U.S. Department of Energy
Hydrogen Program

Summary of Analysis Projects 1994 – 2000

FOREWORD

The U.S. Department of Energy Hydrogen Program has funded a wide variety of analysis projects in support of its mission to conduct research and engineering development for the purpose of making hydrogen a cost-effective energy carrier for utility, buildings, and transportation applications.

The goal of the analyses is to provide direction, focus, and support to the development and introduction of hydrogen through evaluation of the technical, economic, and environmental aspects of hydrogen technologies.

The advantages of performing analyses within a research and development environment are several-fold. The economic competitiveness of a concept can be assessed by evaluating the costs of the process compared to current commercial technology. These analyses can therefore be useful in determining which concepts have the highest potential for near-, mid-, and long-term success. Analysis is also useful in directing research toward areas in which improvements will result in the largest cost reductions. The level of analysis appropriate for a project is dictated by the maturity of the technology and the amount of data that has been gathered, as well as the purpose of the evaluation. A new initiative may require only a literature search in order to determine if process costs can be estimated from related systems or if laboratory data are needed first. Alternatively, a cost boundary analysis is appropriate for a project that has been conceptualized but has not generated a significant amount of data. This type of analysis determines the minimum yields, maximum manufacturing costs, and necessary market conditions for the technology to be economically competitive. Finally, a highly detailed analysis can be performed on processes that have been more or less fully conceptualized, and laboratory work has provided yield and operating data. This type of analysis includes a process flowsheet, material and energy balances, equipment cost estimation, and the determination of the cost of the final product over the expected life of an industrial-scale plant. As the economics of a process are evaluated throughout the life of the project, advancement toward the final goal of commercialization can be measured.

This document contains summaries of 76 reports or publications of analysis work funded by the Hydrogen Program from 1994 through 2000. A review of the subjects covered by these studies indicates that:

- many studies have been done for near- and mid-term hydrogen production and hydrogen distribution,
- few studies have been completed for long-term hydrogen production and distribution,
- many transportation-sector studies have been completed for all time frames, and
- very few studies have been conducted in the areas of safety and environmental concerns.

The purpose of this work is to help determine areas of focus for future analyses and also to provide a quick reference for studies already completed.

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(1) Hydrogen Energy Systems Studies

Author(s):	Ogden, J., Strohbehn, J. and Dennis, E.
Date:	July 31, 1994
Organization(s):	Princeton University
Publication:	Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies):	Transportation, Market Analysis, Production
Subcontract No.	

This study consisted of three tasks focused on near-term opportunities for hydrogen:

1. Assess options for producing hydrogen from natural gas
2. Assess the feasibility of using hydrogen blends and pure hydrogen in the existing natural gas transmission and distribution system
3. Evaluate PEMFCs for dispersed residential cogeneration systems

The results of each task are summarized below.

Hydrogen from Natural Gas

Two primary hydrogen production methods were evaluated in this task: large centralized steam reforming and on-site small scale steam reforming. Natural gas was selected as the feedstock since it is the cheapest alternative and it is commercially available. Since it was projected that hydrogen would be used in vehicles in Southern California first, data were used from this area, wherever possible.

When comparing the two alternatives, the authors focused on the following areas:

- Delivered hydrogen cost for various supply options and levels of demand
- Hydrogen refueling station conceptual design
- Environmental impacts compared to other production methods
- Synergisms between natural gas and renewable hydrogen production scenarios

The type of storage was an important consideration and for this study, the authors selected high-pressure gaseous storage at both the station and onboard the vehicle.

The authors compared three types of CNG refueling stations: booster, cascade and direct. Since the direct type would not be applicable for hydrogen due to the need of the reformer to run continuously, it was not pursued further.

Large centralized steam reforming was projected to produce hydrogen at \$6-9/GJ. Trucking the hydrogen to Southern California was estimated to increase the cost by \$15-20/GJ for a demand of 0.5 million SCFD. The authors planned to obtain better information regarding delivery and to evaluate refueling station designs.

Hydrogen and Hydrogen Blends in Existing Natural Gas Pipelines

In this task, the authors worked with researchers at the IGT to evaluate the use of hydrogen and hydrogen blends in existing natural gas transmission (i.e., 1000 psia) and distribution (i.e., 50-500 psia) pipelines. Specifically, the authors addressed the impact of hydrogen on: materials, compatibility of existing equipment (e.g., compressors), end-use equipment (e.g., heaters), energy flow rate, leak rate and safety issues.

A summary of earlier IGT work on distribution systems was summarized. These studies had shown that the existing equipment, except meters, should be adequate for hydrogen service. Larger capacity meters may be required. It also showed that short term (< 6 month) exposure to hydrogen did not affect the metallic components, but that the plastic components may be affected. The energy flow rate of the hydrogen would be the same as that for natural gas (assuming equal pressures), but the volumetric leak rate would be 2.9-3.5 times more.

The authors also relied on earlier IGT studies for evaluation of impacts to end-use systems. In general, end-use systems are not significantly impacted at hydrogen concentrations of 1-20%.

The long distance pipeline evaluation was more extensive. The authors described and compared the three types of hydrogen embrittlement: internal (I-H), reaction (H-R), and environment (H-E). For hydrogen pipelines, H-E embrittlement was considered to be the most important. The authors pointed out that while embrittlement has been studied extensively and the mechanisms are well understood, it is difficult to apply this knowledge to real-world situations and to be used for prediction. The degree of embrittlement is affected by pipeline construction and several studies have been published regarding embrittlement with various materials. Several studies point out that additives such as oxygen or sulfur dioxide could eliminate embrittlement, but would raise serious safety issues.

From this analysis, the authors concluded that:

- Only minor changes would be required to use hydrogen and hydrogen blends in existing distribution lines
- End-use systems could use hydrogen blends of up to 15-20% without significant modifications
- Hydrogen embrittlement could be a serious concern for long distance hydrogen transmission lines
- Potential embrittlement mitigation measures are currently not well known in terms of feasibility or cost
- Replacement of aging natural gas pipelines for dual use (hydrogen/ natural gas) should be explored

***PEMFCs for Residential Cogeneratio*n**

Only preliminary results were available for this task. The researchers were currently collecting performance data from PEMFC manufacturers. In addition, they were developing a model of a PEMFC cogeneration system. With this information, they planned to estimate the performance of the fuel cell cogeneration system for various types of buildings.

The authors ended their report with a listing of potential future projects. Included in this list were the evolution of a hydrogen transportation fuel infrastructure, expanded analysis of hydrogen transmission and distribution pipelines and fuel cell systems for transportation and power generation.

(2) Development of Industrial Interest in Hydrogen

Author(s): Mauro, R., Smith, D.
Date: July 31, 1994
Organization(s): National Hydrogen Association
Publication: Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies): Market Analysis, Industrial Outreach
Subcontract No.

This report provided an outline of work projected for the subcontract. No results were presented.

The subcontract was slated to:

- provide regional information on production, transport and use of hydrogen
- identify hydrogen consortia, describe their programs and discuss interests
- determine NASA's interest in a vehicle demonstration in the Southeast
- determine the feasibility of a hydrogen pipeline linking supplies in the Southeast to demand in Southern California
- determine interest and identify potential DOE role in consortium activities
- categorize industrial interest in hydrogen

The authors then described the general methodology they would employ performing this work. The work plan included a survey of hydrogen production and use, potential near-term venture opportunities, the near-term hydrogen supply in Southern California and public information and education on hydrogen issues. Supporting these efforts, the authors provided resource listings including NHA technology review committee members, NHA Board of Directors, demonstration and consortium projects and a description of methods used by NHA to answer questions from the public.

The subcontract was scheduled for completion in October.

(3) Supporting Analyses and Assessments

Author(s):	Ohi, J.
Date:	July 31, 1994
Organization(s):	NREL
Publication:	Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies):	Market Analysis, Industrial Outreach
Subcontract No.	

The overall goal of this effort was to identify and evaluate near-term market opportunities for hydrogen use in cooperation with industry, the National Hydrogen Association, and regulatory agencies. In this phase, one or more potential industrial partnership for near-term hydrogen production, distribution or utilization was identified. The author summarized progress to date in each sector: utility, industrial, and commercial.

In the utility sector, NREL was conducting studies for the DOE Office of Utility Technologies and for the Office of Planning and Analysis. These studies included interactions with the National Association of Regulatory Utility Commissioners, the Independent Power Producers Association, and the American Public Power Association. In addition, NREL was conducting an analysis of technical, economic and environmental impacts of distributed utility generation. Finally, the author described current interactions with Bonneville Power Administration, Euro-Quebec Hydro-Hydrogen Pilot Project, and EPRI.

In the industrial sector, the author listed some of the technologies that NREL was currently cooperatively working with industry to develop. These technologies included advanced vacuum insulation for batteries and ethanol from MSW. Based on these interactions NREL would pursue cooperative partnerships with industry. The first step in this process was to contact industrial associations such as the Compressed Gas Association and the National Petroleum Refiners Association to determine potential partners. The author also briefly described two potential associations that NREL was pursuing. The first was by-product hydrogen from chemical production. Potential partners in this effort were identified as Kerr-McGee, Dow Chemical, and Texas Sustainable Economic Development Commission. The second association was with the Foster Wheeler/Energy Technology Engineering Center (ETEC). In this project, NREL was developing a small-scale natural gas reformer to be used for distributed hydrogen production and vehicle refueling. Other potential partners included Air Products, ORNL, and the Gas Research Institute.

The primary project in the commercial sector was for the Natural Energy Laboratory for Hawaii (NELH) and Hilton Hotels. Here, NREL was working to develop eco-tourism and as an example, the Hilton Hotels were exploring hydrogen use at one of its resorts.

The author then defined success for this effort as NREL successfully facilitating partnerships among industry, utility, and government for near term hydrogen production storage or use.

The author concluded with a listing of potential future projects.

- development of a systematic method to identify and screen potential near-term market opportunities

- development of a comprehensive criteria to evaluate near-term demonstration opportunities
- collaboration with ETEC to develop modeling and testing capability for hydrogen production, storage and dispensing
- conduct a programmatic benefits analysis to develop quality metrics to aid in setting program direction.

(4) Energy Pathway Analysis

Author(s): Badin, J., Kervitsky, G, Mack, S.
Date: July 31, 1994
Organization(s): Energetics, Inc.
Publication: Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies): Analysis Methodology
Subcontract No. BC-2-12150

This report described the development of an analytical framework that estimates life-cycle costs and impacts resulting from environmentally-driven, market-based and prescriptive scenarios. The framework was based on a series of recommendations of the Hydrogen Technical Advisory Panel (HTAP). Its overall objective was to provide a comparative normalized analysis of energy pathways.

The pathways from the framework describe technologies with the greatest potential for meeting DOE goals. These pathways are then combined in a linear programming (LP) network model. Selected results from the application of the framework were presented as the E3 (Energy, Economics, Emissions) Pathway Analysis Model.

A pathway is a series of source to end-use processes and include primary energy processes, energy storage, transport and end-uses. The framework is a methodology for comparing among pathways.

The authors outlined three primary objectives of the framework:

- Create a unified conceptual design for analyzing different technologies
- Demonstrate an accounting framework used to estimate measures of costs and impacts along a pathway that result from an incremental use of different fuels
- Identify critical trends, impacts, issues and information needs

The E3 Pathway Model has four major areas: efficiency, capital costs, life-cycle costs and emissions. Using sensitivity studies in these major areas, the model identifies potential opportunities, which then provide guidelines and goals for technology development and provides a framework for decision-making. It was run in a relational database, which contained libraries of activity nodes or pathway steps.

The authors provided descriptions of the data libraries in the model.

Data Set	Description	Parameters
Activities Library	Technology characterization, cost and performance data • Current • Advanced	• Capital Cost • O&M • Capacity factor • Efficiency • Life • Emissions

Data Set	Description	Parameters
Node-Pairs Library	Establishes links among energy conversion, delivery and end-use	To Node From Node Activity Type
Pathway Library	Saved and completed pathway analysis	Energy In/Out Annual Cost Present worth Levelized Cost Emissions
Financial Library	Discounted cash flow data for life-cycle analysis	• Discount rate • Inflation rate • Depreciation • Tax rate • Property taxes and insurance

Using these libraries, the authors developed a rigorous methodology for estimating life-cycle costs and impacts for each energy pathway and then modeled them in the E3 Pathway Analytical Model.

As noted earlier, the model focuses on four major areas: efficiency, capital costs, life-cycle costs and emissions. Efficiency may be defined in numerous ways. The authors provided the following efficiency definition.

Capacity i = Capacity (i +1)/Efficiency (i+1)
where: i+1 is the downstream process step

Life-cycle costs are based on a capital recovery factor (CRF) and fixed charge rate (FCR) and are calculated as follows:

$$\text{LCC (\$/kWh)} = [P_{pw}(FCR_p)+R_{pw}(FCR_R)+CRF(OC_{pw})]/kWh_{out}$$

where:
P_{pw} = Present worth of plant capital
FCR_p = Fixed charge rate for plant
R_{pw} = Present worth of replacement capital
FCR_R = Fixed charge rate for replacement
OC_{pw} = Present worth of all annual and intermittent operating costs, fuels and electricity costs, maintenance and externalities

The total pathway life-cycle cost was then calculated as the sum of all component life-cycle costs.

In the emissions category, the authors discussed costs (i.e., externalities) such as increased health care expenses, impacts to agricultural resources and impacts to quality of life that have not typically been included in economic assessments. To include these impacts, the authors compared emission values from various regulatory agencies and other studies. The model developed may use these emission values or may have used a percentage production adder to account for externalities.

An LP model was then used to show the trade-offs and conflicts of the competing technologies. It provided boundary conditions for the analysis and projected the optimum mix of primary resource for hydrogen production as well as other impacts. The model provided equilibrium conditions, which can then be used to establish program priorities. In summary, the LP model provided the least cost solution to the problem with various alternatives.

When developing the E3 network scenario, a base case was analyzed without considering externalities. Because only economics were considered, this resulted in the least-cost alternative. All other scenarios would be the same cost or higher cost.

In addition, the LP optimization provided a reduced cost, which can be used for sensitivity analyses. Reduced costs are specific to each processing step. Some steps had positive reduced costs, while some had zero reduced costs. Thus, to meet demand, each step will be utilized or not at all. For activities with non-zero values, their corresponding reduced costs indicate how much the total system cost could be decreased if one additional unit of the resource were available. A zero-level process with a high reduced cost would predict significant economic resistance to its introduction. Alternatively, a non-zero level process with a low reduced cost would point to a technology that may be economically attractive.

The authors then presented results from the application of the framework and model to the current and advanced transportation and utility pathways, including energy ratio, life-cycle costs, levelized emissions and gross emissions. The authors concluded that:

- vehicle costs dominate in life-cycle costs
- delivered fuel costs are a minor component of life-cycle costs
- emission values would be important determinants of pathway competitiveness, increasing gasoline/ICE costs by 40-75% and alternative fuels only 5%
- emission values could cause some alternative fuels to be competitive
- gasification production routes appear to be the most promising
- lower power production costs can mitigate downstream costs
- R&D should continue, especially on photolysis
- efficient, low-cost compact storage is necessary
- inexpensive and high-efficient fuel cells would improve hydrogen's attractiveness
- cogeneration systems would increase overall system efficiency due to hydrogen's thermal value

The authors concluded with suggestions for future work including:

- expansion of E3 Pathway Analysis Model to account for reliability and safety
- expansion of model to include nodes for aircraft applications and other scenarios
- inclusion of uncertainty in the model
- application of the model as a screening tool for competing options

(5) Passive Ventilation Systems for the Safe Use of Hydrogen

Author(s): Swain, M.R.
Date: July 31, 1994
Organization(s): University of Miami
Publication: Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies): Safety
Subcontract No.

In this analysis, the authors evaluated passive ventilation systems for hydrogen. The authors modeled hydrogen leaks using a computational fluid dynamics software package (FLUENT 3.03) and used it to predict unsafe conditions. In the modeling, the authors evaluated the size and placement of vents, ceiling configuration and hydrogen leak rates. The specific parameters evaluated were:

- number of vents
- vent location(s)
- vent sizes
- ceiling slope (0°, 26.6°, 45°, 63.4°)
- rate of forced ventilation (0, 1.5, 7.5 L/s-m^2)
- rate of hydrogen leakage (10, 100, 1000 L/min)

In this study, only passive ventilation (i.e., self venting structure – SVS) was analyzed. These systems all conform with ANSI/ASHRAE fresh air ventilation rates which accounts for energy losses due to fresh air ventilation. Active ventilation systems, those that detect hydrogen and evacuate it, were not included in the analysis. These systems were thought to require significant maintenance and redundancy to ensure proper reliability, given their infrequent use.

The hydrogen leak rates were based on the maximum leak rates measured by a natural gas company. To ensure conservative assessments, the base case rate was obtained by quadrupling the maximum leak rate found by the company. Other leak rates were then analyzed up to a maximum of 100% greater than the base case.

The authors identified three ranges of hydrogen concentrations: < 4.1% were classified as safe; 4.1%-10% were marginal and > 10% were unsafe. The analyses were based on a room size 12 feet by 8 feet with 8 foot ceilings.

In the first analysis, a parametric study of vent location and size was conducted. Both the size and location of the upper and lower vents were varied. For a hydrogen leak rate of 10 L/min and a single vent, the standard cloud concentration was ~0.90% after 12 minutes, independent of vent location. Thus, it was concluded that a single vent would result in unsafe conditions very rapidly.

This situation can be improved with the addition of a second vent. While the location of the first, lower, vent is not important, the location of the second is very important. When the upper vent is distant from the leak, the hydrogen is very diffuse when it reaches it and so the concentration in the room builds.

The size of the vents was also varied. As with the location of the vents, the parameters of the upper vent had a greater impact on the cloud size than the lower vent. There appeared to be optimal sizes since the impacts diminished at very large vent sizes or increased significantly at very small vent sizes.

Next, the authors evaluated the effect of ceiling configuration. Here, the authors used a room with the same volume as before, a floor vent around the perimeter and a single roof vent. The configuration of the roof was then varied and the size of the hydrogen cloud measured. The authors concluded that the ceiling configuration did not appreciably affect the size of the hydrogen cloud. It was also shown that using the ANSI/ASHRAE compatible fresh air ventilation rate of 7.5 L/s-m^2 was the most important factor in reducing the hydrogen cloud size.

Finally, the authors analyzed the impact of leakage rate. As expected, this parameter had a significant effect on the accumulation of hydrogen. In general, the hydrogen accumulation rate increases linearly with leakage rate provided the air ventilation standard is maintained. The authors also evaluated concentration gradients. They showed that the typical hydrogen clouds obtained with different concentration levels were very different. This suggests that the concentration gradients in the room were small.

From this analysis, the authors concluded the following:

- Size of the lower vent had a weak effect on combustible gas cloud size
- Lower vent position had the least effect on cloud size
- Upper vent size had a stronger effect on cloud size than the lower vent size
- Benefit from larger upper vent decreases with large vents
- Upper vent had strongest effect on cloud size
- Ceiling slope had little effect on combustible gas cloud size
- Fresh air ventilation and leakage rate had strong effects on combustible gas cloud size
- Inverse linear relationship between steady state hydrogen concentration and air ventilation rate
- For low fresh air ventilation rates (0.3 SCFM/ft^2), leakage flow rates of 40 L/min caused unsafe conditions
- For higher fresh air ventilation rates (1.5 SCFM/ft^2), leakage flow rates of 500 L/min caused unsafe conditions

(6) Systems Study of Metal Hydride Storage Requirements

Author(s): T-Raissi, Sadhu, A.
Date: July 31, 1994
Organization(s): Florida Solar Energy Center
Publication: Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies): Market Analysis, Industrial Outreach
Subcontract No. XAR-3-13444-01

This report compares several conventional and emerging technologies for on-board hydrogen storage. Included in the assessment were sponge iron/water, cryoadsorption, pure hydrogen storage (e.g., compressed gas), and metal hydrides. The study had not yet been completed, but preliminary results were provided.

Costs and some performance characteristics were provided for the technologies. Recent developments and the present status of the technology were summarized and then the expected system performance was also presented. The expected system performance was summarized in thirteen key areas.

1. Energy Density
2. Normal State of Chemical Components
3. Hydrogenation/Dehydrogenation Temperatures and Pressures
4. Ex-Situ Energy Requirements
5. On-board Energy Requirements
6. Projected Costs
7. Improvement Potential
8. Technological Maturity
9. Infrastructure Compatibility
10. Safety
11. Refueling
12. Hydrogen Purity
13. Poisoning

Costs and performance parameters for each category were obtained from the literature and are summarized in the following table.

Parameter	**Iron Sponge**	**Cryoadsorption**	**Compressed Gas**	**Metal Hydride**
Energy Density	wt% 2.64 MJ/kg 4.8 MJ/L	2.390 MJ/L 5.22 MJ/kg	3.4 MJ/L 7MJ/kg	1-2 MJ/kg 2-4Mj/L
State	Solid, liquid and gas	solid and gas	Gas	Solid and liquid
Temperatures and Pressures	600-800 °C	4.2-8.2 MPa	Ambient temperature and 5-15 kpsi	

Parameter	Iron Sponge	Cryoadsorption	Compressed Gas	Metal Hydride
Energy Requirements	0.7 kWh/lb or 51 Wh/in^3	None required	Compression energy	
On-board Energy Requirements	Waste heat from fuel cell	Provided by shaft work	None required	Not reported
Costs	$110-125/ton	$6.96/MM Btu	$1,000/5 kpsi	Not reported
Potential for Improvement	Requires demonstration	3 major researchers: Syracuse University, University du Quebec, NREL	Improvements in composite materials for storage expected	Not reported
Technological Maturity	Lab scale; no published data	Under development; Mid to long-range technology	Mature technology; Demonstrated on fuel cell buses	Not reported
Infrastructure Compatibility		No data available	No systems have been built or demonstrated	Not reported
Safety		No data available	No data available	Not reported
Refueling	< 5 minutes	< 5 minutes	Station costs: $4-6/GJ 3-5 minutes	Not reported
Hydrogen Purity	99.9999%	No data available	No data available	Not reported
Poisoning	No data available	Capacity loss of 30% possible	No data available	Not reported

No conclusions were drawn for this work.

(7) Engineering and Regulatory Requirements for a Hydrogen Refueling Facility

Author(s):	Singh, S.
Date:	July 31, 1994
Organization(s):	ORNL
Publication:	Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies):	Environmental
Subcontract No.	

This report summarized proposed work that was scheduled to commence within the month. The study would provide an engineering assessment of a small-scale (~ 1 MMSCFD) stand-alone natural gas reforming facility to provide hydrogen for a fleet of buses.

No results were presented. However, the authors proposed to do the following:

- gather data on conventional and innovative natural gas to hydrogen conversion processes
- determine the end use fuel requirements for a typical fleet facility
- engineer a stand-alone hydrogen production facility, including process design, cost estimates, and waste treatment
- perform systems studies of alternative hydrogen fueling station designs, including a cost/benefit analysis of environmental considerations
- identify potential impediments to market penetration
- propose solutions to resolve impediments
- develop systems requirements for the demonstration of a small-scale prototype

The authors also proposed several follow-on tasks:

- coordinate the development and operation of a stand-alone small-scale refueling facility
- perform engineering assessments of hydrogen production processes, space heating and power generation
- coordinate prototype demonstrations of other hydrogen fuel applications

(8) Integrated Technical and Economic Assessment of Transport and Storage of Hydrogen

Author(s):	Berry, G.D., and Smith, J.R.
Date:	July, 1994
Organization(s):	LLNL
Publication:	Proceedings of the 1994 DOE/NREL Hydrogen Program Review, April 18-21, 1994, NREL/CP-470-6431
Category(ies):	Transportation
Subcontract No.	W-7405-Eng-48

This report outlined the goals and methodology and presented preliminary results for a study of the transport and storage of hydrogen. This effort was focused on the transportation sector since this is projected to be where hydrogen has greatest value.

Four different areas would be evaluated in this effort: transmission, storage, distribution, and small-scale production. Transmission would cover both energy and hydrogen. Two different energy transmission options would be compared: electricity and natural gas pipeline. Electricity would be evaluated for hydrogen production via electrolysis and the natural gas would be as a feedstock for hydrogen production via SMR. Transport of hydrogen would be evaluated as:

- truck (cryogenic liquid, microspheres, hydrides, other chemical carriers)
- trains (cryogenic liquid, microspheres, hydrides, other chemical carriers)
- hydrogen pipelines

Each of these technologies would be evaluated in terms of its current status and future prospects in the areas of energy efficiency, capital costs, energy, other operating costs, timelines and scale.

Several storage options would also be evaluated:

- Compressed gas
- Liquid hydrogen
- Microspheres
- Metal hydrides

These technologies would be evaluated in terms of storage cycle energy costs, capital and operating costs, suitability as a transport technology and compatibility with other portions of a hydrogen infrastructure.

Hydrogen distribution would be examined at the fleet, local outlet, and residence scale. Evaluation parameters would include total distribution costs, storage costs, space requirements and power requirements.

Five different technologies would be evaluated in the small-scale production section:

- Conventional alkaline electrolysis
- High-temperature and pressure steam electrolysis
- Small-scale SMR
- Small-scale natural gas decomposition
- Mediated electrochemical oxidation

The following table summarizes the preliminary results available.

Technology	Total Cost (cents/mile)
Home Electrolysis	8
Liquid Hydrogen $40/GJ $25/GJ	 7 5
Station Electrolysis	5
Natural Gas Reforming	3

The results were presented in terms of energy, capital and operating costs. The costs in the table above compare well to current U.S. fuel costs of $4.2 cents per mile and 17.6 cents per mile in Europe. In generating these results the following assumptions were used.

- Off-peak electrolysis at $0.05/kWh
- 88 hours of off-peak electrolysis per week for residential customers
- 128 hours of off-peak electrolysis per week for stations
- $4000 investment for single user refueling station
- Residential users borrow money at 10%
- Capital cost of hydrogen storage (compressed gas) for stations - $300,000
- Storage volume at refueling stations: 15,500 gal at 80 MPa
- Natural gas cost: $2.40/GJ
- Liquid hydrogen cost $25 and $45/GJ
- Discount rate for filling stations 20%

The authors concluded with a listing of proposed future work:

- Identify technologies and costs for home electrolysis
- Delivery costs for LH2 for small fleets
- Establish delivery conditions (quantities, temperature and pressure) for on-board vehicle storage options
- Preliminary analysis of technologies and costs for small-scale electrolysis and steam reforming

(9) Hydrogen Program Combustion Research: Three Dimensional Computational Modeling

Author(s):	Amsden, A., Butler, T., Johnson, N.
Date:	July 31, 1994
Organization(s):	Los Alamos
Publication:	Proceedings of the 1994 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-470-6431
Category(ies):	End-Use
Subcontract No.	

Three dimensional, reactive flow computer modeling of the hydrodynamics of hydrogen gas injection into a fixed-volume combustion chamber was completed and results were presented. Additional analyses were not provided.

(10) Biomass to Hydrogen via Pyrolysis and Reforming

Author(s): Chornet, T., Czernik, S., Wang, D., Gregoire, C. and Mann, M.
Date: July, 1994
Organization(s): NREL
Publication: Proceedings of the 1994 U.S. DOE Hydrogen Program Review, NREL/CP-470-6431
Category(ies): Production
Subcontract No.

This effort had four major objectives:

- Simulate the process and determine the conditions under which the pyrolytic oils can be steam reformed, including equilibrium yields as a function of steam-to-carbon ratio and temperature.
- Assess the feasibility of catalytically converting the pyrolytic oil and to select suitable catalysts and conditions.
- Conduct a bench-scale program to determine real yields as a function of treatment severity, catalyst type and experimental conditions.
- Develop a process flow diagram and preliminary economics as a function of plant capacity.

Thermodynamic Simulation

Thermodynamic simulations of the reforming reactions for specific component of the bio-oil were performed using ASPEN Plus. These results provided a qualitative assessment of the reasonable operating conditions. Given the uncertainties in the composition and the limits of the modeling tools, quantitative assessments were not provided. The authors examined the yield of hydrogen as a function of the steam-to-carbon ratio at an operating temperature of 500 °C. Next, they looked at the approach of many of the oil components to the max stoichiometric yields of hydrogen, also as a function of steam to carbon ratio. From these analyses, the authors concluded that the steam requirement depends only upon the carbon content of the fuel. For an 80% yield, roughly 6.5 moles of steam are required for each mole of carbon; for a 90% yield, this increases to 9-9.5 moles.

Catalytic Conversion

The authors conducted a literature search on the current state of technology for reforming of oxygenates. From this search, they concluded:

- Reforming of hydrocarbons is well understood, operating at steam-to-carbon ratios of 3.5-5.0 and temperatures of up to 775°C.
- Most common catalyst is Ni on alumina; Ca, K and Mg are often used to improve specific properties.
- Mixtures of rare earth oxides and Ni have been used to increase resistance to catalyst poisoning, especially sulfur.
- Methanol is readily steam reformed at temperatures of < 300 °C; ethanol requires higher reforming temperatures. Cu-based catalysts are used for both compounds.
- Data on oxygenated aromatic compounds suggest that they can be steam reformed with existing catalysts.
- The pyrolytic lignin fraction of the bio-oil will be the most challenging to reform.

- May be able to use an Ni-based catalyst in the 700-800 °C range.
- Potential reforming catalyst may be NiO 920-30 wt%), MgO (15 wt%), Al_2O_3 (50-65 wt%), are earth oxides (5-15 wt) and a promoter such as Cr_2O_3 (5-10 wt%).

Process Analysis

The authors discussed two potential designs:

- regional pyrolysis with low-cost, possibly waste feedstocks with condensation of the biocrude and transport to a centralized reformer
- centralized pyrolysis and reforming unit, which processes uncondensed vapors

The first alternative has the advantage of possibly lower feedstock costs while the second has the advantage of no transport or condensation costs. In this analysis, the first alternative was evaluated.

The design of the process was relatively simple. Desulfurization was not required and only a single medium temperature reformer was used. A fixed bed catalyst design, operating at 500 °C, was used. Char and possibly some pyrolysis oil would be used as a fuel for the endothermic process. In the future, the process was to be modeled using ASPEN Plus.

A first-cut economic analysis was performed to determine the minimum boundaries for economic viability. The current market selling price of hydrogen was divided by the pyrolysis oil production cost. A ratio of greater than 1 is required to show potential economic feasibility. This approach provides the minimum limit for economic viability since it assumes on capital or operating costs.

The process was assumed to have a bio-oil feedstock, priced at \$0.141/kg based on a biomass price of \$42/dry ton. Given the then-current hydrogen selling price of \$5-15/MM Btu, the authors plotted the profitability ratio over that range for a hydrogen recovery rate of 70%. This plot showed that at a selling price of > \$7.50/MM Btu, the process could be profitable. The authors also evaluated the effect of hydrogen recovery. For a hydrogen selling price of \$8.8/MM Btu, a process must recover >60% of the hydrogen to be cost effective. Finally, the authors presented a figure showing the combinations of hydrogen recovery and hydrogen selling price with a profitability ratio > 1.

The authors concluded:

- Fast pyrolysis can produce high yields (70-75 wt%) of biocrude
- Steam reforming of simple monomeric materials is thermodynamically and chemically feasible
- Steam reforming of the entire biocrude is thermodynamically feasible
- Fast pyrolysis technology options (fluid beds, entrained beds or ablative reactors) are at the pilot and demonstration stages
- Steam reforming of biocrude requires significant bench-scale testing
- Small to medium-sized regional fast pyrolysis units will likely be used to produce biocrude and then transport it to centralized reforming plants
- The process concept is simple and will not require desulfurization.
- Preliminary economics, based on input/output calculations, show that biomass pyrolysis may be economically attractive.

(11) Technology Characterizations for the E3 (Energy, Economics, Environment) Pathway Analysis

Author(s): DiPietro, J.P., Badin, J.S.
Date: April, 1995
Organization(s): Energetics, Inc.
Publication:
Category(ies): Outreach
Subcontract No.

This analysis conducted a literature search for cost and performance of hydrogen technologies. The overall objective of the analysis was to provide a foundation of consistent and credible information on the current status of hydrogen technologies. In some cases, assumptions were used in the compilation of the information.

The technologies were grouped into electricity generation, hydrogen production, hydrogen storage (stationary and on-board), electricity storage (stationary and on-board), and hydrogen utilization. A summary table was provided for each technology type and detailed reference tables showing the assumptions and literature sources were also provided.

The following tables summarize the literature search. Median values for the capital costs ($/kW) and energy efficiency.

Electricity Generation

Technology	**1992-1995 ($/kW)/Eff. %**	**2000-2005 ($/kW)/Eff. %**	**post 2020 ($/kW)/Eff %**
***Coa*l**			
PC	$1,600/34%	$1,500/41%	$1,400/42%
FB	$1,400/40%	$1,200/45%	$1,200/50%
IGCC	$1,850/38%	$1,600/44%	$1,200/50%
Hydropower	$1,600/85%	$2,000/85%	$2,000/85%
Nuclear	$3,200/32%	$1,950/33%	$1,600/33%
Natural Gas			
Gas Turbine	$370/31%	$350/45%	$345/50%
Combined Cycle	$750/45%	$720/55%	$710/60%
Wind	$1,200/37%	$980/42%	$930/50%
Solar Thermal			
Parabolic Trough	$3,200/15%	$2,700/15%	$2,500/22.5%
Central Receiver	$3,600/11%	$3,100/13%	$2,900/22.5%
Parabolic Dish	$2,800/20%	$1,700/24%	$1,500/27.5%
PV			
Fixed Flat Plate	$4,600/11%	$1,900/17%	$1,000/25%
Concentrator	$4,800/25%	$1,650/35%	1,300/40%
Fuel Cell			
PAFC	$1,100/43%	$700/47%	$500/50%
SOFC	$825/55%	$540/60%	$500/64%
MCFC	$1,500/54%	$750/68%	$700/70%

Hydrogen Production

Technology	**1992-1995 (\$/kW)/Eff. %**	**2000-2005 (\$/kW)/Eff. %**	**post-2020 (\$/kW)/Eff. %**
Electrolysis			
Alkaline water	\$500/80%	\$350/88%	\$300/90%
Solid Electrolyte	\$800/87%	\$650/90%	\$600/94%
High temp steam	\$415/75%	\$350/77%	\$300/78%
Coal Gasification	\$900/62%	\$750/64%	\$650/66%
Steam Iron	\$860/42%	\$850/44%	\$800/45%
Biomass Gasification	\$865/68%	\$525/77%	\$450/79%
Partial Oxidation			
Residual Oil	\$450/60%	\$350/70%	\$300/75%
Methane	\$100//87%	\$90/89%	\$85/93%
NG Reforming	\$300/70%	\$270/75%	\$250/78%
Photo-chemical	NR/2%	\$2,000/7.5%	\$300/7.5%

Hydrogen Storage, Stationary Application

Technology	**1992-1995 (\$/kWh)/Eff. %**	**2000-2005 (\$/kWh)/Eff. %**	**post-2020 (\$/kWh)/Eff. %**
Compressed Gas	\$12/97%	\$10/97%	\$9/97%
Underground	\$2.2/97%	\$1/98%	\$0.04/99%
Liquid	\$1.2/30%	\$1.1/35%	\$1.1/45%
Hydride			
FeTi	\$26/98%	\$20/98%	\$14/98%
Mg	\$13/98%	\$10/98%	\$5/98%
Carbon Adsorption	\$11/88%	\$6/90%	\$4/94%

Hydrogen Storage, Vehicle On-Board Application

Technology	**1992-1995 (\$/kWh)/Eff. %**	**2000-2005 (\$/kWh)/Eff. %**	**post-2020 (\$/kWh)/Eff. %**
Compressed Gas	\$15/97%	\$12/97%	\$10/92%
Liquid	\$5/20%	\$4/62%	\$4/67%
Hydride (FeTi)	\$16/98%	\$10/98%	\$8/98%
Carbon Adsorption	\$10/88%	\$6/91%	\$3/92%

Electricity Storage, Stationary Application

Technology	**1992-1995 (\$/kWh)/Eff. %**	**2000-2005 (\$/kWh)/Eff. %**	**post-2020 (\$/kWh)/Eff. %**
Battery	\$200/72%	\$125/80%	\$80/83%
Pumped Hydro	\$28/76%	\$28/76%	\$28/76%
CAES	\$3/79%	\$3/79%	\$3/79%
Super-conducting Magnetic	\$450/89%	\$450/89%	\$275/91%

Electricity Storage, Vehicle On-Board Application

Technology	**1992-1995 (\$/kWh)/Eff. %**	**2000-2005 (\$/kWh)/Eff. %**	**post-2020 (\$/kWh)/Eff. %**
Battery Powered Electric Vehicle, Battery	\$100/75%	\$70/75%	\$50/75%

Hydrogen Utilization

Technology	**1992-1995 (\$/kW)/Eff. %**	**2000-2005 (\$/kW)/Eff. %**	**post-2020 (\$/kW)/Eff. %**
Fuel Cell Vehicle			
PEM	\$200/40%	\$35/55%	\$30/60%
PAFC Bus	\$1,300/51.5%	\$400/50%	\$300/55%
Fuel Cell Onsite Cogen (PAFC)	\$2,500/44%	\$1,500/55%	\$1,000/60%

(12) Analysis of Near-Term Production and Market Opportunities for Hydrogen and Related Activities

Author(s): Mauro, R., Leach, S.
Organization: National Hydrogen Association
Date: April 18, 1995
Category(ies): Market Opportunities, Transport
Publication: Proceedings of the 1995 U.S. DOE Hydrogen Program Review, Volume 1, NREL/CP-430-20036
Subcontract No.

This paper examines the merchant hydrogen market, near-term venture opportunities and the 1995 Codes and Standards Workshop. It also conducted a case study of piping hydrogen from the South Central Region to Southern California.

A literature search and survey of industry were conducted. The industry survey covered five areas: gaseous hydrogen production, liquid hydrogen production, steam reforming costs, hydrogen pipelines, and liquid hydrogen production in the Southeast and Southern California. Four different companies were sent a copy of the industry questionnaire.

The report summarized the 40 gaseous hydrogen plants by region, reporting number of plants and total regional production. In addition, the amount of by-product hydrogen purchased by region was also summarized. In general, the West South Central region, encompassing Arkansas, Louisiana, Oklahoma and Texas, had the most plants, highest capacity and greatest by-product hydrogen sales by far. The questionnaire also summarized subjective information regarding the future of hydrogen sales by industry. In most cases, hydrogen sales were expected to be level or to increase. Only in the aerospace, food and chemical industry were possible decreases expected.

Costs for liquid hydrogen were obtained via a survey of current producers in Canada and the U.S. Over the fence (i.e., no transport) liquid hydrogen prices ranged from $5-15/Mscf ($0.96-2.88/lb). No information was provided on the factors affecting this wide range.

From this survey, the authors concluded that hydrogen use was growing and this may be due to reformulated gasoline demands. The greatest hydrogen production is in the West South Central region, but liquid hydrogen is shipped throughout the U.S. and Canada.

In the case study, the authors spoke with several companies operating hydrogen pipelines and obtained rules-of-thumb for the cost of hydrogen pipelines. Based on these design parameters, the authors looked at the cost of a 1,500 mile pipeline, 8" diameter, operating at 500-800 psig and with a flow of 50 ft/s. Using optimistic assumptions (e.g., pressure losses of 1 psi/mile, single-stage compression), the annual cost of the pipeline was estimated at almost $100 million. On an energy basis, the cost is over $500/MMBtu, excluding compression costs.

For a larger pipeline (i.e., 24" diameter), the construction cost would be $400 million with an annual cost of $100 million. (The text notes that these costs are 3 times that of the earlier case, but they are roughly equivalent). The incremental cost of this option is $73/MM Btu.

Based on this analysis, the authors concluded that construction of low pressure pipelines with conventional technology would not be cost-effective for hydrogen transport between regions. This high cost is the reason that most hydrogen today is consumed locally.

The subcontractor also sent out a questionnaire regarding demonstrations to seventeen organizations to determine what role, if any DOE should play in the projects. Follow-up contact was also made. Based on these contacts, ten demonstration projects were identified for further study.

In the Codes and Standards section of the report, the authors described the first in a series of workshops on codes and standards for hydrogen. The workshop had presentations in three areas: current and developing codes for handling hydrogen, field experience, and codes and standards for hydrogen products and infrastructure. The workshop reached the following conclusions:

- Consensus must be reached by industry on codes and standards
- Demonstrations are a method to identify codes and standards issues
- A mechanism is needed to inform and coordinate the hydrogen industry response on codes and standards
- Codes and standards activities should be coordinated with the DOT

Subsequent work will focus on prioritizing the most important codes and standards issues.

The authors concluded with a general discussion of work with Westinghouse Savannah River Company (non-Program funded) and potential DOE-related activities.

(13) Supporting Analyses and Assessments

Author(s): Ohi, J.
Organization: NREL
Date: April 18, 1995
Category(ies): Analysis methodology
Publication: Proceedings of the 1995 US DOE Hydrogen Program Review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-20036-Vol 1.
Subcontract No.

In this paper, the rationale for developing a standard method of conducting and evaluating analyses was outlined. The author contended that through consistent coordination of analytic tasks, the overall goals of the Program will be met.

To establish the analytic framework, the author devised a 3-prong approach. All required and suggested directions due to legislation, HTAP, outreach would be mapped against programmatic pathway options. From this, the analysis required for evaluation of the pathways would be defined. And finally, an agenda of critical tasks would be defined.

The author also outlined some of the pertinent questions in this effort, including measurement methods and correlating Program progress with trajectory. In the initial step of this methodology, representatives of NREL met with industry, university and other national lab members to start discussing programmatic analysis needs. In addition, other working groups were convened to discuss production, storage and utilization issues.

NREL was charged with beginning to assess the costs and benefits of hydrogen technology, primarily in the transportation and utility sectors. In the transportation sector, benefits of displacing gasoline were evaluated for three types of hydrogen vehicles: hydrogen-powered internal combustion engine vehicles (ICEV), hydrogen-powered hybrid electric vehicles (HEV), and hydrogen-powered fuel cell vehicles (FCV). Market penetration scenarios were modeled using the Alternative Vehicle Spreadsheet (AVS). No significant competition was modeled for other types of vehicles. Benefits of these vehicles were measured in terms of criteria pollutant emissions, oil imports, and carbon emission reductions.

Values for each benefit were derived from the literature. For criteria pollutants, the avoided costs implied in the 1990 Clean Air Act Amendments (CAAA) while carbon reduction emissions were a mid-range value based on the literature ($0-55/ton CO2). Oil reduction costs were estimated at $4/bbl based on costs of averting or weathering supply reductions. Also included in the study were the increased vehicle costs due to the hydrogen technology.

The results of the study were extremely positive. In constant 1990$, it is estimated that the benefits of hydrogen use in the transportation sector would be $80 billion, discounted and $320 billion, undiscounted.

The study also briefly summarized work in the utility sector. Here, the group completed a comprehensive mapping of a utility system to identify opportunities for hydrogen production, storage, distribution and utilization.

The author also proposed several areas for future work:

1. develop a systematic method to identify and evaluate programmatic pathway options that incorporate various technology drivers (e.g., environmental regulations) into the long-term goals of the Program
2. apply H-Scan to evaluate near-term demonstration opportunities
3. conduct a comprehensive cost and benefit analysis to develop metrics based on strategic national goals and comprehensive portfolio criteria to help set Program priorities and pathways

(14) Systems Analysis - Independent Analysis and Verification

Author(s):	Badin, J.S., DiPietro, J.P.
Organization:	Energetics, Inc.
Date:	April 18, 1995
Category(ies):	General Analysis
Publication:	Proceedings of the 1995 US DOE Hydrogen Program Review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-20036-Vol 1.
Subcontract No.	94 DE-CE001-ENI001

This paper describes a methodology based on the E3 (Energy, Economics, Emissions) Pathway Model for systems analysis to ensure independent and consistent assessment of proposed Hydrogen Program research and development projects. This methodology will enable the Hydrogen Program Manager to set priorities for the budget.

The independent analysis and verification process consists of five steps:

- Proposed System Concept – The hydrogen energy system is defined.
- Pathway Representation – The system is represented by a set of technology nodes from production to utilization.
- Baseline Results and Sensitivities – A series of sensitivity studies is run on the base case derived above.
- Comparison to Benchmark and Conventional Technologies – The competitive threshold for the technology is determined based on comparison with current technologies.
- Report – A report on the analysis is submitted.

As a basis for the analyses, a database of relevant technologies was compiled and was used to ensure consistent analyses. The technologies in the database are grouped into the following categories: electricity generation, hydrogen production, hydrogen and electricity storage (stationary and onboard), and hydrogen utilization.

Seven systems were currently under analysis. The authors provided a progress report for each as well as examples for each stage of the verification process. The information provided was in graphical form and cannot be reproduced here.

(15) Electrolytic Production and Dispensing of Hydrogen

Author(s):	Thomas, C.E., Kuhn, Jr., I.F.
Organization:	Directed Technologies, Inc.
Date:	April 18, 1995
Category(ies):	Production, Transportation
Publication:	Proceedings of the 1995 US DOE Hydrogen Program Review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-20036-Vol 1.
Subcontract No.	DE-AC02-83CH10093

The economic feasibility of producing hydrogen electrolytically at small scales (i.e., for home and fleet use) was evaluated. The system cost was defined and used to determine the electricity rates necessary to make the hydrogen cost-competitive with gasoline in the transportation sector. No life-cycle costs were considered in the analysis because it was assumed that most consumers would make decisions based on the cost at the pump. Thus, no benefits from the expected lower operating costs of a fuel cell vehicle (FCEV) were considered.

The analysis evaluated at a single-car refueling station under three different economic schemes: 1) a business with a 10% real rate of return over 15 years; 2) a utility with a 6.3% real rate of return; and 3) inclusion of the system in a 30-year mortgage at 9%. The report also described an electrolyzer sized to service a fleet of 50 vehicles. The home refueling station was assumed to have excess capacity of 50% to account for daily mileage variations; the fleet system required an excess capacity of only 20%.

Capital costs
Capital costs for the system included costs for the electrolyzer, compressor, storage, safety components, and controls. The report outlined the methodology and sources used for the electrolyzer, compressor and storage, but no information or costs were included for safety equipment or controls. The cost of the electrolyzer (\$300/kW$_{out}$) was based on a literature survey and assuming high volume manufacturing. Very few costs (i.e., 2) were available for small (50 kW) systems.

Compressor costs (\$115/kW$_{out}$) were also based on a literature survey. No costs were obtained for mass-produced, small-scale hydrogen compressors. Therefore, the cost was based on a projected cost of a mass-produced natural gas compressor that is 40% larger and compresses to 50% of the required 6,000 psi.

Storage costs were estimated at \$50/lb H_2. Again, however, information on small-scale, mass produced units were not available. Therefore, the cost was assumed to be equivalent to the cost of a mass-produced tank in 2004 made of carbon, a more expensive material.

As noted earlier, no details or costs were provided for the other major components: safety equipment or controls. The dispensing hose was assumed to be part of the storage tank.

Operating Costs
Operating costs were composed of five components: operating and maintenance, insurance, property taxes, electricity and annualized capital charges. The O&M charges (2%), insurance (0.5%) and property taxes (1.5%) were estimated as percentages of the fixed capital investment.

The capital costs were annualized using a capital recovery factor based on the specific economic lifetimes and interest rates outlined above. The resulting capital recovery factors were 7.15% for the home system, 12.3% for the utility system and 18.54% for the business.

Results

The total capital cost for each alternative was projected to be $3,413. Based on the economic parameters described above, the report concluded that electrolytic hydrogen was cost-competitive with fully taxed gasoline if electricity is available at 3-4.5 cents per kilowatt. If hydrogen fuel is taxed as gasoline, then electricity prices must be less than 1-2.5 cents per kilowatt. Under these conditions (i.e., equal taxation), the benefits of hydrogen fuel such as lower O&M vehicle charges should be considered. Given the economic assumptions, the home refueling station was the most economic and the 15-year business loan, the least.

(16) A Smooth Transition to Hydrogen Transportation Fuel

Author(s):	Berry, G., Smith, J., Schock, R.
Organization:	Lawrence Livermore National Laboratory
Date:	April 18, 1995
Category(ies):	Transportation, Production
Publication:	Proceedings of the 1995 US DOE Hydrogen Program Review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-20036-Vol 1.
Subcontract No.	W-7405-Eng-48

This report evaluated near-term infrastructure options for transition to hydrogen-fueled vehicles. The primary focus of the work was a comparison of decentralized and centralized production with a large-scale infrastructure. Three small-scale scenarios were evaluated: 1) electrolysis at the home for one car; 2) conventional alkaline electrolysis; and 3) steam reforming of natural gas. All scenarios assume fueling a vehicle with a 300-mile range.

The analysis used the following conservative economic assumptions.

Economic Assumptions

Parameter	Value
Economic Assumptions	
Discount rates	
Commercial	20%
Consumer	10%
Equipment life times	
Production plant	20 years
Other	10 years
Salvage value	0
Energy Prices	
Natural gas	\$4/GJ
Hydrogen	\$9/GJ
Gasoline	\$1.25/gallon

The vehicle design used in the study was similar to a GM Impact III, but with only a 300-mile operating range. Gaseous onboard storage (3.75 kg) in carbon fiber wrapped vessels was assumed.

The filling stations were assumed to service 300 cars /day. The operating costs for the station (labor, capital charges) was projected to be \$720/day and gross revenues of \$3,750/day.

Hydrogen transport was assumed to be by truck using liquid hydrogen, a magnesium-based hydride, a cryogenic composite pressure vessel and a microsphere storage bed. The capital costs of these alternatives ranged from \$1000/GJ for LH2 to \$4000/GJ for the cryogenic gas. Each technology can deliver hydrogen about 250 miles for \$20/GJ. It is unlikely that these costs can be decreased using another technology since 50-75% of the costs are fixed (e.g., hydrogen production and storage energy) and would be the same for any technology.

On-site production of hydrogen was evaluated for three technologies: natural gas steam reforming, alkaline electrolysis, and steam electrolysis. The cost of production for each of these systems at the large-scale (i.e., 300 cars/day) is about the same ($20/GJ) as that for the centralized production, truck transport scenario.

The author then evaluated the impact of delivery scale on hydrogen costs and the cost breakdown for stations of 100-500 cars/day. Finally, a short evaluation of home electrolysis was conducted. This option was not shown to be cost competitive except under special conditions (i.e., off-peak electricity) and mass-production of components.

The authors formed the following conclusions based on this study:

- All hydrogen delivery and on-site production pathways were competitive with gasoline today based on station sizes of 300 cars/day
- The cost difference between the various scenarios were small ~$120-240/yr.
- Cost of liquid hydrogen delivery and/or on-site production are low enough for an easy transition
- Real issues for hydrogen vehicles are vehicle issues (e.g., vehicle capital cost and operating life) and small-scale hydrogen technology development

(17) Industry Outreach a Status Report

Author(s): Surek, D. Sen, R.
Organization: R.K. Sen & Associates
Date: April 18, 1995
Category(ies): Marketing
Publication: Proceedings of the 1995 US DOE Hydrogen Program Review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-20036-Vol 1.
Subcontract No.

This report is a status report of the beginnings of an industry outreach project. The project will entail a review of current and past outreach efforts, meetings with industry decision makers, and a workshop between industry and federal agencies.

At the time of the program review, the review of outreach efforts had been completed and meetings with 16 of 25 identified organizations in eight industry sectors had been conducted. All of the identified organizations met the following criteria:

- Diverse in terms of size, industry sector and location
- Current or potential energy in hydrogen energy
- U.S. owned and operated
- Senior-level technical or business leader involvement.

Preliminary conclusions from the meeting included:

- Environmental mandates are behind industry pursuit of hydrogen and other energy alternatives;
- Industry views hydrogen's long-term prospects favorably
- Industry is interested in participating in appropriate demonstration projects.
- Hydrogen has several barriers to commercialization:
    - High production and storage costs
    - Perceived safety and liability issues
    - Lack of infrastructure
    - Competition with natural gas

The committee also identified several issues specific to DOE-industry partnerships. Industry is not familiar with the DOE program, coordination of activities within DOE is not clear, but industry is interested in working with DOE.

(18) Technical and Economic Analyses of Hydrogen Production via Indirectly Heated Gasification and Pyrolysis

Author(s): Mann, M.K.
Organization: NREL
Date: April 18, 1995
Category(ies): Production
Publication: Proceedings of the 1995 US DOE Hydrogen Program Review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-20036-Vol 1.
Subcontract No.

This paper compared the economics of biomass gasification and pyrolysis to produce hydrogen. The gasification process was based on the Battelle-Columbus indirectly heated gasifier and the pyrolysis system was a generic design. Each technology was evaluated at three feedstock rates: 27 T/day, 272 T/day, and 907 T/day. Additionally, the gasification process was evaluated under three different processing schemes. Scheme 1 used all reforming operations typically used in natural gas reforming (i.e., primary reformer, high temperature shift reactor, and low temperature shift reactor). Scheme 2 used just the primary reformer and Scheme 3 included the primary reformer and the high temperature shift reactor. In the case of the pyrolysis process, only Scheme 1 was analyzed. However, one alternative to the process was also analyzed in which a co-product similar to phenolic resins is extracted prior to reforming.

Each process was simulated using ASPEN Plus. The following table presents information from the material balance of each process.

Material Balance Summary

Processing Scheme	**Value**
Gasification Scheme 1	
Stoichiometric Efficiency	39.3%
Energy Conversion Efficiency	79.0%
Hydrogen Production (scmd)	
27 T/d	21,600
272 T/d	215,940
907 T/d	719,800
Gasification Scheme 2	
Stoichiometric Efficiency	30.6%
Energy Conversion Efficiency	69.7%
Hydrogen Production (scmd)	
27 T/d	16,850
272 T/d	168,500
907 T/d	561,500
Gasification Scheme 3	
Stoichiometric Efficiency	37.2%
Energy Conversion Efficiency	76.5%

Processing Scheme	Value
Gasification Scheme 3 – continued Hydrogen Production (scmd) 27 T/d 272 T/d 907 T/d	 20,440 204,390 681,280
Pyrolysis Scheme 1 Stoichiometric Efficiency Energy Conversion Efficiency Hydrogen Production (scmd) 27 T/d 272 T/d 907 T/d	 55.3% 86.5% 30,415 304,152 1,013,840
Pyrolysis Co-Product Stoichiometric Efficiency Energy Conversion Efficiency Hydrogen Production (scmd) 27 T/d 272 T/d 907 T/d	 39.4% 62.8% 24,332 243,322 811,073

For each of these scenarios, the following economic assumptions were used.

Economic Assumptions

Cost Parameter	Value
Operating Costs Feedstock Electricity Water Labor	 416.50-46.30/T $0.05/kWh $330/m^3 Not reported
By-Product Credits Adhesives co-product Steam 500 psig 100 psig	 75% of value of phenol $7.99/1,000 kg $5.18/1,000 kg
Economic Assumptions Dollar years Type of financing On-line factor Construction period Depreciation method Inflation rate	 January 1995 Equity 90% 2 years with 30% of investment in first year 10 year straight-line; 1st and last year 50% of other years

Cost Parameter	Value
Tax rate Plant life Ramp up period Method of analysis Hurdle rate	5% 37% 20 years 50% capacity for the 1st year Internal rate of return 15%

The following tables summarize the results of the economic analysis.

Capital and Operating Costs for Gasification-Based Processes

Plant	Operating Costs (MM$/yr)	Capital Costs (MM$)
Gasification - Scheme 1		
27 T/day	0.30	6.08
272 T/day	1.73	34.5
907 T/day	14.1	90.4
Gasification - Scheme 2		
27 T/day	0.28	5.05
272 T/day	1.43	29.3
907 T/day	13.1	80.0
Gasification - Scheme 3		
27 T/day	0.31	6.02
272 T/day	4.39	34.0
907 T/day	14.1	89.1

Capital and Operating Costs for Pyrolysis-Based Processes

Plant	Operating Costs (MM$/yr)	Capital Costs (MM$)
Pyrolysis Scheme 1		
27 T/day		
Purchased oil	1.02	3.07
In-house oil	0.46	
272 T/day		
Purchased oil	8.87	20.2
In-house oil	3.31	
907 T/day		
Purchased oil	36.56	58.7
In-house oil	18.16	

Plant	Operating Costs (MM$/yr)	Capital Costs (MM$)
Pyrolysis Co-Product		
27 T/day		
Purchased oil	1.04	2.89
In-house oil	0.48	
272 T/day		
Purchased oil	9.05	18.2
In-house oil	3.49	
907 T/day		
Purchased oil	37.18	52.6
In-house oil	18.76	

Hydrogen Selling Price for 15% After-Tax IRR

Plant	Biomass Cost ($/T)	Hydrogen Selling Price ($/GJ)
Gasification Scheme 1		
27 T/day	16.50	23.20
272 T/day	16.50/46.30	13.10/16.20
907 T/day	46.30	13.70
Gasification Scheme 2		
27 T/day	16.50	25.10
272 T/day	16.50/46.30	14.20/18.20
907 T/day	46.30	15.70
Gasification Scheme 3		
27 T/day	16.50	24.30
272 T/day	16.50/46.30	13.70/17.00
907 T/day	46.30	14.20

(19) Hybrid Vehicle System Studies and Optimized Hydrogen Engine Design

Author(s):	Smith, J.R. and Aceves, S.
Organization:	LLNL
Date:	April 18, 1995
Category(ies):	Transportation
Publication:	Proceedings of the 1995 US DOE Hydrogen Program Review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-20036-Vol 1.
Subcontract No.	

This report examined the systems analysis and engine development work that is directed toward the Partnership for a New Generation of Vehicles (PNGV) goal of 80 mpg with very low emissions. Thirteen series hybrid systems were evaluated using HVEC, a vehicle evaluation code that predicts the fuel economy, range, and performance of electric and series hybrid vehicles. For this analysis, the program was used to determine which combination of fuel (gasoline, natural gas, diesel, methanol, hydrogen) and primary power supply (piston engine, turbine, fuel cell) is most likely to meet the PNGV goals. The following table lists the combinations evaluated.

- Gasoline hybrid
- Gasoline hybrid, Lean burn engine
- Diesel hybrid
- Compressed Natural Gas (CNG) hybrid
- CNG hybrid, Lean-burn
- Gas turbine hybrid
- Hydrogen hybrid, Cryogenic liquid hydrogen storage
- Hydrogen hybrid, Iron-titanium hydride storage
- Hydrogen hybrid, Magnesium hydride storage
- Hydrogen hybrid, Pressure storage at 3,600 psi
- Hydrogen hybrid, Methanol and reformer
- Hydrogen-methane hybrid, Pressure storage at 3,600 psi
- Proton exchange membrane (PEM) fuel cell hybrid, Cryogenic liquid hydrogen storage

Each technology was evaluated under identical conditions, as outlined below:

Time for 0-97 km/h acceleration:	10 s
Hill climbing capacity:	6% infinite hill at 97 km/h
Range:	384 km and 608 km
Pay load:	136 kg

Several other design parameters (e.g., aerodynamic drag coefficient) were also specified equivalent.

From this analysis, the authors contended that mass was not a great indicator of fuel economy and that future efforts should focus on increasing the engine fuel economy. Also, it is unlikely that turbines, CNG engines and gasoline engines will achieve the PNGV goal, but diesel, hydrogen and fuel cells show promise. On the other hand, each of these technologies has other potential limitations in emissions (diesel), fuel infrastructure and storage (hydrogen and fuel cell), or cost (hydrogen and fuel cell). Of the three, the authors expect that the hydrogen engine vehicles would be the most likely to solve any problems, economically and so the remainder of the paper was focused on the efforts to optimize hydrogen engines.

The optimal hydrogen engine must show reductions in NO_x emissions and an increase in efficiency. From the literature, the authors concluded that an optimized hydrogen engine for minimal NO_x emissions should operate as a premixed homogeneous-charge, spark-ignition engine at an equivalence ratio of about 0.4. In terms of efficiency, the literature suggests that high efficiency can be achieved with a compact chamber with low surface-to-volume ratio, minimal mechanical friction, and high volumetric efficiency is achieved. Also, it was expected that the optimum engine speed and specific power output will be relatively low. Due to the low specific power output, turbocharging or two-stroke operation may be required.

The authors designed and built a cylinder head for an existing Onan single cylinder diesel engine. Using hydrogen and varying the compression ratio, the researchers achieved engine efficiencies of 42-46%. Further work is planned with a modified Onan engine.

(20) Hydrogen Energy Systems Studies

Author(s): Ogden, J., Steinbugler, M., Dennis, E. Kartha, S., Iwan, L., Jones, A.
Date: July 31, 1995
Organization(s): Center for Energy and Environmental Studies, Princeton University
Publication: Proceedings of the 1995 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Production, Markets, Transportation, Transport
Subcontract No. XR-11265-2 and DE-FG04-94AL85803

This report summarized one subcontract and presented preliminary results from a second subcontract. The results covered a wide range of topics including:

- Near-term options for supplying hydrogen from natural gas
- Feasibility of using the existing natural gas system with hydrogen and hydrogen-blends
- PEM fuel cells for residential cogeneration
- Small-scale production of hydrogen from natural gas
- Potential markets for hydrogen in Southern California

The results in each area are summarized below.

Near-Term Options for Hydrogen Transportation Fuel from Natural Gas
As summarized below, four options for producing and delivering hydrogen for use in vehicles as a compressed gas were evaluated.

Option Number	Production Method	Delivery Method
1	Steam reforming	Liquid delivery via truck
2	Steam reforming	Hydrogen pipeline
3	Small-scale steam reforming	Produced on-site
4	Small-scale electrolysis	Produced on-site

In the assessment of these alternatives, the authors evaluated the following areas:

- Hydrogen refueling system design
- Refueling station capital cost
- Delivered cost of hydrogen
- Emissions
- Synergism between near-term and longer-term (renewable) options

Each option was evaluated for four different sizes of refueling stations: 0.1, 0.366, 1, and 2 million scfd, corresponding to refueling 80, 300, 800 and 1600 vehicles/day. The results of the economic analysis are summarized below. It should be noted that the costs presented in most cases were read off graphs and thus are not precise.

Option Number/ Station Size (MM scfd)	**Refueling Station Capital Cost ($ million)**	**Delivered Cost of Hydrogen Fuel ($/GJ)**
Option 1		
0.1	<$1	$30
0.366	<$1	$22
1.0	<$1	$21
2.0	$1	$20
Option 2		
0.1	<$1	$25
0.366	<$1	$15
1.0	$2	$13
2.0	$3.75	$12
Option 3		
0.1	$2	$40
0.366	$3	$20
1.0	$5.5	$15
2.0	$8.75	$12
Option 4		
0.1	<$1	$30
0.366	$2	$18
1.0	$5	$15
2.0	$10	$12

Feasibility of Using Existing Natural Gas System for Hydrogen and Hydrogen Blends

This task examined the use of existing long distance (i.e., large diameter pipelines operating at 1000 psia), local distribution (gas utility distribution system at 15-500 psia) and end-use systems (i.e., gas-using systems such as boilers) for hydrogen. The issues addressed in the study include:

- Materials
- Equipment
- Energy flow and leak rate
- Safety

In assessing these areas, the following issues were addressed: projected demand for hydrogen and hydrogen blends, delivery alternatives, environmental benefits, benefits of hydrogen blends, and potential scenarios for adapting the existing natural gas system for hydrogen and hydrogen blends.

The analysis was primarily a literature survey with no new analysis. A summary of the conclusions of this task is presented below.

- Hydrogen transport, distribution, and end-use systems can be designed and operated safely
- Costs for high-pressure distribution systems could be 50% higher than for natural gas
- New transmission system construction would be very costly, but the overall contribution to hydrogen delivered costs would still be ~10-20%

- Existing natural gas systems could be used with hydrogen blends of 15-20% without modification; natural gas local distribution systems could use pure hydrogen or blends with minor modifications
- It is unlikely that natural gas local lines would be converted to pure hydrogen unless most of the end-users have converted. Thus, a pure hydrogen distribution system should grow in parallel along existing rights-of-way
- Hydrogen embrittlement could be a series issue for current high-pressure systems
- Long-distance hydrogen transport may not be necessary due to the wealth of local, renewable resources
- Environmental benefits of blends (i.e., emissions reductions) should be studied further

PEM Fuel Cells for Residential Cogeneration

In this analysis, the residential PEM fuel cells are owned and operated by the utility, but are located at the residence. The utility dispatches the fuel cell to meet peak and intermediate loads; waste heat from the fuel cell heats the customer's hot water. The cost of producing the electricity is estimated with and without credits for distributed generation, emissions reductions, and fuel diversity.

The analysis was based on the following assumptions:

- Fuel cell is dispatched when the load >50% of peak capacity.
- Synthetic hourly load data from a summer peaking electric utility were used to determine the fuel cell time of operation
- Fuel cell is sized to meet customer's hot water demand which shows daily, but not seasonal variation
- Hydrogen ($8-12/GJ) is available from a distributed reformer through a low-pressure local distribution system.
- Fuel cell operates on pure hydrogen and air with 90% hydrogen utilization and 75% energy recovery for hot water production.
- Value of distributed power was obtained from EPRI
- Customer sees no change in utility bill.

From this analysis, the authors concluded that the system cannot compete with electricity from a combined cycle gas turbine unless credits are provided. The authors also point out, however, that distributed generation has substantial benefits including improved reliability and increased reserve margin. When these factors are considered and credits are included for low emissions and fuel diversity, this alternative was competitive with natural gas cogeneration systems for almost all systems evaluated.

The next two tasks focused on analyses that were in-progress.

Small-Scale Reformer Technologies

Three different small-scale (< 5 million scfd) reforming technologies were evaluated: catalytic steam, partial oxidation and thermocatalytic (autothermal). For each technology, vendors were contacted to determine cost and performance for commercially-available technologies. Then, to better understand reformer design, computer models were developed for: equilibrium steam reactions, methane conversion in a single reformer tube and hydrogen plant based on steam reforming.

The following table summarizes the status of the vendor contacts to date.

Technology Type/ Vendor	Production Capacity (scfd)	Efficiency	Cost
Catalytic Steam Reforming			
Halder-Topsoe	67,000-3.3 MM	80%	$500/kW
Howe-Baker	1-5 MM	80%	$3 MM/1MM scfd
Hydro-chem	120,000-5 MM	Not reported	$1 MM/120k scfd
KTI	Not reported	Not reported	Not reported
Glitsch	300,000	Not reported	$1-1.3 MM
IFC/ONSI	48,000-140,000	84%	$300/kWe
Ballard	6,000-120,000	80%	$500/kWe
Chiyoda	Not reported	Not reported	Not reported
Partial Oxidation			
ADL	12,500	80%	Not yet commercial
Hydrogen Burner Technology	12,000-96,000	75-80%	<$200k/96,000 scfd
Autothermal			
Rolls-Royce/Johnson-Matthey	1,700-6,200	>90%	Not reported
IFC/ONSI	1.5-20 kW	Not reported	Not reported

In general, the cost of the catalytic steam reformers was due to heat exchange. Thus, the authors evaluated other reforming technology. It is likely that the costs can be reduced by incorporating a design similar to that for fuel cell reformers including mass production of a standard design, lower hydrogen purity, and lower operating temperatures and pressures.

Two of the computer simulations had been completed: reforming equilibrium and a 1-D model of a reformer tube; both showed good agreement with other models and experimental data. Work was progressing on the full hydrogen plant.

The authors concluded with a brief discussion of the impact of the reformer capital cost on the delivered price of hydrogen. They projected that a 50% decrease in this cost could result in a decrease of $5-11/GJ of hydrogen ($0.70-$1.40/gal gasoline equivalent).

Potential Hydrogen Markets in Southern California

The results of this task were at an early stage. The overall goal was to evaluate the potential development of hydrogen markets in Southern California over the next five years. In the initial phase of the project, the authors analyzed potential markets for ZEVs based on mandated levels. From these levels, the authors projected the number of hydrogen vehicles by 2010, assuming 50% of the ZEVs are hydrogen-based. From this preliminary analysis, it is estimated that the L.A. basin would require enough hydrogen (~55 million scfd) to support a large steam reforming operation.

The authors concluded the report with recommendations for further work:

- Evaluate hydrogen a fuel for FCVs
- Evaluate environmental benefits of hydrogen blends

- Case study of developing a hydrogen vehicle refueling infrastructure in Southern California
- Evaluate PEM cogeneration systems for commercial buildings
- Strategies for introducing hydrogen from biomass and MSW

(21) H Scan/AHP Decision Process Planning for Evaluating and Ranking of Proposals Submitted to the DOE Hydrogen Program

Author(s):	Szoka de Valladares, M-R., Mack, S.
Organization(s):	NREL/Energetics, Inc.
Date:	July 31, 1995
Category(ies):	Methodology
Publication:	Proceedings of the 1995 U.S. DOE Hydrogen Program Review, Volume I, July 31-21.
Subcontract No.	

This report outlines a systematic method of identifying and evaluating research and development activities in the Hydrogen Program. The method outlined is divided into three sections:

- Objectives
- H Scan
- The Analytic Hierarchy Process (AHP)

Objectives

The objectives or criteria are defined by the Hydrogen Program Manager and are the basis for the selection process. The criteria are both qualitative and quantitative and take into account both political and technical issues. The objectives are the drivers for the other parts of the evaluation process.

H Scan

H Scan is the process for the submittal and evaluation of proposals. A series of forms is provided to project proposers that provide a framework for the description of the project in areas of concern for the Hydrogen Program. Another series of forms is provided to the project reviewers who can use the forms to evaluate the project. By submitting and evaluating proposals using a standard process, it is likely that the proposals will be evaluated fairly and the best processes will be selected for funding.

The proposers' forms have five sections:

- Candidate Technology System and Market
- Energy Efficiency and Economics
- Environmental Impacts
- Regulation and Operation
- Capabilities, Experience and Commitment

The reviewers forms is entitled Reviewers Summary and Recommendations. In its preliminary form, it will address the following topics:

- Technical and commercial challenges to DOE categories and relevant market sector
- Linkages with the Hydrogen Program and DOE
- Impact of success or failure and benefits of programmatic funding
- Appropriate types of near-term development
- Suggestions on the role of DOE and other participants
- Suggestions for additional analysis
- Assessment of technical and commercial risk

Using this assessment, the reviewers would then rate the proposals on an absolute basis using the criteria developed above. While the final list of criteria was not yet developed, the authors did state that the following criteria would be contained in any final version.

- Cost
- Quality
- Technical

Analytic Hierarchy Process

The final portion of the process is the AHP, a decision-making model, which was developed by Dr. Thomas Saaty. This process is a multi-level decision construct integrating management defined evaluation and selection criteria. It is implemented in two phases. In Phase I, Hydrogen Program Management develops a global strategic context for proposal evaluation and in Phase II, a more specific context for evaluation is developed. During Phase I, program management will compare component technologies and rank their relative importance for programmatic purposes. In Phase II, specific economic, technical, and environmental criteria will be developed for comparison. These criteria will be flexible to allow for refinement and sensitivity studies.

The authors conclude with an outline of eight activities needed in the H Scan/AHP Decision Process. The outline includes the sequence of steps required by proposers, program management, and reviewers to complete the process.

(22) Technical and Economic Assessment of Producing Hydrogen by Reforming Syngas from the Battelle Indirectly Heated Biomass Gasifier

Author(s): Mann, M.K.
Organization: NREL
Date: August 30, 1995
Category(ies): Production
Publication: NREL/TP-431-8143
Subcontract No.

This report is a detailed assessment of the production of hydrogen from biomass using the Battelle indirectly-heated gasifier. The process was evaluated at three feedstock rates: 27 T/day, 272 T/day, and 907 T/day. Additionally, three different processing schemes were evaluated.

- Scheme 1, the base case, used all reforming operations typically used in natural gas reforming (i.e., primary reformer, high temperature shift reactor, and low temperature shift reactor).
- Scheme 2 used just the primary reformer.
- Scheme 3 included the primary reformer and the high temperature shift reactor.

Detailed process models were developed for each process using ASPEN Plus. The following table presents information from the material balance of each process.

Material Balance Summary

Processing Scheme	Value
Scheme 1	
Stoichiometric Efficiency	39.3%
Energy Conversion Efficiency	79.0%
Hydrogen Production (scmd)	
27 T/d	21,600
272 T/d	215,940
907 T/d	719,800
Scheme 2	
Stoichiometric Efficiency	30.6%
Energy Conversion Efficiency	69.7%
Hydrogen Production (scmd)	
27 T/d	16,850
272 T/d	168,500
907 T/d	561,500
Scheme 3	
Stoichiometric Efficiency	37.2%
Energy Conversion Efficiency	76.5%
Hydrogen Production (scmd)	
27 T/d	20,440
272 T/d	204,390
907 T/d	681,280

For each of these schemes, the following economic assumptions were used.

Economic Assumptions

Cost Parameter	**Value**
Operating Costs	
Feedstock	416.50-46.30/T
Electricity	\$0.05/kWh
Water	\$330/m^3
Labor	Not reported
By-Product Credits	
Steam	
500 psig	\$7.88/1,000 kg
100 psig	\$5.18/1,000 kg
Economic Assumptions	
Dollar years	January 1995
Type of financing	Equity
On-line factor	90%
Construction period	2 years
Construction expenses	30% 1st year
Depreciation method	10 year straight-line; 1st and last year 50% of other years
Inflation rate	5%
Tax rate	37%
Plant life	20 years
Ramp up period	50% capacity for the 1st year
Method of analysis	Internal rate of return
Minimum IRR	15%
Royalties	0.5% of sales

The following tables summarize the results of the economic analysis.

Capital and Operating Costs for Gasification

Plant	**Operating Costs (MM\$/yr)**	**Capital Costs (MM\$)**
Scheme 1		
27 T/day	0.30	6.08
272 T/day	1.73	34.5
907 T/day	14.1	90.4
Scheme 2		
27 T/day	0.28	5.05
272 T/day	1.43	29.3
907 T/day	13.1	80.0

Plant	Operating Costs (MM$/yr)	Capital Costs (MM$)
Scheme 3		
27 T/day	0.31	6.02
272 T/day	4.39	34.0
907 T/day	14.1	89.1

Hydrogen Selling Price for 15% After-Tax IRR

Plant	Biomass Cost ($/T)	Hydrogen Selling Price ($/GJ)
Scheme 1		
27 T/day	16.50	23.20
272 T/day	16.50/46.30	13.10/16.20
907 T/day	46.30	13.70
Scheme 2		
27 T/day	16.50	25.10
272 T/day	16.50/46.30	14.20/18.20
907 T/day	46.30	15.70
Scheme 3		
27 T/day	16.50	24.30
272 T/day	16.50/46.30	13.70/17.00
907 T/day	46.30	14.20

This report provides detailed information on the cost of reforming syngas. It provides supporting information such as the cost for the PSA and other units. It also lists the cost factors used to convert equipment costs to the total capital investment. The factors used are listed below. All factors are in percentage of the purchased equipment cost.

Instrumentation	18%
Piping	66%
Electrical	11%
Buildings	18%
Yard Improvements	10%
Service facilities	70%
Land	6%
Engineering	74%
Contingencies	42%

(23) Independent Analysis and Verification of Key Hydrogen Energy Concepts, Annual Report FY 1995

Author(s): DiPietro, J.P., Badin, J.S.
Date: October, 1995
Organization(s): Directed Technologies, Inc.
Publication:
Category(ies): Transportation
Subcontract No.

Eight R&D projects in the Hydrogen Program were evaluated by the authors:

1. Home Electrolysis/Vehicle Refueling Application
2. Palm Desert Fuel Cell Golf Cart
3. HBr-Based Electrolysis and Energy Storage
4. Municipal Solid Waste Gasification
5. Switchgrass gasification and Fuel Cell Electricity Generation
6. California Geothermal/Electrolysis Hydrogen Production
7. Hawaii Geothermal Electricity/Hydrogen-Based Energy Storage
8. Alaska Wind Electricity/Hydrogen-Based Energy Storage

Summaries of the reviews are presented below.

Home Electrolysis/Vehicle Refueling Application
Originator: LLNL
Synopsis: Small-scale electrolyzer (2-k W) at a residence supplies fuel for a hybrid ICE/electric generator/flywheel engine.
Delivered H_2 Cost: 16.7 cents/kWh
Based on:
$3,000 electrolyzer
$525 AC/DC Conversion
$1,000 Hydrogen Storage
$0.03/kwh Electrolyzer
65% LHV Electrolyzer Efficiency
10% Discount Rate
Transportation Cost: 10.8 cents/mile

Parameter	Value
Advantages	Large investments in hydrogen transport infrastructure not required Small number of geographically dispersed end-users possible Lower vehicle range possible due to convenient refueling
Disadvantages	Mass-produced small-scale electrolyzers not available Range 100-150 miles per day High hydrogen cost
Technology Development Needs	Low-pressure H_2 storage for 100-150 miles at < $800 Low-cost small-scale electrolyzer (2 kW) for $3,000 Hydrogen ICE/turbine/flywheel engine $100/kW

Palm Desert Fuel Cell Golf Cart

Originator: The Schatz Energy Research Center, LLNL, The City of Palm Desert

Synopsis: Golf carts equipped with 4-kW PEM fuel cell used for personal transportation in Palm Desert, CA. Renewable hydrogen is produced via wind turbine/electrolysis system.

Delivered H_2 Cost: \$260/MM Btu

Transportation Cost: 21 cents/mile

Parameter	Value
Advantages	High-profile for renewable hydrogen Small-size fuel cell Low pressure PEM
Disadvantages	Expensive hydrogen \$88/MM Btu Stiff competition from battery golf carts Capital costs are 60% of delivered hydrogen cost
Technology Development Needs	Prove low-pressure PEM technology PEM fuel cell: \$400/kW Efficiency 0.5 kWh/mi Integration of turbine and electrolyzer

HBr-Based Electrolysis and Energy Storage

Originator: Solar Reactor Technologies

Synopsis: A reversible HBr cell is used for peak shaving and hydrogen production. Hydrogen is produced via electrolysis. HBr is produced via a solar reactor and the cell.

Peak Electricity Cost: 8.2 cents/kWh

Based on:
\$225,000 fuel cell
\$218,000 auxiliary investment
20-year life
46% fuel cell efficiency
\$0.02/kWh off-peak electricity cost
5% of capital for O&M
6% Discount Rate

Hydrogen Cost: \$10.9/MM Btu

Parameter	Value
Advantages	High utilization of capita equipment Proven technology High efficiency (76% AC/AC) storage Low electricity consumption
Disadvantages	Difficult competition with gas turbine and steam reforming Must identify facilities with a need for both peak shaving and H_2
Technology Development Needs	Solar-based hydrogen production processes must be demonstrated at \$470/kW reactor cost HBr cell cost of \$750/kW

Municipal Solid Waste Gasification

Originator: Texaco, LLNL
Synopsis: An MSW-slurry is gasified to produce hydrogen which is then shifted and purified
Hydrogen Cost: $8/MM Btu

Based on:
$40/ton tipping fee
77% yield on MSW

Parameter	Value
Advantages	Cost competitive with SMR Low-value feedstock Could aid in landfill exhaustion
Disadvantages	Economics depend strongly on sustained tipping fee Raw MSW must be classified
Technology Development Needs	Slurrying process must be demonstrated Integration of processes must be demonstrated Target slurrying cost: $175/kW Target gasifier cost: $540/kW

Switchgrass Gasification and Fuel Cell Electricity Generation

Originator: H-Power Inc., Electro-Farming Inc.
Synopsis: Fast-growing switchgrass is grown and gasified to produce hydrogen. The hydrogen is used in a fuel cell to meet farmers' needs; excess is sold to the grid.
Electricity Generation Cost: $0.062/kWh

Based on:
Switchgrass yield: 9 tons/acre
Farming cost: $120/acre/year
System Capital Cost: $1.9 million
Gasifier Efficiency: 81%
Fuel Cell Efficiency: 46%
Discount Rate: 10%

Parameter	Value
Advantages	Alternate source of income for farmers Novel integration of gasifier, iron bed and PEM fuel cell eliminates the need for purification, compression and storage
Disadvantages	Profitability of switchgrass is low Utility deregulation is limiting availability of avoided cost rates
Technology Development Needs	PEM Efficiency: 50% PEM Cost: $1,000/kW Gasifier Efficiency: 81% Gasifier Cost: $250/kW Integration of process

California Geothermal/Electrolysis Hydrogen Production

Originator: General Electric Corp., Stanford University

Synopsis: Large-scale geothermal electricity unit supplies electricity to a load center. Excess electricity is used in an electrolyzer to produce hydrogen which is used for FCVs

Electricity Generation and Transmission Cost: $0.081/kWh

Delivered Hydrogen Cost: $14/MM Btu

Parameter	Value
Advantages	Large-scale source of hydrogen Eliminates need for expensive, peaking units Waste heat from geothermal integrates well with HTS electrolysis
Disadvantages	Hydrogen cost is 75% higher than SMR Geothermal sites are far from population centers, requiring hydrogen transport
Technology Development Needs	HTS technology must be proven Target HTS cost: $440/kW Target electricity consumption: 39.4 kWh/kWh H_2 Target geothermal cost: $1,800/kW Target operating cost: $0.01/kWh to lower electricity cost to $0.07/kWh and hydrogen to $10/MMBtu

Hawaii Geothermal Electricity/Hydrogen-Based Energy Storage

Originator: Constellation Energy Enterprises, University of Hawaii

Synopsis: Hydrogen-based energy storage system (electrolyzer/storage/fuel cell) is used to meet electricity demand.

Peak Electricity Cost: $0.18/kWh

Based on:

Off-peak electricity purchase price of $0.02/kWh

Parameter	Value
Advantages	Hawaii is a good location for energy storage/peak shaving systems Existing geothermal unit can be expanded at low cost
Disadvantages	High electricity price Low (12 hour/day) utilization of electrolyzer
Technology Development Needs	High-temperature PEM fuel cell PEM Efficiency: 50% HHV PEM Cost: $1,000/kW Reversible cell could lower costs

Alaska Wind Electricity/Hydrogen-Based Energy Storage

Originator: A.D. Little, State of Alaska

Synopsis: Several small (50-kW) wind turbines are used to supply electricity to a remote Alaskan village. Hydrogen storage system (electrolysis/storage/ PAFC) used to match load.

Electricity Generation Cost: $0.50/kWh

Based on:

System Capital Cost: $2.5 million

Discount Rate: 10%

Parameter	Value
Advantages	Diesel generation is expensive in Alaska Many Alaskan villages have Class 2 or better wind resources
Disadvantages	Electricity cost is 25% higher than diesel generation Low (40%) utilization of electrolyzer
Technology Development Needs	PEM substitution may be better at $0.40/kWh Reversible cell could lower system costs

(24) Hydrogen as a Transportation Fuel: Costs and Benefits

Author(s):	Berry, G.
Date:	March 30, 1996
Organization(s):	LLNL
Publication:	UCRL-ID-123465
Category(ies):	Transportation
Subcontract No.	W-7405-Eng-48

This report estimates the costs, efficiencies and benefits of hydrogen use in hybrid electric vehicles (HEVs) and compares them to other alternative fuel vehicles such as ultra-low emissions gasoline internal combustion vehicles (ICEVs), advanced battery powered electric vehicles (BPEVs), and HEVs using gasoline or natural gas. The report used the following conservative economic and technical assumptions.

Technical and Economic Assumptions

Parameter	Value
Electricity (off-peak)	\$0.05/kWh (\$14/GJ)
Natural gas	\$4.00/GJ (stations)
	\$2.50/GJ (large central plants)
Methanol	\$0.66/gal (\$11/GJ)
Ammonia	\$250/ton (\$13/GJ)
Discount rate	20%
Off-peak electrolysis schedule	
Filling stations	128 h/wk (76%)
Home or commercial electrolysis	88 h/wk (52%)
Dollar-year	1996

The author estimates hydrogen production costs at \$9.30/GJ (equivalent to \$1.15/gallon of taxed gasoline). This cost is based on an SMR plant producing 100 million SCFD of hydrogen with a \$200 million investment, \$1.75/GJ in operating costs, and an efficiency of 68%.

Hydrogen delivery by truck was estimated at \$5.55/GJ for liquid hydrogen, \$3.50/GJ for cryogenic hydrogen gas and \$2.10/GJ for glass microspheres. The capital costs for mobile hydrogen storage was estimated at \$112/kg hydrogen for a liquid hydrogen system, \$480/kg for a cryogenic system, \$70/kg for a glass microsphere and \$580/kg for a magnesium-based hydride system. Overall, the total delivered price via truck for hydrogen is \$20-25/GJ for a distance of 250 miles. At short (30-50 miles) distances, a pipeline is cost effective at \$5.15/GJ (transmission costs only).

Costs of liquid hydrogen carriers were also estimated. The cost of hydrogen from methanol is estimated at \$25/GJ based on methanol costs of \$11/GJ. The cost of hydrogen from ammonia is estimated at \$33/GJ based on an ammonia cost of \$250/ton.

Decentralized hydrogen production for homes, filling stations and fleets was also estimated. The following table presents the delivered price of hydrogen for these cases.

Distributed System Hydrogen Delivery Prices

Hydrogen Source	Cost ($/GJ)
Filling stations 300 cars/day 60 cars/day 10 cars/day	 $30-50 $35-60 $60-75
Home electrolysis	$30-75

The author concluded that depending on the production and distribution method, hydrogen would cost $30-50/GJ or $0.045-$0.075/mile. Even at the very small scale, it will still only be $0.10/mile.

(25) Supporting Analysis and Assessments Quality Metrics: Utility Market Sector

Author(s): Ohi, J.
Date: October 31, 1996
Organization(s): NREL
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): End-Use, Analysis Methods
Subcontract No.

This report summarized the results of the preliminary Quality Metrics (QM) analysis for hydrogen use in the utility sector. QM is designed to aid in the decision-making process for potential R&D projects and to provide an analytic framework to estimate longer-term benefits of DOE/EERE programs.

The analysis evaluated the market share of total new installed capacity from 2000 to 2020.

Important assumptions in the analysis included:

- Grid-connected PAFC and PEM fuel cells
- No energy storage
- Initial market penetration by PAFCs followed by PEMFCs in 2005
- Low (<$3.50/MM Btu in 2020) natural gas prices
- Capital costs for PAFC ($850/kW) and PEMFC ($300/kW) by 2020

The basis for comparison was the levelized cost of electricity (LCE) which is based both on the capital and operating costs. Market share was projected based on the Renewable Energy Penetration (REP) model, developed by Princeton Economic Research, Inc.

Based on these assumptions, the analysis projected that the hydrogen fuel cells would capture 5% of the total new market additions (390 GW total) through 2020. The consumption of hydrogen for the utility sector was estimated to increase by almost 5000% from 2005 to 2020 to a value of 0.4 Quads. The vast majority of this new capacity would be captured by natural gas combined cycle gas turbine systems.

The author discussed some of the findings and shortcomings of the current analysis. One of the most important deficiencies were the capital cost estimates. These were difficult to project, especially the PEMFCs due to their early development stage. Production volume impacts were also difficult to assess.

The author also pointed out that the study only addressed grid-connected applications, but that on-site generation may be a more significant market. The impact of deregulation was another significant unknown in this analysis.

Included in the analysis was a section on the barriers to meeting goals. The most significant barrier found in the analysis was the low price of natural gas. The implications of this scenario should be addressed in future studies and raised the need for additional metrics such as environmental quality.

The author also stated that work was currently underway for a QM analysis for the light-duty vehicle market using the Vehicle Choice Model. In addition, the current QM analysis would be refined by evaluating:

- On-site generation
- Cost credits for
    - distributed generation
    - by-products
    - environmental benefits
- Other fuel cell technologies
- Other economic benefits (e.g., employment)

In conclusion, the author stated that the QM analysis was important both to DOEs funding decision process as well as to the Hydrogen Program. The author contended that the QM process had the following benefits to the Program:

- Basis for budget formulation and defense
- Market penetration information
- Coordination of analysis among DOE programs
- Identification of strategic issues for planning

(26) H Scan/AHP Advanced Technology Proposal Evaluation Process

Author(s): Mack, S. and Szoka de Valladares, M.
Date: October 31, 1996
Organization(s): Energetics, Inc./NREL
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Analysis Methods
Subcontract No.

This report summarized the H Scan and Analytic Hierarchy Process (AHP) processes. H Scan was developed by NREL and is used to improve the proposal submittal and evaluation process. AHP was developed by Energetics, Inc. and is a decision-support methodology. H Scan was developed to increase the amount and quality of information obtained from proposers and to streamline the proposal evaluation process while AHP was developed to provide a framework for proposal comparison. Both processes were customized for the Hydrogen Program around a specific set of weighted criteria, developed by Program management.

The H Scan/AHP process was implemented in eight steps:

1. Interview Program management to determine qualitative and quantitative criteria and sub-criteria for proposal evaluation.
2. Structure criteria into a decision hierarchy.
3. Develop a customized H Scan based on the decision criteria hierarchy and specific proposal
4. Distribute the H Scan to the proposal teams.
5. Submit completed H Scan forms to reviewers.
6. Submit AHP evaluation package to reviewers. Reviewers completed AHP.
7. Program management evaluates decision model and generates criteria weights.
8. Proposal rankings and criteria weighting was presented to Program management.

This implementation plan was conducted as a trial for two unsolicited proposals. While it was easily implemented, the proposal evaluation was lacking due to the significant difference in quality between the two trial proposals. The process was designed to discriminate among more evenly matched applications.

The following set of criteria and sub criteria were developed from this process for Hydrogen Program proposals.

- Technical
    - Insight, Approach, Safety
- Market
    - Size, Cost, Adaptability, Infrastructure
- Team
    - Capabilities, Experience, Commitment, Facility
- Success
    - Technical, Administration, Funding
- Finance and Administration
    - DOE cost, Team cost, Administration Management
- Externalities
    - Emissions, Public relations, Catalyst

The most insightful result of the analysis was the noticeable difference in criteria importance among the reviewers and Program manager. The following table summarizes the weights between the two reviewers and the manager. Since the data are read from a graph, the values are only approximate.

	Program Manager	**Reviewer 1**	**Reviewer 2**
Technical	0.35	0.19	0.18
Market	0.18	0.18	0.25
Team	0.15	0.19	0.18
Success	0.11	0.19	0.24
Administration and Finance	0.17	0.06	0.12
Externalities	0.04	0.19	0.03

As shown in the table, the biggest discrepancies were in the technical and externalities categories. Program management rated technical very high and externalities low. Reviewer 2 also rated externalities low, but Reviewer 1 indicated that they were important.

The authors concluded that the process needed to be refined both on logistical (e.g., document formatting) and content (e.g., alignment with Program objectives) grounds. In addition, input from other stakeholders such as HTAP would be solicited. The authors also acknowledged that further work must be done to reconcile the differences among reviewers and management on the weighting criteria so that the Program's objectives are well understood. Finally, the authors suggested that the application of the AHP process to other planning activities would be investigated.

(27) Systems Analysis - Independent Analysis and Verification

Author(s): DiPietro, J.P., Skolnik, E.G., and Badin, J.S.
Date: October 31, 1996
Organization(s): Energetics, Inc.
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Analysis Methods
Subcontract No.

Previously, this task has evaluated:

- Integrated electricity storage and H_2 production system with a solar-powered HBr reactor and reversible HBr cell
- Gasification of dedicated switchgrass with iron-bed purification and baseload electricity generation with a PEMFC.
- Small-scale (1-2 kW) residential electrolyzer for fuel production for hybrid H2 ICEV
- Small (50-kW) wind turbines and a hydrogen storage system are located at a remote Alaskan village are used to match the renewable to the load.

The current year's efforts were focused on the following systems and achieved the associated results. The range of analysis varied from preliminary (MSW-project) to detailed (HBr-project).

System	Results
Hydrogen production from MSW via slurry gasification	Base case H_2 cost: $8/MM Btu Economics determined by: low-value feedstock, tipping fee, and degree of biomass classification.
ZEV use in L.A. based on 100-MW geothermal electricity generator with excess fueling an electrolyzer	Geothermal is a good match for HTS electrolysis due to waste heat, but sites are far from population centers and thus transportation costs are high. Project scale is high compared to ZEV forecasts.
Hawaiian energy storage system (electrolyzer/H_2 storage/fuel cell) for off-peak electricity storage and peak release	The island has high fuel costs, a surplus of baseload capacity and on-site generation can improve reliability. These benefits are reduced, however, by the low avoided cost of peak electricity (i.e., $0.06/kWh). Thus, the concept has limited viability.
Wind turbine/electrolysis system for fueling PEMFC-powered golf carts in Palm Desert, CA	Advantages of this application are the low-pressure of the PEMFC and the ease of building the vehicles, but a battery-powered system would likely be competitive.
Integrated electricity storage and hydrogen production using solar-powered HBr reactor and reversible HBr cell	Significant technical breakthroughs are required before it is commercially viable. A large solar field (i.e., 6-acres/100,000 scfd H_2) is required and the process has low conversions (9 mol%) that increase the size and cost of downstream processing equipment.

The authors also summarized several smaller studies:

- Revision of Hydrogen Technology Cost and Performance Database
- Development of Hydrogen Program Utility Sector Quality Metrics Analysis
- Study of licensing as a means of forming partnerships to develop and commercialize technology
- Developed a draft framework for incorporating environmental impacts into pathway selection and ranking process based on an environmental performance index (EPI).
- Initiated a survey of utility representatives to construct scenarios for utility sector participation in the development of hydrogen energy system studies.

In the future, the authors will finalize the Hydrogen Technology Cost and Performance Database, publish the report, "Utility Restructuring Research and Environmental Externalities" and will perform additional analyses, as needed.

(28) System Comparison of Hydrogen with Other Alternative Fuels in Terms of EPAct Requirements

Author(s): Barbir, Ozay, K. Verziroglu, T.
Date: October 31, 1996
Organization(s): University of Miami
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Transportation
Subcontract No.

This study evaluated the feasibility of five EPACT-defined alternative fuels (natural gas, methanol, ethanol, hydrogen and electricity) to displace 10% of gasoline by 2000. Both vehicle technologies and fuel production, storage and distribution were evaluated.

The study had three overall objectives:

- Determine the technical and economic feasibility of each fuel to meet EPACT goals
- Determine the economic and environmental impacts of fuel replacement
- Highlight hydrogen's potential compared with other fuels

The authors began with a comparison of past and projected gasoline consumption, new vehicle efficiency and vehicle miles. The current consumption of vehicle fuels in the U.S. was then presented. The alternative fuels in the study comprise significantly less than 1% of the vehicle fuel market; the largest use is with LPG at only 0.23%.

In the vehicle efficiency analysis, the authors evaluated internal combustion engine vehicles (ICEVs) with each of the fuels, fuel cell vehicles with some of the fuels, including on-board reforming and battery vehicles.

All of the vehicles had the following performance requirements:

- Mass: 800 kg
- Payload: 136 kg
- Engine Power: 100 hp (75 kW)
- Range: 300 miles (483 kW) except battery vehicles (100 miles).

The mass of the engine, specific energy of the fuel tank and the engine efficiency in the FUDS cycle were calculated based on literature values for each of the fuels and vehicle technologies. The fuel economy was then determined and is shown in the table below. ICEV and FCVs have ranges of 300 miles; electric vehicles were assumed to have a range of 100 miles. For comparison, the FCV was also evaluated with a 100 mile range.

Vehicle Type/Range	Efficiency KWh*/km	Efficiency Mpg**
ICEV		
Gasoline	0.734	28.6
CNG	0.661	31.8
LPG	0.650	32.3
Methanol	0.578	36.3
Ethanol	0.567	37.0
GH_2	0.707	29.7
LH_2	0.624	33.6
FCEVs		
GH2	0.306-0.327	68.6-64.2
LH2	0.301-0.311	69.8-67.5
CNG	0.464-0.478	45.3-43.9
Methanol	0.470-0.483	44.7-43.5
Battery-Vehicles		
Na/S	0.256	82.0
Pb-Acid	0.516	40.7
Li-Ion	0.230	91.3
Li-AIS or Li-FeS	0.276	76.1
Ni/Fe	0.533	39.4
Ni/MeH	0.250	84.0
Zn/Bromine	0.281	74.7

*Based on lower heating value of fuel (1 kWh = 3,412 Btu) and for battery vehicles, charging is included.
** Gasoline equivalent

The vehicle efficiency analysis was expanded to include upstream production, processing and delivery. Several pathways are available for each fuel type and each pathway has its own benefits and costs. The authors evaluated several pathways, calculating the primary energy requirement and "high quality inputs". The high quality inputs are other energy inputs needed for production, processing and/or delivery. The following table summarizes the results of this analysis.

Fuel/Vehicle Type	Primary Energy 10^9 kWh/yr	Primary Energy Type	High Quality Feedback 10^9 kWh/y	High Quality Feedback Type
CNG				
ICEV	271.0	Natural gas	54.5	Elec./Nat. gas
FCV	196.0	Natural gas	39.4	Elec./Nat. gas
LPG				
ICEV	266.5	Nat gas/oil	30.9	LPG/Nat. gas
FCV	Not reported		NA	
Methanol				
Natural Gas				
ICEV	381.0	Natural gas	34.7	Elec./Fuel
FCV	318.0	Natural gas	30.0	El./Fuel

Fuel/Vehicle Type	**Primary Energy 10^9 kWh/yr**	**Primary Energy Type**	**High Quality Feedback 10^9 kWh/y**	**High Quality Feedback Type**
Biomass				
ICEV	11200.0	Solar	56.0	Fuel/El.
FCV	9360.0	Solar	46.8	Fuel/El
Ethanol from Corn				
ICEV	12900.0	Solar	65.0	Fuel/El.
FCV	Not reported	NA	NA	
GH2				
Natural gas				
ICEV	402.6	Natural gas	87.4	Nat. gas/Elec.
FCV	186.2	Natural gas	40.4	Nat. gas/Elec.
Biomass				
ICEV	12000.0	Solar	82.0	Fuel/Elec.
FCV	5550.0	Solar	37.9	Fuel/Elec.
Electricity				
ICEV	828.3	Mix	63.2	Electricity
FCV	383.1	Mix	29.2	Electricity
Solar				
ICEV	2636.0	Solar	63.2	Electricity
FCV	1220.0	Solar	29.2	Electricity
Wind				
ICEV	1530.0	Wind	63.2	Electricity
FCV	708.0	Wind	29.2	Electricity
LH2				
Natural gas				
ICEV	355.4	Natural gas	104.0	Nat. gas/Elec.
FCV	177.1	Natural gas	51.8	Nat. gas/Elec.
Biomass				
ICEV	10600.0	Solar	99.2	Fuel/Elec.
FCV	5280.0	Solar	49.4	Fuel/Elec.
Electricity				
ICEV	731.0	Mix	82.6	Electricity
FCV	364.0	Mix	41.2	Electricity
Solar				
ICEV	2326.0	Solar	82.6	Electricity
FCV	1160.0	Solar	41.2	Electricity
Wind				
ICEV	1347.0	Wind	82.6	Electricity
FCV	671.0	Wind	41.2	Electricity

(29) Integrated Analysis of Transportation Demand Pathway Options for Hydrogen Production, Storage, and Distribution

Author(s): Thomas, C.E.
Date: October 31, 1996
Organization(s): Directed Technologies, Inc.
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Transportation
Subcontract No.

A preliminary computer model to evaluate potential Hydrogen Program pathways was developed. This model was based on the assumption that government and industry must work together to bring hydrogen technologies into the marketplace. The payback for industry was evaluated using a return on investment while that for the government was estimated using a cost/benefit analysis. This initial model focused on the hydrogen transportation sector, specifically a hydrogen fuel cell vehicle, but it could be applied to other market segments in the future. This initial analysis was based on preliminary data and was mainly intended to show the facility of the model.

The model was based on past hydrogen analyses; a literature search was conducted to obtain information on fuel cell vehicle (FCV) technology, hydrogen infrastructure, FCV market penetration studies, and environmental impacts of FCVs.

The programmatic pathway model is based on four components: vehicle technology, fuel, market scenarios and governmental actions. As noted earlier, the vehicle technology in this analysis was a direct hydrogen fuel cell. Governmental actions, in this preliminary study, were limited to R&D and demonstrations; no impacts from education or regulatory relief were included.

Inputs to the model are market penetration scenario(s) and governmental actions. The inputs are converted into the following inter-dependent industry and government time functions to 2030.

- Cumulative number of FCVs sold
- FCV price
- FCV industry investment
- Industry profit
- Required hydrogen production
- Hydrogen cost
- Hydrogen investment
- Hydrogen industry profits
- Government investment
- Societal benefits

The model assumed that initially, FCVs would be expensive, but that the price would decrease due to a "manufacturing learning curve". The learning curves were projected, where possible, on fully mature component costs from automobile mass production. A similar approach was taken for hydrogen hardware. As noted earlier, the model has three outputs: return on investment for the automobile and gas supply industries and the cost/benefit ratio for the government.

The initial model included three potential markets: bus demonstrations, centrally-fueled fleets of light-duty vehicles, and zero emission vehicles (ZEVs). All demonstrations were assumed to have 50/50 cost sharing between industry and government. The model assumed that 110 buses would be sold for demonstrations. Due to the early development of FCVs, it was assumed that they would not be ready to enter the centrally-fueled fleet market as required by the Energy Policy Act (EPACT) of 1992. In the ZEV market, the model assumed that FCVs would capture 50% of the ZEV market (up to 1 million vehicles per year by 2010) if its cost were equal to its competition (i.e., electric vehicles). FCVs were assumed to have better performance than the EV (i.e., equal to the ICE). This conservative assumption should compensate for the public's perception of the safety of FCVs.

Market share for the FCV depends both on the price of the vehicle and the price of hydrogen. The impact of vehicle price on market share was determined based on a non-linear relationship. The impact of fuel cost is a multiplicative function. When the hydrogen price is less than or equal to gasoline price, the factor is 1. At higher prices, the factor decreases. In general, it was assumed that the average vehicle owner would have a high discount rate for the fuel cost compared to the initial price of the vehicle. The price of hydrogen was presented as a function of the size of the production facility. Using a 10% after-tax real rate of return, the cost of hydrogen required to compete with fully taxed gasoline per mile driven, assuming that the FCV is 2.67 times more efficient than the gasoline ICEV.

Based on this analysis, hydrogen is competitive with gasoline only from very large SMR systems supporting 50,000 FCVs. For the small scale-systems, electrolysis would be competitive after manufacturing 100,000 systems, but SMR systems would be competitive at 1,000 units. For ultra-small systems (i.e., servicing 50-100 FCVs). For these systems, the price of hydrogen starts out extremely high at >$25/gallon, but by 2009, the cost is comparable to gasoline.

The authors concluded with a listing of success parameters and plans for future work. The programmatic pathway model would be considered successful when it is used as a standard methodology by DOE and industry and increases hydrogen support. In the future, the authors planned to increase the types of FCV fuels, evaluate societal benefits and other alternative fuel vehicles, increase the type of government input, and extend the methodology to other hydrogen markets.

(30) Comparative Costs and Benefits of Hydrogen Vehicles

Author(s): Berry, G.
Date: October 31, 1996
Organization(s): LLNL
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Transportation
Subcontract No

Costs and benefits of hydrogen as a vehicle fuel were compared to gasoline, natural gas and battery-powered vehicles. Included in the analysis were the costs, energy, efficiency, and full fuel-cycle emissions from a variety of production, transmission, and refueling pathways for hydrogen systems. These estimates were then compared to those for competing fuels and then used to determine oil use, air pollutant and greenhouse gas emission scenarios for the U.S. passenger car fleet from 2005 to 2050.

Seven alternative hydrogen pathways were evaluated:

1. LH2 delivery by truck from a central steam-reforming plant
2. On-site steam reforming of natural gas
3. On-site methanol reforming
4. On-site ammonia cracking
5. Conventional alkaline electrolysis
6. Polymer membrane electrolysis
7. Steam electrolysis

Since the cost of hydrogen is a strong function of scale, the author evaluated four different refueling scenarios:

1. Filling station scale: 900 kg H_2/day (300 cars/day)
2. Small station: 180 kg H_2/day (60 cars/day)
3. Fleet: 30 kg H_2/day (10 cars/day)
4. Home refueling: 0.4 kg H_2/12 hr refueling (1 car with 3 kg every 8 days)

The analysis used conservative assumptions throughout. The following is a listing of some of the economic assumptions used:

- Electricity: $0.05/kWh
- Natural gas: $4.00/GJ (stations); $2.50/GJ (large, central plants)
- Methanol: $0.66/gallon
- Discount rate: 20%
- Off-peak electrolysis:
    - Filling stations 128 h/wk (76%)
    - Home 88 h/wk (52%)
- 1996$
- No by-product credits, taxes or other adjustments

To construct the scenarios and conduct the sensitivity analyses, the data were assembled in a relational database using a commercially available software, STELLA II.

Costs were taken from industrial and literature sources. They were scaled and adjusted for inflation using standard methods. Projections for mass production were used for solid polymer electrolysis, steam electrolysis and home alkaline electrolysis. Storage costs were based on compressed gas storage.

Based on these assumptions, the author projected the following delivered hydrogen costs. (All values are approximate as the were presented graphically.)

Facility Size/Pathway	**Hydrogen Cost ($/kg)**
Individual Car (30 mi/day)	
Polymer Electrolysis	7.00
Alkaline Electrolysis	8.00
Fleet (10 cars/day)	
Polymer Electrolysis	8.50
Alkaline Electrolysis	8.75
Liquid Hydrogen (Truck)	7.50
Small Station (60 cars/day)	
Steam Electrolysis	5.90
Polymer Electrolysis	6.50
Alkaline Electrolysis	7.25
Ammonia Reforming	7.30
Methanol Reforming	6.00
Liquid Hydrogen (Truck)	4.30
Full Station (300 cars/day)	
Steam Electrolysis	4.50
Polymer Electrolysis	5.50
Alkaline Electrolysis	5.90
Ammonia Reforming	5.75
Methanol Reforming	4.75
Steam Reforming	4.25
Liquid Hydrogen (Truck)	3.75

In terms of emissions, the author contended that the electricity-generation mix has a strong impact on the full fuel cycle emissions of hydrogen vehicles. To evaluate this effect, the author modeled three different electricity-generation mixes: reference, market and climate. The reference scenario is a clean-coal based (75%) in 2035. Market scenario is based on using efficient, advanced technologies, pollution control and renewable energy where economically competitive with 40% of electricity coming from non-fossil sources in 2035. The climate scenario has only 5% of electricity coming from coal. Using full fuel cycle emission factors from the literature for each scenario, estimated of emissions from hydrogen cars from 2005 to 2050 were determined. These were then compared to the base case where the U.S. passenger fleet meets ULEV emissions standards and an average fuel efficiency of 30 mpg. Other important assumptions included the growth of the U.S. passenger fleet from 169 million vehicles in 2005 to 200 million in 2050 and a 30% growth in vehicle miles traveled over the same period. The value of emissions reductions was obtained from the literature.

Using the best case (i.e., climate scenario), the author projected an annual benefit for hydrogen vehicles at over $400/car. Furthermore, the analysis showed that only a small fraction (5-15%) of the benefits are uniquely achievable by hydrogen vehicles. That is, other alternative vehicles could achieve the same if not better results. Thus, to justify hydrogen vehicles, more compelling arguments besides environmental benefits and oil-import reductions must be developed.

Overall conclusions from the report included:

- High-efficiency (80 mpg) vehicles are critical for competitiveness of hydrogen vehicles. HEVs can be competitive without the need for FCVs
- Hydrogen fuel costs with conservative assumptions range from $30-75/GJ ($0.045-0.11/mile), depending on scale
- Greatest potential for cost savings is likely in storage
- Although hydrogen vehicles have lower tailpipe emissions than ULEVs, the full fuel cycle emissions are not as favorable due to the current energy mix
- Other, possibly intangible, factors should be explored regarding the benefits of hydrogen vehicles. Included in this category are ease of transition from gasoline, safety, economic efficiency enhancement through the marriage of utility and transportation sectors and the introduction of renewables into the electricity mix.

(31) Hydrogen Energy Systems Studies

Author(s):	Ogden, J., Kreutz, T. Steinbugler, M., Cox, A. and White, J.
Date:	October 31, 1996
Organization(s):	Center for Energy and Environmental Studies, Princeton University
Publication:	Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies):	Transportation, Production
Subcontract No	

Two major activities were conducted during this year of the subcontract: 1) assessment of small-scale technologies for hydrogen production from natural gas and 2) case study of hydrogen refueling infrastructure development in Southern California.

In the first activity, three technologies for stationary hydrogen production from natural gas were evaluated: steam reforming, partial oxidation and autothermal reforming. Each of these systems was evaluated at a size of 0.1-2.0 million scfd since that was expected to be a typical refueling station size. In the analysis, the following issues were addressed.

- Performance and cost of small-scale reformers currently available and how does this compare to partial oxidation and autothermal systems.
- Scale dependence of reformer technologies.
- Identification of critical technologies that drive the cost and performance of small-scale systems.
- Prospects for potential cost and performance improvements in critical technologies
- Impact of reformer capital cost reductions on the delivered cost of hydrogen transportation fuel.

Cost and performance data for both commercially-available and near-term small-scale reformer technologies were compiled. All three types of reforming technologies were included. Included in the summary were size, temperature, pressure, efficiency, hydrogen purification, efficiency, dynamic response, physical size and cost. Sizes for steam reformers ranged from 6,000 to 3.3 million scfd with costs of about \$500/kW and efficiencies of 80-84%. Two different partial oxidation systems were summarized with capacities of 12,500 to 96,000 scfd and efficiencies of 75-80%. The cost of the larger system was estimated at <\$200,000. The autothermal option were still under development at sizes from 1.25 to 20 kW. No costs were provided.

Computer modeling of small-scale reforming was completed. Specific items modeled were: 1) equilibrium and kinetics of reformer reactions, 2) conversion of methane in a single reformer tube and 3) conventional SMR plants.

Several reformer manufacturers and developers, fuel cell developers, partial oxidation system developers and industrial gas companies were contacted for information on cost and design issues for small-scale reformers.

The authors then discussed the technical design and issues for each of the three technologies. Costs for each of the options at the small-scale were then presented.

From this analysis, the authors concluded that there appears to be opportunities to reduce the capital costs of small-scale reformers. The potential cost reductions are due to the use of fuel cell SMRs that are based on convective heat transfer instead of radiative as is done in conventional systems. Other potential savings were operation at lower pressures and elimination of downstream purification systems.

In the second analysis, the near-term options for delivering gaseous hydrogen fuel in Southern California were evaluated. Included in the analysis were:

- Large, centralized SMR facility
- Truck-delivered LH2
- Gas pipeline delivery
- Small-scale on-site SMR
- On-site, small-scale electrolysis
- Low-cost chemical industry sources (e.g., excess capacity in refineries)

In evaluating these options, the following items were addressed:

- Projected hydrogen demands for ZEVs in the L.A. basin
- Current and potential hydrogen supplies to L.A. basin
- Refueling system capital cost and delivered cost of hydrogen
- Lifecycle cost of hydrogen transportation systems
- Potential hydrogen infrastructure development for L.A. basin
- Synergisms between near-term options and longer term renewable-based options

The analysis projected that the number of ZEVs required in the L.A. basin would be over 700,000 by 2010 based on the revised mandate. The authors assumed that FCVs would comprise 50% of the ZEV market and that 10% of buses would be based on fuel cells. Using standard efficiency assumptions, the authors then projected the amount of hydrogen required at 55 million scfd to fuel 350,000 cars and 300 buses in 2010.

The analysis showed a significant quantity of hydrogen (5-15 million scfd) already available from excess capacity at two existing hydrogen plants and several oil refineries. This quantity of hydrogen would be enough to power 30,000-100,000 cars or 700-2000 buses. The authors also looked at several other potential near term sources of hydrogen including expansion of industrial gas supplies, on-site reforming, on-site electrolysis and landfill gas. These potential sources could provide significant quantities of hydrogen to the ZEV market. By using only 2% of the existing natural gas supply, 1 million FCVs could be fueled; using all the available off-peak power, another 3-5 million FCVs could be fueled and roughly 0.5 million scfd is available from a single landfill which could power 40 buses.

The authors then projected the cost of delivered hydrogen from a variety of production and transport routes. The following table summarizes the results.

Technology Option/ Facility Size (million scfd)	Delivered Hydrogen Cost ($/GJ)
SMR w/ LH2 Truck Delivery	
0.1	30
0.37	21
1.0	19
2.0	18
SMR w/ Pipeline H_2	
0.1	27
0.37	17
1.0	16
2.0	15
On-site Reforming	
0.1	45
0.37	23
1.0	16
2.0	14
On-site Electrolysis	
0.1	34
0.37	27
1.0	26
2.0	25

Lifecycle costs for the PEMFC and diesel buses were developed and compared. While the PEMFC bus costs more initially, it has a lower lifecycle cost due to greater efficiency. The lifecycle cost of the PEMFC bus was $0.75/km and that for the diesel bus was $0.85/km.

The authors then looked at potential scenarios in the development of a hydrogen refueling infrastructure in the L.A. basin. They expected that PEMFC buses would be the first introduced due to the status of the Ballard demonstrations and commercialization, centralized refueling, economies of scale due to large refueling stations and lower cost goals in bus markets. Los Angeles ahs about 3000 diesel buses. Assuming that 10% would be replaced as ZEVs and 10% of these would be PEMFCs then the authors projected that 30 fuel cells per year would be required. Existing sources would be sufficient to supply this demand for about 10 years, but on-site reforming could become an option.

For the automobile market, the authors contended that mass-produced PEMFC vehicles would likely be available between 2004 and 2010. They expected that liquid hydrogen truck delivery or onsite production from natural gas would likely provide the lowest delivered hydrogen price until 2010. Centralized production with pipeline distribution would not be feasible until much higher hydrogen demand due to the high cost of pipeline distribution. On-site electrolysis does not appear attractive in the near term due to the high cost ($0.03/kWh) cost of off-peak electricity.

It was projected that natural gas could supply the hydrogen transportation market for several decades with renewables supplementing the supply later.

The authors concluded with a brief summary of other work to begin that year as well as suggestions for future work. In the current year, the authors will evaluate potential hydrogen market scenarios over the next five years and a comparison of hydrogen as a fuel for FCVs with other fuels. Potential future work could include expanding the hydrogen fuel comparison study to include lifecycle costs, other primary energy sources for hydrogen and environmental impacts. Also, an assessment for the production of hydrogen from MSW in New York City was planned.

(32) Coupling Renewables via Hydrogen into Utilities: Temporal and Spatial Issues, and Technology Opportunities

Author(s): Iannucci, J., Horgan, S., Eyer, J., Schoenung, S.
Date: October 31, 1996
Organization(s): Distributed Utility Associates/ Longitude 122 West, Inc.
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Production, Storage
Subcontract No

This subcontract was charged with evaluating hydrogen as an energy storage medium that couples time-dependent renewable energy with time-dependent utility loads. The effort was in an early stage and no results were presented. The report, however, did describe the proposed methodology, which is summarized below.

Four different renewable technologies (wind, PV, solar thermal, and hydroelectric) were to be evaluated. The three intermittent technologies would be simulated on an hourly basis throughout the year in various regions of the U.S. Their electricity production patterns would then be compared to typical regional electric load demands. The analysis would be set for 2010.

The analysis would determine hydrogen demand and storage required for each region based on the time-dependent model. In addition, the analysis would also investigate the sensitivity of the results to fraction of peak load to be served and the land area for the renewables. Sensitivity studies would also be performed on the efficiencies of hydrogen production, conversion and storage.

As noted earlier, the analysis is of a regional nature. The U.S. was divided into the NERC regions. The availability of each renewable in each area was evaluated and only those areas with an appreciable source of the renewable were evaluated. A preliminary grid of evaluation options was developed and is presented below.

PV	Wind	Solar Thermal
SERC	SPP	WSCC South
ECAR/MAIN	MAPP	ERCOT
NPCC/MAAC	WSCC South	
WSCC South	ERCOT	
ERCOT	WSCC North	

The hydroelectric case would be handled differently. No hydrogen storage would be considered since these systems have their own inherent storage. These systems would be evaluated on a national instead of a regional basis.

(33) Modeling of Hydrogen Production Methods: Single Particle Model and Kinetics Assessment

Author(s):	Miller, R., Bellan, J.
Date:	October 31, 1996
Organization(s):	Jet Propulsion Laboratory, California Institute of Technology
Publication:	Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies):	Production
Subcontract No	

This effort concerned modeling biomass pyrolysis reactors, specifically on the formation of tar as a precursor to hydrogen. The overall goal of the effort was to determine the drivers of biomass fast-pyrolysis in the low-temperature regime.

In the first year of a multi-year contract, a detailed mathematical model was developed for the temporal and spatial conditions of solid-fluid reactions in biomass particles. The methodology was applied to the pyrolysis of spherically symmetric biomass particles based on literature for cellulose and wood. A parametric study was then completed to determine the effects of temperature, heat rate, initial porosity, particle size and temperature on char yields and conversion times.

Based on the modeling, the authors concluded that although high temperatures and rapid heat rates minimize the production of char, practical limits exist due to endothermic reactions, heat capacity and thermal diffusion. The model identified three pyrolysis regimes: initial heating, primary reaction, and final heating. In general, the regimes are independent of temperature with the primary reaction regime comprising 60% of the total conversion time and each other regime comprising 20%.

When comparing with available data, the model showed that cellulose kinetics were fairly reliable, but that those for wood required improvement. The wood kinetics were especially unreliable at higher reactor temperatures where they overestimate the char yields and are contrary to experimental results. No further modeling would be undertaken for wood until the kinetics schemes were improved.

The results also showed that if the exterior particle thermal boundary layer was neglected, both the pyrolysis rate and experimentally attainable tar yields could be significantly over predicted. While variations in the initial porosity or particle temperature affected the conversion time, but only mildly impacted the total char yields. This effect was attributed to a parallel thermal conduction model used for the multi-phase heat transfer within the particle, but this assumption requires validation.

In addition to this model, a second model of a vortex reactor with tangentially-injected biomass particles was developed and was being coded. The model has several nested and interacting models that were each based on the initial particle model. The component models included: cluster model, turbulent boundary layer model and wall contact heating.

The authors proposed the following future work:

- Establishment of a kinetic scheme for wood pyrolysis
- Expanding the model to include turbulent diffusion, wall effects, and free stream convection

(34) Technoeconomic Analysis of Renewable Hydrogen Production, Storage, and Detection Systems

Author(s): Mann, M.K., Spath, P. Kadam, K.
Organization: NREL
Date: October 31, 1996
Category(ies): Production, Storage, Detection
Publication: Proceedings of the 1996 US DOE hydrogen program review. Volume 1, National Renewable Energy Laboratory, NREL/CP-430-21968-Vol 1.
Subcontract No.

This paper presents the results of analyses on five different hydrogen production, storage and detection systems. The level of analysis for each system was adjusted depending on the amount of information available and the degree of development of the technology. Systems analyzed in the study were biomass pyrolysis, photoelectrochemical direct conversion system, photobiological hydrogen production using reversibly immobilized bacteria to effect water-gas shift, carbon nanotubes, and fiber-optic chemochromic hydrogen detection system. The results of each analysis are summarized below.

Biomass Pyrolysis

A detailed analysis of hydrogen production via biomass pyrolysis was conducted. The biomass is pyrolyzed in a fluid-bed reactor with the resulting oil being extracted to recover a phenol-like co-product. The remaining bio-oil is then steam reformed to produce hydrogen that is purified with pressure swing adsorption (PSA). In addition to the phenolics, the process produces steam as a co-product. The bio-oil is assumed to be produced at distributed pyrolysis sites and collected for reforming at a central site. This design is expected to result in the lowest overall cost.

The reforming facility was designed to process 930 dry tonnes per day of biomass and produce 35.5 tonnes per day (~400,000 Nm^3/day) of hydrogen. The yield of bio-oil from the biomass was estimated at 66.75 wt%, with an overall co-product recovery of 31.2 wt%. Using a discounted cash flow rate of return analysis and an after tax (37%) internal rate of return of 15%, this process is projected to produce hydrogen at $7.70/GJ.

A parametric study on this base case was then performed examining the effects of:

1. Making vs. buying bio-oil
2. Capital costs (+30%/-10%)
3. Plant size (7-59 Tpd)
4. Co-product selling price ($0.30-0.50/kg)
5. Biomass feedstock cost ($11-55/T)
6. Internal rate of return (0-25%)

In all cases, the projected price of hydrogen was within the current range of hydrogen selling prices ($5-14/GJ). The contribution of the co-product to the economic viability was significant and the authors suggested that research into this and other co-products should continue. In addition, the authors contend that scale-up is required for further analysis.

Photoelectrochemical-Based Direct Conversion System

A boundary analysis was conducted for a photoelectrochemical-based direct conversion system. In this system, an electrocatalyst and semiconductor are combined on a single device, obviating the need for expensive PV/electrolysis systems. Two different configurations were studied: single gap and multi-junction systems. While the theoretical efficiencies of the systems are 24-32% for the single bandgap and dual junction systems, respectively, the practical efficiencies were projected much lower at 10-20%.

Both current and future technologies were evaluated. Tandem cells were based on Gallium-Indium-Phosphide (GaInP2)/Gallim-arsenide (GaAs) systems. For future technology, the cells were assumed to decrease in price by 50%. Thin-film technology was represented by amorphous silicon/amorphous silicon carbide systems (Si/SiC). Examples of high efficiency thin-film cells are CdTe and CuInSe. Costs for the semiconductors were based on current and future costs of solar cells.

In the first pass analysis, the cost of the cell alone was compared to the value of the hydrogen, without any other capital or operating costs. Next, all other projected costs (i.e., additional capital and operating) are added in and the required efficiency to achieve a selling price of $14/GJ is determined. In both analyses, the tandem cells were shown to be prohibitively expensive with no chance of meeting current hydrogen selling prices, even with significant reductions in capital charges. In fact, considering the cell cost alone, the tandem cells would need to have an efficiency of > 150% to meet the $14/GJ target. The thin-film cells, however, appeared to be very promising. When looking at both current and future cells and including all known capital costs, economical hydrogen production appears feasible. The authors point out that this projection is highly dependent upon the capital cost of the cells and given the high degree of uncertainty in these costs, better cost information is required.

Photobiological Hydrogen Production

A detailed technoeconomic study was performed of a biomass gasification/immobilized bacteria system. The biomass gasifier is similar to the Battelle system detailed above, but instead of using conventional technology to shift the product gas, photosynthetic bacteria are used. The water-shift reactor was based on a trickle filter design to ensure high mass transfer rates.

The product gas is about 95% hydrogen. It is further purified in a conventional PSA system.

Using the same economic parameters as in the biomass pyrolysis analysis, the hydrogen selling price was projected to be $17/GJ. From this base case, a series of parametric studies were conducted to evaluate:

1. PSA system
2. Capital costs (+30%/-30%)
3. Productivity (+1000%/-50%)
4. Biomass cost (+20%/-53%)
5. Production capacity (+67%/-80%)
6. IRR (0-20%)

From these studies, the specific reaction rate and biomass cost were shown to have the greatest impact on the price of hydrogen. At the high end of the productivity range, hydrogen can be produced within current range (i.e., $12/GJ). Also, at a biomass cost of $22/T, the hydrogen would be competitive ($13/GJ). Both scenarios are considered plausible by the authors. Finally, the authors project that the use of a PSA system, hydrogen production capacity and IRR are significant factors in the economics. All of these scenarios, however, have technical and/or economic problems. The authors suggest that future work on different reactors be conducted.

Carbon Nanotubes
A preliminary literature search was conducted for competing hydrogen storage systems to provide the economic level of performance required for carbon nanotubes. As shown in the table below, significant variation exists in the literature regarding hydrogen storage costs. The authors attributed the variation to differences in analysis standards and economic bases (e.g., dollar-years).

Storage System	Container Cost ($/GJ)
Gaseous Hydrogen	$2,300-8,500
Liquid Hydrogen	$1,000-3,000
Metal Hydride	$640-13,000
Cryoadsorption	$2,000-4,000
H-Power iron oxidation/reduction	$130-500
Thermocooled pressure vessel	$4,000+

Since carbon nanotubes will likely be used for onboard storage, auxiliaries for onboard storage systems were determined. No costs or other specifications were provided for the listing.

The analysis provided a broad overview of some of the issues for onboard hydrogen storage and lays the foundation for future comparative studies.

Fiber-Optic Chemochromic Hydrogen Detection System
In this analysis, the cost of mass-producing hydrogen detection systems for vehicles was developed. The design of the system is based on a reversible, thin-film, chemochromic sensor that does not require any electrical wiring. A prototype was currently developed and all costs were based on that prototype.

Costs were developed for a matrix of sensors per vehicle versus manufacturing capacity (vehicles/yr). In addition, the effect of the microprocessor type (slow vs. fast response) was also evaluated. All costs are manufacturing costs only - no profits were included. The following table summarizes the results.

Sensors per vehicle/ Microprocessor Response Time	Low Manufacturing Capacity (5,000 vehicles/yr)	High Manufacturing Capacity (3 million vehicles/yr)
6		
Slow response	$17.84	$11.77
Fast response	$19.34	$13.02
20		
Slow response	$9.11	$5.86
Fast response	$9.61	$6.21

In addition to these costs, the breakdown of the system component costs was also provided. The halogen light source with its associated support parts dominated the capital costs, ranging from 27-49% of the overall system cost. Polishing costs was another significant cost ($0.11-2.34/sensor) in a labor-intensive process. Less than 5% of the coating costs were due to non-labor related costs. As shown in the table, the overall cost of the hydrogen detection system is estimated at $5.86 (high manufacturing, slow response, 20 sensors/vehicle) to $19.34 (low manufacturing, fast response, 6 sensors/vehicle). This technology was deemed very promising as other currently available hydrogen sensors range from $27 to almost $4,000 for the sensor alone.

The authors outlined future analysis to be performed and additional data needs.

(35) Hydrogen Storage and Delivery System Development

Author(s): Handrock, J.
Date: October 31, 1996
Organization(s): Sandia National Laboratory
Publication: Proceedings of the 1996 U.S. DOE Hydrogen Program Review, Volume I.
Category(ies): Storage
Subcontract No.

This report presented results from a multi-year project entitled, "Hydrogen Utilization in Internal Combustion Engines (ICE)". One of the major components of the project is the Hydrogen Storage and Delivery System Project, which has the following goals:

- Develop analytic evaluation platform
- Develop an experimental evaluation platform
- Develop fuel cell vehicle delivery system
- Develop ICEV delivery system

In this report, the results of the first goal were reported. In this effort, the following activities had been completed:

- ICE/hydride storage system parametric study
- Fuel cell vehicle analytical model development
- Low load fuel cell temperature evaluation
- Presentation of modeling results

Using a steady state model of integrated ICEV and lightweight hydride storage system, the weight and energy use efficiency were investigated. Several different hydride materials were examined over a range of brake efficiencies at two different engine exhaust temperatures (300 and 400 C). For each case, the vehicle was designed with a 10 kW average power and a range of 483 km.

In general, the study showed that system weight decreases with increasing engine brake efficiency and exhaust temperature. High-temperature hydrides (e.g., Mg-based), the hydrogen storage weight is significantly less than that for the low-temperature hydrides (e.g., FeTi).

Energy use efficiency (the ratio of hydrogen delivered to the engine over total hydrogen availability) was also determined. This parameter is relatively insensitive to engine grade efficiency. In general, as engine efficiency increases, less waste heat is available for dehydriding and so there is an increase in the supplemental fuel required. This effect, however, is counteracted by a reduction in overall hydrogen demand as efficiency increases. Thus, any hydride selected will be unaffected by changes in brake engine efficiency.

The study also showed that as the exhaust temperature increases, the hydride heat of formation decreases and the hydrogen energy use efficiency increases. At some point, the waste heat available is sufficient for dehydriding the bed and so supplemental fuel is not required.

In the second part of the study, the system model was expanded and improved. Each system component was now represented by a module, which could be linked together to form a specific system design. After assembling the modules, the user specifies drive power requirements as functions of time and component design characteristics. The model then calculates component and system operating characteristics (e.g., power distribution and fluid temperatures).

The model was applied to the Palm Desert program fuel cell vehicle. Several simulations were run with the model. This information was then combined with information from the Schatz Energy Research Center (SERC) for model calibration. In general, the model showed good results, correctly predicting increases in temperature with fuel cell power and the differences between inlet and exit temperatures. Further work was needed on the model for the absolute temperature predictions as it under predicted these values, especially at higher power levels. It was expected that the proposed calibrated pressurized gas model will improve these predictions. Work was on-going in this area.

The authors concluded with a listing of near term work.

- Calibration of fuel cell/pressurized gas analytic model
- Incorporation of hydride bed modules into model and calibration with experimental data
- Support fuel cell vehicle storage system design and development activities
- Model other storage and delivery system technologies

(36) Production of HBr from Bromine and Steam for Off-Peak Electrolytic Hydrogen Generation: 1996 Annual Report

Author(s): Schlief, R., Stoy, M., Heaton, H., Vosen, S., Glatzmaier, G., Bingham, C., Lewandowski, A., Cosgrove, J., Markham, J., Radcliff, M., French, R., and Hanrahan, R.
Date: October, 1996
Organization(s): Solar Reactor Technologies, Inc., NREL, Sandia, Advanced Fuel Research, the Florida Solar Energy Center (FSEC) and Energetics, Inc.
Publication:
Category(ies): Production
Subcontract No.

This report summarizes the second year of a multi-year program designed to develop, design, assemble, and test an integrated system using renewable energy for production of hydrogen and oxygen. In this year, the team designed, assembled and tested a 10-kW solar reactor for the production of hydrogen bromide. The HBr is then used in an electrolytic cell to produce hydrogen. The reactor program was named Pathfinder.

The overall goal of the effort was to demonstrate high conversion rates of bromine to hydrogen bromide. In addition, the study wanted to better characterize the reaction between bromine and steam at elevated temperatures in the presence of an intense solar flux.

The study demonstrated a bromine conversion of 17% at 1075 C, 76% of the predicted thermodynamic limit using FTIR. A conversion of 23% was shown by chemical analysis of the effluent. Other significant achievements were safe system operation and the development of an accurate reactor model.

The project team was composed of DOE, SRT, NREL, Sandia, Advanced Fuel Research, the Florida Solar Energy Center (FSEC) and Energetics, Inc. SRT was responsible for the design, construction, testing and shipping the bromine and steam fluid delivery system. NREL was the site for the Pathfinder testing and coordinated the testing. Sandia personnel developed the reactor modeling and Advanced Fuel Research conducted the real-time FTIR reactor measurements. The FSEC developed an efficient product separation scheme while Energetics, Inc. performed an economic analysis of the process. Only the portion of the project completed by SRT, NREL and Sandia were presented in the annual report.

Since most of this effort focused on experimental rather than analytical results, only a brief overview is presented. From this analysis, the authors concluded:

- Reactor performance was characterized using thermocouples, solar pyroheliometry, FTIR, MBMS and pH.
- HBr yields and mole fractions determined by various methods were compared to predictions from a thermodynamic reactor model
- The model could predict HBr concentrations within 22% using a single parameter
- There was a large increase in reactor temperature when the bromine is introduced.
- At 1350 K and 0.26 bromine feed mole fraction exhibited a 23% conversion of bromine to HBr

(37) A Technical and Economic Assessment of Hydrogen as a Fuel for Fuel Cell Vehicles

Author(s): Ogden, J., Steinbugler, M., Kreutz, T.
Date: May 21, 1997
Organization(s): Princeton University
Publication: Proceedings of the 1997 U.S. DOE Hydrogen Program Review, NREL/CP-430-23722
Categories: Transportation
Subcontract No.

In this analysis, the authors evaluated several aspects of using hydrogen as a fuel in fuel cell vehicles (FCVs). Included in the analysis were:

- Projected performance and costs of FCVs for different storage systems (i.e., compressed gas, onboard reforming of methanol and onboard partial oxidation of hydrocarbons)
- Refueling infrastructure for each alternative, assuming a Southern California location
- Delivered fuel cost (Southern California) for various FCV fuels
- Lifecycle cost
- Design and economics of hydrogen refueling stations

Only the results of the first two tasks were presented in this report. The authors stressed that this effort was in conjunction with numerous industrial, academic and governmental organizations.

Comparison of Alternative FCV Designs

A computer model for PEM FCVs was developed that calculated performance, fuel economy and costs. The model is based on the driving schedule, vehicle parameters, fuel cell parameters, peak power battery characteristics, and fuel processor parameters. The fuel cell and peak power device are sized based on the following goals from PNGV:

- Fuel cell alone must be able to provide power to sustain 55 mph on a 6.5% grade
- Fuel cell plus the peak power device must achieve acceleration of 3 mph/s at 65 mph.
- Range of 380 miles

Using these parameters, the model was run for the three alternatives. The following table summarizes the results.

Parameter	**Direct Hydrogen**	**Methanol Steam Reforming**	**Gasoline POX**
Vehicle mass (kg)	1170	1287	1395
Peak Power (kW) (FC/Battery)	77.5 (34.4/43.1)	83.7 (37/46.7)	89.4 (39.4/50)
Driving Parameters (Combined FUDS/FHDS)			
mpeg	106	69	71
Range	425	460	940
Vehicle Cost	\$3666-6500	\$4000-7930	\$4250-7370

From this analysis, the authors concluded that given the same performance criteria, hydrogen FCVs would be simpler, lighter, more energy efficient, have lower emissions (i.e. 0) and cheaper than on-board reforming designs.

Developing a Refueling Infrastructure for Hydrogen Vehicles

Five near-term scenarios for producing and delivering hydrogen fuel were evaluated for four different refueling station sizes (0.1, 0.366, 1 and 2 million scfd):

- Centralized reforming with liquid hydrogen truck delivery
- Distributed SMR (conventional and advanced reforming technologies)
- SMR with gas pipeline
- Distributed electrolysis production
- Chemical industry by-product with gas pipeline delivery

The results of this analysis projected that onsite SMR is economically attractive ($10-15/GJ) for the larger plants. Truck delivered hydrogen and onsite electrolysis have comparable costs of $20-30/GJ. The high price of the onsite electrolysis is due primarily to the high ($.03/kWh) for off-peak power in Southern California. Finally, pipeline hydrogen may be cost-effective depending on the scenario.

The authors presented a cost breakdown for refueling stations under two scenarios: 1) existing excess hydrogen is used and existing infrastructure is used (truck and pipeline) and 2) new hydrogen production and delivery. Under these scenarios, the centralized production case was the least expensive ranging from $1.4 million ($105/car) in scenario 1 to $440 million ($440/car) for scenario 2. The costs for onsite electrolysis, pipeline delivery, and onsite reforming with conventional technology showed very similar costs at$9.6-11.4 million for scenario 1 and $810-870 million for scenario2. Onsite reforming with advanced technology was promising at 6.8 million for scenario 1 and $516 million for scenario 2.

In addition to these analyses, the authors looked at the refueling infrastructure requirements for methanol and gasoline FCVs. For methanol, delivery charges would increase by 90% over gasoline (lower energy density) while the cost to retrofit an existing gasoline refueling station would be minimal at $20,000. Costs for converting existing gasoline stations from conventional vehicles to FCVs is assumed to be 0. The authors then looked at the total infrastructure required for the onboard designs (i.e., including vehicle changes). Based on the literature, the added costs for the vehicles would be about the same as the total (on-vehicle and off) infrastructure costs for a hydrogen FCV.

The authors then provided several reasons why there are no insurmountable issues with hydrogen FCVs including available technology, reasonable economics, sufficient resources and potential demand. Following this discussion was a listing of current fleet demonstrations with hydrogen fueled vehicles and a short summary of work that automobile manufacturers are doing in this area.

(38) Coupling Renewables via Hydrogen into Utilities: Temporal and Spatial Issues, and Technology Opportunities

Author(s): Iannucci, J., Horgan, S., Eyer, J., Schoenung, S.
Date: May 21, 1997
Organization(s): Distributed Utility Associates/ Longitude 122 West, Inc.
Publication: Proceedings of the 1997 U.S. DOE Hydrogen Program Review, NREL/CP-430-23722
Categories:
Subcontract No.

This project evaluated the potential for renewable energy coupled with hydrogen systems to meet all or a portion of a region's electricity demand. Specifically, the report determined the regional capacity requirements for renewable electricity generation and hydrogen storage on an annual basis. These values were determined for 20-100% (in increments of 20%) of the regions' annual energy requirements. The renewable energy resource is used to meet the demand with excess being converted to hydrogen via electrolysis for use during low production periods from the renewable resource.

Three renewable technologies (wind, solar-thermal, PV) were modeled using hourly resource data. Projected electric peak load for each region for 2010 was used to determine demand. No economic analysis was performed.

The country was divided into the eight NERC regions (no information was supplied on these designations). Given that the three renewable resources are not available equally in each area, selection of the most appropriate technology for each area(s) was made. The following table summarizes where each technology was evaluated.

PV	**Wind**	**Solar Thermal**
SERC	SPP	ERCOT
ECAR/MAIN	MAPP	WSCC South
NPCC/MAAC	ERCOT	
WSCC South	WSCC South	
WSCC North	WSCC North	

The analysis was performed using an Excel spreadsheet model, GenStorCalc. This spreadsheet calculates the amount of hydrogen storage, the rating of the electrolyzer and the size of the renewable resource based on the hourly resource and demand profiles as well as the maximum annual demand. After determining the base case, the spreadsheet calculates other cases: an oversized and several undersized.

In each case, the minimum amount of renewable capacity (i.e., MW) to meet the annual load is calculated at the same time as the maximum storage. This combination is the "critical" renewables/storage combination. It is not likely to be the best or most economical combination. If the system is oversized, then the amount of storage can be reduced. Thus, the rationale for the oversized estimate.

From this analysis, the authors concluded that wind plants required the least amount of capacity to meet annual loads in any of the regions because it has the highest annual capacity factor. Solar thermal systems follow with PV requiring the largest resource capacity due to its low annual capacity factor.

Because all three technologies were evaluated in region WSCC south, these results present a good comparison of the technologies and are thus presented below.

Parameter	**PV**	**Solar Thermal**	**Wind**
Resource Capacity MW*	3.84	2.84	1.78
Reservoir Size MWh*	894.7	511.6	571.5
Maximum Hourly Charge MWh*+	2.98	2.03	1.24
Annual Energy Stored GWh*	4.41	3.73	3.16
Annual Load Factor	0.58	0.58	0.58
Annual Capacity Factor	0.23	0.3	0.43

*per MW of regional peak load
+Electrolyzer size

The author concluded that the capacity factor was the determining factor in the analysis.

(39) A Technical and Economic Assessment of Hydrogen as a Fuel for Fuel Cell Vehicles

Author(s): Ogden, J., Steinbugler, and Kreutz, T.
Date: October, 1997
Organization(s): Center for Energy and Environmental Studies, Princeton University
Publication:
Category(ies): Transportation
Subcontract No.

This report compares three options for fuel storage for on-board fuel cell vehicles (compressed gas, on-board steam reforming of methanol, on-board partial oxidation of hydrocarbon fuels) in terms of vehicle performance, fuel economy and cost and infrastructure requirements. The subcontract was divided into five tasks:

1. Evaluate projected performance and cost characteristics of FCVs with
   a. compressed gas hydrogen storage
   b. on-board reforming of methanol
   c. on-board partial oxidation of hydrocarbon fuels derived from crude oil
2. Evaluate the refueling infrastructure requirements for each alternative for Southern California
3. Determine the delivered fuel cost for various fuels for Southern California
4. Calculate the lifecycle cost of each transportation alternative for Southern California
5. Compare the design and economics of hydrogen refueling station options

Results from each of the tasks are presented below.

Projected Performance and Cost Characteristics of FCVs with Various Refueling Options
A model of PEM fuel cell vehicles was used to determine the performance, fuel economy and cost of alternative fuel cell vehicles. The fuel cell system is designed to meet Partnership for a New Generation of Vehicles (PNGV) goals including:

- the fuel cell alone must provide enough power to sustain 55 mph on a 6.5% grade
- the fuel cell plus the peak power device must allow acceleration of 3 mph/sec at 65 mph

After the model was run, the cost of each type of vehicle was determined for a low and high cost case. The cost components used in the estimate are presented in the table below.

Information regarding the assumptions behind most of these values in the table is found in the text.

From these values, the low case direct hydrogen fuel cell vehicle is $3,500. The low case costs for the methanol on-board reformer and gasoline partial oxidation (POX) vehicle is $3,900 and $4,160, respectively. For the high cost case, the costs are about $6,500, $6,930 and $7,370 for the direct hydrogen, methanol reformer and gasoline POX cases, respectively. For comparison, these components in a conventional ICE gasoline vehicle are $3,666.

Component	Cost Range
Fuel cell system	$50-100/kW
Fuel processor system	$15-25/kW
Hydrogen storage cylinder (5000 psia)	$500-1000/kW
Motor and controller	$13-26/kW
Peak power battery	$10-20/kW
Extra structural support	$1/kg
12 kg gasoline or methanol tank	$100
Total	$699-1272

Refueling Infrastructure Requirements for Fuel Cell Vehicles
Capital costs were developed for hydrogen delivery and refueling infrastructure for various scenarios. The following table uses existing hydrogen production capacity and serves 13,000 FCV cars at 2 million scf H_2/day.

Scenario	Costs
Centralized Production via Steam Reforming of Natural Gas with LH2 Delivery	
Centralized Production	0 (existing capacity is used)
Hydrogen Distribution	0 (existing trucks are used)
Refueling Stations (2 ea@ 800 cars/day)	$1.4 million
Total Cost	$1.4 million
Cost per car	$105
Centralized Production via Steam Reforming of Natural Gas with Pipeline Delivery	
Centralized Production	0 (existing capacity is used)
Hydrogen Distribution	$6.2 million (10 km pipeline @ $1million/km)
Refueling Stations (2 each serving 800 cars/day)	$3.4 million
Total Cost	$9.6 million
Cost per car	$740
On-site Steam Reforming of Natural Gas: Conventional Steam Methane Reformer	
Refueling Stations (2 each serving 800 cars/day)	$10.8 million
Total Cost	$10.8 million
Cost per car	$830
On-site Steam Reforming of Natural Gas: Fuel Cell Steam Methane Reformer	
Refueling Stations (2 each serving 800 cars/day)	$6.8 million
Total Cost	$6.8 million
Cost per car	$520

Scenario	Costs
On-site Advanced Electrolysis using Off-peak Power Refueling Stations (2 each serving 800 cars/day) Total Cost Cost per car	 $11.4 million $11.4 million $880

The next table presents the capital costs for new hydrogen production, delivery and refueling infrastructure for a fleet of 1 million FCVs delivery 153 million SCFD of hydrogen.

Capital Cost for Developing New Hydrogen Production, Delivery and Refueling Infrastructure

Scenario	Costs
Centralized Production via Steam Reforming of Natural Gas with LH2 Delivery Centralized Production Hydrogen Distribution Refueling Stations (2 ea @ 800 cars/day) Total Cost Cost per car	 $100 million (reformer) $200 million (liquefier and LH2 storage) $40 million (80 LH2 trucks @ 3 T/ea w/ 2 local deliveries per day) $104 million $440 million $440
Centralized Production via Steam Reforming of Natural Gas with Pipeline Delivery Centralized Production Hydrogen Distribution Refueling Stations (2 each serving 800 cars/day) Total Cost Cost per car	 $170 million (reformer and compressor) $380 million (600 km pipeline @ $1million/km) $260 million $810 million $810
On-site Steam Reforming of Natural Gas: Conventional Steam Methane Reformer Refueling Stations (2 each serving 800 cars/day) Total Cost Cost per car	 $830 million $830 million $830
On-site Steam Reforming of Natural Gas: Fuel Cell Steam Methane Reformer Refueling Stations (2 each serving 800 cars/day) Total Cost Cost per car	 $516 million $516 million $516

Scenario	Costs
On-site Advanced Electrolysis using Off-peak Power Refueling Stations (2 each serving 800 cars/day) Total Cost Cost per car	 $870 million $870 million $870

Estimates of the delivered cost of hydrogen at refueling stations were also developed and presented in graphical form. These estimates are based on tables above and show the relative contributions of the capital and operating cost components. The estimates are based on a natural gas cost of $2.8/GJ, off-peak power cost of $0.03/kWh and a capital recovery factor of 15%. The delivered hydrogen costs are presented below for refueling stations of 0.1 to 2 million scfd.

Station Type	**Delivered Hydrogen Cost ($/GJ)**
LH_2 Truck Delivery	$19-30
Pipeline H_2	$17-27
On-site Conventional Reforming	$12-40
On-site Fuel Cell Reforming	$12-26
On-site Advanced Electrolysis	$25-35

The low range of costs in the table are for a 2 million SCFD facility and the high range is for 0.1 million SCFD.

Delivered Fuel Cost for Southern California
The delivered fuel cost was estimated for both near-term and longer term options. In addition, different size refueling stations (0.1, 0.366, 1.0, 2.0 million SCFD) were evaluated. The following table summarizes the results. The results have some uncertainty as they were read from a graph.

Alternative	**0.1 MM SCFD ($/GJ)**	**0.37 MM SCFD ($/GJ)**	**1.0 MM SCFD ($/GJ)**	**2.0 MM SCFD ($/GJ)**
LH2 Truck Delivery	30	20	19	18
Pipeline H2	27	18	17	16
Onsite Conventional Reforming	40	20	15	13
Onsite Advanced Reforming	25	15	14	13
Onsite Advanced Electrolysis	33	25	24	23

0.1 MM SCFD = 65 FCV cars/day

As shown above, in the near term, SMR is the least expensive ($13/GJ) alternative while electrolytic hydrogen ($22-33/GJ) is the most expensive.

The authors also projected the delivered cost of renewable methanol and gasoline fuel. Delivered price for renewable methanol is estimated at $9.80-11/GJ and for reformulated gasoline, it is $6.76/GJ in 2010.

Lifecycle Transportation Costs for Southern California
In this analysis, a base vehicle price of $18,000 was assumed. Depending on the assumptions used for mass production, the total fuel cell vehicle price ranges between $21,400 and $26,000. Then, using a lifetime of 11 years, and a discount rate of 10%, the capital portion of the total lifecycle cost was calculated in cents/mile. Added to this is the fuel cost (based on fuel economy and fuel price) and other operating costs (e.g., parking, maintenance). The other operating costs were assumed to be the same for all vehicles and each vehicle was assumed to have a lifetime of 120,000 miles. Using these assumptions, the following lifecycle costs were calculated.

Vehicle Type	**High Estimate (cents/km)**	**Low Estimate (cents/km)**
Hydrogen FCV	0.286	0.256
Methanol FCV	0.293	0.262
Gasoline FCV	0.296	0.263

These costs were based on delivered fuel prices of $12.8/GJ for hydrogen, $9.8/GJ for methanol and $8.4/GJ for gasoline.

From this analysis, the authors concluded that:

- Fuel cost is a small fraction of the cost of vehicles due to high efficiency
- Hydrogen vehicles have the lowest lifecycle costs
- Based on mass production, the lifecycle cost of a hydrogen vehicle would be comparable to a gasoline vehicle

Comparison of Hydrogen Refueling Station Options
Alternative designs for Capital costs of a hydrogen infrastructure were estimated for four alternatives:

1. On-site production of hydrogen from natural gas
2. On-site production of hydrogen from electrolysis
3. Truck delivery of liquid hydrogen
4. Pipeline delivery of gaseous hydrogen

These costs were presented in the refueling infrastructure section (Task 2).

From the analysis, the authors concluded:

- Hydrogen FCVs are simpler, lighter, more energy efficient and lower cost than those with on-board fuel processors.
- For mid-size vehicles with PNGV characteristics, the fuel economies are:
    - 106 mpeg for hydrogen FCVs
    - 69 mpeg for FCVs with on-board methanol reforming
    - 71 mpeg for FCVs with on-board gasoline reforming

- Compared to hydrogen FCVs, mass-produced FCVs with on-board processing would cost:
    - $500-600 more for methanol
    - $850-1190 for gasoline
- Infrastructure for hydrogen refueling infrastructure would cost $310-620/vehicle in the near term
- Delivered cost of hydrogen transportation fuel is $13-33/GJ in the near term, depending on the production method.
- Delivered cost for methanol are $10-12/GJ and $8.4/GJ for gasoline
- Hydrogen is the preferred fuel for FCVs

(40) Incorporating Carbon Dioxide Sequestration into Hydrogen Energy Systems

Author(s): DiPietro, P.
Date: October, 1997
Organization(s): Energetics, Inc.
Publication: Proceedings of the 1997 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-430-23722
Category(ies): CO_2
Subcontract No.

This analysis evaluated the cost and full life-cycle carbon dioxide emissions from four natural gas and biomass-based systems and one PEM electrolysis system, each designed to provide compressed (5,000 psia) hydrogen to fuel cell vehicles (FCVs). The systems evaluated are listed below.

- Large-scale reforming of natural gas
- Distributed steam reforming of natural gas
- Biomass pyrolysis with biocrude reforming
- Large-scale biomass gasification
- Wind turbine/ distributed PEM electrolyzer

Each of the biomass and natural gas systems already contains CO_2 capture (i.e., PSA systems) and since this is the most expensive portion of CO_2 capture and sequestration, it was surmised that hydrogen systems would be excellent candidates for CO_2 reductions.

All of the systems, except the PEM electrolyzers, were designed both with and without carbon dioxide sequestration systems. The entire systems (i.e., production, sequestration, utilization) are then compared to a gasoline internal combustion system.

Each of the systems evaluated included the following basis:

- Technology: 20-30 years in the future
  - Technology improvements
  - Mass manufacturing
- System size: 25 MM scfd for 170,000 FCVs
- Fuel Economy
  - Gasoline ICE 80 mpg
  - Hydrogen FCV 180 mi/kg

The table below summarizes some of the results of the study.

Technology Option	**Hydrogen Production Cost ($/MM Btu HHV)**	**Vehicle Fuel Cost (Fuel Cost/ Gasoline Cost)**	**Normalized CO_2 Emissions (lb CO_2/100 mi)**
Large-scale SMR			
Sequestration	13.7	1.05	10
No Sequestration	12.9	1.0	16

Technology Option	Hydrogen Production Cost ($/MM Btu HHV)	Vehicle Fuel Cost (Fuel Cost/ Gasoline Cost)	Normalized CO_2 Emissions (lb CO_2/100 mi)
Distributed SMR			
Sequestration	17.4	1.3	11
No Sequestration	13	1.0	17
Biomass Pyrolysis			
Sequestration	14.9	1.15	-25
No Sequestration	9.9	0.7	-15
Biomass Gasification			
Sequestration	19.9	1.5	-7
No Sequestration	18	1.4	7
Distributed PEM	18.4	1.4	0
Gasoline ICE	Not applicable	1	29

The author also showed the relative amounts of CO_2 produced from each alternative. In all cases, not all the CO_2 can be captured. He points out that two advanced technologies currently being evaluated by the Program, SERP and ITM, can be applied to SMR and POX, respectively to increase the amount of CO_2 capturable.

The author concludes with a discussion of the sensitivity of the results. Specifically, he addressed the maturity of the technologies, uncertainty of capital costs and mass production. Carbon dioxide capture is mature technology and so there is little uncertainty here; however, small-scale reforming technology is new and a 50% increase in the assumed capital costs would raise the hydrogen price by 7%. Distribution factors such as pipelines and extra storage were also addressed. Using a hydrogen pipeline would increase the hydrogen price by 10-15% while back-up liquid storage would increase it by 5-10%.

(41) Market Penetration Scenarios for Fuel Cell Vehicles

Author(s): Thomas, C.E., James, B.D., and Lomax, Jr., F.D.
Date: October, 1997
Organization(s): Directed Technologies, Inc.
Publication: Proceedings of the 1997 U.S. DOE Hydrogen Program Review, NREL/CP-430-23722
Category(ies): Transportation
Subcontract No. ACF-4-14266-01, Modification #3

This report describes a time-dependent computer market penetration model that estimates the number of FCVs purchased over time as a function of their cost, the cost of hydrogen relative to the costs of other fuels and vehicles, the return on investment, and governmental benefit/cost ratio. This model was designed to assist industry and government in choosing the best investment strategies to maximize benefit/cost ratios and achieve high ROIs. The model can be used to illustrate trends, highlight the sensitivity of market penetration, and illustrate potential benefits of R&D.

The model was used to predict the market penetration and ROI for direct hydrogen FCVs and on-board processors and compared to that for natural gas vehicles and hythane vehicles.

The model is composed of four major components: vehicle technology, fuel, vehicle markets, and governmental actions. Inputs to the model include vehicle market scenarios and governmental actions. Outputs include ROI for the automotive and fuel industries and benefit/cost ratios based on environmental factors and oil import reductions.

The model is best used qualitatively rather than quantitatively. It should be used to compare alternative transportation options and assessing the impact of government and industry actions. Eight time functions are calculated by the model:

1. Number of FCVs
2. FCV Cost
3. FCV Industry Investment
4. FCV Industry Profit
5. Hydrogen Production
6. Hydrogen Cost
7. Hydrogen Infrastructure Investment
8. Hydrogen Industry Profits

All of the time functions are dependent upon the number of FCVs sold, which is determined by two price elasticity curves (hydrogen and vehicles) and two vehicle markets (ZEV, and conventional light-duty). The model assumes that 50% of the ZEV market is available to FCVs. The number sold depends on the FCV price and the price of hydrogen relative to gasoline.

The vehicle price elasticity curve depends on two parameters: the price of the competitive vehicle and the market share for FCVs at twice the price of the competition. The EV was considered to be the competitive vehicle and was priced at $25,000. At this price, an FCV would capture 50% of the market. If the FCV costs twice the EV then it will capture only 0.1% of the market.

The hydrogen price elasticity curve was projected to be less steep than the vehicle curve because it was thought that the initial fuel price would be less of an inhibitor than the initial vehicle price. If hydrogen costs twice as much as gasoline, then the sales decrease by 150-200%. If hydrogen costs less than gasoline, then the FCV market share increases significantly.

The basis for the cost models was that the costs of the fuel and vehicles are based on the cumulative sales through the previous years. Prices decrease as production volume increases. Progress ratios of 70-90% were used for each major component. However, no industry-wide experience curves were used.

For FCVs, the cost of a PEM fuel cell was expected to be $1500/kW at the beginning of the period, decreasing to 40/kW when 300,000 vehicles are sold. Assuming similar progress for other components, the cost of the entire vehicle would decrease as shown below for all three vehicle types.

Vehicle Type	**Initial Cost (> Gasoline Vehicle)**	**Mass-Production Cost (> Gasoline Vehicle)**
Hydrogen FCV	$2,580	$198
Battery EV	$4,000	$604
Hythane Vehicle	$840	$189

The cost of hydrogen was based on an earlier study by Ford Motor Company. This study showed that hydrogen in an FCV could be competitive with gasoline even if the hydrogen were made in small-scale factory built SMR and electrolyzers. As shown in the table below, at the very small scales, electrolysis is favored with SMR being favored at a little larger scale.

Parameter	**Electrolyzer**	**SMR**
Hydrogen Production Rate	2.72	44.2-272
Initial Capital Cost ($)	15,500	221,900-447,000
Manufacturing Progress Ratio Factor	0.819	0.85
Capital Cost @ 10,000 produced	4,380	33,400-76,000
Cost/Vehicle ($/FCV)	1,622	667-203

For natural gas costs, it was assumed that it would cost $3.12/GJ to fuel a NGV at the beginning of the study period. After 300,000 vehicles were sold, it would cost $2.62/GJ. The results for Hythane were based on the relative amounts of hydrogen and natural gas.

Investments by government and industry were evaluated next. The model assumed that government would continue funding R&D in FCVs and would start cost-sharing projects to develop and demonstrate small-scale hydrogen production. Specifically, the government would cost share 50% of two hydrogen vehicle demonstration projects. Total government investment would be $432 million from 1995 to 2008. No investment in NGVs was assumed.

On the industrial side, the model assumed that $3,125/FCV would be invested as well as 2% of all sales for capital investment. Almost $23 billion would be invested by industry on FCVs over the study period. In addition, hydrogen producers would invest $328 million and fueling stations $10.8 billion over the same period.

These investment values were used to calculate the government benefit/cost ratios where benefits were measured in terms of reduced oil imports and improved air quality. Specifically, it was the ratio of the NPV of the avoided environmental costs (or oil imports) divided by the present value of the government investment using a 3% discount rate. Environmental impacts were measured in terms of avoided air pollution costs. The following table summarizes the values used.

Pollutant	**U.S. Avoided Cost ($/ton)**	**S. California Avoided Cost ($/ton)**
VOC	5,300	18,000
CO	870	350
NO_x	6,500	17,000
CO_2	22	Not reported

The model showed that for small initial investment by government in FCVs would drive down the price such that industrial investment would significantly increase. The following tables summarize this trend.

Industrial Investments

Industry	**Investment ($ million)**	**% ROI**
FCV (36/21 million FCVs)	20,570/16,050	21.8/17.2
Hydrogen Production Industry	14,808/7,750	54.7/21.4

Government Benefit/Cost Ratios

Benefit	**Investment ($ million)**	**B/C Ratio @ 3% Discount**
Oil Import Savings (11.5/5.2 Quads)	54,750/26,380	61/28
Environmental Savings	29,200/13,400	33/14

The authors also evaluated the impact of on-board fuel processing for FCVs. Both methanol and gasoline on-board processors were evaluated. Each fuel was examined under expected and optimistic scenarios. The following table summarizes these findings.

Component	**Direct Hydrogen FCV Cost**	**Methanol FCV Cost High/Low**	**Gasoline FCV Cost High/Low**
Fuel Cell System	$2,000	$2,400/$2,440	$2,630/$3,120
Peak Power Battery	$312	$337/$343	$337/$355
Motor/Controller	$1,000	$100/$1,100	$1,080/$1,140
Hydrogen Tank	768	0/0	0/0
Methanol Processor	0	$540/$1,100	$540/$1,140
Total	**$4,080**	**$4,357/$4,983**	**$4,587/$5,755**

Fuel economy was evaluated next. A gasoline ICEV was project to have a fuel economy of 25 mpg. Hydrogen had the best fuel economy at 66 mpg while the methanol and gasoline FCVs were respectable at 48 and 42 mpg, respectively. All fuel economy calculations were based on the EPA combined cycles with a factor of 1.25.

Vehicle emissions (local and greenhouse gas) were also evaluated. All of the vehicles had lower air pollutant emissions than a gasoline ICEV except hydrogen from an electrolyzer. Here, the CO_2 emissions were 65% higher than a gasoline ICEV due to the utility power mix.

The market penetration of the hydrogen FCV leads both the methanol and gasoline versions due to higher initial vehicle cost even though hydrogen initially costs more per mile. The NGVs gain a large market share initially. After 2025, the hydrogen FCV overtakes the FGV due to the larger market base of the ZEV market at that time. Hythane vehicles lag behind the NGV due to higher capital and fuel costs.

Finally, the authors presented the cumulative environmental avoided costs for all vehicles. the Hythane NGV save the most at over $18 billion followed by the NGV at greater than $15 billion. The direct hydrogen FCV is slightly more than $12 billion while the methanol and gasoline FCVs lag at $6 billion and $2 billion respectively.

The cumulative greenhouse gas emissions show that the direct hydrogen FCV has the greatest benefit by far at more than 500 million metric tons of CO_2-equivalent emissions. The remaining vehicles save less than half of that.

The authors concluded:

- The model projected a plausible scenario in which small-scale systems could provide economical hydrogen to support a fuel cell market.
- ROIs for both the automotive and hydrogen industries are possible, if the federal government invests $400 million between now and 2008.
- SMRs would likely be more economical than electrolyzers and the electrolyzers would be phased out.
- Electrolytic hydrogen has significant greenhouse gas emissions, unless the grid mix becomes more renewable.
- Methanol and gasoline FCVs would cost more than hydrogen FCVs.
- Natural gas vehicles would have much higher market penetration than the FCVs due to lower vehicle and fuel cost.
- Natural gas vehicles also have attractive environmental impacts except compared to the hydrogen FCVs for greenhouse gas emissions.
- Hythane would have marginal or negative benefits due to higher vehicle and fuel costs.
- In terms of greenhouse gas emissions, the hydrogen FCV is best followed by a methanol FCV, natural gas vehicle, hythane vehicle and gasoline FCV.

(42) Onboard Storage Alternatives for Hydrogen Vehicles

Author(s): Berry,G., and Aceves, S.
Date: October, 1997
Organization(s): LLNL
Publication: Proceedings of the 1997 U.S. DOE Hydrogen Program Review, NREL/CP-430-23722
Category(ies): Transportation
Subcontract No.

The paper evaluated pressure vessels with cryogenic capability and a combination metal hydride and LH2 storage. These alternatives were compared to conventional compressed hydrogen and LH2 storage in terms of volume, vehicle range, dormancy, energy required and cost. From this analysis, the authors contended that the alternatives could result in lower volume or extended range. Also, the energy requirements and costs appeared favorable for the alternatives.

Recent studies have indicated that hydrogen fuel costs are reasonable (less than $0.04/km in 34 km/L gasoline equivalent vehicles; $0.06/mile in 80 mpg) using off-peak electricity or natural gas to either produce hydrogen on-site at fueling stations, or delivering liquid hydrogen by truck from larger centralized plants. Hydrogen vehicles achieving 17-34 km/L (40-80 mpg) fuel economy need to store at least 5 kg of fuel onboard for adequate driving range (320-640 km; 200-400 miles).

The authors state the crucial issue facing ambient high-pressure storage (i.e. 34.4 MPa) may be volume. More than 227 L (60 gal) are required to store 5 kg of hydrogen fuel on a vehicle, raising packaging issues for light-duty vehicles. The following table compares four storage vessels with the same range (640 km; 400 miles).

Vessel parameter	**34.4 MPa (5000 psia) H_2**	**Cryogenic pressure vessel 34.4 MPa**	**Liquid hydrogen storage (LH_2)**	**LH_2 tank and metal hydride**
External volume (L)	237	126	135	195
Internal Volume (L)	216	81.2	78.5	49.3
Volumetric efficiency (%)	90.9	64.6	58.6	77.7
Max. pressure (MPa)	34.4	34.4	0.69	0.69
Mass of LH_2 (kg)		5.17	5	3.14
Mass of H_2 in hydride (kg)				2.5
Mass of compressed H_2 (kg)	5	1.88		
Total H_2 mass (kg)	5	5.17	5	5.64
kg H_2/m3	21.1	41.1	37.1	28.9
Insulation thickness (cm)		1	5	5
Total vessel weight (kg)	37.0	66	31.3	213
Vehicle empty weight (kg)	1100	1146	1091	1383
Vehicle fuel economy (km/L)	34.0	33.4	34.1	30.2
Vehicle range with compressed H_2 (km)	640	238		284
Max vehicle range (km)	640	640	640	640

The vessel used to store compressed hydrogen at 34.4 MPa is assumed to be an advance metallized polymer liner vessel wound with carbon fiber. The cryogenic compressed storage vessels are carbon-composite pressure vessels with 2.5 mm thick aluminum liners, rated to 20.6 MPa. Cryogenic pressure vessels require less than a fifth of the insulation of the liquefied hydrogen tank and store over twice the hydrogen of the baseline 34.4 MPa tank.. Liquid hydrogen is stored in a spherical tank using 5 cm of non-load-bearing multi-layer vacuum insulation to achieve a boil-off rate of 1.8% per day. The liquid hydrogen tank supplemented by metal hydrides use again use a spherical tank with the hydrides modeled as Fe-Ti-based alloys to achieve 1.3 wt% hydrogen.

Results show that for the same vehicle range (640 km; 400 miles), the volume of storing hydrogen in a 34.4 MPa pressure vessel is rather large (237 L; 63 gal) in comparison to a cryogenic pressure vessel (126 L; 33 gal). A comparison of vehicle range for equal volume tanks showed that cryogenic hydrogen storage offer about twice the 640 km range of an ambient 34.4 MPa vessel. The cryogenic designs provide 35-70% of the range of the baseline 34.4 MPa technology on ambient-temperature hydrogen and 130-220% of the baseline range using liquefied hydrogen storage. Under the worst-case scenarios, all of the cryogenic hydrogen storage systems considered can remain idle for more than 5 days without venting hydrogen and moderate driving before parking extends dormancy to over a week.

Cryogenic pressure vessels appear to offer comparable or perhaps lower cost than baseline technologies. These vessels store hydrogen at high density and pressure, reducing insulation and other material related costs per kg of hydrogen stored. This study shows the significant potential volume, range, and energy efficiency advantages of using cryogenic-capable pressure vessels for hydrogen storage.

(43) Integrated Analysis of Hydrogen Passenger Vehicle Transportation Pathways, Draft Final

Author(s):	Thomas, C.E., James, B., Lomax, Jr., F. and Kuhn, Jr., I.
Date:	March 30, 1998
Organization(s):	NREL
Publication:	
Category(ies):	Transportation
Subcontract No.	AXE-6-16685-01

Costs for three types of vehicles using three types of fuels were analyzed: conventional ICEVs (gasoline, natural gas and hythane - a mix of 30% hydrogen and 70% methane), hybrid vehicles (natural gas, hydrogen and diesel) and fuel cell vehicles (hydrogen, methanol and gasoline). In addition, three types of hybrids were analyzed for each fuel: a parallel hybrid and two types of series hybrid options.

The cost of a direct hydrogen fuel cell vehicle is estimated at $20,179 and that for a hydrogen parallel hybrid is $19,890. The comparable conventional gasoline-powered vehicle would cost $18,000. The cost of each component is detailed in the report.

The hydrogen FCV is projected to have the best fuel economy of all vehicles evaluated at 66 mpg, gasoline equivalent. The hydrogen hybrid at 50 mpg is similar to the natural gas hybrid. The diesel parallel hybrid has the second best fuel economy at 57 mpg.

Local air pollution and greenhouse gas effects were also examined. In this analysis, the cost of each ton of air pollution avoided was estimated. The cost to avoid each pollutant is estimated at $24/tonne CO_2, $5,840/tonne VOC, $960/tonne CO, $7,150/tonne NO_x and $4,410/tonne PM-10.

In emissions alone, a hydrogen FCV is the best alternative because it has no tailpipe and no evaporative emissions while providing the full range capabilities of conventional vehicles. However, it is more expensive than other alternatives. The best alternatives, considering both costs and emissions, are hythane ICEVs and natural gas vehicles. In terms of greenhouse gas emissions, the direct hydrogen FCV provides significant reductions in emissions if the production method is SMR. Electrolysis does not provide greenhouse gas emissions due to the projected fuel utility mix. Overall, natural gas is the preferred method for lowering greenhouse gas emissions. When both air pollution and greenhouse gases are considered, the direct hydrogen FCV has the lowest total emission and greenhouse gas costs, but natural gas and hydrogen parallel hybrids and hythane ICEVs have similar environmental impacts, but lower overall costs.

The specific greenhouse gas emission rates for the direct hydrogen fuel cell are estimated at 245 g/mile and 939 g/mile for steam methane reforming and electrolysis, respectively. The hydrogen parallel hybrid has a greenhouse gas emission of 322 g/mile and a local air pollution cost of $3/yr. Finally, the hythane vehicle has a greenhouse gas emission rate of 381 g/mile and a local air pollution cost of $7/yr.

Detailed information on the basis for these costs and emissions can be found in the appendix of the report.

The report also described the costs for 50 and 100-car hydrogen refueling stations based on an annual production volume of 10,000. These costs are summarized in the following table.

Capital Costs for Refueling Stations (Mass Production)

Component	**50-Car Station**	**100-Car Station**
Natural Gas Reformer	10,900	15,187
Hydrogen Compressor	5,795	6,446
Hydrogen Storage	9,672	19,344
Hydrogen Dispenser	4,846	4,846
Total	**31,213**	**45,823**

These costs are based on a real, after tax rate return on investment of 10% or an annual capital recovery factor of 18.4%. Based on this analysis, the cost of hydrogen at each station was also projected. The 50-car station had a hydrogen cost of about $0.82/gallon gasoline equivalent and the 100-car station had a hydrogen cost of about $0.75/gallon gasoline equivalent. These estimates assume that natural gas costs $4/MM Btu and electricity costs $0.06/kWh. Also, the estimate assumes that an FCV has a fuel economy (LHV) 2.2 times that of a conventional gasoline ICEV using a 1.25 factor for the EPA driving cycles.

Considerable detail on these estimates is provided in the report.

(44) Coupling Hydrogen Fuel and Carbonless Utilities Vehicles

Author(s): Berry, G.
Date: April 28, 1998
Organization(s): LLNL
Publication: Proceedings of the 1998 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-570-25315
Category(ies): Transportation
Subcontract No.

This effort evaluated the potential benefits of combining hydrogen fuel production and renewable electricity. Three scenarios were selected to explore this issue.

- Reference Case: Petroleum-based transportation sector and natural gas-based electric sector
- Benchmark Case: Petroleum-based transportation sector and carbonless electric sector
- Target Case: Hydrogen-based transportation sector and carbonless electric sector

Each of these scenarios was modeled, using available information and projections. Only as much detail as was necessary was used. Two different modeling approaches were used: simulation and multi-period equilibrium optimization. The simulations provided only the energy and economic performance of a given system while the optimization model can determine the lowest cost configuration of the technologies as well as the appropriate operating schedule to meet electricity and fuel demands. The optimization program was LLNL's METAnet and was still being refined. The graphical interface simulation software was STELLA, a commercially-available package.

In the optimization model, annual hour-by-hour electricity flows from various sources were modeled to the electric grid and/or stored as hydrogen for use in vehicles, including aircraft and trains. Detailed information on the input parameters for each scenario were provided in the document, but are not reproduced here.

Literature values and industry contacts (Distributed Utility Associates) were used to project the utility supply and demand patterns to 2020. Cost projections were obtained from publications by DOE, EPRI and GRI. Transmission and generation electric costs were estimated by DUA and scaled to meet a 1 TW peak demand.

In the reference scenario, the transportation sector is fueled via petroleum. Very aggressive performance parameters were selected for this scenarios, including PNGV fuel economy levels (i.e., 80 mpg) for all light-duty vehicles, an increase of 300% over EIA projections. In addition, all electricity demands were met with 57% efficient natural gas combined cycle systems. The total carbon emissions from this scenario were estimated at 870 mmtC/y, a significant reduction from the 1400 mmtC/y projected under EIA scenarios.

In the benchmark scenario, only the utility assumptions were changed so that all electricity demands are met by a mixture of solar thermal, wind and PV. To meet the 1 TW demand, wind supplied 0.85 TW, PV 0.35 TW and hydroelectric and nuclear another 0.15 TW. Energy storage was assumed to be steam electrolysis, hydrogen storage and fuel cells. All carbon emissions are due to the aggressive transportation scenario, as outlined in the reference case and were projected at 370 mmtC/y.

The target scenario was the same as the benchmark except that now hydrogen is used for transportation. Compressed hydrogen was used for 85% of light-duty vehicle demand and all commercial trucking; liquid hydrogen was used for aircraft and for long-distance light-duty trips. Carbon emissions from this scenario were zero. Annual costs and carbon emissions of the three scenarios are provided in the table.

Parameter	**Reference Scenario**	**Benchmark Scenario**	**Target Scenario**
Annual Cost ($ billion)	$420	$506	$550
Annual Carbon Emissions (GtC/y)	0.86	0.37	0
Carbon Tax Credit Required ($/tonne C)	NA	$175	$150

Based on the analysis, the authors drew two major conclusions:

- due to the projected long-term inexpensive oil and gas prices and highly efficient vehicles, it will be difficult for alternative fuels to be competitive.
- sequestration would be required to reduce carbon emissions below 0.86 GtC/y unless hydrogen or other alternative fuels were employed
- coupling electrolytic hydrogen fuel production to PV and wind systems can achieve significantly greater carbon reductions than wind or PV alone

Finally, to meet these challenges, the authors believe that:

- High efficiency and coupling vehicles to utilities are the most important carbon-reduction and cost-saving measure
- Super-efficient hydrogen production, storage and use are necessary for hydrogen to compete in both utility and transportation markets
- Unless long-term fossil fuel prices are very low and hydrogen vehicles have no efficiency advantage over fossil-fuel vehicles, coupling hydrogen fuel production to carbonless sources can be a significant benefit

The authors concluded with suggestions for future work in technology development and systems analysis. For technology development, the author contended that high-efficiency electrolysis was crucial with costs of $500/kW and efficiencies of 90%. Hydrogen storage was also deemed important. For systems analysis, the author suggested that the results obtained in this report be studied further so that the advantages can be better understood and exploited.

(45) Integrated Analysis of Hydrogen Passenger Vehicle Transportation Pathways

Author(s): Thomas, C., James, B., Lomax, F., and Kuhn, I.
Date: April 28, 1998
Organization(s): Directed Technologies, Inc.
Publication: Proceedings of the 1998 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-570-25315
Category(ies): Transportation
Subcontract No.

This report evaluated alternatives to hydrogen FCVs. The cost and societal benefits of fourteen vehicles were evaluated:

- Fuel Cell Vehicles (FCV)
  - Direct hydrogen
  - Methanol (probable and best cases)
  - Gasoline (probable and best cases)
- Natural Gas Vehicles (NGVs)
  - 100% natural gas
  - Natural gas/hydrogen mixtures
- Hybrid Electric Vehicles with Internal Combustion Engines (ICEs) in 9 combinations
  - hydrogen, natural gas and diesel fuel
  - Thermostat, load-following, and parallel HEVs

For each vehicle type, the authors evaluated the following four areas:

- Vehicle cost, assuming mass-production
- Local air emissions (VOCs, CO, NO_x, and PM)
- Greenhouse gas (GHG) emissions
- Oil imports

Each of the vehicles was based on the Ford AIV (aluminum intensive vehicle) Sable, weighing 1,168 kg, a decrease of roughly 28% over the conventional design. All other design features of the vehicle (e.g., aerodynamic drag) were assumed to be the same as the Ford Taurus. It was expected that the projected fuel economies were comparable to a U.S. Partnership for a New Generation of Vehicles (PNGV) program.

Pertinent characteristics and assumptions for each of the vehicles were described in detail. The authors then projected the weight for each vehicle including detailed estimates of those for the fuel cell vehicles. The overall weight for each vehicle is shown in the table below.

Vehicle Type	Projected Weight (kg)
Direct Hydrogen FCV	1,291
Methanol FCV	
Probable case	1,414
Best case	1,390
Gasoline FCV	
Probable case	1,475
Best case	1,387

Vehicle Type	Projected Weight (kg)
Diesel Hybrids	
Thermostat	1,493
Load-following	1,361
Parallel	1,245
Fuel Cell Range Extender	1,826
Hydrogen Parallel Hybrid	1,247
NG Parallel Hybrid	1,219
Sable AIV	1,168

In the next section, the authors looked at the fuel economy of each vehicle type. Here, the authors used the Federal Urban Driving Schedule (FUDS), weighted at 55% and Federal Highway Driving Schedule, weighted at 45%, but increased them by 25% for realism. A spreadsheet program was developed to calculate the fuel economy of various types of vehicles. A graph of the fuel economies of the vehicles (in mpg-equivalent) in the study was developed and is summarized in the table below.

Vehicle Type	Fuel Economy (mpg-equivalent)
ICEVs	
Gasoline	30
Natural Gas	30
Hythane	30
FCVs	
Hydrogen	66
Methanol (Probable/Best)	44/49
Gasoline (Probable/Best)	29/42
Hybrids (Parallel/Load-following/Thermostat)	
Natural Gas	51/41/38
Hydrogen	50/40/39
Diesel	58/45/42

As shown in the table, the hydrogen FCV was shown to be the most fuel efficient.

Vehicle emissions were the next area evaluated. Both local emissions (i.e., CO, NO_x, SO_2, PM and VOCs) and GHGs were estimated. For the GHGs, lifecycle emissions were projected, including those from fuel extraction, refining and delivery in addition to tailpipe emissions. The local emissions were based on tailpipe emissions only. The study included the emissions of six GHGs (CO_2, VOCs, CO, CH_4, N_2O and NO_x), each with a CO_2-equivalent rating. The direct hydrogen FCV had the lowest greenhouse gas emissions and the gasoline ICEV had the highest emissions.

The cost of each vehicle was projected in detail in the next section. Costs were developed for each component and were adjusted based on mass production. The following table summarizes the estimated cost for each vehicle.

Vehicle Type	Cost ($)
Direct hydrogen FCV	$20,179
Methanol FCV Probable case Best case	 $21,076 $20,356
Gasoline FCV Probable case Best case	 $23,138 $21,114

The final area evaluated was oil import reductions. An interesting finding here was that all of the most promising fuels were derived from natural gas and thus each would virtually eliminate the vehicle dependence on imported oil. Two vehicles, diesel parallel hybrid and gasoline FCV, do depend on crude oil. The diesel parallel vehicle was projected to reduce imports by almost 60% while the gasoline FCV was estimated to reduce imports by 0-40% for the probable and best cases, respectively.

To convert the vehicle emissions into a quantifiable cost, the authors conducted a literature survey and used the lowest annual avoided cost for each pollutant as summarized below.

Pollutant	Annual Avoided Cost ($)
VOC	$5,300
CO	$870
NO_x	$6,500
PM-10	$4,000
CO_2	$22

To compare the vehicles, the authors graphed the cost of each vehicle on y-axis and the cost of the emissions on the x-axis. Thus, the best alternatives would be located at the lower left hand corner of the graph.

Based on this analysis, the authors concluded that there was no clear winner in all areas. Specifically, they cited these finding for each area.

Analysis Area	Conclusions
Local Air Pollution	H_2 is the only ZEV H_2 FCV has lowest local air pollution NGV has most cost-effective pollution reductions Hythane is cost-effective for reducing local emissions Diesel hybrids are not cost-effective
Greenhouse Gas Emissions	NGVs are lowest cost NG parallel hybrid vehicle has best combination of low additional vehicle cost and lowest projected greenhouse gas emissions; series hybrids are not as effective Adding hydrogen to hythane is not an effective strategy for GHG Hydrogen hybrid vehicles are relatively expensive Direct H2 FCVs are good, but not as good as NGVs

Analysis Area	Conclusions
Greenhouse Gas Emissions – con't	Methanol and gasoline FCVs are poor H_2 via electrolysis is poor due to electricity mix
Oil Imports	All of the front runners in other areas would also have significant advantages in this area as well Technologies that rely on crude oil would also have significant reductions here, reducing oil imports by 40% or more

The authors' final conclusions were:

- There is no clear winner; all of the technologies have drawbacks in at least 1 area
- The gasoline-powered FCV has 3 drawbacks: high cost, highest GHGs and little oil import reductions
- The diesel-powered hybrid is more attractive than the gasoline FCV, but it is still expensive and has high local emissions. It has low emissions of GHGs and would reduce oil imports.
- The NG parallel hybrid is the most attractive vehicle that requires new fuel infrastructure. It has the lowest GHG emissions, lowest incremental cost and low local emissions. However, it is not a sustainable fuel
- The methanol FCV can be sustainable (i.e., from biomass), but it has high GHGs and a high incremental cost.
- The direct H2 FCV is a true ZEV with good GHGs and only a moderate cost differential. Its biggest drawbacks are the need for a new fuel infrastructure, onboard storage issues and its perception as an unsafe fuel.

(46) Economic and Technical Analysis of Distributed Utility Benefits for Hydrogen Refueling Stations

Author(s): Iannucci, J., Eyer, J., Horgan, S. and Schoenung, S.
Date: April 28, 1998
Organization(s): Distributed Utility Associates/ Longitude 122 West, Inc.
Publication: Proceedings of the 1998 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-570-25315
Category(ies): Production and distribution
Subcontract No.

This analysis evaluated the feasibility of coupling hydrogen production at a distributed refueling station with electricity generation. This scenario was compared to separate refueling and distributed utility systems. A market analysis was also performed.

The system was based on an electrolysis system design by Ogden with necessary changes. Five systems were analyzed as outlined below.

System	Components	Design Description
Base Case	Electrolyzer, storage, dispensing station	
PEM Fuel Cell	Electrolyzer, storage, dispensing station, PEMFC	Electrolyzer sized for H_2 needs PEMFC sized for distributed utility output
Regenerative Fuel Cell	Regenerative fuel cell, storage, dispensing station	Sized to meet H_2 needs Oversized fuel cell
Hybrid	Electrolyzer, storage, dispensing station, regenerative fuel cell	Small RFC for utility output and a small amount of H_2 Electrolyzer supplies remaining H_2
Engine	Electrolyzer, storage, dispensing station, ICE	Mass-produced diesel generation technology using H_2

The analysis was based on the following assumptions:

- Vehicles served: 200 or 400
- 24-hour refueling
- Off-peak (6 pm to noon) hydrogen production only
- Compressed gas storage
- Fuel cell dispatch occurs at optimum utility benefit
- Distributed utility operates 1 hr/day at 1.4 MW (200 cars) 2.8 MW (400 cars)
- Regularly spaced car traffic

Cost (capital and operating) factors for each of the major components, their efficiencies and lifetime were developed. All components except the compressor and refueling station were assumed to have lifetimes of 20 years. The other components were projected to have lifetimes of 10 years. In general, O&M costs were estimated at 4% of capital charges. The cost factors and efficiencies are presented below.

Component	Capital Cost Factor ($/kW)	Efficiency or Energy
Electrolyzer	$300	80%
Storage Cylinders Compressor	 $1.1/scf $2000	 NA 0.6225 kW/car
Fuel Cell PEM RFC RFC (future)	 $500 $1000 $500	 60% 60% 60%
ICE	$350	40%
Refueling Station	$277,100 (for entire system)	1.875 kWh/car

Using the assumptions outlined above, the study projected the following hydrogen prices. The prices are not exact as they were read from a graph.

Technology	H2 Price ($/GJ) (200-car station)	H2 Price ($/GJ) (400-car station)
Base Case	$18	$16
PEM	$20	$18
RFC Current Future	 $22 $18	 $19 $15
Hybrid	$22	$19
ICE	$20	$18

The authors then presented results from a series of sensitivity studies that examined the dispatch rating, distribution of avoided costs, and electricity cost. In terms of the dispatch rating, the study showed that both the PEM and hybrid systems became less economical as the dispatch rating increases due to increased capital charges. The opposite was true with the RFC since it was underutilized.

The discussion on the distributed benefits was unclear. However, it did show cost savings with distributed utility benefits for all cases.

For the electricity cost sensitivity, the authors increased the off-peak price from $0.02/kWh to $0.04/kWh and the on-peak from $0.07/kWh to $0.08/kWh. As expected, the economic viability of each alternative decreased; however, the relative differences among the alternatives remained unchanged.

The authors concluded that the alternatives required further study. Small reductions in costs or process improvements could yield substantial results. They also suggested that the system has not yet been optimized and that other trade-offs should be considered, especially distributed utility benefits. Finally, the authors stated that "green" credits should be evaluated for some of the alternatives.

(47) Hydrogen Energy Systems Studies

Author(s): Ogden, J., Steinbugler, M. and Kreutz, T.
Date: April 28, 1998
Organization(s): Princeton University
Publication: Proceedings of the 1998 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-570-25315
Category(ies): Transportation, Market Analysis, Environmental
Subcontract No. DE-FG36-95G010061

This report presented the status of three projects: comparison of hydrogen, methanol and gasoline as transportation fuels, hydrogen demand and supply for the New York City area, and carbon dioxide sequestration for hydrogen energy systems. Only the first study was completed.

After a brief discussion of previous years results, the authors presented the current year results in each area.

Comparison of Hydrogen, Methanol and Gasoline as Transportation Fuels
This effort was composed of five tasks: performance and cost characteristics of FCVs with three types of storage, refueling infrastructure requirements for alternative fuel vehicles, delivered fuel costs for hydrogen production, lifecycle costs for each alternative, comparison of design and economics of hydrogen refueling stations. Each task is described in greater detail below.

Equilibrium, kinetic and process (ASPEN) models of on-board steam reforming and POX fuel processors were developed. These models were integrated with a FCV model to determine vehicle performance characteristics. The following results were obtained from this analysis:

Parameter	Direct H2 FCV	Methanol Steam Reformer	Gasoline POX
Vehicle Mass (kg)	1170	1287	1395
Peak Power (kW) (FC/Battery)	77.5 34.4/43.1	83.7 37.0/46.7	89.4 39.4/50.0
Fuel Efficiency FUDS (mpeg) FHDS (mpeg)	 100 115	 62 79	 65 80
Range, miles (55% FUDS, 45% FHDS)	425	460	940

From this analysis, the authors concluded that for the same performance, hydrogen FCVs are simpler, lighter weight, more energy efficient and lower cost than the other two alternatives. In general, on-board steam methane reforming vehicles are 10% heavier and gasoline/POX vehicles are 20% heavier than hydrogen FCVs. On-board reforming or POX is less efficient than direct hydrogen FCVs due to conversion losses, reduced cell performance on reformate, increased vehicle weight and fuel response time. Assuming mass production, methanol FCVs and gasoline/POX FCVs will cost $500-600 and $800-1200 more than hydrogen FCVs, respectively.

When evaluating near-term hydrogen refueling options, the authors evaluated the following five supply options:

- large centralized steam reforming with liquid hydrogen delivery via truck
- large centralized steam reforming with compressed gas delivery via pipeline
- chemical industry sources of hydrogen (e.g., excess capacity) with pipeline delivery
- on-site production via small-scale steam reforming with conventional or advanced technology
- on-site production via electrolysis

Based on this analysis, the authors determined that:

- hydrogen infrastructure cost: \$400-800/car
- methanol infrastructure cost: \$50/car when using excess capacity and \$400-800/car for new capacity
- gasoline POX cost: \$800-1200/car
- hydrogen FCVs would likely be introduced in fleets or buses where centralized refueling is the norm

The delivered fuel cost was evaluated next. For Southern California, the cost was determined to be \$14-40/GJ, depending on the station size and the type of technology. On-site reforming was shown to be the lowest cost alternative, by far, while centralized production and on-site electrolysis were the most expensive.

The delivered price of methanol and gasoline were lower than that for hydrogen. However, due to the greater fuel efficiency of hydrogen FCVs, the overall cost per km for hydrogen and gasoline were about the same. In terms of lifecycle costs, the hydrogen vehicles were shown to be less expensive than methanol or gasoline FCVs, due primarily to the lower initial cost of the vehicle and its higher fuel economy.

The authors then presented the costs for each of the conceptual designs for the hydrogen refueling stations. Costs were developed for refueling stations servicing 80 (100,000 SCFD), 300 (366,000 SCFD) and 800 (1 million SCFD) cars per day. The following table summarizes the costs presented.

Refueling Station	**80 cars/day**	**300 cars/day**	**800 cars/day**
LH2 Delivery	\$175,000	\$307,000	\$680,000
Pipeline Delivery	\$200,500	\$620,500	\$1,681,500
On-site Reforming			
Conventional	\$1,769,000	\$3,054,740	\$5,379500
Advanced (FC)	\$626,300	\$1,369,740	\$3,378,500
On-site Electrolysis			
Conventional	\$860,500	\$3,042,500	\$8,245,500
Advanced	\$608,500	\$2,132,500	\$5,745,500

Hydrogen Demand and Supply for New York City and Surrounding Area

This effort addressed three questions:

1. What is the potential hydrogen demand for the transportation market in the New York City/New Jersey area?

2. What are the potential supplies of hydrogen for this market, including
   - truck delivered or pipeline delivered merchant hydrogen
   - hydrogen byproduct from chemical plants and refineries
   - on-site hydrogen production from steam reforming of natural gas at small scale
   - electrolytic hydrogen from off-peak power
   - hydrogen from gasification of MSW
3. What is the production cost and delivered cost of hydrogen transportation fuel from these sources?

Preliminary results were available for each area, except Task 3 concerning costs.

Hydrogen demand for the transportation market in this area was estimated using broad assumptions to provide limits on the total required. Using assumptions for fuel economy, vehicle miles traveled, projected vehicle demand and other pertinent assumptions, the authors projected the following hydrogen demands:

- 1000 millions SCFD for NJ light-duty vehicles in 2010
- 33 million SCFD for NJ transit buses
- 250 million SCFD for NYC light-duty vehicles
- 15 million SCFD for NYC transit buses

In the second task of this project, the authors looked at potential existing hydrogen supplies as well as unexplored hydrogen supplies. The following table summarizes the preliminary results for this project.

Hydrogen Source/Production Method	**Status**
Area Industrial Gas Companies	Area gas companies provide H2 via truck as liquid or compressed gas No hydrogen gas pipelines All primary gas companies serve the area
Refinery and Chemical Plant Excess Hydrogen	Several area refineries and chemical plants may have excess hydrogen Few million SCFD may be available from this source
Off-peak power	Significant (18,000 MW) off-peak power available High off-peak power cost ($0.07-0.08/kWh) On-site electrolysis would be expensive Costs may go down with deregulation
On-site production from natural gas	Moderately high natural gas prices
Gasification of MSW	H2 from MSW could fuel 44% of NYC's light-duty vehicles Landfill space is almost exhausted Commercial process not available

Carbon Dioxide Sequestration for Hydrogen Energy Systems

In this project, three primary areas were addressed:

1. The scale economy issues for hydrogen energy systems with sequestration

2. Determine conditions where pipeline hydrogen with sequestration could compete with other options
3. Project potential scenarios for transition to large-scale hydrogen energy systems with CO_2 sequestration

The authors reported the following progress and/or conclusions:

- Engineering and economic models were being developed for pipeline transmission of hydrogen, methane and CO_2, and for hydrogen production with various methods of CO_2 separation
- Strong economies of scale exist for gaseous hydrogen pipeline transmission, hydrogen production, CO_2 separation and CO_2 injection
- For long pipeline distances, a large flow is required to minimize transmission costs
- Collection of CO_2 from small dispersed sources is not economically attractive
- CO_2 sequestration would only be considered when there is large-scale centralized production.

The authors concluded with a lengthy and detailed proposal for future work in the area of PEMFCs for distributed generation and cogeneration.

(48) Technoeconomic Analysis of Different Options for the Production of Hydrogen from Sunlight, Wind, and Biomass

Author(s):	Mann, M., Spath, P. and Amos, W.
Date:	April 28, 1998
Organization(s):	NREL
Publication:	Proceedings of the 1998 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-570-25315
Category(ies):	Production, Storage and Transport
Subcontract No.	

This report summarized the results of three studies. In the first study, the authors performed a technoeconomic evaluation of hydrogen production from sunlight and wind. The second study looked at hydrogen production from biomass and the third study, which is not indicated in the title, looked at the costs of storage and transport of hydrogen.

Hydrogen Production from Sunlight and Wind

Three methods for hydrogen production were evaluated in this phase of the study: direct photoelectric conversion (PEC), PV/electrolysis and wind/electrolysis. The PEC system was evaluated under a unique set of conditions while the electrolysis options had common conditions for comparison.

The evaluation of the PEC system was conducted assuming a solar insolation value of 5.74 kWh/m2/day and a hydrogen production rate of 500,000 kg/yr. In addition, technology improvements were projected as shown in the following table.

Parameter	**Near term (2000)**	**Mid-term (2010)**	**Long-term (2020)**
Photocatalyst efficiency (sunlight to H_2, LHV)	7.5%	9%	14%
Photocatalyst cost ($\$/m^2$)	125	100	70
Membrane cost ($\$/m^2$)	475	225	50

One significant, and unexpected outcome of the study was the design of the housing unit. It was found to be quite expensive (~20% of capital) and due to its early stage of development, highly uncertain.

From this analysis, the authors concluded that PEC could be cost competitive. In the near term (2000), it was expected to still be expensive at $121/GJ, but would decrease to $33/GJ by 2010. Both of these values were based on a 15% IRR. For a 0% IRR, the respective values are $32/GJ in the near-term and $10/GJ in the long-term.

Hydrogen Production from PV and Wind

The electrolysis options were evaluated using four scenarios:

- ***Base Case*** – direct coupling of the renewable to the electricity, independent of the grid. The only product is hydrogen
- ***Alternative 1*** – Couple electricity and hydrogen production to produce the lowest cost hydrogen possible. That is, make hydrogen when the electricity price is low (non-peak) and electricity when the price is high (peak). Under this scenario, the technologies receive a prorated capacity credit and the total electricity available for hydrogen production is reduced 11% for PV and 9% for wind.
- ***Alternative 2*** – Make hydrogen from the renewable electricity and from the grid to minimize the price of hydrogen. The electrolyzer would be sized for the maximum renewable output
  - ***2a*** – Buy energy such that the electrolyzer is always at 90% of nameplate capacity
  - ***2b*** – Only use non-peak electricity for hydrogen production
- ***Alternative 3*** – The electricity production is physically decoupled from the hydrogen production. Electricity from the renewable is sent across the grid to the electrolyzer. This may be the most realistic scenario and would result in lower storage and transport costs.
  - ***3a*** – Sell electricity during on-peak periods and make hydrogen during off-peak
  - ***3b*** – Sell all electricity to the grid and purchase non-peak electricity for hydrogen production.

Each scenario was evaluated for near-term (2000) and longer-term (2010) technology characteristics. The following table summarizes the assumptions for both technologies in the near and mid-term.

	Near term (2000)	**Mid-term (2010)**
Electrolysis System		
Type/Size	Alkaline/2 MW	Same
Efficiency	82%	87%
Capital Cost	\$600/kW	\$300/kW
Operating Costs	3% of capital	2% of capital
Wind System		
Capital Costs	\$900/kW	\$700/kW
Variable Operating Costs	\$0.008/kWh	\$0.005/kWh
Fixed Operating Costs	\$0.0005/kWh	\$0.0005/kWh
Capacity Factor	35%	40%
Capacity Credit	40% of \$4/kW – mo	Same
PV System		
Capital Cost	\$3,133/kW	\$1,662/kW
Variable Operating Costs	\$0.008/kWh	Same
Fixed Operating Costs	\$0.0003/kWh	Same
Capacity Factor	28%	30%
Capacity Credit	85% of \$4/kW-mo	Same

Electricity prices were obtained from Distributed Utility Associates. Three different rate schedules (on-peak, off-peak, super off-peak) were provided for the purchase cost and selling price. The hours of operation per year were also provided. On-peak prices (650 h/yr) averaged \$0.14/kWh for purchasing and \$0.05/kWh for selling. Off-peak prices (4,966 h/yr) averaged

$0.06/kWh for purchasing and $0.03/kWh for sales. Super off-peak prices (3,144 h/yr) were estimated at $0.05/kWh for purchases and $0.02/kWh for sales.

The following table summarizes the results of the study.

Technology	**Near-term (2000) Hydrogen Price**	**Longer-term (2010) Hydrogen Price**
PV/Electrolysis		
Independent	$124/GJ	$53/GJ
Grid Integrated	$52/GJ	$32/GJ
Wind/Electrolysis		
Independent	$50/GJ	$28/GJ
Grid Integrated	$28/GJ	$21/GJ

From this study, the authors concluded that the economics of both PV and wind/electrolysis technologies improve when integrated with the grid. The improvement for PV is better and is likely because its hours of production coincide more readily with on-peak electricity prices.

Hydrogen Production from Biomass

In this phase, three different technologies were compared for conversion of biomass to hydrogen: indirect gasification, direct gasification, and pyrolysis followed by partial oxidation. The indirect gasification technology was simulated as the Battelle-Columbus Laboratory/FERCO (BCL/FERCO) gasifier. Direct gasification was modeled after the Institute of Gas Technology (IGT) high-pressure oxygen-blown gasifier and partial oxidation was based on Texaco technology.

Each technology was evaluated at raw biomass feed rates of 300, 1,000 and 1,500 bone dry Mg/day. The gasification technologies used biomass as the feedstock, and the partial oxidation scenario used pyrolysis oils. The pyrolysis oils were assumed to be produced from raw biomass at distributed sites to minimize cost. All technologies had shift processing, PSA hydrogen recovery and heat integration to produced a steam co-product. In addition, the pyrolysis option was evaluated under two scenarios: high temperature processing and cool gas processing.

Each technology was modeled using ASPEN Plus for material and energy balances. Costs for each technology were obtained from previous studies or literature values and were scaled to the appropriate size. Economic evaluations for each scenario were performed based on a discount cash flow rate of return (DCFROR).

After evaluating each scenario, several sensitivity studies were conducted, focusing on capital investment and feedstock price.

From this analysis, the authors concluded that the BCL/FERCO system is the most economical and could compete with other hydrogen production technologies at reasonable feedstock prices. The other technologies, however, would not be competitive unless the feedstock prices were negative.

Hydrogen Storage and Transport

This phase of the analysis evaluated four different storage technologies, underground, liquefied hydrogen (LH2), metal hydride (MH), and compressed gas (CG) and four transport technologies (rail, truck, pipeline and barge). The transport technologies were evaluated in conjunction with specific storage technologies, but not all combinations were feasible (e.g., pipeline delivery of liquefied hydrogen) and so these were not evaluated. Following is a summary of the combinations evaluated.

- LH2 – truck, rail and barge
- CG – truck, rail, and pipeline
- MH – truck and rail

Each technology was evaluated for storage periods of 1 to 30 days, hydrogen production rates of 5, 500 and 50,000 kg/hr, and transportation distances of 0 to 1,500 km.

In terms of storage, underground storage was shown to be the least expensive method at all production rates and storage times. At low flow rates and short storage times, the other three technologies are similar. Liquid hydrogen is generally only cost-effective at high production rates due to the high capital cost of the liquefier. The economics of metal hydride storage decreases with production rate as there was no economy of scale. Compressed gas is most cost-effective at low production rates and low storage times.

Liquid hydrogen transport via truck was shown to be the least expensive alternative except for large quantities of hydrogen, when compressed gas is economical. One important result of the study was the need for any transport method to be fully utilized as this will result in the lowest costs. The authors also pointed out that the capital costs of the methods varied widely.

When storage and transport costs are added together, liquid hydrogen is the most economical. The benefit increases with transport distance.

(49) Technical and Systems Evaluation

Author(s): Skolnik, E., DiPietro, P.
Date: April 28, 1998
Organization(s): Energetics, Inc.
Publication: Proceedings of the 1998 U.S. DOE Hydrogen Program Review, Volume I. NREL/CP-570-25315
Category(ies): Production, Storage
Subcontract No.

This paper summarized the results of three analysis: HBr for electricity storage, carbon-based hydrogen storage, and hydrogen-fueled buses.

HBr for Electricity Storage

In this analysis, the authors described and evaluated a reversible HBr electricity storage system that was used for peak shaving applications. After briefly describing the process, the authors outlined the following technical challenges that must be solved prior to commercialization.

- Demonstration at high (> 500 A/ft2) current densities instead of the current standard of 200 A/ft2.
- Address stack voltage limitations
- Demonstrate a field life for the membrane electrode assemblies (MEAs) of 5-7 years
- Achieve high (1000 psi) outlet pressure from the PEM fuel cell

The authors estimated the capital cost of a 300-kW process at almost $350k designed for operating 8 hr/day for 250 days per year. These costs were based on a reversible PEM fuel stack cost of $350/kW, a power electronics cost of $175/kW and an AC/AC efficiency of 72%. Roughly 30% of the cost is attributable to the PEM stack.

The authors then conducted a financial analysis to determine the energy rate for peak electricity using the following parameters.

- 15% after-tax (28%) IRR
- 2 c/kWh off-peak electric rate
- $8/kW/month demand charge
- 20-year system life
- 50% debt/equity
- 7.5% interest on debt
- 10% ACRS depreciation

Based on this analysis, the authors contended that the base case electricity cost was $0.0079/kWh and ranged from $0.06/kWh to $0.12/kWh based on a variety of factors. These values compare favorably with peak electricity rates for diesel ($0.054/kWh) and current industrial customers in New England ($0.0792/kWh).

The authors concluded this section with future work proposals including evaluation of the system as part of remote wind/diesel systems. The HBr system would improve the efficiency and utilization of the diesel generators and would allow a higher capacity wind turbine system.

Carbon-based Hydrogen Storage

In this section, the authors provided summaries of work on three different carbon storage technologies: carbon nanotubes (NREL), fullerenes (ORNL) and carbon nanofibers (Northeastern University). No original analyses were presented.

The authors began with a comparison of the three methods as shown below.

Technology/ Developer	Production Method	Wt % Hydrogen	Postulated Adsorption Mechanism	Hydrogenation/ Dehydrogenation Temp./Press.
Nanotubes/ NREL	Arc-Discharge Laser Vaporization	5-10	Adsorption on inner tube walls	Ambient/15-100's psi
Fullerenes/ ORNL and MER	Arc furnace	6-8	Physical sorption and/or chemical reaction	200-400 °C/500-4000 psi (w/out catalysis)
Nanofibers/ Northeastern University	Vaporization and Catalytic Condensation	10-75	Layers of hydrogen selectively condensed between graphite plates	Ambient/1500 psi

For the carbon nanotubes, the authors claimed that they were the furthest along in development and offered the best opportunity for near-ambient operation. NREL was pursuing the laser vaporization production method since it was more stable and showed higher hydrogen capacity.

In the fullerene option, the authors presented information regarding the kinetics of hydrogen desorption which was shown to be first-order with respect to the carbon concentration. Thus, this suggests that the storage phenomenon is physical rather than chemical. They also noted that further studies have shown that with catalysis, another kinetic term appears, thus suggesting that the process can have a chemical component as well. Both of these factors suggest that the adsorption limit will be greater than that projected by chemical adsorption alone.

Finally, the nanofiber option was discussed. In general, the authors stated that the results projected by the researchers was very promising, but that they needed to be confirmed independently. The researchers were proposing hydrogen adsorption rates of up to 75%, which is almost twice that of a perfect monolayer on a perfect graphite plate. Thus, there must be several layers of hydrogen molecules. The authors appeared skeptical of the claims since if they are true, a hydrogen vehicle could travel 2000 miles between fill-ups.

Hydrogen-fueled Buses

In this project, the merits of hybrid electric vehicles (HEVs) as transit buses were explored. The authors summarized some then recent industrial activity regarding HEVs, but most were focused on fuels other than hydrogen.

Next, the authors presented a table comparing the weights of the components of conventional buses, hybrid buses and hydrogen-fueled hybrid buses. The hydrogen fueled hybrid buses were the heaviest due not only to the batteries for the hybrid design, but also due to the low weight density of the fuel.

The authors then compared the fuel costs for each type of bus. This graph showed that the proposed distributed natural gas reforming system for a fleet of 40 buses would not be competitive with other fuel sources.

The authors also noted the importance of the development of a peaking battery in the success of hybrid electric vehicles. When this is accomplished, it would be difficult to find any advantage to hydrogen fuel compared to natural gas. One potential advantage identified would be that hydrogen is carbonless and so the lifecycle emissions would likely be less. However, the authors pointed out that even this claim would require the use of non-fossil sources for hydrogen and other modifications. The other potential advantage would be in safety if economical hydride or carbon-based storage systems were developed.

(50) Exploring the Technical and Economic Feasibility of Producing Hydrogen from Sunlight and Wind

Author(s): Mann, M., DiPietro, P., Iannucci, J. Eyer, J.
Organization: Energetics Inc./NREL
Date: June 21, 1998
Category(ies): Production
Publication: XII World Hydrogen Energy Conference, Buenos Aires.
Subcontract No.

This study evaluated the economic viability of three renewable hydrogen production technologies: direct photoelectrochemical conversion (PEC) of sunlight, PV-electrolysis and wind-electrolysis. Costs were developed for current and future scenarios.

For the PEC system, the following assumptions were used. All costs are in 1995$.

PEC Economic Assumptions

Cost Component	Near term (~2000)	Mid-term (~2010)	Long term (~2020)
Photocatalyst efficiency (Sunlight to hydrogen, LHV)	7.5%	9%	14%
Photocatalyst cost ($\$/m^2$)	125	100	70
Membrane cost ($\$/m^2$)	475	225	50

Each of these systems was evaluated assuming an average solar insolation rate of 5.74 $kWh/m^2/day$, a hydrogen production rate of 500,00 kg/yr based on a 90% operation rate.

Using the assumptions outlined above as well as an after tax IRR of 11% and a tax rate of 28%, projections of the economics of the PEC system are summarized in the following table.

PEC Economic Analysis

Cost Component	Near term (~2000)	Mid-term (~2010)	Long term (~2020)
Capital cost (million $)	36.0	21.0	9.4
Hydrogen selling price ($/GJ)	90.4	53.6	25.1

As expected, the cost of the PEC system declines with time, due primarily to technology improvements in the photocatalyst and mass production of the membrane. The housing of the system is currently a significant unknown. Its cost is not projected to decrease as quickly as other components such that it will be 19-23% of the total capital investment.

The wind and PV-electrolysis systems were evaluated under the same conditions. The basic assumptions for these cases are shown in the following table.

Design and Economic Bases for PV and Wind Analyses

Cost Component	**Near-term (~2000)**	**Mid-term (~2010)**
Electrolyzer		
Efficiency	82%	87%
Capital cost	$600/kW	$300/kW
Operating costs	3% of capital costs	2% of capital costs
Wind System		
Capacity factor	35%	40%
Capital cost	$900/kW	$700/kW
Operating cost		
Fixed	$0.0005/kWh	$0.005/kWh
Variable	$0.008/kWh	$0.0005/kWh
PV System		
Capacity factor	28%	30%
Capital cost	$3,133/kW	$1,662/kW
Operating cost		
Fixed	$0.008/kWh	$0.008/kWh
Variable	$0.0003/kWh	$0.0003/kWh

Both the near and mid-term cases for each technology were evaluated under five different scenarios of off-peak and on-peak generation. The following table summarizes these scenarios as well as the projected hydrogen selling price. The projected selling prices are only approximate as they were read from a graph. Purchase costs of electricity for the scenarios was 14 c/kWh for on-peak (650 hr/yr), 6 c/kWh for off-peak (4,966 hr/yr) and 5 c/kWh for super off-peak (3,144 hr/yr). Selling prices for these same cases were 5c/kWh for on-peak, 3 c/kWh for off-peak and 2 c/kWh for super off-peak. Other important assumptions include a 20 year life, equity financing, 1 year construction period, 28% tax rate, 10 year straight line depreciation and 11% IRR.

Economic Evaluation Scenarios and Results for PV and Wind-Electrolysis

Scenario	Goal	Description	H2 Selling Price for Wind ($/GJ)	H2 Selling Price for PV ($/GJ)
1 Near-term Mid-term	Lowest cost hydrogen	H_2 production during non-peak periods only from renewable systems	 39 22	 93 40
3a Near-term Mid-term	Decoupling of electricity and hydrogen production	Renewable electricity generated during on-peak hours is sold to the grid; during non-peak hours, electricity is sent over the grid to make H_2	 25 19	 42 27
3b Near-term Mid-term		Sell all renewable electricity to the grid and purchase only non-peak grid electricity to generate H_2	 30 24	 48 32

Integration with the grid appears to be the most economical method. Also, as shown in the table, the various scenarios have a greater impact on the PV case than the wind case because the hours of operation for the PV system correspond with on-peak electricity usage.

(51) Technoeconomic Assessment of Four Biomass-to-Hydrogen Conversion Technologies

Author(s): Mann, M., Spath, P.
Organization: NREL
Date: June 21, 1998
Category(ies): Production
Publication: XII World Hydrogen Energy Conference, Buenos Aires.
Subcontract No.

In this paper, the economics of three gasification (Texaco, BCL/FERCO, Institute of Gas Technology) technologies and one fluid bed pyrolysis unit for converting biomass to hydrogen were compared. The Texaco gasifier is a high pressure, high temperature entrained flow gasifier where both gasification and reforming reactions take place in the same vessel. The BCL/FERCO gasifier is a low-pressure indirectly heated gasifier and the IGT gasifier is a direct-fired high pressure gasifier.

Each technology produces steam as a by-product and the pyrolysis system also produces an adhesive co-product. For all of the technologies except the Texaco gasifier, the feed was biomass. In the case of the Texaco gasifier, the feed was oils from biomass pyrolysis. Each technology was evaluated at three different sizes: 300, 1,000 and 1,500 bone dry Mg/day. In addition, the Texaco gasifier was evaluated under two scenarios: heat recovery and quench. The heat recovery option includes sensible heat recovery for steam production and electricity generation. The quench option has a water quench which minimizes the heat for recovery as well as the associated heat exchange equipment.

The basis for the economic evaluations are summarized in the table below

Economic Analysis Basis

Parameter	Value
Economic Basis	January 1995
Evaluation Method	Internal rate of return
IRR Required	15%
Lang factor	3.15
Type of financing	Equity
Plant life	20 years
Construction period	2 years
On-stream factor	90%
Working capital	18% of installed capital
Tax rate	37%
Depreciation	10 year straight-line

The following table summarizes the results of the study.

Summary of Hydrogen Production Costs from Biomass Gasification and Pyrolysis

Technology	Small Plant (300 Mg/day)	Medium Plant (1,000 Mg/day)	Large Plant (1,500 Mg/day)
Texaco			
H_2 produced (kg/day)	19,767	65,891	98,836
Total Capital Investment			
Quench	$56.8 million	$127.6 million	$168.8 million
High temp cooling	$83.0 million	$207.0 million	$282.8 million
IGT			
H_2 produced (kg/day)	22,232	74,106	111,159
Total Capital Investment	$75.4 million	$175.6 million	$234.3 million
BCL			
H_2 produced (kg/day)	21,044	70,148	105,222
Total Capital Investment	$40.7 million	$105.0 million	$144.5 million
Pyrolysis w/co-product			
H_2 produced (kg/day)	11,394	37,981	56,971
Total Capital Investment	$17.1 million	$43.6 million	$59.7 million

Using this information, the allowable cost of biomass was determined in order to obtain a hydrogen selling price of $14.2/GJ with a 15% after tax IRR for the 1,000 Mg/day plant size. The allowable biomass cost was $31.4/Mg, $80.4 /Mg, -$29.9/Mg, and -$30.1/Mg for the BCL/FERCO, pyrolysis, IGT and Texaco systems, respectively.

(52) Costs of Storing and Transporting Hydrogen

Author(s): Amos, W.
Date: September 30, 1998
Organization(s): NREL
Publication:
Category(ies): Storage and Transport
Subcontract No.

This report provided detailed analyses of several methods of hydrogen storage (compressed gas, liquefied gas, metal hydride, underground) and transport (truck, rail and ship). The author evaluated each of these technologies for various conditions including variable hydrogen production rates (45,800-45.8 million GJ/yr), storage periods (1-30 days), and transportation distances (16-1600 km).

The transport technologies were evaluated in conjunction with specific storage technologies, but not all combinations were feasible (e.g., pipeline delivery of liquefied hydrogen) and so these were not evaluated. Following is a summary of the combinations evaluated.

- LH2 – truck, rail and barge
- CG – truck, rail, and pipeline
- MH – truck and rail

Assumptions used in the estimation of capital and operating costs for hydrogen storage are provided in the following tables.

Hydrogen Storage Capital Cost Assumptions

	Base Size	Base Cost	Base Pressure	Size Factor	Pressure Factor
Compressor	4,000 kW	$1000/kW	20 MPa	0.80	0.18
CG Vessel	227 kg	$1323/kg	20 MPa	0.75	0.44
Liquefier	454 kg/hr	$44,100/kg/hr		0.65	
Dewar	45 kg	$441/kg		0.70	
Metal Hydride		$2200/kg		1.00	
Underground		$8.80/kg	20 MPa	1.00	1.00

Hydrogen Storage Operating Cost Assumptions

Parameter	Assumption
Power Compressed Gas Compressor Liquefier	 2.2 kWh/kg 10 kWh/kg

Parameter	Assumption
Cooling Compressed Gas Liquefier Hydride	 50 l/kg 626 l/kg 209 l/kg
Boil-Off (LH2)	0.1%/day
Hydride Heat of Reaction	23,260 kJ/kg
Utility Costs Electricity Steam Cooling Water	 $0.05/kWh $3.80/GJ $0.02/100 liter
Operating Period	350 days/yr (96%)
Depreciation Method	22-year straight-line ADS Method

Due to the report detail, not all of the results can be presented here. However, the following table highlights some for each technology.

Storage Technology	Short-term (1-day) Storage Hydrogen Cost ($/GJ)	Long-term (30-day) Storage Hydrogen Cost ($/GJ)
Compressed Gas	$2-$4	$7-$37
Liquefied Hydrogen	$5-$17	$6-$23
Metal Hydride	$3-$7	$61
Underground	$1-$5	NA

From this analysis, the author concluded:

- Underground storage was the least expensive method in all cases (i.e., differing production rates and storage times) due to the low cost of the cavern.
- Metal hydride systems had significant capital charges and no economy of scale, but, due to its low operating costs, it is competitive with LH2 and compressed gas for small systems.
- For long storage periods, LH2 is more economical than CG due to its lower capital investment.
- For the shorter periods, the high operating costs of LH2 dominate and compressed gas is more economical.

As noted earlier, the report also evaluated hydrogen transport. The following tables summarize the assumptions used in the capital and operating costs for hydrogen transport using trucks, rail, ship, and pipeline.

Hydrogen Transport Assumptions

Parameter	**Cost**	**Capacity**
Truck Transport		
Tube Unit	$100,000	
Liquid Unit	$410,000	180 kg
MH Unit	$2,200/kg	4,080 kg
Truck	$90,000	454 kg
Rail Transport		
Tube Assembly	$200,000	
Liquid Unit	$400,000	454 kg
Hydride Unit	$2,200/kg	9,090 kg
Undercarriage	$100,000	910 kg
Ship Transport	$350,000	4,080 kg
Pipeline Transport		
Pipeline Capital	$620,000/km	NA
Compressor	$1,000/kW	$4,000 kW

Hydrogen Transport Operating Cost Assumptions

Parameter	**Value**
Truck Transport	
Gas Mileage	2.6 l/km
Average Speed	80 km/h
Load/Unload Time	2 hr/trip
Truck Availability	24 hr/day
Driver Availability	12 hr/day
Driver Wage	$28.75/hr
Diesel Price	$1.00/gal
Boil-Off rate	0.3%/day
Trailer Depreciation	6 years straight-line, ADS
Cab Depreciation	4 years straight-line, ADS
Rail Transport	
Average Speed	40 km/hr
Load/Unload Time	24 hr/trip
Railcar Availability	24 hr/day
Freight Charge	$400/wagon
Boil-off Rate	0.3%/day
Depreciation	15 years, straight-line, ADS

Parameter	Value
Ship Transport	
Average Speed	16 km/hr
Load/Unload Time	48 hr/trip
Availability	24 hr/day
Freight Charge	$3000/internodal unit
Boil-off Rate	0.3%/day
Depreciation	NA
Pipeline Transport	
Roughness	4.6E5 m
Diameter	0.25 m
Temperature	283 K
Delivery Pressure	20 MPa
Viscosity	8.62E-6 kg/m s
Gas Constant	4,124 N m/kg K
Compressor Power	2.2 kWh/kg

The transport analysis concluded that:

- LH2 transport via truck is the least expensive alternative ($1-$5/GJ) for all cases except for very large quantities of hydrogen when pipeline delivery is the least expensive.
- There is a minimum transport cost for each technology, except pipeline, which occurs when the mode of transport is not fully utilized
- Rail and ship transport costs were fairly insensitive to distance due to the flat freight charges.
- Rail costs for liquid hydrogen were $1-2/GJ; those for CG were $21-24/GJ and those for metal hydrides were $29-43/GJ.
- The cost of transporting liquid hydrogen via ship was $13-15/GJ.
- Truck transport depends heavily upon distance due to fuel and labor charges.
- Compressed gas has the highest fuel and labor charges since this method has the lowest capacity per truck.

(53) Hydrogen Energy Storage Comparison

Author(s): Schoenung, S.
Date: October 1998
Organization(s): Longitude 122 West, Inc.
Publication:
Category(ies): Storage and Transport
Subcontract No. DE-FC36-96-GO10140

This study compared hydrogen energy storage systems with other types of utility storage including CAES, batteries and pumped storage. Specifically, the following technologies were evaluated:

- Batteries
- Compressed air energy storage (CAES)
- Pumped hydro
- Flywheels
- Superconducting magnetic energy storage (SMES)
- Capacitors (double-layer electrochemical, super- or ultra-capacitors)
- Compressed hydrogen
- Metal hydrides

Technology	**Application**
Hydrogen-fueled Electric Generator with Storage	Power Quality Remote/UPS/Distributed Utility Transmission & Distribution Spinning Reserve/Load Management Load Leveling
Batteries	Power Quality Remote/UPS/Distributed Utility Transmission & Distribution Spinning Reserve/Load Management
CAES	Remote/UPS/Distributed Utility Transmission & Distribution Spinning Reserve/Load Management Load Leveling
Pumped hydro	Transmission & Distribution Spinning Reserve/Load Management Load Leveling
Flywheels	Power Quality Remote/UPS/Distributed Utility
SMES	Power Quality Remote/UPS/Distributed Utility Transmission & Distribution Spinning Reserve/Load Management Load Leveling
Supercapacitors	Power Quality

Using these scenarios, the author developed energy storage costs.

Technology	Energy Cost ($/kWh	Power Cost ($/kW)	Electrolyzer ($/kW)	Compressor ($/scf)	Discharge Efficiency
Batteries					
Low	175	200			0.85
High	250	300			0.85
SMES					
Mu	70,000	350			0.95
mid	3,000	300			0.95
Flywheels	50,000	300			0.93
Supercapacitors	100,000	300			0.95
SMES	800	300			0.95
CAES	10	425			0.79
Pumped hydro	15	600			0.87
Hydrogen Fuel Cell - Cylinder					
Low	10	500	300	112.5	0.59
High	20	1,500	600	112.5	0.59
Hydrogen Fuel Cell - Underground	1	500	300	112.5	0.59
Hydrogen Fuel Cell - Hydride	15	350	300	57	0.44

The author concluded:

- Hydrogen fuel cells may be used in power quality applications where 15 seconds or more of ride-through are required
- Hydrogen fuel cells or combustion engines are suitable for distributed generation with dispatch
- Large hydrogen systems compete with CAES for cost-effective load management
- Hydrogen-fueled engine systems may be the initial application for stationary systems due to low cost and availability

(54) Fuel Options for the Fuel Cell Vehicle: Hydrogen, Methanol or Gasoline?

Author(s): Thomas, C.E., James, B.D., Lomax Jr., F.D. and Kuhn Jr., I.F.
Date: November, 1998
Organization(s): Directed Technologies, Inc.
Publication:
Category(ies): Transportation
Subcontract No.

In this report, the authors compared the merits of hydrogen, methanol, and gasoline as a fuel for FCVs in five areas:

- Cost (vehicle, fuel and infrastructure)
- Local air pollution
- Greenhouse gas emissions
- Oil imports/national security
- Long term sustainability

Cost

The total cost of the systems was estimated including the fuel infrastructure investment costs, on-board fuel processing costs and fuel prices. The assumptions and costs in each area are detailed in this section.

For the hydrogen FCV, on-site production was assumed. Assuming mass-produced (1,000 units) steam reformers, the infrastructure cost per vehicle was estimated at $230. Up to 1.5 million methanol vehicles could be supported with existing infrastructure, requiring only $50/vehicle for storage and dispensing. When this threshold is exceeded, the investment would be $450/vehicle for the next 2.2 million FCVs. Gasoline was assumed to use existing infrastructure.

On-board fuel processing costs had been examined by the authors in detail in earlier reports. Both pure and hybrid (i.e., with a battery) systems were evaluated. The following table summarizes the infrastructure and on-board fuel processing costs associated with each vehicle type.

Vehicle Type	No Peak Power Augmentation ($/FCV)	Peak Power Augmentation ($/FCV)
Direct Hydrogen FCV	992-1142	992-1142
Methanol FCV		
< 1.5 million FCVs	1359-2414	934-1595
> 1.5 million FCVs	1809-2864	1384-2045
Gasoline FCVs	2388-5247	1509-3169

From this analysis, the authors concluded that hydrogen would be the least costly option, although methanol vehicles would be cost-competitive initially.

In the next section, the fuel costs were estimated, both delivered fuel prices and consumer prices, including taxes were estimated. All fuels were assumed to be taxed on a $/GJ basis ($3.05/GJ) rather than on a per gallon basis. A summary of the results is provided in the table below.

Vehicle Type	Retail Untaxed Price ($/gallon)	Retail Untaxed Price ($/GJ - LHV)	Total Tax ($/gallon)	Consumer Cost (cents/mile)
Gasoline ICEV	0.78	6.45	0.37	3.83
Gasoline FCV				
Best Case	0.78	6.45	0.37	2.73
Probable Case	0.78	6.45	0.37	3.94
Methanol FCV				
Best Case	0.76	12.67	0.183	3.93
Probable	0.76	12.67	0.183	4.39
Hydrogen FCV	NA	11.0	3.05 ($/GJ)	2.58

Incremental vehicle emissions were estimated next. All costs assume mass production and are compared to the base case gasoline ICEV, estimated at $18,000. The cost of the hydrogen FCV is the least at only $2,000 more than the base case. The methanol FCV is the next least costly at $2,800-3,600 more than the base case and the gasoline FCV is the most expensive at $4,000 to 6,500 more.

Local Air Pollution

To determine the local air pollution emissions, an estimate of the fuel economy for each vehicle was made and compared to the conventional gasoline ICEV. The following table summarizes these results.

Vehicle Type	Fuel Economy (mi/gal gasoline equivalent - LHV)
Gasoline ICEV	30
Hydrogen FCV	66
Methanol FCV	
Best Case	48
Probable Case	45
Gasoline FCV	
Best Case	42
Probable Case	29

All estimates were based on a 1.25 factored EPA combined (55% urban/45% highway) schedule. From these economies, the local emissions were projected. These emissions are compared to various vehicle standards and are presented in the table below.

Vehicle Type	VOCs (g/mi)	CO (g/mi)	NO_x (g/mi)
Gasoline ICEV	0.755	7.553	0.704
Hydrogen FCV	0.004	0.003	0.001
Methanol FCV			
Best Case	0.020	0.003	0.001
Probable Case	0.023	0.004	0.001

Vehicle Type	VOCs (g/mi)	CO (g/mi)	NO_x (g/mi)
Gasoline FCV Best Case Probable Case	 0.268 0.371	 0.004 0.005	 0.001 0.001
Tier II	0.125	1.7	0.2
ULEV	0.04	1.7	0.2
SULEV	0.01	1.0	0.02
EZEV	0.004	0.17	0.02

Greenhouse Gas Emissions

The greenhouse gas emissions for each vehicle were determined from the fuel economy estimates. Total well-to-wheel estimates were determined and all major greenhouse gas emissions were converted to CO_2-equivalent emissions.

The following table summarizes the greenhouse gas emissions from each vehicle type and compared to the gasoline ICEV.

Vehicle Type	Greenhouse Gas Emissions (g CO_2-equivalent/mile)
Gasoline ICEV	415
Direct Hydrogen FCV	252
Methanol FCV Best Case Probable	 283 318
Gasoline FCV Best Case Probable	 280 388

Oil Imports/National Security

Both methanol and hydrogen FCVs would virtually eliminate oil consumption. The gasoline FCV, on the other hand, would cut oil consumption by 29% using optimistic assumptions.

Long-term Sustainability

Both hydrogen and methanol meet this criterion since they can both be produced by gasification of biomass or MSW. Gasoline, however, is produced from crude oil and as such is not sustainable.

Conclusions

From this analysis, the authors concluded the following:

- No storage breakthroughs are required for hydrogen FCVs
- Hydrogen requires the least fuel infrastructure per vehicle, assuming on-site production with mass-produced steam reformers
- Hydrogen would be the least costly fuel at 2.6 cents per mile
- Fuel costs for all vehicles would be less than 10% of the total operating costs

- Direct hydrogen FCV would be the least costly vehicle followed by the methanol and gasoline FCVs
- All three fuels would meet the most stringent CO and NOx regulations.
- Methanol and gasoline tail-pipe VOC emissions would exceed SULEV tailpipe emissions.
- Hydrogen FCVs would have the lowest greenhouse gas emissions followed by methanol and gasoline FCVs.
- Methanol and hydrogen FCVs would eliminate oil consumption while gasoline FCVs could decrease it by 29%
- Hydrogen and methanol are potentially sustainable while gasoline is not.

(55) PNGV-Class Vehicle Analysis Task 3 Final Report

Author(s): Thomas, C.E.
Date: June, 1999
Organization(s): Directed Technologies, Inc.
Publication:
Category(ies): Transportation
Subcontract No. ACG-8-18012-01, Modification #2

This report analyzed the fuel economies, costs, and environmental impacts of alternative fuel vehicles using the PNGV-class vehicles. Three types of FCVs (direct hydrogen, methanol, and gasoline) and nine different hybrid electric vehicles were evaluated. Much of this work was built on earlier work performed for the same vehicles using an AIV (aluminum intensive vehicle) Sable design.

The following table compares the AIV and PNGV designs.

Parameter	AIV Sable	PNGV
Drag Coefficient	0.33	0.27
Cross Sectional Area (m^2)	2.127	2.08
Rolling Resistance	0.0092	0.0072
Glider Weight (kg)	852	649
Direct Hydrogen FCV Curb Weight (kg)	1,155	896

The design of the FCV vehicle was the next parameter described. Because there are currently no operating on-board reformers, the author projected best and probable cases as presented in the following table.

Parameter	Methanol Processor Best/Probable	Gasoline Processor Best/Probable
Fuel Cell Size Increase over H2 Fuel Cell	1.10/1.12	1.21/1.36
Efficiency Curve	Theory/Experience	Theory/Experience
Hydrogen Utilization	90%/83.3%	90%/83.3%
Fuel Processor Efficiency (LHV)	84.5%/80%	75%/70%
Anode Exhaust Gas Heat Recovery	75%/75%	70%/0
Reformer Weight (kg)	46/60	55/100

On-board hydrogen storage was assumed to be in 5,000 psi carbon –fiber wrapped composite tanks.

As noted earlier, nine types of hybrid electric vehicles were analyzed. Both series (load-following and thermostat) and parallel HEVs were included. For each of the three HEVs, three different fuel options (hydrogen, natural gas, diesel) were evaluated for each. Peak efficiencies were 38%, 40%, and 43% for natural gas, hydrogen and diesel fuels, respectively.

The authors estimated the vehicle weights using a derived compounding formula. The weights of all power train components were adjusted iteratively to provide equal performance. If extra weight is required for one component, then all other components are similarly increased to provide sufficient acceleration.

Next, the study looked at fuel economy and drive cycles. Several different driving cycles were evaluated including the EPA FUDS/FHDS, car manufacturers' and international driving cycles. In general, the analysis corrected the FUDS/FHDS driving cycles by increasing them by 25% to provide a more realistic estimate of current American driving patterns. From this analysis, the author concluded that at 85.2 mpgge, only the direct hydrogen FCV could meet the PNGV goal of 80 mpgge. The next best vehicle was the diesel parallel hybrid at 74.9 mpgge.

All of the cost estimates were based on mass-production of individual components. Component cost breakdowns for each vehicle were provided in the report. The following table summarizes the total cost of each vehicle as provided in the breakdown.

Vehicle Type	**AIV Sable Design Weight (kg)/($)**	**PNGV Design Weight(kg)/($)**
ICEV	1,304/$2,425	1,042/$2,316
Hydrogen FCV	1,283/$4,527	1,023/$3,966
Hydrogen FCV w/ Battery Power Augmentation	1,291/$4,727	1,032/$4,148
Probable Methanol FCV w/ Battery	1,414/$5,177	1,119/$4,624
Probable Gasoline FCV w/ Battery	1,475/$6,781	1,172/$6,014
Natural Gas Thermostat HEV	1,435/$4,789	1,158/$4,182
Hydrogen Thermostat HEV	1,507/$6,276	1,229/$5,313
Diesel CIDI Thermostat HEV	1,472/$5,073	1,185/$4,481

From this analysis, the author concluded that the conversion from an AIV Sable design to a PNGV would have little effect on the relative merits of fuel cell and hybrid vehicles compared to conventional ICEVs. However, the absolute values of fuel economy, emissions and cost would improve for the PNGVs. Specifically, the author concluded with the following points:

- Only the direct hydrogen FCV can meet the PNGV fuel economy goal using realistic driving cycles.
- The PNGV design improves the fuel economy of the FCV by 29% and the ICEV by 27%.
- The parallel hybrids are the lowest greenhouse gas emitters at 160 g/mi.
- Greenhouse gas and local air pollution would decrease for all vehicles by 27-30% based on the improvement in fuel economy over the AIV Sable design.
- The PNGV design would decrease vehicle cost by more than 10% for FCVs and 20% for ICEVs.

(56) The Delivered Cost of Hydrogen from PV and Wind Electrolysis Systems

Author(s): Mann, M., Putsche, V., Amos, W.
Date: August, 1999
Organization(s): NREL
Publication: P-milestone report
Category(ies): Production, Distribution
Subcontract No.

Four cases were evaluated in this report.

- Case 1 - Minimal renewable size while the storage is sized to meet the load each week
- Case 2 - Oversized renewable to meet the load during the worst resource week of the year and minimal storage requirements with the excess electricity sold over the grid
- Case 3 - Same as Case 2 with the excess hydrogen sold to another customer
- Case 4 - Same as Case 1 with production located at filling station to eliminate transport costs

The study had three objectives:

1. Identify possible low-cost scenarios for hydrogen production from PV and wind
2. Identify problems associated with using hydrogen as a storage medium for wind and PV
3. Test the integration of three models previously developed for hydrogen analysis

In this analysis, three models developed in earlier studies were integrated. The models included an IEA model used to match PV or wind with storage and load, a model to calculate costs of storage and transport and the third model estimates hydrogen production costs from wind and PV.

The analysis was performed in three steps:

1. Determine the power output for each case to meet the hydrogen demand
2. Calculate the hydrogen selling price to ensure an IRR of 15%
3. Determine the lowest cost storage and transport option for 10, 100 and 1,000 miles

The hydrogen production costs were based on the following assumptions.

Plant Installation Date	**2000**	**2010**
Electrolyzer Efficiency	82%	87%
Electrolyzer Capital Cost	$600/kW	$300/kW
Electrolyzer Operating Costs	3% of capital charges	2% of capital charges
Wind Plant Capital Costs	$900/kW	$700/kW
Wind Operating Costs	$0.008/kWh (variable) $5/kW-yr (fixed)	$0.005/kWh (variable) $5/kW-yr (fixed)
Wind Capacity Factor	35%	40%
PV Plant Capital Costs	$3,133/kW	$1,662/kW
PV Plant Operating Costs	$0.008/kWh (variable) $2.75/kW-yr (fixed)	$0.008/kWh (variable) $2.75/kW-yr (fixed)
PV Capacity Factor	28%	30%

Graphs showing the hydrogen in storage were presented next. The least expensive method for storage and transportation were determined for each case and transportation distance. These data are summarized in the following table.

Technology/Case	10 miles	100 miles	1,000 miles
PV			
Case 1	G+GT	G+GT	L+LR
Case 2	M+GT	M+GT	L+LR
Case 3	M+GT	M+GT	L+LR
Case 4	M	M	L
Wind			
Case 1	G+GT	G+GT	L+LR
Case 2	G+GT	G+GT	L+LR
Case 3	G+GT	G+GT	G+GR
Case 4	G	G	G

G - Compressed Gas
M - Metal Hydride
L - Liquid
T - Truck transport
R - Rail Transport

The results of the analysis are provided in the following three tables, one for each transportation distance.

Summary Results at a Transportation Distance of 10 miles

Technology/Case	System Size (kW)	Delivered H_2 Price ($/GJ)
PV		
Case 1	1,700	$196
Case 2	2,843	$167
Case 3	2,843	$129
Case 4	1,700	$187
Wind		
Case 1	2,717	$164
Case 2	14,859	$81
Case 3	14,859	$77
Case 4	2,717	$149

Summary Results at a Transportation Distance of 100 miles

Technology/Case	System Size (kW)	Delivered H_2 Price ($/GJ)
PV		
Case 1	1,700	$196
Case 2	2,843	$172
Case 3	2,843	$134
Case 4	1,700	$187

Technology/Case	System Size (kW)	Delivered H_2 Price ($/GJ)
Wind		
Case 1	2,717	$168
Case 2	14,859	$85
Case 3	14,859	$83
Case 4	2,717	$149

Summary Results at a Transportation Distance of 1,000 miles

Technology/Case	System Size (kW)	Delivered H_2 Price ($/GJ)
PV		
Case 1	1,700	$196
Case 2	2,843	$167
Case 3	2,843	$128
Case 4	1,700	$187
Wind		
Case 1	2,717	$164
Case 2	14,859	$81
Case 3	14,859	$100
Case 4	2,717	$149

From this analysis, the authors concluded:

- Hydrogen from PV systems is more expensive than wind systems
- For both cases, the least expensive hydrogen is obtained in Case 3
- Case 2 is more expensive than Case 3 because electricity is less valuable than hydrogen
- Case 1 is more expensive than Case 3 due to hydrogen storage costs
- Case 4 is more expensive than Case 3 because of higher production costs
- Systems designed to meet a constant load are not economical
- Brokered hydrogen will be the least expensive
- Unless the load matches the resource profile, hydrogen for remote energy needs may not be feasible
- Future studies should focus on grid interaction

(57) Technoeconomic Analysis of Hydrogen Production from Low-Btu Western Coal Augmented with CO_2 Sequestration and Coalbed Methane Recovery Including Delivered Hydrogen Costs

Author(s): Spath, P., Amos, W.
Date: September 1999
Organization(s): NREL
Publication:
Category(ies): Production
Subcontract No.

A technoeconomic analysis of hydrogen production via coal gasification with CO_2 sequestration and coalbed methane recovery was conducted by NREL and the Federal Energy Technology Center (FETC). Four different scenarios were evaluated:

1. Reference Case – Coal gasification, shift and hydrogen production
2. CO2 Sequestration – Reference Case with CO2 sequestration
3. Maximum Hydrogen Production – Case 2 with additional hydrogen production via steam reforming of the coalbed methane
4. Hydrogen/Power Coproduction – Case 2 with power production using the coalbed methane

To evaluate the impact of transport distance, each option was evaluated under six different transport and delivery schemes.

1. Bulk delivery – 16 km one way
2. Bulk delivery – 160 km one way
3. Bulk delivery – 1,610 km one way
4. On-site consumption – 12 hours of storage; no transport
5. Gas station supply
   - Weekly delivery
   - 160 km round-trip
   - Supplying multiple stations along the way
   - Hydrogen use of 263 kg/day/station
6. Pipeline
   - 3 km to nearest infrastructure
   - No storage
   - An additional 160 km pipeline distance for delivery to end-user
   - Cost shared by 5 companies

Each facility was sized to process 2,727 tonne/day of coal, as received. They were assumed to operate at a 90% capacity factor. By-products from the process included electricity, steam (100 and 500 psi) and sulfuric acid. Detailed information on the specific cost factors was provided in the report.

The following table summarizes the material and energy balance for each of the four system configurations based on a feed rate of 2,727 tonne/day of coal. The energy ratio (i.e., energy out of system/energy into system) is also presented.

Case	Coalbed Methane (kg/hr)	H_2 Production (kg/hr)	By-product Electricity (MW)	*Energy* Ratio
Reference	0	8,011	12	0.83 (with off gas) 0.58 (w/out off gas)
CO_2 Sequestration	0	8,011	4	0.57
Maximum H_2	47,366	18,739	-43	0.65
Power Coproduction	36,419	8,011	241	0.50

Using these results and the specified cost parameters, the cost of each option was determined and is presented in the following table.

Option	Reference Case	CO_2 Sequestration	Maximum Hydrogen	Co-Power Production
Plant Gate Selling Price ($/GJ)	17.98	18.72	9.89	13.92
Option 1	19.29	20.03	11.06	15.23
Option 2	21.33	22.07	12.06	17.27
Option 3	26.76	27.50	17.96	22.70
Option 4	19.03	19.77	10.81	14.97
Option 5	21.33	22.07	12.06	17.27
Option 6	18.67	19.41	10.51	14.61

As shown in the table, the plant gate hydrogen cost ranged from about $10/GJ to a high of almost $19/GJ. Delivery adds $1-9/GJ, with bulk delivery at a distance of 1,610 km being the most expensive.

Carbon emissions for each scenario were then developed and are presented in the table below.

Case	CO_2 Emissions (kg/hr)
Reference With off-gas energy credit Without off gas energy credit	 195,707 185,297
CO_2 Sequestration	-3,667
Maximum H_2	65,985
Power Coproduction	-109,065

These values assumed that any electricity displaced would be produced by a ratio equivalent to that in the mid-continental U.S. All greenhouse gas emissions were converted to CO_2-equivalent emissions.

As shown in the table, cases 2 and 4 result in a net decrease in the CO_2 emissions while Case 1 emits the most CO_2.

After the initial cases were evaluated, sensitivity analyses were performed for the following parameters:

- Electricity selling price
- No credit for excess steam
- Increasing the cost of coal
- Eliminating the off-gas fuel credit (Reference case only)

Finally, an estimation of the carbon tax required for carbon sequestration feasible for the CO_2 sequestration case. A value of $13.38/tonne of CO_2 would be required. This tax would have minimal impacts on the other cases, decreasing them from $0.17-$1.42/GJ.

The authors concluded that sequestering CO_2, recovering coalbed methane and making hydrogen or power are economically viable. However, increasing the hydrogen production from SMR is not an environmentally favorable alternative. Finally, a carbon tax would make sequestering the CO_2 economically viable.

The authors proposed future work such as additional cases for evaluation. Primarily, however, they felt that LCAs were mandated for each case in the current study.

(58) Survey of the Economics of Hydrogen Technologies

Author(s): Padro, C.E.G., Putsche, V.
Date: September 1999
Organization(s): NREL
Publication: NREL/TP-570-27079
Categories: Analysis Methodology/General Analysis
Subcontract No.

This report surveyed studies regarding the economics of hydrogen production, storage, transport and end-use applications. Over 100 publications were included in the survey.

The economics of the technologies were standardized using a methodology described in the report. Where standardization was not possible, the literature values were used as a cross-check against the standardized values. The report describes the various technologies and presents the results of the survey and standardization analysis. Both tabular and graphical formats were used.

Costs were presented as the specific total capital investment (TCI) in \$/GJ. This is a measure of the capital cost of the technology for each unit of hydrogen produced, processed or stored. All energy units (i.e., GJ) were on a lower heating value (LHV) basis.

The following is a summary of the standardized results.

Hydrogen Production Technologies

Production Technology	Specific TCI (\$/GJ)	Hydrogen Price (\$/GJ)
SMR		
Large facilities	\$9.0-\$14.7	\$5.4-\$7.5
Small facilities	\$27.5	\$11.2
Coal Gasification	\$33.1-\$34.2	\$9.9-\$11.6
Noncatalytic Partial Oxidation	\$9.6-\$22.2	\$6.9-\$9.8
Large facilities (off-gas and residual oil)	\$22	\$10.7
Small facilities (off-gas)		
Biomass Gasification	\$20.6-\$73.9	\$8.7-17.1
Biomass Pyrolysis		
All reformed	\$14.9-\$26.1	\$12.4-\$15.5
Co-product	\$16.7-\$30.7	\$8.9-\$12.7
Electrolysis		
Large facilities	\$3.0-\$31.0	\$20.6-\$24.5
Small facilities	\$31.9-\$485.8	\$11.0-\$41.8
Concentrated Solar Energy	\$186-\$380	\$34.1-\$62.3

Hydrogen Storage Technologies

Storage Technology	Specific TCI ($/$GJ_{capacity}$)	Storage Cost ($/GJ)
Compressed Gas		
Short term (1-3 days)	$1,726-$16,600	$2.0-$33.0
Long term (30 days)	$580-$3,235	$7.4-$36.9
Liquefied Hydrogen		
Short term (1-3 days)	$1,827-$35,649	$5.1-$17.1
Long term (30 days)	$169-$1,687	$5.9-$25.3
Metal Hydride		
Short term (1-3 days)	$4,191-$18,372	$2.9-$7.5
Long term (30 days)	$18,372	$205
Cryogenic Carbon	$4,270	$26.6
Underground	$7.0-$1,679	$1.0-$5.0

The large ranges in the table are due to differing storage amounts from 131 to 130,600 GJ for short term storage and 3,900 to 3.9 million GJ for long term storage.

Hydrogen End-Use Technologies

End-Use Technology	Specific TCI ($/kW)	Electricity Price ($/kWh)
Fuel Cells		
Short term (1-3 days)	$1,726-$16,600	$2.0-$33.0
Long term (30 days)	$580-$3,235	$7.4-$36.9
Liquefied Hydrogen		
Short term (1-3 days)	$1,827-$35,649	$5.1-$17.1
Long term (30 days)	$169-$1,687	$5.9-$25.3
Metal Hydride		
Short term (1-3 days)	$4,191-$18,372	$2.9-$7.5
Long term (30 days)	$18,372	$205
Cryogenic Carbon	$4,270	$26.6
Underground	$7.0-$1,679	$1.0-$5.0

Hydrogen Transmission Technologies

End-Use Technology	Specific TCI ($/$GJ_{transported}$)	Transport Costs ($/GJ)
Pipeline		
161 km	$2.1-$21.2	$0.5-$2.8
805 km	$7.5-$106.2	$1.2-$13.8
1,609 km	$14.1-$210.3	$2.0-27.2
Truck Transport		
Liquefied Gas	$0.4-$11.0	$0.2-$4.7
Compressed Gas	$4.1-$57.6	$4.7-$79.7
Metal Hydrides	$7.5-$105.5	$2.6-$42.1
Rail		
Liquefied Gas	$0.1-$11.0	$0.8-$2.1
Compressed Gas	$47.2-$78.7	$20.7-$24.8

End-Use Technology	Specific TCI ($\$/GJ_{transported}$)	Transport Costs ($/GJ)
Metal Hydrides	$183.8-$275.6	$28.6-$42.7
Ship	$8.2-$24.6	$13.3-$15.4

On-Site Hydrogen Production Technologies

Production Technology	Specific TCI ($/GJ)	Hydrogen Price ($/GJ)
SMR	$16.7-$56.6	$8.6-$18.3
Electrolysis		
Alkaline	$41.4-$65.3	$25.4-$29.1
PEM	$25.7-$50.5	$22.9-$34.8
Steam	$18.0-$43.5	$17.5-$21.4
Residential	$40.2-$101.3	$21.7-$48.8

Hydrogen Refueling Technologies

Refueling Technology	Specific TCI ($/GJ)	Hydrogen Cost ($/GJ)
LH2	$9.1-$121.9	$11.3-$28.7
Compressed Gas	$29.3-$96.5	$15.9-$26.3
Liquefaction Plant	$13.7	$7.6

The final area summarized was carbon dioxide removal for hydrogen production facilities. Both ocean disposal and well injection were evaluated.

Carbon Dioxide Removal Costs for Hydrogen Production Facilities

Technology	TCI ($/GJ)	Hydrogen Cost ($/GJ)	CO_2 Removal Cost ($/T)
SMR	$13.6-$17.3	$6.2-$6.8	$6.6-$22.7
Coal Gasification	$44.9	$12.3	$13.8

(59) Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming

Author(s): Spath, P., Mann, M.
Date: September, 1999
Organization(s): NREL
Publication: C-milestone report
Category(ies): Production
Subcontract No.

The life cycle analysis (LCA) was a cradle-to-grave assessment covering plant construction and decommissioning, natural gas production and distribution, electricity generation, and hydrogen plant operation. The reforming plant was based on the following parameters.

Design Parameter	**Value**
Plant Size (Hydrogen Production)	1.3 million Nm^3/day
Capacity Factor	90%
Natural gas feed rate	422 Mg/day
Steam requirement 380 psi 700 psi	 1,293 Mg/day 1,858 Mg/day
Electricity requirement	151,700 MJ/day
Plant efficiency (HHV)	89%

The global warming potential (GWP) of the system was estimated for each process area and are summarized in the table below.

Process Area	**% of Total GWP**
Construction and Decommissioning	5.2%
Natural Gas Production and Transport	9.0%
Electricity Generation	4.6%
Hydrogen Plant Operation	81.2%
Total CO_2-equivalent Emissions (g/kg H_2)	11,041

Carbon dioxide emissions accounted for 99 wt% of the total emissions, contributing over 92% of the system's GWP. The remaining greenhouse gases were emitted as follows.

Greenhouse Gas	**Emissions (g/kg H_2)**
NMHCs	65
CH_4	36
SO_x	9.5
NO_x	5
CO, PM, N_2O	<1

Most of the emissions of the non-CO_2 greenhouse gas emissions are due to natural gas production and distribution.

In addition to the emissions, the authors also evaluated several energy balance parameters: hydrogen plant efficiency, life cycle efficiency, external energy efficiency, net energy ratio and external energy ratio. The following table summarizes the definitions of each parameter and the calculated results.

Energy Parameter	Definition[1]	Base Case Value
Hydrogen plant energy efficiency	$\frac{H2 + steam}{NG + elec. + steam}$	89.3%
Life cycle efficiency	$\frac{Eh2 - Eu - Ef}{Ef}$	-31.3%
External energy efficiency	$\frac{Eh2 - Eu}{Ef}$	68.7%
Net energy ratio	$\frac{Eh2}{Eff}$	0.70
External energy ratio	$\frac{Eh2}{Eff - Ef}$	24.7

[1]Where:
Eh2 - Energy in the hydrogen (HHV)
Eu - Energy consumed by all upstream processes required to operate the hydrogen plant
Ef - Energy contained in the natural gas fed to the hydrogen plant (HHV)
Eff - Fossil fuel energy consumed within the system

Resource consumption was the next area evaluated. The following table summarizes these results.

Resource	Total Used (g/kg H_2)	Percentage of Total
Natural gas	3,654	91.8
Oil	169	4.3
Coal	157	3.9
Iron scrap	1	<1
Iron ore	1	<1

Water and solid waste emissions were also evaluated. Water emissions were found to be negligible compared to other emissions. Solid waste produced was considered miscellaneous non-hazardous waste, totaling 77 g/kg of net hydrogen produced. The majority (80.6%) of the waste is due to electricity production, followed by natural gas production and distribution (15.7%), and construction and decommissioning (3.6%).

The final effort was a sensitivity analysis, which looked at the impact of six variables on GWP, life cycle efficiency, external energy ratio, net energy ratio, and external energy efficiency. The following table summarizes the parameters evaluated.

Variable	Base Case	Sensitivity
Materials of construction	Not reported	+50%/-50%
Natural gas losses	3.96%	+10%/-5%

Variable	Base Case	Sensitivity
Operating capacity factor	0.90	0.80/0.95
Recycled/landfilled materials	75/25	50/50
Steam energy	Energy credit for 700 psi steam; energy debit for 380 psi steam	No energy credit for 700 psi steam; 380 psi steam made internally
Hydrogen plant energy efficiency	89.3%	80%

Of all the variables, the reduction in plant efficiency had the greatest impact, increasing most parameters by 15%.

The authors concluded the following:

- Production of hydrogen from natural gas has environmental impacts
- Plant emissions are fairly low, except for carbon dioxide
- Study can be used to compare with other hydrogen production technologies

(60) Comparison of On-board Hydrogen Storage Methods

Author(s): Lane, J.
Date: October, 1999
Organization(s): NREL
Publication: P-milestone report
Category(ies): Storage
Subcontract No.

In this report, eight hydrogen storage technologies were analyzed and compared to gasoline storage. The eight technologies include four well-known conventional technologies and four longer-term technologies as shown below.

- Compressed gas
- Liquid hydrogen
- Metal hydrides
- Carbon adsorption
- Glass microspheres
- Slush hydrogen
- Zeolites
- Sponge iron

Each hydrogen technology was designed for 5-kg storage, corresponding to a 400-mile range for a fuel cell vehicle. The advantages and disadvantages of each technology are discussed below.

Compressed gas
For this technology, the author described a generic version followed by four specific applications: thermocontrolled tank, Ballard fuel cell buses, Ford's compressed tank and Daimler Benz's fuel cell vehicles. In general, these storage systems are simple with a high hydrogen mass density, rapid refueling capability and low cost. The greatest drawback to this technology is its large volume at up to 12 times the space required for an ICE compared to gasoline.

This technology is also advantageous because it can build on the natural gas industry. In fact, four types of natural gas vessels were identified as appropriate for hydrogen storage: aluminum or steel cylinders, hoop-wrapped cylinders, thin metal-lined fully-wrapped cylinders and composite cylinders.

The thermocontrolled tank has been developed by Concordia University for direct injection of hydrogen without additional compression or cryogenic pumps. The Ballard buses use both aluminum alloy lined fiberglass-epoxy composite, hoop-wrapped cylinders or all-composite cylinders. In the Ford system, a very thin laminated metallic polymeric bladder is used for fiber wrapped pressure vessels in passenger vehicles. The Daimler-Benz vehicles use composite tanks.

Liquid hydrogen
This technology can achieve the highest hydrogen mass fraction (7-25 wt%) as well as low system volumes, fast fill and safe operation. Disadvantages of this system include high energy

consumption and hydrogen losses due to boil-off. BMW developed a liquid hydrogen-powered car in the mid-1980's, which was approved for on-road application.

Metal hydrides

Two metal hydride systems were identified as suitable for on-board applications: iron-titanium (FeTi) and magnesium-nickel (Mg-Ni). Metal hydrides are advantageous due to their low volume, safety, and low energy losses. The low volume requirements may be the greatest advantage. Disadvantages include expensive materials, high weight, low operating temperatures, and slow charging times.

Carbon adsorption

Three different carbon adsorption technologies were discussed: activated carbon, carbon nanotubes, and carbon aerogels. Conventional activated carbon technology can be enhanced at high pressures and low temperatures. Carbon nanotubes are currently being developed at NREL in the form of single-wall nanotubes (SWNT's). Researchers there have achieved hydrogen adsorption of 6-7 wt% at ambient temperatures. Carbon aerogels are open-cell foams that are commercially available. Hydrogen adsorption of 3.7 wt% at 8.3 MPa has been demonstrated.

Glass microspheres

In this technology, hydrogen is stored at high pressure (40-62 MPa) in hollow glass spheres. This technology has a simple design and thus the potential for low material cost. While the weight and cost of a glass microsphere system would be one-half that for a metal hydride system, the volume requirement would be double. The technology is still at the laboratory stage with improvements required in high pressure vessel design and system recharging.

Slush hydrogen

Slush hydrogen reduces the volume and structural weight of the system compared to gaseous or liquid systems. This technology stores a homogeneous mixture of 50% solid and liquid at the triple point. It is very energy intensive and costly and is thus generally only being considered for aircraft storage.

Zeolites

Zeolites are crystalline aluminosilicates which operate similarly to glass microspheres. Hydrogen can be stored in zeolites at 200 C and high pressures. This option offers good safety and moderate volume relative to other options.

Sponge hydrogen

H Power Corporation is developing this technology for use in vehicles. Basically, iron oxide reacts with water to produce hydrogen and iron oxide. Regeneration is accomplished by heating the iron oxide in the presence of hydrogen.

This technology has a weight disadvantage due to the water and iron storage requirements. Also, it is unlikely that this technology would be used with FCVs using PEMFC technology due to the high temperature requirements. The development of this technology is still in its infancy and significant operational procedures such as the location of iron reduction is still unclear.

The author concluded that each technology had advantages and disadvantages. The decision of the type of on-board storage would depend on the application.

(61) Manufacturing Cost of Stationary Polymer Electrolyte Membrane (PEM) Fuel Cell Systems

Author(s): James, B.D., Lomax, Jr., F.D., Thomas, C.E.
Date: November, 1999
Organization(s): Directed Technologies, Inc.
Publication:
Category(ies): Utility
Subcontract No. ACG-8-18012-01

This report summarizes the cost of mass-produced PEM fuel cells for use in stationary systems. The authors stressed the differences between PEM fuel cells developed for stationary systems and vehicles and the higher standards required for stationary systems.

The authors developed an equation for estimating the cost of the fuel cell stack based on nine parameters, including two parameters (A and B) that are based on production volumes. The values for A and B were developed for five different parameters and are shown in the table below.

Production Volume (units)	**Cost Parameter A ($\$/m^2$)**	**Cost Parameter B ($)**
100	811.77	311.3
1,000	722.54	363.33
10,000	454.45	428.51
30,000	329.24	405.79
60,000	312.26	160.98

In addition to the fuel cell stack, the system requires several ancillary components such as an air blower, piping and controls. The mass-produced cost of each of these components was also estimated and is summarized in the following table.

Ancillary Component	**4-kW Gross DC Power (100/10,000 units)**	**50-kW Gross DC Power (100/10,000 units)**	**200-kW Gross DC Power (100/10,000 units)**
Air Blower	$208/$197	$774/$733	$1,276/$1,209
Humidification	$110/$110	$115/$110	$130/$117
Radiator	$259/$218	$651/$548	$1,547/$1,303
Stainless Steel Pump	$321/$270	$414/$348	$716/$603
Iron Pump	$50/$50	$136/$128	$435/$411
Controls	$150/$120	$209/$167	$400/$320
Actuation and misc.	$2,291/$2,062	$2,850/$2,565	$4,675/$4,207
Piping, valves	$206/$165	$275/$220	$500/$400
Totals	$3,595/$3,192	$5,423/$4,820	$9,678/$8,569

The authors then compared the total system cost for stationary systems and mobile systems for a 50-kW system. The following table summarizes these results.

Component	**Stationary 50-kW System (100/10,000 units)**	**Mobile 50-kW System (300,000 units)**
Fuel Cell Stack		
($)	$18,395/$9,962	$903
($/kW)	$367.9/199.24	$18.05
Ancillary Components		
($)	$6,270/$5,585	$939
($/kW)	$125.4/111.7	$18.77
Total System Cost		
($)	$24,665/$15,647	$1,841
($/kW)	493.3/310.94	36.82
Fuel Cell Assumptions		
Degradation	6%/year	0
Lifetime (hours)	87,600	5,000
Platinum Loading (mg/cm^2)	0.6	0.25
Cell Power Density (W/cm^2)	0.625	0.646

All costs were based on a platinum price of $380/troy ounce.

(62) Economic Market Potential Evaluation for Hydrogen Fueled Distributed Generation and Storage

Author(s): Iannucci, J., Eyer, J., Horgan, S.
Date: January, 2000
Organization(s): Distributed Utility Associates, Longitude 122 West, Inc.
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review NREL/CP-570-26938
Category(ies): Storage and Transport
Subcontract No.

This report evaluated the potential market penetration of hydrogen-fueled distributed generation and storage and the resulting impacts on the total air emissions from all generation. The market evaluation is based in the Southwestern U.S. for the year 2002.

Six peaking and six baseload distributed generation technologies that could use either natural gas or hydrogen were evaluated. The following table summarizes the technologies evaluated.

Type of Distributed Generator	Heat Rate (Btu/kWh)	Total Installed Cost ($/kWh)
Base Load		
1. Microturbine	11,500	600
2. Advanced Turbine System (ATS)	9,500	425
3. Conventional Turbine/Diesel Engine (NG/H2)	10,000/8,800	700/500
4. PAFC (NG/H2)	8,500/6,375	1500/1500
5. PEMFC (NG/H2)	8,500/6,375	1000/1000
6. SOFC (NG/H2)	7,600/5,700	1000/1000
Peak Load		
1. Microturbine	13,000	500
2. ATS	9,500	425
3. Combustion Turbine	11,000	550
4. Dual-Fuel Engine	9,500	500
5. Diesel Engine Genset	8,500	375
6. Spark-Gas Engine	9,700	375

Using these technologies, environmental externalities were considered. Emission penalties for criteria pollutants were assigned for both the central and distributed generation. These penalties were 3.956c/kWh delivered for centralized distribution and ranged from 2.3c/kWh for combustion turbines to 8.25c/kWh for diesel generators in the distributed generation.

The market potential was then evaluated using the DUVal model. This model uses a statistical methodology based on “value mountains”. These value mountains are the costs to implement a distributed generation option versus an avoided cost option. Included in the cost of ownership for distributed resources are purchase price, installation, financing, depreciation and taxes. Benefits to the utility for distributed generation are the avoided costs not incurred by the utility if it uses the distributed generator, including fuel, O&M, overhead, transmission and distribution costs.

The model assumes that the maximum potential size of the market for distributed generation is proportional to the load growth (MW). Only annual increases in load are considered, which may understate market estimates. The model was based on the Southwest U.S. in 2002, but is assumed valid for 2000-2004.

The authors compared the market share of each alternative both with and without environmental penalties. These results are provided in the tables below. All analyses are based on a total potential market of 1.9 GW/yr.

Peaking Distributed Generator Option	**% of Market No Environmental Penalties**	**% of Market W/ Environmental Penalties**
System Only	100	100.0
Microturbine	26.1	41.9
ATS	74.2	94.2
Combustion Turbine	21.7	34.2
Dual Fuel Engine	32.7	43.0
Diesel Genset	58.2	45.4
Spark Gas Engine	81.6	95.9

Baseload Distributed Generator Option	**% of Market No Environmental Penalties**	**% of Market W/ Environmental Penalties**
System Only	100.0	100.0
Microturbine	0.0	14.5
ATS	0.1	34.2
Diesel Genset	0.0	0.7
PAFC	0.0	100.0
PEMFC	0.1	100.0
SOFC	0.1	100.0

From these tables, it is clear that without environmental penalties, peaking distributed generators are economically competitive for new loads. When penalties for emissions are considered, the economic competitiveness of hydrogen fueled generators increases significantly. Specifically, the market potential for combustion turbines and microturbines increases by greater than 50% for peaking applications. ATSs and spark engines also increase appreciably for peaking sites. For baseload operations, the increases are even more dramatic. For example, fuel cells capture 0-0.1% of the market without environmental constraints, but this rises to 100% when environmental penalties are applied. Similar results are seen for the microturbine and ATSs which rise from near zero market share to 15 and 34%, respectively.

The authors then discussed the fuel cell market potential. Four different situations were evaluated:

1. Fuel cells are cost-effective for **50%** of electric utility load growth **without** environmental externalities

2. Fuel cells are cost-effective for **50%** of electric utility load growth **with** environmental externalities
3. Fuel cells are cost-effective for **10%** of electric utility load growth **without** environmental externalities
4. Fuel cells are cost-effective for **10%** of electric utility load growth **with** environmental externalities

For each situation, plots of fuel efficiency versus installed cost were provided for three fuel price levels. For case 1 with a fuel price of $3/MM Btu and a 55% efficient fuel cell, the installed cost can be $800 kW or less to be cost-competitive for 50% of the electric load growth. With environmental externalities, this cost could increase to $2,600/kW. Using the same assumptions for cases 3 and 4, the allowable installed cost is $1,030/kW for case 3 and $2,830/kW for case 4. Costs for the 50% market penetration are lower than the 10% penetration because at the higher penetrations, the fuel cells will have to compete in locations where the marginal cost for electricity is low.

From this study, the authors concluded:

- Hydrogen-fueled peaking resources have a significant market potential of 33-91% compared to only 45-98% for conventional natural gas peaking technologies.
- With environmental penalties, the market share for hydrogen peaking technologies increases to 44-98%.
- Hydrogen technologies, in general, do not gain considerable market potential unless environmental externalities are considered.
- With environmental externalities, hydrogen-fueled turbines and fuel cells are promising.

(63) Applications Analysis

Author(s):	Ohi, J.
Date:	January, 2000
Organization(s):	NREL
Publication:	Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):	Outreach
Subcontract No.	

Three activities supporting hydrogen technology development were summarized: establishment of codes and standards for hydrogen applications, technical coordination of Hydrogen Program activities, and technical support to the DOE Hydrogen Technical Advisory Panel (HTAP). The accomplishments in each area are summarized below.

Codes and Standards

In 1997-1998, NREL worked with the Hydrogen Research Institute (HRI) at the University of Quebec and a panel of hydrogen experts from industry, academia and government to develop a sourcebook on hydrogen safety. The sourcebook, *The Sourcebook for Hydrogen Applications*, is a compilation of prevailing practices and applicable codes, standards, guidelines and regulations for the safe use of hydrogen. Its purpose is a reference guide for use by developers of safe hydrogen projects at a non-industrial scale; it is not a design handbook or a surrogate for the codes and standards currently under development by the International Standards Organization (ISO).

The team plans to continue their work, initially addressing the safety concerns of key stakeholders in hydrogen safety, including the insurance industry and building and fire code officials. The team will also look at public perceptions of hydrogen and take steps to rectify its negative image, including the development of general publications, a web site, and more focused versions of the *Sourcebook*.

Technical Coordination

This effort focused on hydrogen use in aircraft and buses. NREL presented a paper on the environmental benefits of hydrogen use in aircraft at a NASA workshop. It also drafted a memorandum of understanding between DOE and NASA on hydrogen RD&D.

NREL initiated a coordinated hydrogen bus technology development program in California among DOE, the Federal Transit Administration, the California Air Resources Board, the California Energy Commission, the South Coast Air Quality Management District, three transit agencies and other interested groups, which resulted in the formation of the California Hydrogen Bus Coordination Committee. The Committee plans to work with the California Fuel Cell Partnership to develop a comprehensive technology development plan for hydrogen vehicles in California.

Technical Support

NREL summarized all major recent scenario analyses of future energy use and energy systems for the HTAP Scenario Development Committee. This summary will provide a long-term context for hydrogen RD&D investments by the federal government.

NREL also addressed fuel choice. It co-chaired and gave presentations on this issue at the Fuel Cell Seminar, organized and chaired the first SAE session for fuels in fuel cells and conducted a fuel choice session a the Spring HTAP meeting. Finally, NREL co-authored a paper with HTAP on fuel choice, which was scheduled for expansion in 1999.

(64) Hydrogen Cluster Council (H_2CC)

Author(s): Keller, J.
Date: January, 2000
Organization(s): Sandia National Lab
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):
Subcontract No.

This paper described the purpose, membership, funding and efforts of the Hydrogen Cluster Council (H_2CC). Its purpose is the use and acceptance of hydrogen. It catalyzes and assists regional efforts to establish and maintain hydrogen clusters for the advancement of hydrogen. The regional groups are comprised of representatives of federal funding agencies (e.g., DOE, NASA), HTAP, academia, and professional organizations. The overall objective of the Council is the facilitation of a national effort to create an infrastructure for hydrogen energy utilization.

In the past year, the Council held two meetings, commissioned a subcommittee to draft guidelines for potential cluster sites, and worked on several new California transportation demonstration activities. In the future, the committee plans to develop more cluster activities to promote the development of a hydrogen infrastructure and to obtain funding, on a regional basis, outside of DOE.

(65) Development of Codes and Standards for the Safe Use of Hydrogen

Author(s): Miller, K. and Mauro, R.
Date: January, 2000
Organization(s): National Hydrogen Association
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):
Subcontract No.

This subcontract was initiated in February 1999 and so results were presented for only the first quarter. However, the authors presented a summary of past work, specifically on the work done through a cooperative agreement between U.S. DOE and NHA. In general, the past year's work focused on the development of work groups to establish standards for hydrogen based on experience with natural gas and to encourage the safe use of hydrogen in vehicles. The work groups included:

- Connectors – focused on hydrogen fuel connectors
- Containers – focused on hydrogen tanks and other containers
- Service Stations – focused on service stations, especially material compatibility
- Sourcebook for Hydrogen Applications – development of a reference manual for hydrogen development projects

All of the tasks interfaced with International Standards Organization Technical Committee 197.

The current year's work was comprised of four tasks:

1. Facilitation of the Development of Recommended Practices and Codes and Standards
2. Determination of the Need for Development of Additional Recommended Practices and Codes and Standards
3. Codes and Standards Session
4. Validation of Hydrogen Codes and Standards

As noted earlier, this subcontract had just started and so only brief results were presented. However, the authors did describe planned work under the subcontract. Both the to-date results and proposed work for each task are summarized below.

Facilitation of the Development of Recommended Practices and Codes and Standards
Plans for a workshop were underway.

Determination of the Need for Development of Additional Recommended Practices and Codes and Standards
A Codes and Standards (C&S) workshop was held in July 1998 and a list of ten items for consideration was developed. From this list, another list of four near-term importance was generated and is reproduced below:

- C&S for the use of electrolyzers and fuel cells at customer sites, including homes
- C&S for safe self-service refueling of hydrogen vehicles
- Certification program for hydrogen vehicle fuel systems
- C&S for maritime unique applications of hydrogen

The NHA also identified hydrogen tanks, specifically composite and metal hydride, as another area for further development. These issues would be addressed within the ISO-TC/197.

Codes and Standards Session

The NHA organized and conducted a plenary session for the 1999 ISO/TC 197 meeting and related ISO working groups at the 10th Annual U.S. Hydrogen meeting.

Validation of Hydrogen Codes and Standards

NHA solicited technical reports on current and recent demonstration evaluations, which will be used to refine the codes and standards activities. Presentations on the reports were provided at the 10th Annual Hydrogen meeting. In addition, the NHA attended the DOE Fuel Cell Codes and Standards Summit.

The authors concluded with a listing of future work under the contract, including planning and conducting a codes and standards workshop, collecting and evaluating information on the safety record and codes and standards employed for current hydrogen field tests and technology validations, and collecting and evaluating boilerplate codes that may be applicable to hydrogen systems.

(66) Hydrogen Outreach, Education and Awareness

Author(s): Anderson, D. and Hurwitch, J.
Date: January, 2000
Organization(s): Sentech, Inc.
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):
Subcontract No.

The main objective of the final year of a three-year effort was the dissemination of information, both technical and non-technical to a variety of audiences. The outreach focused on three major stakeholders: US industry, educators and students, and the general public.

In the area of industry outreach, the authors worked on determining the near-term direction and requirements for a hydrogen transportation infrastructure. Included in this effort were targeted industry and other stakeholder meetings culminating in a workshop scheduled for late 1999. The authors would also prepare a meeting report and brochure. In addition to this effort, the authors had participated in a variety of pertinent meetings with groups such as HTAP, H_2CC and a California-led bus project.

The primary effort in the education task was the development of *Mission* H_2, an interactive CD-ROM about hydrogen. The software, along with a teacher's guide was scheduled for completion in 1999. Sentech was also working to obtain funding from the project from industry sources. At that time, SunLine Transit Agency had contributed $10,000 and sponsorship from International Fuel Cells was being pursued.

Public outreach was accomplished primarily through a hydrogen "roadshow". During the past year, the authors presented technical papers and exhibited a hydrogen display. The following list summarizes the papers and exhibitions.

- Prepared the paper, "Enabling Hydrogen in the 21st Century, The U.S. Department of Energy Hydrogen R&D Program", presented at the Canadian Hydrogen Conference
- Created and exhibited, "Hydrogen Power – The Evolution of Energy" at the Annual National Hydrogen Association meeting
- Exhibited at the 4th Annual Renewable Energy and Energy Efficiency Expo: Clean Energy Works '99, the 5th Annual Clean Cities Conference, and the 7th Annual Electric Vehicle and Alternative Fuel Conference
- Developing general, non-technical hydrogen awareness brochure and a series of 1-page technology success story fact sheets.

The authors concluded outlining their plans for future work:

- Utilize technology roadmapping in the hydrogen R&D effort by holding workshops and building consensus action plans between government and industry
- Development of a teacher's information package for secondary schools, including the *Hydrogen Clean Corridor Curriculum*, *Mission* H_2 CD-ROM, *Hydrogen 2000 Renewable Power* video, and instructions for hydrogen experiments

- Continue hydrogen roadshow exhibitions
- Expand multi-media material for hydrogen promotion
- Measure the effectiveness of outreach projects.

(67) Hydrogen Energy Systems Studies

Author(s):	Ogden, J.
Date:	January, 2000
Organization(s):	Princeton University
Publication:	Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):	
Subcontract No.	DE-FG36-95G010061

This report summarizes the results of two studies: 1) The Assessment of Potential Supplies and Demands for Hydrogen Energy in the New York City/New Jersey Area and 2) Carbon Dioxide Sequestration for Hydrogen Energy Systems.

Task 1: Assessment of Potential Supplies and Demands for Hydrogen Energy in the New York City/New Jersey Area

This effort addressed three questions:

1. What is the potential hydrogen demand for the transportation market in the New York City/New Jersey area?
2. What are the potential supplies of hydrogen for this market, including
    - truck delivered or pipeline delivered merchant hydrogen
    - hydrogen byproduct from chemical plants and refineries
    - on-site hydrogen production from steam reforming of natural gas at small scale
    - electrolytic hydrogen from off-peak power
    - hydrogen from gasification of MSW
3. What is the production cost and delivered cost of hydrogen transportation fuel from these sources?

Results from each area are presented below.

Hydrogen demand for the transportation market in this area was estimated using broad assumptions to provide limits on the total required. Using assumptions for fuel economy, vehicle miles traveled, projected vehicle demand and other pertinent assumptions, the authors projected the following hydrogen demands:

- 1000 million SCFD to fuel 209 million miles/day for NJ light-duty vehicles in 2010
- 33 million SCFD for NJ transit buses
- 250 million SCFD for NYC light-duty vehicles
- 15 million SCFD for NYC transit buses
- 20 million SCFD for a fleet of 100,000 cars

In the second task of this project, the authors looked at potential existing hydrogen supplies as well as unexplored hydrogen supplies. The following table summarizes the preliminary results for this project.

Hydrogen Source/Production Method	Status
Area Industrial Gas Companies	Area gas companies provide H_2 via truck as liquid or compressed gas No hydrogen gas pipelines All primary gas companies serve the area
Refinery and Chemical Plant Excess Hydrogen	Several area refineries and chemical plants may have excess hydrogen Few million SCFD may be available from this source
Off-peak power	Significant (18,000 MW) off-peak power available High off-peak power cost ($0.07-0.08/kWh) On-site electrolysis would be expensive Costs may go down with deregulation
On-site production from natural gas	Moderately high natural gas prices
Gasification of MSW	H_2 from MSW could fuel 44% of NYC's light-duty vehicles Landfill space is almost exhausted Commercial process not available

In the third area of this task, the delivered cost of hydrogen was determined. The authors estimated the cost of delivered hydrogen from the following scenarios based on electricity and natural gas prices in the NYC/New Jersey area.

- Centralized SMR with liquid truck delivery
- Centralized SMR with pipeline delivery
- On-site, small-scale SMR
- On-site, small-scale electrolysis using off-peak power

The following table presents the results of this study.

Production/Delivery Method	Delivered Hydrogen Price ($/GJ)
SMR w/ LH2 truck delivery	$19
SMR w/ pipeline delivery	$17
MSW gasification w/ pipeline delivery	$18
On-site reforming	$15
On-site Electrolysis	$33

Based on this information, the authors contended that delivered hydrogen in the NYC/NJ region would range from $15-40/GJ with electrolytic sources being the most expensive.

The authors then concluded this section with a description of data sources, analysis methods, and technology transfer.

Task 2: Carbon Dioxide Sequestration for Hydrogen Energy Systems

In this task, the low-cost separation and permanent underground sequestration of CO_2 produced during hydrogen production (e.g., steam reforming, biomass gasification) was evaluated. After separation of the CO_2, it is compressed and piped to a site for underground storage.

The analysis addressed to answer the following issues:

- Cost of hydrogen production with CO_2 sequestration vs. other options
- Economies of scale for CO_2 sequestration with hydrogen production
- Plausible scenarios for transition to a large-scale hydrogen energy system

Each of these issues was addressed as a separate sub-task of the subcontract, but were not delineated in the report.

The authors begin this section by presenting the hydrogen required to meet various end-use demands. The values presented range from 0.04 GJ/day for a single FCV to 0.3 million GJ/day to fuel all of the cars in L.A. to 3 million GJ/day to replace all of the current natural gas in Southern California.

The authors described steam reforming in detail and provided cost estimates. They also compared different hydrogen purification schemes (i.e., PSA vs. absorption) in terms of hydrogen purity, costs, and other factors (e.g., secondary environmental impacts). The costs for reformers were estimated for mass-produced small-scale (0.1 million SCFD) to large-scale (300 million SCFD). Even though mass production would decrease the cost of small-scale decentralized units, centralized production would still result in lower costs due to the lower feedstock prices. The cost of hydrogen production from both centralized and decentralized, small-scale, mass-produced reformers are evaluated. Conventional, centralized, large-scale SMR can produce hydrogen at < \$5/GJ. For on-site reforming, the costs range from \$10/GJ for a conventional design to \$5/GJ for 1000 units of an advanced design.

The cost of pipeline transmission was presented next as a function of pipeline length and number of fuel cells served. In general, costs are lowest for large flowrates and short distances. Local distribution costs were also presented. These costs vary with the density of the demand and can range from \$2/GJ to \$5/GJ.

Centralized and decentralized hydrogen production from natural gas was compared next. Decentralized production with mass-produced advanced reformers is competitive with centralized production at about \$10/GJ due to the high distribution costs of centralized production. The authors contended that this suggests that a hydrogen infrastructure will be built up using on-site production first.

The incremental costs for separating and compressing CO2 were projected for the two cases:

- 50% recovery of carbon from NG = \$53/tonne C
- 70% recovery of carbon from NG = \$61/tonne C

These costs are about the same as those for removing CO_2 from flue gases.

The authors then evaluated the feasibility of collecting CO_2 from distributed applications. This option, however, was found to be costly due to the distribution costs. It would always be more cost effective to have centralized production with a distribution charge than to have distributed production with a distribution charge. The major advantage of on-site distribution is the lower distribution costs.

The incremental cost of CO_2 pipeline transmission was evaluated next. As expected, costs increase with distance and are with decreasing flow. For example, the incremental cost for a single refueling station servicing 9000 cars and transporting the CO_2 1000 km is about $400/GJ. At the other end, to fuel all of the cars in L.A. and transport the CO_2 100 km, the cost is roughly $0.20/GJ.

Costs for CO_2 injection and storage were also presented. Storage costs in onshore aquifers were estimated to be $2-8/tonne CO_2 and $0.50-3/tonne CO_2 for storage in large onshore gas fields. The total costs, again, depend on the flowrate. At a flowrate of 340 tonnes/day of CO_2, the cost is about $8/ tonne CO_2 ($0.3/GJ H_2) but at ten times the flow, the cost is less than $2/tonne CO_2 ($0.1/GJ H_2).

The costs of long distance pipeline transmission for hydrogen, natural gas and carbon dioxide were compared. In general, hydrogen transmission costs are 10-20% of the hydrogen production price and natural gas transmission is less than half the cost of hydrogen transmission. Carbon dioxide transmission costs, for the most part, fell between these values.

From these analyses, the authors concluded the following:

- Engineering and economic models were developed for pipeline transmission of hydrogen, methane and CO_2, and for hydrogen production with various methods of CO_2 separation
- Strong economies of scale exist for gaseous hydrogen pipeline transmission, hydrogen production, CO_2 separation and CO_2 injection
- For long pipeline distances, a large flow is required to minimize transmission costs
- A large CO_2 flow would be required to minimize transmission costs unless sequestration was performed near the site
- At large flows, the cost of hydrogen pipeline transmission is 10-20% of the cost of production over distances of 300-1000 km
- At very large flows (i.e., fueling half the cars in L.A.), the cost of CO2 transmission is < 5% of hydrogen production cost
- Collection of CO_2 from small dispersed sources is not economically attractive
- CO_2 sequestration would only be considered when there is large-scale centralized production
- Initially, demand for hydrogen would likely be met by on-site production from natural gas without sequestration.

As with the previous section, the authors detailed their data sources, analysis methods and technology transfer interactions.

The authors concluded with a lengthy and detailed proposal for future work in the area of PEMFCs for distributed generation and cogeneration.

(68) Studies on the Production and Delivery of Hydrogen from Renewable Resources

Author(s):	Mann, M., Spath, P. and Amos, W.
Date:	January, 2000
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Summaries of four studies were presented in this paper:
1. Storage and Transport Computer Module
2. Application of the Module to Hydrogen from Biomass Gasification
3. PEC Housing Unit Analysis
4. Hydrogen Production from low-Btu Coal

The first three studies have been completed and the fourth is an on-going effort with FETC. Summaries of the studies are presented below.

Storage and Transport Computer Module

An Excel spreadsheet-based computer module was developed to determine the lowest cost storage and transportation method for a specific production rate and delivery distance. This module includes compressed gas, liquid and metal hydride storage methods and pipeline, truck, ship and rail transport. Assumptions for the costing are clearly spelled out and can be overwritten by the user. The minimum information requirements are:

- Production rate
- Delivery distance
- Minimum on-site storage
- Weighted average cost of capital

After this minimum set of information is entered, the module calculates and highlights the minimum cost option.

In this analysis, a hypothetical example was selected for demonstration. For a production rate of 100 kg/h, a delivery distance of 200 km (one-way), a minimum on-site storage time of 12 hours and a weighted cost of capital of 15%, metal hydride storage with truck delivery was the least cost option.

For illustration, a table and a figure comparing three different storage methods with truck delivery were provided. The authors then discussed some of the trade-offs among the various storage and transportation methods. Specifically, they noted that the cheapest alternative will vary depending on the production rate and delivery distance. A graph showing the regions of least-cost was presented for varying distances and production rates. In general, the authors pointed out that pipeline or liquefied gas options were the most cost-effective at high production rates to justify the high capital expenditures. At lower production levels, compressed gas is the least cost. In addition, the authors noted that there is a region between compressed gas and liquefied gas where metal hydrides are the least-cost option.

The authors then presented a graph showing the non-linear relationship between transportation cost and delivery distance. A graph of the cost versus production rate was also presented.

Future analyses will use this module to help determine the delivered price of hydrogen.

Application of Module to Hydrogen from Biomass Gasification
The module was then applied to an earlier analysis of hydrogen production via biomass gasification using the IGT gasifier.

Six different scenarios were studied:
1. Bulk delivery: 16 km one-way
2. Bulk delivery: 160 km one-way
3. Bulk delivery: 1,610 km one-way
4. On-site consumption (no transport): 12-hour storage
5. Gas station supply: weekly hydrogen delivery to multiple refueling stations, 160-km round trip, 263 kg/day hydrogen use per station
6. Pipeline: 3 km to nearest pipeline, no storage, 160-km to 5 end-users

Each of these scenarios was evaluated for both the 100 and 1,000 Mg/day plants. The most economical method for each scenario and plant size is shown in the table below.

Plant Size/ Scenario	**Storage Method**	**Transport Method**	**Storage cost ($/GJ H_2)**	**Transport cost ($/GJ H_2)**	**Total cost ($/GJ H_2)**
300 Mg/day					
1	Gas	Pipeline	1.53	1.79	3.32
2	Gas	MH – truck	1.53	8.73	10.26
3	Liquid	Liquid – rail	9.97	2.04	12.01
4	Gas	None	1.53	None	1.53
5	Gas	MH – truck	1.53	6.03	7.56
6	None	Pipeline	None	3.94	3.94
1,000 Mg/day					
1	Gas	Pipeline	1.23	0.55	1.78
2	Gas	Pipeline	1.23	5.44	6.67
3	Liquid	Liquid – rail	7.95	1.98	9.93
4	Gas	None	1.23	None	1.23
5	Gas	Pipeline	1.23	5.44	6.67
6	None	Pipeline	None	1.26	1.26

The total delivered cost was then calculated by adding the plant gate cost to each scenario.

Hydrogen Production from low-Btu Coal
Hydrogen production via gasification of low sulfur Western coal and the subsequent sequestration of the CO_2 for recovery of coal bed methane was the focus of this on-going study. The recovered methane is then used in the gasification process. Several processing schemes were evaluated to maximize hydrogen production or co-produce hydrogen and electricity.

Wyodak coal was selected for evaluation because it is inexpensive, abundant, and coalbed methane extraction is permissible from these beds. The gasification process selected for evaluation was the Destec gasifier. This system is a two-stage, upflow gasifier that is being demonstrated under FETC's Clean Coal Technology Program at the Wabash River Coal Gasification Repowering Project. Feed to the gasifier is a coal/water slurry with 53 wt% solids.

Two options were evaluated for the study:
1. Maximize hydrogen production
2. Co-produce hydrogen and power

Other options may also be explored in this on-going study. A base case was also evaluated which included only gasification, sulfur removal, shift, and hydrogen production. Carbon dioxide sequestration and coalbed methane recovery were not included in this case.

Sulfur removal was an important consideration in this study. The authors briefly compared various sulfur-removal methods and selected hot gas clean-up as the most economical.

Parameters for the coalbed methane recovery were presented.

PEC Housing Unit Analysis
This analysis expanded the work done in a 1998 analysis where the cost of PEC housing was projected to be more than 20% of the total capital costs, but with a high degree of uncertainty.

The authors began the analysis with a description of the PEC process. They then outlined the necessary characteristics for PEC housing as follows:
- Resistant to electrolyte solution
- Stability in an aqueous environment
- Transparent to light from 400-1000 nm
- UV stable
- Stable within the expected temperature range
- Low hydrogen permeability
- Low cost

Thermoplastic resins were selected as potentially applicable for this system. These resins can be classified into three broad cost categories: low, mid and high-cost. A table summarizing these categories is provided below.

	Low-cost	**Mid-cost**	**High-cost**
Examples	Styrene acrylonitrile (SAN), crystal polystyrene, clear acrylic butadiene styrene (ABS)	Acrylic, PETG, and polycarbonate	Fluoropolymers
Price of Raw Pellets	\$0.36-1.00/lb	\$0.90-2.00/lb	\$6.00-12.00/lb

The authors then contacted polymer suppliers and summarized information for many types of polymers in the categories outlined above. From this summary, several polymers were eliminated from further consideration. Three polymers, acrylic, PETG and PET, appeared the most promising and were evaluated further. The authors also noted that some of the polymers that were disqualified could meet the specified criteria using coatings; however, this option was not explored in this analysis.

The optics of the systems were tested by constructing acrylic cylinders of various sizes, bonding bases onto them and filling with water. Tests were also conducted with acid and base to increase the index of refraction. It was noted that light reflection appeared high and should be addressed.

Costs for each of the remaining polymers were obtained from the manufacturers. In general, acrylic was the most expensive ($3.50-3.60/ft) and PET/PETG were roughly the same ($1.80-2.75/ft).. The authors estimated that the entire housing assembly would cost 20-50% more than the price of the tubes. Based on this assumption and the prices obtained from the manufacturers, the authors estimated the price of the housing at $4.20-5.25/ft for acrylic and $3.00-3.75/ft for PET or PETG. If the number of units is very large, the cost of a PET housing could be as low as $2.10-2.60/ft.

When compared to the 1998 analysis, the costs for PET/PETG are similar to those in the study for near and mid-term technologies, but the long-term prices are higher. The acrylic prices are considerably higher and were not considered further.

The price of PET/PETG may rise due to the current oversupply and the likelihood of new markets and applications. While PET and PETG are similar in cost, PET is likely the better choice due to its lower hydrogen permeability and higher durability. The UV stability of PET, however, must be improved.

The authors concluded with a summary of the housing prices based on different economic scenarios. The summary is provided in the table below.

	Base Case Material Cost ($7.00/m)	**Low Material Cost ($9.80/m)**	**High Material Cost ($12.30/m)**	**Very low Material Cost $6.90/m**
15% after-tax IRR, 37% tax rate	$36.2/GJ	$39.7/GJ	$42.9/GJ	$36.0/GJ
15% after-tax IRR, 28% tax rate	$33.1/GJ	$36.3/GJ	$39.2/GJ	$33.0/GJ
0% pre-tax IRR	$8.5/GJ	$9.2/GJ	$9.8/GJ	$8.5/GJ
Housing % of total capital cost	23%	29%	33%	22%

The authors concluded that if a large volume of PEC housing units are produced, then the cost would likely be close to that in the 1998 analysis. It is more likely, however, that the costs will be significantly higher due to smaller production volumes and/or higher raw material prices. The housing would remain a significant cost for this technology.

(69) Hydrogen Education Outreach

Author(s): Szoka-Valladares, M.
Date: January, 2000
Organization(s): M.R.S. Enterprises
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
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This paper summarized the work in the Hydrogen Education Outreach effort. This effort was designed to educate students and teachers about the properties and benefits of hydrogen, its technology applications and its potential as a fuel and energy carrier. The projected audience for this effort is kindergarten through college, but the primary emphasis thus far has been for secondary school. In addition, the outreach will also focus on informal education for non-technical students. Specifically, the Outreach has two technical goals:

1. to develop and disseminate instructional materials and educational tools consistent with "inquiry-based" pedagogy and practice of science education
2. to produce live science education shows for target audiences.

The outreach focused on two major activities: educational materials and live science shows. Summaries of each effort are presented below.

Educational Materials

In this area, a formal high school curriculum, *The Clean Corridor Curriculum*, has been developed. The CCC is organized into five modules and a final project:

- Fundamentals
- Production
- Storage
- Distribution and Safety
- Utilization
- Final Project: Hydrogen Filling Station

The curriculum was designed with a 5E format – engagement, exploration, explanation, extension, and evaluation. The curriculum may be used in several ways:

- All 5 modules and the final project
- Individual modules, as needed
- Mix of lessons from 1 or many of the modules
- Final project as a stand-alone unit

In 1999, the curriculum was reviewed and the field test phase was initiated. In this phase, new and revised curricula will be introduced to targeted classrooms. After assessing their merit and utility, the results will be used to provide guidance for revisions and enhancements of the material.

Teachers were solicited to participate in the field testing of the CCC. In the recruitment process, the following items were considered: geographic representation, school district diversity, commitment to science education reform. No stipend was available for this effort, and so teacher involvement was voluntary. Teachers receiving the curriculum represented all areas of the country. A classroom commitment of 10 hours was asked of each teacher. To incorporate the teachers' input, a two-week workshop was planned for the summer. Revisions for advanced placement classes had already been proposed.

Another workshop was planned to develop a middle school curriculum. Participants would be local middle school science teachers. The existing CCC would be the starting point in this effort. It was expected that the middle school curriculum would not be standardized as the high school CCC due to the wide range of middle school curricula currently employed in the country.

Live Science Shows

The live science shows are part of the Secondary School Invitational, an annual seminar held in conjunction with the National Hydrogen Association Annual Conference. The science shows, the Dr. Bob Show, is a DOE-created program to teach students about the promise of a hydrogen future, incorporating the annual theme of the conference. At the Invitational, the show is held in the morning with hands-on activities in the afternoon. In addition, special events such as debates or career opportunities are also presented. This show has expanded to include on-site presentations at schools. One of the shows was filmed for use as a video.

At this year's conference, the Dr. Bob Show focused on setting global standards and relied heavily on the CCC. Also included in the presentation was another film, Renewable Power: Earth's Clean Energy Destiny. An addition to the show was a sidekick, Little Jon. Two demonstrations were also part of the program. Red Thunder, a remote-controlled fuel cell car was the first demo and a fuel cell powered ice cream maker developed by Merit Academy students in conjunction with Schatz Energy Research Center was the second.

Another student group, an AP class, presented the results of their Hydrogen Filling Station Project. In the afternoon, the students participated in three small groups covering the following topics:

- Hands-on science with Dr. Bob and crew
- Learning Center which included a fuel cell hardware, hydrogen sensors, photobiological hydrogen production and applications, hands-on experience with the fuel cell car and ice cream maker
- Live Fuel Cell vehicles

Finally, the Dr. Bob Show was taken to a local middle school. Both the high school and middle school shows were filmed.

Promotion and Product Branding

In addition to these efforts, the Hydrogen Education Outreach program was promoted at several conferences:

- Maryland Association of Science Teachers (MAST)
- National Science Teachers Association (NSTA)
- Maryland Eisenhower Conference
- ChemEd Biennial Conference

The author concluded the report with a discussion of future work.

- Live Science Shows – They will continue and may expand to be stand-alone events. A Dr. Bob Show may be produced with FY99 footage for broadcast by local cable. In addition, plans for a major cable production for educational purposes and a film for broadcast are underway
- Instructional materials – A video clip of *Red Thunder* is scheduled for production. Two existing hydrogen film resources, *Element One* and *Renewable Power: Earth's Clean Energy Destiny*, will be incorporated into the curriculum if contractual details can be resolved. Field testing of the middle school curriculum will be initiated along with additional field testing of the revised CCC. In addition, the Outreach would like to develop a curriculum to teach education majors. Finally, primary school and college educational materials will be developed.
- Curriculum Dissemination – Selection of appropriate distribution channels is a high priority. Development of a web-based methodology in conjunction with traditional dissemination methods had been proposed.
- Challenge Grant – A grant program will be developed ($250-$2500) to provide motivation to teachers to undertake hydrogen programs and to stimulate greater hands-on involvement.
- Dream Project – Exploration of providing remote control fuel cell car kits would be explored.

(70) Hydrogen Enriched Fuels

Author(s): Roser, R.
Date: January, 2000
Organization(s): NRG Technologies, Inc.
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):
Subcontract No.

This activity focused on the development of hardware and infrastructure to allow mixtures of hydrogen and conventional fuels to become viable alternatives to conventional fuels alone. To achieve this goal, the author contends that emission levels of < 0.03 g/kWh NO_x and CO and 0.15 g/kWh of NMHC at full engine power without catalysts. Major obstacles to reaching these goals is the lower engine output with lean-burn engines, high hydrocarbon emissions and higher cost. To address these issues, the author evaluated known technologies and techniques.

This effort was designed for completion over a three-year period. In this paper, the results of Year 2 are presented. The tests conducted for this year were:

- Single-cylinder engine
- Exhaust gas recirculation
- Lean-burn power recuperation with an innovative supercharger system
- Steady-state engine dynamometer testing for the effects of excess air, speed, load, ignition timing, and catalyst effects with 30% H_2 and natural gas
- Different cylinder head designs
- Vehicle driveability
- Transient emissions testing
- Pre and post-catalyst speciation

A description of the methodology and the results obtained are summarized below.

Single-Cylinder Engine
The cylinder head was replaced with a dual-plug head because it would allow evaluation of extending the lean limit by adding extra ignition energy. The head was also changed to have a 12:1 compression ratio, up from a 8.7:1. The testing of the new head was not yet complete and so no data were presented.

Exhaust Gas Recirculation
EGR and lean burn operating methods were compared in terms of their NO_x emissions. Both systems used 28% hydrogen and wide-open-throttle, 1800 rpm, and a constant 6% exhaust oxygen content. EGR was defined as excess air and recirculated exhaust gas while lean burn included excess air only.

This test showed that the NO_x emissions from both systems were similar. The author also evaluated total hydrocarbon (THC) emissions and the coefficient of variation (COV), a measurement of engine stability. The EGR engine had superior performance in THC emissions, but lower performance for COV.

Supercharger System
The supercharger system incorporated into the 4.6L engine was the same as that used for Ford Mustangs. A short study on pulley size was conducted and a 3 in diameter pulley was selected.

Emissions for the supercharged engine under wide open throttle conditions with a constant 10% excess oxygen in the exhaust were presented. While these conditions are in the normal driving range, the authors contended that they should provide the worst-case emissions. The results showed that the supercharger does increase air flow and power, but it increases NO_x emissions. Future work would thus look at inter-cooler options to address the increased NO_x emissions.

The author also evaluated NO_x emissions as a function of speed, load and oxygen content. From this evaluation, the author was able to determine the safety margin between clean, stable operation and high THC, unstable operation.

Steady-state Engine Dynamometer Testing
In this part of the study, the effects of excess air and ignition timing were evaluated. The excess air evaluation is covered below in cylinder head design.

For ignition timing, the author evaluated the effect on emissions when the ignition timing was retarded at 1700 rpm, 50% load, and 10% excess exhaust oxygen. Although THC emissions increased, the reductions in NO_x were assumed to be more advantageous.

Cylinder Head Design
Two types of cylinder head designs were evaluated: high-swirl and high-flow. In general, the high-swirl cylinders decrease THC emissions at the expense of NO_x emissions while high-flow do the opposite. As expected, the high-flow cylinders decreased NO_x emissions significantly while slightly reducing THC emissions. The authors contended that this was an acceptable trade-off and selected the high-flow heads as the standard.

Vehicle Driveability
These tests suggested changes in the rear axle gear ratio to allow for a better take-off feel. In addition, several minor tuning changes were made for transient driveability.

Transient Emissions
The Crown Victoria was evaluated using the Hot 505 portion of the Federal Test Procedure (FTP). The results were then compared to California's LEV, ULEV, and SULEV emissions certification standards. These data are presented below.

	CARB Low-	**Emission Vehicle**	**Standards**
	NMOG (g/mi)	**CO (g/mi)**	**NO_x (g/mi)**
LEV	0.075	3.4	0.2
ULEV	0.04	1.7	0.2
SULEV	0.02	1	0.01
Crown Victoria	0.05	0	0.111

As shown in the table, the Crown Victoria emissions were excellent. The author contended that both the NMOG and NO_x emissions could meet SULEV emissions with feedback control and/or better catalyst selection.

Pre and Post-catalyst Speciation

Pre and post-catalyst exhaust gas samples were taken from the 4.6L engine to determine catalyst performance. The results suggest that unsaturated hydrocarbons (e.g., ethene) were more easily converted to harmless products than saturated hydrocarbons (e.g., ethane). More work in this area was planned.

(71) Analysis of Utility Hydrogen Systems and Hydrogen Airport Ground Support Equipment

Author(s): Thomas, C., Barbour, J., James, B., and Lomax, F.
Date: January, 2000
Organization(s): Directed Technologies, Inc.
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):
Subcontract No.

Three analyses are summarized in this report: 1) Mass production cost estimate for stationary PEM fuel cells; 2) Assessment of the costs of producing electricity from stationary fuel cells with hydrogen and heat cogeneration; and 3) Assessment of the use of hydrogen for airport ground support equipment.

Mass Production Cost Estimate for Stationary PEM Fuel Cells

These costs were based on the DTI cost database that had been built over several years in conjunction with DOE and Ford Motor Company. Primarily, these costs were based on a detailed "bottom-up" analysis of the individual system components, using commercial cost estimation software for large-scale, mass production materials, manufacturing processes, and assembly time and cost.

The database had been developed for mobile applications and as shown in the table below, stationary applications have significantly different requirements

Parameter	**Stationary Application**	**Mobile Application**
Operating lifetime	> 50,000 hours (5 years)	5,000 hours
Operating period	Constant output for much of the day	Few hours per day; peak power 1 min/day
Production volume	~10,000 per/year	300,000 vehicles/yr
Output	3, 50 and 200 kW	50-80 kW
Capacity Factor	50%	10%

The authors then presented cost equations for each major component of a stationary fuel cell system (fuel cell stack, inverter/controller, SMR, compressor, hydrogen storage, dispenser) based on production volume. Details on the estimates can be obtained in the original paper.

In addition, for some cases, the actual projected price for volumes of 100, 10,000 or 300,000 were provided. From this analysis, the authors estimated that the cost of a 50-kW PEM fuel cell would be $493.3/kW for 100 unit level, $310.94 for 10,000 unit level. For a mobile system at 300,000 units, the cost would be $36.82/kW.

These costs along with those for the SMR, compressor, storage and dispenser were used in the next part of the analysis.

Co-production of Electricity, Hydrogen and Heat from Stationary Fuel Cells

This section evaluates a second product from the stationary fuel cell system: hydrogen for use in a fuel cell vehicle (FCV). Currently, distributed fuel cell systems are not competitive with conventional electricity sources. Due to the daily and seasonal variations in electricity demand in homes and buildings, different electricity/hydrogen production scenarios can be evaluated. The report looked at the economics of building fuel cell systems to deliver heat, electricity and hydrogen.

It evaluated the system return on investment for four primary cases:

1. Selling electricity only
2. Selling electricity and heat
3. Selling electricity and hydrogen
4. Selling electricity, heat, and hydrogen

in four different locations: Alaska, California, Massachusetts and New York. It also looked at the effect of mass-production for each of these locations.

These scenarios were evaluated based on the following economic assumptions.

Economic Assumptions

Parameter	**Value**
Insurance rate	0.002
Property tax rate	0.012
Inflation rate	0.02
Marginal corporate income tax rate	0.26
After tax real rate of return	0.1

Operating costs were based on the following assumptions.

Technology	**O&M Costs (% of Capital Cost)**	**Lifetime (yrs)**
Steam Methane Reformer	3.5	15
Fuel Cell System	3.0	10
Inverter/Control System	1.0	20
Compressor System	4.5	10
Storage Tanks	2.5	20
Connector/dispenser	5.0	15

From these analyses, the authors concluded that commercial building stationary fuel cell systems have some economic merit, but residential fuel cell systems are not promising. Specifically, for commercial buildings, if hydrogen is produced during off-peak periods and sold for use in vehicles, the return on investment can be improved by 10-15%. In residential units, the cost of electricity would need to be \$0.38/kWh before a 3.4 kW unit would return 10% on the investment in avoided electricity costs alone.

Use of Hydrogen for Airport Ground Support Equipment

Three types of airport ground support equipment (GSE) were analyzed for conversion to hydrogen fuel cell operation and were compared to battery-powered vehicles.

1. 22-foot shuttle bus
2. baggage belt loader
3. baggage tractor

To power these vehicles, two alternatives were considered: a pure fuel cell vehicle (FCV) and a range extender (RE). The FCV, the fuel cell was designed to meet maximum power requirements. In the RE, the fuel cell was designed to meet only the average power requirements with the battery supplying peak power.

The study looked at both the technical feasibility of the alternatives and their economics. The costs were based on previously derived estimates for fuel cells, hydrogen tanks, and batteries and were adjusted for initial manufacture and future mass production. In general, the FCVs were more expensive initially, but with mass production, they are less expensive than the battery-powered vehicles. Energy costs were estimated at \$2/kg, assuming hydrogen production from mass-produced SMRs. Lifecycle costs were calculated and showed the RE to be less expensive.

The authors also evaluated local air pollution and greenhouse gas emissions and compared them to those found in diesel, natural gas and battery-powered alternatives. They found that there was no clear winner for greenhouse gas emissions due to the primary energy sources. For local pollutants, FCVs and battery-powered GSEs had less than 3% of the emissions of diesel or natural gas vehicles.

In summary, the authors concluded that:

- Fuel cell GSE are technically feasible
- Fuel cell GSE can be economically attractive with mass production
- Airports may be a pathway for the introduction of hydrogen fuel due to the central refueling and public exposure
- GSE is a limited market, which could hinder its economic competitiveness
- FCVs are likely a better long-term candidate than the RE due to their lower weight, longer range and lower power requirements
- Energy costs for a fuel cell vehicle would be comparable to or better than battery or diesel powered GSE, assuming mass produced SMRs
- Demonstration of these technologies are currently underway

The authors then presented the results of the cost comparison between battery and hydrogen-powered GSE. They presented costs based on initial production and volumes of 10,000 and 500,000 units. The following table summarizes the results. (The results were taken from graphs and so the values are not exact.)

Production Volume /Equipment Type	22' Shuttle Bus ($)	Baggage Tractor ($)	Belt Loader ($)
Initial Production			
BPEV	$15,000	$7,000	$5,000
FCEV	$130,000	$80,000	$66,000
RE	$61,000	$50,000	$48,000
10,000 Unit Production			
BPEV	$9,500	$3,700	$3,000
FCEV	$10,500	$6,500	$5,000
RE	$5,000	$4,000	$3,500
500,000 Unit Production			
BPEV	$9,300	$3,700	$3,000
FCEV	$4,500	$3,000	$2,200
RE	$3,500	$2,500	$2,000

As shown in the table, the battery-powered option is less expensive than the fuel cell options until the 10,000 or 500,000 production levels. However, it is not likely that these volumes will be met since the total number of GSEs in the U.S. is only 50,000 vehicles. Assuming a 10% turnover rate, and a 10-20% market penetration, less than 1,000 vehicles would be sold per year. Thus, other fuel cell markets would be required to reduce production costs and make hydrogen fuel cell GSE equipment cost competitive.

(72) Technical Assessment and Analysis of Hydrogen R&D Projects

Author(s): Skolnik, E., DiPietro, J., Haq, Z.
Date: January, 2000
Organization(s): Energetics, Inc.
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):
Subcontract No. DE-FC36-98GO90291

This subcontract focused on two areas: site visits to hydrogen production and storage R&D projects and the evaluation of the use of low-rank coal as the carbon source for the regeneration of hydrides.

Site Visits

Eight site visits were conducted in the subject year. Prior to each visit, a literature review was conducted to assess the current state of the project and related technologies. A set of discussion points is then sent to the PI, about two weeks prior to the visit. During the site visit, a demonstration of the experiments is conducted, if possible. The PI then presents a summary of the project and its current status. In general, the site visits last about one day.

The following table summarizes the site visits conducted in the subject year.

Project	Laboratory	Date of Visit
Storage and Purification of Hydrogen Using Ni-coated Mg	Arthur D. Little, Inc.	June 1998
Hydrogen Transmission and Storage with a Metal Hydride Organic Slurry	Thermo Power, Inc.	June 1998
Thermal Management Technology for Hydrogen Storage	ORNL and Materials and Environmental Research, Inc.	August 1998
Improved Metal Hydride Technology	Energy Conversion Devices, Inc.	August 1998
Hydride Development for Hydrogen Storage	SNL	September 1998
Biomass to Hydrogen via Fast Pyrolysis and Catalytic Steam Reforming	NREL	December 1998
Hydrogen Separation Membrane Development	Savannah River Technology Center	March 1999
Hydrogen Production by Photosynthetic Water Splitting	ORNL	March 1999

From these visits, the authors concluded the following:

- Steady progress is being made in renewable hydrogen production, storage and hydride systems
- PIs may lose sight of Hydrogen Program goals

- More effort should be directed toward CO_2 reductions
- Magnesium-hydride systems will likely be in niche applications only; further work in this area is not suggested
- Alternatives to PSA should be researched
- Communication between the Program and some of the projects needs improvement

Use of Coal for Regeneration of Hydrides

This section reported on the results of a study in-progress. The authors looked at the feasibility of using a low-rank coal as a carbon source for the regeneration of hydrides in use as on-board, slurry-based hydrogen/hydrolysis process. Thermo Power was developing this process. Wyodak coal was selected as the carbon source and Massachusetts was selected as the refueling site. The analysis compared:

1. shipping Wyodak coal for Wyoming to Massachusetts as a carbon source for refueling
2. shipping spent hydroxide slurry from Massachusetts to Wyoming for regeneration at the mine and shipping the regenerated slurry back to Massachusetts
3. using a baseline "char" material as the regeneration source.

No information was available on the transportation of Wyoming coal to Massachusetts. Thus, a rough methodology was used based on the aggregate transportation costs (i.e., transportation + taxes + commissions + insurance + equipment lease costs) as a function of distance. There were considerable scatter in the data, but for this preliminary analysis, it was determined to be acceptable. The delivered coal cost was thus determined to be \$26.30/ton based on a \$6.00/ton mine-mouth cost.

A similar methodology was used for the transportation of the slurry. Optimistic transportation costs were used because it was assumed that the transport of the slurry would be the same as that for coal. That is, no special treatment of the cars or coverings were required.

From these analyses, the following costs were obtained.

Cost Parameter	**Option 1 Transporting Coal**	**Option 2 Transporting Hydroxide and Hydride**	**Option 3 Char**
Delivered cost (\$/ton) (\$/MM Btu)	 \$26.30 \$1.52	 20.30*	
Delivered carbon cost (\$/ton)	\$52.60	NA	
Delivered fixed carbon cost (\$/ton) (\$/MMBtu)	 \$76.45 \$4.43	 NA NA	 \$1.67
Delivered cost (\$/MM Btu H_2)	 \$3.76	 \$4.45-6.91**	 \$2.30

*Transportation costs only

** Lower limit is for lithium slurries and the upper is for calcium slurries

This analysis showed that the char option was least expensive unless the carbon conversion were low.

In the future, the study will be expanded to evaluate the following:

- variable transportation distances
- conversion of coal to char, including costs
- cost of char as a function of transportation distance
- incremental cost of a regeneration process

(73) International Energy Agency Agreement on the Production and Utilization of Hydrogen

Author(s): Elam, C., Gregoire Padro, C., Putsche, V., Turner, J., Heben, M. and Czernik, S.
Date: January, 2000
Organization(s): NREL
Publication: Proceedings of the 1999 U.S. DOE Hydrogen Program Review, Volume II. NREL/CP-570-26938
Category(ies):
Subcontract No.

After a brief description of the history of the International Energy Agency (IEA) and the Hydrogen Agreement, the authors provided the following list of areas covered by the Agreement.

- On-board storage
- Renewable hydrogen production
- Integration of production, storage and end-use through modeling
- Hydrogen safety

The authors then described the achievements and on-going activities in three technology areas: integrated systems, photoproduction of hydrogen, and storage in metal hydrides and carbon.

Integrated Systems
In this activity, twenty-four component models were developed for hydrogen production, storage, distribution and utilization.

Production
- PV-Electrolysis
- Wind-Electrolysis
- Grid-Electrolysis
- Steam Methane Reforming
- Biomass Gasification
- Biomass Pyrolysis
- Coal Gasification

Storage
- Low/High Pressure Gas
- Metal Hydrides
- Liquefaction
- Chemical Storage
- Chemical Hydrides

Distribution
- Transport Tanker
- High Pressure Pipeline
- Low Pressure Pipeline
- Tank Truck
- Methanol Transport

Utilization
- PEM Fuel Cell
- Phosphoric Acid Fuel Cell
- Solid Oxide Fuel Cell
- Molten Carbonate Fuel Cell
- Gas Turbine
- Internal Combustion Engine
- Refueling Station

From these models, two integrated system models were evaluated for grid-independent remote village applications: PV-electrolysis-metal hydride PEM fuel cell system and wind-electrolysis-compressed gas-internal combustion engine generator set. Using hourly resource and demand data, the village needs were met. In another similar analysis, high-temperature and low-temperature metal hydride systems were compared to compressed gas for a grid-independent village in Central America.

The integrated systems activity also supports fifteen international demonstration projects as listed below. Each of the projects was evaluated and compared in terms of system performance, safety and regulatory issues.

Project	**Lead**
Solar-Hydrogen Production Facility	Electrolyser Corp
Demonstration Plant for Hydrogen Production and Use in a Fuel Cell	ATEL
Solar Hydrogen Pilot Plant with 3 Storage Systems	INTA
Stand-Alone PV-Hydrogen Small-Scale Power System (SAPHYS)	ENEA
Alkaline Bipolar Electrolyzer	ENEA
Off-Peak Storage System	Kogakuin University
CO2 Fixation and Utilization in Catalytic Hydrogenation Reactor	RITE
Hydrogen Vehicle	Mazda
Hydrogen Rotary Engine Cogeneration System	Mazda
Hydrogen Production Utilizing Solar Energy	Kansai Electric Power Co., Mitsubishi
Development of Solar Hydrogen Processes	Helsinki University of Technology
Solar Hydrogen Fueled Truck Fleet and Refueling Station	Clean Air Now, Xerox
Genesis Ten Passenger PEMFC Vehicle	Energy Partners
Schatz Solar Hydrogen Project	Humboldt State University
City of Palm Desert Renewable Hydrogen Transportation	Humboldt State University

Photoproduction of Hydrogen

In this activity, the photoproduction of hydrogen was evaluated to determine potential and ideal efficiencies, and solar hydrogen production efficiencies. In addition, studies were completed that surveyed the state-of-the-art for solar hydrogen options as well as technological assessments of various options.

These studies showed that the ideal limit of the conversion efficiency for 1 sun irradiance is ~31% for a single photosystem and ~42% for a dual photosystem. However, real systems will not likely exceed 10-16%.

An analysis of four types of solar photochemical hydrogen systems was conducted: photochemical, semiconductor, photobiological and hybrid. From this activity, four solar hydrogen systems were identified as promising for further research and development:

- Photovoltaic cells plus and electrolyzer
- Photoelectrochemical cells with one or more semiconductor electrodes
- Photobiological systems
- Photodegradation systems

Metal Hydride and Carbon Storage
In this effort, work towards development of hydride and carbon materials for on-board storage with improved gravimetric (5 wt%) and lower temperature (100-150°C) hydrogen release. Building on the work at the Max Planck Institute, several international collaborations were established to develop catalyzed sodium aluminum hydrides for hydrogen storage. A material capable of 5wt% reversible hydrogen storage at 150°C has been identified; work is underway to lower the temperature to 100°C.

Future Activities
The authors concluded with a listing of the following future activities.

- Photoproduction
- Hydrogen use in non-energy processes
- Carbon reductions

(74) Update of Hydrogen from Biomass – Determination of the Delivered Cost of Hydrogen

Author(s): Spath, P.L., Lane, J.M., Mann, M.K., Amos, W.A.
Date: April 2000
Organization(s): NREL
Publication:
Category(ies): Production
Subcontract No.

The authors assessed the economic feasibility of producing hydrogen from biomass via two thermochemical processes: 1) gasification followed by reforming of the syngas, and 2) fast pyrolysis followed by reforming of the carbohydrate fraction of the bio-oil. In each process, water-gas shift is used to convert the reformed gas into hydrogen, and pressure swing adsorption is used to purify the product. This study was conducted to incorporate recent experimental advances and any changes in direction from previous analyses. The following systems were examined in this analysis:

- the Battelle/FERCO low pressure indirectly-heated biomass gasifier,
- the Institute of Gas Technology (IGT) high pressure direct-fired gasifier, and
- fluidized bed pyrolysis followed by coproduct separation.

The delivered cost of hydrogen, as well as the plant gate hydrogen selling price, were determined using both a cash flow spreadsheet and Crystal Ball® risk assessment software. This software predicts the sensitivity of the hydrogen selling price to changes in various analysis parameters, and determines which of the parameters contribute the greatest uncertainty to the results. All of the parameters are varied at once, giving a combined uncertainty of hydrogen selling price.

Several cases were run for each of the biomass conversion technologies at varying plant sizes and internal rate of return (IRR) values. Three hydrogen production rates were examined for the gasification technologies: 22,737 kg/day, 75,790 kg/day, and 113,685 kg/day. For the pyrolysis case, because some of the bio-oil is used in the production of the coproduct, only the small and medium plant sizes were studied. Even with several remote pyrolysis plants, the feed required for the large plant would likely be more than could be economically secured. The base case analysis assumes an after-tax IRR of 15%, which is a value typically required by investors. Cases were also tested at a 20% and 10% after-tax IRR and a 0% pre-tax IRR. The 20% case was chosen because these technologies are new and thus result in a higher risk. The 0% case represents the pre-tax break-even point, or the production cost of hydrogen. The 10% IRR cases are presented for illustrative purposes only, as such a low rate would probably be unacceptable to investors with multiple investment opportunities.

Hydrogen Selling Price

For any given IRR, the plant gate hydrogen selling price is lowest for the pyrolysis case ($8-9/GJ for a 15% after-tax IRR), followed by the Battelle/FERCO gasifier plant ($14-17/GJ for a 15% after-tax IRR), and then the IGT gasifier system ($16-21/GJ for a 15% after-tax IRR). As the plant size increases, the hydrogen selling price decreases due to economy of scale. The delivered cost is important because even if the hydrogen is produced cheaply, the cost to store and transport the hydrogen will make a difference in determining if the hydrogen is economical.

Six likely scenarios for hydrogen use were examined, and the cheapest storage and delivery methods were identified. For these six options, storage and delivery adds between $1 and $10/GJ to the plant gate cost, resulting in a delivered cost of hydrogen between $9.1/GJ and $32.7/GJ (using a 15% after-tax IRR) for all cases studied.

Sensitivity Analysis Results

For both of the gasification options (Battelle/FERCO and IGT), the two variables having the largest effect on the uncertainty in the hydrogen selling price are hydrogen production factor and operating capacity. Combined, these two variables account for roughly 51-76% of the uncertainty in the hydrogen selling price depending on the plant size and IRR. For the pyrolysis case, the bio-oil feedstock cost, pyrolytic lignin selling price, and yield of carbohydrate from the bio-oil are the largest contributors to variance, and combine to account for 82-95% of the variability. Roughly 40-44% of the contribution comes from the bio-oil feedstock cost alone.

(75) Distributed Hydrogen Fueling Systems Analysis

Author(s): Thomas, C.E., Reardon, J.P., Lomax Jr., F.D.
Date: October 2000
Organization(s): Directed Technologies, Inc.
Publication:
Category(ies): Transportation-infrastructure
Subcontract No.

The authors have analyzed the costs of the infrastructure to supply hydrogen, methanol, and gasoline to fuel cell vehicles. It was determined that the costs of maintaining the existing gasoline infrastructure per vehicle supported are up to two times more expensive than the estimated costs of maintaining either a methanol or a hydrogen fuel infrastructure. This is because the analysis assumed a less costly option of producing and dispensing the hydrogen locally by reforming natural gas and utilizing the existing natural gas infrastructure.

Infrastructure Costs

- Gasoline: maintaining the current gasoline infrastructure systems requires annual capital investments of approximately **$1,230** for each new conventional vehicle sold.
- Hydrogen: maintaining the existing natural gas infrastructure and producing and installing small-scale steam methane reformers to produce hydrogen at the local fueling stations requires annual capital investments of between **$600** and **$800** for each new direct hydrogen fuel cell vehicle (FCV) sold.
- Methanol: installing a local methanol infrastructure requires about **$75** for each fuel cell vehicle sold initially, up to a six million vehicle capacity. After this amount, methanol capital expenditure costs will add **$525-700** per vehicle sold. If the natural gas field has to be developed to supply the methanol plant, the infrastructure costs increase to between **$830** and **$1,000** per vehicle.

Based on total fuel infrastructure costs, both on and off the fuel cell vehicle, the authors conclude that hydrogen is the least costly option, followed by methanol and then gasoline as the most expensive option. The following table shows their estimates of fuel infrastructure and incremental vehicle costs for each fuel.

	Direct Hydrogen Fuel Cell Vehicle	**Methanol Fuel Cell Vehicle**	**Gasoline Fuel Cell Vehicle**
Incremental vehicle cost	$1,800	$2,300 to $3,400	$3,400 to $6,300
Infrastructure cost/vehicle	$600 to $800	$75 to $700	$1,230
Total incremental cost	$2,400 to $2,600	$2,375 to $4,100	$4,630 to $7,530

Fuel Costs

Other secondary findings include looking at the likely costs for reducing the sulfur content below 1 ppm in gasoline, a requirement to protect the onboard fuel processor and the fuel cell anode. Two options were discussed: (1) use of an onboard sulfur absorber costing less than $50 that would last the life of the car and (2) oil companies supplying a low octane, fuel cell-grade of gasoline with less than 1 ppm sulfur at a cost equal to or less than the cost of current high octane gasoline.

Priced at \$0.75/gallon, delivered methanol would be competitive with wholesale gasoline at \$0.90/gallon. Methanol from a new dedicated production plant using cheap \$0.50/MMBTU natural gas could be delivered to the Gulf of Mexico for \$0.33/gallon and to the pump at \$0.52/gallon, which would provide a 30% cost reduction over gasoline.

Producing hydrogen on-site from methanol would cost 30% more than reforming natural gas with methanol and natural gas at their historic price levels. Producing hydrogen by electrolyzing water would increase greenhouse gas emissions in most nations of the world, since much of the world's electricity is produced by coal or natural gas. Installing a 200 kWe stationary fuel cell electrical generator at a hydrogen fueling station can improve the project economics over selling hydrogen alone and, more importantly, can provide needed revenue in the early days of FCV market penetration while FCVs are still scarce.

The following table compares methanol and gasoline fuel costs

	Gasoline ICEV		**Methanol FCV**
Fuel Economy (mpgge)	30		44 to 49
Fuel Cost at US Gulf	[Crude Oil = \$30/barrel]	[Crude Oil = \$15/barrel]	[Methanol = 56 ¢/gallon
Retail Fuel Cost (¢/gallon), before taxes	102	65.5	71 to 78
Consumer Cost per mile (¢/mile), before taxes	3.4	2.2	3.2 to 3.5

Thomas gave results of hydrogen and peak electricity co-generation for a hydrogen fueling station. With only 50 FCVs, hydrogen would have to be sold at \$2.14/gallon of gasoline equivalent to provide the owner with a 10% return on investment. The stationary fuel cell system would make the goal 10% return if electricity could be sold to the grid at \$0.14/kWh for six hours per day. When the hydrogen fueling station was fully utilized (500 FCVs), hydrogen could be sold at \$1.00/gallon of gasoline equivalent with on-peak electricity sold to the grid at \$0.06/kWh (at a 10% ROI).

(76) A Techno-Economic Analysis of Infrastructure Issues: Centralized Versus Distributed Hydrogen Production

Author(s): DiPietro, J.P., Badin, J., Skolnik, E..

Date: Not reported

Organization(s): Energetics, Inc.

Publication:
Category(ies): Production
Subcontract No.

This analysis looked at the conversion of surplus off-peak electricity to peak electricity by producing hydrogen through electrolysis, storing it and then converting it in a fuel cell. It was expected that PEM fuel cells and alkaline electrolyzers would improve enough to make this viable. In addition, deployment of wind turbines and other renewable electricity sources would provide a new supply of renewable energy.

To evaluate these possibilities, a series of nomographs were developed. These graphs can be used for a first-order comparison of centralized and distributed hydrogen energy systems. In this report, the basis for the nomographs is presented. Specifically, the methodologies and assumptions for costing the electrolysis (capital and operating), hydrogen delivery, and peak electricity prices are shown.

The non-energy portion of the electrolyzer cost was estimated as follows:

$$\text{EC} = \frac{EI * (CRF + O\,\&\,M) * 100}{CFE * 8760}$$

Where:

EI	-	Electrolyzer investment
CFE	-	Capacity Factor
O&M	-	Operating and maintenance (5%)
CRF	-	Capital recovery factor (0.1214) based on: 20-year life, 6.1% real discount rate, 7-year depreciation, 2% insurance

The hydrogen production cost was estimated with the following equation:

$$\text{HPC} = \frac{(EC + e)}{NE}$$

Where:

EC	-	Non-energy cost of the electrolyzer
E	-	Electricity cost
NE	-	Electrolyzer efficiency (80%)

The next parameter evaluated was the delivered hydrogen cost which was defined as the hydrogen production cost plus any delivery charges. Six scenarios are evaluated based on truck transport of two storage technologies (low pressure hydrides and compressed gas) and three transportation distances (0, 50 and 100 miles).

The equation for delivered hydrogen cost was defined as:

$$\text{DHC} = \text{HPC} + \text{CC} + \frac{SI*(CRF + O\&M)*100}{CPY} + \frac{TFC(CRF + O\&M)*100}{LPY*LC} + (\text{TVC*TD})$$

Where:

HPC	-	Hydrogen production cost
CC	-	Compressor costs
SI	-	Storage investment
CRF	-	Capital recovery factor
O&M	-	Operating and maintenance costs
CPY	-	Cycles per year
TFC	-	Transport fuel cost
LPY	-	Transport loads per year
LC	-	Transport load capacity
TVC	-	Transport investment cost
TD	-	Transport distance

Compressor costs were estimated as:

$$\text{CC} \quad = \quad \frac{CI*(CRF + O\&M)*100}{CFC*8760} + (\text{Ce*e})$$

Peak electricity cost was the last parameter calculated as follows:

$$\text{PEC} \quad = \quad \frac{DHC}{NFC} + \frac{FCI*(CRF + O\&M)*100}{PD/24*8760)}$$

Where:

DHC	-	Delivered hydrogen cost
NFC	-	Fuel cell efficiency
FCI	-	Fuel cell investment
CRF	-	Capital recovery factor
O&M	-	Operating and maintenance costs
PD	-	Peak duration

The electrolysis/fuel cell system was evaluated using the screening process outlined above. The system was determined to generate electricity at 15 to 30 cents per kWh assuming that it is generated for 3 hours per day (i.e., 12.5% fuel cell capacity factor).

The authors then used the nomographs to compare centralized and decentralized systems. For a 500-kW distributed system, the cost was estimated at 8.5 cents per kWh. Using this value as the starting point, the authors traversed the nomographs to determine the allowable cost for the fuel cell for a centralized system. Without transport costs, the electrolyzer could cost \$575/kW while with a 100-mile transport distance, the electrolyzer could cost \$325/kW.