current panel design was about 4 or 5 times larger than with a low panel current design. The RCA design used an

even lower panel current than the EPRI system--2.5 amps. In this study the total wiring costs (including the source circuit, cabling and the DC interface) were only $0.0315/Wp.

A low panel current was possible in the EPRI and RCA designs, both of which based their arrays on thin film solar cells, because these cells can be easily configured into low current, high voltage modules. The combination of low current and high voltage would be much more difficult and expensive with crystalline silicon solar modules like those used in the Sandia design.

The remainder of the electrical system cost was estimated to be $0.0614/Wp for the EPRI system and $0.0054/Wp for the RCA system, and $0.18/Wp for the Sandia system.

3. A base case $\$33/m^2$ BOS design for an amorphous silicon PV array: We have used the Sandia estimate for the panel support structure, foundation and panel installation costs, based on panel assembly at a remote site factory. The total installed support structure cost is $\$26.2\ /m^2$.

For the electrical system, we have used the RCA design, which appears to be optimized for amorphous silicon modules and takes advantage of wire cost savings inherent in low panel current design. The total cost estimated by RCA was $\$3.69/m^2$ for the electrical system costs.

Site preparation and land costs are clearly site dependent. If we assume a site preparation cost of $\$2.5/m^2$ and a land cost of $\$0.25/m^2$ ($1000/acre), then the total BOS cost is $\$32.6/m^2$.

90. It may be possible to further reduce the BOS costs by adopting alternative support structure designs.

For example, Dr. Grassi and his colleagues have analyzed the area- related costs of a number of European experimental PV arrays in the 30-300 kW size range. Area-related BOS costs for these projects ranged from $\$50\text{-}180/m^2$. The $\$50/m^2$ figure often cited as a 1990s goal for multi-megawatt array BOS costs by the US DOE has been already acheived in relatively small experimental (and therefore presumably more expensive) arrays in Europe!

Moreover, Grassi *et. al*. have produced conceptual designs with area-related BOS costs as low as $\$29/m^2$. Instead of using steel with concrete footings costing perhaps $\$24/m^2$ (the design favored in most US studies), the support structure in this low cost design (built of wooden poles with steel guy wires) costs only about $\$10\text{-}20/m^2$ and is flexible enough to endure strong winds without damage to the glass in the PV modules. (The usual strategy with steel and concrete support designs is to make the structure rigid and strong enough to remain unmoved by buffeting winds.) Grassi's design could be assembled locally using fairly simple construction skills and might be attractive for use in developing countries.

Dr. Ted Taylor of NOVA, Inc. has proposed using inflatable plastic structures or horizontal embedding in asphalt for supporting amorphous silicon PV modules on plastic substrate. The costs of these support structures are estimated to be much lower than standard designs--perhaps in the range of $\$10\text{-}15/m^2$. If this could be acheived the total area-related BOS costs would be reduced to about $\$20/m^2$, taking conventional estimates for wiring, site prep and installation costs. The installation costs would probably be reduced, as concrete foundations for tilted support structures would not be neccessary. The wiring costs could also be reduced in a large horizontal array.

Sources: G. Grassi, P. Paoli, L. Leonardini, E. Vitali, P. Conti, E. Colpizzi, "Low-Cost Support Structures for Large Photovoltaic Generators," 18th IEEE Photovoltaic Specialists' Conference, Las Vegas, Nevada, (October 1985); T. B. Taylor and H. B. Warren, "The Development of Low Cost Photovoltaic Systems Based on Amorphous Silicon Solar Cells", NOVA, Inc., draft, (October 1984).

91. The system efficiency is defined as the electrical energy produced by the entire PV array divided by the incident solar energy. System efficiency includes losses due to wiring of modules, etc. Typically a 10% efficient system is made up of 12% efficient modules; a 15% efficient system of 18% efficient modules.

92. The cost of DC photovoltaic electricity Ce (in \$ per kWh) can be expressed as:

$$Ce = \{(CRF + INS) \times (1 + ID) \times [Cp + Cb/(n \times Ip)] + Com\}/(Aw \times nBOS) \qquad (1)$$

where:

CRF = capital recovery factor
INS = insurance/property tax factor
ID = indrect cost factor
Cp = cost of solar PV module (in \$ per peak Watt)
Cb = cost of balance of systems components (in \$ per square meter) (array support structure, wiring and other DC electrical components, land, and construction costs)
n = PV module solar conversion efficiency
Ip = peak insolation = 1000 Watts per square meter
Ia = average yearly insolation (in kW per square meter)
Com = annual operation and maintenance cost (in \$ per peak Watt)
Aw = number of kWh produced annually per peak Watt of solar array = (8760 hours/year) x (Ia/Ip) = 8.76 Ia on a fixed flat collector tilted at the latitude angle.
nBOS = balance of system efficiency = PV system eff./PV module eff.

From Eq. (1) the DC electricity cost can be obtained as a function of solar module cost (Cp) and balance of system cost (Cb), if the other parameters are fixed at typical values. In this study the following values are considered:

CRF = 0.0734 (30-year life)
INS = 0.005
ID = 0.25 (although values of 50% are often used today, Sandia researchers who have done conceptual designs of large (>5MW) PV system indirect costs of 25% are appropriate for a mature PV industry *)
n = 12% and 18%
Com = [$0.45 per square meter (suggested by field data from large flat plate PV arrays)]/(n x Ip)
Aw = 2.37 kWh/year per W_p for El Paso, TX (equivalent to a capacity factor of 0.271) and 1.45 kWh/year per W_p for Newark, NJ (equivalent to a capacity factor of 0.166).
nBOS = 0.85

Thus:

$$Ce = \{(0.0980) \times [Cp + Cb/(1000 \times n)] + 0.00045/n\}/(Aw \times nBOS) \quad (2)$$

93. There are currently three electrolysis technologies commercially available or under development. Two of these, the "unipolar" and "bipolar" alkaline electrolyzers, which form hydrogen and oxygen by passing direct current through an aqueous solution of potassium hydroxide (lye), are commercially available, mature technologies. Only modest refinements and cost improvements are expected in the next 5-15 years. Unipolar electrolyzers are less expensive, more efficient, and more modular; bipolar electrolyzers have the advantage of high pressure operation, which saves on compression costs for the produced hydrogen. The third type of electrolyzer, which uses solid polymer electrolytes (SPE) made of an acid resin, is still in the demonstration stage. At present, platinum catalysts are required for stable operation. Although the search for less expensive and rare catalyst materials continues, a long-term solution to this problem is uncertain. In the present study only alkaline type electrolysers are considered.

It has been suggested that running the electrolyzer at high pressure could reduce overall hydrogen costs by eliminating the need for external compression. The tradeoffs between less costly, more efficient unipolar electrolysers and bipolar electrolysers that require less compression of the produced hydrogen are considered for various applications in the present study.

94. The cost of electrolytic hydrogen Ceh (in $/GJ) for a large plant supplied with DC electric power (so that no rectifier is required) can be expressed as:

---

* According to Sandia researchers field experience shows that this is an appropriate indirect cost factor for crystalline solar cells in flat plate arrays. As a-Si technology is expected to reach a comparable level of maturity before 2000, this indirect cost factor is assumed for the present anaylsis.

$$\mathrm{Ceh} = \mathrm{Cehc} + \mathrm{Cehe} \tag{1}$$

where:

Cehc = capital component of electrolysis cost

$$\begin{aligned} &= [(\mathrm{Vr}/1.481 \text{ volts})/(8760 \text{ hours/year})/(0.0036 \text{ GJ/kWh})] \\ &\quad \times [(\mathrm{CRF} + \mathrm{INS} + \mathrm{OM})/\mathrm{CF}] \times \mathrm{Cem} \\ &\quad \times \{\mathrm{f1} \times (\mathrm{ir}/\mathrm{i}) + (1 - \mathrm{f1}) + 0.5 \times \mathrm{f2} \times [1 + (\mathrm{ir}/\mathrm{i})]\}, \end{aligned} \tag{2}$$

Cehe = DC electricity cost component of electrolysis cost

$$= \mathrm{Ce}/(0.0036 \text{ GJ/kWh})/\mathrm{ne}, \tag{3}$$

and:

Vr = rated voltage of electrolyzer (in volts)
CRF = capital recovery factor
INS = insurance factor
OM = operation and maintenance cost factor
CF = capacity utilization factor = no x (1000/8760) x Aw
no = coupling efficiency between PV array and electrolyzer

Cem = electrolyzer cells and accessories unit capital cost (1986$/kW of DC power input, at V = Vr)
f1 = fraction of electrolyzer cells and accessories capital cost independent of operating current density
f2 = installation-related costs, as a fraction of the cells and accessory cost--half independent of operating current density and half increasing linearly with operating current density
ir = rated electrolyser current density (in milliamps per square cm)
i = operating current density (in milliamps per square cm)
Ce = cost of DC electricity (in $ per kWh)
ne = electrolyzer efficiency (DC power to hydrogen) = 1.481/V
V = operating voltage of electrolyzer (in volts)

The following were assumed for all cases considered in this study:

CRF = 0.0879 (20-year life)
INS = 0.005
OM = 0.02
Aw = 2.37 kWh/Wp/year (El Paso); 1.45 kWh/Wp/year (Newark)
no = 0.93 (see Note 87) =>
CF = 0.252 (El Paso) and 0.154 (Newark)

The contribution of photovoltaic power to the cost of electrolytic hydrogen is [combining equation (1) in Note 92 and equation (3) above]:

$$\mathrm{Cehe} = \{27.22 \times [\mathrm{Cp} + \mathrm{Cb}/(1000 \times \mathrm{n})] + 0.125/\mathrm{n}\}/(\mathrm{ne} \times \mathrm{Aw} \times \mathrm{nBOS}) \tag{4}$$

For large (>10 MW) electrolyzers:

Parameter	Unipolar	Bipolar	SPE (projected)
ne (at V = Vr)	0.85	0.80	0.90
Vr	1.74	1.85	1.65
V (operating range)	1.7-2.0	1.7-2.0	1.65
ir	134	215	1076
i (operating range)	134-320	250-1000	1000-2000
f1	0.9	0.8	0.5
f2	0.45	0.45	0.75
Cem	170	200 (1 atm.) 255 (30 atm.)	200

Parameters other than capital costs are from Leroy and Stuart (R.L. Leroy and A.K. Stuart, "Unipolar Water Electrolyseers: a Competitive Technology," in Hydrogen Energy System, Proceedings of the 2nd World Hydrogen Energy Conference, Zurich, 21-24 August, 1978). The capital estimates for large unipolar electrolizers are from Craft (private communication from R.F. Craft, Electrolyser Corporation, Ontario, Canada, 1985). The capital costs for atmospheric pressure bipolar and SPE electrolyzers are from Fein and Edwards (E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Services Territories," Electric Power Research Institute Report EPRI EM-3561, May 1984). The capital cost for a pressurized bipolar electrolyzer is estimated to be 25-30% higher than for an atmospheric pressure unit (private communication from R.F. Craft, Electrolyser Corporation, Ontario, Canada, 1985). The capital cost for an SPE unit is estimated to be the same as for an atmospheric pressure bipolar unit (E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Services Territories," Electric Power Research Institute Report EPRI EM-3561, May 1984).

Cehc, the capital contribution to the cost of electrolytic hydrogen (in $/GJ) depends sensitively on the ratio (i/ir), as is indicated by the following, for operation in El Paso:

i/ir	Unipolar	Bipolar	SPE
1	4.41	5.15	5.54
2	2.52	3.32	4.16
3	1.99	2.72	*

Thus, operating above the rated current could reduce the electrolyzer capital cost contribution substantially. However, the electrolyzer lifetime is reduced and the electrolysis efficiency is reduced when the electrolyzer is operated at high current density. Such tradeoffs

---

* Outside electrolyzer operating range

are considered in determining the optimum operating current density. For the unipolar electrolyser, the costs of produced hydrogen for different values of i/ir and electricity price are as follows:

Eff.	$/Wp	$/kWh	(i/ir=1; ne=0.90)			(i/ir=2; ne=0.84)			(i/ir=3; ne=0.80)		
			cap.	elct.	tot.	cap.	elct.	tot.	cap.	elct.	tot.
0.12	0.40	0.0347	4.11	10.71	14.82	2.52	11.44	13.96	1.99	12.02	14.00
0.18	0.40	0.0296	4.11	9.14	13.25	2.52	9.76	12.28	1.99	10.26	12.25
0.12	0.20	0.0250	4.11	7.72	11.83	2.52	8.23	10.75	1.99	8.65	10.63
0.18	0.20	0.0199	4.11	6.14	10.25	2.52	6.56	9.07	1.99	6.89	8.88

In this study i/ir = 2 is chosen as the operating value.

-----

* Outside electrolyzer operating range.

95. The efficiency and capital costs of electrolyzers are shown here as a function of hydrogen output capacity.

EPRI Estimates for Capital Costs of Advanced Electrolysis Plants (SPE and Alkaline Technology)

Size (kW of H2 output)	25 kW	40 kW	100 kW	500 kW	2 MW
Module cost ($/kW H2 out)	750	520	450	380	250
Total plant ($/kW H2 out)	3050	2060	1600	720	380
Site prep ($/kW H2 out)	2600	1650	760	312	114
Rectifier ($/kWAC in)	100	100	100	100	100
Plant efficiency	.56	.56	.63	.8	.81

Electrolyzer Corp. Estimates of Capital Costs for Unipolar Plants

Plant Size	25 kW	40 kW	100 kW	500 kW	2MW
Module cost ($/kwH2 out)	750	500	250	250	200
Plant cost ($/kwH2 out)	2200	1000	320	320	320
Site Prep	1000	500	100	100	100

($/kwH2 out)					
Plant efficiency	.6	.7	.8	.8	.8

Source: E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Service Territories", EPRI Report, EM-3561, May 1984; R.F. Craft, Electrolyser Corp., private communications, 1985.

96. Most design studies for central station PV power plants have chosen 1-10 MW as an appropriate "building block" size. There is little economy of scale above sizes of about 5-10 MW (G. T. Noel, D. C. Carmichael, R. W. Smith, and J. H. Broehl, "Optimization and Modularity Study for Large-Size Photovoltaic Flat-Panel Array Fields," 18th IEEE Photovoltaic Specialists' Conference, Las Vegas, Nevada, October 1985).

97. Oxygen is produced in electrolysis at a rate of 0.0563 tonnes per GJ of produced hydrogen. The net value of the oxygen byproduct is estimated to be $1.5-2.2 per GJ of hydrogen (in 1986 US$) (see Note 155, and M. Hammerli, "When Will Electrolytic Hydrogen Become Competitive?" Journal of Hydrogen Energy, vol. 9, no. 1/2, pp. 25-51, 1984.)

98. In this note, alternative types of hydrogen storage are described and the cost of hydrogen storage is estimated.

A. Types of Hydrogen Storage

1. Large-Scale Hydrogen Storage for an Energy System: Gaseous hydrogen can be stored underground at 600-750 psi in depleted oil or gas fields, aquifers, and rock or salt caverns. Such formations typically have very large capacities (up to 10^9 Nm^3, or large enough to store up to 0.01 EJ of hydrogen).

For gas wells or aquifers only a few percent of this capacity is accessible per storage cycle, as the rest must be filled with "cushion gas". If pure hydrogen is stored, the cushion gas is additional capital cost. Rock caverns allow about 25% turnover in capacity per storage cycle. Wet salt caverns may allow 100% turnover of the gas storage volume.

Let us assume that a solar hydrogen storage system would have to cycle a day's worth of hydrogen production to level the output to the pipeline. A single rock cavern 5 x 10^6 Nm^3 in size could cycle one day's output from a 750 MWp solar-powered electrolysis plant operated at 25% capacity factor. An aquifer or depleted gas field 10^9 Nm^3 in size could cycle 10^7 Nm^3/day, which is equivalent to one day's output from 5900 MWp of solar hydrogen capacity.

2. Storage of Gaseous Hydrogen for Industrial Use: Alternatively, gaseous hydrogen can be stored in rows of pressurized steel tanks above ground at typically at 450-2500 psi. Tank storage is modular, with very little economy of scale. Most industrial hydrogen is currently stored this way in the US. At the present, the total US storage capacity is about 10 days hydrogen production, or about 3% of the annual total.

For small scale industrial gaseous hydrogen storage, pressurized steel tanks are the best alternative, unless liquid hydrogen is needed at the point of end use. In a survey by Fein and Edwards small hydrogen users reported storage costs between \$1.5-15/GJ depending on the application. (See E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Service Territories," EPRI Report, EM-3561, May 1984.)

B. The Cost of Hydrogen Storage

The cost of hydrogen storage is made up of storage capital costs plus power costs per storage cycle plus O+M costs. The cost of storage per GJ of hydrogen output from the electrolyzer is

$$Psto = \frac{Csto \times [(CRF + INS + fom) \times xs + Nsc \times Pcyc \times Pe]}{p \times Ho} \qquad (1)$$

where:

Psto = contribution of storage costs to hydrogen product in \$/GJ
Csto = storage capacity in kscf of hydrogen
CRF = capital recovery factor
INS = insurance
fom = (yearly O&M cost)/(storage capital and installation cost)
xs = capital + installation cost in \$/kscf of hydrogen stored
Nsc = number of storage cycles/year
Pcyc = number of kWh used per storage cycle per kscf of stored H2
Pe = cost of electricity used to run storage cycle (\$/kWh)
p = annual average capacity factor of electrolyzer
Ho = maximum electrolyzer output in kW of H_2 out.

Equivalently, we can write Eq. (1) as:

$$Psto = 2.777 \times fs \times [(CRF + INS + fom) \times xs + Nsc \times Pcyc \times Pe]$$

where

$$fs = 0.360 \text{ (GJ/kscf } H_2) \times Csto/(p \times Ho)$$

= fraction of annual electrolyzer output which is stored

and

p x Ho = annual hydrogen output of the electrolyzer in GJ.

We assume:

CRF = 0.0734 (30-year lifetime for storage facilities, 6.1% discount rate)
INS = 0.005
Nsc = 365 cycles/year (or one storage cycle per day)
Pe = cost of PV electricity at the electrolyzer site (see Note 92)
fs = 2/(3 x 365) (the storage system is sized to hold 2/3 of one day's

electrolyzer output or 2/(3 x 365) of annual electrolyzer output)

In the Table below, we show values for large-scale hydrogen storage systems, based on a recent study. In all cases compression from a unipolar atmospheric pressure electrolyzer to storage pressure is assumed. (Storage costs might be less if a bipolar electrolyzer at 450 psi were used, as no storage system compressor would be required.) A range of storage pressures is given, reflecting the pressure cycle as the storage reservoir is charged and discharged. For a unipolar electrolyzer (operating at atmospheric pressure), the compression power needed to reach a pipeline pressure of 1000 psi would be reduced at night, when hydrogen is taken from storage. However, electricity costs might also be higher at night, because low-cost DC PV power would not be available.

1. Gaseous Hydrogen Underground Storage Parameters

	Rock Cavern	Salt Cavern "Wet"	Salt Cavern "Dry"	Gas Well
Csto (kscf)	70,620	70,620	70,620	141,240
xs($/kscf)	874	865	766	329
Pcyc(kwh/cyc/kscf)	3.60	3.99	3.60	0.595
fom	4.6%	4.7%	4.8%	2.1%
Pressure Range (psig)	250-370	0-840	250-370	28-110

Source: J.B. Taylor J.E.A. Alderson, K.M.Kalyanam, A.B.Lyle, and L.A. Phillips, "Technical and Economic Assessment of Methods for the Storage of Large Quantities of Hydrogen," International Journal of Hydrogen Energy, Vol. 11, p. 5, 1986.

2. Storage Contribution to Hydrogen Cost ($/GJ)

	Rock Cavern	Salt Cavern "Wet"	Salt Cavern "Dry"	Gas Well
Capital+Install	0.348	0.344	0.305	0.131
Power *	0.132	0.147	0.132	0.022
O+M	0.204	0.206	0.186	0.035
Total	0.685	0.698	0.624	0.188

* For electricity costing $0.020/kWh.

99. The cost of hydrogen compression Ccm (in $/GJ) can be expressed as:

$$Ccm = Ccmc + Ccme, \qquad (1)$$

where

Ccmc = capital component of compressor cost

$$= [1/(0.0036 \text{ GJ/kWh} \times 8760 \text{ hours/year})] \times (\text{CRF} + \text{INS} + \text{OM})$$

$$\times [(\text{Pcm} \times \text{CAcm})/(\text{Ho} \times \text{CF})], \qquad (2)$$

Ccme = energy cost component of compressor cost

$$= [1/(0.0036 \text{ GJ/kWh})] \times [(\text{Pcm} \times \text{Ce})/(\text{Ho} \times \text{nc})], \qquad (3)$$

and:

CRF = capital recovery factor
INS = insurance factor
OM = operation and maintenance cost factor
CF = capacity utilization factor
Pcm = compressor capacity needed (in kW)
CAcm = capital cost of compressor (in $/kW)
Ho = maximum electrolyzer output (in kW of hydrogen product)
nc = compressor efficiency
Ce = cost of electricity for running compressor (in $/kWh).

The compressor capacity needed is:

$$\text{Pcm} = \text{Q} \times (\text{Pb/Tb}) \times (\text{T1/nc}) \times \text{Z} \times [\text{Ng}/(\text{g}-1)]$$

$$\times [(\text{P2/P1})^{[(\text{g}-1)/(\text{Ng})]} - 1]/(1000 \text{ W/kW}), \qquad (4)$$

where

Q = maxiumum hydrogen flow rate (in cubic meters/second, at Tb, Pb)
T1 = hydrogen temperature at compressor inlet (in degrees K)
Pb = 101,300 Newtons per square meter (atmospheric pressure)
Tb = 298 degrees K
T1 = initial temperature of hydrogen (degrees K)
P1 = initial pressure
P2 = final pressure
Z = hydrogen compressibilty = 1
g = ratio of specific heats for hydrogen = 1.41
N = number of stages of compression

The flow rate Q is simply related to the electrolyzer output Ho:

$$\text{Q} = (11.1 \text{ m}^3/\text{kg}) \times (7.049 \text{ kg/GJ})/(10^9 \text{ W-sec/GJ}) \times (10^3 \text{ W/kW}) \times \text{Ho}$$

$$= (8.059 \times 10^{-5}) \times \text{Ho} \qquad (5)$$

Thus

$$\text{Pcm} = 0.02808 \times (\text{N/nc}) \times (\text{T1/Tb}) \times \text{Ho} \times [(\text{P2/P1})^{(0.291/\text{N})} - 1] \qquad (6)$$

For the calculations in this study:

CRF = 0.0879 (20-year life)
INS = 0.005
OM = 0.10
CF = 0.252 (El Paso)
nc = 0.85
CAcm = \$610/kW (for hydrogen flows larger than 0.5 x 10^6 Nm^3 per day)

The compressor capital, O&M, and insurance/property tax values used here were taken from Leroy and Stuart (R.L. Leroy and A.K. Stuart, "Advanced Unipolar Electrolysis," <u>International Journal of Hydrogen Energy</u>, vol. 6, no. 6, pp. 589-599, 1981) and converted to 1986\$.

For the case where photovoltaic power is used to run the compressor, Ce is given by equation 2 in Note 92:

$$Ce = \{(0.0980) \times [Cp + Cb/(1000 \times n)] + 0.00045/n\}/(Aw \times 0.85), \quad (7)$$

so that:

$$Ccme = 326.8 \times (Pcm/Ho) \times Ce \quad (8)$$

$$= 326.8 \times (Pcm/Ho) \times \{(0.0784) \times [Cp + Cb/(1000 \times n)] + 0.00045/n\}/(Aw \times 0.85), \quad (9)$$

and:

$$Ccmc = 14.81 \times (Pcm/Ho). \quad (10)$$

For the case where P1 = 1 atm, P2 = 30.6 atm (450 psia), N = 3, T1 = 353 degrees K, one obtains Pcm/Ho = 0.0462.

For the case where P1 = 30.6 atm (450 psia), P2 = 68 atm (1000 psia), N = 1, T1 = 353 degrees K, one obtains Pcm/Ho = 0.0102.

Thus the total cost (in \$/GJ) of compressing the gas from atmospheric pressure to 1000 psia would be:

$$Ccm = \$0.84 + \{(2.125 \times [Cp + Cb/(1000 \times n)] + 0.00976/n\}/Aw. \quad (11)$$

Summary of Costs for Hydrogen Compression (\$/GJ)

P1->P2(psia)	Capital	Power	Total (for Ce = \$0.02/kWh)
14.7->450	0.69	15.1 x Ce	0.99
450->1000	0.15	3.33 x Ce	0.22
14.7->1000	0.84	18.4 x Ce	1.21

The unit capital cost for the compressor used in the above analysis is a reasonable approximation at high compressor capacities. In general, compressor costs scale as a function of size. According to a 1977 estimate, reciprocating, multi-stage, high pressure (> 1000 psi) hydrogen compressors scale as follows:

CAcm = 455 x (1 - Qhd/2.832) + 228 + Cdrive

where

Qhd = hydrogen flow rate in 10^6 Nm^3/day.
Cdrive = cost of motor drive in $/kW.

and

Pcm (kW)	Cdrive ($/kW)
< 522	171
522 - 746	137
746 - 1679	137
1679 - 2611	68
2611 - 4103	55
> 4103	36

Note, for example, that For Pcm = 3000 kW and Qhd = 0.8 x 10^6 Nm^3 per year, CAcm = $610/kW, according to this analysis.

Source:K. Darrow, N. Biederman and A. Konopka, "Commodity Hydrogen from Off-Peak Electricity," International Journal of Hydrogen Energy, Vol. 2, pp 175-187, 1977.

Another source of hydrogen compressor cost data is a 1986 study:

A 4-stage horizontal reciprocating compressor with a 100 hp (74.6 kW) explosion-proof motor drive costs $150,000 or $2011/kW.

A 4-stage reciprocating compressor with a 2500 hp (1865 kW) electric motor drive costs $1,800,000 or $965/kW.

A 3-stage reciprocating compressor with a 6000 hp (4476 kW) electric motor drive cost $2,300,000 or $514/kW.

Source: J.B. Taylor J.E.A. Alderson, K.M.Kalyanam, A.B.Lyle, and L.A. Phillips, "Technical and Economic Assessment of Methods for the Storage of Large Quantities of Hydrogen," International Journal of Hydrogen Energy, Vol. 11, p. 5, 1986.

100. The flow Q (in m^3/s) for a flat straight section of pipe L (in meters) and diameter D (in meters) with no booster compressors is given by:

$$Q = (-Tb/8Pb) \times [R/(WaGTLZ]^{0.5} \times (1/f)^{0.5} \times [P1^2 - P2^2]^{0.5} \times D^{2.5},$$

where

Tb = base temperature at which Q is measured = 298 °K
Pb = base pressure = 1 atm = 14.7 psia = 1.01325 x 10^5 N/m^2
R = univeral gas constant = 8314.34 Joules/(kg mol °K)

W_a = molecular weight of air = 28.97
G = specific gravity of hydrogen = 0.0695
Z = compressibility factor = 1
T = average operating temperature
f = friction coefficient (Fanning friction)
L = pipeline length (in meters)
D = pipeline diameter (in meters)
P1 = pipeline inlet pressure
P2 = pipeline exit pressure

Thus:

$$Q = 429.93 \times 10^{-5} \times (1/fL)^{0.5} \times [P1^2 - P2^2]^{0.5} \times D^{2.5},$$

Here it is assumed that:

P1 = 1000 psia = 68.93×10^5 Newtons/square meter
P2 = 300 psia = 20.68×10^5 Newtons/square meter
Ho = 16 GW = 16×10^6 kW = 0.505 EJ/year (~ 1% of US fluid fuel use)
Q = $8.059 \times 10^{-5} \times (16 \times 10^6) = 1289\ m^3/s$
L = 1000 miles = 1.609×10^6 M
T = 298 °K

Thus one obtains:

$$57.84 \times D^{-2.5} = (1/f)^{0.5}$$

The friction coefficient applicable for most natural gas operating conditions is that given by the rough-pipe formula, an empirical formula for fully turbulent flow which is assumed to apply to hydrogen as well:

$$(1/f)^{0.5} = 4\log_{10}(3.7D/k) + 2.273,$$

where k = 0.0007 meters is a roughness factor. Thus:

$$57.84 \times D^{-2.5} = 4\log_{10}(5286D) + 2.273$$

$$\Rightarrow D = 1.596 \text{ meters (62.8 inches).}$$

According to Christodoulou (Diomedes Christodoulu, Technology and Economics of the Transmission of Gaseous Fuels via Pipelines, Thesis, Master of Science in Engineering, Princeton University, April, 1984) Cpl, the pipeline cost per meter is:

$$Cpl = 1.193 + 229.19\ D + 269.0\ D^2$$

For D = 1.596 meters,

$$Cpl = 1.193 + 365.787 + 685.201 = \$1052.18 \text{ per meter.}$$

Thus for a 1000 mile pipeline, TPC, the total pipeline cost is:

$$TPC = Cpl \times L = \$1.693 \times 10^9$$

The pipeline cost unit of delivered hydrogen is:

$$Cp = (CRF + INS + OM) \times TPC/(CF \times 0.504 \text{ EJ/year}) = \$0.35/\text{GJ},$$

if:

$CRF = 0.0734$ (30-year life)
$INS = 0.005$
$OM = 0.01$
$CF = 0.85$

101. J. Pangborn and M.I. Scott, "Domestic Uses of Hydrogen," in Hydrogen: Its Technology and Implications, D.A. Mathis, ed., Energy Technology Review No. 9, Noyes Data Corporatin, 1976.

102. Diomedes Christodoulu, Technology and Economics of the Transmission of Gaseous Fuels via Pipelines, Thesis, Master of Science in Engineering, Princeton University, April, 1984.

103. Hydrogen from refinery stack gases has been used as a natural gas extender by some utilities. In addition, some synthetic natural gases from petroleum products are naturally rich in hydrogen. In Honolulu, manufactured gas typcially has a hydrogen content (by volume) of 10%. No adjustment of end-use systems is neccessary at this modest level of hydrogen blending.

Source: W.J.D. Escher, R.W. Foster, R.R. Tison, and J.A. Hanson, "Solar/Hydrogen Systems Assessment", DOE/JPL-9559492, 1980.

CHAPTER 4

104. Birgir Arnason, Methanol from Biomass and Urban Refuse: Prospects and Opportunities, Thesis, Master of Science in Engineering, Princeton University, 1983.

105. Conference Statement of the 1988 World Conference on the The Changing Atmosphere: Implications for Global Security, op. cit.

106. R.K. Lester, "Rethinking Nuclear Power," Scientific American, vol. 254, no. 1, pp. 31-39, March 1986.

107. Present day nuclear power plants fueled with low-enriched uranium and operated on once-through nuclear fuel cycles at 65% average capacity discharge 141 kg of fissile plutonium per year in their spent fuel, some 24.8 kg per billion kWh (H.A. Feiveson, F. von Hippel, and R.H. Williams, "Fission Power: an Evolutionary Strategy," Science, vol. 203, pp. 330-337, January 26, 1979).

108. D. Albright and H. Feiveson, "Why Plutonium Recycle?" Science, vol. 235, pp. 1555-1556, March 27, 1987; D. Albright and H. Feiveson, "Plutonium Recycling and the Problem of Nuclear Weapons Proliferation," Annual Review of Energy, vol. 13, pp. 239-265, 1988.

109. In a full-blown plutonium economy, involving plutonium breeder reactors and light water reactors operated on closed fuel cycles, spent fuel would be reprocessed to recover the plutonium and recycle it in fresh fuel. The fissile plutonium discharge rate would be about 181 kg per billion kWh for a liquid metal fast breeder reactor (H.A. Feiveson, F. von Hippel, and R.H. Williams, "Fission Power: an Evolutionary Strategy," Science, vol. 203, pp. 330-337, January 26, 1979) and 142 kg per billion kWh for a light water reactor operated on natural uranium and plutonium (C.E. Till, "Fuel Cycle Options and Fueling Modes," Argonne National Laboratory, 1978, unpublished). In equilibrium each 1 GW of breeder capacity could produce enough fuel to meet its own recurring needs and support 0.42 GW of light water reactor capacity (H.A. Feiveson, F. von Hippel, and R.H. Williams, "Fission Power: an Evolutionary Strategy," Science, vol. 203, pp. 330-337, January 26, 1979). Thus in a full-blown plutonium economy the fissile plutonium discharge rate would average about 170 kg per billion kWh--or 966 kg per installed GW(e), for nuclear plants operating at a 65% average capacity factor.

The global consumption of fossil fuels in 1986 was as follows (British Petroleum Company, "BP Statistical Review of World Energy," London, June, 1987):

oil	2881.0 MTOE =	120.6 EJ
natural gas	1507.1 MTOE =	63.1 EJ
coal	2309.1 MTOE =	96.7 EJ
Total	6697.2 MTOE =	280.4 EJ

Since 1 billion kWh of AC electricity can produce via electrolysis:

$$0.96 \times 0.84 \times 0.0036 \text{ EJ} = 0.00290 \text{ EJ of hydrogen,}$$

the replacement of 1/4 of fossil fuel with nuclear-derived hydrogen would require the annual generation of 24.14 trillion kWh per year of nuclear electricity from some 4200 GW of nuclear generation capacity (compared to total world electricity production of 9.27 trillion kWh in 1984) and would generate some 4.1 million kg of fissile plutonium per year.

110. See Appendix A in J. Goldemberg, T.B. Johansson, A.K.N. Reddy, and R.H. Williams, Energy for Sustainable World, Wiley-Eastern, 1988. See note 34.

111. Ibid.

112. R.H. Williams, "Potential Roles for Bioenergy in an Energy-Efficient World," Ambio, vol. 14, nos. 405, pp. 201-209, 1985.

113. Ibid.

114. In this note the production costs of gaseous and liquid synthetic fuels derived from coal and biomass are estimated, as a basis of comparison with PV hydrogen (see Notes 92, 94 for production costs of PV hydrogen).

The following fuel cycles are considered:

Gaseous fuels:

- Coal -> high-BTU gas (synthetic natural gas)
- Coal -> medium-BTU gas

Liquids:

- Coal -> gasoline
- Coal -> methanol
- Biomass -> ethanol

Summary of Production Costs of Synthetic Fuels

Process	Plant Size (1000 GJ/day)	Installed Cost ($$10^6$)	Energy Eff. (%)	Production Cost of Fuel ($/GJ)
Coal -> High BTU gas (a)	264	1820	66.8	5.7
	88	756		6.4
	26.4	341		7.9
Coal -> Medium BTU gas (b)	264	1370	72.9	5.1
Coal -> Gasoline (c)	176	5107	63.6	16.2
Coal -> Methanol (d)	322	3860	53.9	7.9
	32.2	567		10.0
	3.22	82.7		13.1
Corn (US) -> Ethanol	13.0	95.2		14.4
Sugar Cane (Brazil) -> Ethanol	2.68	7.7		8.0

[a] For a dry ash Lurgi gasifier using Western coal as a feedstock.

[b] For a Texaco gasifier using Eastern coal as a feedstock.

[c] For the SRC-II Process, for which 65% of the produced energy is gasoline, with 23% and 12% as SNG and LPG byproducts, respectively.

[d] For a Texaco gasifier.

1. Synthetic Gas from Coal

The levelized cost of synthetic gas is estimated as follows:

$$\text{Pfuel} = [\text{CRF} \times (\text{Cap} + \text{SU}) + \text{INS} \times \text{Cap} + d \times \text{WC} + \text{Pom} - \text{Pby}]/(S \times p \times 365\ \text{days/yr}) + \text{Pfeed} / \text{nc}.$$

where:

Pfuel = production cost of fuel in 1986 dollars per Gigajoule of fuel energy (where energy is on a higher heating value basis).
CRF = capital recovery factor = $d/[1 - (1 + d)^{-N}]$
d = discount rate
N = lifetime of plant in years
INS = insurance as fraction of capital cost
Cap = installed capital cost of plant (in $)
SU = start-up capital (in $)
WC = working capital (in $)
S = maximum plant output in GJ of fuel produced per day.
p = capacity factor of plant = 0.80
Pom = operating and maintenance costs (in $/year)
Pby = byproduct credit ($/year)
Pfeed = cost of feedstock (coal or biomass) (in $/GJ)
nc = energy conversion efficiency of feedstock to fuel

1a. Coal -> High BTU gas (SNG)

First consider the production of SNG for various processes for a plant producing 250×10^9 BTU/day (= 264,000 GJ/day = 3055 MWt), assuming:

d = 0.061
N = 30 years
INS = 0.005
p = 0.80
Pfeed = $1.78/GJ (the average price of steam coal projected for the year 2000 by the US Department of Energy (Energy Information Administration, Annual Energy Outlook 1986, with Projections to 2000, DOE/EIA-0383(86), February 11, 1987)

Process	Dry Ash Lurgi	Dry Ash Lurgi	Texaco	British Gas/Lurgi
Coal type	Western	Eastern	Eastern	Eastern
Capital ($1986 billion)	1.82	2.28	3.32	2.01
nc	0.668	0.527	0.475	0.565
Water requirements (liter/GJ)	38.1	231.6	280.3	248.4

The operation and maintenance costs for SNG producion are (in $\$10^6$/year):

Water	0.872	5.24	6.32	5.62
Catalysts/chemicals	10.94	17.48	14.4	26.3
Labor	10.63	10.63	8.86	9.78
Maintenance	63.77	80.02	116.3	70.2
Byproduct electricity	-	-	-23.8	-
Pom (= Total O&M)	85.7	113.4	122.1	112.0

The working capital WC is (in $\$10^6$):

94.4	122.7	146.9	121.7

The start-up cost SU is (in $\$10^6$):

42.0	51.4	54.6	49.3

[Note: The costs in the original reference (in mid 1979$) were converted to 1986$ by multiplying by 1.457, derived from the US GNP deflator.]

Source: M. Teper, D.F. Heming, and W.C. Ulrich, "The Economics of Gas from Coal", Economic Assessment Service, London, England, ISBN 9029-072-2, EAS Report E2/80, January 1983.

The levelized production cost (in $/GJ) for for SNG in a 264,000 GJ/day facility is:

Process Coal type	Dry Ash Lurgi Western	Dry Ash Lurgi Eastern	Texaco Eastern	British Gas/Lurgi Eastern
Capital	1.73	2.18	3.16	1.91
Insurance/local taxes	0.12	0.15	0.22	0.13
Start-up	0.04	0.049	0.052	0.047
Working capital	0.07	0.097	0.116	0.096
Fuel	2.67	3.38	3.75	3.15
O&M	1.11	1.47	1.58	1.45
Total	5.74	7.31	8.88	6.79

The capital cost for synthetic gas plants is estimated to vary with scale according to:

$$C = Co \times (S/So)^q$$

where :

C = capital cost of a plant with capacity S
Co = capital cost of a plant with capacity So
q = scale factor
= 0.66, $300 < S < 1000$ MWt ($25 - 83 \times 10^9$ BTU/day)
= 0.80, $1000 < S < 3000$ MWt ($83 - 250 \times 10^9$ BTU/day)

Thus the capital-related contributions to the levelized gas cost (capital, insurance/local taxes, start-up, and working capital) would increase with decreasing plant size according to:

$$Pcaprel\ (\$/GJ) \sim C/S = Co/So\ (S/So)^{q-1}$$

Thus:

S (MWt)	Pcaprel ($/GJ) Lurgi Dry Ash/WC	Lurgi Dry Ash/EC	Texaco	British Gas/Lurgi
3000	1.96	2.48	3.55	2.35
1000	2.44	3.09	4.42	2.72
500	3.10	3.89	5.58	3.45
300	3.69	4.63	6.65	4.10

The annual O&M costs for methanol production are assumed to vary with scale according to:

$$OM = OMo \times (S/So)^{p}, \text{ so that } Pom\ (\$/GJ) \sim OM/S = OMo/So\ (S/So)^{p-1}.$$

Here it is assumed that $p = 0.85$ (the value assumed above for producing methanol from coal) so that the variation in the O&M cost with scale for SNG plants is given by:

S (MWt)	Pom ($/GJ) Lurgi Dry Ash/WC	Lurgi Dry Ash/EC	Texaco	British Gas/Lurgi
3000	1.11	1.47	1.58	1.45
1000	1.31	1.73	1.87	1.71
500	1.45	1.92	2.07	1.90
300	1.57	2.07	2.24	2.05

Assuming there are no scale effects for fuel, the following is the total cost as a function of scale:

S (MWt)	Ptot ($/GJ) Lurgi Dry Ash/WC	Lurgi Dry Ash/EC	Texaco	British Gas/Lurgi
3000	5.74	7.31	8.88	6.79
1000	6.43	8.18	10.03	7.59
500	7.22	9.19	11.41	8.50
300	7.92	10.08	12.64	9.31

1b. Coal -> Medium BTU gas

Here it is assumed that:

$d = 0.061$
$N = 30$ years
$CRF = 0.0734$
$INS = 0.005$
$p = 0.80$
$P_{feed} = \$1.78/GJ$

The cost of intermediate heating value coal gas is as follows for various processes for a plant producing 250 x 10^9 BTU/day (or 264,000 GJ/day):

Process Coal	Dry Ash Lurgi Eastern	Shell Eastern	Texaco Eastern	British Gas/Lurgi Eastern
Capital ($1986 billion)	1.60	0.822	1.37	0.898
nc	0.659	0.789	0.729	0.804
Water requirements (liter/GJ)	145.4	98.5	132.5	71.5

The O&M costs (including water, catalysts and chemicals, ash removal, labor maintenance, insurance and local taxes) are (in $\$10^6$/year):

Pom 110.5 67.6 93.4 70.8

The working capital WC is (in $\$10^6$):

85.1 61.0 74.7 60.9

The start-up cost SU is (in $\$10^6$):

30.5 24.8 26.7 26.7

The various contributions to the levelized cost of intermediate heating value gas are (in $/GJ):

Process	Dry Ash Lurgi	Shell	Texaco	British Gas/Lurgi
Capital	1.52	0.78	1.30	0.97
Insurance/local taxes	0.10	0.057	0.089	0.058
Start-up	0.029	0.024	0.026	0.026
Working capital	0.067	0.048	0.060	0.047
Fuel	2.70	2.26	2.44	2.21
O&M	1.43	0.88	1.21	0.92
Total	5.86	4.10	5.13	4.12

Source: M. Teper, D.F. Hemming anf W.C. Ulrich, "The Economics of Gas from Coal", IEA Report IEA/EAS-E2/80, January 1983.

2. Coal -> Gasoline (SRC-II Process)

The SRC-II process converts bituminous coal to gasoline, liquid propane gas and synthetic natural gas by liquefaction of coal and refining of the liquefaction products. Starting with 100 GJ of coal, the energy values of the products (on a higher heating value basis) are shown during the various steps:

100 GJ Coal -> Direct Liquefaction
(72% efficient)
Fuel Oil # 2 45.6 GJ -> Refining
Boiler Fuel 3.82 GJ -> (83% efficient)

* Gasoline 41.0 GJ

Naphtha 13.6 GJ -> Conversion
(99% efficient)

* LPG 6.26 GJ
* SNG 7.34 GJ

* Propane/Ethane 1.44 GJ
* SNG 7.42 GJ

---

* Finished product

On an energy basis, the overall conversion efficiency from coal to finished product fuels is:

$$\left[\overset{\text{gasoline}}{41.0} + \overset{\text{LPG}}{(6.26 + 1.44)} + \overset{\text{SNG}}{(7.42 + 7.34)}\right]/100 \text{ GJ (coal)} = 63.6\%$$

The costs for a liquefaction plant producing 50,000 fuel oil equivalent barrels (FOEB) of energy per day have been estimated to be:

Cap = \$4153 million
Pom = \$422 million/year

For a refinery designed to match the output of this liquefaction plant, the costs would be:

Cap = \$954 million
Pom = \$71 million/year

The liquefaction product energy produced would be 308,588 GJ/day (assuming 50,000 FOEB/day and 5.85 MBTU/FOEB).

The coal input required would be 428,593 GJ/day (assuming 72% conversion efficiency for coal liquefaction).

And the energy contained in the finished products would be 272,586 GJ/day (assuming 63.6% of coal energy is converted to finished products--gasoline, LPG, and SNG).

The energy in each product would be 176,363 GJ/day gasoline, 63,240 GJ/day SNG, and 32,923 GJ/day LPG.

Assuming:

d = 6.1%
N = 20 years
CRF = 0.0879
INS = 0.005
p = 0.80
Pfeed = $1.78/GJ
nc = 63.6% (overall process),

the average cost of fuel energy production is then:

$$\text{Pfuel} = (0.0929 \times \$5107 + \$493) \times 10^6/(0.8 \times 365 \text{ days} \times 272{,}586 \text{ GJ/d})$$

$$+ 1.78/0.636 = \$11.83/\text{GJ} + \$2.80/\text{GJ} = \$14.95/\text{GJ}$$

This is an average cost. To estimate the cost of gasoline, it is assumed that the production costs of LPG and SNG are related to the cost of gasoline production by:

PLPG = 0.77 Pgaso
PSNG = 0.80 Pgaso.

where:

PLPG = production cost of LPG
PSNG = production cost of SNG
Pgaso = production cost of gasoline

Then

$$\text{Pfuel} = \text{fLPG} \times \text{PLPG} + \text{fSNG} \times \text{PLPG} + \text{fgaso} \times \text{Pgaso}$$

where:

fLPG = fraction of finished fuel energy in LPG = 0.121
fSNG = fraction of finished fuel energy in SNG = 0.232
fgaso = fraction of finished fuel energy in gasoline = 0.647

And

$$\begin{aligned}\text{Pgaso} &= \text{Pfuel}/(\text{fLPG} \times 0.77 + \text{fSNG} \times 0.80 + \text{fgaso}) \\ &= 14.95/(0.121 \times 0.77 + 0.232 \times 0.80 + 0.647) \\ &= \$16.15/\text{GJ}\end{aligned}$$

Source: "Preliminary Perspective on Pure Methanol for Transportation", US Environmental Protection Agency", EPA 460/ 3-83-003, September 1982.

3. Coal -> Methanol (Texaco gasifier)

Assuming that:

d = 6.1%
N = 30 years
CRF = 0.0734
INS = 0.005
p = 0.80
nc = 53.9%
Pfeed = \$1.78/GJ
S = 322,220 GJ/day (52,209 FOEB/day or 3730 MW)
Cap = \$3.86 billion
Pom = \$149 million/year
Pby = \$20.0 million/year,

the cost of methanol production is:

$$\text{Pfuel} = [(\text{CRF} + \text{INS})] \times \text{Cap} + \text{Pom} - \text{Pby})/(\text{S} \times \text{p} \times 365 \text{ days/yr})$$

$$+ \text{Pfeed} / \text{nc}$$

$$= (0.0734 \times 3860 + 0.005 \times 3860 + 149) \times 10^{6}/(322{,}220 \times 0.80 \times 365)$$

$$+ 1.78/.539 = \$\ 7.88/\text{GJ}$$

Source: "Coal Gasification Systems: A Guide to Status, Applications and Economics", EPRI Report AP-3109, June 1983.

The effect of plant size on methanol production economics is estimated to be as follows:

S		Capital Cost	O&M Cost	Pfuel
(FOEB/day)	(GJ/day)	(million \$/yr)	(million \$/yr)	(\$/GJ)
52,290	322,220	3860	149	7.9
5,229	32,222	567	21	10.0
523	3,222	82.7	2.95	13.1

Source: B. Arnason, "Methanol from Biomass and Urban Refuse: Prospects and Opportunities", Master of Science in Engineering, Princeton University, 1983.

4. Corn -> Ethanol

For a corn-based ethanol plant, it is assumed that:

d = 6.1%
N = 30 years
CRF = 0.0734
INS = 0.005

nc = 9.83 liters ethanol (or 236 MJ on HHV basis) per bushel of corn
Pfeed = price of corn = \$2.50/bushel
S x p = 55 x 10^6 gallons denatured ethanol/year
= 52.195 x 10^6 gallons ethanol/year
= 12,973 GJ/day (2,337 FOEB/day or 158 MW)
Cap = \$95.2 million
Pom = \$32.5 million/year
Pby = \$21.9 million/year

Pfuel = [(CRF + INS)] x Cap + Pom - Pby)/(S x p x 365 days/yr)

+ Pfeed / nc

= (0.0734 x 95.2 + 0.005 x 95.2 + 32.5 - 21.9)

x 10^6/(12,973 x 365) + \$2.50/bushel /(0.236 GJ/bushel)

= \$14.41/GJ

Source: L. Hill, H. Hicks, W. Hopkins, B. Jordan and R. Andersen, "South Point Ethanol's 60 million Gallon per Year Fuel Ethanol Plant", US Department of Energy Report, DOE/ID/12188-T2 (DE87003493), September 1986.

5. Sugar Cane -> Ethanol

For a Brazilian ethanol distillery using sugar cane as a feedstock it is assumed that:

d = 6.1%
N = 15 years
CRF = 0.1036
INS = 0.005
Cap = \$7.7 million
Pom = \$452,600 per year
S = 120,000 liters per day
p = (160 days per year)/365 = 0.438
Pfeed = \$8.47 per tonne of cane
nca = 73 liters

Pfuel = [CRF x Cap + Pom)/(S x p x 365 days/yr) + Pfeed / nc

= (0.1086 x 7.7 + 0.452) x 10^6/(120,000 x 0.438 x 365)

+ \$8.47/tonne cane /(73 liters/tonne cane)

= 0.047 + 0.024 + 0.116 = \$0.187/liter

The heating value of anhydrous alcohol is 23.90 MJ/liter (HHV), or 21.57 MJ/liter (LHV). But 1 liter of anhydrous alcohol is equivalent to 1.071 liters of fuel alcohol so that the heating value of fuel alcohol is 22.32 MJ/liter (HHV) or 20.14 MJ/liter (LHV).

Thus on a HHV basis the cost of ethanol production from sugar cane in Brazil would be \$8.04 per GJ.

Sources: J. Goldemberg, J.R. Moreira, P.U.M. Dos Santos, and G.E. Serra, "Ethanol Fuel: A Use of Biomass Energy in Brazil," Ambio, Vol. XIV, No. 4-5, 1985; H.S. Geller, "Ethanol Fuel from Sugar Cane in Brazil," Annual Review of Energy, Vol. 10, pp. 135-164, 1985.

115. The annual water consumption in the US is about 144×10^{12} liters per year. The annual petroleum consumption is 41×10^{18} GJ or 1.24×10^{12} liters per year. The ratio or water to petroleum use (on a volumetric basis) is then 144/1.24 = 116. See J. Harte Consider a Spherical Cow, William Kaufmann, Inc., Los Altos, California, 1985.

116. Consider hydrogen production in a desert area with average insolation like that near El Paso (271 Watts per square meter on a collector tilted at the latitude angle). As the collectors are tilted, the rows of collectors must be spaced to prevent shading in the winter when the sun is low in the sky. To prevent all shading until 3 pm at the time of the winter solstice, the ground area must be 2.04 times the collector area. For 15% efficient solar modules and 84% efficient electrolytic units, the hydrogen energy production rate per square meter of land area would be:

$$0.84 \times 0.15 \times (271\ \mathrm{W/m^2}) \times (3.1536 \times 10^7\ \mathrm{seconds/year})/2.04 = 0.53\ \mathrm{GJ/m^2/year}.$$

Since the consumptive water requirements for electrolysis are 63 liters per GJ of produced hydrogen, (the water required to cool the electrolyzer can be recirculated), the rainfall required to support this consumptive water requirement is just 3.4 centimeters per year. For 10 percent efficient cells only 2.3 centimeters of rainfall would be required.

117. Consider first synthetic liquids from coal. The total amount of US land which could be strip mined for coal is 24,000 square miles (62,000 square kilometers). If all this land were strip mined, it would produce an estimated 86 billion metric tonnes of coal. Assuming an average heating value of 20 MJ/kg for the coal, 10 years for strip-mined land reclamation, and a 55% average efficiency for converting coal into a synthetic liquid fuel (see Note 114) the amount of synthetic liquid fuel produced per unit of land area used would be:

$$(86 \times 10^9\ \mathrm{tonnes}) \times (20\ \mathrm{GJ/tonne}) \times 0.55\ /\ (6.2 \times 10^{10}\ \mathrm{m^2} \times 10\ \mathrm{years})$$

$$= 1.52\ \mathrm{GJ/m^2/year}.$$

Next consider the production of PV hydrogen. A 15% efficient PV system connected to an 84% efficient electrolyzer would produce about 0.53 $\mathrm{GJ/m^2/year}$ (assuming that land equal to 2.04 times the collector area is needed to avoid shading the array). Thus, according to this estimate about one third as much land would be required for coal synfuels as for PV hydrogen production.

In the above comparison, the estimate of coal resources is an average over all US land which could potentially be strip mined. This would include some regions with a low coal yield and may overestimate the amount of land needed for more productive near-term coal fields.

Source: G. Atwood, "The Strip-Mining of Western Coal", Scientific American, December 1975.

Another estimate of the energy production rate, which may be more relevant to near-term surface mining, can be derived from 1985 US coal production figures. In 1985, 392 million tonnes of coal were surface mined, and a total of 67 square miles (or 173 square kilometers = $1.73 \times 10^8\ m^2$) of land were disturbed. Assuming the reclamation takes 10 years, and that synthetic liquid fuel is produced at a 55% average efficiency, the fuel production rate would be:

$$(392 \times 10^6 \text{ tonnes}) \times (20 \text{ GJ/tonne}) \times 0.55 \;/\; (1.73 \times 10^8 \text{ m}^2 \times 10 \text{ years}) =$$

$$= 2.49 \text{ GJ/m}^2\text{/year.}$$

About one fifth as much land would be required for coal synfuels as for PV hydrogen according to this estimate.

Source: US Energy Information Administration, Coal Production 1985, DOE/EIA - 0118 (85), 1986.

Now consider synthetic liquids from biomass. Assuming an average insolation rate of 200 W/m^2 in biomass-producing areas, an average conversion efficiency of sunlight to biomass of 1/2%, and an average conversion efficiency of 60% for producing synthetic fuel (see Note 114), the annual synthetic fuel production rate from biomass would be:

$$0.005 \times (200 \text{ W/m}^2) \times (3.1536 \times 10^7 \text{ seconds/year}) \times 0.60 \text{ W/m}^2$$

$$= 0.0189 \text{ GJ/m}^2\text{/year}$$

The amount of land needed for biomass synfuel production in this case would be 29 times that required for production of PV hydrogen in the Southwest.

Comparison of Land Use with Coal and Biomass Synfuels and PV Hydrogen

To Replace	Energy (EJ/yr)	Land Area Required (thousand square miles) Coal Synfuels	PV Hydrogen	Biomass
US Oil	33.6	5.2 - 8.5	24.5	686
Oil + NG	51.4	8.0 - 13.1	37.5	1,050
Oil + NG + Coal	65.7	10.2 - 16.7	47.9	1,342

118. J.C. Fisher, Energy Crises in Perspective. Wiley, New York, 1974.

119. "Urban Ozone and the Clean Air Act: Problems and Proposals for Change", Staff paper, US Office of Technology Assessment, April 1988.

120. H. Buchner, "Hydrogen Use--Transportation Fuel," International Journal of Hydrogen Energy, Vol. 9, pp. 501-514 (1984); H. Buchner and R. Povel, "The Daimler-Benz Hydride Vehicle Project," International Journal of Hydrogen Energy, Vol. 7, pp. 259-266 (1982); "Hydrogen Fuel: Problems and Promises," Automotive Engineering, Vol. 88, No. 1, pp. 42-45 (January 1980); R. E. Billings, "A Hydrogen Powered Mass Transit System," International Journal of Hydrogen Energy, Vol. 3, p. 49 (1978).

121. About 500,000 natural gas powered cars are in use worldwide. See, e.g: R. N. Abram, A. L. Titchener, and J. P. West, "Report on Overseas Visit to Investigate Compressed Natural Gas in Italy," New Zealand Liquid Fuels Trust Board, (November 1979); R.L. Brchtold, T.J. Timbario, R.R. Tison and R.J. Sprafka, "The Practical and Economic Considerations of Converting Highway Vehicles to Use Natural Gas as a Fuel," Proceedings of the Society of Automotive Engineers Conference P-129, Pittsburgh, PA, p. 47-69 (June 22-23 1983).

122. Estimates of cargo space from EPA 1986 Mileage Guide, DOE/CE-0019/4, (October 1985).

123. The energy in a 20 gallon tank of gasoline (LHV) is

20 gal. x 3.78 liters/gal x 32.3 MJ/liter = 2.44 GJ.

The volume energy density in GJ/m^3 (LHV) from Table 14 is:

Hydrogen gas (2400 psia) : 1.76
Natural gas (2400 psia) : 5.51
Advanced battery : 0.90
Lead-acid battery : 0.42

To store 2.44 GJ requires a volume (in cubic meters):

Hydrogen gas (2400 psia) : 1.39
Natural gas (2400 psia) : 0.44
Advanced battery : 2.71
Lead-acid battery : 5.81

124. The volume of fuel needed by a vehicle to travel a certain range is given by:

$$Vr = (Ev \times R)/ Wf$$

where:

Vr = volume of fuel (in m^3)
Ev = energy per kilometer to run the vehicle (in GJ/km)
R = range of vehicle (in km)

Wf = fuel energy density (in GJ/m^3)

The energy needed per kilometer is related to the miles per gallon of gasoline (mpg) by

mpg = [(3.786 liters/gal x 0.0323 GJ/liter gasoline)/(1.609 km/mile)]/ Ev

= 0.0760 / Ev

For a vehicle with a range of 200 miles (322 km), the storage volumes needed for various fuels and fuel economies are:

FUEL	Wf (Table 10)	Vr if fuel economy is: 12 mpg	25 mpg	50 mpg	100 mpg
Hydrogen gas @ 2400 psi	1.76	1.16	0.56	0.28	0.14
Metal hydride	4.9	0.42	0.20	0.10	0.050
Natural gas @ 2400 psi	5.51	0.37	0.18	0.089	0.044
Lead-acid Batteries	0.42	4.86	2.33	1.17	0.58
Advanced Batteries	0.90	2.27	1.09	0.54	0.27

125. Even when compressed to 2400 psi, hydrogen gas contains only 5% the energy per unit volume of gasoline. The energy per unit volume for metal hydrides is about 15% that of gasoline, for liquid hydrogen about 26% (Table 14).

126. Energy and Environmental Analysis, "The Motor Fuel Consumption Model, Twelfth Periodical Report," prepared for the Office of Policy, Planning, and Analysis, US Department of Energy, DOE/PE/77000-1, November 1985.

127. J. Goldemberg, T.B. Johansson, A.K.N. Reddy, and R.H. Williams, Energy for a Sustainable World, op. cit. (Note 34).

128. Deborah Bleviss, Preparing for the 1990s: the World Automotive Industry and Prospects for Future Fuel Economy Innovation in Light Vehicles (Washington, DC: Federation of American Scientists, January 1987).

129. S.L. Fawcett and J.C. Swain, "Prospectus for a Consumer Demonstration of a 100 MPG Car," Battelle Memorial Institute Paper, March 1983.

130. Bleviss, Preparing for the 1990s.

131. R.R. Sekar and R. Kamo [Cummins Engine Company, Columbus, Indiana] and J.C. Wood [NASA Lewis Research Center, Cleveland, Ohio], "Advanced

Adiabatic Engines for Passenger Cars," Paper 840434, presented at the International Congress & Exposition of the Society of Automotive Engineers, Detroit, Michigan, February 27 - March 2, 1984.

132. The cost of liquefying, storing and dispensing liquid hydrogen as a transportation fuel can be estimated as follows (HHV basis):

$$Cclh = (CRF+INS) \times [(Clq + Cinst + Clhd) \times Lh + Clhs \times Lhs] \times (1 +ID)$$

$$Coplh = OM \times [(Clq + Cinst + Clhd) \times Lh + Clhs \times Lhs] \times (1 + ID)$$
$$+ Pe \times Elq \times p \times 8760 \text{ h/y}$$

$$Clh = (Cclh + Coplh)/(8760 \text{ hr/yr} \times p \times Lh \times 0.0036 \text{ GJ/kwh})$$

where:

Cclh = capital charge for liquid hydrogen (\$/year)
Clq = cost of liquefaction equipment (\$/kW H_2 out)
Cinst = cost of installation and construction (\$/kW H2 out)
= 20% of equipment cost
Clhd = cost of liquid hydrogen refuelling equipment (\$/kW H2 dispensed)
Lh = hydrogen output (kW H2 out) [1 tonne/day = 1.648 MW H2 out (HHV)]
Clhs = cost of liquid hydrogen storage (\$/tonne)
Lhs = quantity of hydrogen stored (tonnes)
Coplh = operating cost for liquefaction, storage and dispensing (\$/year)
OM = operation and maintenance (fraction of capital cost/year) = 0.02
CRF = 0.0879 (for N = 20 years)
INS = insurance factor = 0.005
ID = indirect cost factor = 0.25
Pe = price of electricity (\$/kWh) = \$0.06/kwh
p = plant capacity factor = 0.90
Elq = electricity required for liquefaction (kwh/GJ) = 72.3
Clh = cost of liquefaction, including storage and dispensing (\$/GJ)

The cost of liquefaction is size-dependent up to a production rate of about 250 tonnes per day:

Lh (tonnes/day)	(kW H2 out)	Clq (\$/kW	Clhd H2)
30	49,400	584	388
100	164,600	304	202
300	494,000	183	121

The cost of storage facilities is also size-dependent:

Lhs (tonnes)	Clhs (\$/tonne)
30	62,500
100	31,250
300	18,750

If one day's storage is desired, the cost of liquefaction (Clh) is:

(tonnes/day)	(tonnes)	Capital Cost ($/GJ)	Power Cost ($/GJ)	O&M Cost ($/GJ)	Liquefaction Cost ($/GJ)
30	30	4.10	4.34	1.77	10.20
100	100	2.14	4.34	0.92	7.40
300	300	1.28	4.34	0.55	6.17

See J.B. Taylor, J.E.A. Alderson, K.M.Kalyanam, A.B. Lyle, amd L.A. Phillips, "Technical and Economic Assessment of Methods for the Storage of Large Quantities of Hydrogen," International Journal of Hydrogen Energy, Vol. 11, pp. 5-22 (1986); W.J.D. Escher, R.W. Foster, R.R. Tison, and J.A. Hanson, "Solar/Hydrogen Systems Assessment," DOE/JPL-955492, Vol. 2, Pt. 2, (1980).

Onboard liquid hydrogen systems have been developed at the Los Alamos National Laboratory and at the Deutsche Forschung und Versuchsanstalt fur Luft and Raumfahrt (DVFLR) in Germany. Estimated cost (in 1986 dollars) for mass produced automotive dewars is $2243, based on a production level of 30,000 tanks/year. The DFVLR tank with a capacity of 151 liters of liquid hydrogen weighs 54 kg filled and 43 kg empty. The boiloff rate is 6% per day. See "Hydrogen Fuel: Problems and Promises," Automotive Engineering, Vol. 88, No. 1, pp. 42-45 (January 1980).

133. The losses for transferring small quantities of liquid hydrogen can be as much as 50%, when a cold gas recovery loop is not included. See J.B. Taylor, J.E.A. Alderson, K.M.Kalyanam, A.B. Lyle, amd L.A. Phillips, "Technical and Economic Assessment of Methods for the Storage of Large Quantities of Hydrogen," International Journal of Hydrogen Energy, Vol. 11, pp. 5-22 (1986).

134. The energy stored in a pressurized tank of hydrogen can be calculated as follows:

$$E = Vhp \times Hlv \times Rha \times P / Patm$$

where:

E = amount of energy stored (in MJ)
Vhp = storage volume (in standard cubic meters--at atmospheric pressure and temperature of 60 ^{o}F)
Hlhv = H_2 energy density = 120.2 MJ/kg (LHV basis)
Rha = H_2 density @ atmospheric pressure = 0.0893 kg/m3
P = storage pressure (in psia)
Patm = atmospheric pressure = 14.7 psia.

For example, let us compute the storage volume needed to store the energy equivalent of 2 gallons of gasoline as hydrogen at 2400 psia. From Table 14, the amount of energy contained in 2 gallons of gasoline is:

E = 2 gal x (3.78 liters/gal) x (32.3 MJ/liter gasoline) = 244.1 MJ

The storage volume needed for this much hydrogen at pressure P = 2400 psia is:

Vhp = E x Patm / (Hlhv x Rha x P)

$$= 244.1 \text{ MJ} \times 14.7 \text{ psia}/(120.2 \text{ MJ/kg} \times 0.0893 \text{ kg/m}^3 \times 2400 \text{ psia})$$

$$= 0.139 \text{ m}^3 = 139 \text{ liters.}$$

The weight Wh (in kg) of the hydrogen fuel is given by:

Wh = E / Hlhv = (244.1 MJ)/(120.2 MJ/kg) = 2.03 kg.

The weight of the needed containers can be estimated for pressurized gas cylinders as follows:

Cylinder type (rated 2400 psia)	volume (liters)	weight (kg)	installed cost (1986$)
Steel	50	52	281
Aluminum	31	26	253

For the example above the added storage weight for is 156 kg for 3 steel cylinders or 130 kg for 5 aluminum cylinders.

The installed cost for 5 aluminum cylinders would be $1265. For three steel cylinders it would be $843.

See R. N. Abram, A. L. Titchener, and J. P. West, "Report on Overseas Visit to Investigate Compressed Natural Gas in Italy", New Zealand Liquid Fuels Trust Board, (november 1979); R.L. Bechtold, T.J. Timbario, R.R. Tison and R.J. Sprafka, "The Practical and Economic Considerations of Converting Highway Vehicles to Use Natural Gas as a Fuel", Society of Automotive Engineers Conference P-129, Pittsburgh, PA, (June 22-23 1983), p.47-69.

135. Filling station costs for gaseous fuels are estimated in this note. In all cases it is assumed that natural gas or hydrogen is available to the filling station at a local pipeline pressure of 300 psia.

For the cases where compressed gas (natural gas or hydrogen) is delivered to onboard gas cylinders in cars, the cylinder pressure is assumed to be 2400 psia, and the gas is assumed to be transferred during refueling from intermediate storage tanks or "cascades" at the filling station maintained at a pressure of 3600 psia. Refuelling takes about 6 minutes with this system.

For the case of hydride storage, hydrogen is compressed from pipeline pressure to about 50 atmospheres (735 psia) and piped directly into the hydride tank. Refuelling takes about 10 minutes per car.

Costs are estimated as follows:

	VEHICLE STORAGE TYPE:		
	Compressed Natural Gas	Compressed Hydrogen	Metal Hydride
No. of vehicles per day	300	300	300
Fuel per vehicle			
(Nm^3)	15 (2 cyl)	32 (4 cyl)	48
(GJ)	0.576	0.387	0.581
Average fuel flow (Nm^3/hour)	450	960	1440
Peak fuel flow (Nm^3/hour)	600	1280	1920
Inlet gas pressure (psia)	300	300	300
Outlet gas pressure (psia)	3600	3600	735
Compressor			
(Nm^3/hour)	600	1280	1920
(kW)	75	130	55
Compressor capital cost ($)	105520	182901	77381
Cascade storage (Nm^3)	600	1280	n.a.
Cascade storage cost ($)	32400	69120	n.a.
Ave. refuelling time (minutes)	6	6	10
No. of hours of operation/day	10	10	8
No. of refuelling bays	5	5	7
Cost per bay ($)	2000	2000	2000
Cost of bays ($)	10000	10000	14000
Total capital cost ($)	147920	262021	91381

	Compressed Natural Gas	Compressed Hydrogen	Metal Hydride
Operating costs			
Salaries ($/year) (2 people @ $7/hour, 8 hours/day, 350 days/year)	39200	39200	39200
Electricity for compressor ($/year @ 6 cents/kWh)	11813	17063	8663
Compressor maint. ($/year)	8686	17024	9677
Overhead, admin. ($/year)	22000	22000	22000
Discount rate	0.061	0.061	0.061
Lifetime of investment(yr)	20	20	20
Capital recovery factor	0.088	0.088	0.088
Insurance	0.005	0.005	0.005
Hydrogen cost increment for filling station ($ per GJ)	1.57	2.94	1.45

The lower pressures needed to recharge hydride tanks make this option less expensive than compressed hydrogen gas.

See R. N. Abram, A. L. Titchener, and J. P. West, "Report on Overseas Visit to Investigate Compressed Natural Gas in Italy", New Zealand Liquid Fuels Trust Board, (november 1979); R.L. Brchtold, T.J. Timbario, R.R. Tison and R.J. Sprafka, "The Practical and Economic Considerations of Converting Highway Vehicles to Use Natural Gas as a Fuel", Society of Automotive Engineers Conference P-129, Pittsburgh, PA, (June 22-23 1983), p.47-69; A. Golovoy and R.J. Nichols, "Natural Gas Powered Vehicles", ChemTech, (June 1983), p. 359-363.

136. The weight and volume of a metal hydride tank needed to store a given amount of energy is estimated as follows:

$$Whd = E / Hhd$$

$$Vhd = Whd / Rhd$$

where:

Whd = weight of hydride storage (in kg)
E = amount of energy stored (in MJ)
Hhd = hydride energy/weight (in MJ/kg) = 1.90 MJ/kg (from Table 14)
Vhd = volume of hydride (in cubic meters)
Rhd = density of hydride (in kg per cubic meter) = 2706 (from Table 14)

As in the Note 134, we consider storing the energy equivalent of 2 gallons of gasoline. Since the total energy stored is E = 244.1 MJ, the weight of the tank is:

$$Whd = 244.1 \text{ MJ} / 1.90 \text{ MJ/kg} = 128 \text{ kg}.$$

Its volume is:

$$Vhd = Whd / Rhd = 128 \text{ kg}/ 2706 \text{ kg/m}^3 = 0.047 \text{ cubic meter} = 47 \text{ liters}.$$

Compared to hydrogen gas compressed to 2400 psi in cylindrical tanks, hydride storage weighs about the same and takes up only about one third as much space.

Since the cost of hydride storage has been estimated to be about $3.97/kg, the cost of 128 kg would be $508. Assuming that installation adds about 25% to the cost, the installed cost would be $635.

In summary, hydride storage would weigh about as much as gaseous storage, would take up about 1/3 as much space, and would cost about half to two thirds as much.

See H. Buchner, "Hydrogen Use - Transportation Fuel", International Journal of Hydrogen Energy, v. 9, (1984), p. 501-514; H. Buchner and R. Povel, "The Daimler-Benz Hydride Vehicle Project", International Journal of Hydrogen Energy, v. 7, (1982), p. 259-266.

137. In this system, a liquid hydride (methylcyclohexane, for example) is broken down (using heat input from the engine exhaust) in an onboard "rehydrogenation" unit to form hydrogen and toluene. The hydrogen is burned in the vehicle's engine, and the toluene is stored in a tank, for subsequent recharging with hydrogen. The potential advantage of this system is that methylcyclohexane and toluene are liquids at standard temperature and pressure, which could reduce local distribution and filling station costs. (See: T.H. Schucan, "Seasonal Storage of Hydrogen and Use as a Fuel for Heavy Vehicles", Swiss Federal Institute for Reactor Research Report, October 1987.

138. H. Buchner, op.cit.

139. John B. Heywood, "Automotive Engines and Fuels: A Review of Future Options", Progress in Combustion Science, v. 7, (1981), p.155-184.

140. Spark-ignited direct-injection (or stratified charge) engines run equally well on a variety of fuels ranging from gasoline to Diesel fuel. These engines could also be used with hydrogen. The efficiency may be as much as 50% higher than that of a conventional spark-ignited gasoline engine. See J.M. Lewis and W.T. Tierney, "Stratified Charge Engine Development with Broad Fuel Tolerance", First International Automotive Fuel Economy Research Conference, Arlington, Virginia, (October 31- November 1, 1979); E. Mitchell and M Alperstein, "Texaco Controlled-Combustion System-Multifuel, Efficient, Clean and Practical", Combustion science and Technology, v.8, (1973),p. 39-49; T. Krepec, T. Tebelis, C. Kwok, "Fuel Control Systems for Hydrogen Fuelled Automotive Combustion Engines", International Journal of Hydrogen Energy, v. 9, (1984), p.109-114; P.C.T. de Boer, W.J. McLean, and H.S. Homan, "Performance and Emissions of Hydrogen Fuelled Internal Combustion Engines", International Journal of Hydrogen Energy, v. 1, (1976), p.153-172.

141. See Note 135.

142. In this note the cost of owning and operating a car is estimated for various fuels (gasoline, natural gas, methanol, ethanol, hydrogen and batteries) and various levels of automotive fuel economy.

BASE CASE AUTOMOBILE WITH INTERNAL COMBUSTION ENGINE

The performance and cost of cars fuelled with gasoline, natural gas, methanol, ethanol, or hydrogen are estimated relative to a "base case" modelled on the gasoline powered Volkswagen Rabbit:

Passenger capacity : 4
Vehicle weight (empty) : 1080 kg
Aerodynamic drag coefficient: 0.42
Rolling resistance : 0.012 kg/kg
Engine : Spark-ignited
Transmission : 5-speed manual
Storage type : metal tank
Fuel : Gasoline
Fuel Economy : 30 miles per gallon gasoline
(703 Watt-hours/kilometer)

Source: F. von Hippel and B.G. Levi, "Automobile Fuel Economy: the Opportunity and the Weakness of Existing Market Incentives", Resources and Conservation, v. 10, 1983, p. 103-124.

The energy used per kilometer is related to the fuel economy in miles per gallon of gasoline by:

Energy/km = 3.78 liter/gal /(mpg x 1.609 km/mi) x (32.3 MJ/l gaso.)

= 75.9/mpg (in MJ/km) = 21080/mpg (in Watt-hours/km)

where mpg = miles per gallon of gasoline

BASE CASE ELECTRIC AUTOMOBILE

The performance and cost of electric cars is estimated relative to a "base case" modelled on the Eaton car, a converted Mercury Lynx which has the following characteristics:

Passenger capacity : 4
Vehicle shell weight (w/o batteries or motor) : 724 kg
Aerodynamic drag coeffcient: 0.467
Rolling resistance: 0.011 kg/kg
Type of battery : Lead-acid
Number of batteries: 16
Weight per battery : 24.4 kg
Total battery weight : 390 kg
Vehicle weight including batteries : 1114 kg
Engine : Electric motor
Transmission : 2 speed transaxle automatic
Measured energy use : 160 Watt-hours/km

Source : J. M. Slicker, "AC Powertrain for an Electric Vehicle", ORNL Report DOE/NV/10320-2 (November 1984).

This car is roughly comparable to the base case internal combustion engine car in size and weight.

ESTIMATED COSTS FOR BASE CASE AUTOMOBILE

The cost of owning and operating a subcompact gasoline-fueled car has been estimated by researchers at Oak Ridge National Laboratory (in $1986):

Initial cost of vehicle :	$7510
Registration, titling :	53/yr
Insurance :	529/yr
Parking, tolls :	100/yr
Repair, maintenance, tires, accessories :	540/yr

We assume for the car a 12 year, 120,000 mile lifetime.

See M.C. Holcomb, S.D. Floyd, and S.L. Cagle, "Transportation Energy Data Book: Edition 9", Oak Ridge National Laboratory Report, ORNL-6325, Table 1.29, April 1987.

The inital cost of a subcompact electric car (excluding batteries) is estimated to be $66 more than an equivalent subcompact gasoline powered car. We assume that the cost of repairs, maintenance, tires and accessories excluding battery replacement is the same for the electric car as for the gasoline powered car. (The cost of batteries is calculated in the discussion on fuel storage systems later in this note.)

See: R.L. Graves, C.D. West, and E.C. Fox, "The Electric Car - Is It Still the Vehicle of the Future?", ORNL Report, ORNL/TM-7904, August 1981.

TECHNICAL INNOVATIONS FOR FUEL ECONOMY

Adoption of more efficient engines:

The automotive Diesel engine has already emerged, with a 40-50% improvement in fuel economy over the conventional spark-ignited internal combustion engine. Not all alternative fuels are equally well suited for use in Diesel engines. However, other advanced automotive engines presently under development, such as spark ignited direct injection engines or stratified charge engines, do have the ability to burn alternative fuels perhaps 50% more efficiently than present gasoline engines. Future internal combustion engines, whether they run on gasoline or on other fuels (alcohols, natural gas or hydrogen) are likely to be about 50% more efficient than today's spark-ignited gasoline engines.

Von Hippel and Levi estimate the cost of an improved Diesel engine for the base case car would be $641 more than a comparable gasoline powered spark-ignited I-C engine.

Heywood estimates that the inital cost of a stratified charge engine (which could burn hydrogen or other alternative fuels) would be 1.25 to 1.5 times that of a conventional spark-ignited gasoline engine. Assuming that a conventional S-I engine costs $1500, this would mean an increase of $375-750. The cost mass producing a stratified charge engine should be about the same for any fuel. We assume an additional cost of $600 for a stratified charge engine.

The effect of various fuels on engine efficiency:

Although numerous alternatively fueled vehicles have been built, (including 400,000 natural gas powered cars and millions of cars fuelled on alcohol or alcohol blends) the data on engine efficiency with different fuels are far from complete or conclusive. The figures quoted here are from descriptions of prototype vehicles driven under varying road conditions rather than laboratory engines.

In cars with conventional spark-ignited engines, ethanol and methanol are used 20-30% more efficiently than gasoline. Hydrogen is used 30-100% more efficiently. Natural gas is used about 10% more efficiently than gasoline.

Methanol, ethanol, natural gas and producer gas have been used in cars with Diesel engines with a fuel economy comparable to that using Diesel fuel.

For stratified charge engines, the engine efficiency is thought be aproximately independent of the fuel used. For these engines, we assume that gasoline, methanol, natural gas, and hydrogen are used with the same efficiency.

Electric car power train:

The engine in a battery powered electric car is an electric motor, which is considerably more efficient than an internal combustion engine. Typically, the motor is connected through a trans-axle to the drive wheels. Unlike an automobile with an internal combustion engine, the efficiency of an electric car (mechanical power out at the wheels /electrical energy in) is not strongly dependent on the motor speed. Thus, an electric motor coupled with a two-speed transmission in an electric car is comparable to a continuously variable transmission used with an internal combustion engine.

Because of the high efficiency of electric motors, electric cars use energy about several times as efficiently as cars with internal combustion engines.

Reduction of aerodynamic drag:

Most cars today have aerodynamic drag coefficients in the range 0.4-0.6. Prototype vehicles are much lower, in the range 0.24-0.30. The energy required to overcome drag is proportional to the drag coefficient times the cube of the velocity. Thus, drag is only important for that portion of the time the vehicle spends at high speed (above 50 mph).

von Hippel and Levi have estimated that for the base case car above, reduction in the drag coefficient from 0.42 to 0.30 would yield an increase in fuel economy of 6%. They estimated the extra cost of aerodynamic streamlining to reduce the aerodynamic drag from 0.42 to 0.30 would be $122.

Reduction of rolling resistance:

Rolling resistance (friction between the tires and the road) can be reduced perhaps 30% by using radial tires. von Hippel and Levi estimated that for the base case car, the effect of reducing rolling resistance from 0.012 to 0.0085 would be a 4% increase in fuel economy. There would be no increase in cost for this improvement.

Reduction of vehicle weight:

The fuel energy needed to propel the car is directly proportional to the weight of the car plus passengers and cargo. For the base case gasoline powered car, von Hippel and Levi estimate that a weight reduction of 170 kg would improve fuel economy by 11.3%.

An upper bound on the cost for weight reduction through substitution of lightweight materials is estimated by von Hippel and Levi to be $2.68 per kilogram.

For electric cars the weight could be also be reduced by using lighter weight advanced batteries rather than lead-acid batteries.

Continuously variable transmissions (CVT):

In present day transmissions, there are only 3-5 gears, so most of the time the engine is not operating at the optimum speed for maximum fuel economy. Continuously variable transmissions, which do a much better job of matching the optimum engine speed to the vehicle speed, can boost fuel economy up to 20%.

von Hippel and Levi estimate that a continuously variable transmission with a speed range of 10:1 would cost $610 more than a five speed manual transmission.

Reduce Engine peak power:

With a continuously variable transmission, the peak power of the engine could be reduced without sacrificing accelerating power. If the peak engine power were reduced for the base case car, von Hippel and Levi estimate a fuel economy improvement of 16%. There would be no extra cost for reducing engine power.

Engine off while idling and coasting:

Fuel could be saved by turning the engine off while the car is idling or coasting. von Hippel and Levi estimate that a 7% energy savings would result from adding this feature to the base case car, at a cost of $244.

Sources: F. von Hippel and B.G. Levi, "Automobile Fuel Economy: the Opportunity and the Weakness of Existing Market Incentives", Resources and Conservation, v. 10, 1983, p. 103-124; John B. Hewood, "Automotive Engines and Fuels: A Review of Future Options", Progress in Combustion Science, v. 7, 1981, p.155-184.

SUMMARY OF FUEL ECONOMY IMPROVEMENT COSTS FOR INTERNAL COMBUSTION ENGINE CAR

	Weight (kg)	Drag Coeff.	Rolling Resist.	Engine type	Transmission type	Fuel Economy (mpg)	Fuel Economy (Wh/km)	Cost ($)
Base Case :	1080	0.42	0.012	S-I	5 speed man.	30	703	0
Stratified ch. engine	1080	0.42	0.012	D-I	5 speed man.	50.5	418	600
Reduce Drag	1080	0.30	0.012	D-I	5 speed man.	53.9	391	122
Reduce roll. resistance	1080	0.30	0.0085	D-I	5 speed man.	56.2	375	0
Contin. var. trans	1080	0.30	0.0085	D-I	CVT 10:1	68.7	307	610
Reduce weight	910	0.30	0.0085	D-I	CVT 10:1	76.4	276	456
Reduce engine peak power	910	0.30	0.0085	D-I	CVT 10:1	84.8	249	0
Engine off at idle and coasting	910	0.30	0.0085	D-I	CVT 10:1	90.9	232	244

SUMMARY OF FUEL ECONOMY IMPROVEMENT COSTS FOR ELECTRIC CAR

	Weight (kg)	Drag Coeff.	Rolling Resist.	Economy (Wh/km)	Cost ($)
Base Case :	1114	0.467	0.011	160	0
Reduce Drag	1114	0.28	0.011	150	122
Reduce roll. resistance	1114	0.28	0.0085	144	0
Reduce weight	752	0.28	0.0085	106	
reduce shell weight by 20%	579				389
use adv. batteries	173				0

FUEL STORAGE SYSTEMS

Each fuel requires a different onboard storage system. For gasoline, methanol, and ethanol a metal tank is used. For compressed natural gas, gas cylinders are used. For hydrogen, a metal hydride tank is used. For electricity lead-acid or advanced batteries are used. The extra costs and weight for storage systems are estimated in this section, for each fuel and for several levels of fuel economy.

Sizing fuel storage systems:

Where possible, the storage system has been sized to store enough energy to travel 400 km (250 miles). But we have also added the proviso that the storage system must be smaller than 150 liters (which is equivalent to 3 compressed gas cylinders of the type now used for natural gas) and must weigh no more than 200 kg, which is approximately 20% of the weight of the car. These storage system restrictions, limit the range for lower density fuels such as natural gas, hydrogen and batteries.

COST OF CARS (INCLUDING ONBOARD STORAGE) FOR THREE LEVELS OF FUEL ECONOMY

Fuel Economy Level I : Here we compare storage system costs for the base case gasoline powered car operated with different fuels. We also compare costs with the base case electric car, which has energy consumption of 160 Watt-hours/km.

Assumptions :

The base case car has fuel economy of 30 mpg (or 703 Watt-hours/km) powered with gasoline.

Methanol and ethanol are used 25% more efficiently than gasoline (the car has energy efficiency of 562 Watt-hours/km).

Natural gas is used 10% more efficiently than gasoline (631 Watt-hours/km).

Hydrogen is used 30% more efficiently than gasoline (541 Watt-hours/km).

FUEL ECONOMY LEVEL I - 30 mpg (gasoline equivalent)

FUEL	STORAGE SYSTEM	Fuel Volume (liters)	Weight		Stored Energy (GJ)	Added (a) Storage Cost ($1986)	Range (km)
			Fuel (kg)	Storage (kg)			
Gasoline	Metal tank	31.3	22.6	21.4	1.01	0	400
Methanol	Metal tank	50.8	40.6	26.2	0.81	0 (b)	400
Ethanol	Metal tank	37.4	29.7	21.3	0.81	0 (b)	400
Natural gas	Compressed gas cylinder (2400 psia)	150	7.5	156	0.83	891 (c)	360
Hydrogen	Compressed gas cylinder (2400 psia)	150	2.2	156	0.264	891 (d)	136
	Metal hydride	73	200		0.360	993 (e)	185
	Liquid H2 (e) dewar	93	6.46	26.8	0.78	2273 (f)	400
Electricity	Lead-acid battery	69	200		0.029	2576 (g)	50
	Advanced battery	72	200		0.065	2937 (g)	113

---

a Relative to gasoline.

b We assume that methanol and ethanol cars cost the same as gasoline powered cars.

c We assume that three 50-liter steel cylinders are used. The indicated cost is the present value of the capital cost of the cylinder plus cylinder testing every 5 years at $48 per test. See Note 134.

d We assume that three 50-liter steel cylinders are used. The cost is the present value of the capital cost of the cylinder plus cylinder testing every 5 years at $48 per test. See Note 134.

e We assume that hydride storage costs $3.97 per kilogram, as estimated in "Hydrogen Fuel : Problems and Promises", Automotive Engineering, January 1980. We assume that installation adds about 25% to the cost, so that the installed cost is $993 for a 200 kg hydride tank.

f The cost of a mass-produced 50 gallon liquid hydrogen dewar for automobiles was estimated as ranging from $200-1550 (in 1977 $) or $341-

2644 (in 1986$) with a mean value of $2240 (in 1986$) in "Hydrogen Fuel : Problems and Promises", Automotive Engineering, January 1980. To estimate the cost of smaller dewars, we assume that half the dewar cost is independent of size and that half of the cost scales as the dewar surface area. This gives a value of $1818 for a 93 liter dewar. If we assume that installation adds 25% to the total, the installed cost is $2273.

g We assume that lead-acid and advanced batteries cost $100/kwh and have a life of 800 cycles, goals cited in "Electric Vehicles", <u>EPRI Energy Researcher</u>, May 1986. We assume that lead-acid batteries would take the car 50 km/cycle, so that they would have to be replaced every 50 x 800 = 40,000 kilometers. For a car travelling 192,000 kilometers in its lifetime, 4.8 sets of batteries would be used. For advanced batteries, the replacement interval would be 90,400 kilometers, so that only 2.1 sets of batteries would be needed. The cost is the present value of the initial set of batteries plus replacements needed over the lifetime of the car minus the salvage value of the batteries.

FUEL ECONOMY LEVEL II - 50 mpg (gasoline equivalent)

Base case internal combustion engine car with stratified charge engine costing $600 and fuel economy of 50 mpg or 422 Watt-hours/km on all fuels. Electric car with energy consumption of 160 Watt-hours/km.

FUEL	STORAGE SYSTEM	Volume (liters)	Weight Fuel (kg)	Weight Storage (kg)	Stored Energy (GJ)	Added (a) Storage Cost ($1986)	Range (km)
Gasoline	Metal tank	18.9	14.2	13.5	0.61	0	400
Methanol	Metal tank	38.4	30.7	21.7	0.61	0 (b)	400
Ethanol	Metal tank	28.2	22.4	17.7	0.61	0 (b)	400
Natural gas	Compressed gas cylinder (2400 psia)	111	12.2	104	0.61	1096 (c)	400
Hydrogen	Compressed Gas cylinder (2400 psia)	150	2.2	156	0.264	891 (d)	173
	Metal hydride	73	200		0.360	993 (e)	236
	Liquid H2 (f) dewar	73	5.07	22.8	0.61	2142 (f)	400
Electricity	Lead-acid battery	69	200		0.029	2576 (g)	50
	Advanced battery	72	200		0.065	2937 (g)	113

---

a Relative to gasoline-powered base case car.

b We assume that methanol and ethanol cars cost the same as gasoline-powered cars.

c We assume that four 30 liter aluminum cylinders are used. The indicated cost is the present value of the capital cost of the cylinder plus cylinder testing every 3 years at $48 per test. See Note 134.

d We assume that three 50-liter steel cylinders are used. The cost is the present value of the capital cost of the cylinder plus cylinder testing every 5 years at $48 per test. See Note 134.

e We assume that hydride storage costs $3.97 per kilogram, as estimated in "Hydrogen Fuel : Problems and Promises", Automotive Engineering, January 1980. We assume that installation adds about 25% to the cost, so that the installed cost is $993 for a 200 kg hydride tank.

f The cost of a mass-produced 50 gallon liquid hydrogen dewar for automobiles was estimated as ranging from $200-1550 (in 1977 $) or $341-2644 (in 1986$) with a mean value of $2240 (in 1986$) in "Hydrogen Fuel : Problems and Promises", Automotive Engineering, January 1980. To estimate the cost of smaller dewars, we assume that half the dewar cost is independent of size and that half of the cost scales as the dewar surface area. This gives a value of $1818 for a 93 liter dewar. If we assume that installation adds 25% to the total, the installed cost is $2273.

g We assume that lead-acid and advanced batteries cost $100/kwh and have a life of 800 cycles, goals cited in "Electric Vehicles", EPRI Energy Researcher, May 1986. We assume that lead-acid batteries would take the car 50 km/cycle, so that they would have to be replaced every 50 x 800 = 40,000 kilometers. For a car travelling 192,000 kilometers in its lifetime, 4.8 sets of batteries would be used. For advanced batteries, the replacement interval would be 90,400 kilometers, so that only 2.1 sets of batteries would be needed. The cost is the present value of the initial set of batteries plus replacements needed over the lifetime of the car minus the salvage value of the batteries.

FUEL ECONOMY LEVEL III - 90 mpg (gasoline equivalent)

Base case car with stratified charge engine, aerodynamic styling, reduced weight, reduced rolling resistance, continuously variable transmission (costing a total of $2032) and fuel economy of 90 mpg (gasoline equivalent) or 234 Watt-hours/km on all fuels. Electric car with aerodynamic styling, reduced weight, reduced rolling resistance (costing a total of $577 more than the base case gasoline powered car) and energy consumption of 106 Watt-hours/km.

FUEL	STORAGE SYSTEM	Volume (liters)	Weight Fuel (kg)	Weight Storage (kg)	Stored Energy (GJ)	Added (a) Storage Cost ($1986)	Range (km)
Gasoline	Metal tank	10.4	7.84	9.1	0.337	0	400
Methanol	Metal tank	21.2	16.9	14.6	0.337	0 (b)	400
Ethanol	Metal tank	15.6	12.4	11.9	0.337	0 (b)	400
Natural gas	Compressed gas cylinder (2400 psia)	61	6.1	52	0.337	590 (c)	400
Hydrogen	Compressed Gas cylinder (2400 psia)	150	2.20	156	0.264	891 (d)	314
	Metal hydride	71	195		0.350	966 (e)	400
	Liquid H2 (e) dewar	40	2.80	14.4	0.337	1897 (f)	400
Electricity	Lead-acid battery	69	200		0.029	1813 (g)	76
	Advanced battery	72	200		0.065	2448 (g)	71

---

a Relative to gasoline-powered base case.

b We assume that methanol and ethanol cars cost the same as gasoline-powered cars.

c We assume that two 30 liter aluminum cylinders are used. The indicated cost is the present value of the capital cost of the cylinder plus cylinder testing every 3 years at $48 per test. See Note 134.

d We assume that three 50-liter steel cylinders are used. The cost is the present value of the capital cost of the cylinder plus cylinder testing every 5 years at $48 per test. See Note 134.

e We assume that hydride storage costs $3.97 per kilogram, as estimated in "Hydrogen Fuel : Problems and Promises", Automotive Engineering, January 1980. We assume that installation adds about 25% to the cost, so that the installed cost is $993 for a 200 kg hydride tank.

f The cost of a mass-produced 50 gallon liquid hydrogen dewar for automobiles was estimated as ranging from $200-1550 (in 1977 $) or $341-2644 (in 1986$) with a mean value of $2240 (in 1986$) in "Hydrogen Fuel : Problems and Promises", Automotive Engineering, January 1980. To estimate the cost of smaller dewars, we assume that half the dewar cost is independent of size and that half of the cost scales as the dewar surface area. This gives a value of $1818 for a 93 liter dewar. If we assume that installation adds 25% to the total, the installed cost is $2273.

g We assume that lead-acid and advanced batteries cost $100/kwh and have a life of 800 cycles, goals cited in "Electric Vehicles", EPRI Energy Researcher, May 1986. We assume that lead-acid batteries would take the car 50 km/cycle, so that they would have to be replaced every 50 x 800 = 40,000 kilometers. For a car travelling 192,000 kilometers in its lifetime, 4.8 sets of batteries would be used. For advanced batteries, the replacement interval would be 90,400 kilometers, so that only 2.1 sets of batteries would be needed. The cost is the present value of the initial set of batteries plus replacements needed over the lifetime of the car minus the salvage value of the batteries.

COST OF OWNING AND OPERATING ALTERNATIVE FUELLED CARS VS. FUEL ECONOMY

The cost of owning and operating the car is given by:

$$\mathrm{Ckm} = [\ \mathrm{CRF} \times (\mathrm{Cv} \times \mathrm{Cs}) + \mathrm{Cmisc} + \mathrm{OM} + \mathrm{OMs}\ ] / \mathrm{Akm} + \mathrm{Pfuel} \times \mathrm{Efuel} \times \mathrm{HLfuel}$$

where:

Ckm = cost of owning and operating car in dollars per kilometer
CRF = capital recovery factor = 0.1468 (For 12 year system lifetime and 10% discount rate)
Cv = initial cost of vehicle ($)
Cs = present value of of storage system, including replacement of storage equipment and O&M costs ($)

Storage system maintenance = $48 test every 5 years for Al gas cyl.
= $48 test every 3 years for steel gas cyl.
= $0 for other systems

Cmisc = annual cost of titling, registration, parking, tolls, insurance ($/year) = $53 + 529 + 100 = $682/year

OMv = vehicle maintenance and repairs ($/year) = $540/year

Akm = kilometers travelled per year = 16,000 km/year
Pfuel = delivered cost of fuel ($/GJ) HHV basis.
Efuel = energy required per kilometer (GJ/km) on LHV basis.
HLfuel = ratio of higher and lower heating values of fuel = 1.067 gasoline
= 1.138 methanol
= 1.110 methane
= 1.185 hydrogen
= 1 battery

FUEL ECONOMY LEVEL I - "30 mpg"

	GASOLINE	METHANOL	METHANE	HYDRIDE	BATTERY
Cv	7510	7510	7510	7510	7576 (a)
Cs	0	0	891	993	2576
Efuel (Wh/km)	703	561	631	541	160
(MJ/km)	2.53	2.02	2.27	1.95	0.576
Pfuel ($/GJ)	17.65	9.91-12.07	9.54-12.0	12.86-17.97	20.56
Range (km)	400	400	365	185	50
Cost (cents/km)					
vehicle	6.89	6.89	6.89	6.89	6.95
miscellaneous	7.64	7.64	7.64	7.64	7.64
storage	0	0	0.83	0.91	2.37
fuel	4.76	2.27-2.77	2.44-3.09	2.97-4.04	1.18
TOTALS	19.29	16.80-17.30	17.78-18.40	18.40-19.58	18.15

---

[a] We assume that the base case electric car costs $66 more than the base case gasoline-powered car (excluding batteries).

FUEL ECONOMY LEVEL II - "50 mpg"

	GASOLINE	METHANOL	METHANE	HYDRIDE	BATTERY
Cv (a)	8110	8110	8110	8110	7576
Cs	0	0	1096	993	2576
Pfuel ($/GJ)	17.65	9.91-12.07	9.54-12.0	12.86-17.97	20.56
Efuel (Wh/km)	422	422	422	422	160
(MJ/km)	1.52	1.52	1.52	1.52	0.576
Range (km)	400	400	400	236	50
Cost (cents/km)					
vehicle	7.44	7.44	7.44	7.44	6.95
miscellaneous	7.64	7.64	7.64	7.64	7.64
storage	0	0	1.03	0.91	2.37
fuel	2.86	1.71-2.04	1.60-2.02	2.31-3.22	1.18
TOTALS	17.94	16.79-17.17	17.69-18.11	18.30-19.22	18.15

---

[a] We assume that the fuel-fired cars are equiped with stratified charge engines which cost $600 more than the base case fuel-fired cars and that the electric cars (excluding batteries).

FUEL ECONOMY LEVEL III - "90 mpg"

	GASOLINE	METHANOL	METHANE	HYDRIDE	ADVANCED BATTERY
Cv (a)	9582	9582	9582	9582	8087
Cs	0	0	590	966	2448
Pfuel ($/GJ)	17.65	9.91-12.07	9.54-12.0	12.86-17.97	20.56
Fuel economy (Wh/km)	234	234	234	234	106
(MJ/km)	0.84	0.84	0.84	0.84	0.382
Range (km)	400	400	400	400	171
Cost (cents/km)					
vehicle	8.75	8.75	8.75	8.75	7.42
miscellaneous	7.64	7.64	7.64	7.64	7.64
storage	0	0	0.56	0.89	2.37
fuel	1.59	0.95-1.15	0.89-1.04	1.28-1.79	0.79
TOTALS	18.01	17.38-17.58	17.96-18.20	18.59-19.10	18.22

---

a We assume that fuel-fired cars cost $2032 more than in the base case for stratified charge engine, aerodynamic styling, reduced rolling resistaance, weight reduction, CVT, and engine-off features for non-electric cars and that electric cars cost $511 more than base case electric cars (excluding batteries) for aerodynamic styling, weight reduction, and reduced rolling resistance.

143. In general, the larger the vehicle, the less important the weight and volume of the fuel storage system. For a hydrogen-powered subcompact car weighing 800 kg, with fuel stored in four 30 liter aluminum pressurized gas cylinders, which weigh 26 kg each, about 12% of the vehicle weight will be due to the storage system. For a 4000 kg truck with a comparable range, the fuel storage system would account for only about 7% of the total vehicle weight. The relatively large storage volume needed for hydrogen would also impose less of a constraint for trucks and buses than for automobiles.

144. Billings Energy Corporation of Provo, Utah, has built and operated several hydrogen-powered buses. See R. E. Billings, "A Hydrogen Powered Mass Transit System," International Journal of Hydrogen Energy, Vol. 3, p. 49 (1978).

145. Frank von Hippel, "US Transportation Energy Demand," PU/CEES Report No. 111, Center for Energy and Environmental Studies, Princeton University, Princeton, New Jersey, 1981.

146. Using liquid hydrogen rather than jet fuel would reduce the fully loaded takeoff weight of a jumbo jet (Boeing 747 type) by perhaps 25%, with a fuel savings of about 12%. Hydrogen could be piped to the airport via a gas pipeline, and liquefed onsite. However, the cost of liquefication and storage of liquid hydrogen is large [$ 8-14/GJ (see Note 132)] even when large quantities of fuel are involved. When these costs are added to a delivered pipeline cost of perhaps $10-14/GJ, the total cost of LH2 is $18-28/GJ, as compared to the projected 2000 jet fuel price of $7.75/GJ.

The 12% energy savings is outweighed economically by the extra fuel cost.

See J.B. Taylor, J.E.A. Alderson, K.M.Kalyanam, A.B. Lyle, amd L.A. Phillips, "Technical and Economic Assessment of Methods for the Storage of Large Quantities of Hydrogen," International Journal of Hydrogen Energy, Vol. 11, pp. 5-22 (1986).

147. The CO_2 emissions from the production and utilization of various fuels are estimated to be the following:

	kg CO_2/GJ fuel (HHV)
Crude oil -> Gasoline + Diesel	77.5
Coal -> Gasoline + LPG + SNG (SRC-II process)	132.7
Coal -> Methanol (Texaco gasifier)	133
Coal -> Synthetic Natural Gas (Lurgi dry ash process)	117
Natural gas	49.5
PV Hydrogen	0

When these fuels are utilized in automobiles, the CO_2 emissions per kilometer are given in Table 17.

These estimates were made as follows:

Gasoline and Diesel fuel from crude oil:

Crude oil has an energy content of 43 MJ/kg, and an atomic hydrogen to carbon (H/C) ratio of about 1.5. The products of crude oil refining in the US are typically:

Product	Energy content (% of total)	HHV (MJ/kg)	H/C ratio
Refinery losses	10%	43	1.5
Gasoline	40%	45.9	1.82
Kerosene (jet fuel)	6%	46.4	1.95
Diesel fuel	10%	44.3	1.72
Fuel oil	30%	42.7	1.58
Non-fuel	4%		

Assuming that only hydrogen and carbon atoms make up the oil, the mass of carbon contained in each product is given by:

$$m_{pro} = m_{oil} \times f_{pro} \times (HHV_{oil}/HHV_{pro}) = (HCratio \times A_H/A_C + 1) \times m_C$$

where:

m_{pro} = mass of product in kg
m_{oil} = mass of crude oil in kg
f_{pro} = fraction of total energy contained in product
HHV_{oil} = higher heating value of crude oil (in MJ/kg)
HHV_{pro} = higher heating value of product (in MJ/kg)
A_H = atomic weight of hydrogen = 1
A_C = atomic weight of carbon = 12
HCratio = hydrogen to carbon atomic ratio of product
m_C = mass of carbon contained in the product (in kg)

When the product is burned, the amount of CO_2 produced is given by:

$$m_{CO2} = m_C \times (1 + A_{O2}/A_C)$$

where:

m_{CO2} = mass of carbon dioxide released by product combustion (in kg)
A_{O2} = molecular weight of oxygen = 32

For 1000 kg of crude oil, the total amount of carbon is 889 kg. This is distributed among the various products as follows:

Product	Carbon (kg)	Energy released (GJ)	CO_2 released (kg)
Refinery losses	89	4.3	326
Gasoline	325	17.2	1192
Kerosene (jet fuel)	48	2.6	176
Diesel fuel	85	4.3	311
Fuel oil	267	12.9	979
Non-fuel	72	-	-

Considering only automotive fuels (gasoline and Diesel) and charging half of the refinery losses to their production, then the total amount of CO_2 released is:

$$\underset{\text{(losses)}}{(1/2 \times 326)} + \underset{\text{(gasoline)}}{1192} + \underset{\text{(Diesel)}}{311} = 1666 \text{ kg.}$$

The total energy available for powering automobiles is:

$$\underset{\text{(gasoline)}}{17.2} + \underset{\text{(Diesel)}}{4.3} = 21.5 \text{ GJ.}$$

Thus the CO_2 emissions per GJ of automotive fuel produced from this process is:

$$1666 \text{ kg}/21.5 \text{ GJ} = 77.5 \text{ kg } CO_2 \text{ / GJ of auto fuel produced.}$$

This can be related to the fuel economy rating of the vehicle to give a CO_2 emission per kilometer travelled.

CO_2 (kg/km) = CO_2 (kg/GJ) x Ev (GJ/km)

where :

Ev = energy required for vehicle to operate (in GJ/km on a higher heating value basis).

For an automobile fuelled on gasoline + Diesel from crude oil,

Fuel Economy (mpg gasoline)	CO_2 Emissions (kg/km)
25	0.251
50	0.126
100	0.063

See E. M. Goodger. "Liquid Fuels for Transport", Progress in Energy and Combustion Science, v. 8, pp 233-260, (1982).

<u>Synthetic gasoline from coal</u> (SRC-II Process)

With the SRC-II process, bituminous coal is processed to produce gasoline, liquid propane gas, and synthetic natural gas (methane).

Product	Energy Content (% of total)	HHV (MJ/kg)	H/C ratio
Losses	36.4%	-	-
Gasoline	41.1%	45.9	1.82
LPG (C_3H_8)	7.7%	50	2.67
SNG (CH_4)	14.8%	55.5	4.0

The composition of a Illinois No. 6 bituminous coal (% on a mass basis) is :

Carbon	61.2
Hydrogen	4.67
Oxygen	8.79
Nitrogen	1.11
Sulfur	3.41
Moisture	12.0
Ash	8.79

The higher heating value of this coal is 26.12 MJ/kg.

Starting with 1000 kg of coal, we have a total of 612 kg of carbon. This is distributed among the various products:

Product	Energy Content (GJ)	Carbon (kg)	CO_2 Emissions (kg)
Losses	9.51	315	1151
Gasoline	10.7	202	742
LPG (C_3H_8)	2.01	33	121
SNG (CH_4)	3.87	53	194

The amount of carbon in each product is found

$$mC_{pro} = E_{pro} / [HHV_{pro} \times (1 + HCrat \times A_H/A_C)]$$

where: mC_{pro} = mass of carbon contained in product (kg)

E_{pro} = energy contained in product (GJ)

HHV_{pro} = higher heating value of product (GJ/kg)

HCrat = ratio of hydrogen to carbon atoms in product

A_H = atomic weight of hydrogen = 1

A_C = atomic weight of carbon = 12

The total CO_2 produced is 2208 kg, the energy available for transport fuels is 16.64 GJ, and the CO_2 emissions are 132.7 kg/GJ of fuel produced (on a higher heating value basis).

For an automobile fuelled on SRC-II products (gasoline, LPG, SNG) from coal,

Fuel Economy (mpg gasoline)	CO_2 Emissions (kg/km)
25	0.430
50	0.215
100	0.108

See "Preliminary Perspective on Pure Methanol Fuel for Transportation", US Environmental Protection Agency, EPA 460/3-83-003, September 1982; "Coal Gasification Systems: A Guide to Status, Applications and Economics," EPRI AP-3109, June 1983.

<u>Methanol from coal</u> (Texaco gasifier)

With the Texaco gasifier, for 1000 kg of coal with composition (% on a mass basis),

	% mass
Carbon	61.2
Hydrogen	4.67
Oxygen	8.79

Nitrogen	1.11
Sulfur	3.41
Moisture	12.0
Ash	8.79

626 kg of methanol is produced. If this coal has a higher heating value of 26.12 MJ/kg, then, for a higher heating value of 22.7 MJ/kg for methanol, 54% of the energy in the coal is converted to methanol, and 46% is lost. The CO_2 production is then:

Product	Energy %	Content (GJ)	Carbon (kg)	CO_2 Emissions (kg)
Losses	46	11.91	279	1023
CH_3OH	54	14.21	234	860

The emissions rate during methanol production and combustion is (1023 + 858 kg)/(14.12 GJ) = 133 kg CO_2/GJ fuel.

For an automobile fuelled on methanol from coal,

Fuel Economy (mpg gasoline)	CO_2 Emissions (kg/km)
25	0.460
50	0.230
100	0.115

See "Coal Gasification Systems: A Guide to Status, Applications and Economics," EPRI AP-3109, June 1983.

<u>Coal -> Synthetic Natural Gas with the Dry Ash Lurgi Process</u>

For this process the inputs and products are:

Input:	
Coal	1000 kg
(Carbon	528 kg)

Output:	
SNG	274 kg
(CO_2	7.07 kg)
(CH_4	263 kg)
Naphtha	8 kg
Oil	18 kg
Tar	29 kg
Ammonia	0.6 kg
Phenol	0.6 kg
Claus gas	23 kg
CO_2	21 kg
Waste gases	
CO_2	927 kg
Ash	61 kg

Assuming higher heating value of 55.5 MJ/kg for methane, and 28.67 MJ/kg for coal, the process converts 51% of the coal energy to methane.

Product	Energy %	Content (GJ)	Carbon (kg)	CO_2 Emissions (kg)
Losses	49	13.68	-	955
CH4	51	14.6	206	754

The emissions rate during SNG production and combustion is (955 + 754 kg)/(14.6 GJ) = 117 kg CO_2/GJ fuel.

For an automobile fuelled on SNG from coal,

Fuel Economy (mpg gasoline)	CO_2 Emissions (kg/km)
25	0.394
50	0.197
100	0.099

Source: "Coal Gasification via the Lurgi Process, Volume I - Production of SNG", USDOE Contract Report No. DE-AC01-82-FE-05081 (September 1984).

CO_2 Emissions from the Combustion of Natural Gas

When CH_4 is burned, the reaction is:

$$CH_4 + 2\ O_2 \rightarrow CO_2 + 2\ H_2O$$

For each kg of CH_4, 2.75 kg of CO_2 is created. Since CH_4 has a HHV of 55.5 MJ/kg, the CO_2 emissions are 49.5 kg/GJ. For a natural gas fuelled car, the CO_2 emissions per km are:

Fuel Economy (mpg gasoline)	CO_2 Emissions (kg/km)
25	0.167
50	0.084
100	0.042

Source: E. M. Goodger. "Liquid Fuels for Transport", Progress in Energy and Combustion Science, v. 8, pp 233-260, (1982).

148. The economics of SNG production are strongly scale-dependent (see Note 114). As PV hydrogen production facilities would have essentially no economy of scale above sizes of about 5-10 MW, PV hydrogen might be less expensive than SNG from coal in areas of relatively small gas demand.

Consider, for example, the island of Hawaii, with a population of 800,000 people, or about 300,000 households. To match the demand for residential heating (assuming that the average space and water heating demand in a sunny area is 15 GJ per household per year), the synfuel plant would have to have a productive capacity of 180 MWt, a size at which PV hydrogen could probably compete with coal-derived SNG on an energy-equivalent cost basis.

149. J. Pangborn and M.I. Scott, "Domestic Uses of Hydrogen", in Hydrogen: Its Technology and Implications, David A. Mathis, ed., Energy Technology Review No. 9, Noyes Data Corporation, (1976).

150. A number of catalysts have been tried experimentally for catalytic hydrogen combustion. Researchers in the US (J. B. Pangborn and J. C. Sharer at Institute of Gas Technology, Chicago, Ill.) have reported that platinum coated anodized aluminum gave the best results for heating applications. The optimum platinum loading was 0.1-0.2 milligrams per square centimeter. The heaters had an output of 7000-9000 BTU per hour per square foot of catalyst coated surface.

The cost of platinum raw material for a hydrogen fuelled catalytic space heater can be estimated as follows:

CPth = CPt x Ptload x (Hout / Hcat)

where:

CPth = cost of platinum for heater catalyst in dollars.
Cpt = cost of platinum in dollars per troy ounce = \$500/oz.
Ptload = platinum loading of catalyst in ounces per square foot
= 0.00328-0.00655 oz/ft^2 = 0.1-0.2 milligrams/cm^2.
Hout = total output of heater in BTU per hour = 5000-10000 BTU/h.
Hcat = measured output of heating surface in BTU per hour per square foot
= 7000-9000 BTU/h/ft^2.

The output of a room-sized catalytic space heater would lie in the range 5,000-10,000 BTU/h.

For a 10,000 BTU/h heater, about 0.00364-0.00936 ounces of platinum costing \$1.8-4.7 would be required.

Platinum raw material would not be a significant cost in the construction of the heater. Nor would platinum supply be a serious constraint. Even at a manufacturing level of ten million 10,000 BTU/h space heating units per year, only 2270 pounds of platinum would be required. The yearly platinum production in the US in 1983 was 375,000 pounds.

J. B. Pangborn, "Catalytic Combustion of Hydrogen in Model Appliances", 15th Intersociety Conference on Energy Conversion, Seattle, April 18-22 1980, p. 1731; <u>1985 Statistical Abstract of the United States</u>.

Hydrogen catalytic heaters using stainless steel pads have also been built and tested by R.E. Billings. (See: R.E. Billings, "Hydrogen Appliances", 7th World Hydrogen Energy Conference, Moscow, USSR, September 1988.

151. The "Platinum Cat" is a natural gas fuelled catalytic space heater for residential use, which consumes about 5200 BTU of natural gas per hour. Depending on the venting system, 80-90% of the heating value of the fuel (or 4160-4680 BTU/h) is delivered to the room. The heater costs about $350, plus an average of $100 for installation.

<u>Source</u>: B. Wells, Thermal Systems, Inc., Tumwater, Washington, private communications, 1987.

152. Hydrogen produces some NOx emissions, even with the relatively low temperatures of catalytic combustion. The maximum amount of NOx production which could be tolerated from an unvented hydrogen space heater can be estimated as follows:

$$\text{NOXht} = \text{V} \times (\text{PPMin} - \text{PPMout}) \times \text{Kppmlb} \times \text{AC} / \text{Hmax}$$

where:

NOXht = maximum allowable NOx production by catalytic heater (lb/MBTU)
PPMin = maximum indoor NOx level allowed (= 0.055 ppm = EPA standard, for NO_2 = 100 micrograms/Nm^3)
PPMout = ambient outdoor NOx level (ppm of NO_2)
Kppmlb = conversion factor; 1 ppm NO_2 in air = 1.135×10^{-7} lb/cu.ft.
V = volume of house (cubic feet)
AC = number of air changes per hour
Hmax = maximum heat required by house (MBTU/h)

For a conventional new house with

AC = 0.75 air changes per hour
V = 12,000 cu.ft.
Hmax = 40,000 BTU/h = 0.04 MBTU/h
PPMout = 0.03
PPMin = 0.05

the maximum amount of NOx production allowed from an unvented space heater would be:

$NOXht = 5.2 \times 10^{-4}$ lb/MBTU.

For a superinsulated house with

AC = 0.25 air changes per hour
V = 12,000 cu.ft.
Hmax = 10,000 BTU/h = 0.01 MBTU/h
PPMout = 0.03
PPMin = 0.05

the maximum amount of NOx production allowed from an unvented space heater would be:

$NOXht = 6.9 \times 10^{-4}$ lb/MBTU.

The NOx emissions from model catalytic hydrogen appliances have been measured in the range of $0.22 - 0.62 \times 10^{-4}$ lb/MBTU, well below the maximum permissible levels. Thus, the catalytic combustion of hydrogen should not pose an indoor air pollution problem.

Source: J. C. Sharer and J.B. Pangborn, "Utilization of Hydrogen as an Appliance Fuel", in Hydrogen Energy: Part B, T.N. Veziroglu, ed., Plenum Press, (1974).

153. When combustion products from a hydrogen catalytic heater are vented directly into a room, high humidity due to water vapor buildup is a consideration. The humidity in a house heated with hydrogen catalytic heaters can be found as follows, assuming steady state conditions:

The rate at which water vapor is produced by the space heater is:

$$mw3 = Q \times (kg\ H_2O/kg\ H_2)/[HHV \times (1000\ kJ/MJ) \times n]$$
$$= 6.401 \times 10\text{-}5 \times Q$$

where:

mw3 = rate of water vapor production in heater (kg/sec)
Q = output of heater in kW required to keep inside temperature at T2 (we have assumed that Q is calculated from knowledge of the house design as in note 158).
HHV = higher heating value of hydrogen = 142.4 MJ/kg H_2
n = thermal efficiency of space heater = 0.99 (on a higher heating value basis. We have taken credit here for heat added to the room as water vapor from the heater exhaust.)

We assume that inside air flowing out of the house (due to infiltration losses) is exactly balanced by outside air flowing into the house.

Then,

$$ma1 = ma2 = V \times pair \times AC/\ (3600\ sec/hr) = 3.59 \times 10^{-4} \times V \times AC$$

where:

ma1 = airflow into house (kg/s)
ma2 = airflow out of house (kg/s)
V = volume of air in house (m^3)
pair = density of air in kg/m^3 = 1.293 kg/m^3
AC = number of air changes per hour

Let:

T1 = outside temperature
w1 = outside specific humidity (in kg H_2O/kg air)
T2 = inside temperature
w2 = inside specific humidity

Then, by conservation of mass for water:

$$ma1 \times w1 + mw3 = ma2 \times w2$$

or, solving for the specific humidity indoors,

$$w2 = w1 + 0.1782 \times Q / (V \times AC)$$

Humidity is often given in terms of the "relative humidity" phi, defined as the partial pressure of water vapor divided by the saturation water vapor in air.

The specific humidity is related to the relative humidity by

$$w = 0.622 \times phi \times pg / [P \times (1 - phi)]$$

or

$$phi = w \times P / (w \times P + 0.622 \times pg)$$

where:

phi = relative humidity
pg = saturation pressure at temperature T (kPa)
pv = partial pressure of water vapor (kPa)
P = total pressure (kPa)

As an example let us consider how the humidity in two houses (one "coventional" house and one "superinsulated" house) varies with weather:

We assume that the volume of each house is 340 m^3 = (12,000 ft^3).
The conventional house has AC = 0.75 air changes per hour.
The superinsulated house has AC = 0.255 air changes per hour.

The temperature and pressure conditions are:

Outdoors		Indoors
CASE 1 "COLDEST WINTER DAY"	CASE 2 "AVERAGE FALL DAY"	
T1 = -10^{o}C	T1 = 10^{o}C	T2 = 23^{o}C
P1 = 100 kPa	P1 = 100 kPa	P2 = 100 kPa
pg1 = 0.25991 kPa*	pg1 = 1.2276 kPa*	pg2 = 2.837 kPa*
phi1 = 0.8 (80% rel. humidity)	phi1 = 0.6 (60% relative humidity)	
w1 = 0.006466*	w1 = 0.011454*	

* These values can be found in standard steam tables, given the pressure, temperature, and relative humidity.

We can now find the indoor relative humidity and the dew point temperature (temperature at which indoor condensation begins) from the equations above. (In solving the equations, we have assumed values for the heat output Q required in each house to maintain an indoor temperature of 23^{o}C, based on heat loss calculations similar to those in note 158 below.)

	"COLDEST WINTER DAY"			"AVE. FALL DAY"		
HOUSE	Heater output Q (kW)	Indoor rel.hum. phi2	Indoor dew pt. temp. (^{o}C)	Heater output Q (kW)	Indoor rel.hum. phi2	Indoor dew pt. temp. (^{o}C)
Conventional	11.7	45.6%	11	5.8	46.9%	11
Super-insulated	2.92	41.6%	7	1.46	45.1%	10

The generally accepted indoor comfort range is for relative humidity of 20-50%, and temperatures of 20-28 ^{o}C. We see that for both houses, the indoor humidity lies in the mid to upper end comfort of the comfort range. The added humidity from the hydrogen heater could be beneficial on very cold days. (For a heater vented to the outdoors, the indoor humidity on the coldest day would be only 26.8%, which is on the low humidity end of the comfort range.)

We might expect some condensation to occur in the conventional house on cold surfaces, such as single glazed windows, on the coldest day. For double or triple glazing the inner surface of the window should be warm enough to avoid this problem.

Sources: ASHRAE Handbook, 1981 Fundamentals, American Society of Heating, Refrigeration and Air conditioning Engineers, Atlanta, Georgia, 1981.

J. Mercea, E. Grecu, and T. Fodor, "Heating of a Testing Room by use of a Hydrogen-Fuelled Catalytic Heater", International Journal of Hydrogen Energy, vol. 6, No. 4, pp. 389-395, (1981).

154. J. B. Pangborn and J. C. Sharer, "Catalytic Fluid Heater", US Patent No. 3955556, (May 11, 1976).

R. J. Dufour, "Heat Exchange Apparatus", US Patent No. 3916869, (November 4, 1975).

155. M. Haruta, Y. Souma, and H. Sano, "Catalytic Combustion of Hydrogen-II", International Journal of Hydrogen Energy, v. 7, No. 9, pp. 729-736, (1982).

M. Haruta and H. Sano, "Catalytic Combustion of Hydrogen-III", International Journal of Hydrogen Energy, v. 7, No. 9, pp. 737-740, (1982).

M. Haruta and H. Sano, "Catalytic Combustion of Hydrogen-IV", International Journal of Hydrogen Energy, v. 7, No. 10, pp. 801-807, (1982).

156. Catalytic space heaters include a case, controls for starting combustion and adjusting the heat output, and the catalyst material. In addition the cost of fabricating the heater must be considered. Based on conversations with catalyst manufacturers, a catalyst/heating element cost of about $80-100/square foot seems reasonable for natural gas or hydrogen heaters.

The "Platinum Cat" natural gas heater (see note 151) contains about 1.3 square feet of heating area and delivers 4420 BTU/h to the room (at 85% efficiency). The total cost of the heater is $350. If 1.3 x 100 = $130 of the cost is due to the heating surface, then the case, controls, and fabrication would account for perhaps $220.

A hydrogen catalytic space heater designed by Dufour and tested by Pangborn and Sharer delivers 7000-9000 BTU/h/sq.ft. of heating surface area. For a 97% efficient hydrogen heater designed to deliver 4420 BTU/h, the required heating area would be about 0.55 square feet. The cost of the heating element would be about $55. Assuming that the controls, case and manufacturing costs are the same, the hydrogen heater would cost about $220 + 55 = $275.

For new construction, the installation cost for a natural gas catalytic heater is estimated to be about $100 per 5200 BTU/h unit. This includes running gas and electric connections to the heater and building a vent to the outside. Building the vent is by far the most time consuming and expensive step, so that the installation cost for an unvented hydrogen heater cost would probably be much less than $100.

Sources: B. Wells, Thermal Systems, Inc., Tumwater, Washington, private communications (1987); representatives of the Jaeger Products Company, private communications (1987); R. J. Dufour, "Heat Exchange Apparatus", US Patent No. 3916869, (November 4, 1975), J. B. Pangborn, "Catalytic Combustion of Hydrogen in Model Appliances", 15th Intersociety Conference on Energy Conversion, Seattle, April 18-22 1980, p. 1731.

157. In a conventional cylindrical natural gas tank type heater, the flue gases from an open flame burner at the bottom of the tank pass through a central pipe, heating the surrounding water, before being vented to the outside. The thermal efficiency is about 50-55%. A hydrogen water heater with essentially the same design, cost and performance could be constructed by using a burner with different-sized holes.

Catalytic hydrogen water heaters have been designed that are similar to natural gas fueled tank-type storage heaters. In a catalytic hydrogen heater, the central pipe is replaced by a pair of cylindrical catalytic surfaces which heat the surrounding water. If the steam from combustion is vented to the room, the efficiency of water heating would be 84%. If the steam from combustion is condensed to preheat incoming water, the efficiency of water heating would be close to 100%.

A tank-type water heater is made up of the tank, controls, and the heating elements. The cost of the water storage tank and controls should be about the same for conventional design heater and for the catalytic heater. The differences in cost will arise from the cost of the heating elements. In addition the conventional water heater will require a vent costing perhaps $50, while the catalytic hydrogen heater will not.

In the conventional tank-type heater, the burner and central pipe are assumed to contribute about half of the bare unit cost. Installation costs are assumed to be approximately equal to the bare unit cost. Thus, the heating elements are assumed to contribute 25% of the total installed cost of the heater.

In a catalytic heater, the heating surface area needed is computed from the maximum fuel input needed. This is given by:

$$\mathrm{Hmax} = \mathrm{Wmax} \times (\mathrm{Thot} - \mathrm{Tin}) \times (8.35\ \mathrm{lb/gallon}) \times (1\ \mathrm{BTU/h/{}^{o}F})/n$$

where:

Hmax = maximum fuel consumption (in BTU/h)
Wmax = maximum water flow rate (in gallons/h) = hot water recovery rate
Thot = hot water temperature (^{o}F)
Tin = water temperature at inlet to heater (^{o}F)
n = thermal efficiency of heater on a higher heating value basis

The catalytic heating surface area needed is:

$$\mathrm{Acat} = \mathrm{Hmax/Hcat}$$

and the cost of the catalytic surface is:

$$\mathrm{Ccat} = \mathrm{Acat} \times \mathrm{Pcat}$$

where:

Acat = heating surface area (in square feet)
Hcat = heat output of heating surface (in BTU/h/sq.ft.) = 8000 BTU/h/ft^2
Ccat = cost of heating element in dollars
Pcat = cost of heating element in \$/ft^2.

The installed cost of the heater can be estimated as follows, for typical water heater values (see sources at end of note):

	H2 CATALYTIC	H2 OR NAT.GAS TANK-TYPE
Tin = WATER INLET TEMPERATURE (°F)	55	55
Tout = HOT WATER TEMPERATURE (°F)	120	120
TEMPERATURE RISE (°F)	65	65
TANK SIZE (GALLONS)	40	40
Wmax = HOT WATER RECOVERY RATE (GAL/HR)	23	23
n = THERMAL EFFICIENCY (BASED ON HIGHER HEATING VALUE OF FUEL)	0.83 (a)	0.52
Hmax = FUEL INPUT (kBTU/H)	12.3	24.2
Hcat = HEAT OUTPUT OF CATALYTIC SURFACE (BTU/H/SQUARE FOOT)	8000	
Acat = CATALYTIC HEATING SURFACE REQUIRED (SQUARE FEET)	1.85	
Pcat = COST OF CATALYTIC SURFACE (\$/SQ.FT.)	100	
TOTAL INSTALLED COST OF HEATER(\$)	428	320
OPEN FLAME BURNER (\$)	-	80
Ccat = CATALYTIC SURFACE (\$)	185	-
REST OF TANK (\$)	240	240
COST OF VENTS	-	50
COST OF WATER HEATER PLUS VENTS	428	370

---

[a] We have assumed that the steam from catalytic combustion of hydrogen is vented to the room as steam, so that the thermal efficiency is 83%. If exhaust steam were condensed for water preheating instead, the thermal efficiency would be 99%, the heating surface area required would be about 1.58 square feet and the heater would cost about \$398 plus the cost of a heat exchanger for condensing the exhaust.

Sources: "TAG Technical Assessment Guide, Volume 2: Electricity End Use, Part I: Residential Electricity Use", EPRI, P-4463-SR, (September 1987), J. B. Pangborn, "Catalytic Combustion of Hydrogen in Model Appliances", 15th Intersociety Conference on Energy Conversion, Seattle, April 18-22 1980, p. 1731.

158. ESTIMATES OF MAXIMUM ENERGY DEMAND FOR SPACE HEATING

When designing a space heating system for a house, the heating load on the coldest expected day of the year ("design day") must be calculated.

Heat losses in houses are primarily due to transmission and infiltration.

Maximum heat transmission losses can be roughly estimated as follows:

$$Ht = (Af/Rf + Ac/Rc + Aw/Rw + Awin/Rwin + Ad/Rd) \times (Tin - Tdesign)$$

where:

Ht = heat loss due to transmission (BTU/h)
Af = floor area (sq.ft.)
Rf = R-factor for floor (BTU/sq.ft./^{o}F/h)
Ac = ceiling area (sq.ft.)
Rc = R-factor for ceiling (BTU/sq.ft./^{o}F/h)
Aw = wall area (sq.ft.)
Rw = R-factor for walls (BTU/sq.ft./^{o}F/h)
Awin = window area (sq.ft.)
Rwin = R-factor for windows (BTU/sq.ft./^{o}F/h)
Ad = area of outside doors (sq.ft.)
Rd = R-factor of doors (BTU/sq.ft./^{o}F/h)
Tdesign = coldest expected outside temperature (^{o}F)
Tin = temperature inside house (^{o}F)

(In practice, heat transmission calculations can be much more complicated than this formula, if heat transmission between rooms and the effects of attic and basement construction are considered.)

Maximum infiltration heat losses can be estimated as:

$$Hi = Cpair \times AC \times V \times (Tin - Tdesign)$$

where:

Hi = heat loss due to infiltration (BTU/h)
Cpair = specific heat of air = 0.018 BTU/ft^{3}/^{o}F
AC = number of air changes per hour
V = volume of house in cubic feet

Heat gains in a house come from the sun, people, lights and appliances. For a household with 3.06 people and the most energy efficient appliances available in 1982, the heat gains were estimated to be 53,000 BTU/day, or on average 2208 BTU/h (M.H. Ross and R.H. Williams, Our Energy: Regaining Control, McGraw-Hill, 1981). If average efficiency appliances were used, the heat gain was found to be 77,000 BTU/day or 3208 BTU/h.

ASHRAE recommends an average heat gain per person of 225 BTU/h. For kitchen appliances the recommended average heat gain is 1200 BTU/h. If an average lighting level of 500 watts is assumed, the heat gain would be

1706 BTU/h. For a house with three people, the total average heat gain would be:

$$Hg = 3 \times 225 + 1200 + 1706 = 3581 \text{ BTU/h}$$

Using the formulas above, we have estimated the maximum heating loads for a "conventional" new house and a "superinsulated" house in New Jersey.

For both houses, we have assumed that three people occupy the house, on average, and:

Af = Floor area = 1500 ft^2
V = Volume of house = 12,000 ft^3
Width = 30 ft
Length = 50 ft
Tin = 70^{o}F
T design = 14^{o}F (for Newark,NJ or New York City)
DT = Tin - Tdesign = 56^{o}F

HEAT TRANSMISSION LOSSES:

	CONVENTIONAL			SUPERINSULATED		
	Area	R	Ht = A/R x DT	Area	R	Ht = A/R x DT
Floor	1500	9	9333	1500	49	1714
Ceiling	1500	30	2800	1500	41	2054
Wall	1088	19	3207	1088	45.3	1345
Windows	192	2	5376	192	4.35	2473
Doors	42	3	776	42	3	776
TOTAL TRANS. HEAT LOSS (BTU/h)			21,492			8362
Air change/h	0.8			0.255		
INFILTRATION HEAT LOSS (BTU/h)			9677			3084
HEAT GAIN (BTU/h):			3208 1980 average appliances			2208 1982 efficient appliances
HEAT REQUIRED FROM HEATING SYSTEM (BTU/h)			27961			9780

(This is the heat which must be delivered to the conditioned space. the fuel use will depend on the efficiency of the system.)

As a check, we have also estimated the heating demand from an EPRI formula, which was derived from a fit to detailed simulations. For the two cases we obtained:

EPRI ESTIMATE OF HEAT REQUIRED FROM HEATING SYSTEM (BTU/h)	30550	9713

ESTIMATES OF ANNUAL ENERGY DEMAND

The annual space heating energy demand can be estimated, if the house design and weather data are known. We have used formulas from the EPRI Technical Assessment Guide for the annual energy consumption in the New York City area.

	CONVENTIONAL	SUPERINSULATED
ANNUAL SPACE HEATING ENERGY DEMAND (MBTU/yr)	45.2	5.32

The annual water heating energy demand can be estimated as follows:

$$Ew = Gdp \times Np \times (365 \text{ days/yr}) \times (Thot - Tc) \times (8.35 \text{ lb/gl}) \times (1 \text{ BTU/lb/}^{\circ}\text{F})$$

where:
Ew = annual water heating energy demand (BTU/yr)
Gdp = gallons per day per person
Np = number of people
$Thot$ = hot water temperature ($^{\circ}$F)
Tc = inlet water temperature ($^{\circ}$F)

Assuming:
$Gdp = 15.6$ gallons/person/day
$Np = 3$ people
$Thot = 120^{\circ}$F
$Tc = 55^{\circ}$F
then
$Ew = 9.27$ MBTU/yr

This is the energy which must be delivered to the water. The fuel use will depend on the efficiency of the water heater.

We have assumed that the water heating energy demand is the same for the conventional and superinsulated houses.

Sources: "TAG Technical Assessment Guide, Volume 2: Electricity End Use, Part I: Residential Electricity Use", EPRI, P-4463-SR, (September 1987); R.H. Williams, "Policy Proposals to Promote Energy Conservation in the Residential Sector in New Jersey", (1983); ASHRAE Handbook, 1981 Fundamentals, American Society of Heating, Refrigeration and Air conditioning Engineers, Atlanta, Georgia, 1981.

159. It is difficult to estimate the added cost of a superinsulated house such as the NEH because the modular construction of the NEH facilitates both a high level of quality control and rapid site construction. As a

consequence the first costs of these houses have not been notably higher than conventional with more typical heat loss characteristics (see R.H. Williams, G.S. Dutt, and H.S. Geller, "Future Energy Savings in US Housing," Annual Review of Energy, Vol. 8, pp. 269-332, 1983.) However, in Sweden, where most new houses are prefabricated, one manufacturer (Faluhus) has offered both conventional and superinsulated versions of the same basic prefabricated housing design: the superinsulated design costing $3140 more requires 32.3 GJ less heating energy per year than the conventional version (J.Goldemberg, T.B. Johansson, A.K.N. Reddy, Energy for a Sustainable World, World Resources Institute, Washington DC, September 1987). From Note 158, our superinsulated house uses 5.32 MBTU/yr (5.61 GJ/yr) for space heating as compared to 45.2 MBTU/yr (47.7 GJ/yr) for the conventional house, resulting in a savings of 42.1 GJ/year. Assuming the initial cost is proportional to the savings the Faluhus experience suggests that the superinsulated house considered here, which requires 42.1 GJ less heat per year than a house of conventional construction would cost $4100 more to build than a similar house equiped with conventional amounts of insulation. This estimate is consistent with an EPRI estimate that superinsulated houses (in the 1500 square foot size) would cost $3764-6428 more than conventional houses (Electric Power Research Institute, Technical Assessment Guide, Volume 2: Electricity End Use, Part I: Residential Electricity Use, EPRI, P-4463-SR, September 1987).

160. We have estimated the cost and performance of space heating and water heating systems for three different heating fuels, natural gas, hydrogen and electricity and three sets of energy end-use technologies:

1. Low First-Cost Technologies for Conventional New Houses: conventional furnaces for natural gas and hydrogen; conventional tank-type water heaters for natural gas and hydrogen; electric resistance space and water heating for electricity.

2. Energy-Efficient Technologies for Conventional New Houses: condensing furnaces for natural gas and hydrogen; tankless water heater for natural gas; catalytic water heater for hydrogen; and heat pumps for space and water heating with electricity.

3. Energy-Efficient Technologies for Superinsulated Houses: catalytic space heaters for both natural gas and hydrogen; tank type water heater for natural gas, catalytic water heater for hydrogen, resistance space heating and heat pump water heater for electricity.

The energy demands for each case are taken from Note 158 for convnetional and super-insulated houses in New Jersey:

		CONVENTIONAL HOUSE	SUPERINSULATED HOUSE
Peak Demands:			
Space Heating	(BTU/h)	27961	9780
Water Heating	(gallons/min)	1.8	1.8
	(gallons)	40	40
Annual Demands:			
Space Heating	(MBTU/yr)	45.2	5.32
Water Heating	(MBTU/yr)	9.27	9.27

The heating unit for each case can be sized by dividing the peak energy demand by the heating unit's efficiency. The performance, size and costs for hydrogen space and water heaters were calculated as in Notes 156 and 157.

Cost and performance figures for the various systems are summarized below and and in Table 20.

		Costs ($) (a)						
	Size	Installed Unit	Ducts	Vents	System Total	Effic. or COP	Life (yr)	O&M ($/yr)
1. Low First-Cost Technologies, Conventional New Houses								
NATURAL GAS:								
Conventional furnace	41 kBTU/h	700	1500	50	2250	0.69	18	25
Tank-type water heater	40 gal	320	-	50	370	0.52	10	5
HYDROGEN:								
Conventional furnace	43 kBTU/h	700	1500	50	2250	0.65	18	25
Tank-type water heaterr	40 gal	320	-	50	370	0.49	10	5
ELECTRICITY:								
Resistance space heat	8.28 kW	1100	-	-	1100	0.99	15	15
Resistance water heater	40 gal	300			300	0.85	10	5
2. Energy-Efficient Technologies, Conventional New Houses								
NATURAL GAS:								
Recuperative furnace	29 kBTU/h	2200	1500	50	3750	0.95	20	80
Tankless water heater	40 gal	750	-	50	800	0.78	10	30
HYDROGEN:								
Recuperative furnace	29 kBTU/h	2200	1500	50	3750	0.95	20	80
Catalytic water heater	40 gal	425	-	50	475	0.83	10	5
ELECTRICITY:								
Heat pump (b)	2.87 kW	2700	1500	-	4200	2.85	15	25
Heat pump water heater	40 gal	1550			1550	1.8	10	30

3. Energy-Efficient Technologies, Superinsulated Houses

NATURAL GAS:								
Tightened building shell (c)					4100			
3 Catalyt. sp. htrs	11.5 kBTU/h	1245 (d)	-	-	1245	0.85	15	10
Tank type water heater	40 gal	320	-	50	370	0.52	10	5
HYDROGEN:								
Tightened building shell (c)					4100			
3 Catalyt. sp. htrs	9.9 kBTU/h	855 (e)	-	-	855	0.99	15	10
Catalytic water heater	40 gal	425 (f)	-	50	475	0.83	10	5
ELECTRICITY:								
Tightened building shell (c)					4100			
Resistance heaters	2.89 kW	800	-	-	800	0.99	15	15
Heat pump water heater	40 gal	1550	-	-	1550	1.8	10	30

---

[a] For electric and conventional natural gas systems performance and cost figures were taken from the Electric Power Research Institute's "TAG Technical Assessment Guide, Volume 2: Electricity End Use, Part I: Residential Electricity Use", EPRI, P-4463-SR, September 1987. For the catalytic natural gas heater, cost and performance estimates are from B. Wells, Thermal Systems, Inc., Tumwater, Washington, private communication, 1987.

[b] The cost of the heat pump includes a credit for air-conditioning.

[c] See Note 159.

[d] For the superinsulated house we have used three in-room space heaters. The total space heating demand is 9780 BTU/h, so that each heater must supply 9780/3 = 3260 BTU/h to the house. For natural gas the units are vented to the outside for a thermal efficiency of 85%. Each natural gas catalytic heater consumes 3835 BTU/h of fuel. We have estimated the cost of each heater (as in Note 88) to be $315, with a $100 installation charge per unit. The total installed system cost is then 3 x (315 + 100) = $1245.

[e] The hydrogen units exhaust directly into the room, for a thermal effciency of 99%. Each unit consumes 3293 BTU/h, and costs $260 plus an installation charge of $25. The total system cost is 3 x (260 + 25) = $855.

[f] The hydrogen water heater is a catalytic type with cost as calculated in Note 157. We have assumed that this water heater is vented to avoid humidity buildup.

161. Using the information in Tables 19 and 20, the levelized annual cost of heating can be calculated for each case as follows:

$$Ph = CRF \times Csys + Pom + Pfuel \times Hdem/n$$

where:

Ph = levelized annual cost of heating in dollars per year
Csys = total installed cost of system including ducts and vents plus extra construction costs for superinsulated house (See Note 159).

CRF = capital recovery factor = $d/[1 - (1 + d)^{-N}]$
d = discount rate
N = unit lifetime
Pom = annual operating and maintenace costs in dollars per year
Pfuel = cost of fuel in dollars per Gigajoule
Hdem = annual energy demand for heating in GJ per year.
n = heating system efficiency

Assuming a discount rate of 10%, we have plotted the levelized annual cost of space and water heating for conventional and super-insulated houses for natural gas, hydrogen and electricity in Figure 19.

162. The credit for oxygen as a byproduct of electrolysis can be estimated as follows:

The chemical reaction of electrolysis is:

$$2\ H_2O \text{ --> } 2\ H_2 + O_2.$$

For each mole of O_2 (weighing 32 grams/mole), 2 moles of hydrogen (weighing 2 grams/mole) are produced. Each gram of H_2 has an energy content of 142.3 kJ (higher heating value basis). If 32 grams of oxygen are produced, 4 grams of hydrogen with energy content of 4 x 142.4 = 568 kJ are produced. Equivalently, for each GJ of hydrogen fuel, 56.33 kg of oxygen is produced. From Hammerli, oxygen from a cryogenic air separation plant would cost about \$38-44/tonne or \$0.038-0.044/kg. The maximum oxygen credit would be 56.33 kg O_2/GJ x (\$0.038-0.044/kg O_2) = \$2.14-2.47 per GJ of hydrogen produced.

Assuming that the electrolysis takes place at atmospheric pressure (as in the unipolar electrolyzer technology), the oxygen might be compressed prior to storage or onsite use. Oxygen end-use pressures vary from 25-35 psia to 500 psia, depending on the application. Typical pressures for oxygen storage vary from 300-500 psia.

Oxygen compression costs can be estimated as follows:

Ccm = Ccmc + Ccme

where:

Ccm = cost of oxygen compression (in \$ per GJ of hydrogen electrolyzed)
Cmc = capital contribution to cost of oxygen compression (\$/GJ H_2)
Ccme = energy contribution to cost of oxygen compression (\$/GJ H_2)

The capital contribution is:

Ccmc = (CRF + INS + OM) x Pcm x Cc / Hann

where:

CRF = capital recovery factor
INS = insurance
OM = operating and maintenance costs
Pcm = capacity of compressor (in kW)
Cc = capital cost of compressor (\$/kW)
Hann = annual hydrogen production (in GJ/yr)

The power contribution is:

$$\mathrm{Ccme} = \mathrm{Pcm} \times p \times (8760\ \mathrm{h/yr}) \times \mathrm{Ce} / \mathrm{Hann}$$

where:

p = the electrolyzer capacity factor
Ce = cost of electricity in \$/kwh

The compressor capacity in kW is given by:

$$\mathrm{Pcm} = \mathrm{Qo} \times (\mathrm{Pb}/\mathrm{Tb}) \times (\mathrm{T1}/\mathrm{nc}) \times Z \times [\mathrm{Ng}/(g-1)] \times [(\mathrm{P2}/\mathrm{P1})^{[(g-1)/\mathrm{Ng}]} - 1]/1000$$

where:

Qo = flow rate of oxygen (cubic meters/second at Tb, Pb)
T1 = oxygen temperature at inlet (degrees K)
Tb = reference temperature = 298 degrees K
Pb = reference pressure = 101,300 Newtons per square meter = atmospheric pressure
P1 = inlet pressure
P2 = outlet pressure
Z = oxygen compressibility = 1
g = ratio of specific heats for oxygen = 1.395
N = number of stages of compression
nc = compressor efficiency

For each mole of oxygen produced, two moles of hydrogen are produced, thus the flow rate of oxygen is related to the electrolyzer capacity as follows:

$$\begin{aligned}\mathrm{Qo} &= \mathrm{Qh}/2 = H \times (10^{3}\ \mathrm{W/kW}) \times (10^{-9}\ \mathrm{GJ/W\text{-}sec})/(\mathrm{HHV} \times \mathrm{nh} \times 2) \\ &= 3.94 \times 10^{-5} \times H\end{aligned}$$

where:

Qh = flow of hydrogen in cubic meters per second
nh = density of hydrogen at T=298 K, P = 1 atmosphere = 0.0893 $\mathrm{kg/m^3}$
HHV = higher heating value of hydrogen = 0.14202 GJ/kg.
H = electrolyzer output in kW of hydrogen produced (HHV basis).

The annual hydrogen production Hann in GJ/yr is:

$$\mathrm{Hann} = p \times (8760\ \mathrm{h/yr}) \times (3600\ \mathrm{sec/h}) \times H \times (10^{-6}\ \mathrm{GJ/kW\text{-}sec})$$

We have assumed the following values:

CRF = 0.0879 (6.1% discount rate, 20 year compressor life)
INS = 0.005
Cc = \$610/kW
OM = 0.1
p = 0.271 (corresponding to a solar PV powered electrolyzer in El Paso)
T1 = 343^{o} K
P1 = 14.7 psia = atmospheric pressure (as in unipolar electrolysis)
N = 4 stages of compressor
nc = 0.85

Then the cost of oxygen compression in \$ per GJ of hydrogen for various conditions is:

P1 --> P2	Ce = \$0.02/kwh	Ce = \$0.035/kwh	Ce = \$0.05/kwh
14.7 -> 100	0.21	0.26	0.31
14.7 -> 300	0.35	0.43	0.51
14.7 -> 500	0.42	0.51	0.60

Subtracting the compression costs from the maximum oxygen byproduct credit gives a net oxygen credit of \$1.5-2.2 per GJ of hydrogen produced, depending on P2 and Ce.

Sources: M. Hammerli, International Journal of Hydrogen Energy, v. 9, No. 12, p.25-51, (1984); B. Kribel, Air Products, Inc., private communications, (1987).

CHAPTER 7

163. W. Balthasar, "Hydrogen Production and Technology: Today, Tomorrow and Beyond", International Journal of Hydrogen Energy, v. 9, p.649-668, 1984.

164. Here the economics of alternative industrial hydrogen production methods are described. The cost of hydrogen is given by:

$$Ph = \frac{CRF \times (Cap + SU) + (INS + Ci) \times Cap + d \times WC + Pom - Pby}{p \times 365 \text{ days/yr} \times Hout \times 0.0003601 \text{ GJ/scf}} + Pfeed/n$$

where:

Ph = cost of hydrogen production (\$/GJ)
CRF = capital recovery factor = $d/[1 - (1+d)^{-N}]$
d = discount rate
N = lifetime of plant (years)
Cap = installed capital cost of plant (\$)
SU = start-up capital (\$)
INS = insurance as fraction of plant capital cost
Ci = interest during construction as fraction of plant capital cost
WC = working capital (\$)
Pom = operations and maintenance cost (\$/year)
Pby = byproduct credit (\$/year)
p = plant capacity factor (or stream factor)
Hout = plant output capacity in scf of hydrogen per day
Pfeed = feedstock cost in \$/GJ of feedstock
n = conversion energy efficiency of feedstock to hydrogen

Costs for various processes are estimated below for a plant with:

Hout = 10^8 scf/day (416.8 MW H_2),

assuming N = 20 years, INS = 0.005, Ci = 0.15, and d = 0.061.

ECONOMICS OF HYDROGEN PRODUCTION AT LARGE SCALE (100 MILLION SCF/DAY) WITH ALTERNATIVE PRODUCTION METHODS

PROCESS	Steam Reforming	Partial Oxidation	Coal Gasification		Unipolar Electrolysis	
			Koppers-Totzek	Steam-Iron		
Feedstock	Nat. Gas	Resid. Oil	WY Coal	MT Coal	Electricity	
p	0.9	0.9	0.9	0.9	0.9[a]	0.25[b]
Cap ($106)	75.0	215.0	366.8	289.3	92.5	74.0
SU ($106)	1.47	4.27	7.35	5.74		
WC ($106)	9.85	10.7	10.3	10.6		
Pom ($106/yr)						
Utilities	2.59	2.55	4.98	3.34		
Maint.	6.37	16.07	28.22	18.18		
Total O&M	8.96	18.62	33.20	21.52	1.85	1.48
Byproduct	Steam	Sulfur	Sulfur	Electricity	Oxygen	
Value	\$9.67/tonne	\$13/tonne	\$13/tonne	\$0.029/kwh	\$1.5/GJ H_2	
Pby ($106/yr)	4.82	0.146	0.088	36.5		
n	0.74	0.827	0.594	0.626	0.84	
Pfeed($/GJ)	4-6	4-6	1.78	1.78	11.1	5.53-9.64
Ph ($/GJ)	7.36-10.06	10.90-13.32	13.44	7.69	12.6	7.62-12.51

---

[a] For grid powered electrolysis, with electricity cost of \$0.04/kwhAC. The capital cost includes a rectifier to produce DC power for the electrolyzer.

[b] For PV powered electrolysis in the Southwestern US, with electricity cost of \$0.020-0.035/kwhDC (corresponding to PV module efficiency of 12-18% and cost of \$0.2-0.4/Wp). No rectifier is needed.

Source: D.P. Gregory, C.L. Tsaros, J.L. Arora, and P. Nevrekar, "The Economics of Hydrogen Production", American Chemical Society Report, 0-8412-0522-1/80/47-116-003, 1980.

(Here the costs presented by Gregory et al. have been converted from 1979\$ to 1986\$ using the GNP deflator.)

The various costs which make up a hydrogen production plant scale with plant capacity as follows:

$$C = Co \times (H/Ho)^q$$

where:

C = cost for plant with capacity H (in \$)
Co = cost for reference plant with capacity Ho (in \$)
H = plant capacity (scf/day)
Ho = reference capacity (scf/day)
q = scaling factor

Gregory *et al*. suggest the following scaling factors for capital costs (including insurance, start-up and working capital costs) and the maintenance part of Pom:

	Steam Reforming	Partial Oxidation	Coal Gasification (Koppers-Totzek)	Steam-Iron
q = scale factor	0.65	0.6, 0.7	0.6, 0.7	0.65
Hout (106 scf/day)	25-100	25-50, 50-100	25-50, 50-100	25-100

They also suggest that the costs of feedstocks, the Pom costs attributed to utilities and the byproduct credits scale directly with plant capacity.

COST OF HYDROGEN (in $/GJ) VS. PLANT SIZE

	PROCESS			
Plant Size (10^6 scf/day)	Steam Reforming	Partial Oxidation	Coal Gasification (Koppers-Totzek)	Steam-Iron
100	7.36-10.06	10.90-13.32	13.44	7.69
50	7.95-10.65	12.25-14.67	15.76	9.77
25	8.69-11.40	14.56-16.98	19.71	12.42

Capital costs for small steam reforming plants have also been discussed by Fein (a). The following are estimates of the production cost of hydrogen based on these values:

Plant Size (10^6 scf/day)	Capital ($\$10^6$)	Pom Maintenance[b] ($\$10^6$/yr)	Labor[c] ($\$10^6$/yr)	Ph[d] ($/GJ)
100	87.9	3.52	3.31	7.03-9.74
2.41	3.802	0.152	0.115	8.23-10.93
0.48	1.909	0.0764	0.115	13.53-16.24
0.1	1.098	0.0439	0.115	31.97-34.68

---

[a] E. Fein, "The Market Potential for Electrolytic Hydrogen," *International Journal of Hydrogen Energy*, v. 6, p. 53-66, 1981.

[b] Maintenance was taken to 4% of the capital cost.

[c] For small plants, Fein assumes that 0.15-0.26 operators per 8-hour shift are needed, or 1182-2050 operator hours per year, with a plant capacity factor of 90%. Fein has taken the operator's salaries to be $17/hour, but the total labor cost be $73 per shift hour including operators' salaries, supervision, benefits, administration, etc. For the 100 million scf/day plant, we have used labor figures from Gregory *et al*.

[d] Here a plant lifetime of 10 years is assumed, as suggested by Fein.

As before, it is assumed that the discount rate is 6.1% (CRF of 0.1365), INS = 0.005, n = 0.74, and the natural gas price is in the range $4-6/GJ.

165. E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Service Territories", EPRI Report, EM-3561, May 1984.

166. W. Balthasar, "Hydrogen Production and Technology: Today, Tomorrow and Beyond," International Journal of Hydrogen Energy, v. 9, p.649-668, 1984.

167. Energy Information Administration, Annual Energy Outlook 1986, with Projections to 2000, DOE/EIA-0383(86), February 1987.

168. P.K. Takahashi and S.H. Browne, "Hydrogen from Renewable Sources," a report of the Hawaii Natural Energy Institute, 1987.

169. W. Balthasar, "Hydrogen Production and Technology: Today, Tomorrow and Beyond."

170. Large electrolysis plants sited near hydroelectric power are:

Location	Type	Manufacturer	Year Installed	Power In (MW)	H2 Out (10^6 scf/hr)
Trail, BC	Unipolar	Cominco	1939	n.a.	0.7
Nangal, India	Bipolar	DeNora	1958	130	1.1
Aswan, Egypt	Bipolar	DeMag	1960-1977	170	1.4
Rjukan, Norway	Bipolar	Norsk	1927-1965	250	2.2
Cuzco, Peru	Bipolar	Lurgi	1958	25	0.2

Source: E. Fein and T. Munson, "An Assessment of Non-Fossil Hydrogen," Gas Research Institute Report, GRI 79/0108, 1980.

171. Ibid.

172. K. Darrow, N Biederman, and A. Konopka, "Commodity Hydrogen from Off-Peak Electricity," International Journal of Hydrogen Energy, v. 2, pp. 175-187, 1977; R.W. Foster, R.R. Tison, W.J.D. Escher, and J.A. Hanson, "Solar/Hydrogen Systems Assessment," DOE/JPL-955492, 1980.

173. E. Fein and K. Edwards, "Market Potential of Electrolytic Hydrogen Production in Three Northeastern Utilities' Service Territories," EPRI Report, EM-3561, May 1984.

174. J. Nitsch and C.-J. Winter, "Solar Hydrogen Energy in the F.R. of Germany: 12 Theses", International Journal of Hydrogen Energy, v. 12, p. 663, 1987.

175. Ibid.

176. Maricopa County Regional Public Transit Authority, "Building Mobility : Transit 2020", draft report, Phoenix, Arizona, 1988.

177. Ibid.

178. A.J. Pfister, General Manager, Salt River Project, Phoenix, Arizona, private communication, 1988.

179. Suppose that 30,000 fleet automobiles driven 100 miles per day, on average, and having an average fuel economy of 30 mpg (gasoline equivalent) are refueled every night with hydrogen (metal hydride storage) derived via electrolysis using off-peak AC electricity from local conventional power sources.

The required fuel would be 100,000 gasoline-equivalent gallons per day, or 12,500 GJ per day (386 MW) of hydrogen energy. Assuming an electrolyzer efficiency of 80.6% and off-peak power available 9 hours a day (10pm to 7am), the required off-peak electric power is 480 MW.

As there are no scale economies for hydrogen production above 10 MW, there could be 39 hydrogen charging stations in Phoenix, each servicing 769 cars per night.

The cost of hydrogen for these cars would be as follows (in $/GJ):

Electricity for Electrolyzers[a]	6.89 to 10.33
Electrolyzer[b]	2.34
Capital Charge for Compressors[c]	1.01
Electricity Cost for Compressors[d]	0.34 to 0.50
Capital Charge for Storage[e]	0.13
Capital Charge for Refueling Bays[f]	0.020
Labor Cost for Operating Refueling Bays[g]	0.79
Administrative, Overhead Costs for Refueling[h]	0.44
Total	11.96 to 15.69

---

[a] In Phoenix, off-peak electricity is available from 10pm to 7am at rates between 2 and 3 cents per kWh (private communication from Jack Pfister, Director of the Arizona Salt River Project, October 1988). The electricity cost contribution to the cost of hydrogen is determined by this price and the assumed overall electrolyzer efficiency of 80.6% (96% for the rectifier and 84% for the rest of the system).

[b] The electrolyzer is assumed to operate at an average capacity factor of 36% (10pm to 7am, 350 days per year) and to cost 25% more than PV-

based systems, to account for the cost of the rectifier (see Note 94).

c The compressor capacity needed, in kW is given by (see Note 99):

$$Pcm = 0.02808 \times (N/nc) \times (T1/298) \times Ho \times [(P2/P1)^{(0.291/N)} - 1],$$

where

N = number of compressor stages
P1 = inlet gas pressure
P2 = exit gas pressure
Ho = maximum hydrogen flow rate (in kW)
nc = compressor efficiency
T1 = hydrogen temperature at compressor inlet (in ^{o}K)

If N = 4, nc = 0.85, T1 = 353 ^{o}K, and P2/P1 = 750/15 = 50, then

$$Pcm = 0.0515\ Ho.$$

The hydrogen flow rate per servicing center is 10,000 kW, so that the required compressor capacity is 515 kW per servicing center.

The compressor/drive cost CAcm (in $/kW) for 4-stage compressors in this size range is given approximately according to (see Note 99):

$$CAcm = 6919 \times Pcm^{-0.287},$$

where Pcm is the compressor capacity in kW. Thus the compressor capital cost is about $1153/kW.

The compressor capital charge to energy is given by:

$$[1/(0.0036 \times 8760)] \times (CRF + INS + OM) \times [(Pcm \times CAcm)/(Ho \times CF)]$$

where:

CRF = capital recovery factor = 0.0879 (20-year life)
INS = insurance and property tax rate = 0.005
OM = operation and maintenance rate = 0.10
CF = capacity factor = 0.36

d The cost of electricity for running the compressor is given by:

$$[1/(0.0036)] \times [(Pcm \times Ce)/(Ho \times nc)],$$

where Ce is the electricity price in $/kWh.

e It is assumed that only one hour of storage is needed, as it is envisaged that the fleet vehicles would be fueled at a continuous rate, from 10pm till 7am. The total throughput per servicing center would be 320 GJ or 26,440 Nm^3 of hydrogen per night. One hour of storage would be 2940 Nm^3. Tank storage in this range is estimated to cost about $54 per Nm^3 (see Note 98). Thus the cost of the storage tank would be $159,000 and the capital charge to energy for storage would be:

0.093 x $159,000 / [(350 days/year) x 320 GJ] = $0.15/GJ.

f To determine the number of refueling bays needed per servicing center, an estimate of the refueling time is needed. To begin with, the amount of hydrogen required per car per fillup is:

12,500 GJ/(30,000 cars) = 0.4167 GJ/car/day

Since the refueling time is estimated to be 10 minutes for a charge of 0.581 GJ (see Note 135), the refueling time for a charge of 0.4167 GJ would be:

0.4167/0.581 x 10 = 7.1 minutes

Thus the maximum number of cars serviced per bay per night is:

(9 hours x 60 minutes)/ 7.1 = 76 cars

Here it is assumed that 64 cars will be serviced per bay per night (84% capacity factor), so that 12 bays are needed per charging station. At $2000 per bay (see Note 135), the capital cost of bays would be $24,000, and the capital charge to energy for bays would be:

0.093 x $24,000 / [(350 days/year) x 320 GJ] = $0.023/GJ.

g Assuming that 4 persons @ $7 per hour are required to operate the bays, the labor charge to energy for operating the bays would be:

[4 x ($7/hour) x (9 hours)] / (320 GJ) = $0.79/GJ.

h Overhead and administrative costs are assumed to be 56% of direct labor cost (see Note 135).

180. M.C. Holcomb, S.D. Floyd, S.L. Cagle, "Transportation Energy Data Book: Edition 9", Oak Ridge National Laboratory, ORNL-6325, April 1987.

181. See Note 142.

182. The estimated fixed capital required to convert 30,000 fleet vehicles to hydrogen produced off peak using existing power sources is the following, in million dollars:

Electrolyzers[a]	101.5
Compressors[b]	22.9
Hydrogen Storage[c]	6.2
Refueling Bays	0.9
Total	131.5

---

[a] The capital required per kW of power input is assumed to be 25% higher than for the PV-based hydrogen system (see Note 94) or $212.5 per kW of input power input. Since the rectifier is assumed to be 96% efficient, this becomes $221 per kW of DC input power. The DC input power is 459 MW.

[b] The compressor capital cost (see Note 179-c) is

$$(\$1153/\text{kW}) \times 0.0515 \times (386{,}000\ \text{kW}).$$

[c] The cost of hydrogen storage (see Note 179-e) is 39 x $159,000.

[d] The cost of refueling bays (see Note 179-f) is 39 x $24,000

183. It is assumed that cars last 105,000 miles. Driven 100 miles a day for 350 days per year, they thus last 3 years. In contrast, the hydrogen system is expected to last 20 years, and serve many generations of fleets. Assuming straight line depreciation and a 6.1% discount rate, the capital cost allocated to the first generation of fleets is:

$$\$131.5 \times 10^6 \times [1 - (17/20)/1.061^3]/30{,}000 = \$1264 \text{ per car.}$$

184. Metal hydride tanks are estimated to cost $635 (see Note 142) and last more than 2000 cycles. But in 3 years of operation in fleet cars they would use only 1050 cycles, if refueled every night for 350 days per year. Thus it is assumed that hydride tanks are used in two generations of fleet vehicles. Assuming straight line depreciation, the cost allocated to the first generation of vehicles is:

$$\$635 \times [1 - 0.5/1.061^3] = \$369 \text{ per car.}$$

185. Maricopa County Regional Public Transit Authority, "Building Mobility: Transit 2020."

186. Suppose that by the year 2000 30,000 additional fleet automobiles

driven 100 miles per day, on average, and having an average fuel economy of 30 mpg (gasoline equivalent) are refueled every night with hydrogen (metal hydride storage) derived via electrolysis using DC electricity a PV electric system.

The required fuel would be 100,000 gasoline-equivalent gallons per day, or 12,500 GJ per day of hydrogen energy. Assuming an electrolyzer efficiency of 84% the daily electricity requirement would be some 1.45 billion kWh per year. For insolation similar to El Paso, the electricity production rate is 2.37 kWh per year per peak Watt, so that the required installed electric capacity is 610 MW.

As there are no scale economies for PV hydrogen production above 10 MW, there could be 39 hydrogen charging stations in Phoenix, each servicing 769 cars per night.

The cost of hydrogen for these cars would be as follows (in $/GJ):

Electricity for Electrolyzers[a]	6.57 to 11.47
Electrolyzer[b]	2.52
Capital Charge for Compressors[c]	1.01
Electricity Cost for Compressors[d]	0.30 to 0.51
Capital Charge for Storage[e]	1.18
Capital Charge for Refueling Bays[f]	0.020
Labor Cost for Operating Refueling Bays[g]	0.79
Administrative, Overhead Costs for Refueling[h]	0.44
Total	12.83 to 17.94

---

[a] For 12% (18%) PV modules costing $0.4/Wp ($0.2/Wp) the cost of electricity is $0.0347 ($0.0199) per kWh, and, for 84% efficient electrolyzers, the corresponding electricity cost component of the cost of hydogen is $11.47 ($6.57) per GJ (see Note 94).

[b] See Note 94.

[c] See Note 179-c.

[d] The cost of electricity for running the compressor is given by:

$$[1/(0.0036)] \times [(Pcm \times Ce)/(Ho \times nc)],$$

where Ce is the electricity price in $/kWh.

[e] It is assumed that one day's storage is needed. The total throughput per servicing center would be 320 GJ or 26,440 Nm^3 of hydrogen per night. Tank storage in this range is estimated to cost about $54 per Nm^3 (see Note 98). Thus the cost of the storage tank would be $1,430,000 and the capital charge to energy for storage would be:

$$0.093 \times \$1,430,000 / [(350 \text{ days/year}) \times 320 \text{ GJ}] = \$1.18/\text{GJ}.$$

[f] See Note 179-f.

[g] See Note 174-g.

[h] See Note 179-h.

187. M.C. Holcomb, S.D. Floyd, S.L. Cagle, "Transportation Energy Data Book: Edition 9."

188. The cost of pipeline transmission depends on the pipeline flow rate. There is considerable economy of scale for pipelines up to levels of perhaps 100,000 million BTU/hr. To supply this flow rate, an electrolyzer would have to have a peak output of 29,000 MW of hydrogen. Still the overall contribution of transmission costs over 1000 miles is a small part of the total cost even for flow rates of 20,000 million BTU/hr (corresponding to an electrolyzer about 6000 MW in size).

    Sources: K.E. Cox and K. D. Williamson, Hydrogen: Its Technology and Implications, CRC Press, Cleveland, Ohio, 1975; D. Christodoulou, "Technology and Economics of the Transmission of Gaseous Fuels", Princeton University Master's Thesis, 1984.

189. J.M. Hall, Sales Manager, RIX Industries, Oakland, CA, private communication, 1988.

190. H.G. Broadman and W.W. Hogan, "Oil Import Policy in an Uncertain Market," Energy and Environmental Policy Discusssion Paper No. E-86-11, Johan F. Kennedy School of Government, Harvard University, November 1986.

191. W.U. Chandler, H.S. Geller, and M.R. Ledbetter, Energy Efficiency: A New Agenda, American Council for an Energy Efficient Economy, Washinton, DC, July 1988.

192. J. Goldemberg, T.B. Johansson, A.K.N. Reddy, and R.H. Williams, Energy for a Sustainable World (Note 34).

193. J. Goldemberg, T.B. Johansson, A.K.N. Reddy, and R.H. Williams, Energy for a Sustainable World (Note 34).

194. See Note 174.

195. As the era of low-cost oil and gas draws to a close, financing energy supply expansion will become more and more challenging, because the major alternative energy supplies are much more capital-intensive than in the past. The table below compares the unit capital costs required for alternative energy systems.

    Bringing PV hydrogen production capacity on line would require capital expenditures of $3.7-5.8/(Watt-yr/yr) for PV arrays and electrolyzers. See Note 114. (Hydrogen storage systems and pipelines would be a relatively small addition to this cost.)

Coal-based synthetic fuels would require capital expenditures of $0.6-1.1/(Watt-yr/yr) for plants to produce synthetic natural gas, and $1.0-2.5/(Watt-yr/yr) for plants producing synthetic liquids (methanol and synthetic gasoline). See Note 114. (In addition to the cost of building synfuel plants, modest additional capital would be needed for expansion of coal mining and transport systems.)

The unit capital costs for electricity systems are estimated to be in the range 7.7 to 10 Watt-yr/yr during the period 1980--2000 (a).

Thus capital requirements for a PV hydrogen energy system would be itermediate between those required for electricity systems in the period 1980-2000 and those required for coal synthetics systems in this same period.

Development of a global PV hydrogen system capable of supplying 5 Terawatt-yr/yr (or 1 kW-yr/yr for each of 5 billion people) would cost 18-30 trillion dollars.

For comparison the cumulative capital investment expected between 1980 and 2000 for oil, natural gas, coal and electric energy systems is in the range 14 to 20 trillion dollars (or 700 to 1000 billion dollars per year) (a).

Thus if the estimated 1980-2000 capital requirement for global energy is taken as an indicator of the level of capital investment society will make on energy systems it is apparent that building a worldwide PV hydrogen energy system would take many decades.

ESTIMATED CAPITAL REQUIRED FOR THE WORLD'S ENERGY SYSTEMS, 1980-2000[a]

	Low Energy Growth Scenario					High Energy Growth Scenario				
	Oil	Nat.Gas	Coal	Elec.	Total	Oil	Nat.Gas	Coal	Elec.	Total
Capital Cost per Watt-yr/yr [$/(Watt-yr/yr)]	0.69	0.62	0.20	7.7	1.3	0.75	0.79	0.33	10.1	1.7
Cumulative Capital Cost (Trillion $)	2.82	1.36	0.61	8.9	13.7	3.23	1.89	1.25	13.3	20

ESTIMATED CAPITAL COSTS FOR PV HYDROGEN SYSTEMS[b]

	PV module eff.=18% PV module cost=$0.2/Wp			PV module eff.=12% PV module cost=$0.4/Wp		
Capital Cost [$/(Watt-yr/yr)]	3.67			5.85		
Energy Production (TW-yr/yr)	1	5	10	1	5	10
Cumulative Capital Cost (Trillion $)	3.7	18.3	36.7	5.8	29.3	58.5

ESTIMATED CAPITAL COSTS FOR SYNTHETIC FUELS FROM COAL[c]

	Methanol		Syn. Gasoline		SNG	
Capital Cost [$/(Watt-yr/yr)]	1.0-2.2		2.5		0.6-1.1	
Energy Production (TW-yr/yr)	1	5	1	5	1	5
Cumulative Capital Cost (Trillion $)	1.0-2.2	5-11	2.5	12.5	0.6-1.1	3.0-5.5

---

[a] H. K. Schneider and W. Schulz, "Investment Requirements of the World Energy Industries 1980-2000", World Energy Conference, London, September 1987.

[b] These estimates are for PV hydrogen systems in the Southwestern US, with balance of systems cost = $\$33/\mathrm{m}^2$, electrolyzer capital cost = \$170/kWDCin, electrolyzer efficiency = 0.84, electrolyzer-PV coupling efficiency = 0.93, and average insolation = 271 Watts/m^2.

[c] For coal synthetic fuel plants in the US. See Note 114 for details.

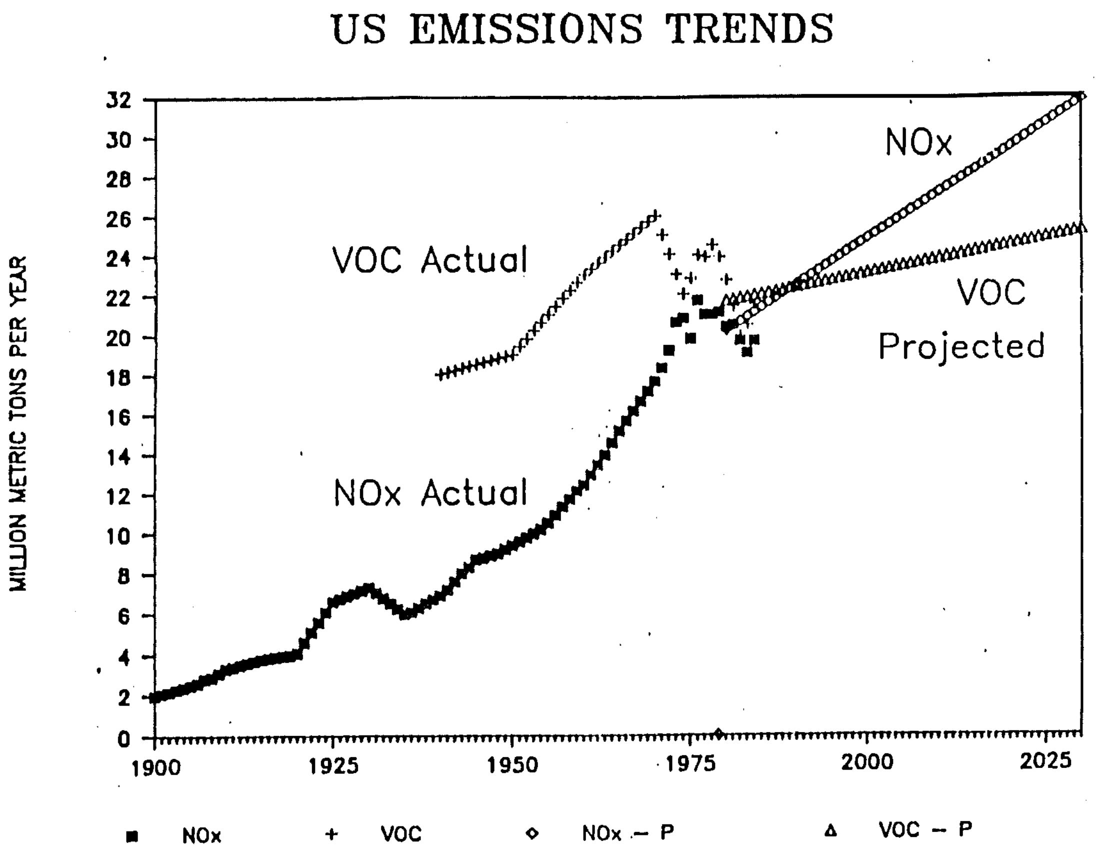


Figure 2.

Trends in air pollutant emission from all sources in the United States.

Historical data and EPA projections are shown.

Source: Michael P. Walsh, "Pollution on Wheels," Report to the American Lung Association, February 11, 1988.

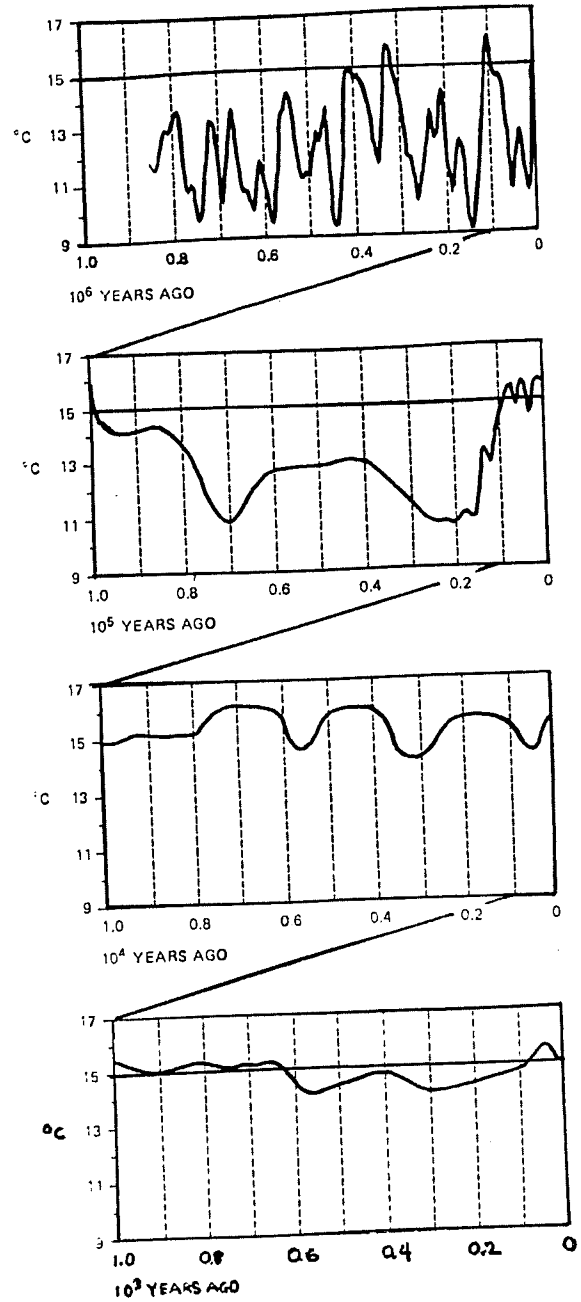


Figure 4.

An estimated temperature history of the Northern hemisphere for the last 850,000 years.

The panels are shown at the same temperature scale. The top panel illustrates the past 1,000,000 years, the second panel the last 100,000 years, the third panel the last 10,000 years and the fourth panel the last 1000 years. The data shown are average surface air temperatures for various locations, most of which are over land. Because the data are inhomogenous in space and time (they were taken from a number of different localities and refer to different eras), these graphs do not represent a true hemispheric or global temperature average. They are however indicative of the range of local average surface temperatures experienced.

Source: W.C. Clark, editor, Carbon Dioxide Review 1982, Clarendon Press, Oxford University Press, New York, 1982.

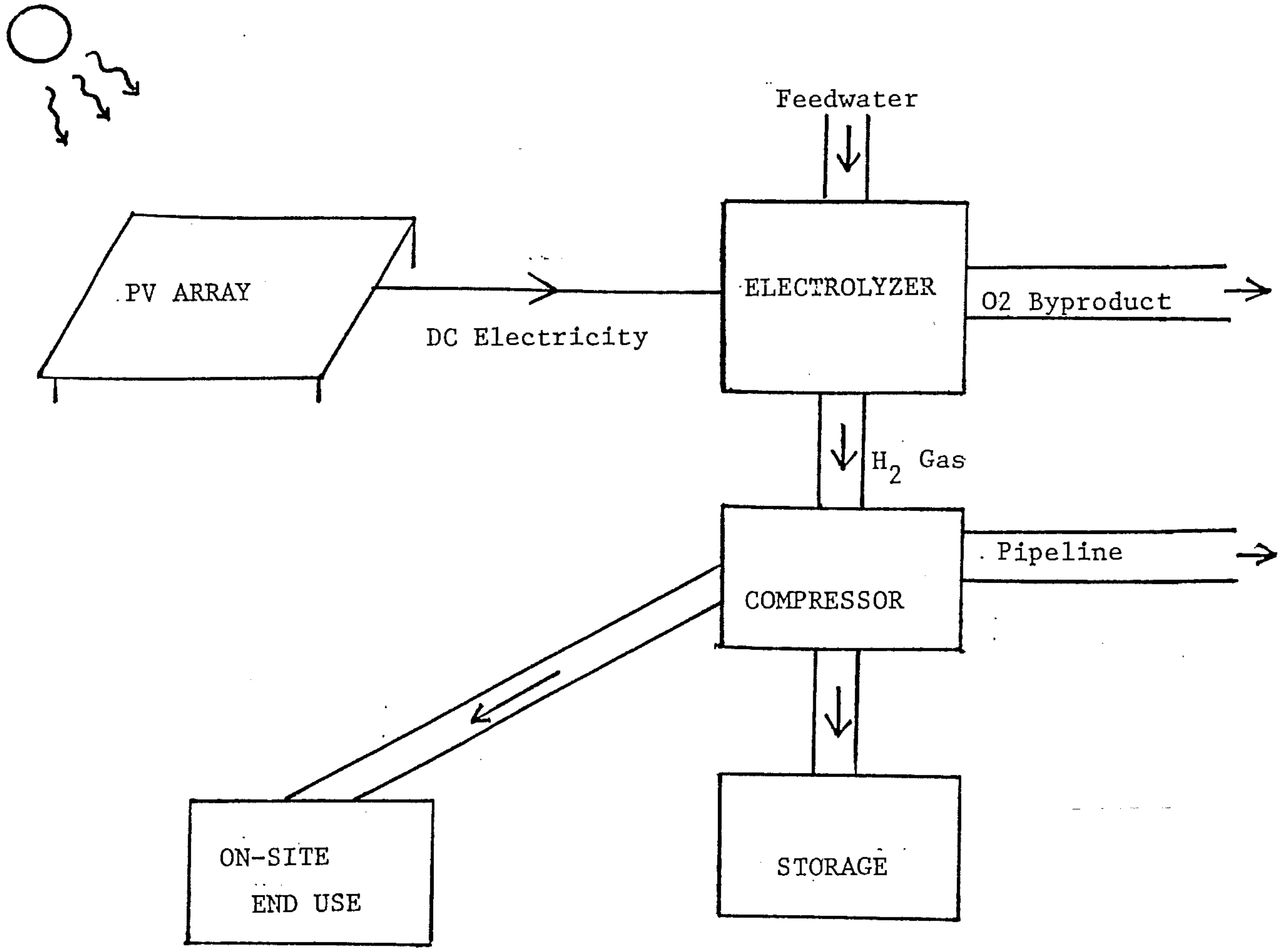
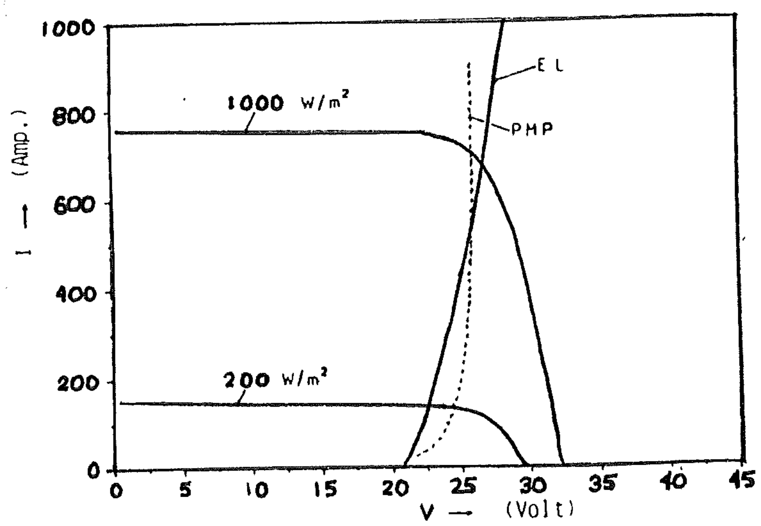


Figure 5. A solar photovoltaic electrolytic hydrogen system.

The electrolyzer is a DC load with its own current-voltage characteristic, which depends on the electrolyzer type, the electrolyte temperature, and the number of electrolysis modules connected in series and parallel. I-V curves for a PV-array and an electrolyzer are shown together below. When the PV array is connected directly to the electrolyzer, the system operating point is the intersection of the two I-V curves. Ideally, the operating point should be near the maximum power point of the PV array for most operating conditions that occur throughout the day, to assure maximum conversion efficiency over the expected range of conditions.



As insolation and temperature change over the course of a day's operation, the maximum power point (PMP) describes a curve in I-V space, as shown above. Typically the temperature lags slightly behind the insolation, giving a curve for the maximum power point as sketched above. If the maximum power point curve followed the electrolyzer characteristic (EL) perfectly, the PV array and the electrolyzer would be perfectly matched. Although a perfect match is not possible, the mismatch can be made quite small if the PV system is designed to operate at the maximum power point for the most likely weather conditions (averaged over a year or more of local insolation and temperature data.) Since the shape of the maximum power curve over the course of a day is relatively close to the shape of the electrolyzer characteristic, this gives a system efficiency which is 90-95% of the ideal efficiency. For a well-matched PV array and

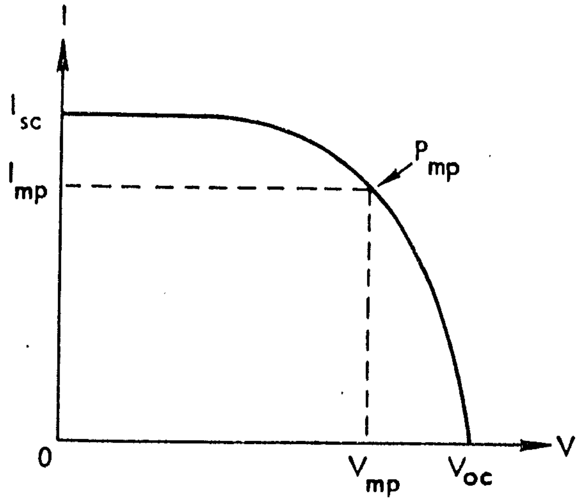
CHAPTER 3

86. Hydrogen transmission costs can be less than those of synthetic medium BTU coal gas and comparable to those for natural gas, with optimized pipelines. For a 1000 mile (1600 km) pipeline, the cost of hydrogen transmission is about \$0.35/GJ. See Note 100 and D. Christodoulou, " Technology and Economics of the Transmission of Gaseous Fuels Via Pipeline", Princeton University, Department of Mechanical and Aerospace Engineering, Master's Thesis, 1984.

    The cost of long-distance DC electrical transmission is about \$0.09 to \$0.11 per GJ per 100 km for distances longer than about 1000 km. For a 1600 km transmission line, this is a cost of about \$1.44 to 1.76/GJ, roughly four times the cost of hydrogen transmission via pipeline. See D. W. Devins, *Energy : Its Physical Impact on the Environment*, John Wiley and Sons, New York, 1982.

87. The interface between the PV array and the electrolyzer must be considered when calculating the efficiency of a PV hydrogen system. Achieving a good electrical match is neccessary for efficient conversion of sunlight to hydrogen.

    The PV array is a variable DC power source, where the output current I and voltage V depend on the physical parameters of the solar cell, the electrical connection pattern, the module temperature and the insolation. The current varies from 0 to Isc (short circuit current) and the voltage from 0 to Voc (open circuit voltage). The maximum power output Pmp and solar energy conversion efficiency occur for Imp and Vmp determined by d(IV)/dI = 0, as shown below:



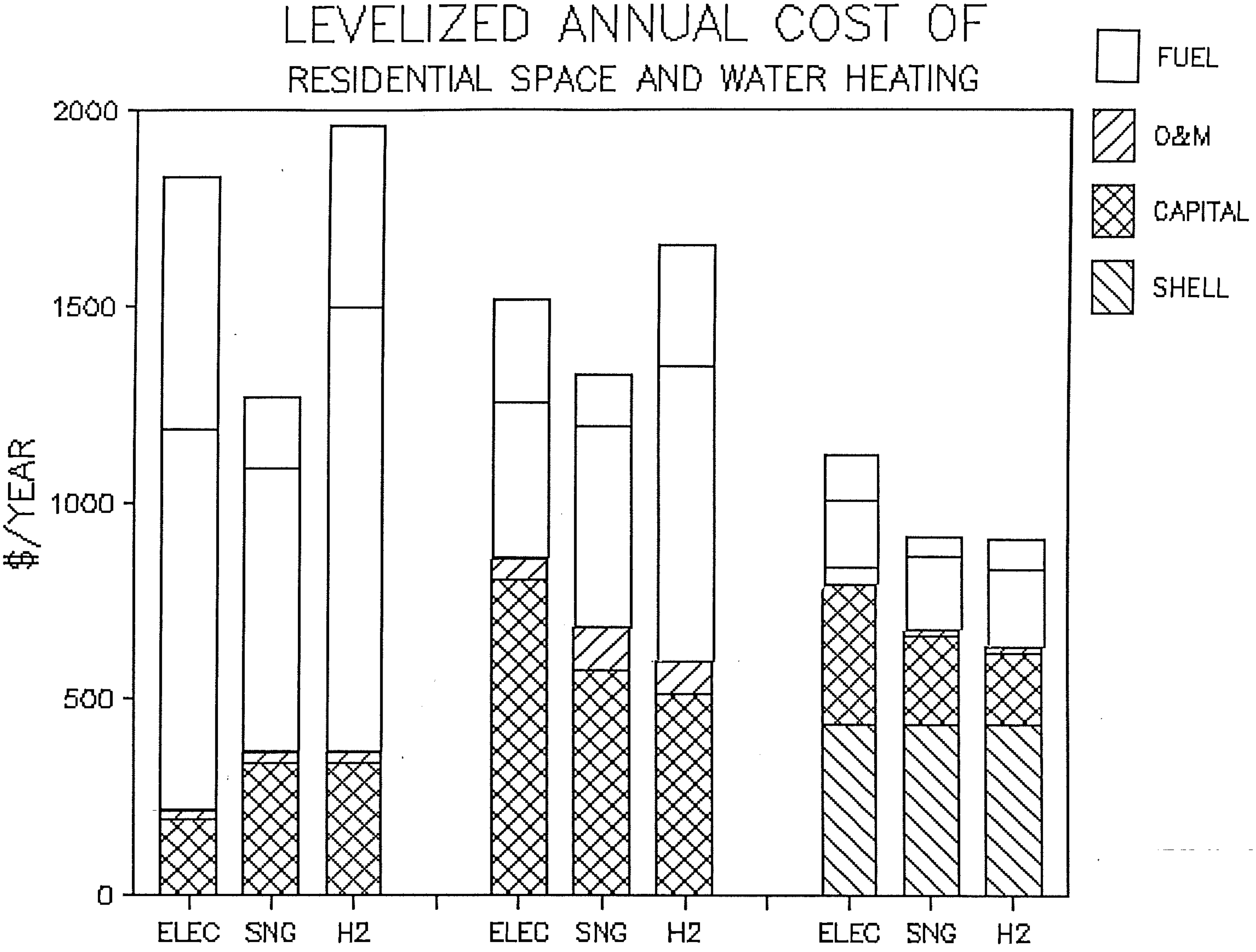


Figure 19. CASE I CASE II CASE III

Levelized costs for residential space and water heating.

The costs are for houses located in New Jersey and heated with electricity, synthetic natural gas from coal, and PV hydrogen for three levels of energy end-use technology. Level I involves low first-cost equipment in conventionally-constructed houses. Level II involves the use of energy-efficient equipment in conventionally-constructed houses. Level III involves the use of energy-efficient equipment in super-insulated houses. The levelized cost has four components: building shell retrofit costs (which apply to the super-insulated house), heating system capital costs, operation and maintenance costs and fuel costs. A range of fuel costs are shown, corresponding to high and low energy prices from Table 19. The energy requirements for space and water heating are presented in Note 158. The assumed capital and O&M costs are presented in Table 20. A ten percent discount rate is assumed for the lifecycle cost calculations (Note 161).

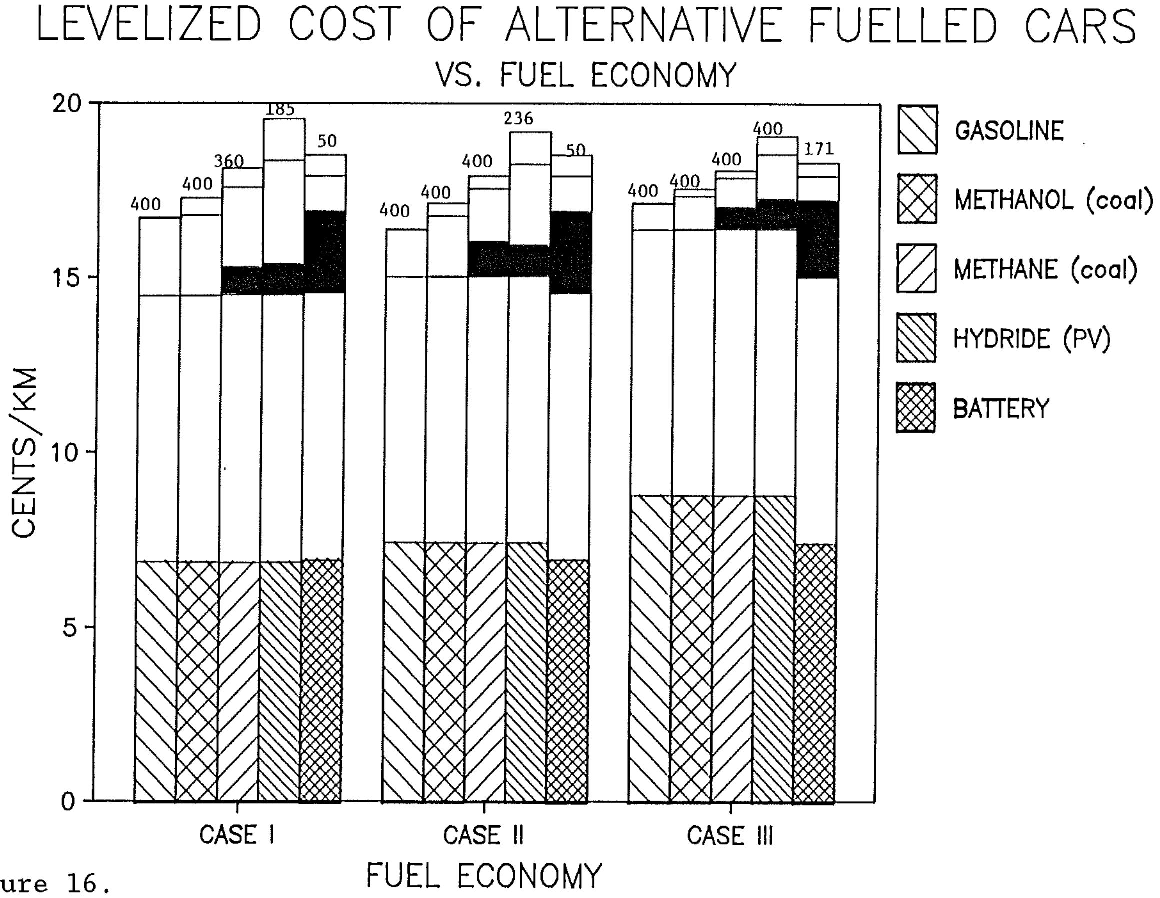


Figure 16.

A comparison of levelized costs for owning and operating cars on various fuels for three levels of automotive fuel economy. The levelized cost in cents per kilometer is shown for automobiles fueled with gasoline, methanol from coal, synthetic natural gas from coal, electricity stored in batteries, and PV hydrogen. Case I is roughly equivalent to a present day sub-compact car with a fuel economy of 30 miles per gallon of gasoline equivalent. Case II is roughly equivalent to a subcompact car with a more efficient engine (Diesel or stratified charge), with fuel economy of 50 mpg gasoline. Case III corresponds to a car with a more efficient engine, aerodynamic styling and a continuously variable transmission. (A detailed description of each case is presented in Note 142.) For each case, the levelized cost has four components: initial capital cost of the vehicle (which is shown in hatched patterns and includes the purchase price of the car, exclusive of extra storage system costs), miscellaneous expenses (shown in white above the initial capital cost of the vehicle, this includes tolls, registration fees, insurance, parking, repairs and maintenance), the storage cost (shown in black and includes any extra cost for a special fuel storage system such as batteries, compressed gas cylinders or hydride tanks), and the fuel cost (shown in white at the tops of the bars). The delivered costs of fuels (from Table 15) are: $8.19/GJ ($1/gallon) for gasoline, $9.91-$12.1/GJ for methanol from coal, $8.83-$11.0/GJ for synthetic natural gas from coal, $0.06-0.10/kwh for electricity, and $12.9-$18.0/GJ for PV hydrogen. The travelling range (in km) for each option is shown at the top of the bar.

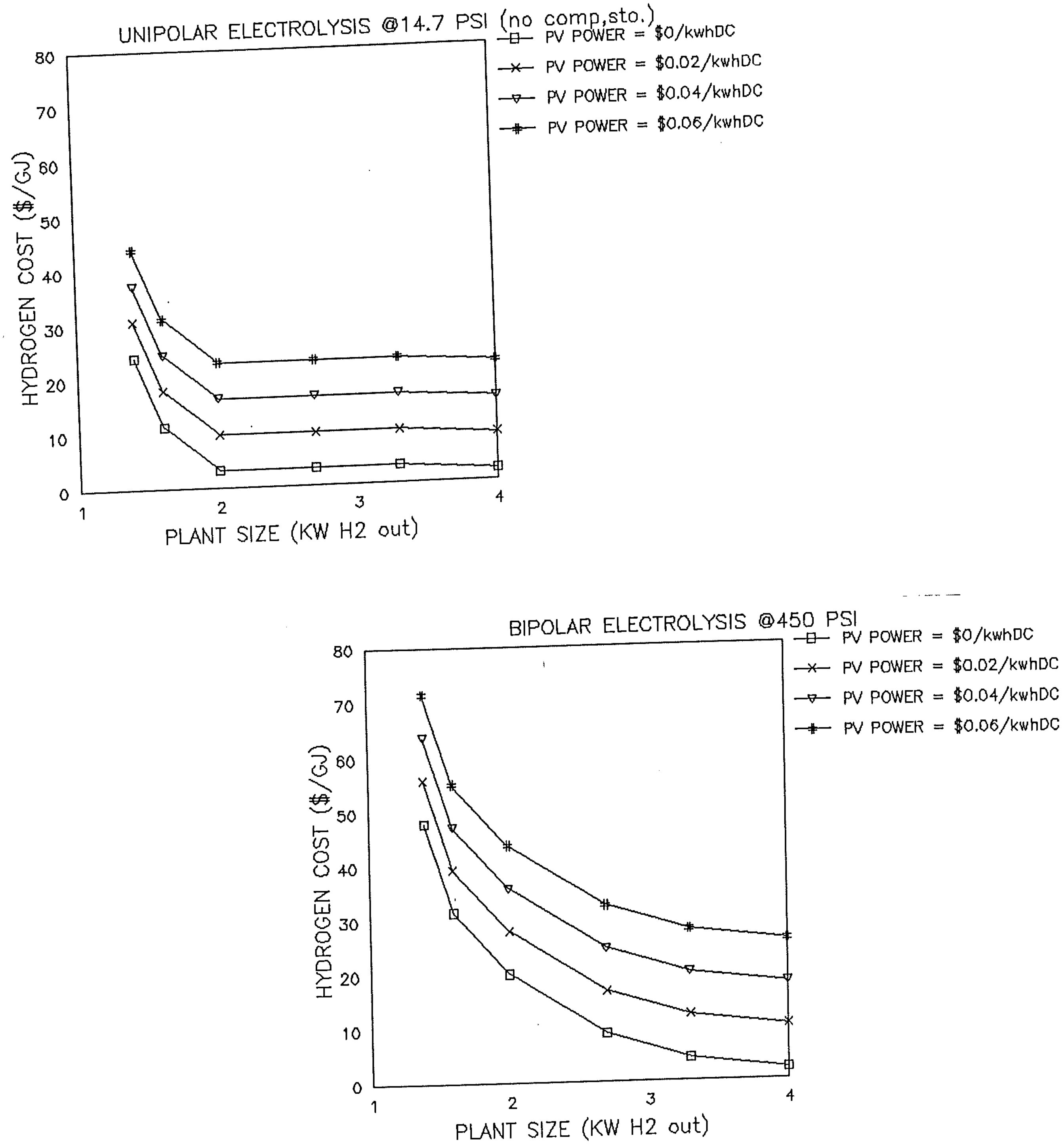
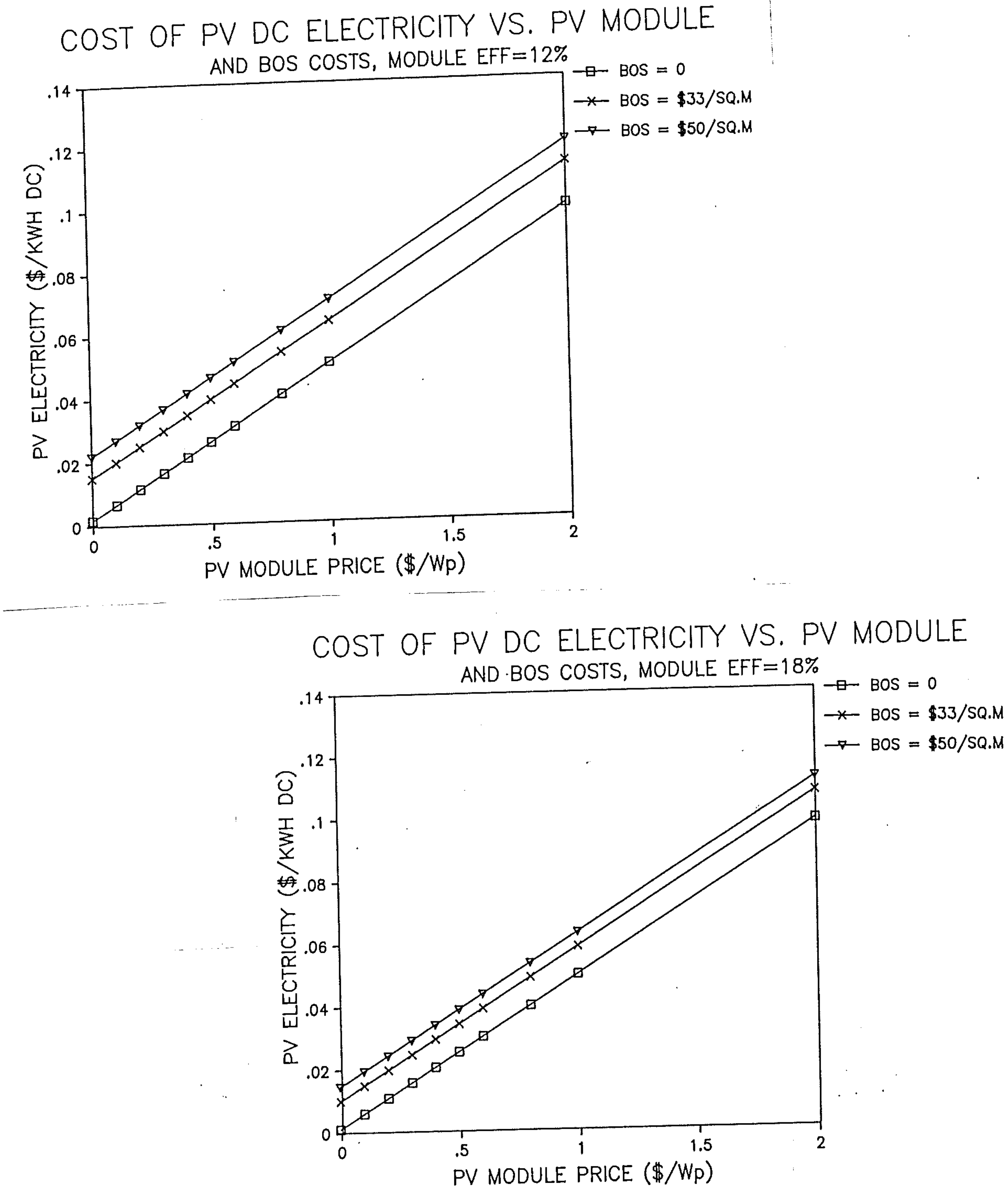


Figure 10.

The cost of electrolytic hydrogen as a function of plant size and DC electricity cost.

For unipolar electrolysis at atmospheric pressure (top) and bipolar electrolysis at 30 atmospheres (bottom).



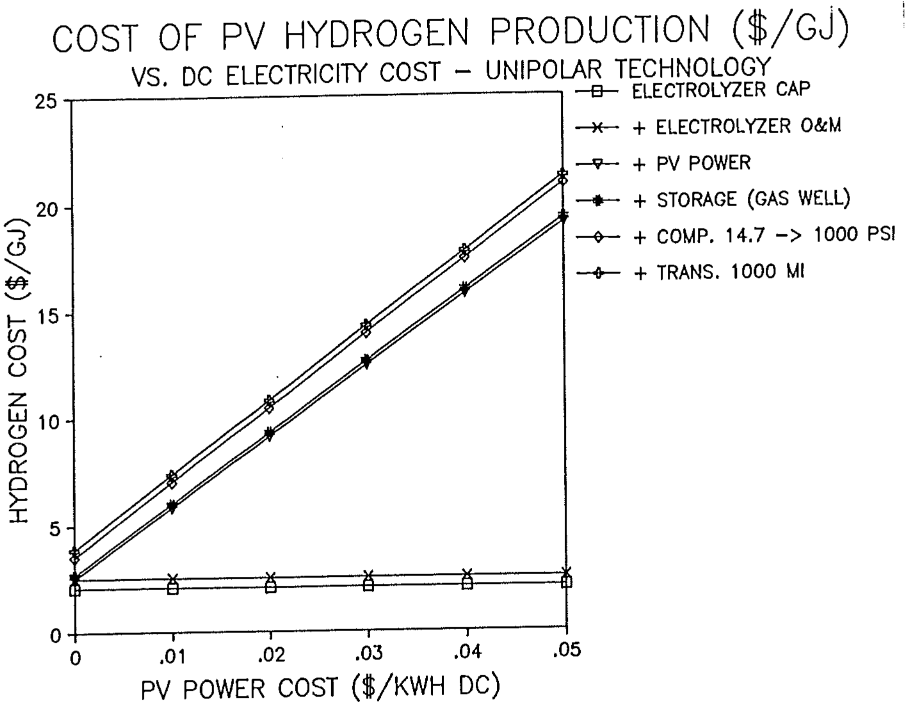
COST OF PV DC ELECTRICITY VS. PV MODULE AND BOS COSTS, MODULE EFF=12%

COST OF PV DC ELECTRICITY VS. PV MODULE AND BOS COSTS, MODULE EFF=18%

Figure 9.

The cost of DC PV electricity vs. solar module and balance of systems costs.

For a 10% efficient system (top) and a 15% efficient system (bottom) located in the Southwestern US with average insolation of 271 Watts per square meter, assuming a system lifetime of 30 years and an annual operation and maintenance cost of $0.45 per square meter. (See Note 92).



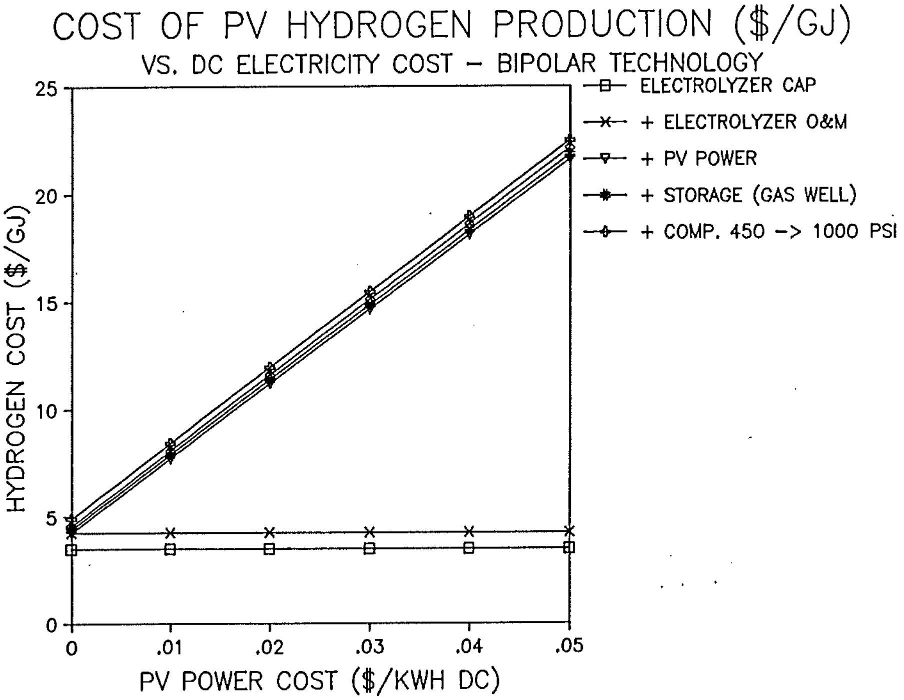


Figure 8.

The production cost of PV hydrogen as a function of DC PV electricity cost for unipolar (top) and bipolar (bottom) electrolyzer technologies.

The hydrogen production cost includes electrolyzer capital costs, operation and maintenance costs, the cost of DC PV electricity, the cost of storage, the cost of compression from electrolyzer pressure (14.7 psia for unipolar technology and 450 psia for bipolar technology) to pipeline pressure of 1000 psia, and the cost for 1000 miles of pipeline transmission.

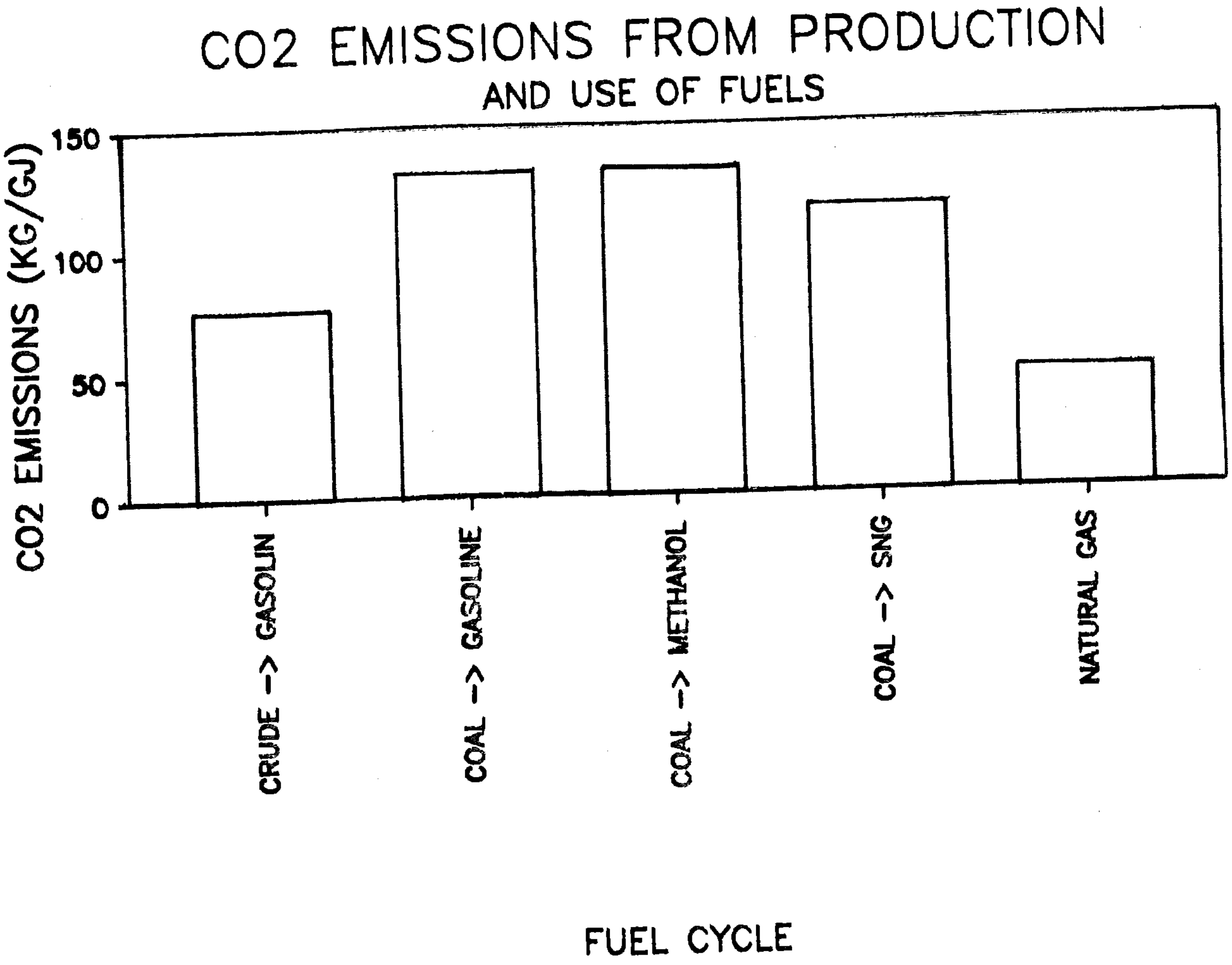


Figure 3.

CO_2 emissions from the processing and use of various fuels, in kilograms of CO_2 released per Gigajoule (GJ) of fuel energy used.

Here it is assumed that crude oil is refined to give gasoline and Diesel fuel with 10% refinery losses; coal is converted to synthetic natural gas via the Lurgi dry ash process; coal is converted to methanol via the Texaco gasifier process; coal is converted to gasoline plus liquid propane gas plus synthetic natural gas via the SRC-II process.

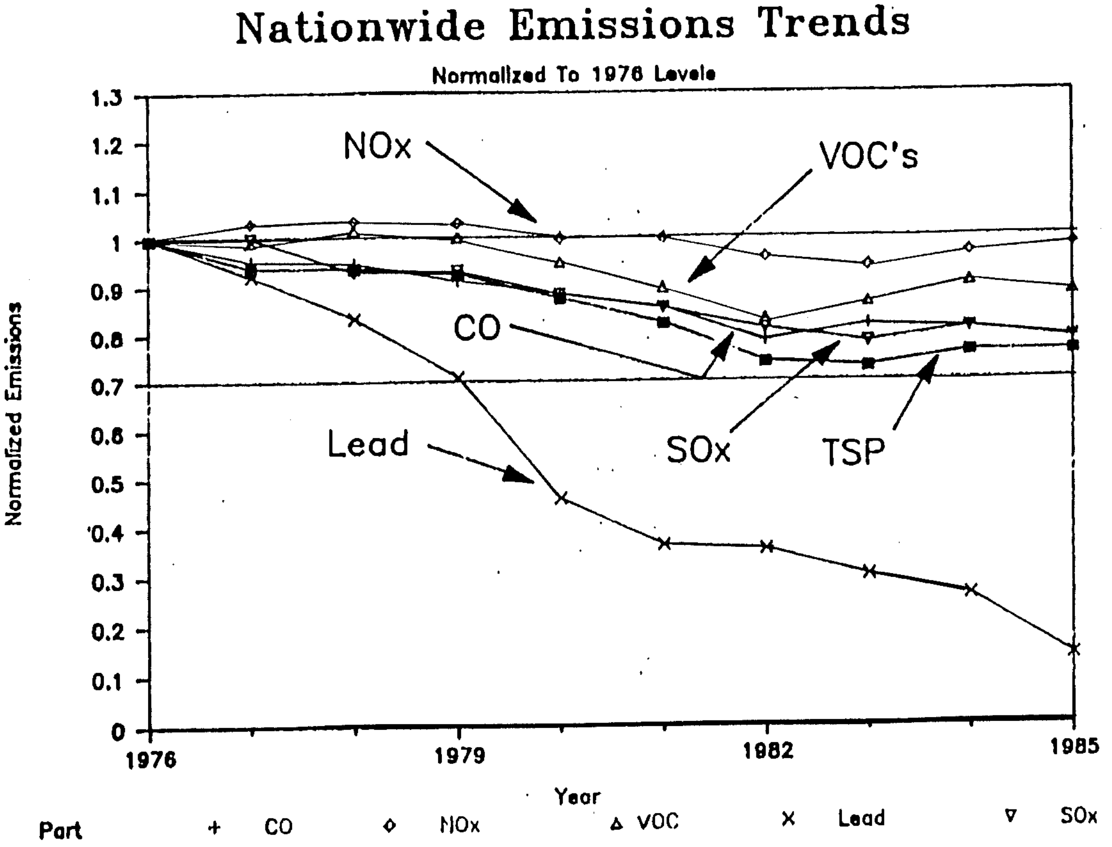


Figure 1.

Trends in NOx and VOCs emissions from all sources, normalized to the 1976 emissions levels.

Source: Michael P. Walsh, "Pollution on Wheels," Report to the American Lung Association, February 11, 1988.