

Economics and Environmental Effects of Hydrogen Production Methods

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Intro

By consuming hydrogen, energy can be produced without emitting local air pollutants or carbon dioxide, the gas that many scientists believe will be most responsible for potential climate change in the 21st century. Hydrogen can be combusted or combined with oxygen inside a fuel cell to produce energy. However, hydrogen gas does not occur naturally in large quantities on earth; it must be separated from other compounds such as water or fuels that contain carbon such as fossil fuels or biomass. The separation process raises many questions about how hydrogen might be used in the future to help solve problems of energy security, air pollution, and climate change.

Current technology allows for many different methods of producing hydrogen. Policies and economics will most likely determine which methods are used in the future, which will have significant environmental consequences. For example, hydrogen produced by coal gasification without carbon sequestration will release almost twice as much carbon to the atmosphere per unit of energy as is contained in gasoline. Hydrogen produced by electrolysis using wind turbines releases almost no carbon to the atmosphere, and if biomass gasification with carbon sequestration is used then there is a net decrease of carbon in the atmosphere. Production methods have other environmental impacts as well, such as the effects of mining for coal, drilling for gas, growing biomass on plantations, or siting large solar arrays and wind turbines.

Benefits of Hydrogen

Hydrogen could have the potential to reshape the entire energy industry. Environmental benefits are obvious. Whether hydrogen is combusted or consumed in a fuel cell, it directly produces almost no local air pollutants or greenhouse gas emissions. If vehicles were all run on hydrogen fuel cells, it would be a huge step towards solving air pollution problems in cities. Emissions of volatile organic compounds (VOCs, the precursors of ozone), SO_x, NO_x, carbon monoxide, and particulate matter could be dramatically reduced if all vehicles were fueled by hydrogen. According to the EPA, vehicles in the U.S. account for 78% of carbon monoxide emissions, 45% of NO_x, and 37% of VOCs.¹ These pollutants lead to human health and visibility problems.

Although no greenhouse gasses are released to the atmosphere when hydrogen is consumed, some production methods do release greenhouse gasses into the atmosphere. However, when carbon-based fuels are reformed or gasified to produce hydrogen, a stream of nearly pure carbon dioxide is easily produced as a byproduct. These technologies effectively decarbonize the fossil fuels. Technologies are emerging to isolate this carbon dioxide from the atmosphere by sequestering it in the ocean or in geological formations; however, the long-term effects of carbon sequestration and storage security are not entirely known. Geologic or ocean storage of carbon dioxide could prove to be a difficult, costly, or even impossible solution. If sequestration proves to be a viable and economical technique, fossil fuels could be converted to hydrogen and consumed to produce energy with small greenhouse gas emissions. Electrolysis produces no carbon dioxide directly since there is no carbon involved in splitting water into hydrogen and

¹ <http://www.fuelcells.org/fct/benefits.htm>

oxygen. However, the entire process is only carbon-free if a non-carbon source of electricity, such as wind, solar, or nuclear power is used.

The United States currently imports over 60% of its crude oil. There is more potential for producing hydrogen in the U.S. than oil. The U.S. has many natural resources that could potentially be converted to hydrogen, such as coal, gas, biomass, wind, and other resources. Although the reserve to production ratio (R/P) of oil and natural gas in the U.S. is about 10 years, the R/P ratio of coal is over 250 years. Other resources, such as biomass, wind, and sun, are renewable. A conversion to a “hydrogen economy” would allow the U.S. to be more energy secure – a larger percentage of energy consumed in the U.S. could be produced in the U.S. Energy security is important today because of decreasing production of oil in the U.S. and increasing political instability in oil-rich regions of the Middle East.

Hydrogen may change the electric power industry as well. If electrolysis costs reach a certain point, it could be used as a technique to store electricity. This could make it economical for power companies to convert off-peak power into hydrogen, which could be converted back into electricity during peak periods. This would require less electric power capacity for the same amount of peak power. For example, a 100 MW plant could serve an area which has a peak power demand of 110 MW if there was lower demand during off-peak periods. The ability of hydrogen to store electricity could also help stabilize and promote renewable electricity generation from intermittent sources such as wind or solar power.

Fuel cells have similar efficiency to a large-scale gas turbine power plant, but the fuel cells are able to maintain that efficiency in smaller units, unlike gas turbines. This allows for very large improvements in efficiency for small scale power sources, such as generators or vehicle power. A typical gasoline internal combustion engine can convert about 15-20% of its energy source to useful wheel power, while a fuel cell can convert 40-50%, making it 2-3 times more efficient (Toyota published an efficiency of 16% for its conventional gasoline engine vehicle and 48% for its fuel cell vehicle).²

Barriers and Disadvantages to Hydrogen

There are many barriers that might slow or prevent a transition in U.S. energy consumption to hydrogen energy. Economics will dominate what fuels are used in the future; however, there is a significant “momentum” of the energy infrastructure that exists today. For example, even if the life cycle cost of mass produced fuel cell vehicles prove to be competitive with those of a current gasoline engine, the transformation will not be guaranteed. The current infrastructure supports gasoline or liquid fuel transportation, delivery, and consumption. Pipelines would have to be installed, replaced, or converted. Filling stations would have to be replaced or converted as well. Without a specific plan or policy to implement hydrogen infrastructure, it is unlikely that this will occur before hydrogen vehicles are mass produced. It may be unlikely for hydrogen fuel cell vehicles to be mass produced before a hydrogen delivery system becomes widespread. This applies to infrastructure changes in any sector, not just transportation. However, the world’s

² <http://www.fuelcells.org/fct/benefits.htm>

commercial energy system will be entirely replaced at least two times between now and 2100 (Johansson 1996). This could provide an opportunity for changes and conversion of energy infrastructure.

It will be difficult to plan a transition to a different energy infrastructure based on hydrogen fuel. Certain technologies, however, could help simplify the transition to a hydrogen delivery infrastructure. Steam methane reforming and electrolysis are two hydrogen production techniques that can be performed on a relatively small scale or at the delivery station. Delivery infrastructure already exists for their feedstocks, natural gas and electricity. However, these may not be the preferable methods to use in the long run. Electrolysis is about 2-3 times more expensive than other methods of hydrogen production and it could be difficult to sequester carbon dioxide from steam methane reforming if the reforming was done at delivery stations.

While hydrogen could potentially be an economically competitive alternative to some energy carriers in large scale use today, it will take long term planning and foresight to bring about a transition.

Production methods

One of the advantages of hydrogen is the diverse range of methods for producing it. Fossil fuels and other carbon fuels can be decarbonized to produce hydrogen. Decarbonizing the fuels to produce pure hydrogen greatly reduces local air pollutants, separates the carbon dioxide (which could possibly be isolated from the atmosphere), and also allows the energy to be used more efficiently since the chemical process inside a fuel cell is more efficient than combustion. Hydrogen can be separated from water using electricity (electrolysis) or a thermochemical process that requires high temperatures.

The following analysis is a brief description of the commercial or near commercial production methods and an outlook on their prospects for the future. A more in-depth analysis of each method is in the next section. Table 1 includes a rough estimate of the quantity required of various feedstocks if only one method were used to produce enough hydrogen to fuel the entire U.S. transportation sector. Transportation is not the only sector that might consume hydrogen, but it makes a good starting point to give an estimate of scale. In 2001, the U.S. transportation sector consumed about 25 exajoules (EIA 2001); if hydrogen were used, efficiency increases could cut that down to as few as 10 exajoules. The chart is not meant to be a precise projection of how much land area or feedstock is required, only a rough estimate to answer questions such as how much coal would be required or how much land would be covered by solar panels to fuel the transportation sector. Efficiencies are given in terms of the fraction of potential energy contained in the feedstock that is contained in the hydrogen output ($E[\text{output}]/E[\text{input}]$).

Steam Methane Reforming (SMR) – SMR is currently used to produce more hydrogen for chemical industries than any other technique. It is the most mature technology, and currently the least expensive. Carbon dioxide can easily be separated from the feedstock, and local air pollutants are low. However, natural gas prices are volatile (and rising); North American

supplies are limited. Efficiency of conversion to hydrogen is 80-90%.³ SMR appears to be a process that could be implemented on a large scale in the future.

Coal Gasification – Coal gasification is slightly more expensive than SMR, but it offers several advantages. Coal prices have historically remained relatively stable (and lower than natural gas), and there is a vast supply of coal in many regions of the world. In the U.S., proven reserves will last 250 years at current production rates. Other countries around the world are heavily dependant on coal, and the worldwide reserve to production ratio is over 200 years. Carbon dioxide can be easily separated from the feedstock, and local air pollutants are low. Environmental and health concerns over mining processes and solid waste are higher than other methods. Efficiency of conversion to hydrogen is 50-75%; an additional 5% of the energy is converted to electricity that is output from the system. Coal gasification appears to be a promising method of hydrogen production throughout most of the world.

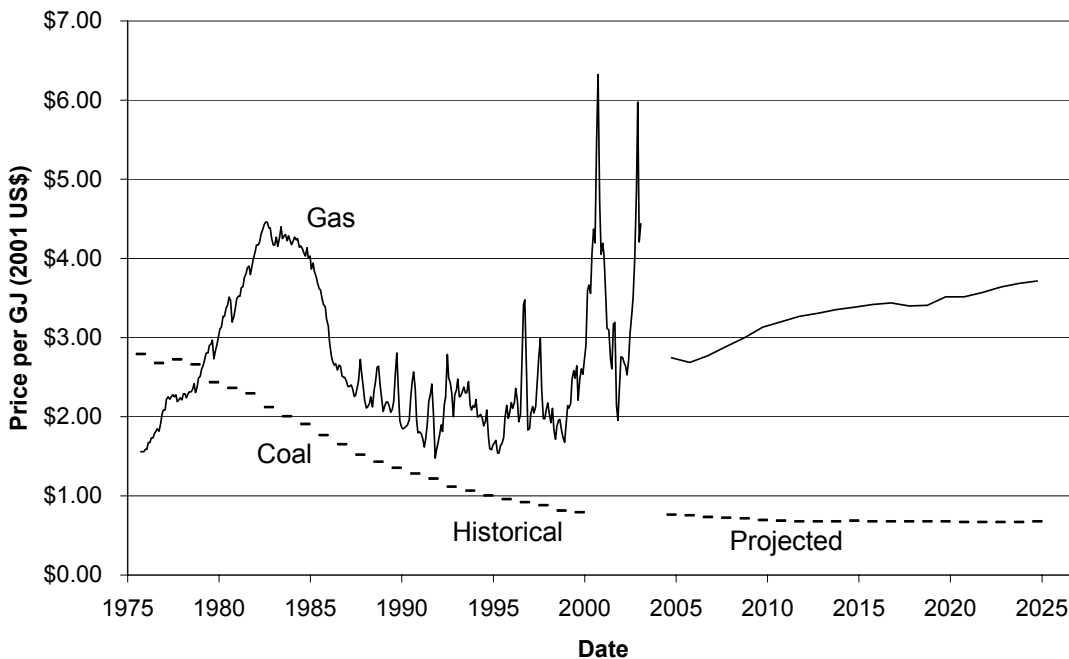


Figure 1 – Coal and Natural Gas Prices, Historical and Projected

Source: Energy Information Agency; coal prices measured at minemouth and natural gas prices measured at wellhead

Electrolysis – Electrolysis using electricity from renewable sources such as solar or wind power is a technology favored by environmentalists. Hydrogen could be produced with negligible local air pollutants and greenhouse gasses. However, electricity from any source is 3-10 times as expensive as fossil fuels (per unit of energy). Efficiency is high, 80-90%. Hydrogen produced from fossil fuel produced electricity is unlikely to be competitive with hydrogen extracted

³ Efficiency is measured in energy contained in hydrogen produced divided by energy contained in the feedstock.

directly from the fossil fuels since efficiency of electricity production is so low. Renewable energy capital costs would have to come down dramatically or fossil fuel costs would have to rise dramatically (unlikely in the case of coal) for electrolysis to become a large scale production method. If sequestration proves to be insecure or very expensive, a heavy carbon tax could help electrolysis from renewable or nuclear sources become competitive. Electrolysis could be useful for demonstration projects or off-peak electricity conversion, but it is unlikely to be used on a large scale in the foreseeable future.

Biomass Gasification – Biomass gasification is an interesting potential hydrogen production technique that could actually remove carbon dioxide from the atmosphere if the carbon that is contained in the biomass is sequestered after gasification. Even without sequestration, lifecycle carbon emissions are relatively low if the biomass is grown sustainably. Although future prices of biomass from energy plantations and other sources are uncertain, hydrogen produced by biomass is expected to be competitive with coal, and efficiency is similar to coal. Land use constraints could prevent large scale implementation of biomass gasification in some parts of the U.S. and the world. In certain regions, biomass gasification appears to be a possibility for large scale production of hydrogen.

Thermochemical Process – High temperature heat could be used from nuclear or solar sources to drive a chemical process that separates water into hydrogen and oxygen. This technique is further from commercialization than the techniques discussed above, and estimates of the cost vary. Nuclear thermochemical processes could prove slightly less expensive than electrolysis using nuclear electricity. High temperatures are required, and efficiency is likely to be near 50%. Nuclear electricity efficiency inside a high temperature reactor is slightly less than 50%, making the thermochemical process more efficient than production of electricity followed by electrolysis. The ability to switch between electricity and hydrogen production immediately (for example, producing hydrogen during off-peak hours and electricity during peak hours) could possibly give an economic advantage to the electricity producing reactor since it is more flexible and only slightly less efficient.

Power Source	Method	Amount of Source	Fraction of current U.S. consumption
Natural Gas ⁴	Steam Methane Reforming (SMR)	300 billion cubic meters	0.45
Coal ⁵	Coal Gasification	560 million tons (metric)	0.65
Wind ⁶	Electrolysis	3,300 TWh 1.25 million MW 850,000 large turbines	270
Solar ⁷	Electrolysis	3,300 TWh 14 million MW 3.5 million acres	Large
Switchgrass ⁸	Biomass Gasification	200 million acres cropland	0.4
Nuclear ⁹	Thermochemical	700 GW _{thermal}	2.3
Nuclear	Electrolysis	780 GW _{thermal}	2.6

Table 1 – Feedstock Requirements for Transportation Sector Hydrogen

Several insights can be learned from the table above. Replacing transportation sector fuel with hydrogen from a single source would require gas consumption to increase by 45% or coal consumption to increase by 65%. A mixture of the two sources would make it possible to fuel the transportation sector by hydrogen produced by gas and coal with reasonable increases in consumption (23% for gas and 33% for coal).

Resource constraints would probably not be significant for wind or solar electricity technologies in the United States. There is enough wind and solar power in the United States that a significant portion of hydrogen production could come from these sources if the economics made it possible. Nuclear production of significant quantities of hydrogen is theoretically possible if other barriers (economic, political, etc) can be overcome. Biomass gasification from energy plantations, however, will probably be limited in the United States due to regional land use

⁴ Steam Methane Reforming: 85% efficiency, natural gas energy content is 39 MJ / m³, current consumption is 670 billion m³ per year (EIA)

⁵ Coal Gasification: 66% efficiency, current coal consumption is 23 GJ per year

⁶ Electrolysis: 85% efficiency requires 3.3 trillion kWh per year, wind energy: 0.30 capacity factor, installed capacity 4719 MW (<http://www.awea.org/projects>)

⁷ Electrolysis: 85% efficiency requires 3.3 trillion kWh per year, solar energy: 12% efficiency, 2000 kWh/m²-yr solar irradiation

⁸ Biomass Gasification: 75% efficiency, 13 billion GJ/yr; 4 tons/acre, 18 GJ/ton

⁹ Nuclear power: Thermochemical life cycle 50% thermal efficiency, electrolysis 45% thermal efficiency, both using high temperature reactors, current installed capacity 100 GWe

(http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/reactsum.html) at 33% thermal efficiency

(http://eia.doe.gov/cneaf/nuclear/page/uran_enrich_fuel/convert.html), or 300 GW_{thermal}, 0.90 capacity factor

constraints. Biomass could possibly be an important method of hydrogen production in agricultural regions throughout the United States and the world. Agricultural and forestry residues could also supply significant amounts of biomass in certain regions.

Economic Analysis Techniques

A literature review was done for each near-commercial hydrogen production method and a statistical analysis was performed to determine the range of expected costs for each method. Costs for each method are separated into capital costs, operation and maintenance costs, and feedstock costs. Feedstock costs per unit of energy are standardized, but efficiency of the system will affect the total feedstock cost. Each type of cost is averaged and ranges are computed. Costs for each estimate are also recomputed using 2002 U.S. dollars and identical fixed capital charge rates so that comparisons can be made. If the capacity factor is not directly stated in the source, it is assumed to be 0.90, meaning the process runs on average at 90% of its production capacity.¹⁰ All energy content values are expressed in terms of higher heating value (HHV).¹¹

The cost of producing hydrogen can be separated into four categories: capital, operation and maintenance, feedstock, and carbon costs. The total cost of hydrogen produced by each production method can be expressed as an equation with four terms:

$$C_{H_2} = C_{CAP} * FCR + C_{OM} + C_F / \text{Eff} + C_C * P$$

Where:

C_{H_2} is hydrogen cost (\$/GJ)

C_{CAP} is the capital cost (\$-y / GJ)

C_{OM} is the operation and maintenance cost (\$/GJ)

C_F is the feedstock cost (\$/GJ)

C_C is the carbon cost (\$ / ton C)

FCR is the fixed charge rate on capital (1/y)

Eff is the efficiency (GJ of hydrogen produced / GJ of potential energy in feedstock)

P is the carbon emissions (tons of C / GJ of hydrogen produced)

In order to determine how to convert capital cost per unit of capacity to capital cost per unit of production, a fixed capital charge rate (FCR) must be determined. This includes investment return rate, income taxes, insurance charges, interest during construction, and other costs. Since representations of these values can vary significantly, FCR values were estimated from the literature for public utilities and private companies. The values used were 15% and 20%, respectively, for public utilities and private companies.¹² Private companies require a higher rate of return on investment which leads to a higher FCR. The FCR means that a certain percentage of the total capital cost of a production facility must be paid annually. For example, a utility must pay \$15 annually for every \$100 of capital cost.

¹⁰ 90% was a typical value observed in the literature for capacity factor (Padre and Putsche 1999).

¹¹ Higher heating value is the maximum potential energy in dry wood; it includes heat energy contained in water vapor after a gas is combusted.

¹² FCR values of utilities and private companies are from Herzog (1999) and Simbeck (2001), respectively.

Carbon costs are included in the calculation to account for the possibility that national or global policies are implemented during the economic lifetime of the hydrogen production plant that would charge the operator for releasing carbon into the atmosphere. While there is a possibility that the carbon could be sequestered from the atmosphere, this process would cost the operator as well. Sequestration would only make sense economically if the cost of sequestration is lower than the imposed cost of releasing carbon to the atmosphere. Since the success of sequestration is still unknown, carbon is included in the equation as a variable cost per ton that could represent the cost of carbon in a tax system, a permit trading system, or the cost to sequester each ton of carbon.

For comparison purposes, the cost of gasoline production is about \$7 / GJ (just under \$1/ gallon) when oil is \$23 / barrel, or \$3.75 / GJ. However, comparison between hydrogen and gasoline is not simple. Hydrogen can be consumed much more efficiently in a fuel cell than gasoline in an internal combustion engine (2-3 times more efficiently). Fuel transportation must be considered as well; transporting a gigajoule of gasoline from the production plant into the tank of a vehicle is currently many times cheaper than transporting a gigajoule of hydrogen. See the appendix for tables and figures comparing the costs of production for different methods.

Steam Methane Reforming

In the United States, steam reforming of natural gas produces most of the hydrogen for industry, and steam reforming is the most common commercial form of hydrogen production worldwide. Because steam reforming has been commercialized for longer than any other method, costs are known accurately and will probably not come down significantly with advancements in technology. The largest uncertainty comes from the natural gas feedstock price, which is a significant uncertainty.

Natural gas prices are very volatile; spot prices can double or triple in a short period of time. Although the Department of Energy's Energy Information Agency (EIA) forecasts natural gas prices to rise slowly through 2025 (see Figure 1), the future is even less certain after 2025. The United States has proven natural gas reserves of 183 trillion cubic feet, or about 10 years at current production levels.¹³ If proven and unproven (both conventional and unconventional) reserves from all of North America are considered, there could be about 1500 trillion cubic feet available. However, these are technically recoverable resources without considering environmental or economic constraints. At current consumption levels, this amount of natural gas could supply the United States for 65 years. When significant increases in consumption (at

¹³ Here are the data used in the natural gas calculations:

U.S. consumption is 22.6 trillion cubic feet per year (EIA <http://www.eia.doe.gov/oiaf/aeo/gas.html#ngc>)

U.S. consumption projections are 31.8-37.5 trillion cubic feet per year in 2025 (EIA)

U.S. proven reserves are 183 trillion cubic feet (EIA <http://www.eia.doe.gov/oiaf/aeo/assumption/tbl51.html>)

U.S. unproven unconventional reserves 445 trillion cubic feet (USGS

http://www.usgs.gov/public/press/public_affairs/press_releases/pr1183m.html)

U.S. unproven unconventional reserves 660 trillion cubic feet (USGS)

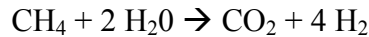
North American (excluding U.S.) proven reserves are 70 trillion cubic feet (BP Annual Energy)

North American (excluding U.S.) proven reserves are 154 trillion cubic feet (USGS)

least 40% increase by 2025 according to EIA) are included as well as consumption in Canada and Mexico, this figure could easily fall below 40 years.

It is possible to import natural gas in its liquid form (LNG), although it's more expensive due to refrigeration and transportation costs. Significant quantities of LNG imports would increase the price and decrease the competitiveness of natural gas. In the near term, however, steam reforming of natural gas appears to be the least expensive and most proven technique of hydrogen production.

There are two basic steps to steam methane reforming, not including desulfurization or other cleaning steps. The first step involves combining the methane with steam to produce a gas mixture that is mostly hydrogen with about 12% CO and 10% CO₂ (Kirk-Othmer 1995). This process occurs at about 800 deg C. The next step is called the water gas shift reaction, and it involves combining the carbon monoxide with water to produce hydrogen gas and carbon dioxide. The process results in mostly carbon dioxide and hydrogen as gas outputs, with smaller amounts of carbon monoxide, methane, water, and other gasses:



The hydrogen is separated from the carbon dioxide and other gasses using pressure swing adsorption (PSA), which results in pure (>99.9%) hydrogen. The hydrogen, carbon monoxide, and methane that are purged from the process can account for up to 90% of the fuel required by the reformer burners.

There is significant agreement in the literature on the price of producing hydrogen by steam methane reforming. All aspects of the production cycle are known with reasonable accuracy. However, feedstock costs account for over half of the cost of hydrogen, even at gas prices of \$3 per GJ. Almost all the uncertainty in future prices of steam reforming of natural gas stem from the price of the natural gas feedstock. In the economic statistical analysis, published values were used from Kirk-Othmer, Leiby, Foster-Wheeler, Blok, Williams, Stiegel, and Rutkowski. Their estimates are shown in the following table after being normalized for the common assumptions.

Source	C _{CAP} (\$-yr / GJ)	C _{OM} (\$ / GJ)	Eff (%)	P (ton C / GJ)
Kirk Othmer	\$8.69	\$0.71	84%	
Leiby	\$10.81	*	*	
Foster-Wheeler	\$8.57	*	*	
Blok	\$9.27	*	*	
Williams	\$11.84	\$1.07	90%	
Stiegel	\$6.75	*	82%	
Rutkowski	\$7.69	*	86%	
Statistics				
Mean	\$9.10	\$0.90	86%	0.018
Standard Dev	\$1.80	\$0.30	3%	

Table 2 – Cost Estimates for SMR Hydrogen Production

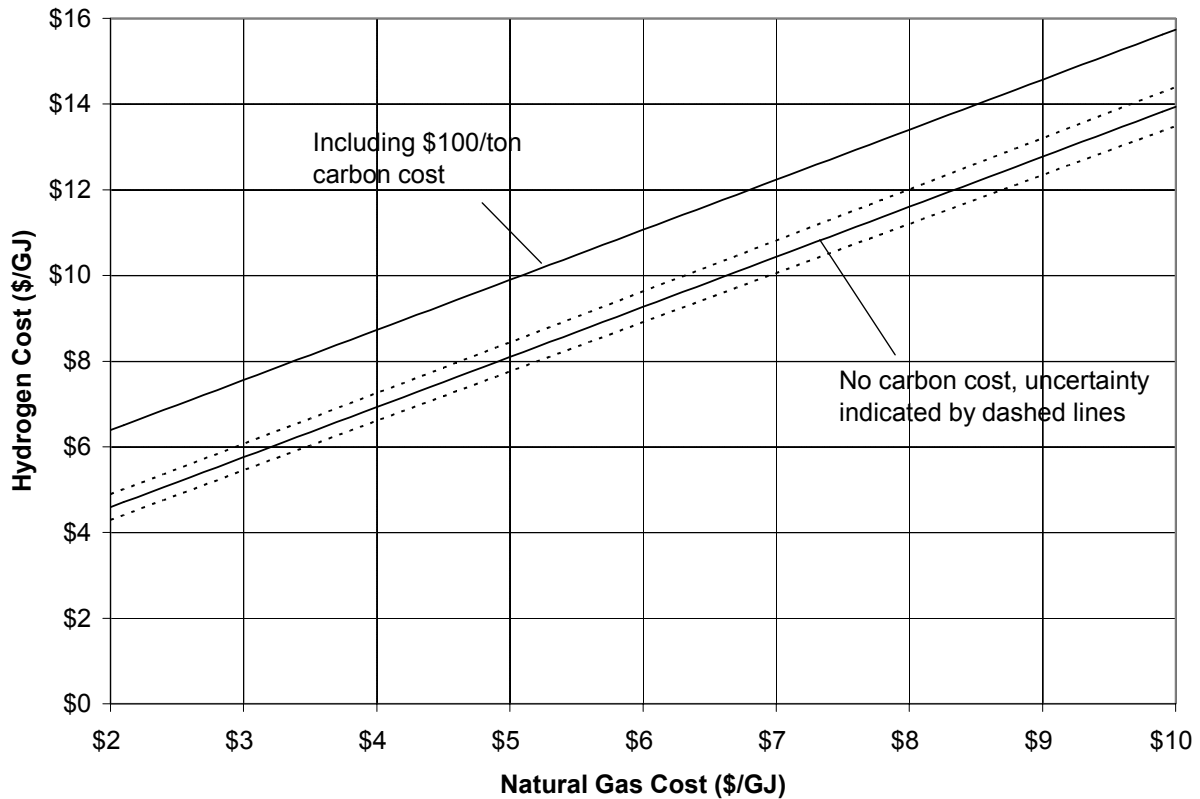


Figure 2 – Cost of SMR Hydrogen Production

Steam reforming of natural gas produces about 18 kg of carbon (in the form of carbon dioxide) per GJ of hydrogen. Sequestration could prove relatively inexpensive for natural gas. If the carbon dioxide is dried and compressed, it can be injected into the natural gas reservoir underground, repressurizing the reservoir and enhancing natural gas recovery. This will allow more gas to be collected from the reservoir and decrease the cost of recovery.

A carbon tax would probably not have a large effect on the cost of SMR hydrogen unless sequestration proves unsuccessful since sequestration cost estimates are typically under \$25 per ton C (less than \$0.50 per GJ). A carbon cost of \$50 per ton of carbon would increase hydrogen prices by slightly under \$1 per GJ. It would take a \$100 per ton carbon cost and \$5 per GJ gas price for SMR hydrogen to approach \$10 per GJ, the approximate price of electrolytic hydrogen at electricity costs of just \$0.02 per kWh.

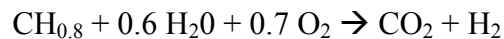
Other than the 18 kg of carbon per GJ, probably the largest environmental effect of SMR is the land use effects of drilling for natural gas. There is little local air pollution or solid waste produced by steam reforming natural gas. Although further cost reductions appear unlikely, steam methane reforming is the least expensive, most commercialized method in the near term. Its environmental effects are modest compared to other hydrogen production technologies and miniscule compared to current energy production methods.

Coal Gasification

Many people view coal as one of the most important feedstocks worldwide for hydrogen production in the future. Coal is inexpensive (about 3 times cheaper than natural gas and 10 times cheaper than electricity in the U.S.), abundant (worldwide proven reserves will last over 200 years at current production rates according to BP), and prices have fallen steadily over the past 30 years. The EIA projects coal costs to continue to fall slightly between now and 2025 (see Figure 1).

Coal is an important resource in many countries around the world, such as India, China, Australia, and the United States. Although coal gasification is not as commercially advanced as SMR, about 20% of current hydrogen production worldwide is produced by coal gasification (Kirk-Othmer 1995). China produces most of its 5 million tons of hydrogen (700 million GJ, most of it is for ammonia production) by coal gasification.

The overall process of coal gasification follows the following formula:



The first step in hydrogen production from coal is to gasify the coal by combining it with steam and oxygen to produce a raw gas mixture. After the ash is removed, the raw gas is desulfurized to produce synthetic gas (often called “syn gas”). Syn gas has slightly different composition depending on what type of gasifier is used; it contains mostly hydrogen, carbon monoxide, and carbon dioxide. The carbon monoxide is converted to carbon dioxide and hydrogen using the water gas shift reaction, and the hydrogen is separated from the carbon dioxide using PSA or another separation technique.

There is reasonable agreement in the literature on the cost of hydrogen production from coal gasification. The most disagreement occurs in the efficiency of conversion, which does not have major effects on the overall cost of hydrogen since the cost of coal is very inexpensive relative to the cost of the hydrogen produced. Coal prices tend to be stable even over long periods of time. Feedstock costs make up a small fraction of the cost of hydrogen from coal at typical coal prices, with capital and maintenance costs dominating the overall cost.

Some of the waste heat created from coal gasification can be converted into electricity. About 5% of the original energy content of the coal is converted to electricity (Stiegel 2000) and output from the system (some additional electricity is created but is consumed in the gasification process). The process creates about 20 kWh of electricity per GJ of hydrogen; at current wholesale electricity costs this could reduce the net cost of hydrogen production by \$1/GJ.

In the economic statistical analysis, published values were used from Kirk-Othmer, Foster-Wheeler, Williams, Stiegel, and Rutkowski. Their estimates are shown in the following table after being restandardized for the common assumptions.

Source	C_{CAP} (\$-yr / GJ)	C_{OM} (\$ / GJ)	Eff (%)	P (ton C / GJ)
Kirk-Othmer	\$33.02	\$3.27	57%	
Foster-Wheeler	\$28.37	*	*	
Stiegel	\$22.17	*	66%	
Williams	\$29.04	\$2.98	77%	
Rutkowski	\$27.95	*	63%	
Statistics				
Mean	\$28.10	\$3.10	66%	0.038
Standard Dev	\$3.90	\$0.20	9%	

Table 3 –Cost Estimates for Coal Hydrogen Production

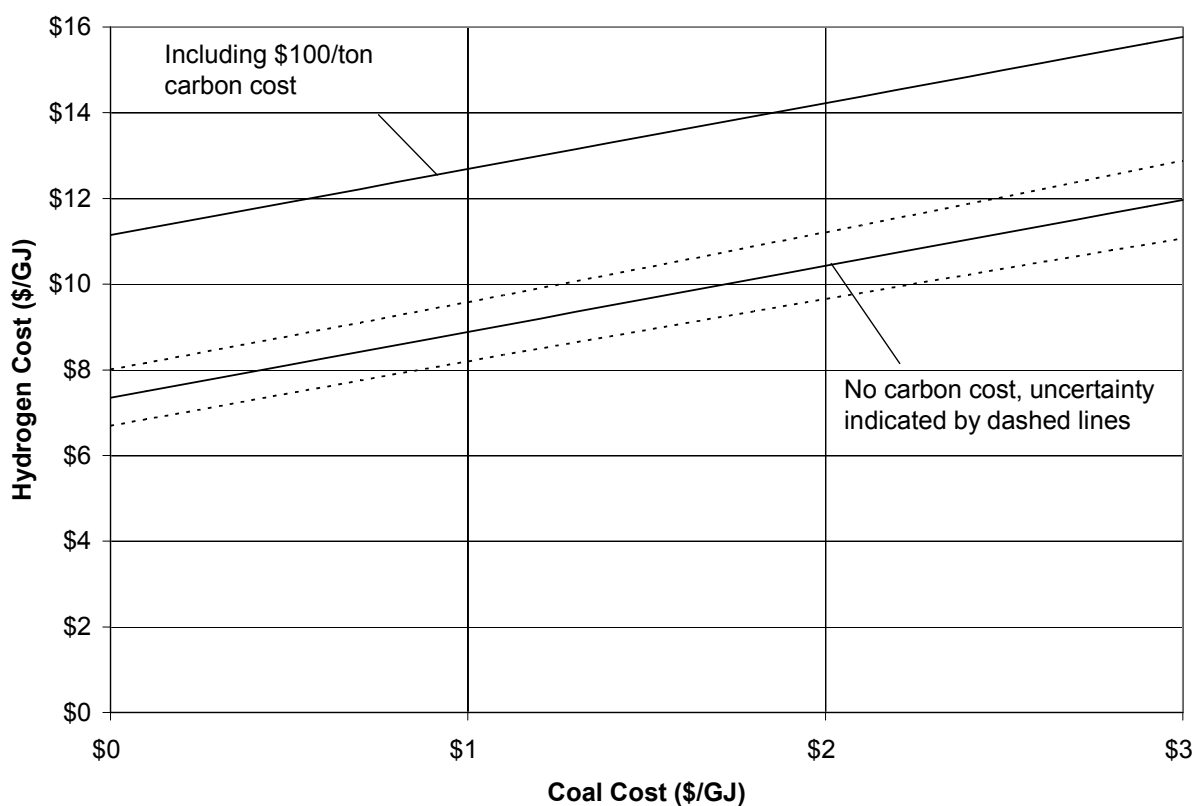


Figure 3 – Cost of Coal Hydrogen Production

The largest wildcard in the cost of hydrogen produced by coal gasification is the cost of the carbon dioxide. Without a carbon tax, hydrogen produced by coal is likely to remain below \$10 per GJ. Since coal is abundant and prices are stable in most regions of the world, this can be treated as a ceiling for hydrogen production costs in the absence of a carbon tax.

Introduction of a \$50 carbon tax (in the absence of sequestration) would increase the price of coal gasified hydrogen by slightly under \$2 per GJ. If sequestration costs remain below \$50 per ton, this might not make coal costs prohibitive. However, if sequestration is unsuccessful and

higher carbon taxes are levied, coal could lose its competitiveness with natural gas and possibly renewable electrolysis as a feedstock for hydrogen production.

Since coal gasification is not as widely commercialized as steam reforming, there is potentially more room for technical advancements. According to Rutkowski 2000, inorganic membranes could be used to produce hydrogen from coal for total production costs approaching \$5 per GJ (including capital, operation and maintenance, and feedstock costs, but not carbon costs). The U.S. Department of Energy is hoping their FutureGen coal gasification plant¹⁴ will help engineers learn how to produce hydrogen from coal for costs of around \$4 per GJ (although this is probably using government interest, tax, and insurance rates).

Coal gasification has more significant environmental effects than most other hydrogen production methods. Coal mining can be dangerous and harm the landscape and water quality of an area. Transportation of coal can be a fossil fuel intensive process depending on how it is done. Although local air pollutants are expected to be near zero, significant amounts of solid waste will be produced from the ash, sulfur, and other pollutants that are found naturally in coal.

Hydrogen produced from coal gasification releases about 38 kg of carbon per GJ. Most of this can probably be sequestered, but if that is unsuccessful then coal will produce twice as much carbon dioxide per unit of energy than natural gas, and many times more than biomass or electrolysis. Increased life cycle efficiencies would allow for greenhouse gas improvements over current coal combustion technologies.

Coal gasification provides a realistic long term way for hydrogen to be produced at a reasonable cost in most regions of the world. For this reason, coal can be viewed as a “backstop;” a production method that can produce hydrogen at a predictable cost for the foreseeable future.

Biomass gasification

Biomass gasification is similar to coal gasification in many ways. The process is similar, leading to similar capital costs. The feedstock is relatively inexpensive, although costs are much more speculative. There are more constraints (such as land use) to biomass production than coal. The process of biomass gasification starts by heating the biomass to produce a syn gas consisting mostly of hydrogen, carbon monoxide, carbon dioxide, and water. This gas is cleaned and then steam is introduced to cause the water gas shift reaction to convert the energy in carbon monoxide to hydrogen. Pressure swing adsorption separates the hydrogen from the carbon dioxide.

Biomass has several advantages over coal as a hydrogen feedstock. It is more reactive and contains less sulfur, which requires costly equipment to remove. However, coal gasification plants can benefit more from economies of scale than biomass since coal plants can be larger. It

¹⁴ DOE FutureGen fact sheet available at http://www.fe.doe.gov/programs/powersystems/futuregen/futuregen_factsheet.pdf

is uneconomical to build biomass plants the size of coal plants since biomass has less energy density by volume therefore is more expensive to transport.

Published estimates show some disagreement over the cost of biomass production, due to moderate uncertainties in capital costs, operation and maintenance costs, and efficiency. This can be seen from the error margins in the total cost, which amounts to an uncertainty range of \$3-4 per GJ of hydrogen in most circumstances. In the economic statistical analysis, published values were used from Williams, Bowen, Spath, and Hamelinck. Their estimates are shown in the following table after being restandardized for the common assumptions.

Source	C _{CAP} (\$-yr / GJ)	C _{OM} (\$ / GJ)	Eff (%)	P (ton C / GJ)
Williams	\$23.95	\$2.48	73%	
Bowen	\$14.66	\$1.50	66%	
Spath	\$32.61	\$1.70	57%	
Hamelinck	\$27.75	\$1.12	61%	
Statistics				
Mean	\$24.80	\$1.70	65%	0
Standard Dev	\$7.60	\$0.70	8%	

Table 4 – Cost Estimates for Biomass Hydrogen Production

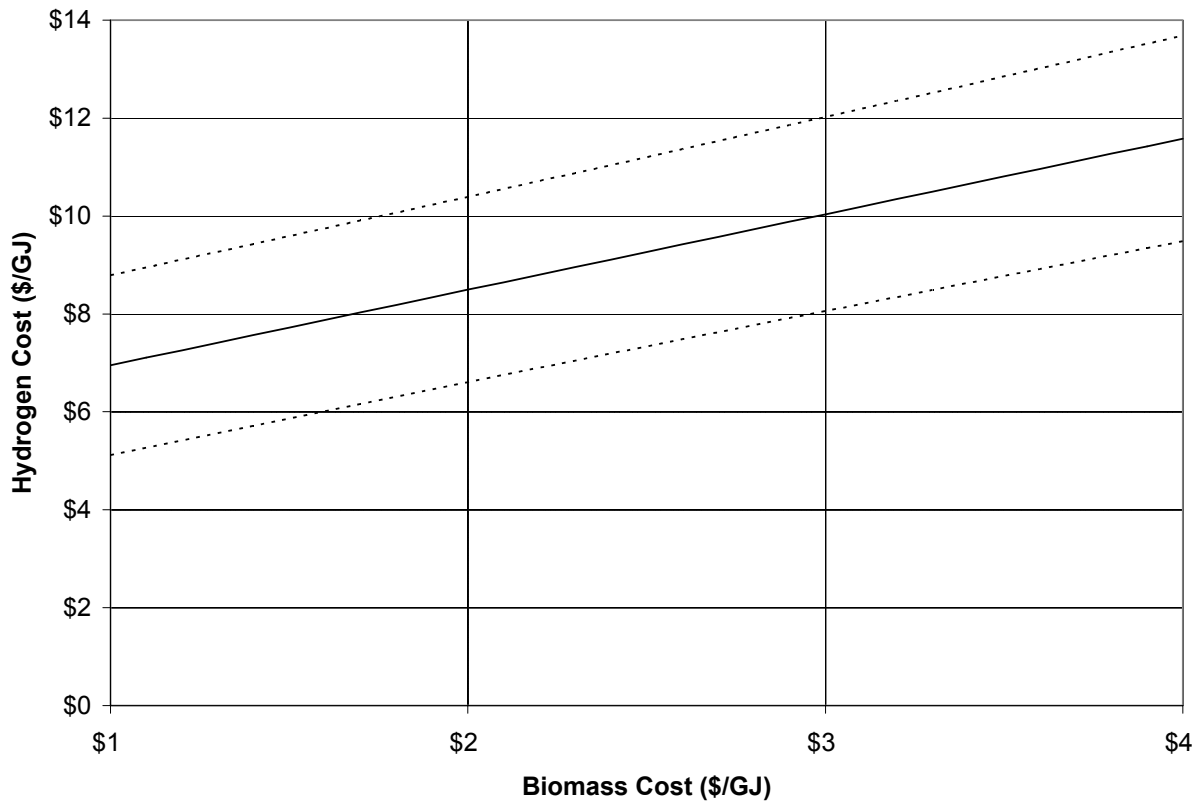


Figure 4 – Cost of Biomass Hydrogen Production

The future of biomass gasification depends on several factors. The cost and availability of feedstock is probably the most important. The Energy Information Administration forecasts that there will be about 250 million GJ of biomass available in 2020 in the U.S. at a price of \$1.20 per GJ, and 2 billion GJ at a price of \$2.40 (Hag 2002). Most of this comes from agricultural residues and wood mill residues, while some of it comes from energy crops. Energy crops would probably be less expensive in countries around the world where land and labor is less expensive.

Since biomass and coal gasification follow similar processes, biomass gasification could be improved by emerging coal technologies as well. Inorganic membranes could contribute to declining biomass costs in the future. Although biomass production could not fulfill all the world's potential hydrogen needs, it could possibly be a major contributor in agricultural regions around the world.

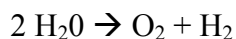
A carbon tax would have very little effect on the cost of biomass since less than 2 kg of carbon per GJ are released to the atmosphere during the life cycle of hydrogen production (in the cost calculation no cost is added for carbon). This occurs due to the energy involved in producing and harvesting the biomass. All of the carbon that is contained in biomass originally came from atmospheric carbon dioxide that was photosynthesized by the plant. Carbon dioxide from biomass gasification could possibly be sequestered, leading to negative carbon emissions of around 18 kg per GJ. If this proves to be relatively inexpensive, a carbon permit system with an emissions trading scheme could allow biomass producers to effectively get paid to sequester the carbon. This would only occur if the marginal cost of sequestering carbon from biomass production is less than or similar to the marginal cost for other methods.

Solid waste and local air pollutants from biomass are similar to other methods. The largest environmental effects are land use and transportation. If agricultural or wood residues are used, land use effects might not be significant. Energy crops, however, could take up vast amounts of land if they are implemented on a large scale. This could have dramatic environmental effects, especially if forest or other important ecosystems are destroyed to make room for cropland. Transportation of the high volume (per unit of energy) biomass could be even more fossil fuel intensive than coal, depending on how it is transported. If hydrogen fuel is used in the transportation it lowers the "life cycle efficiency" of the process, since some of the hydrogen output would be consumed during the process.

Even with the disadvantages, biomass gasification could prove an economically efficient way to produce energy without releasing greenhouse gasses to the atmosphere in many regions of the world. Sequestration could even allow biomass to effectively "offset" greenhouse emissions from other methods of hydrogen production or other sectors.

Electrolysis

Electrolysis is a very simple method of hydrogen that splits water into its elements – hydrogen and oxygen – by running a direct current between two electrodes in the water.



Electrolytic hydrogen production offers the potential to produce hydrogen with almost no pollution or greenhouse gas production. Most regions in the world have solar and/or wind resources to produce enough energy to fuel a significant part of energy demand. Nuclear energy can also produce carbon-free electricity that can be used to split water into hydrogen and oxygen.

Currently, most of the world’s electricity is produced by combusting fossil fuels. It is very unlikely that hydrogen produced by mostly fossil fuel electricity will ever be competitive with hydrogen produced directly from the fossil fuels since the efficiency of electricity production is much less than direct hydrogen production. Fossil fuel feedstocks will be more expensive per unit of hydrogen if they are combusted to create electricity first. Capital is required for both electricity production and electrolysis, and so capital costs are unlikely to offset the higher feedstock costs. Combustion would release more greenhouse gasses (due to lower efficiency) and local air pollutants into the atmosphere.

While there is some agreement on the efficiency of hydrogen production, capital costs are less certain. However, at current electricity prices feedstock costs make up about 80% of the total cost of hydrogen. Feedstock costs prove to be more important than capital cost in the cost of electrolysis. In the economic statistical analysis, published values were used from Kirk-Othmer 1995, Foster-Wheeler, Williams, Stiegel, and Rutkowski. Their estimates are shown in the following table after being restandardized for the common assumptions.

Source	C_{CAP} (\$-yr / GJ ¹⁵)	C_{OM} (\$ / GJ)	Eff (%)	P (ton C / GJ)
Kirk- Othmer	\$13.79	\$0.84	81%	
Foster-Wheeler	\$26.54	*	*	
Andreassen	\$27.32	*	*	
Williams	\$9.51	\$1.45	83%	
Statistics				
Mean	\$19.30	\$1.20	82%	0
Standard Dev	\$9.00	\$0.40	1 %	

Table 5 – Cost Estimates for Electrolytic Hydrogen Production

¹⁵ 1 cent / kWh = \$2.78 / GJ

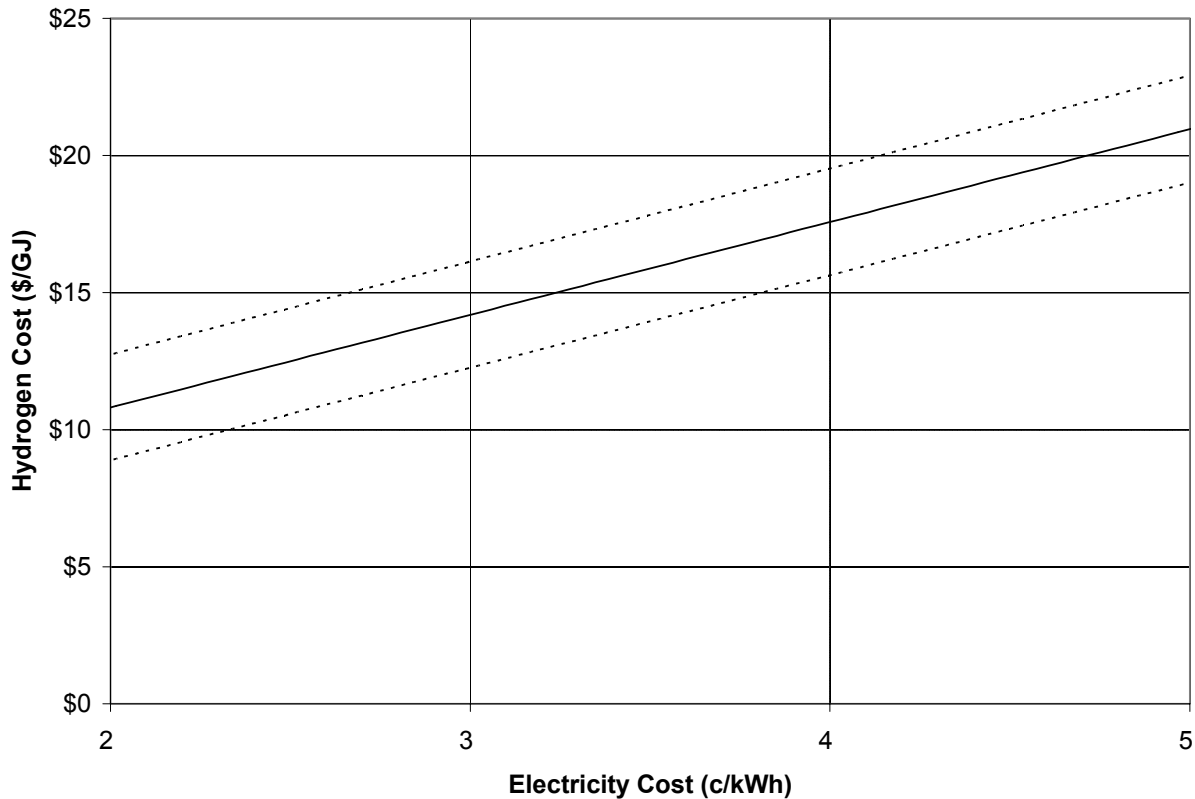


Figure 5 – Cost of Electrolytic Hydrogen Production

A quick look at the economics will reveal the difficulties involved in using electricity from renewable sources to produce hydrogen (for the purposes of this discussion, nuclear electricity is considered “renewable” since fuel is abundant and carbon dioxide is produced only in manufacturing the production equipment). Nonfeedstock costs are lower for SMR than electrolysis, and coal and biomass nonfeedstock costs are only slightly higher. In order for hydrogen from electrolysis to be competitive with hydrogen from fossil fuel decarbonization, feedstock costs must be in the same general range. This would require a significant increase in fossil fuel costs and/or a decrease in renewable electricity costs.

Since coal gasification is less efficient than electrolysis, it is possible for electricity to be slightly more costly than coal and still be competitive. However, coal at \$1.50 per GJ is equivalent to electricity at about a half penny per kilowatt-hour. Electricity currently costs ten times that amount. Capital costs could potentially make up some of that difference, but probably not all. In order for hydrogen from electricity to be competitive with hydrogen from coal (\$1.50 per GJ of coal, no carbon cost), renewable electricity must cost less than 2 ¢/kWh. The comparison between electricity and coal is important because coal has stable prices and is abundant in many parts of the world.

A carbon tax could help improve the competitiveness of hydrogen produced by renewable electrolysis since no carbon dioxide is released to the atmosphere during the life cycle. A carbon cost of \$50 per ton C would not affect the price of hydrogen produced by renewable electrolysis,

but SMR and coal produced hydrogen would increase by about \$1 and \$2 per GJ, respectively. If sequestration proves successful and costs remain less than \$50 per ton C as projected,¹⁶ this cost increase will probably not be enough to make electrolysis competitive with SMR or coal gasification on a large scale unless prices increase significantly.

Carbon sequestration is an unproven technology; if it turns out to be unsuccessful in the long run or prohibitively expensive, electrolytic hydrogen could possibly compete in the marketplace. Even without sequestration, a large carbon tax (greater than \$100 per ton), high natural gas prices (greater than \$5 per GJ), and cheap renewable electricity (less than \$0.03 per kWh) would be required for electrolytic hydrogen to be economically attractive on a large scale.

Even without the conditions noted above that are necessary for electrolytic hydrogen to be competitive with fossil fuel hydrogen on a large scale, it is possible that electrolysis will be competitive on a small scale. Small scale electrolysis plants can be implemented for costs similar to steam reforming plants, making it a potentially useful technology for small demonstration purposes. A hydrogen station in a city without hydrogen infrastructure could use electrolysis to avoid trucking compressed or liquid hydrogen. Electrolysis could prove to be a useful way to store electricity for time periods of hours to days. Hydrogen could be produced from off peak electricity and stored for use during peak hours. This could be economically attractive for base load plants such as nuclear or hydro; it would enable a plant to increase its peak load capacity without increasing its actual capacity.

The environmental effects of renewable electrolysis depend on what technique is used to produce the electricity. Nuclear electricity production produces radiation and radioactive solid waste, but no local air pollution or greenhouse gasses. The nuclear waste is a problem that has yet to find a politically and scientifically acceptable solution; all nuclear waste are stored in temporary locations. Uranium mining also contributes to environmental degradation caused by nuclear energy production, although the environmental footprint is probably much less than coal mining or gas drilling.

Other renewable electricity production methods produce almost no solid waste, local air pollution, or greenhouse gasses. Solar and wind electricity production both have environmental land use effects. Wind turbines can harm the beauty of a landscape and create noise for nearby residents. If the turbines are placed in important habitat for birds, bird kills can also be a problematic effect of wind energy. Wind turbines have a small footprint on land. Solar panels have a larger footprint, unless panels are constructed on top of buildings or structures that serve another purpose. Overall, the environmental effects of renewable electrolysis are probably much less degrading than other hydrogen production methods.

Thermochemical

¹⁶ Literature review done by Padre & Putsche 1999, also Williams 1995, show carbon sequestration costs (including removal, transportation, and storage of CO₂) consistently estimated at under \$50 per ton C for hydrogen produced by gas and coal.

Since thermochemical hydrogen production is further from commercialization, a literature review with statistical analysis was not performed. However, a discussion of the potential of thermochemical production (which could be done using nuclear or solar heat) is important to understand its potential role in future hydrogen production.

The role of thermochemical hydrogen production is probably similar to electrolysis. It can only become competitive if sequestration proves very costly or impossible, a large carbon tax is implemented (probably greater than \$100 per ton), natural gas prices increase to more than \$5 per GJ, and biomass production proves unsuccessful on a large scale. Hydrogen produced by nuclear thermochemical process costs are unlikely to go much below \$14 per GJ (Williams 2003). This includes about \$8 per GJ for the nuclear heat and \$6 per GJ for the capital and operational costs of producing the hydrogen. Solar heat costs are likely to be higher.

Another way of looking at a lower minimum of the cost of nuclear thermochemical hydrogen production is to observe the future costs of nuclear electricity generation. The process requires a high temperature reactor, and efficiency is around 50% (Shultz 2002). This is similar to efficiency of electricity production in a high temperature reactor. If we make the assumption that the cost of the turbines used to generate electricity is less than or equal to the costs of the thermochemical hydrogen production process, we can see electricity costs as a lower limit of hydrogen costs.

Nuclear electricity costs for a plant built today are around 6.7 cents per kWh (MIT 2003). This is equivalent to \$18.60 per GJ. Assumptions including reduction in construction time, lower maintenance costs, and a reduction in capital costs to levels of coal and gas plants show that a minimum cost would be about 4.2 cents per kWh. This is equivalent of about \$11.70 per GJ, and is a very optimistic estimate.

At a minimum of \$11.70 per GJ, thermochemical production of hydrogen is in a similar situation to renewable electrolysis production. It would require sequestration to be costly or impossible, a high carbon tax, and high natural gas prices in order to be competitive with fossil fuel production.

Conclusion

From the economic analysis done, it can be estimated what the future of hydrogen production might hold if the cost of fuel cells and other hydrogen consumption technologies creates a competitive market for hydrogen fuel. These estimates are based on the cost of hydrogen production and the different feedstocks that create hydrogen.

In the near term, it is likely that steam reforming of natural gas will dominate in areas where natural gas is readily available. Costs of production are well known, although future gas prices are not. However, even if the levelized gas price over the economic lifetime of the plant (20 years for these estimates) averages \$5 per GJ (much higher than is predicted by EIA), costs of hydrogen will be around \$8 per GJ. In the near term, this is likely to be the least expensive method of hydrogen production.

Coal gasification can fulfill near term demand for hydrogen in regions that are coal dependant and/or do not have natural gas readily available. Costs are relatively well known and feedstock costs are very stable. The cost of hydrogen is unlikely to be much more than \$10 per GJ. Coal gasification could also fulfill mid to long term demand for hydrogen in many parts of the world. If natural gas becomes costly in any particular area, coal could be a competitive alternative. Feedstock costs will likely remain stable in the long term, and supplies will last 200 years at current production rates. Costs of production will probably come down in the long term as well, making \$10 with sequestration a reasonable estimate. However, if sequestration is unsuccessful and a carbon tax is levied, \$100 per ton would increase the cost of hydrogen from coal gasification by almost \$4 per GJ.

Biomass gasification is likely to play some role in mid and long term hydrogen production. Resources are abundant in some regions, and negligible carbon emissions mean no risk of carbon taxes eliminating the competitiveness of biomass. In regions where biomass can be purchased for \$2 per GJ, hydrogen can be produced competitively with fossil fuels.

Each of the methods above has some uncertainty involved in the long term. Natural gas prices make steam reforming uncertain. The potential for a large carbon tax and costly sequestration methods could hurt coal gasification in the long run. Biomass is dependent on regional resource availability and land use constraints, so it probably cannot fulfill world demand if hydrogen becomes the fuel of choice in the future. If all of these possibilities occur, there is the potential for renewable electrolysis or thermochemical hydrogen production to become competitive with other methods. Large scale implementation of electrolysis and thermochemical hydrogen production, however, appears unlikely unless natural gas prices triple, carbon sequestration is unsuccessful (or extremely expensive), a significant carbon tax is levied, and biomass constraints (land use, high cost) are in place. Without these conditions, however, electrolysis will probably be confined to demonstration projects and temporary storage of off peak electricity.

Appendix – Figures including Costs for all Production Methods

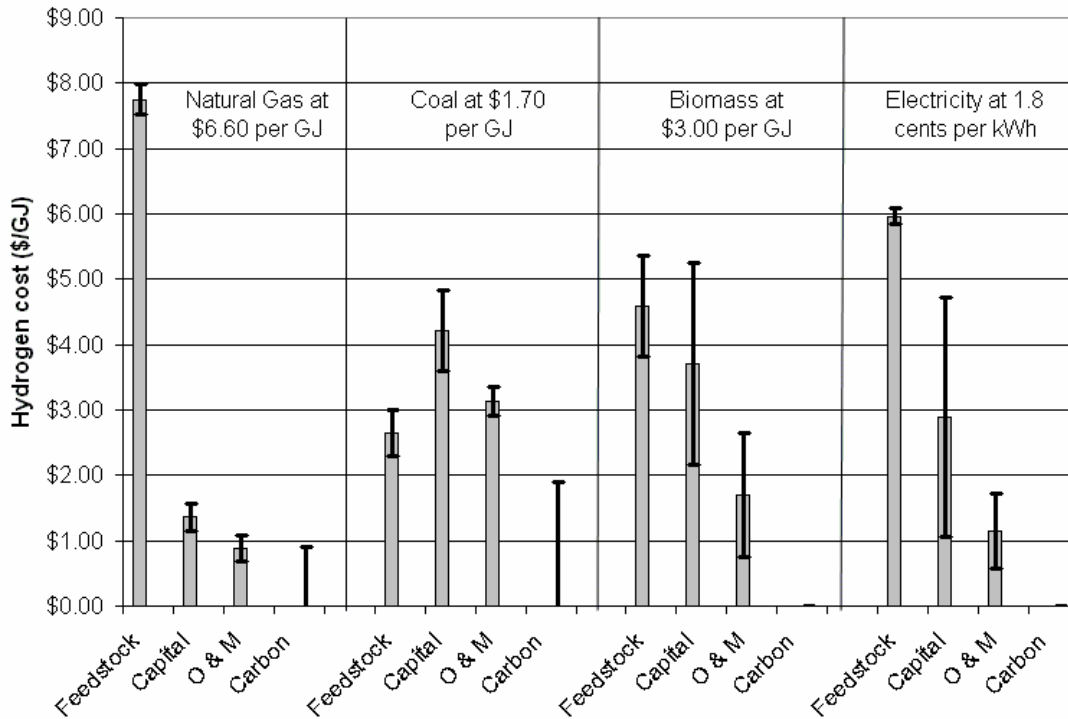


Figure A1. Different Methods of Producing Hydrogen for \$10 / GJ Broken into Components, with Uncertainty (using utility interest rates)

Figure A1 shows the costs of producing hydrogen at \$10 / GJ by four different feedstocks. While carbon costs are not included in the base price of the hydrogen, a \$50 per ton cost of carbon is included in the uncertainty bars. By observing this plot, one can see the relative uncertainties of each method of production. Feedstock costs were chosen to make the production cost of the hydrogen equal to \$10 per GJ. The uncertainty in the cost per unit of feedstock is not considered in this plot; feedstock uncertainty is calculated based on uncertainty in efficiency of production.

The uncertainty in natural gas comes mostly from a possible carbon cost, which might be mitigated if sequestration proves less expensive than \$50 per ton. Long-term prices of natural gas, as well as short term price volatility, remain uncertain. This uncertainty is not reflected in the figure. Capital cost and potential carbon cost remain the dominant uncertainties for coal production; coal prices have been stable in the past. Uncertainty in biomass production comes from all sectors (except carbon cost since biomass gasification produces no significant carbon emissions), although capital cost uncertainty contributes the most. Biomass feedstock costs are not known accurately. Capital cost uncertainty dominates electrolysis hydrogen production. Although uncertainty in efficiency is low, it should be noted that the electricity cost required to produce hydrogen at \$10 per GJ (1.8 cents / kWh) is less than half of the current wholesale price of electricity.

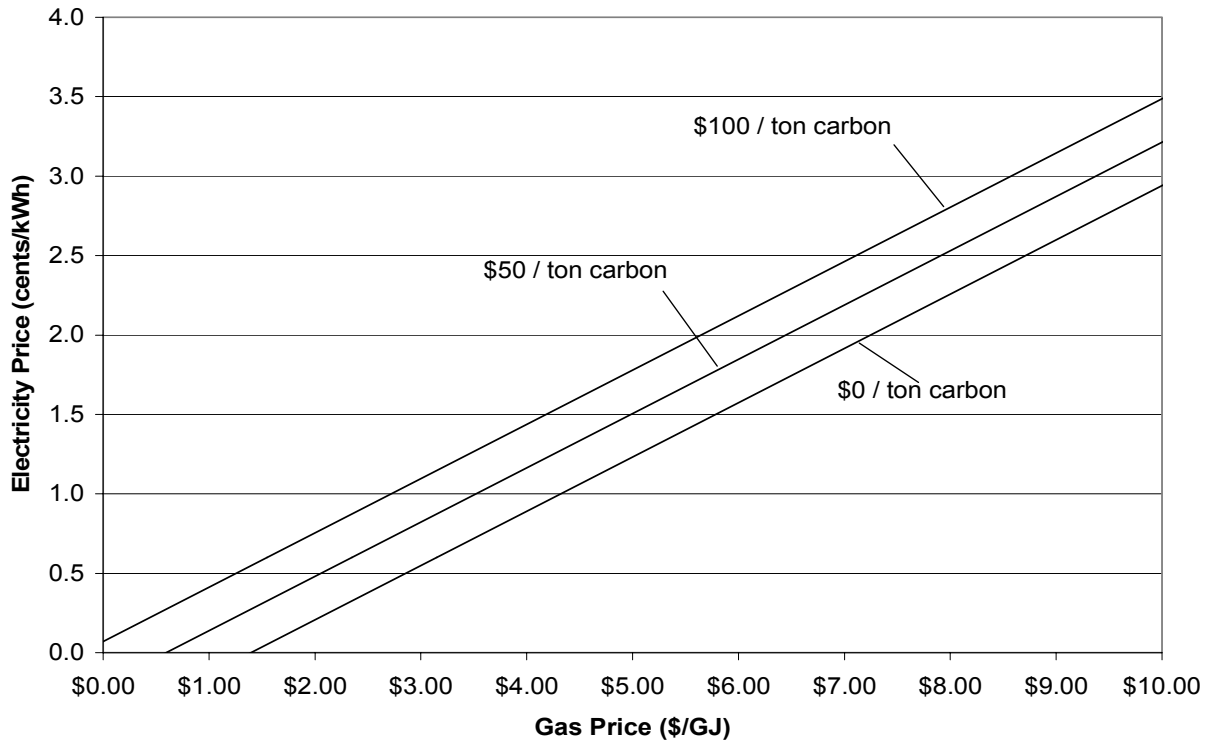


Figure A2 – Break-even Feedstock Costs of Gas and Electricity

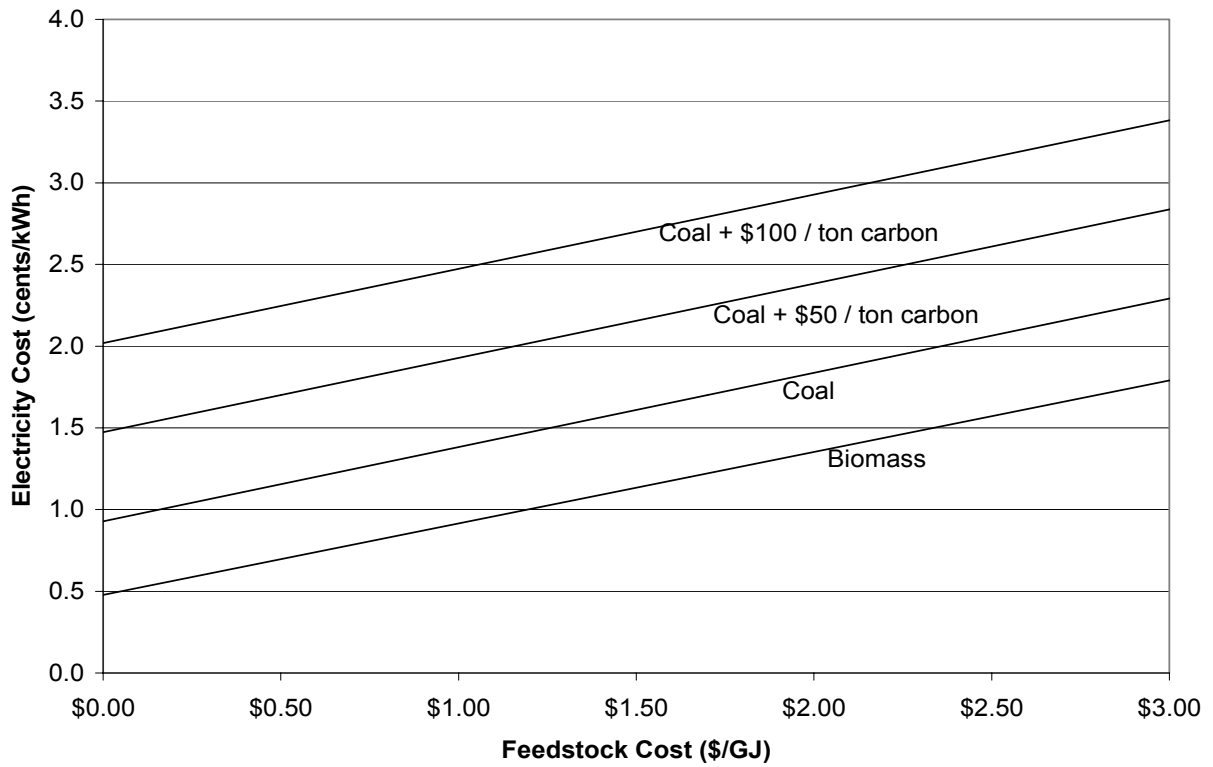


Figure A3 – Break-even Feedstock Costs of Coal, Biomass, and Electricity

Figures A2 and A3 show the break-even costs of coal, biomass, gas, and electricity. The lines on these plots show the feedstock costs at which production costs are equivalent for the production methods considered. Carbon costs of \$50/ton and \$100/ton are considered. Carbon costs do not affect the production cost of hydrogen produced by biomass or electricity (it is assumed to be renewable or nuclear).

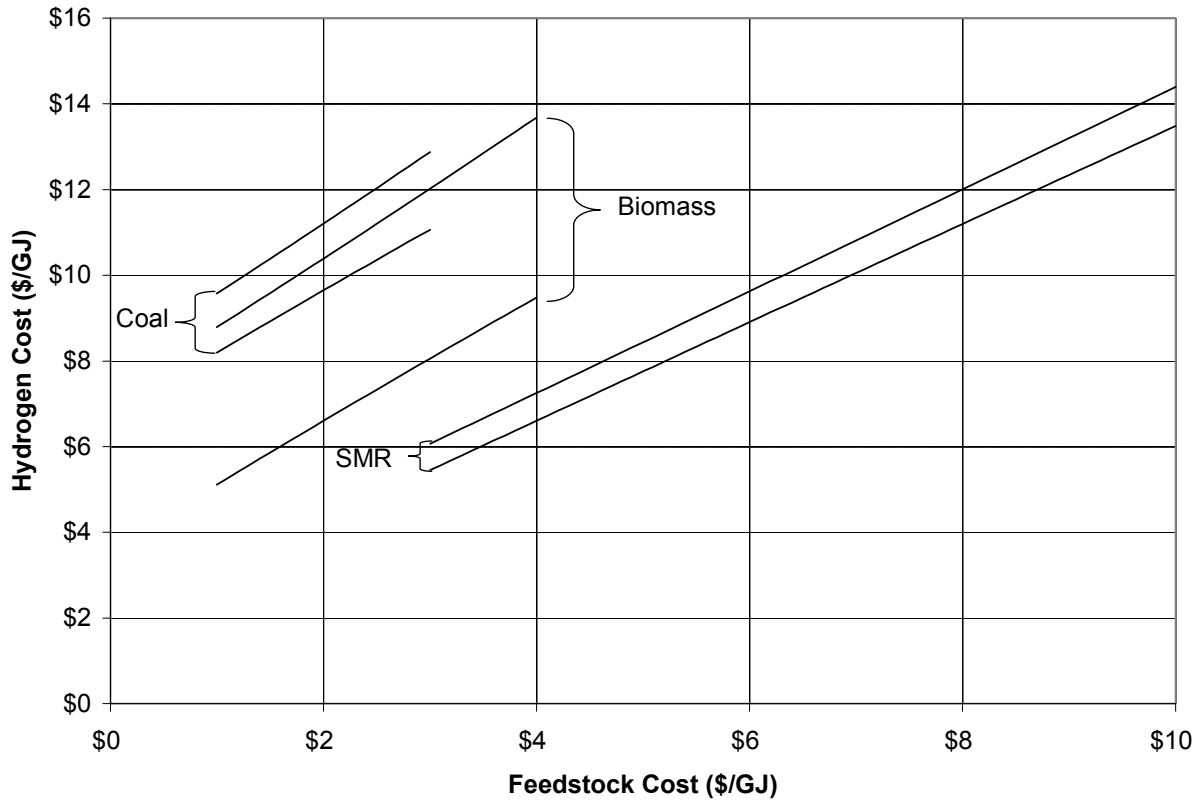


Figure A4 – Hydrogen Cost vs. Feedstock Cost for Different Production Methods – Utility Rates on Capital

Figures A4 and A5 display the cost of producing hydrogen based on the cost of different feedstocks. It also shows the relative uncertainty involved in the cost of production. Since the cost of electricity is not usually expressed in terms of \$/GJ, the comparison to cents / kWh is included. 2 cents / kWh is roughly equivalent to \$5.50 per GJ. For example, at a cost of 2 cents per kWh for electricity, hydrogen could be produced at \$9-\$14 per GJ. Carbon costs are not included in this figure. To consider carbon costs, each range would be increased by a constant value. See Table X for increases to hydrogen production cost with a \$50 per ton cost of carbon.

For all figures and calculations, a CRF of 0.15 is used for public utility facilities and a CRF of 0.20 is used for private facilities to reflect the higher interest rates and cost of capital associated with a private facility.

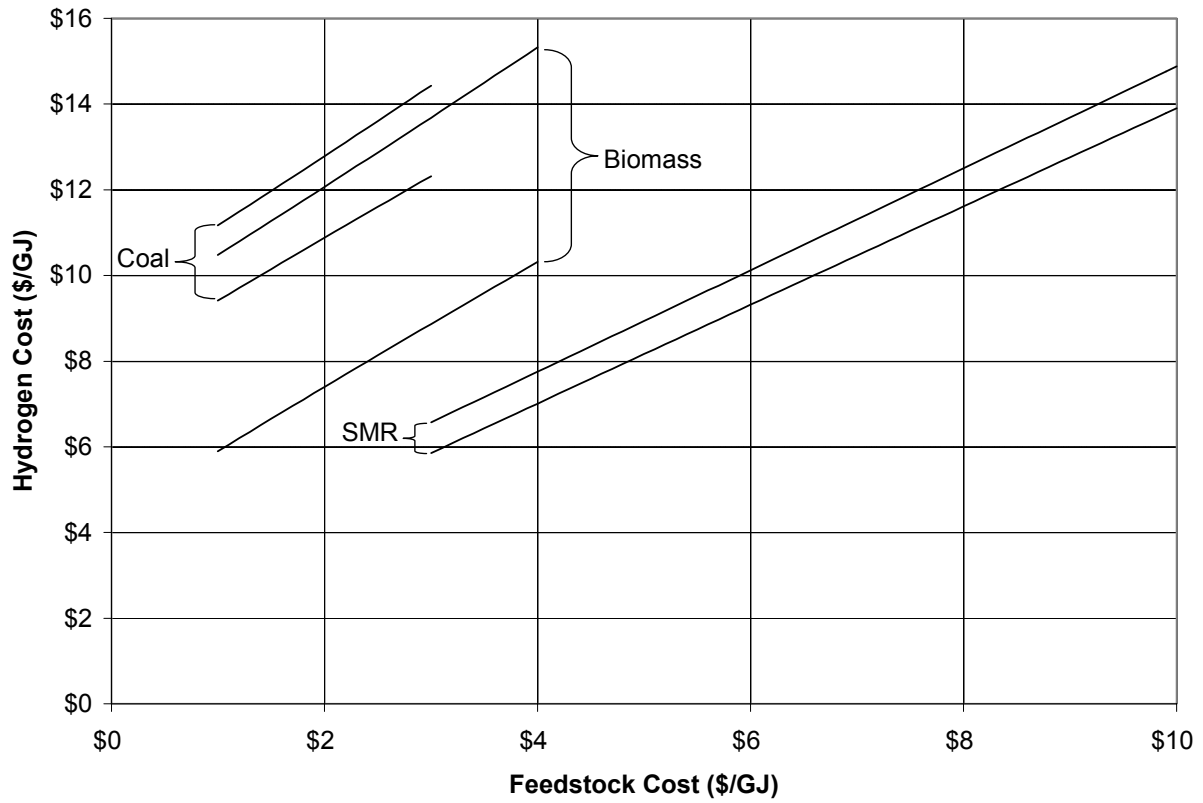


Figure A5. Hydrogen Cost vs. Feedstock Cost for Different Production Methods – Private Rates on Capital

	Lifecycle CO2 generation (kg C / GJ) ¹⁷	Cost increase if carbon costs \$50/ton (\$ / GJ hydrogen)	CO2 emissions per unit of transport service provided (g C/km of car driving) ¹⁸
Hydrogen from natural gas	18	\$0.90	25
Hydrogen from coal	38	\$1.90	47
Hydrogen from renewable or nuclear electricity	0	\$0	4
Hydrogen from biomass	2	Negligible	6
Reformulated gasoline	23	\$1.10	72

Table A1 – Carbon Emissions and Costs for Hydrogen Production Methods

Hydrogen (\$/GJ)	Natural Gas (\$/GJ)	Coal (\$/GJ)	Electricity (\$/kWh)	Biomass (\$/GJ)
\$6	\$3.15(± 0.25)	N/A	\$0.006 (± 0.006)	N/A
\$8	\$4.90 (± 0.3)	<\$0.80	\$0.012 (± 0.006)	\$1.65 (± 1.25)
\$10	\$6.60 (± 0.3)	\$1.70 (± 0.5)	\$0.017 (± 0.006)	\$3.00 (± 1.3)
\$15	\$10.90 (± 0.4)	\$5.00 (± 0.8)	\$0.032 (± 0.006)	\$6.35 (± 1.65)
\$20	\$15.15 (± 0.55)	\$8.30 (± 1.2)	\$0.047 (± 0.006)	\$9.65 (± 2.05)

Table A2 – Feedstock Costs Required to Produce Hydrogen at Different Costs (with uncertainty) – Utility Interest Rates on Capital

Hydrogen (\$/GJ)	Natural Gas (\$/GJ)	Coal (\$/GJ)	Electricity (\$/kWh)	Biomass (\$/GJ)
\$6	\$2.80 (± 0.3)	N/A	N/A	N/A
\$8	\$4.50 (± 0.3)	N/A	\$0.009 (± 0.008)	N/A
\$10	\$6.15 (± 0.35)	\$0.75 (± 0.55)	\$0.015 (± 0.008)	\$2.15 (± 1.55)
\$15	\$10.45 (± 0.45)	\$4.10 (± 0.8)	\$0.029 (± 0.008)	\$5.55 (± 1.75)
\$20	\$14.75 (± 0.55)	\$7.35 (± 1.15)	\$0.044 (± 0.008)	\$8.85 (± 2.15)

Table A3 – Feedstock Costs Required to Produce Hydrogen at Different Costs (with uncertainty) – Private Interest Rates on Capital

¹⁷ Lifecycle carbon emissions from Williams 1996. The figures do not include carbon released during production of equipment used to produce the hydrogen, but do include carbon released during production of the feedstock. 3.6 kg C/GJ subtracted from each value that was included in Williams (1996) for electricity costs at a hydrogen refueling station (Williams 1995).

¹⁸ Williams 1996. Renewable electricity includes identical carbon refueling costs to other production methods since refueling might be done using non-renewable electricity

Tables A2 and A3 show the potential feedstock costs required to produce hydrogen at various costs. Uncertainty is included as a 90% confidence interval. Carbon costs are not included, which would require feedstock costs of natural gas to be about \$0.80 less expensive and coal to be about \$1.20 less expensive per \$50/ton carbon cost (to produce hydrogen at the same price). For specific information on carbon costs, see Table A1.

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