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Technical Report

Survey of the Economics of Hydrogen Technologies

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Introduction

A survey of the economics of hydrogen production, storage, transport, and end-use technologies has been completed. More than 100 publications concerning the economics of current and near-term hydrogen technologies were surveyed. Technologies more than 20 years from commercialization were not considered.

Table 1: Technologies Included in the Survey

Hydrogen Production	Steam Methane Reforming Noncatalytic Partial Oxidation Coal Gasification Biomass Gasification Biomass Pyrolysis Electrolysis
Hydrogen Storage	Compressed Gas Liquefied Gas Metal Hydride Carbon-Based Chemical Hydrides
Hydrogen Transport	Pipelines Truck Transport Rail Transport Ship Transport
Stationary Power	Proton Exchange Membrane Fuel Cells (PEMFC) Phosphoric Acid Fuel Cells (PAFC) Solid Oxide Fuel Cells (SOFC) Molten Carbonate Fuel Cells (MCFC) Alkaline Fuel Cells (AFC) Gas Turbine Stationary Internal Combustion Engine
Transportation Applications	Hydrogen Fuel Cell Vehicles Hydrogen Internal Combustion Engines Hybrid Vehicles Onboard Storage Onboard Reforming Refueling Options

Where possible, the results of the studies have been standardized using the methodology described in Appendix A. If standardization was not possible, the literature values were used to provide rough checks against the detailed estimates. This report briefly describes each technology, summarizes the status, and presents the results of the survey and standardization analysis.

In this report, capital costs are shown as the specific total capital investment (TCI) in $/GJ. Specific TCI is a measure of the capital cost of a facility for each unit of hydrogen produced, processed, or stored. For hydrogen production technologies, this value is the TCI divided by the annual hydrogen production capacity. For hydrogen storage technologies, the specific TCI is the TCI divided by the annual throughput. Another important convention of the report is the energy convention. Unless otherwise specified, all energy units (e.g., GJ) are reported on a lower heating value (LHV) basis.

Hydrogen Production Technologies

Hydrogen may be produced from a variety of feedstocks (e.g., natural gas, biomass, water) using several technologies (e.g., reforming, gasification, electrolysis). For this analysis, commercial and near-commercial technologies, including steam methane reforming (SMR), coal gasification, noncatalytic partial oxidation, biomass gasification and pyrolysis, electrolysis, and concentrated solar energy, will be discussed.

Steam Methane Reforming

Steam methane reforming is the most common and least expensive method of producing hydrogen; almost 48% of the world's hydrogen is produced from SMR (Gaudernack 1998). SMR can also be applied to other hydrocarbons such as ethane and naphtha. Heavier feedstocks, however, cannot be used because they may contain impurities and the feed to the reformer must be a vapor (Leiby 1994). Other processes such as partial oxidation (POX) are more efficient with higher hydrocarbons.

Steam methane reforming is a well-developed, fully commercialized process. Potential areas for technical improvements include the use of prereformers and medium temperature shift reactors (Leiby 1994).

The literature was surveyed regarding the economics of SMR and four detailed estimates were obtained (Leiby 1994; Kirk-Othmer 1991; Foster-Wheeler 1996; Blok et al. 1997). The standard methodology (Appendix A) was applied to the data and the results of the analysis are summarized in Table 2.

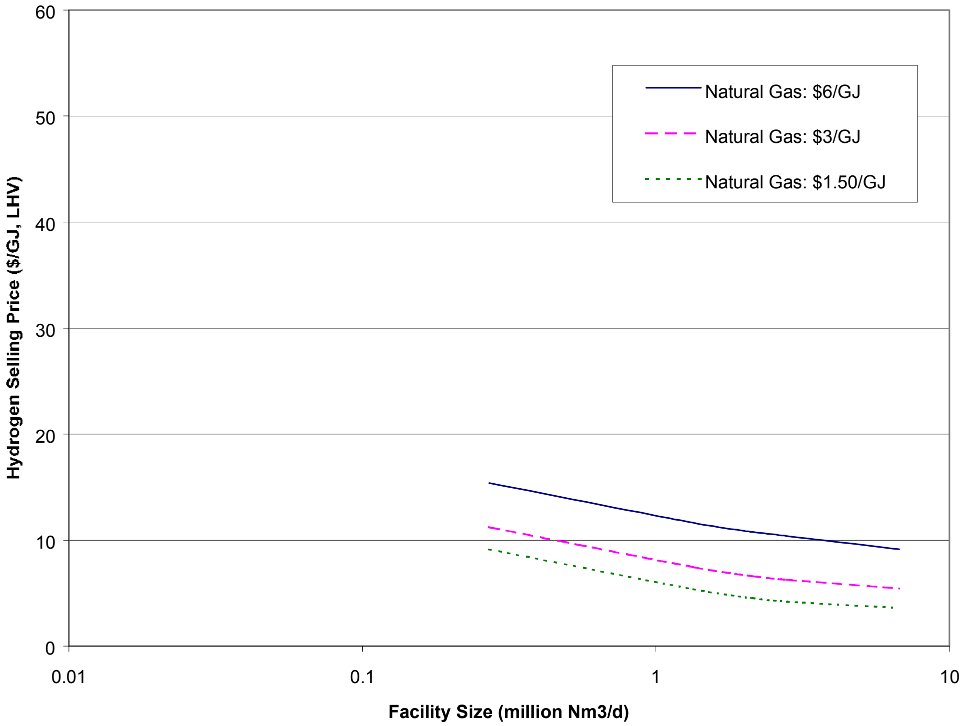
Table 2: Summary of SMR Costs

Facility Size (million Nm^3/d)	Reference	Specific TCI ($/GJ)	Hydrogen Price ($/GJ)
Large Facilities			
1.34	Leiby 1994	14.74	7.46
2.14	Leiby 1994	12.61	6.90
2.80	Kirk-Othmer 1991	9.01	6.26
6.75	Foster-Wheeler 1996	10.00	5.44
25.4	Blok et. al 1997	10.82	5.97
Small Facilities			
0.27	Leiby 1994	27.46	11.22

In each detailed analysis, the price of the natural gas feedstock significantly affects the final price of the hydrogen. In fact, for these analyses, feedstock costs were 52%-68% of the total cost for large plants and approximately 40% for small plants. Capital charges comprised most of the remaining costs. In most systems, a small (i.e., < 1% of hydrogen price) credit for steam produced was taken. Overall, the hydrogen prices in the table (i.e., $5-$8/GJ) agree well with other published values (Hart 1998; Veziroglu and Barbir 1998; Gaudernack 1998; Fisher 1990; Carlsson et al. 1997).

As shown in Figure 1, there is a significant economy of scale for these systems. The actual savings realized, however, depends on the source document. Other authors (Thomas et al. 1998) have proposed that SMR may be cost effective for small-scale distributed fuel cell applications when combined with vehicle refueling. This effect will be discussed in detail in the section on distributed applications.

Figure 1: Economics of Hydrogen Production via SMR



Coal Gasification

Hydrogen production from coal gasification is a well-established commercial technology, but is only competitive with SMR where oil and/or natural gas is expensive (e.g., South Africa and China) (Kirk-Othmer 1991). Three primary types of gasifiers are used: fixed bed, fluidized bed, and entrained flow.

Two detailed cost estimates for the Texaco entrained flow gasifier were obtained from the literature (Kirk-Othmer 1991; Foster-Wheeler 1996). The results of the standardization economic evaluation are presented in Table 3.

Table 3: Summary of Coal Gasification Costs

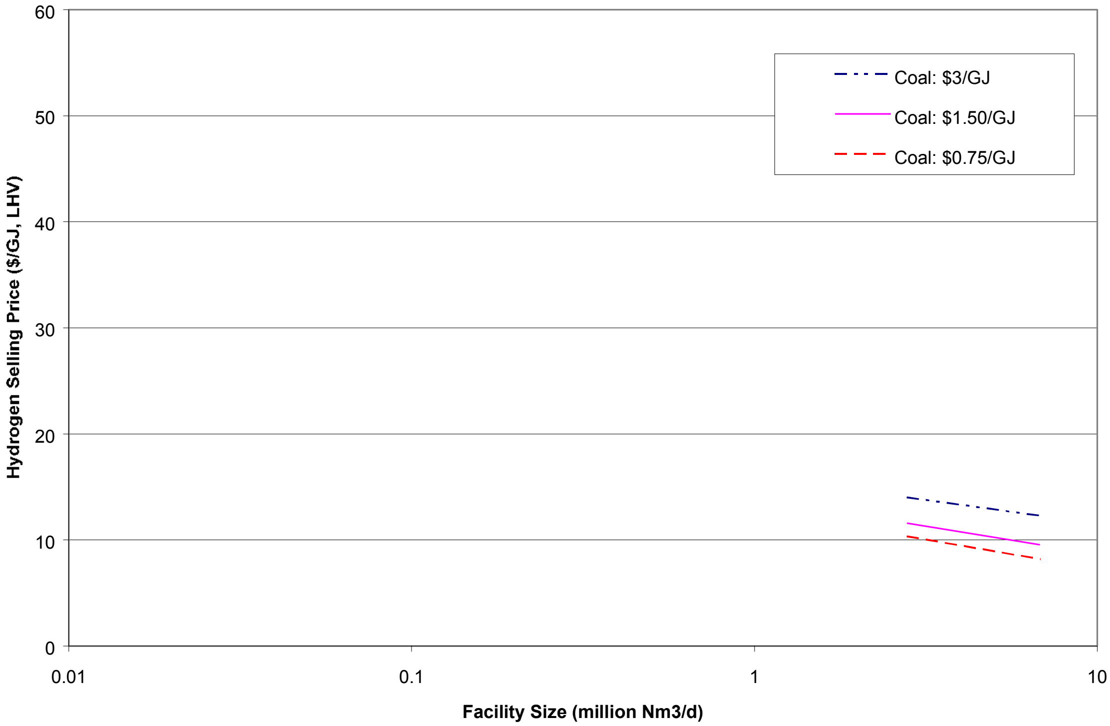
Facility Size (million Nm^3/d)	Reference	Specific TCI ($/GJ)	Hydrogen Price ($/GJ)
2.80	Kirk-Othmer 1991	34.2	11.57
6.78	Foster-Wheeler 1996	33.1	9.87

As shown in the table, the price of hydrogen from a coal gasification plant is about $10-$12/GJ. For this technology, the feedstock cost is around 25% of the final hydrogen cost. Capital charges, maintenance, and solid waste disposal are other significant costs. The costs provided in the table are similar to those provided in other sources (Gaudernack 1998; Lipman and DeLuchi 1996), but are lower than those found in several others $13/GJ (Hart 1998), $14-$16.5/GJ (Veziroglu and Barbir 1998), and $19.3/GJ (Fisher 1990). Because many of these sources did not list the feedstock price or the energy convention (i.e., lower heating value, LHV or higher heating value, HHV) of the reported value, the discrepancy may not be significant. For example, the feedstock price may be higher than that used in the standard economic analysis and if the hydrogen prices were on an LHV basis instead of the assumed HHV basis, the cost would be lower. In any case, the values are all within reasonable bounds of each other, given the uncertainty in the source documents.

Because there are significant coal reserves in many areas of the world, coal could replace natural gas and oil as the primary feedstock for hydrogen production (Kirk-Othmer 1991). However, this technology has environmental impacts (e.g., feedstock procurement) that may prove significant in the future.

Figure 2 summarizes the cost of hydrogen production from coal gasification.

Figure 2: Economics of Hydrogen Production via Coal Gasification



Partial Oxidation of Hydrocarbons

Hydrogen may be formed from the noncatalytic partial oxidation (i.e., gasification) of hydrocarbons such as residual oil. Any hydrocarbon feedstock that can be compressed or pumped may be used in this technology (Kirk-Othmer 1991). However, the overall efficiency of the process (50%) is less than that for SMR (65%-75%) and pure oxygen is required (Veziroglu and Barbir 1998; Kirk-Othmer 1991). Two commercial technologies for this conversion are available: the Texaco Gasification Process and the Shell Gasification Process (Kirk-Othmer 1991; Leiby 1994).

Table 4 summarizes the results of the economic standardization analysis for noncatalytic partial oxidation.

Table 4: Summary of Hydrogen Production Costs from Noncatalytic Partial Oxidation

Facility Size (million Nm^3/d)	Reference	Feedstock	Specific TCI ($/GJ)	Hydrogen Price ($/GJ)
Large Facilities				
1.34	Leiby 1994	Coker off-gas	11.24	7.39
2.14	Leiby 1994	Coker off-gas	9.63	6.94
2.80	Kirk-Othmer 1991	Residual oil	22.2	9.83
Small Facilities				
0.27	Leiby 1994	Coker off-gas	21.96	10.73

From these analyses, the price of hydrogen from coker off-gas is estimated at $7-$11/GJ based on a feedstock price of $2.7/GJ (HHV). The hydrogen price from residual fuel ($1.4/GJ) is estimated at roughly $10/GJ. These results agree well with other published values (1998$) $10.6/GJ (Hart 1998) and $11.8/GJ (Veziroglu and Barbir 1998).

The specific TCI for the residual oil case is significantly higher than that for a similar facility based on coker off-gas. This result is expected because of increased equipment for feed handling and impurity removal. For the facilities based on coker off-gas, there is a significant economy of scale with a resulting reduction in the price of hydrogen. A similar effect is expected for a facility based on residual fuel.

Biomass Gasification

As with coal gasification, biomass may be gasified using a variety of methods, primarily indirect and direct gasification. Indirect gasification, as exemplified by the Battelle-Columbus Laboratories and Future Energy Resources Corporation (BCL/FERCO) gasifier, uses a medium such as sand to transfer heat from the char combustor to the gasification vessel (Spath and Mann 1998). In direct gasification (e.g., the Institute of Gas Technology, IGT, gasifier) heat to the gasification vessel is supplied by the combustion of a portion of the feed biomass.

Comprehensive, detailed studies on indirect gasification using the BCL/FERCO gasifier were completed (Mann 1995a; Larson and Katofsky 1992). The Larson and Katofsky (1992) study also presented results for the Wright-Malta (WM) indirect gasifier. Similar studies on the direct gasification method have not been obtained, but general information is available (Spath and Mann 1998). In addition, two other sources have reported hydrogen production costs from generic biomass gasification systems (Hart 1998; Lipman and DeLuchi 1996).

Capital costs for a large (0.7-2.0 million Nm^3/d) BCL/FERCO indirect biomass gasification are estimated at $20.6 (Larson and Katofsky 1992) to $38.2/GJ (Mann 1995a). The specific TCI for the WM gasifier is projected to be $26.91/GJ. The major operating cost, by far, for this technology is the feed. Using the projected biomass costs of $46.30/dT, the feedstock price is about 40% of the cost of hydrogen from large facilities producing 0.7-2.2 million Nm^3/d. This feedstock price represents the expected feedstock price from dedicated biomass production. Waste biomass, however, may be available for as low as $16.50/dT (Mann 1995a). Another important factor in the price of the hydrogen is the by-product steam credit; this credit is roughly equivalent to all the variable operating costs, except feedstock.

The overall price of hydrogen from the BCL/FERCO gasifier is $13.08/GJ for the 0.7 million Nm^3/d facility (Mann 1995a) and $8.69/GJ for the 2.2 million Nm^3/day facility (Larson and Katofsky 1992). Costs for the WM gasifier are similar, at $10/GJ. Smaller facilities (0.02 and 0.2 Nm^3/d), which could likely be supported with waste feedstocks at $16.50/dT, would produce hydrogen for $17.10 and

$10.65/GJ, respectively. These costs are similar to others for generic gasification facilities: $15.3/GJ (Hart 1998) and $11-$14/GJ (Lipman and DeLuchi 1996).

In general, hydrogen produced via direct gasification is expected to cost slightly more (i.e., 5%) than that from the indirect mode. Hydrogen produced using the Texaco gasifier is projected to be prohibitively expensive (Spath and Mann 1998).

Biomass Pyrolysis

In this process, biomass is thermally decomposed at a high temperature (450°-550°C) in an inert atmosphere to form a bio-oil composed of about 85% oxygenated organics and 15% water (Mann 1995b). The bio-oil is then steam reformed using conventional technology to produce hydrogen. Alternatively, the phenolic components of the bio-oil can be extracted with ethyl acetate to produce an adhesive/phenolic resin coproduct; the remaining components can be reformed as in the first option. The product gas from both alternatives is purified using a standard pressure swing adsorption (PSA) system.

Several sources (Spath and Mann 1998; Gregoire 1992; Chornet et al. 1995; Mann 1995b) have provided economic analyses of biomass pyrolysis processes. Many of the analyses compare purchasing the oil with making it in-house. Although making the oil in-house results in a hydrogen price that is lower than when purchasing oil, the oils will likely need to be purchased based on a projected market for the oils (Mann 1995b). Therefore, in this analysis, the oil was assumed to be purchased at $110/tonne.

Based on the Mann (1995b) analysis and the standard economic methodology, the specific TCI for a large facility, processing bio-oils equivalent to 907 dTpd of biomass, is estimated at $15-$17/GJ. The higher value corresponds to the coproduct case because less hydrogen is produced; thus, the capital investment per unit of hydrogen increases. The overall hydrogen production price is estimated to be $9-$12/GJ for both cases. As expected, the coproduct option can be more cost-effective than the total reformation case, because the selling price of the coproduct is moderate to high. Costs were also developed for facilities processing oils based on feedstock rates of 272 and 27 dTpd. The overall hydrogen production prices for these cases are $10-$15/GJ. Table 5 summarizes the standardized costs for biomass gasification and pyrolysis.

Table 5: Summary of Hydrogen Production Costs for Biomass Gasification and Pyrolysis

FacilityType/Size (million Nm^3/d)	Reference	Specific Total Capital Investment ($/GJ)	Hydrogen Price ($/GJ)[1]	Biomass Price ($/dry tonne)
Biomass Gasification				
2.26	Larson 1992	26.91	10.03	46.30
2.16	Larson 1992	20.60	8.69	46.30
0.720	Mann 1995	38.19	13.09	46.30
0.215	Mann 1995	42.00	10.65	16.50
0.022	Mann 1995	73.85	17.10	16.50
Biomass Pyrolysis				
All Reformed				
1.014	Mann 1995a	14.94	12.42	46.30
0.304	Mann 1995a	17.14	12.92	16.50
0.030	Mann 1995a	26.05	15.52	16.50
Coproduct				
0.811	Mann 1995a	16.74	8.86	46.30
0.243	Mann 1995a	19.31	10.11	16.50
0.024	Mann 1995a	30.66	12.73	16.50

Figures 3 and 4 present the costs for biomass gasification and pyrolysis, respectively.

Figure 3: Economics of Hydrogen Production via Biomass Gasification

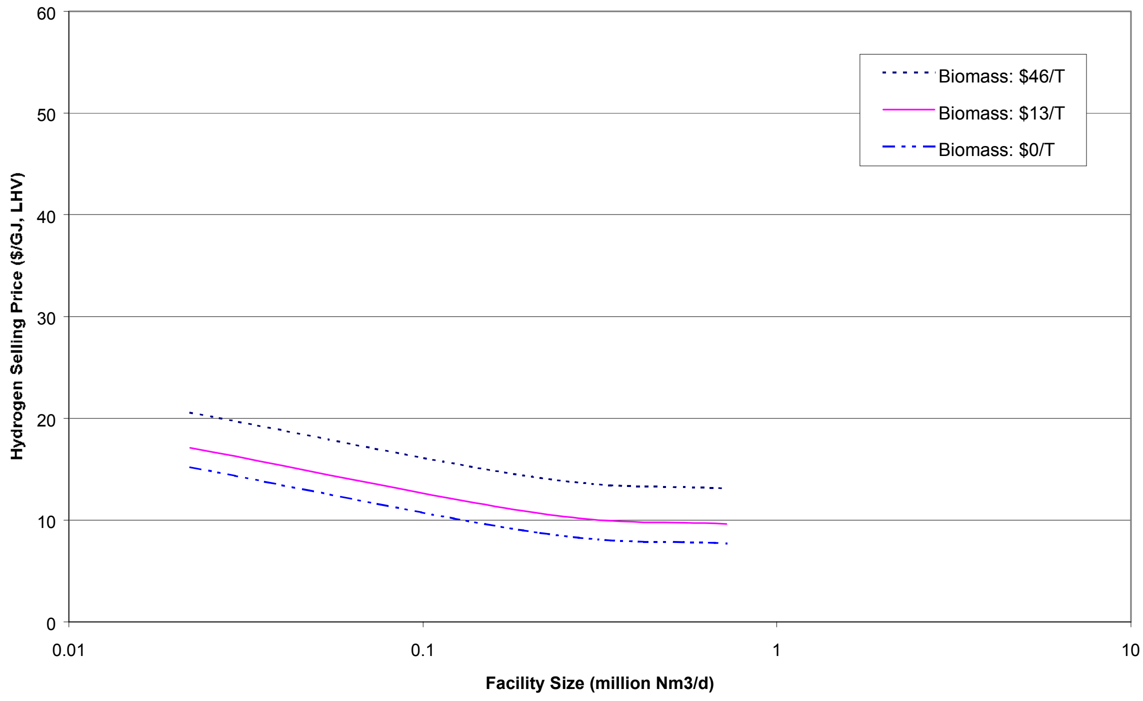
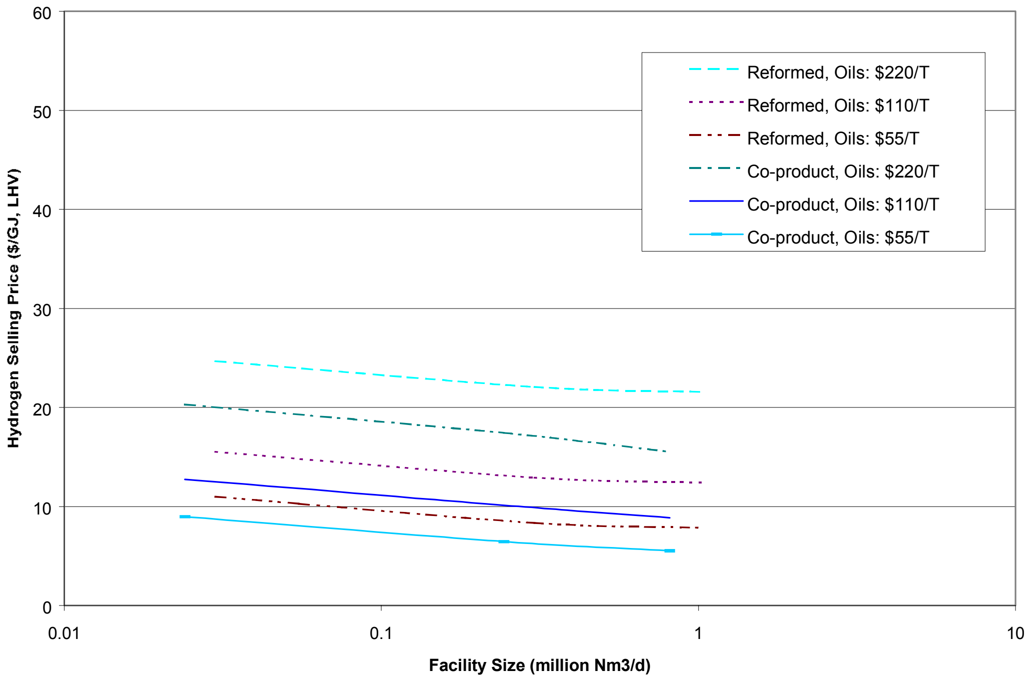


Figure 4: Economics of Hydrogen Production via Biomass Pyrolysis



Electrolysis

A small amount (4%) of the world's hydrogen is produced by electrolysis of water. For users requiring small amounts of extremely pure hydrogen, electrolysis can be a cost-effective means of obtaining the required hydrogen. The major cost factor for electrolysis is the electricity. In some cases, using the standard electricity price of $0.049/kWh, this cost is more than 80% of the resulting hydrogen selling price. For renewable technologies, the capital costs dominate. For example, the annual capital costs of the photovoltaic (PV) system could be as much as 85% of the hydrogen price. The cost of the electricity is a major concern because it is three to five times more expensive a "feedstock" than fossil fuels. In fact, the high cost of the electricity is the driving force behind the development of high-temperature steam electrolysis. In this process, some of the energy driving the process can be from steam instead of electricity. For example, at 1000°C, more than 40% of the energy required could be supplied as heat (Kirk-Othmer 1991).

Several detailed studies on the economics of hydrogen production from electrolysis were obtained in the literature (Foster-Wheeler 1996; Kirk-Othmer 1991; Andreassen 1998; Mann et al. 1998). Some focused on renewable electricity sources (i.e., wind and PV) and/or on very small-scale systems. Table 6 summarizes the standardized costs for hydrogen production via electrolysis.

Table 6: Summary of Costs for Hydrogen Production from Electrolysis

Facility Size (million Nm^3/d)	Reference	Specific TCI ($/GJ)	Hydrogen Price ($/GJ)
Large Facilities			
Nonspecific			
2.8	Kirk-Othmer 1991	12.95	20.6
6.75	Foster-Wheeler 1996	30.97	24.5
Small Facilities			
Nonspecific			
0.096	Andreassen 1998	31.88	28.7
PV-Based[1]			
0.195 (2000)	Mann et al. 1998	485.8	41.8
0.209 (2010)	Mann et al. 1998	242	24.8
Wind-Based[1]			
0.247 (2000)	Mann et al. 1998	158.6	20.2
0.279 (2010)	Mann et al. 1998	92.5	11.0

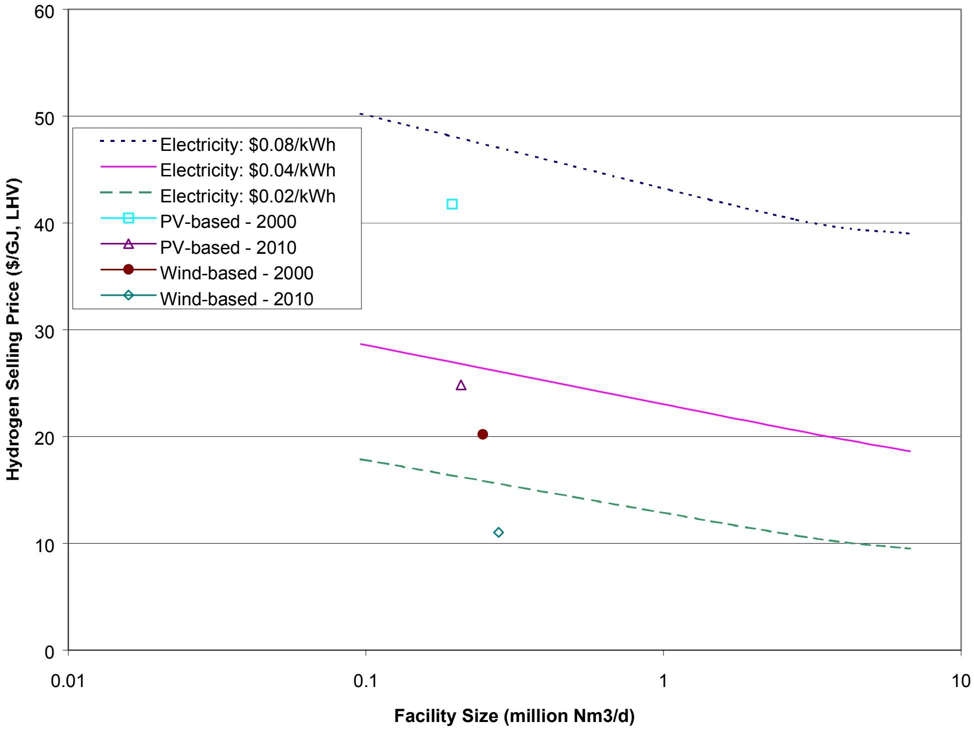
[1] The costs shown are for assumed technology improvements for 2000 and 2010.

The cost of hydrogen from water electrolysis (> $20/GJ) is significantly higher than any technology evaluated thus far. In fact, even when proposed technology improvements for wind and PV systems are implemented, their costs will still be $11-$25/GJ. However, because the hydrogen is produced on-site and on demand, no transportation and storage costs are likely to be incurred, resulting in a competitive cost compared to the cost of small amounts of "delivered" hydrogen. The costs in Table 6 agree well with other published values: $4-$24/GJ (Gaudernack 1998), $14-$61/GJ (Fisher 1990), $15-$40/GJ (Hart 1998), $20/GJ (Buteau et al. 1992), $31/GJ (Hassmann and Kuhne 1992), and $15/GJ (Carlsson et al. 1997).

Costs for proton exchange membrane (PEM) electrolyzer systems are expected to be less than conventional alkaline electrolyzers. Thomas et al. (1995a) conducted a survey of the capital costs for electrolyzer systems and projected specific capital investments (1998$) of $42.8/GJ and $13/GJ for 530 MW$_e$ alkaline and PEM systems, respectively. Carlsson et al. (1997), projected specific capital investments of $32-$55/GJ for alkaline systems of 500 kW to 12 MW and $159/GJ for a 100-kW PEM system.

Figure 5 presents the costs for hydrogen production using electrolysis.

Figure 5: Economics of Hydrogen Production via Electrolysis



Concentrated Solar Energy

A promising longer-term technology is concentrated solar energy for hydrogen production via electrolysis. Two primary process configurations are used with this method. In the first, ambient temperature electrolysis, concentrated solar energy is used to generate alternating current (AC) electricity, which is supplied to the electrolyzer. The second is the high-temperature electrolysis of steam. In this system, the concentrator supplies both heat and AC electricity to convert steam (1273 K) to hydrogen and oxygen.

Glatzmaier et al. (1998) evaluated two solar energy concentrators for these applications: the dish-Stirling and power tower. The dish-Stirling was sized at 10 MW_{ac} with no thermal storage; the power tower was sized at 200 MW_{ac} with thermal storage. The scenarios were evaluated based on 2010 and 2020 technology. Cost reductions and efficiency improvements were assumed to occur with time. The capital costs for the dish-Stirling system are expected to decrease from $1,660/$kW_{ac}$ in 2010 to $1,495/$kW_{ac}$ in 2020; operating and maintenance (O&M) costs are projected to exhibit a similar decrease from $27/kW/yr to $26/kW/yr. For the power tower case, reductions will also occur for the capital costs ($2,605/$kW_{ac}$ to $2,523/$kW_{ac}$) and the O&M costs ($30/kW/yr to $25/kW/yr). In addition, the capacity factor for this technology is expected to increase from 65% to 77% over the specified time period.

Using the standard methodology, production costs for hydrogen were developed. For both the 2010 and 2020 technology scenarios, the power tower system produced hydrogen at a lower cost than the dish-Stirling. In 2010, the power tower is expected to produce hydrogen at almost $41/GJ; the dish-Stirling system has a hydrogen price of $65/GJ. In 2020, the power tower cost is $34/GJ; the dish-Stirling system costs $60/GJ.

Another method for producing hydrogen using concentrated solar energy is high-temperature steam electrolysis. In this system, an SOFC system would be operated in a reverse mode to generate hydrogen instead of electricity (Glatzmaier et al. 1998). Because this technology is in an early stage of development, only the 2020 power tower case was evaluated.

Based on this information and the standard economic methodology, hydrogen production costs were developed using two electrolyzer costs: \$2,000/kW$_{dc}$ and \$500/kW$_{dc}$ and three current densities: 0.19, 0.37 and 0.55 A/cm^2 (Glatzmaier et al. 1998). The best results were obtained for the highest current density and are \$49/GJ for the low electrolyzer case and \$62/GJ for the high electrolyzer case. Based on this analysis, the authors concluded that ambient-temperature electrolysis and high-temperature electrolysis were roughly the same when the electrolyzer costs are the same. They also point out that the most cost-effective mode of operation for the high temperature system was at the highest current densities with no direct thermal input (Glatzmaier et al. 1998). Thus, there appears to be no benefit to this configuration at this time.

Table 7 presents the results of the standard economic analysis for hydrogen production from concentrated solar technologies (Glatzmaier et al. 1998).

Table 7: Summary of Hydrogen Production Costs from Concentrated Solar Energy

Facility Size (million Nm^3/d)	**Specific TCI (\$/GJ)**	**Hydrogen Price (\$/GJ)**
Ambient-Temperature Electrolysis		
Dish-Stirling		
0.015 (2010)	372	64.72
0.015 (2020)	344	60.48
Power Tower		
0.700 (2010)	226	40.75
0.829 (2020)	186	34.14
High-Temperature Electrolysis		
Low-cost electrolyzer		
High-cost electrolyzer	288	48.94
	380	62.31

Hydrogen Storage Technologies

Use of hydrogen as an energy carrier requires that it be stored and transmitted. The primary methods for hydrogen storage are compressed gas, liquefied hydrogen, metal hydride, and carbon-based systems. Most of these systems may be used either for stationary applications or for onboard vehicle storage. Long term (i.e., ~ 100 days), seasonal storage of hydrogen is generally in the form of chemical hydrides. In the following section, each hydrogen storage technology will be evaluated as a stationary system and where applicable, onboard use will be discussed. The stationary systems, except chemical hydrides, will be evaluated for both 1-day and 30-day storage periods. All capital costs are expressed in \$/GJ of annual throughput.

Compressed Gas

Hydrogen may be stored as a compressed gas above ground, below ground, and onboard vehicles. Each technology is discussed in detail.

Above-ground compressed gas storage

In a compressed gas system, hydrogen is compressed to about 20.7 MPa and stored in standard-pressure (50-L) gas cylinders and greater than 15,000 Nm^3 in spherical containers. One source (Taylor et al. 1986), states that compressed gas storage in high-pressure tubes is generally confined to systems of 14,000 Nm^3 or less because of their high cost.

Detailed costs for above-ground compressed gas storage have been estimated by several sources (Amos 1998; Taylor et al. 1986; Schwarz and Amankwah 1993). Using the standard methodology, the TCI for daily storage is $1,700-$9,000/GJ for stationary vessel storage and $16,600/GJ for pressurized tube storage. Operating costs for this option include power and O&M charges. In general, power charges are the most significant and are estimated at 7-18 kW/GJ.

The overall storage cost is projected to be $1.50-$4.20/GJ and more than $30/GJ for tube storage for a storage period of 1 day. The tube storage costs are for a specific application; thus, extrapolating the data may not be appropriate. The cost of hydrogen storage as a compressed gas is highly dependent on the turnover rate. For example, at low turnover rates (e.g., 30 days), the capital cost can be 70%-90% of the storage costs (Amos 1998). At high turnover rates (e.g., daily storage), each volume of storage is used more than 300 times per year such that the capital cost, hence the total storage cost for each unit of storage is decreased. This trend is exemplified by looking at 30-day storage costs, which increase to $7.40-$36.90/GJ overall.

The costs resulting from this analysis compare well with storage costs from other sources (Carpetis 1994; Newson et al. 1998; Huston 1984; Ledjeff 1990; Carlsson et al. 1997). In general, these papers provided capital cost estimates of $4,000-$16,700/GJ. One source, Newson et al. (1998), estimated costs that were significantly lower at $150-$190/GJ. The estimates were not documented and so the discrepancy was not resolved.

Underground compressed gas storage

In general, underground compressed gas systems are most suitable for large quantities and/or long storage times. There are several large-scale underground hydrogen storage systems. The city of Kiel, Germany has been storing town gas (60%-65% hydrogen) in a gas cavern since 1971; Gaz de France, the French National Gas company, has stored hydrogen-rich refinery product gases in an aquifer structure near Beynes, France; and Imperial Chemical Industries stores hydrogen in salt mine caverns near Teeside, UK.

Several studies (Taylor et al. 1986; Amos 1998; Carpetis 1994) evaluate the storage of hydrogen below ground. Taylor et al. analyzed hydrogen storage in salt caverns (dry and wet mode), a mined cavern, and a depleted gas well. Amos evaluated storage in a generic cavern; Carpetis provided capital cost estimates for several applications.

Capital costs for underground storage have been estimated at $16-$80/GJ (Carpetis 1994) depending on the type of storage used with solution-mined salt caverns or mechanically excavated caverns at the high end of the range. Amos (1998) estimated the capital costs at $73/GJ. Taylor et al. (1986) projected the lowest capital investments for salt caverns ($6.6/GJ) and the highest for depleted gas wells ($18/GJ). Operating costs for underground storage are primarily for compression power.

As with all storage technologies, the overall cost of hydrogen storage depends on throughput and storage time. Using the standard costing methodology (Appendix A), costs for underground storage of hydrogen were developed. The incremental costs of hydrogen storage were $1-$4.7/GJ for daily storage; analysis of 30-day storage resulted in a 50%-80% increase in costs. For the cases analyzed by Taylor et al. (1986), storage in a depleted gas well ($3.5/GJ) was the most expensive and storage in a salt cavern

($1.7/GJ) was the least. However, Taylor et al. point out that the analysis was very specific and extrapolation of the results may not be valid.

Compressed gas storage for vehicles

Compressed gas storage (20.7-55.2 MPa) is the simplest and least expensive alternative for onboard hydrogen storage (Lipman and DeLuchi 1996). However, this method also has a very low volumetric energy density (1.3-3.4 MJ/L) compared to gasoline (32.4 MJ/L). Although the energy density may be improved by increasing the storage pressure, safety issues become important. Fiber-reinforced composite (e.g., aluminum-carbon) tanks have been developed to address this issue. An aluminum-carbon tank with a design pressure of 55.1 MPa is estimated to cost $5,100/GJ (1998$) with an energy density of 3.4 MJ/L (Lipman and DeLuchi 1996).

Liquefied Hydrogen

Hydrogen may also be liquefied for storage as a stationary system or for use in onboard vehicle systems. In this system, the hydrogen is compressed, cooled, and expanded in a variety of sequences to form a liquid. Most liquid hydrogen systems (LH2) are stored at -253°C (Veziroglu and Barbir 1998). The largest storage system (3,800 m^3 capacity) is at the U.S. National Aeronautics and Space Administration (NASA). Because of the low temperatures used in this technology, boil-off is a significant concern. Boil-off can be 2%-3%/d for small vessels, or as little as 0.1%/d for large spherical vessels (Carpetis 1994).

Stationary storage

Costs for stationary liquefied hydrogen were obtained from several sources, including three detailed assessments (Amos 1998; Schwarz and Amankwah 1993; Taylor et al. 1986). Capital costs for these systems are $1,830-$7,200/GJ for daily storage of 13,100-20,300 GJ. For 30-day storage, the costs are $170-$1,690/GJ for 3,900-3.9 million GJ.

Electricity for compression is by far the largest operating expense. This demand ranges from 82.4 kW/GJ (Amos 1998) to 165 kW/GJ (Taylor et al. 1986). For the standard electricity cost of $0.049/kWh, this annual cost is 60%-82% of the hydrogen cost for large (> 13,000 GJ) daily storage systems and 32%-68% of 30-day systems >100,000 GJ.

For large (>13,000 GJ) liquefied hydrogen storage systems, the price of storage is relatively insensitive to the system size, $5-$8/GJ. Smaller systems of 131 and 3,919 GJ have considerably higher storage costs of $17-$23/GJ for daily and monthly storage, respectively. One analysis by Taylor (1986) projected a price of storage of $25/GJ for a large (108,000 GJ) system. This high cost is due primarily to the high energy demand used in the analysis. In addition, Taylor assumed much higher O&M costs than did Amos (1998). The estimated costs using the standard methodology are similar to those found in other studies (Carpetis 1994; Fisher 1990).

Methods for reducing the energy requirement of this technology are ongoing. One method, magnetic liquefaction, is a potential solution that is under development (Veziroglu and Barbir 1998).

Onboard storage

Onboard liquefied gas storage has been suggested for vehicles, but there are significant drawbacks, including, as noted earlier, fuel losses as high as 3%/d. Not only would this fuel loss be a significant cost, but safety issues are of concern with confined-space parking (Lipman and DeLuchi 1996). The onboard storage tank is projected to cost from $1,280-$2,550/GJ (1998$) (Lipman and DeLuchi 1996).

Metal Hydride

Metal hydrides are compounds that store hydrogen in the interatomic lattice of a metal. Absorption of the hydrogen into the lattice (hydriding) is an exothermic process and requires cooling. Release of the hydrogen (dehydriding) is endothermic and requires heating. The temperature and pressure of these reactions depend on the specific composition of the hydride. In general, metal hydride systems for hydrogen storage can be classified as either high (~300°C) or low (<150°C) temperature, depending on their operating temperatures at modest pressures (0.1-1.0 MPa). Because hydrides require heat to release hydrogen, the chance of accidental releases is slight. Thus, they are considered a safe hydrogen storage technology. However, these systems also are heavy, have low gravimetric hydrogen densities (1%-7%), and are generally expensive. Stationary and onboard systems have been examined and are discussed here.

Stationary storage

Detailed cost estimates of metal hydride systems were not obtained. Some authors specified the cost of the individual alloys (Huston 1984; Sandrock 1997); others provided broad-based capital and operating costs for a generic "hydride" (Amos 1998; Carpetis 1994). Two sources (Schwarz and Amankwah 1993; Newson et al. 1998) did provide an estimate of a specific metal hydride, iron-titanium (FeTi), but they were significantly lower than other estimates. This lack of estimates is likely due to the paucity of commercial, large-scale metal hydride systems for hydrogen storage.

Operating costs for metal hydrides include heating and cooling for the dehydriding and hydriding reactions, respectively. The amount of heating required depends on the type of metal hydride selected and its application. For example, if the metal hydride storage system is integrated with a fuel cell, the heating demand could be met by the cooling load of the fuel cell and the cost would thus be minimal. Low-temperature hydrides would thus integrate well with PEM fuel cells that operate at 80°C; high-temperature hydrides would integrate well with the high-temperature fuel cells such as SOFC and MCFC, operating at 1,000°C and 650°C, respectively. Other storage systems do not enjoy (or rely on) this integration advantage.

The overall cost of hydrogen storage is dominated by the capital costs of the metal hydride. These systems are further penalized because there is no economy of scale. That is, the capital cost of the system increases linearly with the amount of storage required, so that the specific capital cost (i.e., $/GJ stored) remains the same.

Two analyses from the literature (Amos 1998; Schwarz and Amankwah 1993) were evaluated using the standard methodology. These analyses projected a specific capital cost of $4,200/GJ (Schwarz and Amankwah) to $18,400/GJ (Amos). The reason for the significant difference in the costs between these technologies could not be determined. Both are based on a low-temperature FeTi metal hydride. For a large storage system (30-day), the storage costs are prohibitive (i.e., >$200/GJ) (Amos), a cost that is 20 times the cost of the original hydrogen. Daily storage systems, although still expensive, incur costs of only $2.90-$7.50/GJ (Schwarz and Amankwah; Amos). Very small systems are expected to be cost competitive with other storage technologies.

The costs obtained using the detailed methodology agree well with costs from other sources (Vosen 1997; Carpetis 1994). However, Newson et al. (1998) projected capital costs of $150-$200/GJ, which are significantly lower than any other estimates.

There is considerable uncertainty regarding the costs of metal hydride systems. Supply considerations also cause concern. Although the price of the component alloys can be determined today, there is no good method for projecting manufacturing costs. Sandrock (1997) projects a manufacturing markup of 100%; Huston (1994) states that manufacturing costs could increase the alloy costs by 200%-400%. Because many of the alloys are not used in significant quantities today, however, large-scale use of the metals could cause shortages and increased prices. Thus, the usual decreases in prices seen with increased output may not occur with metal hydrides.

Onboard Storage

Onboard hydrogen storage using metal hydrides has been evaluated in several sources. Lipman and DeLuchi (1996) estimated that an Fe-Ti metal hydride onboard storage system would cost $4,200-$7,020/GJ (1998$).

Carbon-Based Storage

Two sources were obtained regarding the costs of carbon-based hydrogen storage systems (Fisher 1990; Schwarz and Amankwah 1993). At cryogenic temperatures (70-113 K) and moderate pressures (42-54 atm), activated carbon can reversibly adsorb 0.043-0.072 kg H_2/kg activated carbon (Schwarz and Amankwah 1993; Carpetis 1994). The National Renewable Energy Laboratory (NREL) recently reported a gravimetric storage capacity of 5%-10% at room temperature, using carbon nanotubes.

Carbon-based hydrogen storage materials that can store significant amounts of hydrogen at room temperature are also under investigation. Carbon nanostructures could provide the needed technological breakthrough that makes hydrogen-powered vehicles practical. Two carbon nanostructures, single-walled nanotubes and graphite nanofibers, are of interest. Single-walled carbon nanotubes, elongated pores with diameters of molecular dimensions (12 Å), adsorb hydrogen by capillary action at noncryogenic temperatures. Single-walled nanotubes have recently been produced and tested at NREL in high yields using a number of production techniques, and have demonstrated hydrogen uptake of 5-10 wt % at room temperature. Graphite nanofibers are a set of materials that are generated from the metal catalyzed decomposition of hydrocarbon-containing mixtures. The solid consists of an ordered stack of nanocrystals that are evenly spaced at 0.34-0.37 nanometers, which are bonded together by van der Waals forces to form a "flexible wall" nanopore structure. Northeastern University estimates that excellent hydrogen storage capacities are possible in these structures.

Using the standard methodology and the information from Schwarz and Amankwah (1993), the specific capital cost of hydrogen storage on activated carbon (cryogenic) is estimated at $4,270/GJ for daily storage. For a before-tax 10% internal rate of return (IRR), the storage cost is $3.50/GJ. About one-third of this cost is for electricity for compression and cooling, assuming a demand of 26.63 kW/GJ of hydrogen stored. Carbon nanostructure systems are expected to have significantly reduced costs because there is no cryogenic requirement, but the technology is still in the early development stages and so costs have not yet been developed.

Currently, there are no commercial applications of carbon-based hydrogen storage. However, researchers are continuing to look into increasing the gravimetric capacity of these systems and to improve the overall system engineering.

Chemical Hydrides

Chemical hydrides constitute another method for storing hydrogen, primarily for seasonal storage (i.e., > 100 days). Seasonal storage would be an option for countries such as Canada that have a surplus of hydropower during the summer, but an energy deficit during the winter (Newson et al. 1998). Numerous chemical hydrogen carriers, including methanol, ammonia, and methyl-cyclohexane, have been proposed. Use of a chemical system is advantageous because the transport and storage infrastructure is already in place, the technology is commercial, and liquid storage and handling are easier.

Newson et al. (1998) analyzed seasonal storage using a methylcyclohexane-toluene-hydrogen (MTH) storage system. This analysis assumes that the capital cost for a single day of storage with this system would be $1,400/GJ, dropping to $15/GJ at 100 days. This significant drop is because the dehydrogenation plant is the same size whether the storage is daily or seasonal (Newson et al. 1998). Thus, a tremendous economy of scale can be realized.

An integrated hydropower-electrolysis-MTH storage and fuel cell system was also analyzed. Based on current bench-scale testing of the dehydrogenation system and projected fuel cell costs, the authors concluded that electricity generated from this system at $0.24/kWh would be competitive with electricity generated from new hydropower projects at $0.21/kWh (Newson et al. 1998).

Berry (1996) also estimated the costs of chemical hydrides for vehicle refueling. Hydrogen from methanol is estimated to cost $29.50/GJ based on methanol costs of $11/GJ (HHV). The cost of hydrogen from ammonia is estimated at $38.9/GJ based on an ammonia cost of $250/ton.

Summary of Hydrogen Storage Costs

Table 8 contains a summary of the hydrogen storage costs for stationary applications as described earlier.

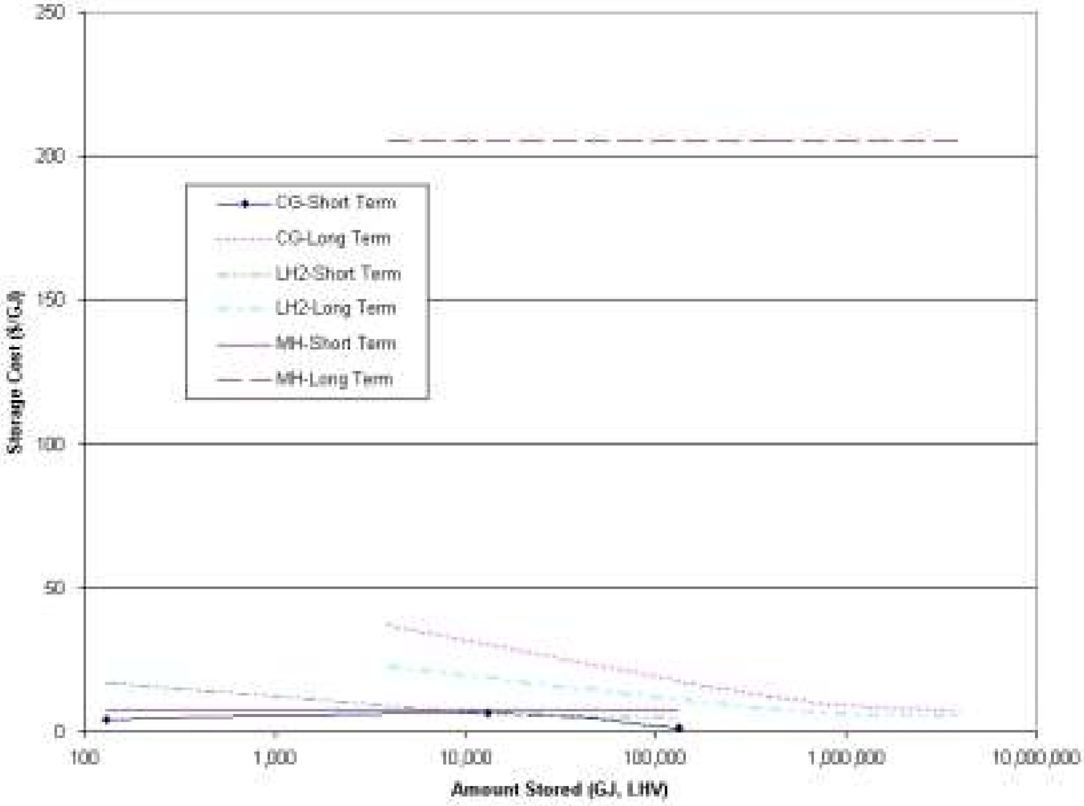
Table 8: Summary of Hydrogen Storage Costs for Stationary Applications

Storage System/ Size (GJ)	Specific TCI ($/GJ $_{capacity}$)	Storage Cost ($/GJ)
Compressed Gas		
Short term (1-3 days)		
131	9,008	4.21
147 [1]	16,600	33.00
13,100	2,992	1.99
20,300	2,285	1.84
130,600	1,726	1.53
Long term (30 days)		
3,900	3,235	36.93
391,900	1,028	12.34
3,919,000	580	7.35
Liquefied Hydrogen		
Short term (1-3 days)		
131	35,649	17.12
13,100	7,200	6.68
20,300	1,827	5.13
130,600	3,235	5.26
Long term (30 days)		
3,900	1,687	22.81
108,000	1,055	25.34
391,900	363	8.09
3.9 million	169	5.93
Metal Hydride		
Short term (1-3 days)		
131–130,600	4,191-18,372	2.89-7.46
Long term (30 days)		
3,900-3.9 million	18,372	205.31
Cryogenic Carbon (1-day)	4,270	26.63
Underground (1-day)	7-1,679	1.00-5.00

[1] This value is based on storage in pressurized tubes in a specific application and may not be appropriate for extrapolating (Taylor et al. 1986)

Figure 6 shows the cost of hydrogen storage as a function of amount stored and type of storage.

Figure 6: Economics of Hydrogen Storage



Utility Sector Applications

Two major stationary end-use applications are available for hydrogen: fuel cells and conventional combustion. Fuel cell technologies include PEM, PAFC, MCFC, SOFC and AFC. Combustion turbines and internal combustion engines (ICE) are two conventional technologies that could be modified for hydrogen use. The technical and economic characteristics of each technology will be discussed in this section. Large-scale utility applications and smaller distributed applications (e.g., building or residential) will be described.

Distributed stationary applications use small-scale fuel cells or ICEs to supply electricity and/or heat to commercial buildings such as hospitals or residences, which are located at the site. This concept has been evaluated by several authors (Garche 1998; Ogden et al. 1996) and has been examined in conjunction with vehicle refueling (Thomas and James 1998). These studies have focused on PEM fuel cell systems, but PAFC systems are a possibility. Other fuel cell types are less suited to these applications because of their limited ability for load following. For example, SOFC and MCFC systems require 1-3 days for startup (Garche 1998).

Fuel Cells

As described earlier, five major fuel cell technologies are currently under development or commercially available for hydrogen use.

Proton exchange membrane fuel cell

The PEM fuel cell has an efficiency of 40%-60% and operates at near ambient temperatures (80°C) using an ion exchange membrane (e.g., fluorinated sulfonic acid) as the electrolyte. Platinum-based catalysts are used at both the cathode and anode. Because of its low operating temperatures, internal reforming is not possible, but it has excellent load following capabilities and has a startup time of 1-3 seconds (Garche 1998).

Several studies have been conducted on the economics of PEM fuel cells; however, many were conducted for their use in the transportation sector. These studies will be discussed in the transportation section.

One study (Barbir and Gomez 1997) evaluated stationary PEM fuel cells for the current technology and projected improvements. A prototype 10-kW PEM fuel cell with an efficiency of 40% is currently projected to cost \$3,000/kW. Assuming a hydrogen cost of \$20/GJ, electricity from this system would cost \$0.25-\$0.30/kWh for a 5-year lifetime, 90% capacity factor, and 7% discount factor. This cost would decrease to \$0.09-\$0.095/kWh after a doubling of cell performance, a decrease of 50% in the fuel cost, and a reduction in the capital cost to \$1,150/kW because of mass production.

The current capital costs are significantly lower than those reported by Carlsson et al. (1997) and Wurster (1998) at \$100,000/kW and \$10,000/kW, respectively. The ultimate future capital costs from all sources is consistent at about \$1,000/kW. The reason for the discrepancy is not known; however, the more expensive systems could include fuel reforming.

Garche (1998) evaluated the use of a 5-kW PEM fuel cell to provide electricity and heat for a family home. The analysis showed that if the PEM supplied 100% of the electricity demands of the home, only 40% of the heating demand would be met. Thus, during the winter, the fuel cell would presumably operate above the electricity demand in order to meet the heating demand. Excess electricity would be sold to the grid. The author concluded that a system driven by the electricity demand (and not the heat) would be economical if the specific capital costs were below \$1,200/kW. No information on the economics of the heat-driven scenario was provided.

Since distributed fuel cell systems are currently not competitive with conventional electricity sources, Thomas and James (1998) evaluated a third product from the stationary fuel cell system: hydrogen for use in a fuel cell vehicle (FCV). Because of the daily and seasonal variations in electricity demand in homes and buildings, numerous electricity/hydrogen production scenarios can be evaluated. The report looked at the economics of building fuel cell systems to deliver heat, electricity, and hydrogen.

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.

A similar result was obtained by Ogden et al. (1996). A PEM fuel cell was evaluated for a residential application to supply electricity and hot water and compared to the cost of electricity from a combined cycle gas turbine. In all cases, the combined cycle system provided power at a lower cost than did the fuel cell. The authors suggested that credits should be given for distributed generation, fuel diversity, or environmental impacts.

Recently, Plug Power and General Electric formed a joint venture, GE Fuel Cell Systems, to sell PEM fuel cells in the residential and commercial markets. They expect to sell residential systems starting in 2001 and small business-sized units in 2002 (Plug Power 1999). The retail units will be 7-kW and will retail for about

$8,500 in 2001 and are expected to decrease to $4,000 by 2003 (Plug Power 1999). Electricity prices from these units are projected to be $0.07-0.10/kWh (Plug Power 1999).

Phosphoric acid fuel cell

The PAFC is available commercially for stationary applications (i.e., the 200-kW system by ONSI, a division of International Fuel Cells) (Garche 1998). More than 100 of these systems have been sold at the prototype price of $3,000/kW (Hart 1998). In addition, portable units have been demonstrated (Garche 1998). Other developers include Fuji Electric Corporation, Toshiba Corporation, and Mitsubishi Electric Corporation (Hirschenhofer et al. 1994).

The PAFC uses platinum-based catalysts at both electrodes, and as the name suggests, the electrolyte is concentrated phosphoric acid. PAFC systems operate at 150°-220°C and can achieve 37%-42% efficiency (HHV) on natural gas. Because of the relatively low temperatures, hydrocarbons must be reformed externally. In addition, CO is a catalyst poison and must be below 3-5 vol% (Hirschenhofer et al. 1994).

Several sources (Simader and Kordesch 1994; Carlsson 1997; Mugerwa and Blomen 1993) have projected costs for PAFC systems. A detailed estimate was obtained for PAFC systems of 25 and 250 kW (Mugerwa and Blomen). In this analysis, cost estimates were developed for the entire range of development, from the initial plant to mass production. Cost reductions were specified based on the stage of development.

The cost estimates were based on natural gas fuel. To project the cost of a hydrogen-based system, the cost of the reformer was subtracted out and the efficiency of the system was increased by 15%. The reformer represented 14.9% of the equipment cost of the 25-kW system and 21.6% of the cost of the 250-kW system. Using these assumptions and full commercial production, the standardized capital investment for the 25-kW plant was estimated at $2,253/kW. That for the 250-kW plant was $2,442/kW. The electricity prices necessary to achieve a 10% before tax IRR based on a hydrogen cost of $10/GJ are $0.13/kWh for both plants. The specific TCI for the 25-kW system is less than that for the 250-kW system because the authors assumed that the 25-kW systems could be produced robotically (Mugerwa and Blomen 1993).

These specific capital costs and electricity prices agree well with other reported values. Simader and Kordesch (1994) reported an electricity price of $0.11-$0.16/kWh for a generic PAFC; Hirschenhofer et al. (1994) and Carlsson et al. (1997) projected installed capital costs of $3,500/kW and $3,000/kW, respectively. These studies did not specify the fuel, but is probably natural gas, and so the higher capital investment would be expected. Finally, the Electric Power Research Institute (EPRI) (1988) projected the installed capital cost of a 100-MW facility to be around $1,000/kW.

Solid oxide fuel cell

The SOFC uses a solid-state system that operates at high temperatures (1,000°C). Because it is a two-phase system (solid and gaseous) instead of the three found with other fuel cells, it is a simpler design. Other advantages of this system include the absence of noble metal electrocatalysts; CO is not a poison and can be directly oxidized; and high-grade waste heat is available for steam generation or other applications (Murugesamoorthi et al. 1993). In addition, because of the high operating temperatures, the SOFC can reform hydrocarbon fuels internally without a catalyst. Thus, it is expected to operate on hydrocarbons rather than on pure hydrogen (Garche 1998).

The SOFC is not currently commercially available, although many companies are currently developing these systems. Detailed designs and costs for SOFC were not found in the literature. Three sources (Murugesamoorthi et al. 1993; Ippommatsu et al. 1996; Gas Research Institute (GRI) 1999), however, reported current and projected SOFC costs. Murugesamoorthi et al. (1993) reported electricity prices of \$0.06-\$0.08/kWh based on an efficiency of 50%, natural gas costs of \$1.90/GJ and an operating period of 7,000 h/yr. They project the ultimate capital cost of SOFC power plant systems to be \$1,000/kW.

Ippommatsu et al. (1996) evaluated SOFC production costs using six methods. The cost estimates assumed mass production (i.e., 1 million cells/facility) and included costs for raw materials, depreciation, labor, and maintenance. Cell production costs ranged from \$54/kW to \$170/kW for the sintering and supported planar type cells, respectively. The authors concluded that yield was the most important factor in the cost. They also projected that the target cost for SOFCs should be \$2,000/kW for the whole system and \$700/kW for the cell alone.

Finally, GRI and EPRI formed a consortium for the commercialization of planar SOFCs. The consortium will use SOFC technology developed by the University of Utah and Materials and Systems Research Inc. (MSRI), which is expected to achieve a total system cost of less than \$700/kW. This cost goal is assumed achievable even with small production volumes and small-size units (GRI 1999).

Solid oxide fuel cell systems could be used to supply the electrical and thermal requirements of commercial buildings. They could probably provide a better match for the thermal-to-electric ratio for buildings than current cogeneration systems. In fact, an economic analysis of SOFCs for commercial buildings showed that they are competitive with reciprocating engines in low thermal-to-electric and low load factor sites (Minh and Takahashi 1995). SOFC systems would also likely be good candidates for industrial cogeneration applications because of its high thermal load and the potential for integration.

Costs for SOFC systems for distributed power systems were not found. Because of the modularity of the fuel cells, however, the capital costs would likely be similar to those for the utility application. The operating costs, of course, would depend significantly on the thermal-to-electric load.

Molten carbonate fuel cell

The MCFC uses a mixture of alkali (sodium and potassium) carbonates as its electrolyte, contained in a ceramic matrix. Inexpensive nickel and nickel oxide are used as the anode and cathode, respectively. With an operating temperature of 600°-700°C, internal reforming is possible with the addition of a catalyst. Another advantage of the high temperature is the potential for heat integration or steam generation. Although CO is not a system poison, sulfur (H_2S) is detrimental at greater than ppm levels (Hirschenhofer et al. 1994). One of the most significant drawbacks to the use of this fuel cell with pure hydrogen is its requirement for CO_2 at a 1:1 molar ratio with hydrogen at the cathode. Recycling CO_2 from the anode to the cathode would meet most of this demand, but not all the CO_2 could be recovered. Obtaining the makeup CO_2 for a pure hydrogen feed could prove unworkable.

All the economic evaluations for MCFC systems obtained were based on hydrocarbon, primarily natural gas, fuel. Two of the studies (Mugerwa and Blomen 1993; Bohme et al. 1994) presented detailed cost estimates. Mugerwa and Blomen evaluated the impact of mass production on fuel cell costs as well as the estimated cost of current prototype systems. Assuming mass production, they estimated the specific capital cost of natural gas-based MCFC systems to be \$1,355/kW for a 25-kW system; \$1,740/kW for a 250-kW system; \$1,330/kW for a 3.25-MW system; and \$600/kW for a 100-MW system. Using the standard methodology, the necessary electricity prices would be \$0.12/kWh, \$0.11/kWh, \$0.10/kW and \$0.06/kW for the 25-kW, 250-kW, 3.25-MW and 100-MW systems, respectively. As with the PAFC systems, the authors assumed that the specific TCI (\$/kW) of the 25-kW system is less than that for the 250-kW system because of robotic production.

Bohme et al. also evaluated three MCFC processing schemes: (a) external reforming, (b) internal reforming with steam, and (c) internal reforming with fuel recycle. The capital costs for a 100-MW facility are estimated at \$2,900/kW for external reforming, \$2,000/kW for internal reforming, and

$1,700/kW for internal reforming and fuel recycle. Using the standard methodology, the expected electricity prices for these systems are $0.12/kWh, $0.10/kWh and $0.08/kWh for schemes a, b, and c, respectively. These values are higher than those by Mugerwa and Blomen because of the higher initial investment. Based on this analysis, the authors concluded that fuel (and oxidant) recycle is an important cost consideration in MCFC systems.

The Electric Power Research Institute (1995) completed a detailed design of a 2-MW MCFC system. This technology sheet estimated that the cost of a pre-commercial 2-MW MCFC system would be 1,700/kW and would fall to $1,200/kW for commercial units. No electricity costs were provided.

Alkaline fuel cell

Alkaline fuel cells use an alkaline electrolyte such as sodium hydroxide (NaOH) or potassium hydroxide (KOH). They operate at atmospheric pressure and 70°C. Unfortunately, CO_2 will react with the electrolyte and render it ineffective and so it must be removed. Currently, AFC systems are used primarily in space and submarine applications.

Lindstrom and Lavers (1997) suggest that the AFC can be integrated into existing ammonia production facilities. The AFC can be substituted for the ammonia synthesis section or can be operated in parallel. The ammonia production facility, however, would need to be modified for the AFC because it does not require nitrogen. Using conventional costs for ammonia-processing facilities, the authors project that a 163-MW AFC plant, which is comparable in size to a 1,000 Tpd ammonia plant, could produce electricity at $0.07/kWh.

Table 9 summarizes the economics of fuel cells.

Table 9: Economics of Fuel Cells

Fuel Cell Type/ Size	Source	Specific TCI ($/kW)	Electricity Price ($/kWh)
PEMFC			
10 kW (today)	Barbir and Gomez 1997	$3,000	$0.25-0.30
(future)	Barbir and Gomez 1997	$1,150	$0.09-0.095
7 kW (2001)	Plug Power 1999	$8,500	Not provided
(2003)	Plug Power 1999	$4,000	$0.07-0.10
PAFC			
25 kW (future)	Mugerwa et al. 1993	$2,250	$0.13
200 kW (today)	Garche 1998	$3,000	Not provided
250 kW (future)	Mugerwa et al. 1993	$2,440	$0.13
Not specified	Simader et al. 1994	Not provided	$0.11-0.16
	Hirschenhofer 1994	$3,500	Not provided
	Carlsson et al. 1997	$3,000	Not provided
100 MW	EPRI 1988	$1,000	Not provided
SOFC			
Not specified (future)	Murugesamoorthi 1996	$1,000	$0.06-0.08
Not specified (future)	Ippommatsu et al. 1996	$2,000 (system)	Not provided
		$700 (cell alone)	Not provided
Not specified (future)	GRI 1999	$700 (system)	Not provided
MCFC			
25 kW (future)	Mugerwa et al. 1993	$1,355	$0.12
250 kW (future)	Mugerwa et al. 1993	$1,740	$0.11
2 MW			
pre-commercial	EPRI 1995	$1,700	Not provided
commercial	EPRI 1995	$1,200	Not provided
3.25 MW (future)	Mugerwa et al. 1993	$1,330	$0.10
100 MW (future)	Mugerwa et al. 1993	$600	$0.06
100 MW	Bohme et al. 1994		
external reforming		$2,900	$0.12
internal reforming		$2,000	$0.10
w/ fuel recycle		$1,700	$0.08
AFC			
163 MW	Lindstrom et al. 1997	Not provided	$0.07

Internal Combustion Engine Generator Sets

Research on hydrogen-fueled ICEs is currently underway (Aceves 1996; Johnson et al. 1996; Van Blarigan and Keller 1998). Most of this research is directed at the transportation sector, but the information should be transferable to the utility sector. No specific costs on the use of hydrogen-powered stationary ICEs was found in the literature. However, the cost of these systems is not likely to differ significantly different from conventional diesel-powered ICEs.

Gas Turbines

Gas turbine technology is well known and commercialized for a variety of fuels, including natural gas and fuel oils. Operation of gas turbines on hydrogen fuels, however, is still relatively new, but one source reports that European Gas Turbines (GEC Ahlsthom) have more than 72,000 operating hours with a heavy-duty gas turbine with a refinery gas of 70% hydrogen (Foster-Wheeler 1998). Sources differ on the impact hydrogen fuel will have on system design and operation.

The government of Japan, under its World Energy Network (WE-Net) program is currently working with several turbine manufacturers (Westinghouse, Mitsubishi Heavy Industries, and Toshiba) to develop hydrogen-based power systems that include combustion turbines (Bannister et al. 1997). The overall goal of this 28-year program is the demonstration of a hydrogen-power system with 70.9% efficiency or greater by 2020. Literature was obtained on the approach taken to this problem by two of the turbine manufacturers (Bannister 1997 et al.; Sugishita and Mori 1998). Much of the information describes the power system configuration (e.g., Rankine cycle versus Topping Extraction cycle) rather than specific hardware concerns.

Sources suggest that the higher flame speed of hydrogen would require burner modifications (Foster-Wheeler 1998; Johansson 1999). Foster-Wheeler (1998), however, does not expect that these would represent a significant technical or economic hurdle. Another potential technical hurdle for hydrogen-fueled gas turbines is the high operating temperature. Temperature-resistant materials and better cooling techniques will be required, especially when operated on pure oxygen. Finally, turbines using hydrogen will likely be more efficient than those using natural gas because of the potential for higher inlet gas temperatures (Johansson 1999).

Specific costs for gas turbines using hydrogen could not be obtained, but costs for gas turbines using natural gas were obtained as a baseline. The performance and/or costs of the turbines will probably not be significantly affected by the use of hydrogen (Foster-Wheeler 1998). The cost of gas turbines for natural gas use range from \$200-\$600/kW (Gas Turbine World 1997). Costs were also obtained for turnkey combined cycle systems. These costs ranged from \$320-\$1,200/kW (1997\$) with efficiencies of 40.3%-58.0% (Gas Turbine World 1997).

Grid-Independent Renewable Power Systems

An interesting application of hydrogen technology is as grid-independent hydrogen production, storage, and usage systems that use renewable power (e.g., wind, solar). Several authors (Vosen 1997, Fairlie et al. 1998) have explored this possibility. These papers primarily include the technical and modeling aspects of these systems, but some provide limited economic information.

In these applications, the renewable power source would provide electric power to meet the entire demand of a remote village or community with no other source of power. Because renewable resources are intermittent and variable, some method of supplying energy must be provided when the resource cannot meet the demand (e.g., nighttime for a PV system). Typically, the backup source of power has been diesel generators (Fairlie et al. 1998). However, these systems are expensive and may have adverse environmental impacts. A promising alternative would be a hydrogen system. In this option, an electrolyzer is used to generate hydrogen when the renewable power source exceeds the base load. The hydrogen is stored as a compressed gas or possibly in a metal hydride system. When the renewable system cannot meet the base load, the hydrogen is used to power a fuel cell or an ICE generator.

Vosen (1997) compared energy storage options for a stand-alone PV-electrolyzer-PEM fuel cell system, for storage in a metal hydride, battery storage, and a combination of the two systems. Each system was simulated for a year to determine the storage requirements. Normalized costs (based on the hydrogen-only scenario) were projected assuming 0% interest. The individual costs, efficiencies, and lifetimes for each component are shown in Table 10.

Table 10: Economic Assumptions for Stand-Alone PV System

Component	Efficiency (%)	Cost	Lifetime (yrs)
PV	14	$2500/kW	20
Fuel Cell	47	$2500/kW	5
Electrolyzer	74	$1900/kW	5
Hydride	100	$4/kWh	10
Power Conditioning	92	$1000/kW	10
Batteries	90	$200/kWh	4

The least expensive system is battery storage for daily fluctuations and hydrogen storage for longer-term storage.

In the Fairlie et al. study, a wind-hydrogen power system for a remote Arctic village was examined. A conceptual design of a wind-electrolysis-hydrogen-generator (e.g., fuel cell) system was developed. The design was based on an electricity price of $0.045/kWh, an average electrical demand of 780 kW, a peak demand of 1,367 kW and an average wind speed of 21.8 km/h. The design assumed that at some times (i.e., during high winds), a significant amount of power is generated, but cannot be used. During these times, the power is dumped to a resistive water heater, which can be used for district heating. Based on these parameters, the fuel cell capacity was sized at 1.4 MW with an energy storage capacity of 920 GJ (3 million scf) of hydrogen. The wind farm was sized at 8 MW and the electrolyzer at 4 MW with the ability to operate as a controllable load to 6 MW. For a projected system cost of $25 million, the annual energy saving alone would be $4 million/yr.

Transportation Sector Applications

Hydrogen use in transportation applications has been evaluated by numerous sources. Light-duty (e.g., automobiles) and heavy-duty (e.g., buses) applications have been examined. In addition, liquid hydrogen is being considered as an aviation fuel.

An important consideration unique to hydrogen use in the transportation sector is whether the hydrogen should be stored on the vehicles or generated by onboard reforming from a liquid fuel such as methanol. Results from studies on both options are also summarized in this section.

Light Duty (automobiles)

Hydrogen can be used in light-duty vehicles (LDVs) in a variety of applications, including ICEVs, hydrogen fuel cell vehicles (FCEVs), and hydrogen hybrid vehicles (HHEVs). These vehicles have been evaluated using both onboard storage of hydrogen and onboard reforming. Each of these scenarios is discussed below.

Fuel cells

Because of their high power density, fast start up at a wide range of temperatures, and simple construction, most of the literature on fuel cells in the transportation sector focuses PEM fuel cells (Ekdunge and Raberg 1998). The operating conditions and design constraints of fuel cells in this sector differ considerably from those in utility applications. Transportation applications have power density, space, safety, and reliability requirements that are more challenging than those for utility applications, but they have an advantage in that the required lifetime is only about 5,000 hours on an intermittent basis (Appleby 1993). Thus, many sources consider that this sector may provide the breakthrough for fuel cells.

Hydrogen FCEVs have several potential advantages over conventional gasoline ICEVs including higher fuel efficiency, lower greenhouse gas and conventional pollutant emissions, longer lifetimes, and lower drive train maintenance costs (Ekdunge and Raberg 1998; DeLuchi 1992; Birkle et al. 1994). DeLuchi (1992) estimates the efficiency of an FCEV at 40% based on a fuel cell efficiency of 46% and a drive train efficiency of 88%. This value compares favorably with a conventional gasoline ICEV at 13%-14%. In addition, the hydrogen FCEV is projected to have excellent fuel economy at 66 mpg, gasoline equivalent (Thomas et al. 1998).

Wurster (1998) provides an overview of companies developing LDVs based on PEM fuel cells. Vehicles described in the article include the Daimler-Benz Necar II, the Renault Laguna Break, the PSA Peugeot 806 van, the Toyota RAV4LV, and the Energy Partners Gator, Genesis, and Green Car.

Although PEM fuel cells are considered the front-runner for LDVs, other fuel cell systems are also being considered for this market. For example, Zevco has developed AFC vehicles. Zevco recently sold its first AFC vehicle, a van, to Westminster Council in London (Fuel Cell 2000 1999) and it is testing other vehicles as taxis in London. The taxis are estimated to cost about $7,400 more than a conventional diesel taxi (Fuel Cell 2000 1999). SOFCs are also being developed by Delphi and BMW as an automotive auxiliary power source for gasoline vehicles (Delphi Automotive Systems 1999). This arrangement will increase the electric power and efficiency of the vehicles as well as reduce the emissions.

Internal combustion engines

Vehicles using ICEs can be operated on either hydrogen or hydrogen/natural gas blends. One blend, Hythane, (a mixture of hydrogen (30%) and natural gas) has been studied in several applications.

Use of hydrogen in an ICEV has several potential advantages, including increased efficiency (25%-30%), a wide range of ignition limits, and high flame and diffusion speeds (Lipman and DeLuchi 1996; Hart 1998). On the other hand, these vehicles have lower power output and because of hydrogen's low ignition energy, they are prone to pre-ignition.

Hydrogen-hybrid electric vehicle

A third hydrogen vehicle is the hybrid hydrogen electric vehicle (HHEV) that uses hydrogen either in an ICE or in a fuel cell and a generator. Two primary types of HHEVs are proposed: parallel and series. In a parallel hybrid vehicle, both the electric motor and the ICE are coupled through the transmission to the wheels. In a series hybrid, the ICE is not connected to the wheels and all power to the wheels comes from the electric motors. Overall efficiencies for these vehicles are estimated at 39% for the ICE series version and 35% for the fuel cell series version (Lipman and DeLuchi 1996). Thomas et al. (1998) estimates similar (38%-39%) efficiency for series hybrid ICEVs; for a parallel hybrid, it is almost 25%. In general, these values compare favorably with the 30% efficiency projected for an electric vehicle and the 13% for conventional gasoline ICEVs (Lipman and DeLuchi 1996). Thomas et al. (1998) projects the fuel economy of an HHEV at 50 mpg, gasoline equivalent. Other advantages of this vehicle include its low emissions and technical feasibility (Lipman and DeLuchi 1996).

Onboard hydrogen storage versus onboard reforming

Several methods of onboard storage of hydrogen are available: compressed gas, metal hydride, and liquid hydrogen. Other methods such as a cryoadsorbed gas, a cooled and compressed gas, and iron oxidation/reduction have also been proposed (DeLuchi 1992). In addition, the fuel can be carried onboard in another form such as methanol or methyl cyclohexane and be reformed or gasified (i.e., partial oxidation) within the vehicle.

Ogden et al. (1997) evaluated several methods for supplying hydrogen to a vehicle, including onboard reforming and onboard POX. Based on this analysis, the authors concluded that mass-produced vehicles with onboard reforming or POX will cost more than hydrogen FCEVs. A methanol fuel cell system is projected to cost $500-$600 more than a FCEV while gasoline POX FCEVs will cost an additional $800-$1,200.

Although the vehicle costs for the onboard reforming/gasification systems for gasoline and methanol FCEVs would be greater than those for hydrogen FCEVs, the refueling infrastructure costs would be lower. No infrastructure costs would be incurred for the gasoline case and the infrastructure costs would be minimal (i.e., $12-$15/car) to retrofit a gasoline station for methanol because excess methanol production capacity could be used (Ogden 1998). When new methanol production capacity is required (i.e., after a few million cars), the methanol refueling infrastructure would cost $400-$800/car. This cost is the same as that for a hydrogen refueling infrastructure.

The total infrastructure (all equipment on and off the vehicle) required for a hydrogen FCEV would be $400-$800. In the case of methanol, this cost would be $500-$600 for the initial million or so vehicles, but it would increase to $900-$1,400 after excess capacity was used. Finally, total costs for a gasoline POX vehicle would be $800-$1,200/vehicle. These costs translate into a delivered cost of hydrogen transportation fuel, which is roughly $1.60-$5.20/gal of gasoline-equivalent energy (Ogden 1998).

Comparison of light-duty vehicle costs

Several sources (Thomas 1998; Lipman and DeLuchi 1996; Ogden et al. 1997; DeLuchi et al. 1991) have evaluated the costs of hydrogen LDVs. These analyses have concentrated on the specific costs of the vehicle, including fuel storage and the life cycle costs. Brief discussions of these sources follow.

Thomas et al. (1998) estimated the costs and air emissions for three types of vehicles using three types of fuels: conventional ICEVs (gasoline, natural gas, and hythane), hybrid vehicles (natural gas, hydrogen, and diesel) and FCEVs (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 (thermostat and load-following).

The cost of a direct hydrogen FCEV is estimated at $20,200; that for a hydrogen parallel hybrid is $19,900. The comparable conventional gasoline-powered vehicle would cost $18,000. These costs are lower than those projected by Lipman and DeLuchi (1996) of $19,300 for a gasoline ICEV and $26,900 for an FCEV (see Table 11).

As noted earlier, the hydrogen FCEVs have the best fuel economy (66 mpg, gasoline equivalent), but hybrid vehicles are close behind at 57 mpg, gasoline equivalent. When air pollution and greenhouse gases are considered, the direct hydrogen FCEV has the lowest total emission and greenhouse gas costs. However, hydrogen parallel hybrids and hythane ICEVs have similar environmental impacts, but lower overall costs.

Lipman and DeLuchi (1996) developed life cycle costs for ICEVs using several methods of onboard hydrogen storage, gasoline vehicles, and a hydrogen-based FCEV. The life cycle cost is the sum of all yearly operating costs (e.g., fuel, registration) and all annualized initial costs (e.g., vehicle) divided by the average distance driven per year. Table 11 provides a summary of these costs. The costs in the original reference were provided in 1991$, but have been converted to 1998$.

Table 11: Hydrogen Vehicle Costs

Item	Gasoline	H_2 ICEV LH2	H_2 ICEV Hydride	H_2 ICEV GH2	H_2 FCEV
Fuel Retail Price, excl. taxes ($/gal gasoline eq)	1.26	3.89	1.65	1.92	1.92
$/GJ	11.31	34.80	14.76	17.19	17.19
Full retail price of vehicle, incl. taxes ($)	19,255	21,765	25,930	26,296	26,876
Levelized annual maintenance cost (c/km)	424	420	420	420	403
Total life cycle cost (¢/km)	22.5	28.15	26.15	26.32	21.52
Break-even gasoline price ($/gal)	N/A	3.95	3.12	3.18	1.19

The costs in the table were not standardized. They are based on mass production of the components and a hydrogen price of $9.70/GJ. Assumptions for the ICEVs are considered optimistic but plausible (Lipman and DeLuchi 1996). The lowest overall life cycle costs are predicted for the FCEVs, which are lower without taxes, than the assumed price of gasoline with taxes (i.e., $1.19/gal versus $1.26/gal).

A similar result was obtained by Birkle et al. (1994), who concluded that the drive-specific costs of the gaseous hydrogen-fueled vehicles would be competitive with gasoline ICEVs. The lower costs are due to the higher net efficiency of the vehicles (i.e., 40% versus 14%), the lower annual maintenance costs, and, most importantly, the longer life of the electric drive train (Lipman and DeLuchi 1996). These factors more than compensate for the disadvantages (e.g., more expensive fuel and fuel storage) of the hydrogen FCEVs. Ogden et al. (1997) also concluded that the life cycle costs of a hydrogen FCEV are slightly lower than those for methanol or gasoline FCEVs (with onboard reformers) because of their lower initial cost and 50% higher fuel economy. A different result was obtained by DeLuchi et al. (1991) who concluded that methanol FCEVs would have the lowest total life cycle costs, followed by gasoline ICEVs and hydrogen FCEVs. Both FCEVs, however, would have life cycle costs that were comparable to gasoline FCEVs (DeLuchi et al. 1991).

The hydrogen ICEV systems have the highest life cycle costs primarily because of the higher initial vehicle costs and higher fuel costs (Lipman and DeLuchi 1996). Of the ICEVs, the hydride system has the lowest cost because it has the lowest delivered hydrogen costs (i.e., high compression or liquefaction are not required). Although liquid hydrogen ICEVs have the lowest vehicle costs of the three systems examined, the study assumed high boil-off losses (i.e., 3% at three transfer points), and so the fuel costs are significant. The compressed gas ICEV option has relatively low delivered hydrogen costs, but the highest vehicle costs of the three ICEV options.

Heavy-duty Applications

Hydrogen use in heavy-duty transportation applications (e.g., buses) is being demonstrated. Commercial production is expected in the near future. Very few data are available on the costs in this area.

Fuel cells

Several companies, including Ballard, H Power, Neoplan, and MAN/Siemens are currently developing city and transit buses that are based on PEM fuel cells. In addition, PAFC and SOFC systems are being considered for heavy-duty applications such as railroads (Wurster 1998; Minh and Takahashi 1995). This section summarizes some efforts in this area.

In 1993, the world's first hydrogen fuel cell-powered light-duty bus (93 kW) was commissioned. The commercial prototype, a 40-foot heavy-duty bus (205-kW) was introduced in 1995. Both systems were powered by PEM fuel cells developed by Ballard. In 1997, Daimler-Benz commercialized the NEBUS (New Electric Bus), which also uses Ballard PEM fuel cells. The fuel cell has an efficiency of 55% and delivers enough power for the fully loaded bus to travel as fast as 80 km/h (Ballard 1999).

Three Ballard Commercial Prototype Fuel Cell buses were delivered to the Chicago Transit Authority; the BC (British Columbia) Transit will take delivery of three more in 1998. These buses are part of a two-year testing program that will provide performance, cost, and reliability data. Ballard is developing a commercial bus that is expected to be available by 2002. The commercial buses will be equipped with the 205 kW fuel cell engine with a range of 560 km and a capacity of 75 passengers (Ballard 1999).

In 1997, the prototype Ballard bus had a price of $1.4 million (Wurster 1998). The goal for the small fleets (i.e., Chicago and Vancouver) is roughly $600,000/bus, a price that is double that for a natural gas bus (Wurster 1998).

H Power Corporation has also developed a transit bus that is fueled by a PEM fuel cell. It has an onboard reformer for the methanol fuel. Neoplan, MAN/Siemens, and Daimler-Benz also have PEM buses. Both Neoplan and MAN/Siemens are expected to demonstrate their buses in Bavaria. Daimler-Benz has a demonstration in southern Germany (Wurster 1998).

Minh and Takahashi (1995) contend that SOFC systems may be the most practical of all fuel cell systems for heavy-duty applications. Because of onboard fuel processing, these systems can internally reform methanol or other hydrocarbon fuels. An SOFC system would also be compact because it can operate at high current and power densities. And because it is solid state, it can be designed in a variety of configurations. The major drawback to the SOFC in transportation applications is its high temperature and its corresponding lengthy power-up time. Thus, these systems would be best suited for applications such as locomotives, trucks, and barges that have long duty cycles (i.e., infrequent startups and shutdowns) (Minh and Takahashi 1995). No costs for SOFC systems in the transportation sector were obtained.

Internal combustion engines

Heavy-duty vehicles equipped with ICEs are also in operation. Hart (1998) reports that a Hythane bus has been operating in Quebec since late 1995. The bus, which was manufactured by Novabus, is powered by a 180 kW Cummins ICE and has a range of 400 km. The bus can store 1,500-L of fuel as a compressed gas on the roof. MAN Nutzfahrzeuge Akriengesellschaft has also developed a hydrogen-fueled bus based on a 4-stroke Otto ICE. The bus can operate on either hydrogen or gasoline, with maximum outputs (at 2,200 rpm) of 140 kW and 170 kW, respectively. This bus was demonstrated during 1996 and 1998 in city service (Johansson 1999). No costs for heavy-duty hydrogen powered systems with ICEs were obtained.

Onboard hydrogen storage versus onboard reforming

The Ballard buses use compressed gas cylinder storage located on the roof (Ballard 1998). The gas is stored at 24.8 MPa and is delivered at 0.207 MPa. Complete fuel use is ensured by recirculating unused hydrogen. As described earlier, heavy-duty vehicles that are based on an SOFC system would use onboard reforming. This option would likely be the most economical for these applications, given that internal reforming without a catalyst is possible.

Other Transportation Uses

Hydrogen has been proposed for use as an aviation fuel (Hart 1998; Contreras et al. 1997). The joint Russian-German Cryoplane project is evaluating the use of liquid hydrogen in a modified Airbus A310 where the fuel would be stored on the roof of the aircraft (Hart 1998; Contreras et al. 1997). NASA is also developing a hydrogen-fueled plane as part of its National Aerospace Plane Program (NASP). This aircraft would operate at hypersonic speeds with slush hydrogen, a mixture of liquid and frozen hydrogen (Contreras et al. 1997). In addition, several other companies have studied hydrogen as an aviation fuel.

Contreras et al. developed cost estimates for liquid hydrogen as an aviation fuel for 1995 and 2000, assuming technology improvements. The direct operating cost (DOC) for an aircraft using liquid hydrogen was \$12.60/GJ in 1995 (1998\$) and \$11.90/GJ in 2000 (1998\$). This cost was based on electrolysis. The DOC for liquid hydrogen was 1.55 times that of Synjet in 1995. When environmental constraints and efficiency gains are taken into consideration, this ratio drops to 1.43 in 1995 and 1.39 in 2000. Clearly, other cost reductions or carbon taxes would be necessary for liquid hydrogen to be competitive.

Hydrogen Transport and Distribution

Hydrogen may be transported using several methods: pipeline, truck, rail, and ship. The method selected depends not only on the distance transported, but also on the production method and/or the use.

Pipelines

Several authors have examined hydrogen transport by pipeline. However, in most cases, the costs provided were based on extant natural gas pipelines or were very rough estimates (e.g., \$1 million/mi with no specification on diameter). The cost of natural gas pipelines varies by the pipe diameter. For example, the construction cost of a 4-in. pipeline would cost \$100,000/mi; the cost of a 42-in. pipeline would cost \$1.5 million/mi (True 1996). Veziroglu and Barbir (1998) state that the cost of a hydrogen pipeline would be 50%-80% higher than that of a natural gas pipeline and Kirk-Othmer (1991b) suggests that regional transportation could be as much as five times higher than natural gas, primarily because of the lower volumetric energy density of hydrogen. Ogden et al. (1997) estimates the capital cost of a hydrogen pipeline at \$1 million/km.

Several reports discuss the use of extant natural gas pipelines to transmit hydrogen or hydrogen-natural gas blends. Kirk-Othmer (1991b) notes that embrittlement may be a problem with high pressure transmission of hydrogen and that although some components of a natural gas system could be used for hydrogen transmission, compressors and meters would not be applicable.

Oney et al. (1994) provided a detailed analysis of pipeline transport of hydrogen and hydrogen-natural gas mixtures. An analysis was conducted to find the minimum transmission cost based on the optimal diameter. Transporting 0.5 GW of pure hydrogen was projected to cost \$0.89/GJ for a distance of 100 km up to \$2.60/GJ for a distance of 500 km. The authors also looked at the effect of the energy delivery rate on the economics. Transmission of hydrogen for 100 km was projected to cost \$1.30/GJ for 0.1 GW delivery rate and \$0.83/GJ for 1.0 GW delivery rate. In all cases, the transmission costs of hydrogen were apparently in line (i.e., 50%-80% higher than natural gas) with the value proposed by Veziroglu and Barbir (1998). The paper did state, however, that although hydrogen transmission is more expensive than natural gas, this cost differential could be eliminated if the hydrogen were produced at 0.65 MPa instead of atmospheric. This conclusion was based on a transportation distance of 500 km and an energy delivery rate of 1.0 GW.

Amos (1998) also provided detailed pipeline transmission costs. For a distance of about 100 km, the cost of transmission is \$0.50-\$0.58/GJ for energy delivery rates of 1.5 GW and 0.15 GW, respectively. At 300 km, these costs are \$0.75-\$2.17/GJ for 1.5 GW and 0.5 GW, respectively. The costs by Amos were based on an installed capital cost of \$1 million/mile and compressor costs of \$1,000/kW.

The detailed estimates by Amos (1998) and Oney et al. (1994) were standardized using the economic methodology outlined earlier. Several different pipeline lengths and energy transmission rates were evaluated. Interestingly, the standard methodology increased the projected costs by Amos and decreased those by Oney et al. The results of this analysis are shown in Table 12.

Table 12: Summary of Hydrogen Transmission Costs via Pipeline

Transmission Rate (GW)	Distance (km)	Reference	Specific TCI ($/GJ $_{\text{delivered}}$)	Hydrogen Transmission Cost ($/GJ)
0.15				
	161	Amos 1998	21.22	2.83
		Oney et al. 1994	14.14	2.03
	805	Amos 1998	106.24	13.84
		Oney et al. 1994	67.53	8.87
	1609	Amos 1998	210.32	27.23
		Oney et al. 1994	134.18	17.41
0.5				
	161	Oney et al. 1994	4.80	0.83
	805	Oney et al. 1994	20.81	2.88
	1609	Oney et al. 1994	38.82	5.44
1.0				
	161	Oney et al. 1994	2.66	0.57
	805	Oney et al. 1994	10.80	1.60
	1609	Oney et al. 1994	20.80	2.88
1.5				
	161	Amos 1998	2.83	0.83
		Oney et al. 1994	2.13	0.49
	805	Amos 1998	11.59	2.09
		Oney et al. 1994	7.47	1.17
	1609	Amos 1998	22.30	3.53
		Oney et al. 1994	14.13	2.03

The assumptions used by Oney et al. result in lower pipeline hydrogen transmission costs compared to those by Amos. In general, this difference is due to the lower capital investment costs proposed by Oney et al. The difference could become greater if the diameter was optimized as described by Oney et al. The diameter was not optimized was not done to ensure a level comparison, as the report by Amos had a fixed diameter (0.25 m). In both cases, as expected, the cost of transmission increases with pipeline length and decreases with the amount transmitted.

Truck Transport

Hydrogen may be transported on trucks as a compressed gas, liquefied hydrogen, metal hydride, or other media such as glass microspheres. Two studies (Amos 1998; Berry 1996) looked at the transportation of hydrogen via trucks. The Amos report evaluated numerous scenarios, including those with very low quantities for transport such that the initial truck was not fully used, which resulted in high capital charges. In these cases, the transporter would likely rent the truck and incur only operating expenses. For this analysis, only scenarios where at least one truck is fully used are evaluated.

Both Amos and Berry evaluated liquid hydrogen transport on trucks. The Amos report looked at numerous scenarios for varying quantities and distances. The Berry study looked at a single case. The Amos study was based on a liquid hydrogen storage tank with a capacity of 500 GJ and a cost of $410,000. The Berry report used a truck trailer with a capacity of 420 GJ and a cost of $400,000. The truck cost for the Amos report was $90,000; that for the Berry report was $60,000.

The Berry study was based on transporting 10.38 million GJ of hydrogen/yr, a delivery distance of 410 km, and an annual truck mileage of 164,000 km. The Amos study evaluated several delivery distances (16 km-1,609 km) and quantities (5,000-50 million GJ/yr). The costs in the Berry study were significantly higher than those for a comparable scenario in the Amos study. The Berry study had more conservative estimates for O&M costs, fuel costs, and capital charges. The Berry study estimated that transport would cost about $5.60/GJ in capital charges and would add almost $6/GJ to the cost of hydrogen. For the scenarios evaluated in the Amos study, the transportation costs increase both with distance and quantity transported. At some point, however, the quantity ceases to affect the costs - the costs are affected only by the distance. Table 13 presents the range of transportation costs for several trip distances evaluated by Amos. Each distance was evaluated for quantities of 45,418-45.6 million GJ/yr. In each case, the lower end of the range corresponds to the higher quantity transported.

Table 13: Hydrogen Transport as a Liquefied Gas via Truck

Trip Distance (km)	TCI ($/GJ)	Transport Cost ($/GJ)
16	0.44-11.0	0.24-1.60
161	0.77-11.0	0.52-1.84
322	2.20-11.0	1.0-2.20
805	2.70-11.0	2.00-3.10
1,609	5.10-11.0	3.90-4.70

The Amos report also evaluated hydrogen transport on trucks as a compressed gas. Costs were based on a truck tube unit with a capacity of 21.72 GJ and a capital cost of $160,000. A major cost component for this method is labor. When the trucks are fully used, the major cost factor is the distance traveled. Table 14 summarizes the cost for compressed gas transport via truck for several distances. The ranges shown are due to slight differences in capital charges based on the percentage used.

Table 14: Hydrogen Transport as a Compressed Gas via Truck

Trip Distance (km)	Quantity Transported (GJ/yr)	TCI ($/GJ)	Transport Cost ($/GJ)
16	458,000-45.8 million	4.10	4.70
161	458,000-45.8 million	8.20	10.60
322	45,800-45.8 million	13.7-16.4	18.30-18.60
805	45,800-45.8 million	30.20	41.10
1,609	45,800-45.8 million	57.60	79.10-79.70

In the Amos study, truck transport using metal hydrides was based on a truck cost of $100,000 and a hydride cost of $18,375/GJ hydrogen stored. Because there is no economy of scale for the metal hydride storage containers, once the trucks are fully used, the cost of transportation depends only on the distance traveled. If the first truck is not fully used, both the amount transported and the distance would impact the costs. Table 15 summarizes the transportation costs for metal hydride systems, assuming that each truck is fully used.

Table 15: Hydrogen Transport via Truck in Metal Hydrides

Trip Distance (km)	Quantity Transported (GJ/yr)	TCI ($/GJ)	Transport Cost ($/GJ)
16	458,000-45.8 million	7.54	2.63
161	458,000-45.8 million	15.08	5.75
322	45,800-45.8 million	25.13	9.80
805	45,800-45.8 million	55.28	21.92
1,609	45,800-45.8 million	105.54	42.11

Other Transport

Amos evaluated rail and ship transport of hydrogen. Rail shipment was assumed to be viable for compressed gas, liquefied hydrogen, and metal hydride; only liquefied hydrogen was evaluated for ship transport.

Capital costs for rail transport were estimated to be $3,670/GJ for the rail tube assembly for compressed gas transport; $370/GJ for a liquefied gas unit; and $18,300/GJ for a metal hydride system. The rail car undercarriage was assumed to cost $100,000. Various scenarios were evaluated using these assumptions as well as specific assumptions for operating costs, including the average speed (40 km/h), availability (99%), and freight charge ($400/wagon) to project the rail transport costs. These assumptions were used in the standard economic methodology to project the cost of each type of transport. In each case, the specific TCI (i.e., $/GJ transported/yr) and the cost/unit hydrogen transported depends primarily on the amount transported. This result is due to the flat shipping charge. The only exception to this is for situations in which the distance traveled takes longer than a single day. In these cases, the capital cost is increased by the number of travel days because more railcars would presumably be required. Table 16 summarizes the costs for shipping via rail (Amos 1998).

Table 16: Costs for Hydrogen Transport via Rail

Transport Method/ Transport Time	Amount Transported (GJ/yr)	Specific TCI ($/GJ transported)	Transport Costs ($/GJ)
Liquid Hydrogen			
1 day (< 984 km)	45,600	10.97	2.14
	455,600	4.39	1.30
	45.6 million	3.95	1.24
2 days (< 1970 km)	45,600	10.97	2.14
	455,600	6.58	1.58
	45.6 million	0.07	0.75
Compressed Gas			
1 day (< 984 km)	45,800	52.44	21.41
	457,600	47.20	20.73
	45.8 million	47.20	20.73
2 days (< 1970 km)	45,800	78.67	24.77
	457,600	78.67	24.77
	45.8 million	78.67	24.77
Metal Hydride			
1 day (< 984 km)	45,700	183.76	30.90
	457,00	165.38	28.55
	45.7 million	165.38	28.55
2 days (< 1970 km)	45,700	275.63	42.68
	457,00	275.63	42.68
	45.7 million	275.63	42.68

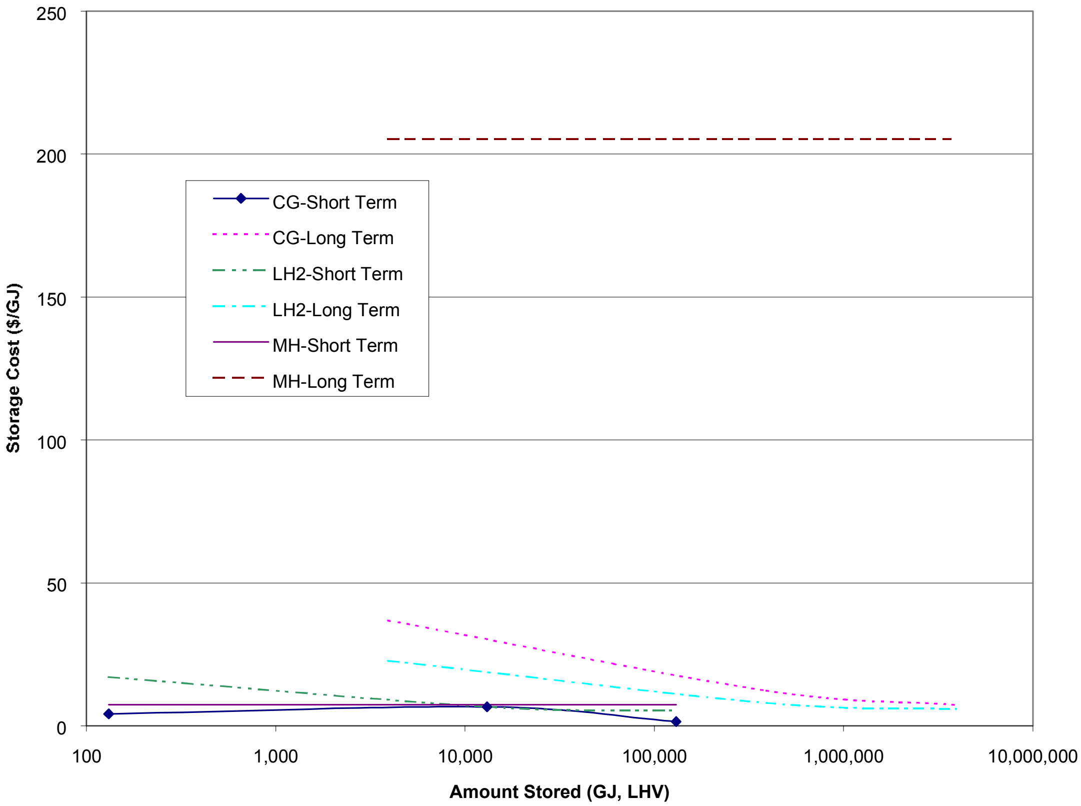
Transport by ship will likely be feasible only for liquefied hydrogen because of the long transport times. The cost of ship transport was estimated based on a specific capital cost of $715/GJ. Operating costs were based on an average ship speed of 16 km/h, an availability of 98.6%, and a freight charge of $3,000/unit. Based on these assumptions and the standard methodology, the cost to transport hydrogen via ship will increase the cost by $13-$25/GJ. The cost of ship transport, over the range studied, depends primarily on the distance traveled. For a given distance, the specific TCI and the transportation price were insensitive to the amount transported. This relationship is due to the linear relationship between the TCI and the quantity transported. This remains constant for a given distance, and so the only factor affecting the costs is the distance traveled. Based on the standard methodology, the cost to ship 0.46 million-46 million GJ/yr of LH2 1,609 km has a specific TCI of almost $25/GJ transported and an overall cost of $15/GJ. The corresponding costs for other distances are summarized in Table 17.

Table 17: Costs of Liquid Hydrogen Transport via Ship

Distance	Specific TCI ($/GJ $_{transported}$)	Transportation Cost ($/GJ)
322 km	8.22	13.34
805 km	16.43	14.39
1,609 km	24.58	15.44

Figure 7 shows the costs for hydrogen transport over varying distances.

Figure 7: Hydrogen Transport Costs for Varying Distances



Refueling

Several studies (Thomas et al. 1998; Thomas and James 1998; Berry et al. 1996; Ogden et al. 1997; Thomas and Kuhn 1995a; Thomas and Kuhn 1995b) have been conducted to evaluate the cost of vehicle refueling. The studies have looked at both centralized hydrogen production and on-site hydrogen generation. Centralized production has the advantage of lower initial hydrogen production costs, but the hydrogen requires transport to the refueling station. On-site hydrogen generation and refueling suffer from poor economies of scale, but have no transport costs. Each of these alternatives is described in greater detail and cost estimates are presented.

Distributed (On-site) Generation of Hydrogen

Both on-site SMR and electrolysis have been evaluated in the literature. These applications have been evaluated at the home, fleet, and large station scales. Thomas et al. (1998) described the costs for 50- and 100-car hydrogen refueling stations using an on-site reformer. Costs for the system assumed mass production of components with an annual volume of at least 10,000 units/yr. These costs are summarized in Table 18.

Table 18: 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**

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/gal gasoline equivalent and the 100-car station had a hydrogen cost of about \$0.75/gal gasoline equivalent. These estimates are based on a natural gas cost of \$3.80/GJ and electricity costs \$0.06/kWh. Also, the estimate assumes that an FCEV has a fuel economy 2.2 times that of a conventional gasoline ICEV using a 1.25 factor for the EPA driving cycles (Thomas et al. 1998). Thus, the authors concluded that distributed hydrogen systems were competitive with current gasoline ICEV technology. Not enough backup information on the operating costs was provided in the document for standardization.

Thomas and James (1998) evaluated hydrogen for refueling in conjunction with and SMR/PEM fuel cell system for heat and electricity. During off-peak periods, the SMR would produce hydrogen for vehicle refueling. Their assumptions were standardized to determine the cost of the hydrogen produced for vehicle refueling for a residence and for a 50-car refueling station located at a commercial building with a 50-kW PEM fuel cell. All components were assumed to be mass produced. Using the standard economic methodology, the specific TCI of the 50-car station is roughly \$17/GJ/yr with a hydrogen price of \$9/GJ. A single-car station was projected to cost \$40/GJ/yr with a hydrogen price of almost \$22/GJ.

Berry et al. (1996) also evaluated the cost of refueling systems with distributed hydrogen generation. The systems were evaluated using the standard methodology. On-site SMR, alkaline electrolysis, PEM electrolysis, and steam electrolysis were evaluated; a residential electrolysis system was also presented. Based on the standard methodology, an on-site SMR system could deliver 39,240 GJ/yr of hydrogen for 300 cars/d at slightly more than \$18/GJ. An on-site alkaline system would produce hydrogen at \$25-\$29/GJ for a size range of 1,700-51,200 GJ/yr. This cost range is expected to decrease to \$23-\$27/GJ for PEM electrolysis, primarily because of lower capital costs. Further capital cost reductions are assumed for steam electrolysis, which would lower the delivered hydrogen costs to \$18-\$21/GJ. The residential system would provide 35 GJ/yr at a specific TCI of \$100/GJ and a hydrogen price of \$42/GJ.

Ogden et al. (1997) also estimated the delivered cost of hydrogen at refueling stations. These estimates are based on a natural gas cost of \$2.80/GJ, an off-peak power cost of \$0.03/kWh, and a capital recovery factor of 15%. Refueling stations serving 800 cars/d with centralized production of H_2 via SMR were projected to cost \$700,000 for LH2 delivery and \$1.7 million for pipeline delivery. Refueling stations (800 cars/d) with on-site reforming were estimated to cost \$3.4-\$5.4 million for conventional and fuel cell reforming, respectively. Refueling stations with on-site advanced electrolysis were projected to be the most expensive at \$5.7 million for an 800-car station. Not enough detail was provided in the report for standardization. However, for comparison, the results of the analysis are presented in Table 19.

Table 19: Delivered Hydrogen Costs at Refueling Stations

Station Type	Delivered Cost of Hydrogen (\$/GJ)[a]
On-site conventional reforming	14-47
On-site fuel cell reforming	14-31
On-site advanced electrolysis	30-41

[a] The author did not specify the basis for the estimates and so they were assumed to be for HHV and they were converted to LHV. The low range of costs in the table are for a 53,600 Nm^3/d facility and the high end of the range is for 2,700 Nm^3/d.

Thomas and Kuhn (1995a) looked at a single-car refueling station based on an electrolyzer under three 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 home refueling station was assumed to have excess capacity of 50% to account for daily mileage variations. The fleet system requires a smaller excess capacity of 20%.

The total capital cost for each alternative was projected to be \$3,413 based on a mass-produced electrolyzer cost of \$300/kW_{out}, a compressor cost of \$115/kW_{out}, and a storage cost of \$50/lb H_2. Based on these economic parameters, the report concluded that electrolytic hydrogen would be cost-competitive with fully taxed gasoline if electricity were available at \$0.03-\$0.045/kWh. If hydrogen fuel were taxed as gasoline, electricity prices must be less than \$0.01-\$0.025/kWh. 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.

Thomas and Kuhn (1995a) added to their previous work by evaluating the effect of station size on the cost of hydrogen for refueling. They evaluated a two-car home refueling station, a 50-car fleet (11 cars/d), and a 1,300-car station (160 cars/d). All were evaluated assuming a 15-year lifetime, a real discount rate of 8.86%, and the capital cost assumptions used in the previous study except that hydrogen storage was projected to cost \$60/lb. The authors concluded that the larger systems can compete with fully taxed gasoline using electricity at \$0.05/kWh; the small systems require electricity at \$0.03/kWh. This conclusion conservatively takes no economies of scale for the capital components of the larger systems. If there is an economy of scale, the allowable electricity price would likely be higher.

The cost information provided by Thomas and Kuhn (1995b) was evaluated using the standard methodology. This analysis showed, as in the original analysis, the cost of home refueling (\$49/GJ) is significantly greater than that for the fleet (\$35/GJ) or large refueling (\$31/GJ) stations. The difference in this analysis is greater than that projected by the authors because, as noted earlier, the on-line factor for the home station is only 52% and that for the other stations is 76%. The source document assumed 70% on-line factor for all cases.

A summary of the standardized costs for on-site hydrogen production is provided in Table 20.

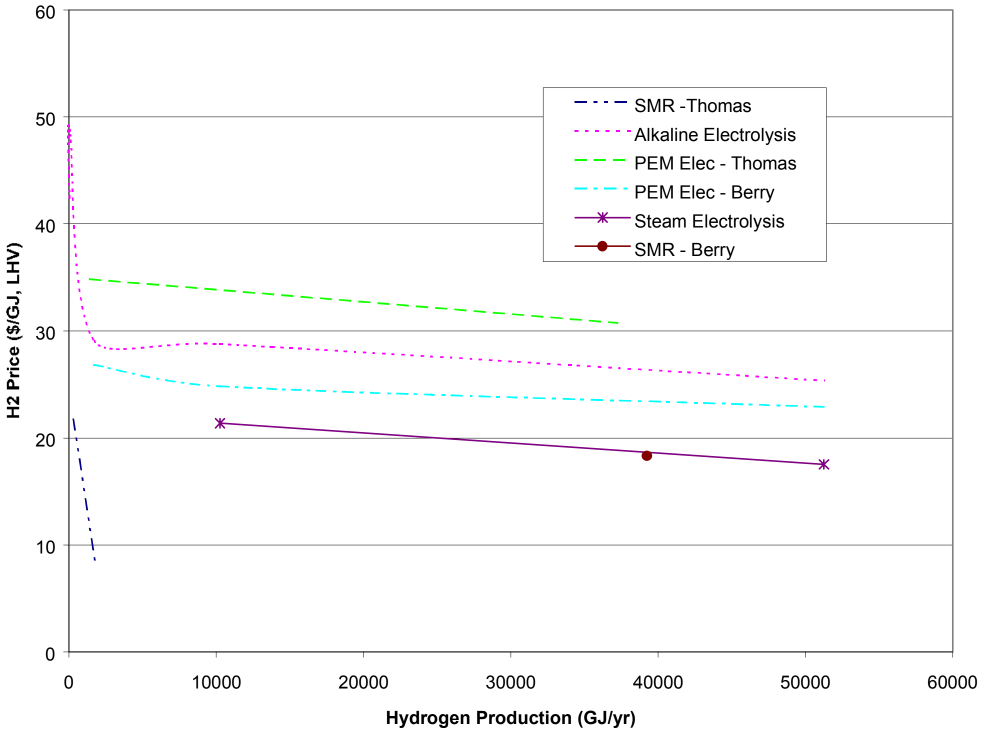
Table 20: Standardized Costs for On-Site Hydrogen Production

Technology/ Size (GJ/yr)	Reference	Specific TCI ($/GJ)	Hydrogen Price ($/GJ)
SMR			
39,240	Berry et al. 1996	56.58	18.31
1,752	Thomas et al. 1998	16.70	8.62
Alkaline Electrolysis			
51,246	Berry et al. 1996	41.35	25.36
10,249	Berry et al. 1996	64.30	28.79
1,708	Berry et al. 1996	65.29	29.07
PEM Electrolysis			
51,246	Berry et al. 1996	25.72	22.91
37,230	Thomas et al. 1995	29.27	30.74
10,249	Berry et al. 1996	38.58	24.82
1,708	Berry et al. 1996	50.45	26.84
1,432	Thomas et al. 1995	49.06	34.84
Steam Electrolysis			
51,246	Berry et al. 1996	18.00	17.53
10,249	Berry et al. 1996	43.53	21.39
Residential			
35 (Electrolysis)	Berry et al. 1996	101.27	42.42
298 (SMR)	Thomas et al. 1998	40.17	21.73
57.3 (Electrolysis)	Thomas et al. 1995	79.64	48.80

The costs estimated by Thomas and James (1998) are significantly lower than those from any other source. This cost differential is primarily due to the significantly lower capital investment projected. The other values show good agreement among themselves as well as with the values by Ogden et al. (1997) that were summarized in Table 19.

Figure 8 shows the cost of on-site generation.

Figure 8: Hydrogen Costs for On-Site Generation



Centralized Generation of Hydrogen

Estimates of delivered hydrogen prices for refueling stations based on centralized production were also presented by two sources (Ogden et al. 1997; Berry et al. 1996). The delivered cost of hydrogen for refueling is estimated at $22-$35/GJ (1998$) for LH2 delivered by truck and $20-$32/GJ (1998$) for delivery via pipeline (Ogden et al. 1997). When these values are compared with the analysis of on-site generation (Table 19), it is apparent that depending on the application, centralized reforming and delivery may be more expensive than on-site production (Ogden et al. 1997). In almost all cases, centralized reforming is less expensive than on-site advanced electrolysis. Not enough information was provided in the source document for standardization.

Berry et al. (1996) also provided costs for centralized production of hydrogen and estimates of the cost of the refueling stations. Liquid and compressed gas stations were evaluated. Using the standard methodology described earlier, the costs of both refueling scenarios were estimated. In general, the costs for the liquid hydrogen refueling station were lower than those for the compressed gas station. The costs for the liquid refueling station ranged from $11/GJ for a capacity of 39,240 GJ/yr to $29/GJ for a capacity of 1,300 GJ/yr. The comparable stations for the compressed gas system cost $16/GJ and $26/GJ. These costs are independent of whether the hydrogen is produced in a central location or is on-site.

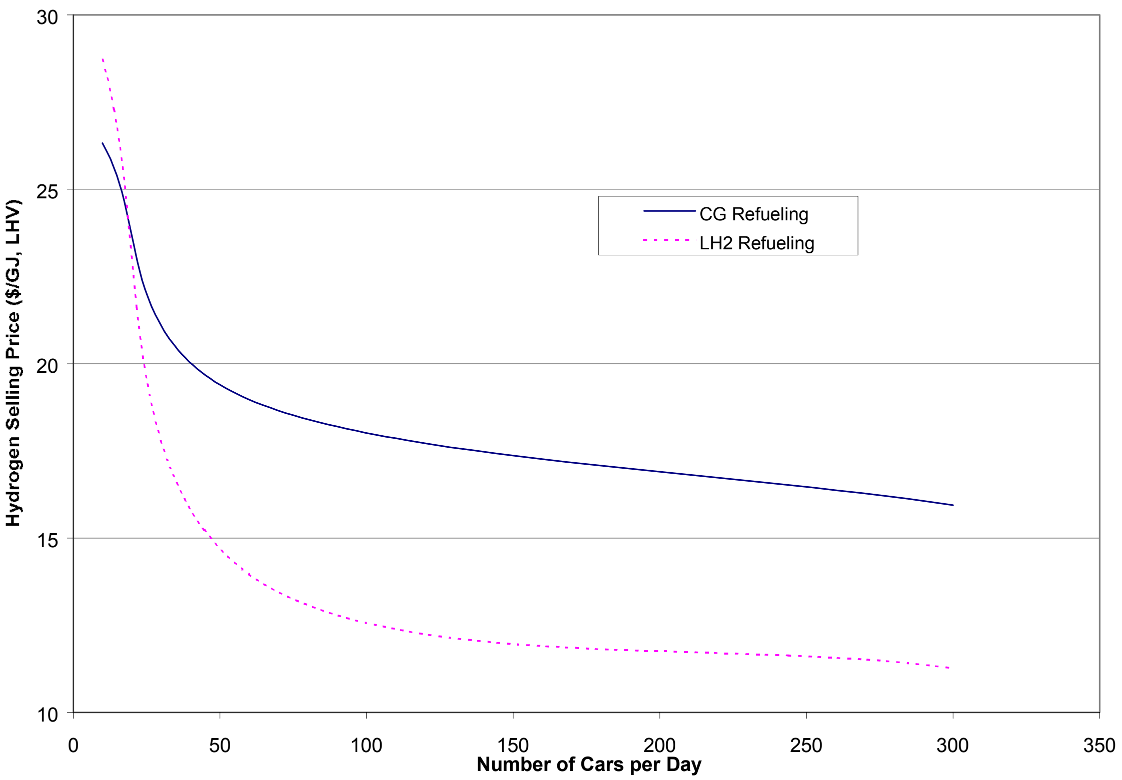
For the special case of LH2, Berry et al. (1996) also provided costs for a large liquefaction plant. A facility with a capacity of more than 10 million GJ/yr of hydrogen would incur capital costs of almost $14/GJ with an incremental hydrogen cost of about $7.50/GJ.

Table 21 and Figure 9 summarize the standardized costs for hydrogen refueling stations from Berry et al. (1996).

Table 21: Standardized Costs for Hydrogen Refueling Stations

Technology/ Size	Number of Cars/day	TCI ($/GJ)	Hydrogen Cost ($/GJ)
LH2			
39,420	300	9.05	11.27
7,884	60	26.49	13.96
1,314	10	121.94	28.71
Compressed Gas			
39,420	300	29.32	15.94
7,884	60	48.87	18.97
1,314	10	96.45	26.32
Liquefaction Plant			
10,380,600	N/A	13.67	7.55

Figure 9: Hydrogen Costs for Vehicle Refueling Stations



Hydrogen's Role in Reducing Anthropogenic Carbon Emissions

Several authors (Fisher 1990; Okken 1992; Okken et al. 1995) have evaluated the use of hydrogen as a method for minimizing greenhouse gas emissions to the environment. Two primary methods have been proposed: (1) hydrogen production using renewable resources (e.g., PV-electrolysis, biomass); and (2) the capture and sequestration of CO_2 from conventional hydrogen production technologies (e.g., SMR). Although the use of renewable technologies such as PV- and wind-electrolysis or biomass gasification would have minimal emissions of greenhouse gases, these technologies are still expensive. As noted earlier, the most common method of hydrogen production is SMR. In this technology, the CO_2 is separated from the hydrogen and vented to the atmosphere. To reduce emissions using this technology, then, the CO_2 must be captured and sequestered.

Several methods are available to remove greenhouse gases, primarily CO_2, from hydrogen production streams. The most commonly proposed methods are amine scrubbing and PSA. Details on the economics of specific applications of both methods are provided here.

Sequestration Options

After CO_2 is removed from the process stream, it must be sequestered so it is not released to the atmosphere. The two most commonly proposed methods for sequestration are ocean disposal and underground injection. In ocean disposal, several options are available. Liquid CO_2 may be released from pipelines at depths of 2,000 m or more; solid CO_2 can be disposed of by ships; or CO_2 can be converted into clathrates/hydrates for disposal (Okken 1992). With underground sequestration, the CO_2 is injected into depleted natural gas reservoirs or other geologic formations such as aquifers (Okken 1992).

The ocean has a CO_2 uptake capacity that is almost 7,000 times greater than current carbon emissions. However, the CO_2 will not remain in the ocean forever and there has been little investigation into the impacts on marine ecosystems (Okken 1992). Okken (1992) estimates that there is a total of 5 years worth of capacity in old natural gas wells and an additional 15 years capacity in sedimentary basins.

Costs for ocean disposal are expected to be twice those of underground injection (Okken 1992).

Economics

Two studies (Foster-Wheeler 1996; Blok et al. 1997) evaluated the economic and technical feasibility of capturing the CO_2 from SMR and sequestering it. The Foster-Wheeler study, which was commissioned by IEA, also looked at CO_2 removal and sequestration from coal gasification. Ocean disposal of the CO_2 was evaluated in the Foster-Wheeler study; the Blok study evaluated underground sequestration. The Foster-Wheeler study projected a CO_2 removal of 85% for the CH_4 case and 97% for the coal gas and the Blok study projected a CO_2 removal of 70%. In the Foster Wheeler SMR process, most CO_2 is removed with amine scrubbing prior to the PSA unit where the remaining CO_2 is removed. In the Blok et al. study, only that CO_2 already removed from the hydrogen in the PSA unit was sequestered. Carbon dioxide removals were higher for the coal process because all the fuel is gasified within the process so CO_2 may be removed in-situ. The CH_4 process requires an external fuel source and some methane is lost. Both factors decrease the removal efficiency (Foster-Wheeler 1996).

The CO_2 disposal costs for the Foster-Wheeler ocean disposal scenario assumed a seaside location, a pipeline length of 30 km, well head facilities, and a disposal well. The capital cost of the CO_2 disposal system was estimated at $23.8 million for the natural gas SMR and $29.9 million for the coal gasification. The overall capital increase for CO_2 capture and sequestration was $198 million (76%) for the SMR system and $314 million (36%) for coal gasification. Operating costs for disposal were assessed as $2 million/yr for both cases. The CO_2 capture added costs for the amine solution, increased maintenance, and additional fuel costs caused by efficiency losses.

Using the methodology outlined earlier, the cost of hydrogen from an SMR plant increases by 26% to $6.83/GJ. The increase from the coal-based plant is 24% to $12.26/GJ. On a CO_2 basis, the cost of CO_2 removal for the SMR case is $22.72/T and $13.80/T for the coal gasification case. The primary reasons for the difference in costs are the higher carbon content of coal and the higher CO_2 removal efficiency (i.e., 97% versus 85%).

The Blok et al. study evaluated an SMR system alone (Scheme A) and with CO_2 removal and disposal in a depleted natural gas well (Scheme B). Additionally, the study evaluated the use of the CO_2 for enhanced gas recovery (EGR) for use in the hydrogen plant (Scheme C).

The CO_2 removal process (i.e., PSA) is currently standard in SMR plants, and so there is no increased capital or operating charges for CO_2 capture within the plant. Detailed information was provided on the transport and removal of CO_2. Table 22 summarizes the assumptions used for CO_2 transport and disposal. The analysis assumed that new wells and a CO_2 distribution center would be required. All costs are in 1991$.

Table 22: Technical and Economic Parameters for CO_2 Removal and Sequestration

Cost Parameter	Value
Carbon Dioxide Transport	
Transport rate	500 T/h
Pipeline diameter	0.5 m
Pressure drop along pipeline	0.12 bar/km
Pipeline distance	100 km
Transport cost	\$3/t CO_2 (100 km)
Carbon Dioxide Injection	
Well injection capacity	40 t/h
Investment cost	\$96,000/t/h
O&M costs, incl. Insurance	3.6% of investment

As noted earlier, Scheme C assumes that the captured CO_2 is used for EGR. Because CO_2 travels rather quickly through the reservoir, the recovered natural gas becomes contaminated within a few years (Blok et al. 1997). When this occurs, the recovered gas rate is assumed reduced such that the amount of recovered CO_2 is less than 5% of the injection rate (Blok et al. 1997). In the source document, the CH_4 and CO_2 recovery rates are averaged over the life of the reservoir, 25 years. For this analysis, this assumption results in CO_2 and CH_4 recovery rates of 0.044 T/T and 0.041 T/T of CO_2 injected. Thus, the EGR would provide 8.4% of the natural gas feedstock requirement for the plant.

From these assumptions and the proposed SMR size of 19 PJ/yr of hydrogen, the capital cost for the CO_2 transport and sequestration system was estimated at roughly \$190 million for both Schemes B and C. Increased operating costs were projected to be \$68 million for both cases. In Scheme C, however, because the CO_2 is used to recover CH_4 for use in the plant, the fuel costs are reduced by about 10% or \$30 million/yr.

Using the standard methodology, the study results in hydrogen production costs of \$6.50/GJ for Scheme B and \$6.24/GJ for Scheme C, increases of 9% and 5%, respectively. On a CO_2 basis, the costs are equivalent to \$12.96/T CO_2 removed for Scheme B and \$6.57/T CO_2 removed for Scheme C.

The authors also performed several sensitivity studies, including the plant location. From this analysis, they were able to show that if the plant were located at the depleted field (i.e., a pipeline length of 0 km), the hydrogen production costs would actually decrease because of the EGR. Another important factor is that the cost of hydrogen transmission (assumed to be 50% greater than natural gas transmission) is less expensive than the cost of CO_2 transmission (\$0.12/GJ). Thus, the CO_2 mitigation costs would be negative and would pay for themselves.

The study also examined the effect of the permeability of the field. In one case, a more permeable field resulted in a decreased recovery of methane such that only 4.6% of the feed to the plant could be recovered. This assumption resulted in a significant (300%) increase in the cost for CO_2 recovery on a

$/T basis. Thus, the specific characteristics of the field are important components of the cost analysis. The results of all three studies are summarized in Table 23.

Table 23: Summary of Hydrogen Costs and CO_2 Removal Costs for Hydrogen Production

Technology	Size M Nm^3/d	TCI ($/GJ)	Hydrogen Cost ($/GJ)	CO_2 Removal Cost ($/T)
Steam Methane Reforming				
Ocean disposal	6.75	17.3	6.83	22.72
Depleted well	25.38	13.6	6.50	12.96
EGR	25.38	13.6	6.24	6.57
Coal Gasification				
Ocean disposal	6.75	44.9	12.26	13.80

Except in the special case of CO_2 use for EGR at the depleted gas field, CO_2 recovery and sequestration from hydrogen production increases the price of the hydrogen. Decarbonized hydrogen is about twice as expensive as CH_4 on an energy basis, and so these cost increases will not be competitive with standard fossil fuel use followed by flue gas cleanup (Foster Wheeler 1998). Thus, the end-use of the hydrogen should perhaps be combined with the hydrogen production and CO_2 removal strategy (Foster Wheeler 1998). Several processing alternatives were evaluated by Foster-Wheeler (1998) and three were identified for further study.

Option 1 is the reduction of carbon emissions from the reformer furnace by the use of 25% of the gas turbine exhaust and 30% of the hydrogen-rich fuel gas product as combustion gases in the reformer.

In Option 2, pressurized (22 bar) reforming is used and the combustion air for the reformer is supplied by the gas turbine compressors. Additionally, hydrogen-rich gas is used to fuel the reformer. In both options 2 and 3, a hydrogen-rich (95%) gas is combusted in the turbine.

Finally, Option 3 uses catalytic partial oxidation (CAPO), in which air and steam are used to partially oxidize natural gas. The air is taken from the air compressor of the gas turbine (20 bar) and the gas burned in the turbine is about 53% hydrogen and 43% nitrogen.

No significant technical hurdles were identified for Option 1. The components required for Option 2 represent significant changes from current technology and significant process development would be required. Option 3 has had limited experience on a large scale (i.e., several days), but would require further demonstration to be commercially acceptable.

As noted earlier, all three options would require a gas turbine that could be operated on hydrogen-rich gas (53%-95%). The authors obtained conflicting information regarding the significance of this detail. However, they concluded that only minor modifications would be necessary (i.e., burner modifications for higher flame speed) and the cost impact would be insignificant.

Using the proposed methodology, each option was evaluated and compared to a standard natural gas combined cycle (NGCC) plant. Each plant had a nominal size of 500 MW_e and each option removed 84% of the CO_2 compared to the NGCC. Based on this analysis, the cost of CO_2 removal was estimated at $33.4/T for Option 1, $42.6/T for Option 2, and $26.5/T for Option 3. These results, as well as the required electricity prices and other parameters, are summarized in Table 24. Costs for CO_2 disposal/sequestration were not included in the evaluation.

Table 24: Summary of Results for CO_2 Removal via Hydrogen Production and Integration with Electricity Production

	Base Case NGCC	**Option 1 Gas Turbine Exhaust Recycle**	**Option 2 Pressurized Reforming**	**Option 3 CAPO**
Facility size				
GWh/y		4,196	4,161	4,284
Efficiency	59%	48%	49%	50%
Capital costs				
Fixed capital investment	$311 million	$505 million	$583 million	$467 million
FCI ($/kWh)	642	1,054	1,227	954
Required electricity price[a] ($/kWh)	0.031	0.043	0.046	0.041
CO_2 removal costs ($/T)	N/A	33.40	42.6	26.5

[a] Price required for a before-tax 10% IRR.

As in the original study, the cost of electricity increased by 33%-50% over that from an NGCC. The costs appeared to be most favorable, both on the electricity price and CO_2 removal costs for Option 3, CAPO. Close behind, however, is Option 1, which has less technical uncertainty. The least favorable option from both a technical and an economic standpoint is the pressurized reforming system, Option 2.

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Appendix A

Economic Basis and Methodology

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To ensure level comparisons among the technologies, they were converted to a standard basis because each report used its own assumptions and methods. The sources also differed in the level of detail provided. For example, some reports outlined all of the technical and economic assumptions and provided a mass balance while others simply presented an overall cost (e.g., \$10.23/GJ). Therefore, two methodologies, detailed and nondetailed, were used for standardization, depending on the information available in the report.

For the nondetailed cases, the costs provided in the source were scaled to the study basis (i.e., mid-1998\$) using the appropriate Chemical Engineering Cost index (see Table A-2) and all costs were converted to an LHV basis. If the energy basis was not provided in the source, to ensure conservative projections, it was assumed to be on an HHV basis. Although rough, this method provides estimates that can be used for order-of-magnitude checks against the detailed estimates.

Sources that contained detailed design and economic information were standardized using the following assumptions. The source of each assumption is also provided.

Table A-1: Economic Analysis Parameters

Parameter	Value	Source
General Parameters		
Heating values		
Hydrogen		
LHV	10,795 kJ/Nm^3	Foster-Wheeler 1996
HHV	12,761 kJ/Nm^3	Himmelblau 1982
Natural gas	40,398 kJ/Nm^3	EIA 1998
Coal	25,507 kJ/kg	EIA 1998
Biomass	19,705 kJ/kg	EIA 1998
Residual oil	41,680 kJ/L	EIA 1998
Energy/Feedstock Costs		
Natural gas	\$2.96/GJ	EIA 1998 – Industrial
Coal	\$1.46/GJ	EIA 1998 – Industrial
Biomass	\$46.30/dry tonne	Mann 1995a
Residual oil	\$1.8/GJ	EIA 1998 – Industrial
Electricity	\$0.049/kWh	EIA 1998 – Industrial
Other Operating Costs		
Labor	\$30,000/yr	Engineering judgement
Solid waste disposal	\$20.31/tonne	Foster-Wheeler 1996
Basic Economic Parameters		
Discount rate	10%	Foster-Wheeler 1996, 1998
Economic lifetime	20 years	
Depreciation schedule	None	Will depend on location
Income tax rate	None	Will depend on location
Construction period	3 years	Foster-Wheeler 1996, 1998
Construction expenditures	Year 1 – 10% Year 2 – 35% Year 3 – 55%	Foster-Wheeler 1996, 1998
Production Capacities		
Base case	Variable	Based on reference size
On-line factor		
Natural gas plants		
Year 1	60%	Foster-Wheeler 1996, 1998
Year 2+	90%	
Coal plants		
Year 1	45%	Foster-Wheeler 1996, 1998

Parameter	Value	Source
Year 2	73.3%	
Year 3	83.3%	
Year 4+	85%	
Biomass[1]		
Year 1	45%	Mann 1995a
Year 2+	90%	
Electrolysis		Foster-Wheeler 1996, 1998
Year 1	60%	
Year 2+	90%	
Storage		
Year 1	61%	Engineering judgement
Year 2+	98.6%	
Transport		
Year 1+	98.6%	Engineering judgement
Refueling		
Fleet and larger (Year 1+)	76%	Berry 1996
Home (Year 1+)	52%	Berry 1996
Storage Parameters		
Storage period	1 day and 30 days	Engineering judgement

[1] To be consistent with other analyses, the initial year of 50% production was scaled to be 50% of maximum annual production, 90% or 45%. This differs from Mann (1995a)

Only the capital and major operating costs for each technology were standardized. Unit operating costs (e.g., fuel price) were modified to match the standard value and capital costs were scaled to mid-1998 U.S. dollars using the Chemical Engineering C&E index of 387. If a source did not provide the dollar-year of the estimate, then it was assumed the same as the publication year. For miscellaneous operating costs, the unit basis was not changed, but the costs were converted to the standard dollar-basis.

Table A-2 presents the annual C&E indices used for this analysis (Chemical Engineering 1983, 1990, 1998). The annual cost index was assumed to represent the entire year. Thus, even if the publication listed mid-1995 as the dollar-year, the annual index was used rather than the index for June 1995. This is not expected to introduce significant error because the annual fluctuations of the index should not be large.

Table A-2: Annual Cost Index

Year	C&E Index
1982	314.0
1983	316.9
1984	322.7
1985	325.3
1986	318.4
1987	323.8
1988	342.5
1989	355.4
1990	357.6
1991	361.3
1992	358.2
1993	359.2
1994	368.1
1995	381.1
1996	381.7
1997	386.5
Mid-1998	387

The original methodology used to develop the costs in the source document was not changed. For example, if Source 1 estimated the O&M charges of a steam methane reforming plant to be 3% of the fixed capital investment and Source 2 itemized these costs, the method for each technology remained unchanged. Of course, the costs projected by each method in the new study would be different than in the original because the base costs (e.g., fixed capital investment or labor) are likely different.

Another important area in which differing cost methodologies were apparent was in the projection of the fixed capital investment (FCI) and the working capital. Some sources used a factored method for the FCI; others itemized the costs. Even if a factored approach was used, the factors differed among as well as within technology classifications. These cost parameters were not standardized because the original analyst was presumably working with a methodology that was internally consistent. That is, the method of estimating each component of the costs used the same assumptions, and so unless the entire plant was to be re-estimated, the assumptions should remain the same.

The methods for calculating working capital were also highly variable. Some were calculated as a percentage of the FCI; others were based on sales or feedstock inventory. In several cases, no method was provided for calculating the working capital, and so the TCI was equivalent to the FCI. Even if the authors did not project a working capital, the methodology was unchanged. This will not likely be a significant source of error when comparing two technologies because, in general, working capital is not a major determinant of the economic viability of a process.

Another major change for each analysis was the basis for the economic viability. Each source used its own methodology and determined its own level of acceptability (e.g., hurdle rate). As noted in Table A-1, the standard economic methodology is based on a discounted-cash-flow-rate-of-return (DCFROR) analysis with an internal rate of return of 10%. Although most of the detailed analyses included the effect of depreciation and income tax, these factors were not evaluated because the laws governing them are country-specific. The effect of inflation (or deflation) was also ignored because it may also depend on the location and it may introduce more uncertainty in the analysis.

Many of the sources used currencies other than U.S. dollars. In some cases, a conversion from the currency to dollars was provided in the text. For most, no conversion was provided. In these cases, the bank rate conversion for October 1998 was used (OANDA 1998). No attempt was made to match the dollar-year used in the publication with the currency conversion for that year. After converting costs to U.S. dollars, the values were escalated to 1998 dollars as described earlier.

Table A-3 contains a summary of the currency conversion factors used in the analysis. The dollar values shown in the table are the equivalent of one unit of the currency listed.

Table A-3: Currency Conversions

Currency	U.S. Dollar Equivalent
German Deutsche Mark (DM)	$0.61
Norwegian Kroner (NOK)	$0.134
Canadian Dollar (CAN$)	$0.83
European Currency (ECU)	$1.20
Dutch Florin (*f*)	$0.55
French Franc (FF)	$0.18

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13. ABSTRACT *(Maximum 200 words)* A survey of the economics of hydrogen production, storage, transport, and end-use technologies has been completed. More than 100 publications concerning the economics of current and near-term hydrogen technologies were surveyed. Technologies more than 20 years from commercialization were not considered.

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