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TECHNOECONOMIC ANALYSIS OF DIFFERENT OPTIONS FOR THE PRODUCTION OF HYDROGEN FROM SUNLIGHT, WIND, AND BIOMASS

M.K. Mann, P.L. Spath, W.A. Amos
National Renewable Energy Laboratory
Golden, CO 80401

Abstract

To determine their technical and economic viability and to provide insight into where each technology is in its development cycle, different options to produce hydrogen from sunlight, wind, and biomass were studied. Additionally, costs for storing and transporting hydrogen were determined for different hydrogen quantities and storage times.

The analysis of hydrogen from sunlight examined the selling price of hydrogen from two technologies: direct photoelectrochemical (PEC) conversion of sunlight and photovoltaic (PV)-generated electricity production followed by electrolysis. The wind analysis was based on wind-generated electricity production followed by electrolysis. In addition to the base case analyses, which assume that hydrogen is the sole product, three alternative scenarios explore the economic impact of integrating the PV- and wind-based systems with the electric utility grid. Results show that PEC hydrogen production has the potential to be economically feasible. Additionally, the economics of the PV and wind electrolysis systems are improved by interaction with the grid.

The analysis of hydrogen from biomass focused on three gasification technologies. The systems are: low pressure, indirectly-heated gasification followed by steam reforming; high pressure, oxygen-blown gasification followed by steam reforming; and pyrolysis followed by partial oxidation. For each of the systems studied, the downstream process steps include shift conversion followed by hydrogen purification. Only the low pressure system produces hydrogen within the range of the current industry selling prices (typically \$0.7 - \$2/kg, or \$5-14/GJ on a HHV basis). A sensitivity analysis showed that, for the other two systems, in order to bring the hydrogen selling price down to \$2/kg, negative-priced feedstocks would be required.

Summary

Renewable resources, such as solar, wind, and biomass are excellent feedstocks for hydrogen because of their inherently clean nature and sustainability. Technical and economic feasibility analyses were conducted on processes to produce hydrogen from sunlight, wind, and biomass. The degree to which a process can be said to have economic potential is measured by comparing the calculated hydrogen selling price to the current market value of hydrogen. Currently, this range is approximately \$0.7 to \$2/kg (\$5/GJ to \$14/GJ, HHV basis).

An important option for the production of hydrogen from renewables is from water by conversion of solar and wind energy. A study was made of the relative economic viability of three technologies: direct photoelectrochemical (PEC) conversion of sunlight, photovoltaic (PV)-generated electricity production followed by electrolysis, and wind-generated electricity production followed by electrolysis. PEC is an alternative to PV/electrolysis systems, combining a semiconductor and an electrocatalyst into a single monolithic device. The base case designs emphasize hydrogen as the only product, derived solely from renewable sources acting independently of the electric grid. However, to identify opportunities to improve the viability of PV- and wind-derived hydrogen, three alternative scenarios were also studied. The first of these explores making an electricity coproduct that can be sold at peak prices to an unspecified customer over the grid. Scenario 2 examines the use of electricity from both the renewable and the grid to produce only hydrogen. Scenario 3 looks at the situation of producing hydrogen at locations remote from where the renewables generate the electricity. Results show that PEC hydrogen has the potential to be economically competitive, and can produce hydrogen at prices below what the PV/electrolysis system can produce if it is not coupled with the utility grid. The selling price of hydrogen from PEC is projected to be \$17.2/kg (\$121/GJ) in the near term, and \$4.7/kg (\$33.1/GJ) in the mid- to long-term (~2010). The selling price of hydrogen from stand-alone PV/electrolysis systems was calculated to be \$17.6/kg to \$7.5/kg (\$124/GJ to \$52.8/GJ) in the years 2000 and 2010, respectively. Hydrogen from stand-alone wind/electrolysis plants can sell for \$7.1/kg and \$4.0/kg (\$50/GJ and \$28.2/GJ) in the same years. Integration with the grid was found to generally improve the economics of the PV and wind systems. The gate-price of hydrogen from PV/electrolysis plants operating in conjunction with the utility grid may be as low as \$7.4/kg and \$4.5/kg (\$52.1/GJ and \$31.7/GJ) in 2000 and 2010, respectively. The grid reduces gate prices from wind/electrolysis plants to \$3.9/kg and \$3.0/kg (\$27.5/GJ and \$21.1/GJ) in these years.

Biomass, such as agricultural waste, forest residue, urban wood waste, and trees and grasses, can be converted to hydrogen through both biological and thermochemical processes. To compare the economic potential of different thermochemical routes, three gasification systems were compared. The systems are: low pressure, indirectly-heated gasification followed by steam reforming; high pressure, oxygen-blown gasification followed by steam reforming; and pyrolysis followed by partial oxidation. For each system, the downstream process steps include shift conversion followed by hydrogen purification. Each system was modeled in ASPEN Plus©, and the resulting material and energy balances were used to determine the size and cost of each major piece of equipment. Discounted cash flow rate of return analyses were used to calculate the selling price of hydrogen from the systems for three biomass feed rates: 1,500, 1,000, and 300 bone dry Mg/day. A series of sensitivity analyses were conducted to determine the conditions under which each process is most feasible and to guide experimental efforts toward the areas that could result in the largest cost reductions.

The calculated selling price of hydrogen from these biomass conversion systems at a feed rate of 1,000 Mg/day ranged from \$0.7/kg to \$3.3/kg (\$5/GJ to \$23/GJ) for a dry feedstock cost of \$0/Mg to \$46/Mg. The low pressure system was found to have the most economic potential, producing hydrogen that can be sold for less than \$2/kg (\$14/GJ) for reasonable feedstock prices. Negative feedstock prices are required by the high pressure gasification and the partial oxidation systems for the hydrogen to be within the range of market values.

In addition to the technoeconomic analyses of hydrogen production processes, a detailed assessment of the costs of storing and transporting hydrogen was performed so that future analyses can be reported in terms of the delivered cost of hydrogen versus the gate price. This will provide a means for identifying markets for novel hydrogen production technologies. The storage options that were considered are liquid hydrogen, compressed gas, metal hydride, and underground storage. The modes of transportation examined are liquid hydrogen delivery by truck, rail and barge, gaseous hydrogen delivery by truck, rail, and pipeline, and metal hydride delivery by truck and rail.

Approach and Rationale

Technoeconomic analyses are performed for the U.S. Department of Energy's Hydrogen Program to advance the development of new technologies and to streamline the portfolio of projects being researched. The primary purpose of this work is to identify those areas of research in which improvements will result in the largest reductions in process costs. This helps to define research goals and moves novel technologies more quickly to commercialization. Additionally, results from these analyses provide information to DOE on the long-term technical and economic feasibility of ongoing and proposed research projects.

The determination of whether a system is economically feasible is made by comparing the calculated hydrogen selling price to the current market value of hydrogen. In today's hydrogen market, depending on the size of the production facility and the amount purchased by the end user, hydrogen is typically valued at between $0.7 - $2/kg, or $5-14/GJ on a HHV basis. Large steam methane reforming plants, which generate the majority of hydrogen on the market today, produce hydrogen at the low end of this range. It should be noted that the market size for hydrogen at the higher end of this price range is small, and large contributions to the hydrogen supply will come only at prices competitive with steam methane reforming.

The method of economic analysis used for determining the economic potential of the solar, wind, and biomass processes is discounted cash flow rate of return, which calculates the necessary selling price of hydrogen when the internal rate of return (IRR) is specified. The IRR is the minimum acceptable rate for an investor to finance a project. Therefore, the perceived risk of the project can be incorporated into the IRR. Because processes to produce hydrogen from renewables currently carry higher risks than conventional hydrogen-generating processes, the IRR specified in these analyses is 15% after tax. The rate for conventional processes is generally between 9% and 12%, depending on the economy and company practices. For a 37% tax rate, a 15% after-tax IRR corresponds to a pre-tax IRR of 20. Other major assumptions for the economic analysis are: equity financing for a 20 year plant life including two years of construction time, 90% on-stream factor except where noted in the PV and wind study, working capital of 18% of installed capital, a tax rate of 37%, and ten year straight-line depreciation. All equipment costs were adjusted to 1995 dollars.

Analysis of the Production of Hydrogen from Sunlight and Wind

An important option for the production of hydrogen from renewables is from water by conversion of solar and wind energy. A study was made of the relative economic viability of three technologies: direct photoelectrochemical (PEC) conversion of sunlight, photovoltaic (PV)-generated electricity production followed by electrolysis, and wind-generated electricity production followed by electrolysis. The base case analysis projected the selling price of hydrogen from these systems, assuming that they are operated independently of the electric grid. On the other hand, the ability to sell valuable electric energy and purchase inexpensive electric energy via the grid may be one of the more viable options for the commercialization of renewables-based hydrogen production. To examine this option, alternative scenarios in which the PV- and wind-based systems interact with the grid were also studied.

Photoelectrochemical Hydrogen Production

Photoelectrochemical (PEC) water splitting represents an alternative to PV/electrolysis systems, combining a semiconductor and an electrocatalyst into a single monolithic device. Researchers on this task are working to develop a stable, cost effective, semiconductor-based system that will collect solar energy and electrolyze water in one step to produce hydrogen, with sunlight as the only energy input. This system eliminates the need for an electrolyzer and additionally reduces semiconductor processing because surface contacts, interconnects, and wiring are no longer necessary. Two configurations are being studied: single gap systems and multijunction systems. The theoretical lower heating value efficiency of dual junction systems is 32% while single bandgap systems have an upper limit on the order of 24%. Practical systems could achieve 20% and 10% efficiencies for multijunction and single bandgap systems, respectively. More information on this research can be found in Kocha *et al* (1996), Kocha *et al* (1997), and Rocheleau *et al* (1996).

Work at the National Renewable Energy Laboratory and the University of Hawaii on PEC conversion systems involves three basic areas of research: semiconducting materials, surface modification, and catalysts. Work thus far has identified gallium indium phosphide ($GaInP_2$) as a promising semiconductor. $GaInP_2$ /gallium arsenide (GaAs) has been identified as a promising tandem cell system; additionally, amorphous silicon/amorphous silicon carbide (a-Si/a-SiC) appear to be promising thin-film systems. Initial work has shown that the $GaInP_2$/GaAs system will split water with very high efficiencies (12% thus far), and is relatively stable in aqueous environments. The a-Si/a-SiC system has also shown some promise, and the a-SiC has been shown to protect a-Si-based multijunction systems from surface oxidation, further enhancing the viability of using this low cost cell. Efficiencies on the order of 7% have been realized in laboratory tests on these cells.

A preliminary analysis determined the contribution of the semiconductor cell to the cost of hydrogen and the minimum photoconversion efficiency necessary for the system to have economic potential (Mann *et al* (1996). Results found that the more expensive tandem cells will not produce hydrogen economically, despite their higher efficiencies. Amorphous silicon thin films, however, have the potential to be viable systems. This previous analysis was not detailed enough to determine if the systems will be economic, but was able to contend that further analysis and research were warranted.

Although hydrogen production via photoelectrolysis will only have the potential to be economical with lower cost cells, reasons exist for continued work on the more expensive materials. Given that the tandem cells have the appropriate bandgap and stability for water splitting, research on these cells is vital to understanding the basic science behind PEC water splitting. Issues such as spectral response, current matching, surface catalyst preparation and application, corrosion control and measurement, efficiency determination, cell and system design, and gas collection techniques, can all be studied with this system while less expensive systems are being developed.

To expand the previous analysis and further determine the situations in which this technology will be viable, a detailed analysis of the costs of photoelectrochemical hydrogen production has been conducted. Table 1 gives the main assumptions not given in the Approach and Rationale section above. Photocatalyst cost is based on projected costs for a-Si PV cells, discounted to reflect the fact that some processing costs such as interconnects and wiring will not be required. This information is based on data in the Photovoltaics section of the Renewable Energy Technology Characterizations (EPRI, 1997) and from personal correspondence with scientists in the National Center for Photovoltaics at NREL. The photocatalyst is immersed in a weak solution (< 3M) of H_2SO_4, (NaOH solution could also be used) with its edges surrounded by a Nafion© (DuPont) type membrane that allows the transfer of ions between the anodic and cathodic parts of the cell. The membrane area is assumed to be equal to the photocatalyst area. This assembly is contained in an extruded plastic housing, which is shaped to concentrate the sunlight by a factor of five when filled with the acid solution. Higher concentrations produced with fresnel lenses and mirrors were found to be uneconomic given the relatively low cost of the photocatalyst. Since the hydrogen and oxygen are evolved on different sides of the membrane, there isn't a requirement to separate them later. It is assumed that 39.89 kWh of energy are needed to split one kg of water at 1.5 V.

Table 1: Major Assumptions for the Economic Analysis of PEC Hydrogen Production

	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) [5]	475	225	50
Solar insolation = 5.74 kWh/m^2/day (Carrissa Plains, CA)			
Hydrogen production rate = 500,000 kg/year			

Designing the housing unit has proved to be a difficult issue for this technology. The material must have the following characteristics:

- Able to resist attack from the electrolyte solution
- Stable in an aqueous environment
- Transparent
- UV stable
- Able to withstand the range of operating temperatures
- Low hydrogen permeability
- Low cost

The hydrogen permeabilities of different plastics were calculated and found to range from approximately zero for glass, to 24% of the produced hydrogen for some polycarbonates. Some materials, including some other polycarbonate formulations, were found to have permeabilities lower that 0.6%. Polycarbonate was chosen for this design, and a vendor quote was obtained. Because of cost issues, it may be most feasible to apply a small layer of impermeable material to the inside of a cheaper plastic.

The results of the analysis, including the hydrogen selling and production costs, are shown in Table 2. These results highlight the parts of the system that contribute significant cost to the overall selling price of the product hydrogen. Although photocatalyst efficiency improvements play a large role in reducing the future selling price of the product, other equipment costs are sufficiently high as to temper the overall decrease. The dramatic reduction in the price of the membrane is due in large part to projected increased demand as PEM fuel cells are mass-produced. Other materials may work equally well and should be investigated, as the PEC system will certainly be less feasible if DuPont is unable to reduce the price of their membrane as much as they project. The cost of the unit supports, obtained from a PV manufacturer in the U.S., is not expected to decline because it is largely a function of the cost of steel. Therefore, as the overall system becomes cheaper, its share of the total cost increases. One of the biggest surprises of these results is the impact of the housing unit on the total cost. Further designs and materials should be investigated.

Table 2: Results of the Economic Analysis of the PEC System

	Current	Near-term (~2000)	Mid/Long term (~2010)
Total land required (ha)	16.9	14.1	9.1
Capital cost (millions of $)	36.0	21.0	9.4
Photocatalyst (% of total capital)	11%	11%	11%
Membrane (% of total capital)	37%	25%	8%
Unit supports (% of total capital)	17%	24%	34%
PEC housing (% of total capital)	19%	20%	23%
H_2 selling price ($/GJ) (given a 15% IRR)	120.9	71.4	33.1
H2 production cost ($/GJ) (given a 0% IRR)	31.9	20.5	10.3

Hydrogen from PV and Wind

Four options for the production of hydrogen from PV and wind systems were studied. The base case system involves direct coupling of the electrolyzer to the renewable. This system acts independently of the grid and produces only hydrogen. Three alternative scenarios were examined to explore the possibility of improving the project economics. The scenarios are structured to provide the framework for evaluation of the trade-offs between: 1) the high value/selling price of on-peak electricity from the grid, 2) the relatively low purchase price for non-peak electricity from the grid, 3) electrolyzer variable operating cost, and 4) amortization of the electrolyzer cost over more units of hydrogen produced.

In the first alternative scenario, hydrogen and electricity production are coupled to produce the lowest cost hydrogen possible. During periods of peak electricity demand, the electricity will be sent to the grid for sale to a customer or to a central pool. Hydrogen production occurs when the renewable is operating and a high selling price for the electricity cannot be obtained. The renewables are assumed to receive a capacity credit, prorated to reflect the fact that they are generating intermittently. This scenario reduces the total annual amount of electric energy available for hydrogen production by about 11% for PV and 9% for wind.

Scenario 2 involves producing hydrogen from the renewably-produced electricity, plus grid electricity purchased during periods of off-peak demand. The goal of this option, like that for Scenario 1, is to minimize the production cost of hydrogen. The electrolyzer size was based on the maximum output of the renewable, sized at 10 MW. Scenario 2 is divided into two parts. In the first case, Scenario 2a, energy is purchased from the grid during all hours (on-peak and off-peak) to augment renewable electricity production, such that the electrolyzer operates at 90% of its baseload capacity. Plant outages are assumed to occur uniformly throughout the hours of operation. In Scenario 2b, only less expensive non-peak electricity is purchased. Thus, the electrolyzer operates during on-peak hours when the renewable is producing, and during all non-peak hours. Using the electrolyzer over more hours than in Scenario 1 allows the owner to amortize capital equipment cost over a greater amount of product hydrogen.

In Scenario 3, electricity production is physically decoupled from the hydrogen production operation. Energy from the wind and PV systems is sent to the grid and to the electrolyzers operating elsewhere. This situation may be more realistic than the others because the times that the electrolyzer operates will not necessarily coincide with hydrogen demand. Additionally, producing the hydrogen where it is needed mitigates the need for many storage and distribution costs. In Scenario 3a, energy generated by the PV and wind systems during on-peak hours is sold to the grid and all renewable energy produced during non-peak hours is sent over the grid to the hydrogen production site. Associated charges and resistive losses are included in the cost analysis. Scenario 3b involves selling all electricity generated by the renewables to the grid and purchasing only non-peak grid electricity to produce hydrogen. Note that in both of these cases, additional electric energy is purchased from the grid only during non-peak hours when the renewable is not producing. Further, it is assumed that operation of the electrolyzer only during non-peak hours allows the hydrogen producer to avoid demand charges. The renewable is also given a partial capacity credit.

All of the scenarios examined are based on the renewables having 10 MW nameplate capacities. The study was conducted for systems installed in the near term (~2000) and the mid-term (~2010) to show how costs will decline as the technologies mature. Table 3 shows the major assumptions for the PV and wind analyses.

Table 3: Assumptions for the PV and Wind Analyses

Date of plant installation	Year 2000	Year 2010
Efficiency of 2MW alkaline electrolyzer	82%	87%
Capital cost of 2MW alkaline electrolyzer	$600/kW	$300/kW
Operating costs for electrolyzer	3% of capital charges	2% of capital charges
Capital cost of wind plants, including necessary power conditioning units	$900/kW	$700/kW
Operating costs of wind plant, variable and fixed	$0.008/kWh, $0.0005/kWh	$0.005/kWh, $0.0005/kWh
Wind plant capacity factor	35%	40%
Capital cost of PV plant, including necessary power conditioning units	$3,133/kW	$1,662/kW
Operating costs of PV plant, variable and fixed	$0.008/kWh, $0.0003/kWh	$0.008/kWh, $0.0003/kWh
PV plant capacity factor	28%	30%
Wheeling charges	$1/kW-mo fixed, ½ ¢/kWh variable	
Capacity credit (applied for number of hours that electricity is sold)	PV: 85% of $4/kW-mo Wind: 40% of $4/kW-mo	

Electricity prices were provided by Distributed Utility Associates, obtained from a variety of proprietary sources and professional judgement. The price of fuel for electric generation is expected to remain fairly constant and stable throughout the study period of 2000 to 2010. Electricity prices in the U.S., however, are forecast to drop during this time, with prices stabilizing beyond the year 2012. These conditions are driven by several key factors: 1) increasing competition putting downward pressure on electricity costs and on prices as deregulation takes hold, 2) the existing overcapacity of inexpensive generation capacity in many regions, and 3) the apparent stability of natural gas and coal supplies and markets. An important unknown in this forecast is the cost, if any, associated with mandated air emission reductions. Electric energy bought by customers (hydrogen producers in this case) is purchased at the retail price. Retail and wholesale prices depend on the time of day and season; however, to simplify the data analysis for this study, average electric prices for each cost period (shown in Table 4) were assumed.

Table 4: Electricity Price/Cost Assumptions

Cost period	Hours per year	Electricity cost/price
On-peak	650	purchase cost: 10¢/kWh - 18¢/kWh, averaging 14¢/kWh selling price: 3.5¢/kWh - 6¢/kWh, averaging 5¢/kWh
Off-peak	4,966	purchase cost: 4¢/kWh - 7¢/kWh, averaging 6¢/kWh selling price: 2.5¢/kWh - 3.5¢/kWh, averaging 3¢/kWh
Super off-peak	3,144	purchase cost: 3¢/kWh - 6¢/kWh, averaging 5¢/kWh selling price: 1.8¢/kWh - 2.2¢/kWh, averaging 2¢/kWh

Note: Electricity selling prices do not include the capacity credit applied (see Table 3)

Figures 1 and 2 show the selling price of hydrogen from the PV and wind-based systems for the years 2000 and 2010, respectively. Overall, process economics for hydrogen from PV and wind can greatly be improved by integration with the electric utility grid. Differences in results between the PV and wind systems can best be understood by noting that the hours of operation of PV coincide with on-peak electricity usage better than wind. Thus, in Scenario 1, the PV system is selling most of the electricity it makes to the grid, causing a substantial reduction in the electrolyzer on-stream factor. This more than outweighs the benefit of being able to sell high-priced electricity during peak hours. The wind system doesn't suffer this disadvantage because it's able to use the electrolyzer during the night as long as the wind is blowing. On the other hand, however, the economics of the PV system are more distinctly enhanced by the other scenarios because it has greater opportunities to sell higher priced electricity to the grid than the wind system. Additionally, when electricity is purchased, PV buys more during super-off peak periods than wind.

Analysis of the Production of Hydrogen from Biomass

Three gasification systems to convert biomass to hydrogen were comparatively studied. The gasifier systems examined were the Battelle Columbus Laboratory/Future Energy Resources Corporation (BCL/FERCO) indirectly-heated gasifier, the Institute of Gas Technology (IGT) direct-fired gasifier, and the Texaco partial oxidation reactor. Basic block flow diagrams of these options plus the process steps necessary for hydrogen production are shown in Figure 3. The high temperature and low temperature shift reactors convert the majority of the CO (and H_2O) into CO_2 and (H_2) through the water-gas shift reaction. Because this reaction is exothermic, it is beneficial to operate these reactors at temperatures lower than that of the reformer. A pressure swing adsorption (PSA) unit is used to separate the product hydrogen from the rest of the shift reactor product stream, which mainly contains H_2, CO_2, and unreacted CO, CH_4, and other hydrocarbons. Before this stream can be purified in a PSA unit, it must contain at least 70 mol% hydrogen. Purifying streams more dilute than this decreases the purity and recovery of the hydrogen. Therefore, part of the PSA product stream is recycled back into the PSA feed. The recovery of hydrogen in the PSA is 85% when purifying a 70 mol% H_2 stream.

All of the systems studied were integrated such that available heat could dry the biomass and generate any necessary process steam, as well as produce a substantial amount of export steam. The assumption that the steam will be able to be sold is probably valid for the medium and large plants as they will most likely be located in more industrialized centers to take advantage of other infrastructure. However, it may be difficult to sell the steam produced by the small plant, as this size represents small refueling stations located near the demand for hydrogen.

The BCL/FERCO Low Pressure, Indirectly-heated Gasifier

The first option examined is based on a low pressure, indirectly heated gasifier, like that developed at Battelle Columbus Laboratories (BCL) specifically for biomass gasification. Future Energy Resources Corporation (FERCO) now owns the rights to this technology and is participating in its demonstration at the existing McNeil power plant in Burlington Vermont. This system is called indirectly heated because the heat necessary for the endothermic gasification reactions is supplied by sand circulating between the char combustor and the gasification vessel. The ASPEN Plus© simulation of this plant was made from test data from the Battelle Columbus Laboratory 9 Mg/day test facility.

After clean-up, the syngas, containing primarily CO, H_2, CH_4, CO_2, and some higher hydrocarbons, is cooled to 91°C (195°F) so that it can be compressed to the pressure required for the PSA system plus the expected pressure losses in the reactors. During this cooling, the water and higher hydrocarbons (tars) remaining in the syngas will most likely condense. Following compression to 3.5 MPa, the syngas is steam reformed to produce H_2 and CO_2 in a process based on that used for natural gas reforming. The primary reformer, a reactor similar to a process furnace with catalyst-filled tubes, converts the methane and higher hydrocarbons to CO and H_2, and performs a significant portion of the water-gas shift reaction to convert CO and water to H_2 and CO_2. The remaining CO is consumed via this reaction in the subsequent high temperature and low temperature shift reactors.

The reforming reactions typically take place at temperatures between 800°C and 850°C in the primary reformer. The heat necessary for these reactions is supplied by combusting the PSA offgas, which consists of unrecovered H_2, CH_4, CO, and inerts, outside of the reactor tubes through which the reactants and products are flowing. The tubes are filled with a commercial nickel-based catalyst. According to results from operating plants, the primary reformer was simulated as an equilibrium reactor with an 11 °C approach temperature. Practically all of the tar and C_2H_x species are consumed, 60 mol% of the CH_4 is converted, and there is a 22 mol% net conversion of CO.

The cost of the gasification train was estimated in a previous study (Craig and Mann, 1996), as well as by several consulting firms working for BCL (see Mann, 1995). These costs were scaled to the appropriate plant size for this study using a 0.7 scale factor. The cost of the primary reformer was based on a furnace reactor, taken from three literature and software sources.

The Institute of Gas Technology Direct-fired Gasifier

The Institute for Gas Technology (IGT) gasifier is a direct-fired high pressure gasifier, developed specifically for biomass power generation. The major system components for this analysis included wood handling and drying, followed by gasification for which an air separation unit is required, reforming, shift conversion, and hydrogen purification. Because the gasifier operates at a high pressure, 2 MPa, only a small amount of compression is needed to obtain the required steam reforming pressure of 3.5 MPa. A large amount of heat integration was required because of the wood drying and steam production requirements for the gasifier, reformer, and shift reactors. The reformer and shift reactors are of the same design as those used for the BCL analysis which is described in the above text. The gasifier was modeled in ASPEN Plus© using run data from the IGT 9 Mg/day test facility. The cost of the IGT gasifier was scaled from literature data and previous studies (Craig and Mann, 1996; Stone & Webster, Weyerhaeuser, Amoco, and Carolina Power & Light, 1995; Wright and Feinberg,1993).

The Texaco Partial Oxidation / Gasifier Reactor

The Texaco gasifier is a high temperature, high pressure entrained flow partial oxidation reactor. Both gasification and reforming reactions take place in this vessel. Thus, this is the only system examined that does not require a separate catalytic steam reforming step. Unlike the other two gasifiers studied in this analysis, the feedstock to the Texaco gasifier was biomass-derived pyrolysis oil. A liquid feedstock is preferred because it will be easier to feed to the high pressure gasifier than solid biomass. The Texaco gasifier has not yet been tested with pyrolysis oil (or biomass). Therefore, in order to estimate the synthesis gas yield, the gasifier was modeled in ASPEN Plus© using coal data (Pietruszkiewicz *et al*, 1988). An approach to equilibrium (ATE) was determined and the simulation was run using the following empirical formula for pyrolysis oil: $CH_{1.33}O_{0.53}$ (55 wt% C, 6 wt% H, 39 wt% O). The same steam requirement, temperature, pressure, and heat loss as the coal system were used. The oxygen required was varied until the heat loss from the gasifier equaled that derived from the coal data.

For this particular analysis, it was assumed that the pyrolysis oil will be shipped from several remote locations to the hydrogen production facility. Many small pyrolysis plants can be built to meet the oil feed requirements of the hydrogen production facility, allowing these plants to be constructed in areas where biomass residues are available, and thus at lower prices.

Because the Texaco gasifier operates at such high temperatures, two system designs were examined to determine which would be the most economical in regards to hydrogen production. In the first analysis, sensible heat was recovered for steam production by radiant and convective heat exchangers from the hot gas stream exiting the gasifier. This option is often considered economical for electricity production because the steam is used to produce power via a steam turbine. In the second analysis, the hot gas was cooled directly at the exit of the gasifier by a water quench. This option does not require the additional heat exchange equipment that is required in the first option, but because the water is put directly into the gas stream, heat recovery will be minimal.

Literature data along with information from Texaco were used to determine the cost of the Texaco gasifier and the oxygen plant while the heat exchangers, pumps, reactors, and PSA were costed individually (Pietruszkiewicz *et al*, 1988; Geosits *et al*, 1994; Matchak *et al*, 1984; Shemo, 1980; Simbeck *et al*, 1983; Winter, 1997). The operating costs for these processes include the wood or oil feedstock, electricity for operating pumps and compressors, water for cooling and steam generation, and labor. Operating costs were also obtained for the air separation unit and the PSA unit.

Results of the Biomass Analyses

Table 5 is a summary of the hydrogen production rates for each system for each of the three feed rates studied. The IGT system produces 5.6% more hydrogen than the BCL system and 12.5% more than the Texaco system.

Table 5: Hydrogen Production Rates

	H_2 produced (kg/day)		
Biomass feed rate (bone dry Mg/day)	BCL	IGT	Texaco
300	21,044	22,232	19,767
1,000	70,148	74,106	65,891
1,500	105,222	111,159	98,836

Table 6 shows the total capital investment (TCI) for each system for each of the three feed rates studied. The factors required to determine TCI based on the total delivered equipment costs were taken from Peters and Timmerhaus (1991), which gives a factor of 3.15. Note that for the Texaco system, the capital cost of the pyrolysis plant are included in the cost of the oil feedstock for the hydrogen production plant, making the capital cost of the Texaco quench system appear to be significantly less than that of the IGT system.

Table 6: Total Capital Investment Costs

	Total Installed Capital Investment (million U.S. $)			
Biomass feed rate (bone dry Mg/day)	BCL	IGT	Texaco - quench case	Texaco - high temp cooling case
300	40.7	75.4	56.8	83.0
1,000	105.0	175.6	127.6	207.0
1,500	144.5	234.3	168.8	282.8

The highest capital cost items for the BCL/FERCO system are the compressors. The compressor used to move the offgas from the PSA to the primary reformer furnace counts for 23% of the total installed capital equipment cost. The compressor that increases the pressure of the syngas prior to the reformer makes up approximately 17%. The primary reformer is the next most expensive item at 13%. The gasifier train is relatively inexpensive since it operates at low pressures and temperatures lower than the other systems.

For the Texaco system, the air separation unit, followed by the gasifier and water quench, make up the majority of the capital cost at 33% and 30% of the total, respectively. For the IGT analysis, the largest capital costs come from the air separation unit and gasifier at 24% and 23% of the total, respectively.

In the case of the Texaco-based system, the equipment costs of the high temperature gas cooling case were compared with those of the direct quench case. The former case was found to be much cheaper. The main difference is the gasifier and cooling equipment costs: $37.8 million for the gasifier plus high temperature cooling versus $12.7 million for the gasifier plus quench. The high temperature gas cooling case was found to be uneconomical for hydrogen production compared to the quench case. This is due to the fact that the installed capital cost is $25 million more than the quench case for the same hydrogen production rate, along with the fact that much of the steam produced from cooling the synthesis gas is required by the process and cannot be used to produce export power.

The stoichiometric efficiency (defined in Mann, 1995) and the energy conversion efficiency were calculated for each process. The stoichiometric efficiency is defined as the actual amount of hydrogen produced from the process divided by the maximum theoretical yield of hydrogen from the wood. The following equation shows the stoichiometry for converting bone dry wood to hydrogen.

$$CH_{1.47}O_{0.67} + 1.33H_2O \Rightarrow CO_2 + 2.07H_2$$

The energy conversion efficiency is defined as the energy out of the process divided by the energy into the process. In each process, excess heat is used to produce steam at two pressures: 690 kPa (100 psig) and 3,450 kPa (500 psig). The steam is exported and a by-product credit is taken for steam generation. The following equation shows how the energy conversion efficiency was calculated for these processes.

$$\frac{(H_2)(HHV_{H2}) + (STM_{ex})(\Delta H_{sh})}{(Feed)(HHV_{feed}) + \bar{e}}$$

H_2 = hydrogen produced (kg)
HHV_{H2} = higher heating value of hydrogen (GJ/kg)
STM_{ex} = steam produced which is sold (kg)
ΔH_{sh} = enthalpy difference between incoming water and steam produced which is sold (GJ)
Feed = wood feed rate (kg)
HHV_{feed} = higher heating value of the wood (GJ/kg)
$\bar{e}$ = imported electricity (GJ equivalents)

The efficiencies calculated for the three gasifier systems are shown in Table 7. The stoichiometric efficiency of the IGT process is slightly higher than the BCL and Texaco processes; however, the BCL system has the highest energy conversion efficiency.

Table 7: Process Efficiencies

	BCL	IGT	Texaco - quench case	Texaco - high temp cooling case
Stoichiometric efficiency	40.7%	43.0%	38.2%	38.2%
Energy conversion efficiency	79.2%	57.8%	76.4%	67.2%

Sensitivity Analyses on the Biomass Systems

Biomass costs were varied to reflect the range of possibilities for residues and those from dedicated biomass supply systems. Figures 4 and 5 show the hydrogen selling price in $/GJ for biomass feedstock costs of $0/dry Mg to $46/dry Mg for the 1,000 dry Mg/day and 300 dry Mg/day plant size, respectively. The lower end of this range represents residues that will be available in small quantities to the pyrolysis-based options and small gasification-based plants. The higher end represents a projected cost for biomass from dedicated feedstock supply systems (i.e., energy crops). Note that it's unlikely that residues will be available in sufficient quantities for the large plant.

Figure 6 shows the sensitivity of hydrogen selling price to capital cost at the 1,000 Mg/day feed rate. The total capital investment determined for each system's base case is shown inside the shaded boxes in bold-face type. The value in the shaded oval represents the necessary reduction in the capital for the hydrogen selling price to be $14.2/GJ, the high end of current market hydrogen costs. Additionally, the installed capital was varied by +/- 30%; the resulting hydrogen selling price are shown as the end-points of the shaded boxes for each case. With this reduction in capital, the BCL/FERCO gasifier is the only system that can produce hydrogen within the range of current market prices.

Determination of the Costs of Hydrogen Storage and Transportation

An analysis was performed to estimate the costs associated with storing and transporting hydrogen. These costs can be added to hydrogen production costs, like those determined for the solar, wind, and biomass processes, to determine the total delivered cost of hydrogen. Storage methods analyzed include compressed gas, liquid hydrogen, metal hydride, and underground storage. Major capital and operating costs were considered over a range of production rates and storage times. For the transport of hydrogen, compressed gas, liquid hydrogen, metal hydride, and pipeline delivery were considered. Modes of transportation included truck and rail transport for the compressed gas and metal hydride. For liquid hydrogen, ship or barge delivery was investigated as an option in addition to truck and rail transport. Transportation costs were estimated for a range of production rates and delivery distances. For more information on the assumptions and data sources used to determine costs summarized here, consult Amos (1998).

Storage of Hydrogen

Figure 7 shows the effect of storage time and hydrogen flowrate on cost for four methods of hydrogen storage. Underground storage was found to be the cheapest method of storage at all production rates and storage times because of the low capital cost of the cavern. Most of the cost of underground storage is associated with the electricity requirements to compress the gas, which is independent of storage volume. This means the cost of underground storage is very insensitive to changes in production rate or storage time. An important consideration with underground storage, however, is the value of the hydrogen remaining in the cavern. Once a site is identified, the cost of not being able to use or sell this hydrogen should be added to the total storage costs.

It was assumed that the metal hydride storage provided no economy of scale, so its hydrogen storage costs are independent of flowrate. Therefore, it cannot compete with the other storage options at long storage times or high hydrogen flows. Because the alloy capital cost is a major portion of the total hydride storage cost, there is very little change in hydride storage costs with higher heating costs. Metal hydride storage, however, does compete with liquid hydrogen and compressed gas storage at low flowrates and short storage times.

Liquid hydrogen storage is not economical at low production rates because of the high capital cost of the liquefier. Even at higher production rates, compressed gas is more economical for short storage periods. However, as the storage time increases, liquid hydrogen has an advantage over compressed gas because the capital cost of a liquid hydrogen dewar is less than that of a compressed gas pressure vessel. Because of the low cost of the dewar, liquid hydrogen storage costs are relatively insensitive to storage time. At high production rates, economy of scale factors reduce the storage costs until they are eventually limited by the electricity costs associated with liquefaction. It was found in the analysis that boil-off rate is not a major cost factor until the storage time was longer than a week; for short-term storage, some cost savings may be possible by using cheaper insulation.

Compressed gas storage competes with liquid hydrogen and metal hydride storage for small quantities of hydrogen and low production rates. At low production rates, the capital cost of the pressure vessel is large, but at higher production rates, the storage cost is eventually limited by the compressor electricity cost because of an economy of scale effect. As storage time increases, the capital cost of the pressure vessel drives up the storage cost.

One option for compressed gas storage is to increase the operating pressure of the system. While this increases the cost of the pressure vessel and compressor, the reduction in tank size can result in overall savings. For short storage periods with compressed gas, an optimum occurs where the reduction in tank capital costs is balanced against the increased compressor and compressor electricity costs. At longer storage times, the capital cost reduction becomes the important factor, so the optimum occurs at the maximum operating pressure which minimizes the tank size and cost.

Transportation of Hydrogen

Figure 8 shows the effect of storage time and flowrate on the most important options for the transportation of hydrogen. Liquid hydrogen transport by truck is the cheapest alternative, except for large quantities of hydrogen, when pipeline delivery becomes competitive. At longer distances, the capital cost of the extra pipeline requires more hydrogen flow before it will compete with liquid hydrogen delivery. Because installation costs dominate the total cost of hydrogen transport by pipeline, sharing a larger pipeline between several suppliers and users would reduce these costs; this is what is currently done along the Gulf Coast and around the Great Lakes. It's important to note that very little energy is required to move hydrogen through a pipeline. Bringing the hydrogen up to pressure would require a great deal more energy than is shown; such power requirements were incorporated into the previously described storage costs.

In all cases, except pipeline delivery, there is a minimum transport cost associated with each delivery method for a given distance. This point is reached when the production rate is high enough that the truck or rail car is being fully utilized 100% of the time. As an example, consider the case of a small hydrogen plant that doubles it's production rate and instead of making one trip per day with a liquid hydrogen truck, it makes two trips per day. The total capital cost remains the same, the cost of one truck, but this cost is now spread out over twice as much hydrogen. If a truck is already fully utilized, however, any increase in production will require purchasing another truck and produces no reduction in transport costs. The lowest capacity methods bottom-out first for any given distance as production rate increases.

As expected, the truck transport costs increases with distance because of the higher labor and fuel costs. Capital costs also increase with distance. For short distances, one truck can make multiple trips each day, but as the distance increases, more trucks are needed because more time is spent in transit--there is less chance to use the same truck for multiple trips. Compressed gas transport is affected the most because that method requires the most trips, but for all methods, labor costs quickly start to dominate for distances over about 160 km (100 miles). Compressed gas delivery costs also see the largest affect from fuel price for the same reason.

For small production rates, liquid hydrogen transport costs are high because the truck is not fully utilized and it may only make a few trips per week. At these low flows, the truck capital cost contribution is the largest cost, but the costs are also less sensitive to distance since there are far fewer trips compared to situations at larger production rates. At all flowrates, as distance increases, liquid hydrogen delivery charges become dominated by the labor costs. However, with liquid hydrogen, the effect is small compared to compressed gas because the driver is carrying more hydrogen per trip; one hydrogen tanker can carry over twenty times the amount of hydrogen as a tube trailer.

At medium production rates of 450 kg/hr (1,000 lb/hr) and 160 km (100 mile) delivery distances, liquid hydrogen tucking was the cheapest means of transport, but metal hydride also competes because of its high storage density. For comparison showing the effect of capacity, at the above production rate and delivery distance, you would need 15 tube trailers making sixty trips per day (four trips per truck), 6 hydride trucks making 24 trips per day (4 trips per truck) or one liquid hydrogen truck making three trips per day.

In comparing transportation costs, it's interesting to note differences in capital expenditures. For transporting the same amount of hydrogen the same distance in the above example, the price of one liquid hydrogen tanker with cab is $500,000; the price of 15 tube trailers with cabs is about $3.75 million, and the price of six metal hydride transports is $6.9 million.

Combined Storage and Transportation Costs

When considering the delivered cost of hydrogen, it is important to understand that there are three factors to consider: production rate, delivery distance and storage time. In some cases, these factors are dependant upon each other. For example, storage time may depend on delivery distance. If a small hydrogen plant is producing one truck of hydrogen every four days, it might need three days of storage if the truck is making a delivery far away and the truck is on the road the whole time. On the other hand, if the delivery distance is ten miles, the most that would be needed is one day, since the truck would only be gone from the site a short time. This becomes more of an issue with rail cars, which may be gone for an long as three days for a short delivery distance. (One day in transit to the customer, one day to unload and switch and a third day to bring it back.)

Different transport and delivery options can also be mixed. For example, metal hydride delivery would be compatible with compressed gas, underground or even liquid hydrogen storage. (Although it does not make sense to evaporate liquid hydrogen for transport, it is theoretically possible.) Pipeline transport without any storage may also be an option.

Figures 9 and 10 give combined storage and transportation costs for two distances (160 km and 1,600 km) for a production rate of 500 kg/hr and a storage time of one day. This production rate may describe the situation for future renewable and small-scale generation. When both the storage and delivery costs are added, the benefit of liquid hydrogen becomes apparent. For a delivery distance of 160 km (100 mile), liquid hydrogen is only slightly cheaper than metal hydride transport. At a longer distance of 1,600 km (1,000 miles), however, liquid hydrogen is four times cheaper than metal hydride storage and seven times cheaper than compressed gas.

Conclusions

Hydrogen production by direct conversion of sunlight by photoelectrochemical devices has the potential to be economically feasible. If research goals on efficiency and stability can be met, the selling price of the product hydrogen will be less than that projected for direct PV/electrolysis systems. Interacting with the grid such that higher value electricity can be sold and lower priced electricity bought, while maximizing electrolyzer use, makes a significant impact on the economics of producing hydrogen by PV/electrolysis. Such coupling also makes wind-based systems more economical, although to a lesser extent. The optimal scenario studied involves electrolysis with only renewable electricity and less expensive non-peak electricity. However, the delivered cost of hydrogen will be cheapest from the decoupled scenarios (Scenarios 3a and 3b) since it is produced at its point of use.

In the analysis of biomass to hydrogen, the BCL/FERCO gasifier produces the cheapest hydrogen. For the 1,000 dry Mg/day plant size, the required hydrogen selling price for the three systems examined ranges from $5/GJ to $23/GJ for a feedstock cost of $0/Mg to $46/Mg. Of the different options studied, only the BCL system produces hydrogen for prices that can compete within the current range of industry selling prices for end-of-pipe hydrogen. For the IGT and Texaco systems, a feedstock sensitivity analysis showed that in order to bring the hydrogen selling price down to $14/GJ, negative-priced feedstocks would be required.

An assessment of the costs to store and transport hydrogen shows that at moderate production rates and short distances, gas storage and metal hydride transport is cheapest. At longer distances, liquid storage and liquid transport is the preferred combination.

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Figure 1: The Projected Selling Price of Hydrogen from Sunlight and Wind in 2000

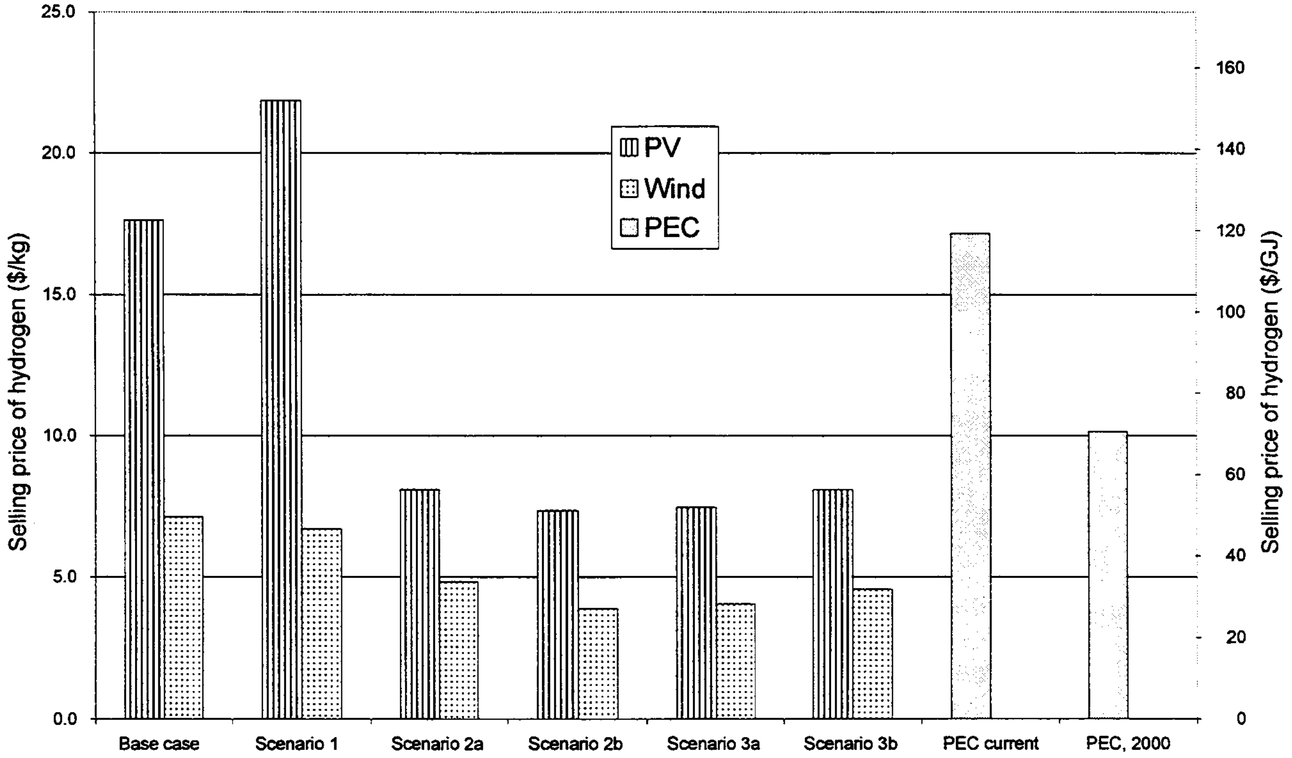


Figure 2: The Projected Selling Price of Hydrogen from Sunlight and Wind in 2010

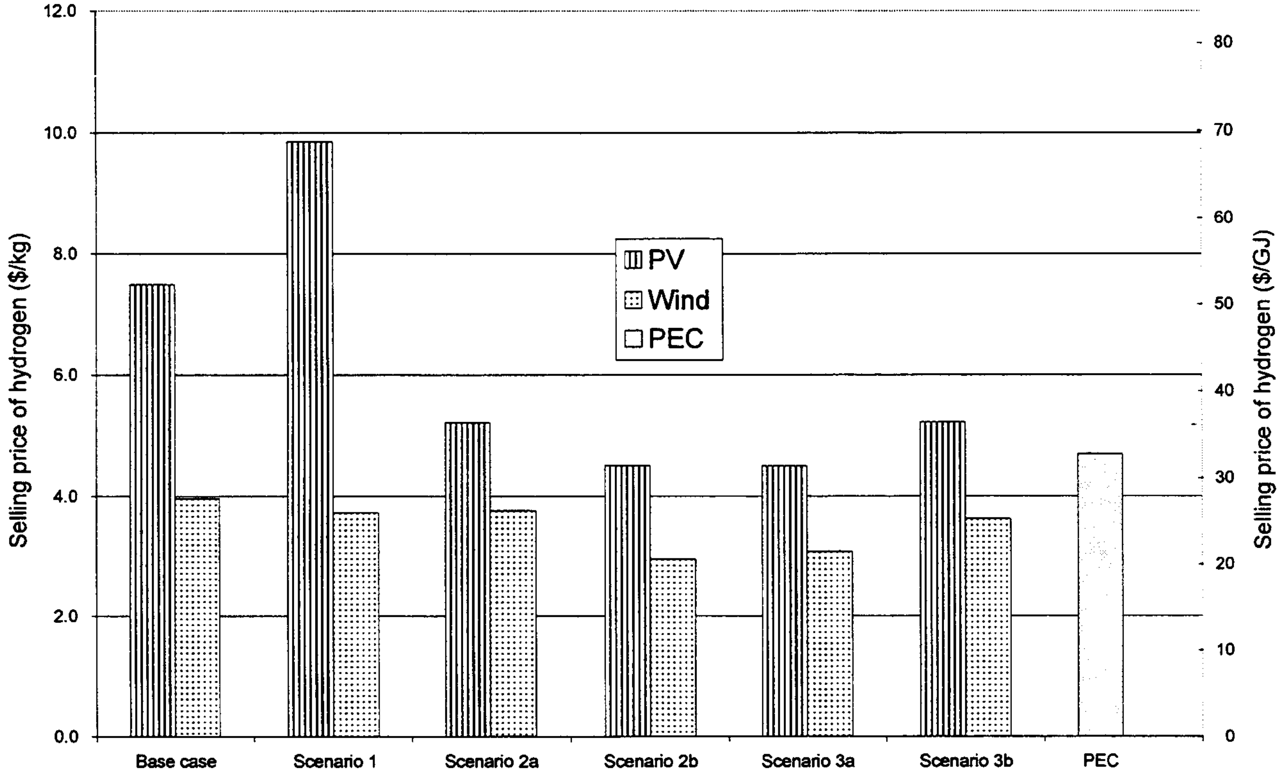
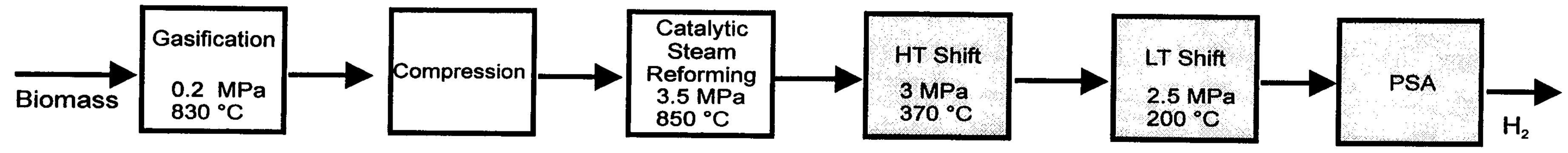
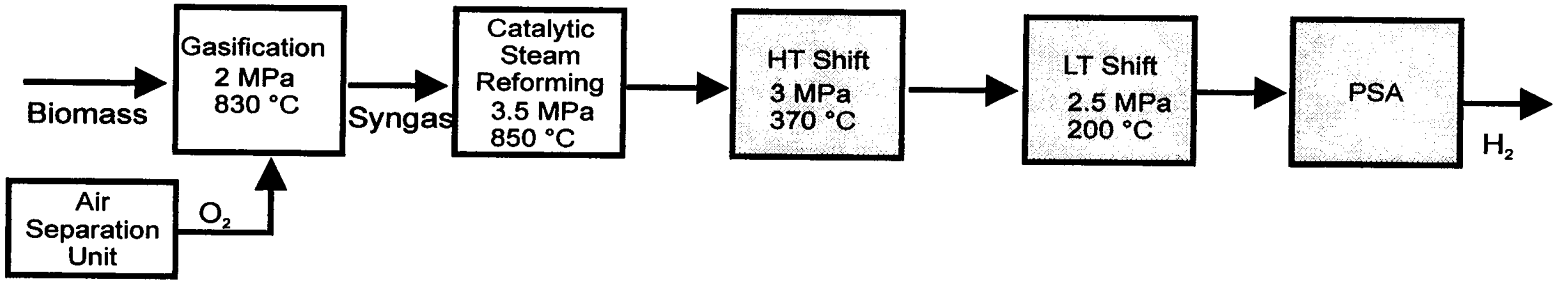


Figure 3: Major Thermochemical Options For The Conversion Of Biomass Into Hydrogen

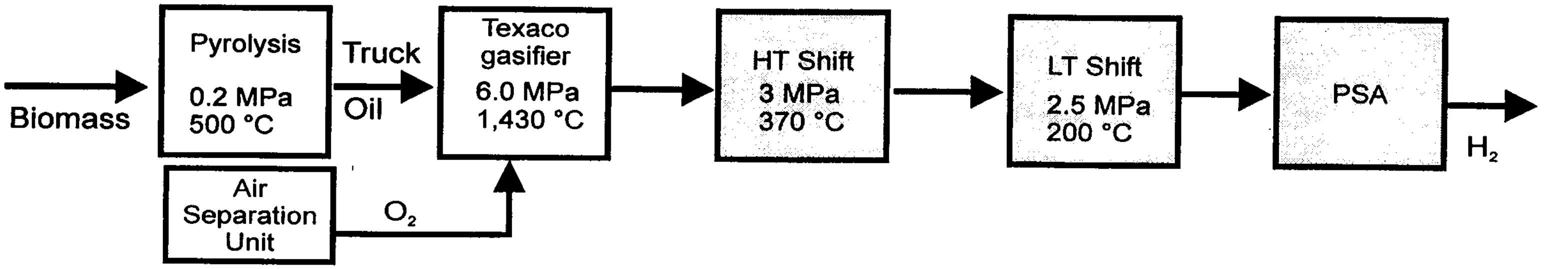
Gasification in the BCL/FERCO Gasifier Followed by Steam Reforming



Gasification in the IGT Gasifier Followed by Steam Reforming



Pyrolysis Followed by Partial Oxidation in the Texaco Gasifier



Shaded boxes represent process steps that are common to all systems

Figure 4: The Selling Price of Hydrogen from Biomass at 300 Mg/day

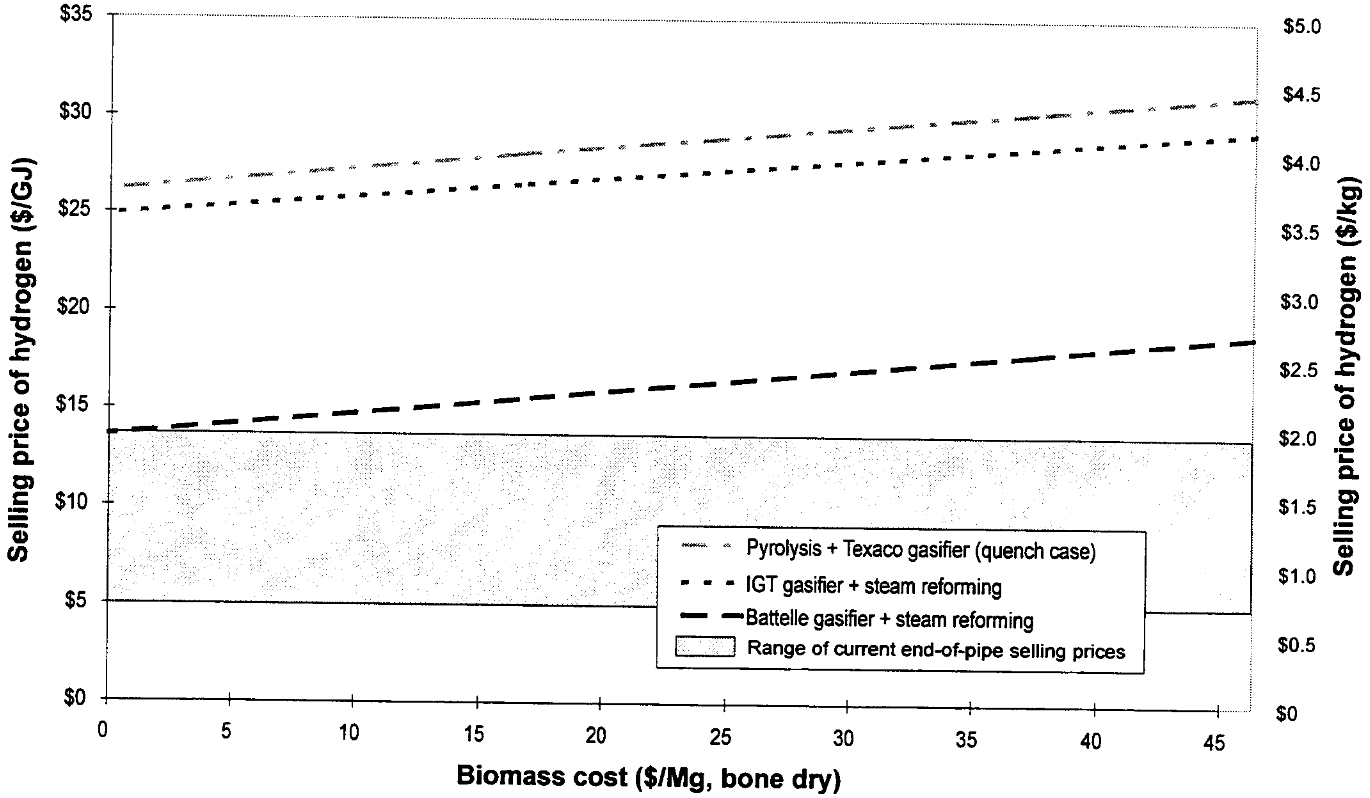


Figure 5: The Selling Price of Hydrogen from Biomass at 1,000 Mg/day

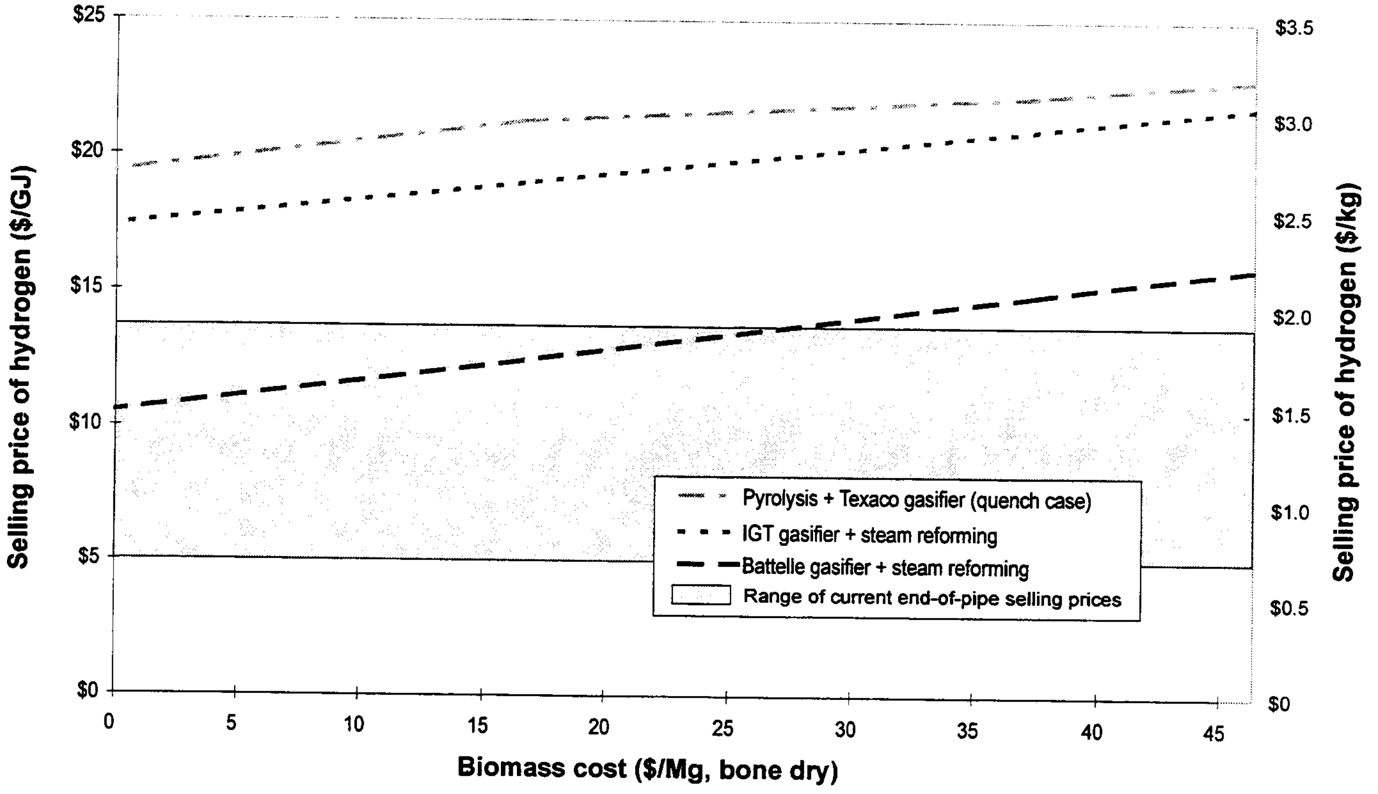


Figure 6: Hydrogen from Biomass: Sensitivity of Hydrogen Selling Price to Capital Cost (1,000 Mg/day plant size, wood feed = $46/dry Mg)

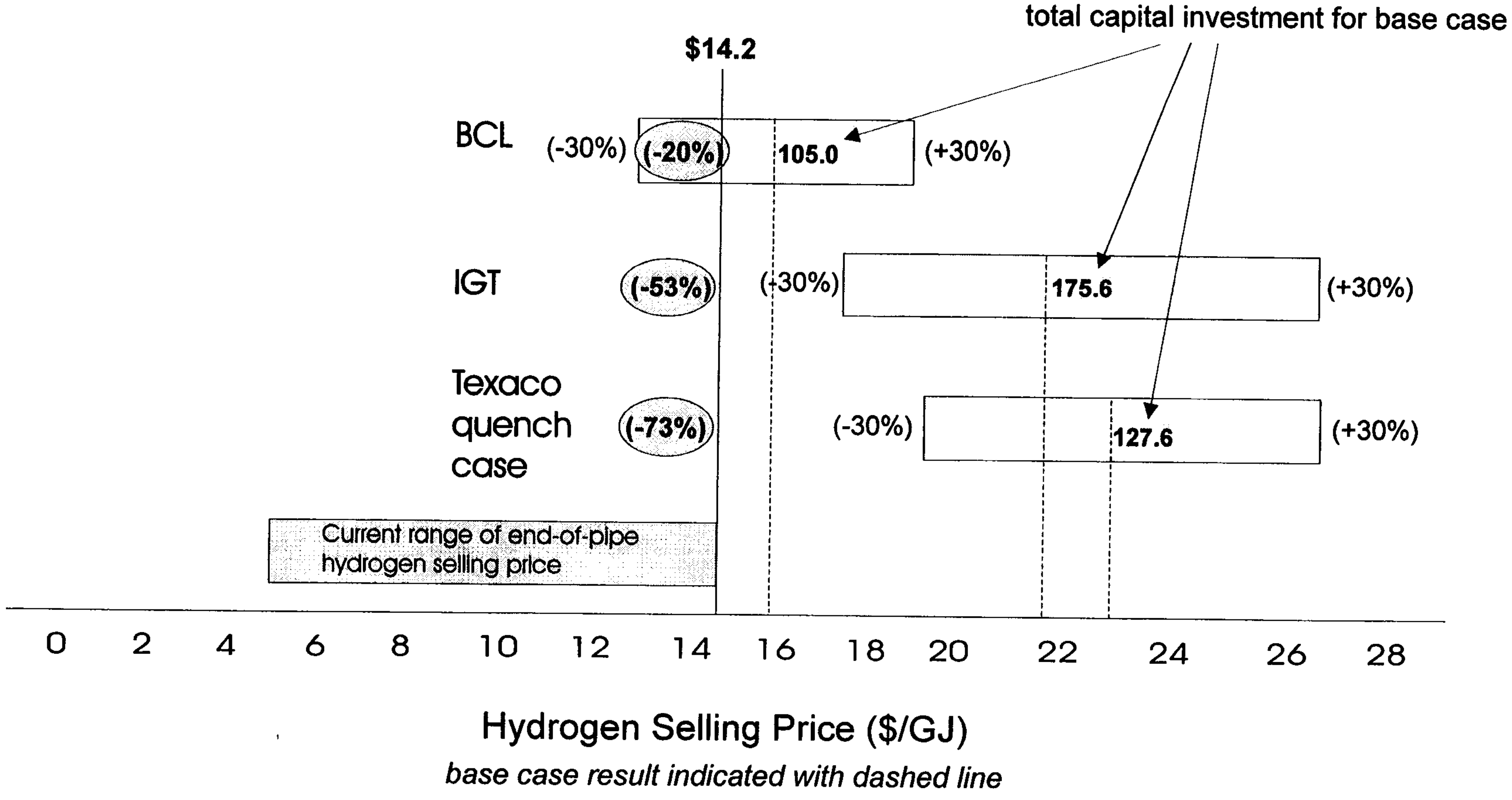


Figure 7: Primary Methods of Hydrogen Storage

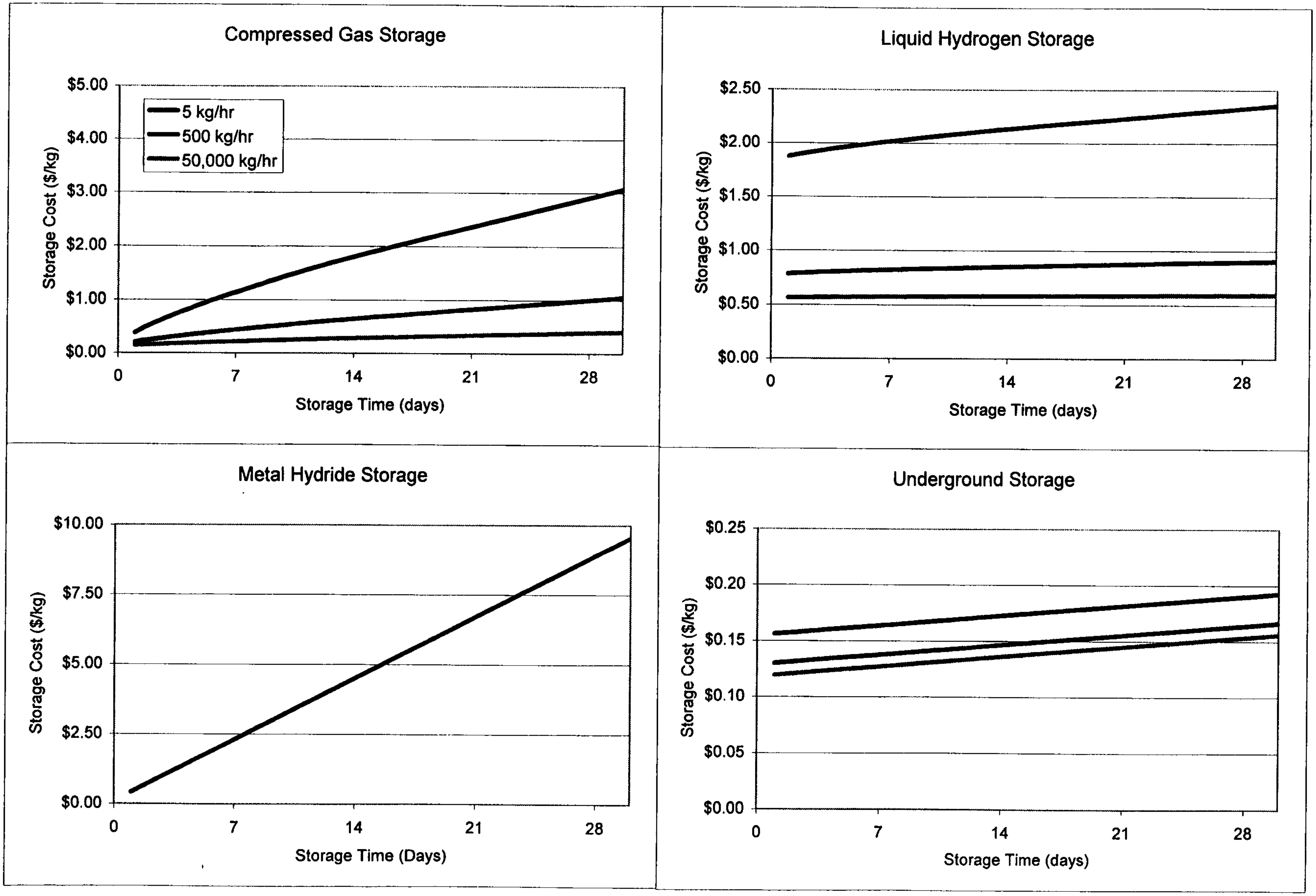
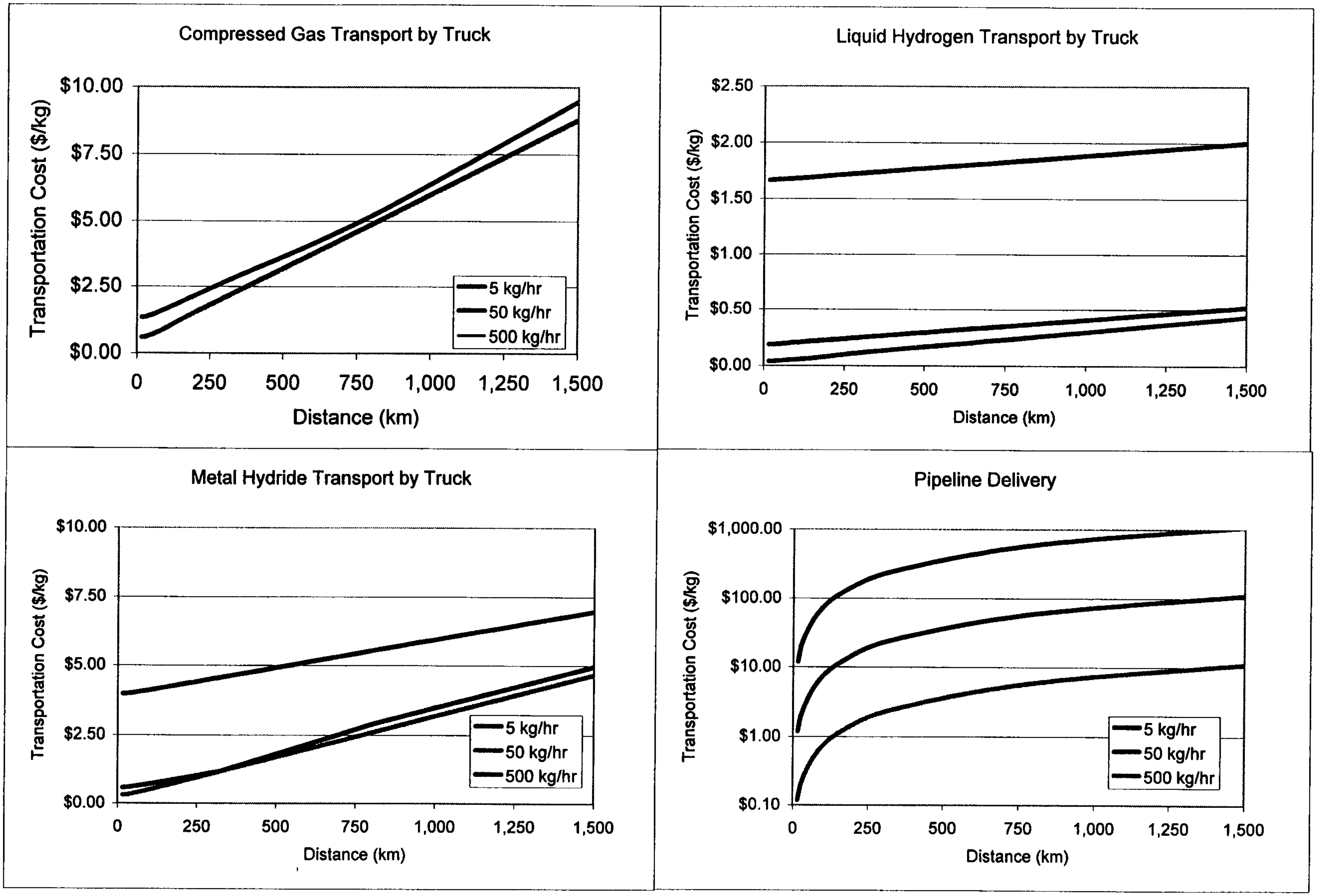


Figure 8: Primary Methods of Hydrogen Transportation



Compressed Gas Transport by Truck

Liquid Hydrogen Transport by Truck

Metal Hydride Transport by Truck

Pipeline Delivery

Figure 9: Combined Storage & Transportation Cost
(500 kg/hr, 160 km, 1 day of storage)

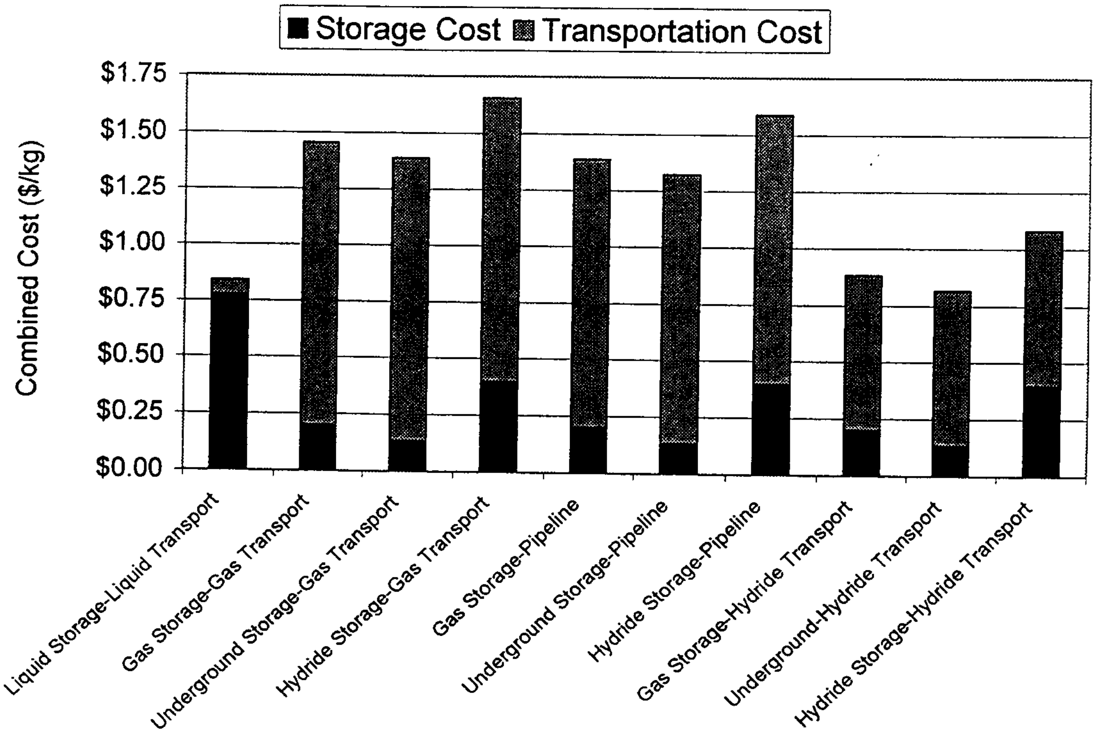


Figure 10: Combined Storage & Transportation Costs
(500 kg/hr, 1.600 km, 1 day of storage)