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Hydrogen Pathways: Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Seven Hydrogen Production, Delivery, and Distribution Scenarios

Technical Report
NREL/TP-6A1-46612
September 2009

Mark Ruth
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Alliance Technical Services, Inc.

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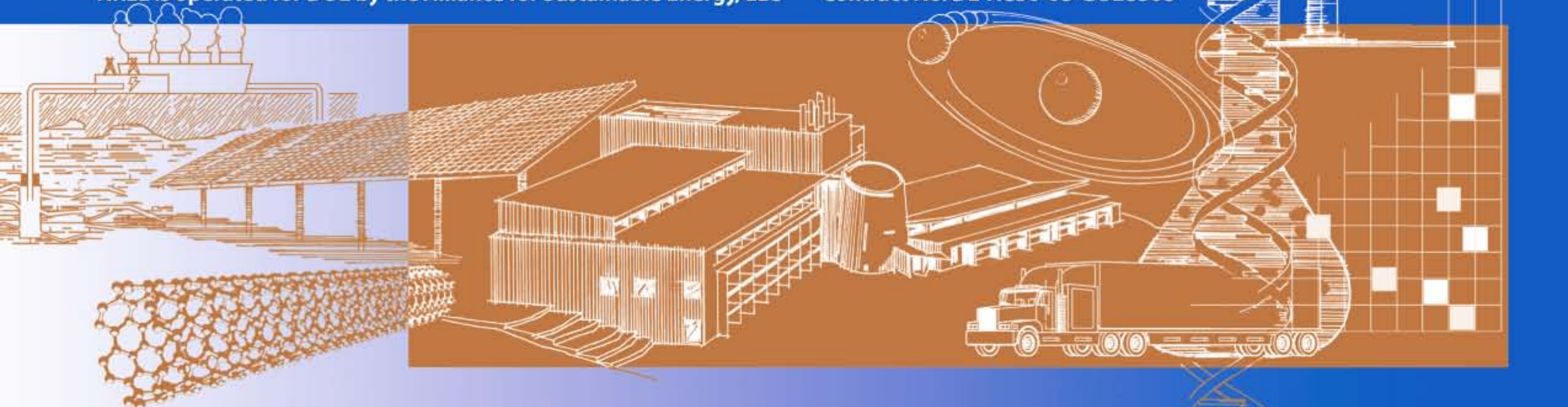

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The FreedomCar and Fuel Partnership's Fuel Pathway Integration Technical Team (FPITT) identified the need to examine concurrently the cost and well-to-wheels energy use and emissions of various hydrogen production and delivery pathways and to carefully document the key parameters of the analysis. They reviewed the results of the study both for content and for presentation and provided many helpful pointers. In addition, they performed the gap analysis that identified issues reported in Section 11. Current and past members of the team include Don Gardner and Matt Watkins (Exxon Mobil Corporation); Graham Moore, Bhaskar Balasubramanian, and Jonathan Weinert (Chevron Corporation); Jim Uihlein and Maria Curry-Nkansah (BP America Inc.); Ed Casey (Conoco-Phillips Company); Henk Mooiweer, Karel Kapoun and CJ Guo (Shell Hydrogen, LLC); Johanna Levene, Todd Ramsden, and Darlene Steward [National Renewable Energy Laboratory (NREL)]; and Fred Joseck [Department of Energy (DOE)].

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1.0 Executive Summary

The United States (U.S.) Department of Energy's (DOE) Fuel Cell Technologies Program (the Program) has identified a need to understand the cost, energy use, and emissions tradeoffs of various hydrogen production, delivery, and distribution options under consideration for fuel cell vehicles. The Program has been researching and developing hydrogen and fuel cell technologies because they have the potential to reduce U.S. dependence on foreign crude oil, diversify energy sources, decrease greenhouse gas (GHG) emissions, and provide domestic economic growth.

This document reports the levelized cost in 2005 U.S. dollars, energy use, and GHG emission benefits of the seven hydrogen production, delivery, and distribution pathways reported in Table 1.0.1. Current technology status is reported for each pathway and refers to technology that has been demonstrated at the bench scale at a minimum. All the technology options have potential for research and development (R&D) improvements.

Table 1.0.1. Seven Hydrogen Production, Delivery, and Distribution Pathways

	Feedstock	Central or Distributed Production	Carbon Capture and Sequestration	Delivery Method	Hydrogen Distribution
1	Natural Gas	Distributed	No	Not applicable	350 bar compressed gas
2	Electricity	Distributed	No	Not applicable	350 bar compressed gas
3	Biomass	Central	No	Liquid H_2 in trucks	350 bar compressed gas
4	Biomass	Central	No	Gaseous H_2 in pipelines	350 bar compressed gas
5	Natural Gas	Central	No	Gaseous H_2 in pipelines	350 bar compressed gas
6	Wind Electricity	Central	No	Gaseous H_2 in pipelines	350 bar compressed gas
7	Coal	Central	Yes	Gaseous H_2 in pipelines	350 bar compressed gas

Plausible production scenarios for mature hydrogen transportation-fuel markets combined with market penetration of hydrogen fuel cell vehicles were used in this analysis. They are not transition scenarios where equipment may not be fully utilized. The assumptions used in the analysis reflect current technology: technology that has been developed to the bench scale (at a minimum) but has not necessarily been demonstrated at commercial scales.

The pathways are described in detail, and system-level parameters are reported and referenced. Availability, cost, and characteristics of necessary resources are reported, as is the current status of supporting infrastructure. The sensitivities of each pathway's cost, pathway energy use, well-to-wheels energy use, and well-to-wheels emissions to many of the primary parameters are reported as an aid in understanding and assessing technology needs and progress, potential environmental impacts, and the energy-related economic benefits of various options. Some of the results are compared with those of current gasoline, diesel, and E85 vehicles including gasoline hybrid electric vehicles.

The Hydrogen Macro-System Model (MSM) was used to analyze the pathways by linking the H2A Production Model, the Hydrogen Delivery Scenario Analysis Model (HDSAM), and the Greenhouse Gas, Regulated Emission, and Energy for Transportation

(GREET) Model. The MSM links those models so a single run utilizes the capabilities of each and ensures consistency among them. Also, the MSM is available to the public and enables users to analyze the pathways and complete sensitivity analyses that are not reported in this document.

The analysis has been reviewed by the FreedomCar and Fuel Partnership's Fuel Pathway Integration Technical Team (FPITT), which includes members from DOE, national laboratories, and energy companies (BP America Inc., Chevron Corporation, Conoco-Phillips Company, Exxon Mobil Corporation, and Shell Hydrogen, LLC).

This report compares fuel cost and well-to-wheel (WTW) emissions among multiple hydrogen fuel pathways and benchmarks those results against current gasoline and diesel fuel. Figure 1.0.1 illustrates six of the seven hydrogen pathways have GHG emissions that are lower than all the crude oil–based pathways and E85 generated from corn grain. All seven hydrogen pathways use less petroleum per mile traveled than the other pathways because of the increased efficiency fuel cells provide. Distributed electrolysis has high GHG emissions and high petroleum use when compared with the other hydrogen pathways because of the electricity grid mix. The coal pathway has low GHG emissions because 90% of the carbon dioxide generated in the hydrogen production facility is sequestered.

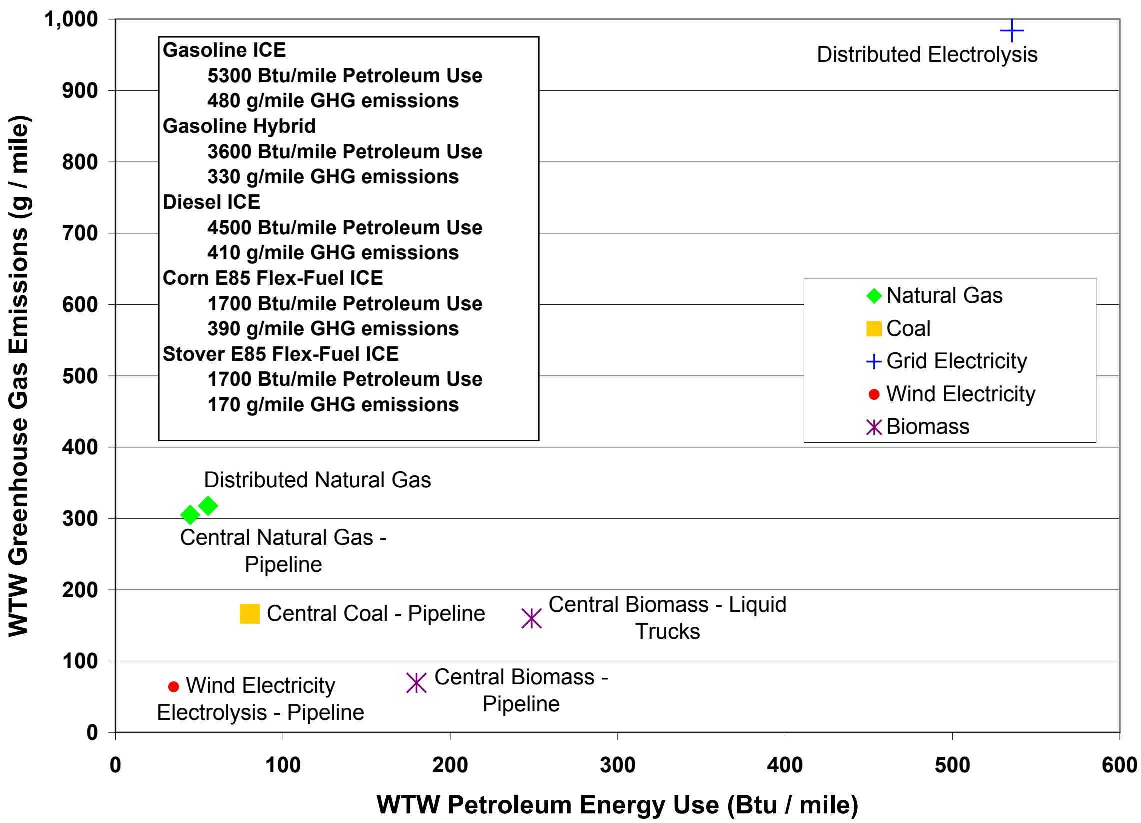


Figure 1.0.1. Comparison of pathways' petroleum use and greenhouse gas emissions

2.0 Introduction

2.1 Document's Intent

The U.S. DOE has identified a need to understand the lifecycle cost, energy use, and emissions tradeoffs of various hydrogen production and delivery pathways under consideration to enable a transition from a hydrocarbon-based economy to a hydrogen-and-electricity-based economy.

Feedstock, capital, capacity, and utility-sensitivity analyses on the cost of delivered hydrogen have been conducted for seven potential hydrogen production and delivery pathways using MSM. This analysis will aid in understanding and assessing technology needs and progress, potential environmental impacts, and the energy-related economic benefits of various hydrogen supply and demand pathways.

The objectives of this analysis were:

- Improved understanding of the primary parameters that affect the levelized cost, WTW fossil energy requirements, and WTW emissions of each of the seven pathways analyzed
- Referencing those parameters and performing an initial sensitivity analysis around them
- Giving industry (through FPITT) the opportunity to review those primary assumptions and provide feedback
- Completing a gap analysis around the parameters to identify possible production, delivery, and distribution issues.

This document reports a greater level of detail than analyses that show only the full pathway results (or maybe have a single break-point in the pathway), but it reports little information at the unit-operation level. Parameters that are expected to have major effects on the results are reported at the unit-operation level.

2.2 Market State and Technology Development Assumptions

The pathways analyzed are intended to be plausible production scenarios for mature technologies with full deployment of a regional hydrogen fueling network. They are not transition scenarios where equipment may not be utilized fully, nor are they technology validation activities where production, delivery, and vehicle costs are higher due to first-of-a-kind plants and low production levels of vehicles. Specifically, today's technical status is extrapolated to a scenario where 50% of the vehicles are fueled by hydrogen in a city with the area (553 mi^2) and population (1,247,364) of Indianapolis, Indiana, and all equipment is fully utilized for its lifetime. Production facilities are not scaled to meet demand; instead, necessary demand from other nearby communities is assumed available so the facilities are kept at the H2A-defined natural scale.

Costs, energy use, and emissions estimates in this study are based on current technologies, and costs are reported in 2005 U.S. dollars. In this analysis, "current technology" refers to technology that is available currently at the bench scale—not necessarily technology that has been demonstrated at production scales. Thus, assumptions about larger-scale performance and equipment requirements and costs were necessary.

Designs and costs in this analysis do not include additional requirements of first-of-a-kind or one-of-a-kind technologies. In many cases, first-of-a-kind technologies require safety factors, instrumentation, and contingencies that are not necessary later in the development process. Those additional costs are not included in this analysis because they are difficult to account for and because they are not well understood. Instead, technology designs and costs are based on "n^{th} plant" techniques (techniques which inherently assume that the technology is mature and do not include additional contingency, capital costs, and yield loss necessary for of first-of-a-kind plants cost estimation).

2.3 Analysis Boundaries

WTW energy use and emissions are assessed for each pathway using the GREET model. Included in the assessment are feedstock recovery, transportation, and storage; fuel production, transportation, storage, and distribution; and vehicle operation. The reported energy use includes both direct and indirect use of raw materials (natural gas, coal, and petroleum). For feedstock recovery, direct use of raw materials involves those used to recover and refine the feedstock, and indirect use of raw materials involves those needed to produce electricity and materials that are used directly.

Energy used and emissions generated to produce the vehicles, produce the equipment required to recover the feedstock, produce the fuel, etc., are not included. The GREET 2 series is capable of including energy and emissions for production, maintenance, and disposal of the vehicles, but it was not used in this analysis.

2.4 Pathways

The seven pathways included in this analysis are shown in Table 2.4.1.

Table 2.4.1. Seven Hydrogen Production, Delivery, and Distribution Pathways

	Feedstock	Central or Distributed Production	Carbon Capture and Sequestration	Delivery Method	Hydrogen Distribution
1	Natural Gas	Distributed	No	Not applicable	350 bar compressed gas
2	Electricity	Distributed	No	Not applicable	350 bar compressed gas
3	Biomass	Central	No	Liquid H_2 in trucks	350 bar compressed gas
4	Biomass	Central	No	Gaseous H_2 in pipelines	350 bar compressed gas
5	Natural Gas	Central	No	Gaseous H_2 in pipelines	350 bar compressed gas
6	Wind Electricity	Central	No	Gaseous H_2 in pipelines	350 bar compressed gas
7	Coal	Central	Yes	Gaseous H_2 in pipelines	350 bar compressed gas

For convenience, the pathways are identified throughout this report using the feedstock and the delivery method; for example: Pathway 1 is referred to as the distributed natural gas pathway, Pathway 2 is referred to as the distributed electricity pathway, Pathway 3 is the central biomass with liquid delivery pathway, and Pathway 4 is the central biomass with pipeline delivery. The product from each of the pathways is the same: gaseous hydrogen with sufficient purity for dispensing to a hydrogen fuel-cell vehicle, compressed to 6,250 psi (430 bar) for on-board storage at 5,000 psi (350 bar).

Each pathway description below includes a flowchart showing the major subsystems of the hydrogen production and delivery pathway and the amount of energy required for each. Not included in these flowcharts are the energy requirements to supply the feedstock for hydrogen production; the energy use for feedstock production and delivery is included in the full WTW results presented in Section 9.0.

Pathway 1—Distributed Natural Gas

In the distributed natural gas pathway, hydrogen is produced from natural gas at the hydrogen refueling site using a 1,500 kg H_2/day steam methane reformer (SMR) with water-gas shift (WGS). Pressure swing adsorption (PSA) is used to obtain the required hydrogen purity. The hydrogen is then compressed to 6,250 psi (430 bar) and stored on-site prior to dispensing as a gaseous fuel to the 5,000-psi (350 bar) vehicle fuel tank. The flow diagram in Figure 2.4.1 shows the fuel production and delivery components of the distributed natural gas pathway and the energy balance for the major hydrogen-related subsystems, and the pathway is on a 1-gallon gasoline equivalent (gge) basis. The production technologies are detailed in Section 5.0, and the forecourt technologies are detailed in Section 6.0.

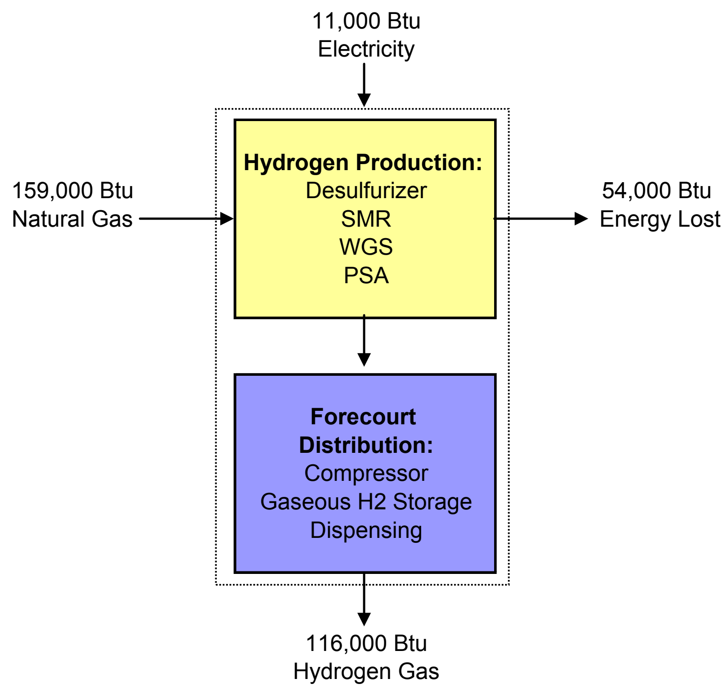


Figure 2.4.1. Flow diagram and energy balance of distributed natural gas pathway

Values may not sum to zero due to rounding.

This pathway is considered among the least costly in the near-term to establish early market refueling capability (Greene et al., 2008). In fact, several stations utilizing this pathway have already been installed throughout the world as seen in Table A.1., Appendix A (Fuel Cells 2000, 2009).

Pathway 2—Distributed Electricity

In the distributed electricity pathway, hydrogen is produced from water at the hydrogen refueling site using a 1,500 kg H_2/day grid-powered electrolyzer. A scrubber is used to obtain the required hydrogen purity. The hydrogen is then compressed to 6,250 psi (430 bar) and stored on-site prior to dispensing as a gaseous fuel to the 5,000-psi (350 bar) vehicle fuel tank. The flow diagram in Figure 2.4.2 shows the fuel production and delivery components of the distributed electricity pathway and the energy balance for the major hydrogen-related subsystems, and the pathway is on a 1-gge basis. The production technologies are detailed in Section 5.0, and the forecourt technologies are detailed in Section 6.0.

This pathway offers an alternative to distributed natural gas, particularly in areas where clean, inexpensive electricity is available.

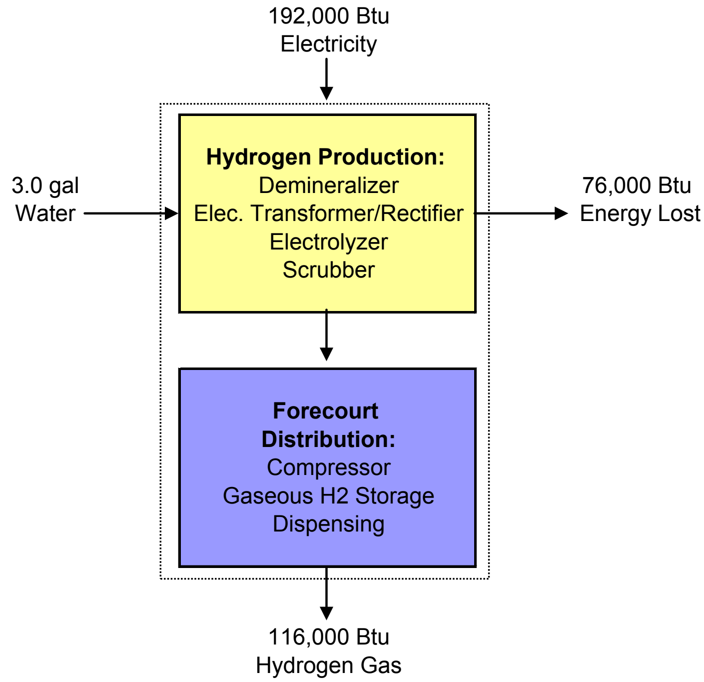


Figure 2.4.2. Flow diagram and energy balance of distributed electricity pathway

Values may not sum to zero due to rounding.

Pathway 3—Central Biomass–Liquid Truck Delivery

In the central biomass–liquid truck delivery pathway, woody biomass (poplar) within a 50-mile radius is transported via truck to a central hydrogen production facility with a design capacity of 2,000 bone dry metric ton/day biomass (~155,000 kg H_2/day). An indirectly heated biomass gasifier converts the biomass to a biogas, which is then converted to hydrogen using a catalytic SMR with WGS. PSA is used to obtain the required hydrogen purity. The hydrogen is liquefied, stored as necessary, and delivered via tube trailer to a 1,500 kg/day forecourt hydrogen refueling station, where it is vaporized, compressed to 6,250 psi (430 bar), and dispensed as a gaseous fuel to the 5,000-psi (350 bar) vehicle fuel tank. The flow diagram in Figure 2.4.3 shows the fuel production and delivery components of the central biomass–liquid truck delivery pathway and the energy balance for the major hydrogen-related subsystems, and the pathway is on a 1-gge basis. The production technologies are detailed in Section 5.0, and the delivery technologies are detailed in Section 6.0.

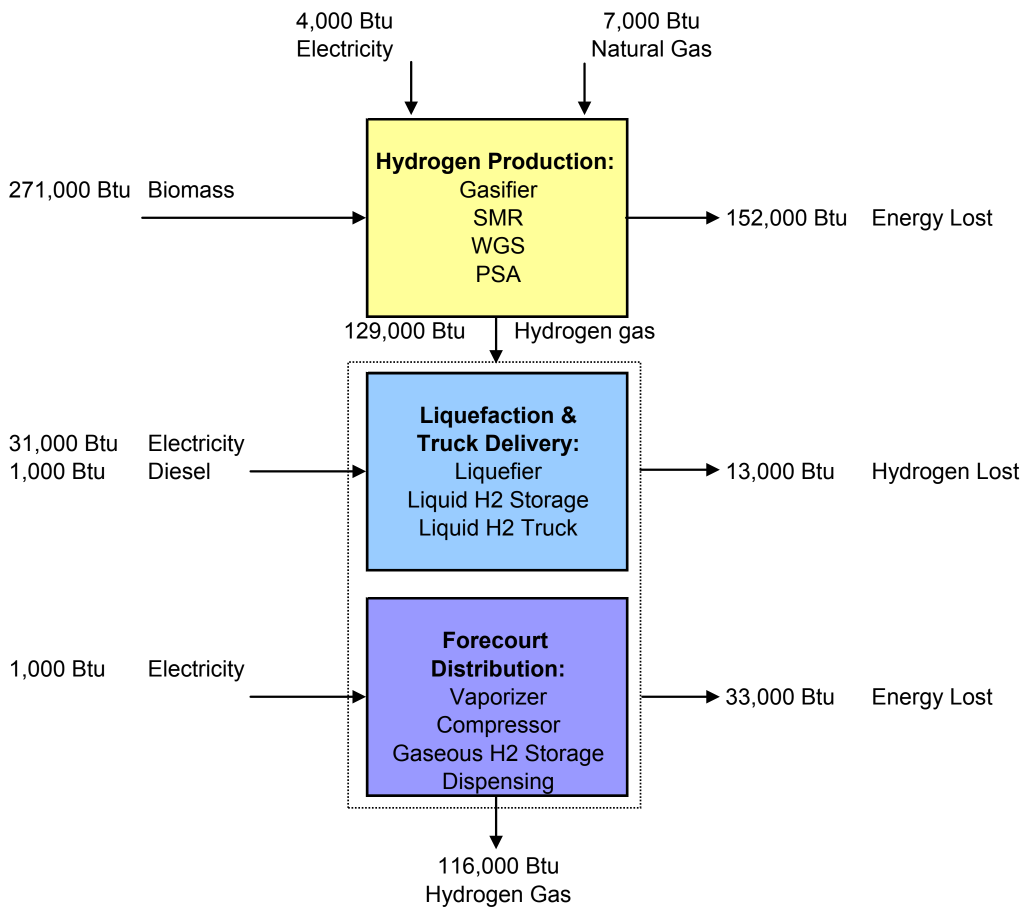


Figure 2.4.3. Flow diagram and energy balance of central biomass–liquid truck delivery pathway

Values may not sum to zero due to rounding.

The biomass pathways were selected for this study because of their potential to provide hydrogen with low- or zero-carbon dioxide (CO_2) emissions and because there are feedstock availability, delivery, and handling issues that are unique to biomass. These pathways are also more dependent on regional resource availability and costs than other pathways; while sensitivities to regionality are outside the scope of this study, they may be determined as more data become available.

This is the only pathway studied that utilizes liquid hydrogen delivery. Comparison with the central biomass–pipeline delivery pathway offers insights to the advantages, disadvantages, and issues associated with liquid hydrogen delivery. It also offers the opportunity to examine the sensitivity of both delivery options (liquid truck and gaseous pipeline) with parameters such as delivery distance and degree of hydrogen penetration in the vehicular fuel market.

Pathway 4—Central Biomass–Pipeline Delivery

In the central biomass–pipeline delivery pathway, woody biomass (poplar) within a 50-mile radius is transported via truck to a central hydrogen production facility with a design capacity of 2,000 bone dry metric ton/day biomass (~155,000 kg H_2/day). An indirectly heated biomass gasifier converts the biomass to a biogas, which is then converted to hydrogen using a catalytic SMR with WGS. PSA is used to obtain the required hydrogen purity. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,500 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 6,250 psi (430 bar) and dispensed as a gaseous fuel to the 5,000-psi (350 bar) vehicle fuel tank. The flow diagram in Figure 2.4.4 shows the fuel production and delivery components of the central biomass–pipeline delivery pathway and the energy balance for the major hydrogen-related subsystems. The production technologies are detailed in Section 5.0, and the delivery technologies are detailed in Section 6.0.

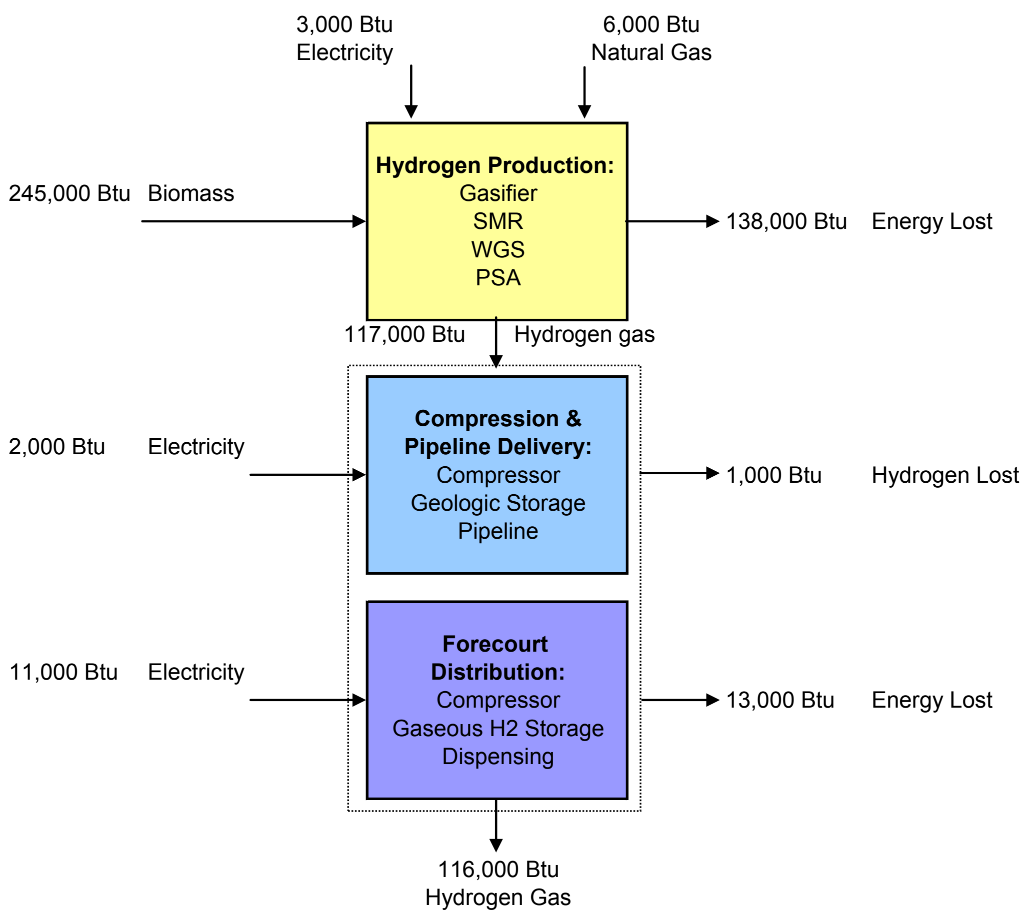


Figure 2.4.4. Flow diagram and energy balance of central biomass–pipeline delivery pathway

Values may not sum to zero due to rounding.

Pathway 5—Central Natural Gas–Pipeline Delivery

In the central natural gas–pipeline delivery pathway, natural gas is carried via pipeline to a central hydrogen production facility with a design capacity of ~379,000 kg H_2/day where SMR with WGS is used to reform the natural gas to hydrogen. PSA is used to obtain the required hydrogen purity. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,500 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 6,250 psi (430 bar) and dispensed as a gaseous fuel to the 5,000-psi (350 bar) vehicle fuel tank. The flow diagram in Figure 2.4.5 shows the fuel production and delivery components of the central natural gas–pipeline delivery pathway and the energy balance for the major hydrogen-related subsystems. The production technologies are detailed in Section 5.0, and the delivery technologies are detailed in Section 6.0.

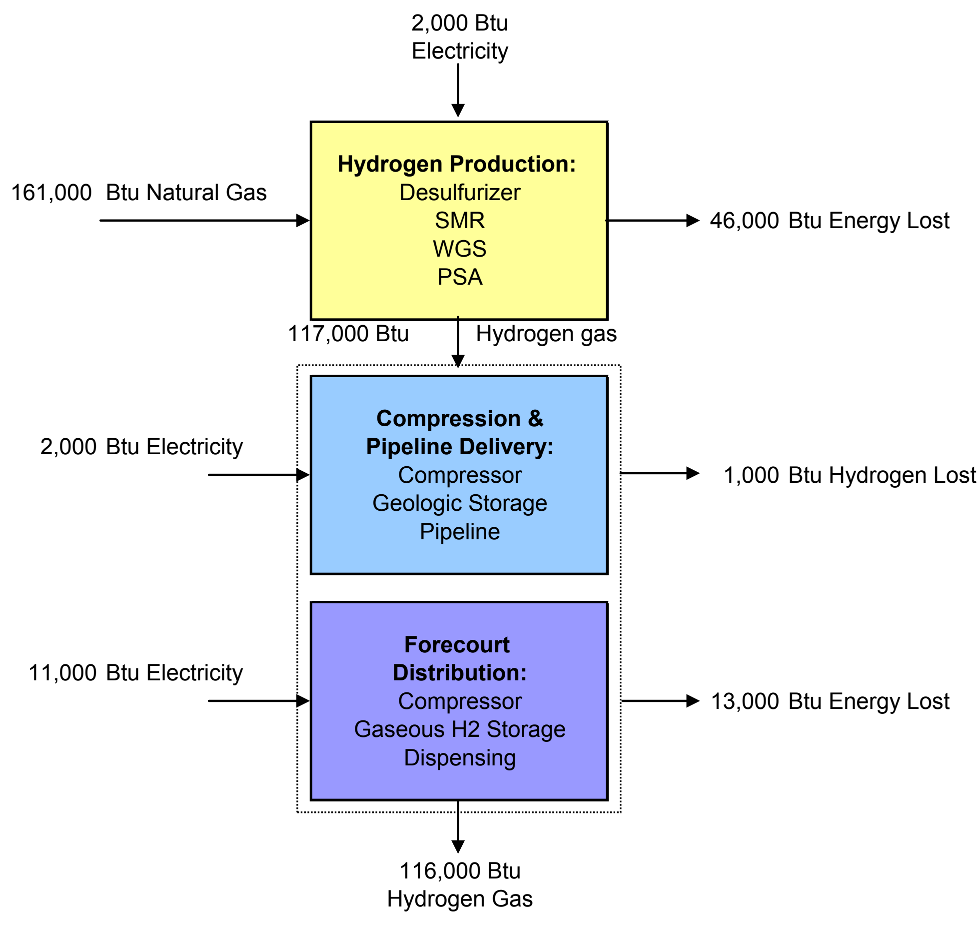


Figure 2.4.5. Flow diagram and energy balance of central natural gas–pipeline delivery pathway

Values may not sum to zero due to rounding.

The central natural gas–pipeline delivery pathway was selected as a benchmark case for this study. Large-scale natural gas reforming is a mature process being used to produce hydrogen for oil refining. It is expected to result in the lowest cost of hydrogen when pipeline delivery is employed.

Pathway 6—Central Wind Electricity–Pipeline Delivery

In the central wind electricity pathway, hydrogen is produced from water at a central production facility using a grid-powered electrolyzer with a design capacity of ~52,300 kg H_2/day. It is assumed that the facility buys wind-power credits for all the electricity purchased. A scrubber is used to obtain the required hydrogen purity. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,500 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 6,250 psi (430 bar) and dispensed as a gaseous fuel to the 5,000 psi (350 bar) vehicle fuel tank. The flow diagram in Figure 2.4.6 shows the fuel production and delivery components of the central wind electricity pathway and the energy balance for the major hydrogen-related subsystems. The production technologies are detailed in Section 5.0, and the delivery technologies are detailed in Section 6.0.

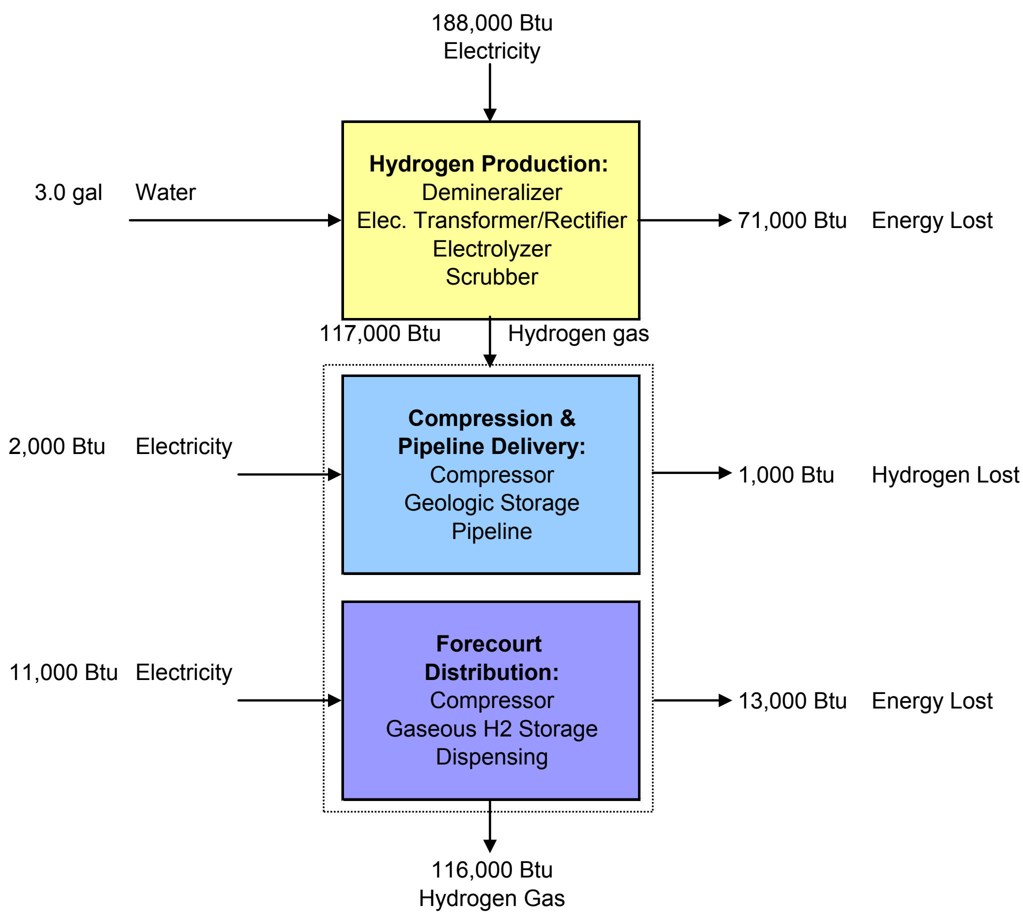


Figure 2.4.6. Flow diagram and energy balance of central wind electricity–pipeline delivery pathway

Values may not sum to zero due to rounding.

The central wind electricity–pipeline delivery pathway represents a low-carbon, renewable energy based option for providing hydrogen as a transportation fuel. Unlike the biomass pathways, which has potential geographic limitations, the wind electricity pathway can be implemented anywhere that wind-power credits are available for purchase.

Pathway 7—Central Coal with Carbon Capture and Sequestration (CCS)–Pipeline Delivery

In the central coal with carbon capture and sequestration (CCS)–pipeline delivery pathway, coal is delivered via rail to a central hydrogen production facility with a design capacity of ~308,000 kg H_2/day where it is gasified. A shift converter is used to convert the syngas to a hydrogen-rich gas, which undergoes acid gas cleanup and sulfuric acid removal prior to entering a PSA unit, which is used to obtain the required hydrogen purity. Carbon dioxide is captured using a Selexol® process and is compressed to 2,200 psi (152 bar) for injection to a pipeline. It is transported via pipeline to a sequestration site. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,500 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 6,250 psi (430 bar) and dispensed as a gaseous fuel to the 5,000-psi (350 bar) vehicle fuel tank. The flow diagram in Figure 2.4.7 shows the fuel production and delivery components of the central coal with CCS–pipeline delivery pathway and the energy balance for the major hydrogen-related subsystems. The production technologies are detailed in Section 5.0, and the delivery technologies are detailed in Section 6.0.

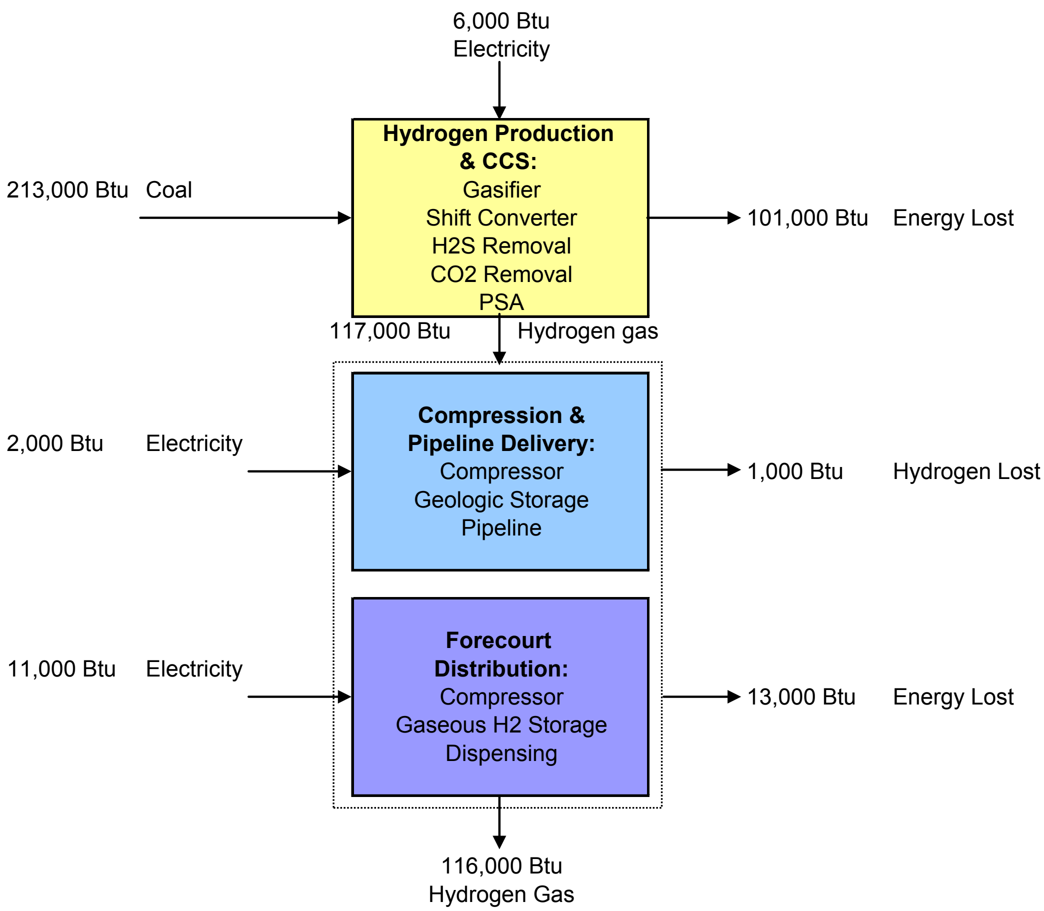


Figure 2.4.7. Flow diagram and energy balance of central coal with CCS–pipeline delivery pathway

Values may not sum to zero due to rounding.

Coal is the most abundant native fossil fuel in the U.S. and is available at lower cost than other fossil fuels. The central coal with CCS–pipeline delivery pathway was selected for this study to enable comparisons between coal and other fossil and renewable options for providing hydrogen transportation fuel. It is the only pathway studied that includes carbon capture and sequestration, thus offering opportunities for better understanding the effects of CCS on hydrogen costs, energy use, and emissions.

2.5 Models Used in the Pathway Analyses

The H2A Production Model Version 2.1 (Steward, Ramsden, and Zuboy, 2008) applies a standard discounted cash flow rate of return methodology to determine the minimum hydrogen selling price for central and forecourt hydrogen production technologies, including a specified after-tax internal rate of return. The H2A Production Model performs carbon sequestration calculations for centralized hydrogen production pathways and refueling station compression, storage, and dispensing calculations for distributed hydrogen production pathways.

The H2A Delivery Scenario Analysis Model (HDSAM) Version 2.0 (Mintz, Elgowainy, and Gillette, 2008) calculates the cost of hydrogen delivery using an engineering economics approach via a single or mixed mode for transmission and distribution (cryogenic tank truck, compressed gas truck, or pipeline) for a scenario defined by type and size of market, penetration rate, and refueling station capacity. Delivery in Version 2.0 includes all transport, storage, and conditioning activities from the outlets of a centralized hydrogen production facility to and including a fuel station that stores, in some cases further conditions, and dispenses the hydrogen to vehicles; this version does not model distributed production scenarios. Discounted cash flow is used to calculate the cost contribution of each component in the delivery chain.

The GREET model (Argonne National Laboratory, 2009) calculates the full fuel-cycle emissions and energy use associated with various transportation fuels for light-duty vehicles. Emissions included are the five criteria pollutants (volatile organic compounds, carbon monoxide, oxides of nitrogen, oxides of sulfur, and particulate matter) and three greenhouse gases (carbon dioxide, methane, and nitrous oxide). Additionally, total fuel-cycle energy consumption, fossil fuel consumption and petroleum consumption are calculated. More than 100 fuel production pathways and more than 70 vehicle/fuel systems are available in the current version of GREET. For this hydrogen pathways report, a modified version of GREET 1.8b downloaded on September 5, 2008, was utilized. The GREET model was modified to make it consistent with previous versions by adjusting the "method for dealing with co-products of soybean-based fuel" from displacement to energy-based allocation.

MSM (Ruth et al., 2009) links the H2A Production Model, HDSAM, and GREET to perform WTW analysis of the energy use, emissions, and economics of hydrogen production and delivery pathways from feedstock extraction through end use of hydrogen in vehicles. The primary inputs to the MSM are technology year, city size and hydrogen fuel penetration, production and delivery technology, and vehicle fuel economy. H2A and HDSAM results are used as inputs for many of GREET's input parameters in each MSM run. Primary energy source requirements and emissions are analyzed. Outputs of the model include the amount and type of feedstock used to produce hydrogen, efficiencies of different technologies, energy use and emissions of various pathways, hydrogen production capacity to meet demand, and cost of hydrogen at the pump achievable under different scenarios.

The MSM provides a Web-based interface that allows users to perform hydrogen pathway analyses following their own interests. It also allows for extensive single-parameter and multi-parameter sensitivities. The MSM will be updated with future versions of the H2A Production Model, HDSAM, and GREET as they are made public. For access to the MSM, please contact Mark Ruth at mark.ruth@nrel.gov.

3.0 Resource Assumptions

The extent to which each of the pathways analyzed in this study can be deployed to supply hydrogen fuel for light-duty vehicles depends on the availability, cost, and quality of required feedstocks, energy sources, and supporting infrastructures. This section examines the availability, cost, and characteristics of each of the feedstocks and energy sources utilized by the seven pathways: natural gas, electricity (including wind electricity), biomass, and coal. The current status and potential of carbon sequestration in the U.S. are also briefly explored because carbon sequestration is an element of the central coal–pipeline delivery pathway assessed in this study.

Additional resources and supporting infrastructures required for producing hydrogen and/or FCVs include water, platinum, carbon fiber, steel, concrete, dispensing equipment, monitoring/safety equipment, testing equipment, land, and skilled labor. Assessment of these resources and infrastructures is outside the scope of this study; however, DOE and the Fuel Pathway Integration Tech Team are currently supporting separate analyses of water and carbon-fiber resources. A summary of platinum resources analyses conducted to date for the DOE Hydrogen Program is provided in Appendix H.

3.1 Natural Gas

Natural gas is an important potential-hydrogen feedstock and also a significant electricity-generation feedstock, accounting for more than 15% of current electricity generation in the U.S. Its availability and cost, therefore, impact the viability and cost of hydrogen for several of the pathways studied.

Availability and Utilization

U.S. reserves of dry natural gas were estimated to be 237,726 billion cubic feet for 2007 (Energy Information Administration, 2009i). Data from EIA (Energy Information Administration, 2009c) show that the United States withdrew 26,032,337 million cubic feet of natural gas in 2008, which was up from 24,590,602 in 2007. For the same 2007–2008 time period, data (Energy Information Administration, 2009b) show the United States consumed 23,208,677 million cubic feet of natural gas in 2008 and 23,047,229 million cubic feet in 2007, increasing about 0.1%. Total consumption includes lease and plant fuel, pipeline and distribution use, and volumes delivered to consumers. The 2008 consumption was at near-record levels, second only to the amount consumed in 2000. One reason for the jump in consumption over 2007 levels was the 5.6% increase in heating degree days for 2008.

If the entire fleet of U.S. passenger vehicles were run on hydrogen produced from natural gas, 10 trillion normal cubic feet would be required annually to produce the necessary hydrogen (not including natural gas necessary for generation of the electricity used within the pathways). Ten trillion normal cubic feet is 43% of the total natural gas consumption in 2008. The demand calculation is based on a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from natural gas of 4.5 Nm^3 natural gas/kg H_2 (159 Nft^3 natural gas/kg H_2, which is 71% efficiency on an LHV basis). This calculation and the natural gas supply scenarios for lower fuel cell vehicle penetration rates are shown in Section 9.1.

Resource Cost

In cases where hydrogen is produced from natural gas, the natural gas price used for this analysis is \$0.24/Nm^3 (\$6.73/MMBtu), and in cases where natural gas is used for supplemental heat, the natural gas price used for this analysis is \$0.34/Nm^3 (\$9.52/MMBtu). These prices are different because industrial rates for natural gas were assumed for cases based on natural gas and because commercial rates were assumed for cases based on other feedstocks. Both rates are from EIA (2005) and are based on the High A Case. In 2007, the electric power price of natural gas was \$7.31 per thousand cubic feet (\$7.23/MMBtu). The cost jumped to \$9.35 per thousand cubic feet (\$9.24/MMBtu) in 2008 (Energy Information Administration, 2009d).

Characteristics

Natural gas consists of a high percentage of methane and varying amounts of ethane, propane, butane, and inert gases (nitrogen, carbon dioxide, and helium). Table 3.1.1 (Avallone and Baumeister, 1996) shows the composition and heating value of various natural gas samples from across the country. In this analysis, the natural gas has a higher heating value of 1089 Btu/ft^3 and a lower heating value of 983 Btu/ft^3.

Table 3.1.1. Composition and Heating Value of Natural Gas

	Composition, mole %						
	Oil or Gas Well				Pipeline		
State of origin	LA	MS	NM	TX	CO	KS	OK
Methane	92.1	96.3	67.7	43.6	94.3	72.3	75.4
Ethane	3.8	0.1	5.6	18.3	2.1	5.9	6.4
Propane	1.0	0.0	3.1	14.2	0.4	2.7	3.6
Butane	0.3	0.0	1.5	8.6	0.2	0.3	1.0
Nitrogen	0.9	1.0	17.4	3.0	0.0	17.8	12.0
Carbon dioxide	1.1	2.3	0.1	0.5	2.8	0.1	0.1
Helium	trace	trace	1.4	trace	trace	0.4	0.4
Heating value*	1,062	978	1,044	1,899	1,010	934	1,044

* Gross / higher heating value, Btu/ft^3, dry at 60°F and 30 inches of Hg.

3.2 Electricity

Electricity is a primary feedstock for the hydrogen production pathways employing electrolysis and is an important energy source for all of the pathways studied, as it is used to run pumps, compressors, and other equipment and controls. Electricity prices vary due to many factors including the energy source used to generate electricity, purchase volumes, time of day (peak vs. off-peak), and reliability requirements. The energy use and emissions attributable to electricity consumption also vary widely depending on how the electricity is produced. The grid mix and electricity prices used in this study are intended to represent a U.S. average; individual facilities may experience different mixes and prices.

Availability and Utilization

EIA data (Energy Information Administration, 2009e) for 2008 show that the United States generated 4,110,259 million kilowatt-hours of electricity, which was down from 4,156,745 million kilowatt-hours in 2007. For that same period, data (Energy Information Administration, 2009f) show that sales of electricity in the United States were 3,721,562 million kilowatt-hours and 3,764,561 million kilowatt-hours in 2008 and 2007, respectively.

If the entire fleet of U.S. passenger vehicles were run on hydrogen produced in distributed electrolysis plants, 3.5 trillion kilowatt-hours would be required annually to produce the necessary hydrogen. Three and a half trillion kilowatt-hours is 85% of the total electricity generated in 2008. The demand calculation is based on a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from electricity of 55 kWh electricity/kg hydrogen (62% efficiency on a hydrogen LHV basis). This calculation and the electricity supply scenarios for lower fuel cell vehicle penetration rates are shown in Section 9.2.

The GREET U.S. mix was used in these pathway analyses and is shown in Table 3.2.1. It is based on the 2005 grid mix (Energy Information Administration, 2005). For comparison, Table 3.2.2 (Energy Information Administration, 2009e) displays the net generation by energy source for the years 2007 and 2008; they are similar to the 2005 mix.

Table 3.2.1. GREET U.S. Mix

	% of Total
Biomass	1.2
Coal	51.7
Natural Gas	15.7
Nuclear	20.3
Residual Oil	2.9
Others (Carbon Neutral)	8.2
Total	100.0

Table 3.2.2. Net Generation by Energy Source

	2007	2008	2007	2008
	thousand megawatt-hours		% of total	
Coal[1]	2,016,456	1,994,385	48.5	48.5
Petroleum liquids[2]	49,505	31,162	1.2	0.8
Petroleum coke	16,234	14,192	0.4	0.3
Natural gas	896,590	876,948	21.6	21.3
Other gases[3]	13,453	11,573	0.3	0.3
Nuclear	806,425	806,182	19.4	19.6
Hydroelectric conventional	247,510	248,085	6.0	6.0
Other renewables[4]	105,238	123,603	2.5	3.0
Hydroelectric pumped storage	-6,896	-6,238	-0.2	-0.2
Other[5]	12,231	10,367	0.3	0.3
Total	4,156,745	4,110,259	100.0	100.0

[1] Anthracite, bituminous, subbituminous, lignite, waste coal, and coal synfuel.
[2] Distillate fuel oil, residual fuel oil, jet fuel, kerosene, and waste oil.
[3] Blast furnace gas, propane gas and other manufactured and waste gases derived from fossil fuels.
[4] Wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic, and wind.
[5] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, fire-derived fuel, and miscellaneous technologies.

Feedstock Conversion Efficiency

Figure 3.2.1 shows various types of power plants for electricity generation and their thermodynamic efficiencies. Hydroelectric plants are by far the most efficient at over 90%. However, as shown previously, hydroelectric plants contribute just 6% of the electricity-generation mix. At over 48% of the source mix, coal is the largest source of power generation in the United States. A coal-fired steam turbine plant has an efficiency of just under 40%, whereas an integrated gasification combined cycle (IGCC) coal-fired plant can achieve approximately 45%. Typically, this type of plant uses syngas to fire a gas turbine whose waste heat is utilized by a steam turbine system.

Resource Cost

Commercial electricity cost an average of $0.0965 per kilowatt-hour in 2007. That cost jumped to $0.1028 per kilowatt-hour in 2008. Industry paid $0.0639 and $0.0701 per kilowatt-hour in 2007 and 2008, respectively (Energy Information Administration, 2009a). The pathway analyses use the 2005 electricity prices from the Annual Energy Outlook 2005 High A Case (Energy Information Administration, 2005): $0.08159 per kilowatt-hour (in 2005 dollars) for commercial electricity and $0.05549 per kilowatt-hour (in 2005 dollars) for industrial electricity. The commercial electricity price is used for the distributed natural gas pathway and for electricity used at the refueling station in the central production pathways. The industrial electricity price is used for the distributed electricity pathway and for electricity used in the centralized production of hydrogen.

Wind Electricity

Wind power contributed more than a third of all new electric-generating capacity in 2007, installing 5,332 MW of capacity and expanding the U.S.'s total wind power–generating capacity by 45% in a single year from 11,575 MW to 16,907 MW; as of April 2009, the installed capacity has grown to 28,365 MW as seen in Figure 3.2.2 (National Renewable Energy Laboratory, 2009). Figure 3.2.3 shows the U.S. wind resource map for different wind power classes [ranging from 3 (fair) to 7 (superb)].

DOE released a report (United States Department of Energy, 2008) concluding that the U.S. possessed sufficient wind resources that would enable it to obtain 20% of its electricity (1.16 billion MWh) from wind by the year 2030. In 2007, the U.S. wind power capacity totaled 11,575 MW (11.6 GW), with wind power installations across 35 states. In 2008, 52,025,898 thousand kilowatt-hours of wind electricity were generated in the U.S., up from 34,449,927 in 2007 (Energy Information Administration, 2009). Wind sources contributed approximately 1.4% of the electricity consumed.

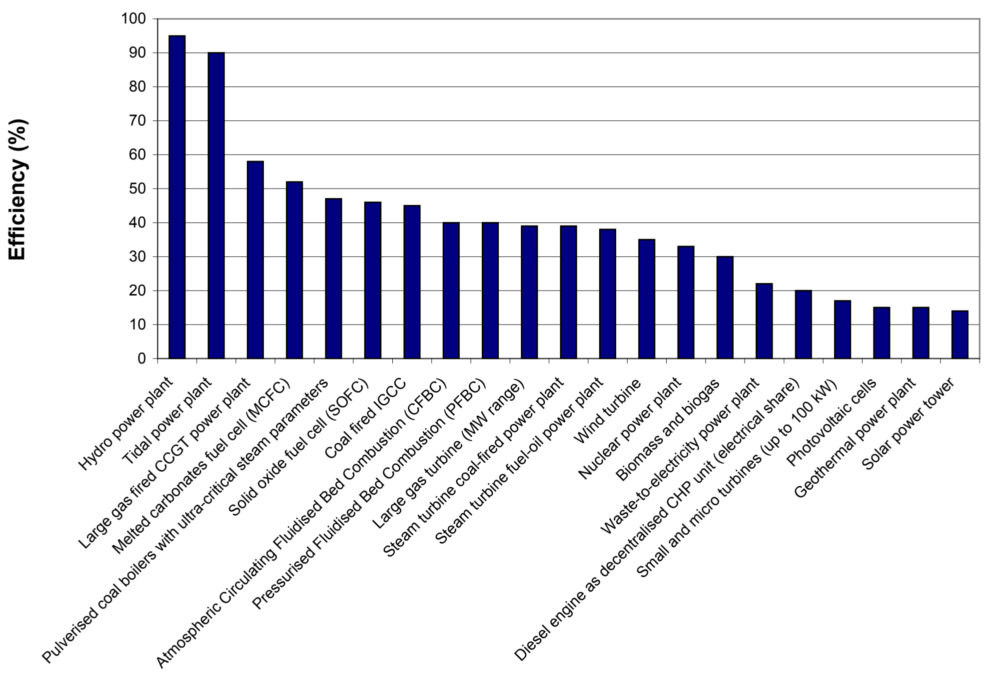


Figure 3.2.1. Efficiency in electricity generation from various sources (van Aart, 2004)

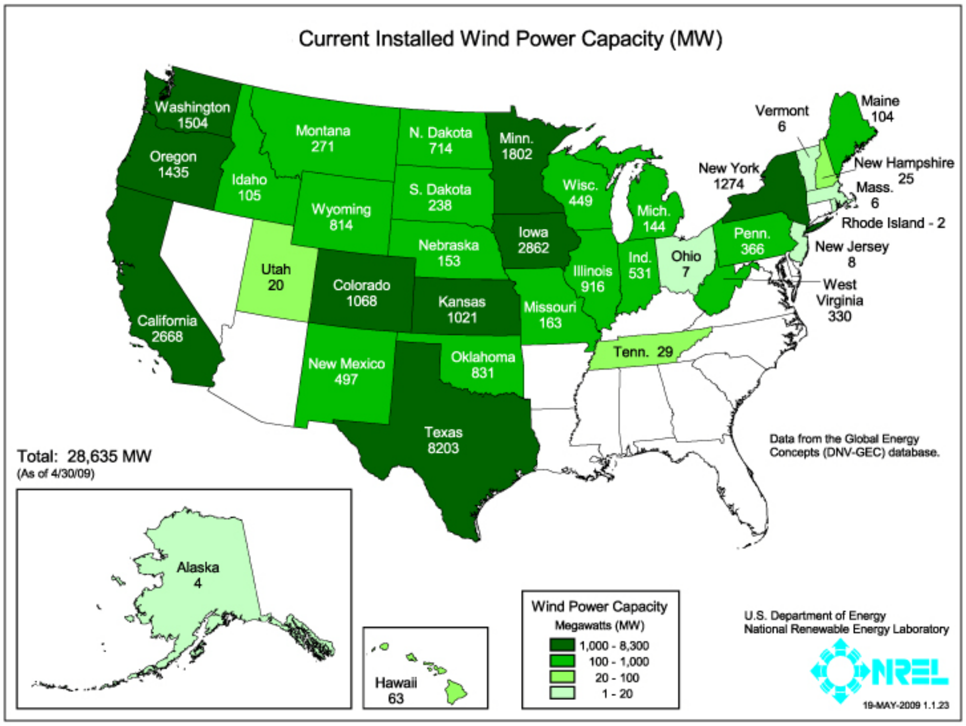


Figure 3.2.2. Installed wind capacity as of April 2009 (National Renewable Energy Laboratory, 2009)

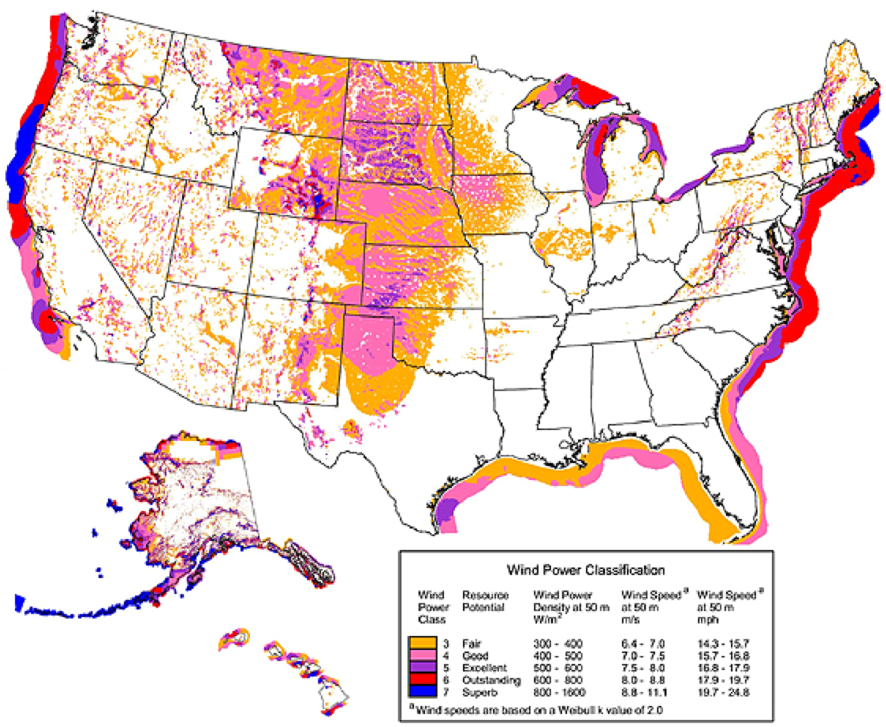


Figure 3.2.3. U.S. wind resource map (National Renewable Energy Laboratory, 2009)

Figure 3.2.4 shows the 2007 "bus-bar" energy cost for wind (wind plant costs only) by location (land-based or offshore) and by class of wind power. The U.S. has more than 8,000,000 MW (8,000 GW) of available land-based wind resources that can be captured economically.

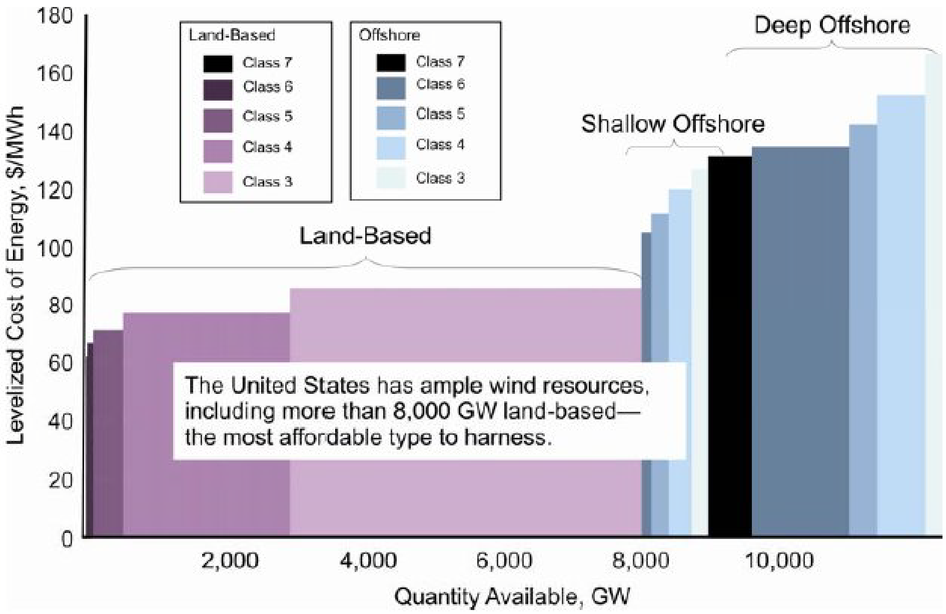


Figure 3.2.4. Wind energy supply curve (U.S. Department of Energy, 2008)

If the entire fleet of U.S. passenger vehicles were run on hydrogen produced from wind electricity, 3.4 trillion kilowatt-hours would be required annually to produce the necessary hydrogen, and 3.4 trillion kilowatt-hours is 6,500% of the total wind electricity consumption in 2008. The demand calculation is based on a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from wind electricity of 53 kWh wind electricity/kg H_2. This calculation and the wind electricity supply scenarios for lower fuel cell vehicle penetration rates are shown in Section 9.6.

3.3 Biomass (Wood)

Woody or herbaceous biomass may be a viable feedstock for hydrogen production in some areas of the U.S. and is already used in limited quantities in electricity generation. Biomass availability and cost vary widely and are location-specific.

Availability and Utilization

The electric power sector, which is composed of electricity generation and combined heat and power (CHP) plants within North America and whose primary business is to sell electricity and/or heat to the public, generated a net of 10.9 billion kilowatt-hours in 2008 from wood and derived fuels, up from 10.7 billion kilowatt-hours in 2007; the industrial sector generated a net of 27.9 billion kilowatt-hours in 2008, down from 28.3 billion kilowatt-hours in 2007 (Energy Information Administration, 2009j). This category included black liquor and wood/wood waste solids and liquids. The renewable energy sector contributed 9% of the 2008 electricity mix (Energy Information Administration, 2009k). Consumption of wood-derived fuels in 2008 was 2.041 quadrillion Btu (quads), accounting for approximately 52% of all biomass consumed for energy (3.884 quads, includes biofuels, waste, and wood-derived fuels) and 28% of all renewable energy consumed (7.301 quads).

In a joint study sponsored by the U.S. Department of Energy and the U.S. Department of Agriculture (Perlack et al., 2005), Oak Ridge National Laboratory sought to determine whether the land resources of the U.S. are capable of producing a sustainable supply of biomass sufficient to displace 30% or more of the U.S.'s present petroleum consumption. This goal would require approximately one billion dry tons of biomass feedstock per year. The researchers concluded that forestland and agriculture land, the two largest potential biomass sources, had the potential to provide 1.3 billion dry tons per year of biomass (see Figure 3.3.1) around the mid-21st century. This annual potential represents an increase in production of more than sevenfold from the amount of biomass consumed at the time of the report for bioenergy.

The report stated that forestlands in the contiguous U.S. could sustainably produce 368 million dry tons of biomass annually. That projection includes 52 million dry tons of fuelwood harvested from forests, 145 million dry tons of residues from wood-processing mills and pulp and paper mills, 47 million dry tons of urban wood residues including construction and demolition debris, 64 million dry tons of residues from logging and site-clearing operations, and 60 million dry tons of biomass from fuel-treatment operations to reduce fire hazards.

Concurrently, agricultural lands in the U.S. could produce one billion dry tons of biomass annually and still continue to meet food, feed, and export demands. This reported projection includes 428 million dry tons of annual crop residues, 377 million dry tons of perennial crops, 87 million dry tons of grains used for biofuels, and 106 million dry tons of animal manure, process residues, and other miscellaneous feedstocks.

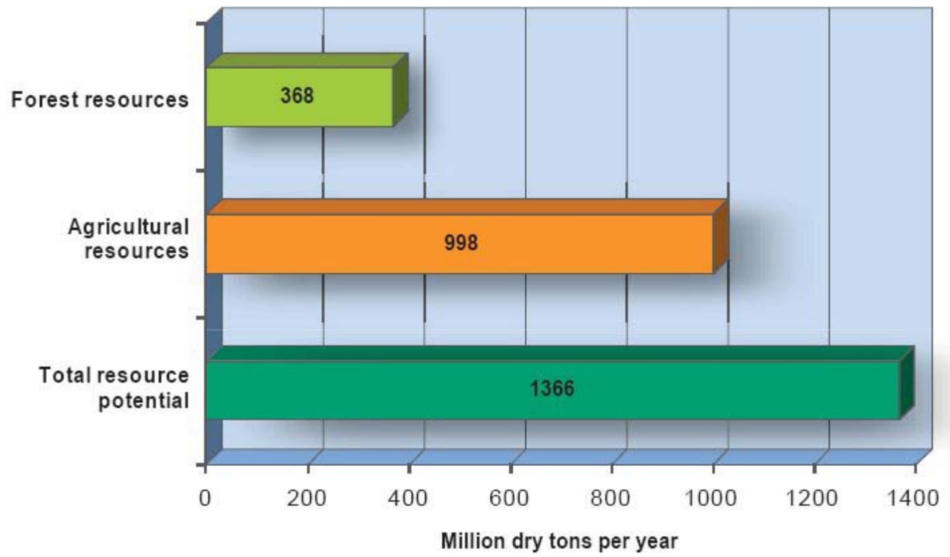


Figure 3.3.1. Annual biomass resource potential from forestland and agricultural land (Perlack et al., 2005)

If the entire fleet of U.S. passenger vehicles were run on hydrogen produced from biomass, 890 million dry tons of biomass would be required annually to produce the necessary hydrogen, and 890 million dry tons is 730% of the wood-derived fuels consumed in the U.S. in 2008. The demand calculation is based on a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from biomass of 12.8 kg dry biomass/kg H_2. This calculation and the biomass supply scenarios for lower fuel cell vehicle penetration rates are shown in Section 9.3.

Resource Cost

Table 3.3.1 summarizes the estimate of the main components that make up the non-feed and food crop biomass available in the U.S. in the near-term at approximately $65 per ton delivered to the processing plant (Board on Energy and Environmental Systems, 2008). The table also includes other estimates for comparison.

Table 3.3.1. Estimated Primary Solid Biomass Components Available in the United States in the Near Term and 2030 for Less than about $65 per Ton (2007 dollars)

	Biomass Amount (million tons per year)				
	NRC Near-Term	Walsh et al. (2000)	Milbrandt (2005)	Perlack et al. (2005)	NRC 2030
Crop residue	160	50	173	179	315
Forest residues	55	44	62	136	55
Mill wastes[1]	5	90	88	106	
Urban wood waste	30	37	34	37	30
Energy crops	85	188	99	-	100
Total	335	509	456	458	490

[1] NRC estimate includes only the fraction that is estimated as not already being used.

Characteristics

Table 3.3.2 provides a typical analysis of dry wood (Avallone and Baumeister, 1996).

Table 3.3.2. Typical Analysis of Dry Wood

	Most Woods, range
Proximate analysis, %	
Volatile matter	74–82
Fixed carbon	17–23
Ash	0.5–2.2
Ultimate Analysis, %	
Carbon	49.6–53.1
Hydrogen	5.8-6.7
Oxygen	39.8–43.8
Heating value, Btu/lb	8,560–9,130

3.4 Coal

Because reserves of coal are abundant in the U.S., coal cannot be overlooked as a potential feedstock for hydrogen production. It is also the dominant feedstock for electricity production in the U.S. Coal availability and prices thus have both direct and indirect consequences for the costs of the hydrogen production pathways studied.

Availability and Utilization

Data from EIA (Energy Information Administration, 2008d) show that the United States produced 1.15 billion short tons of coal in 2007 from 1,374 mines, but no data on coal production were reported for 2008. As of January 2008, the demonstrated U.S. reserve base was estimated to contain 489 billion short tons (Energy Information Administration, 2009l). Data (Energy Information Administration, 2009g) show the United States consumed 1.13 billion short tons of coal in 2007; data available for 2008 show the United States consumed 1.12 billion short tons of coal, down slightly from the previous year.

If the entire fleet of U.S. passenger vehicles were run on hydrogen produced from coal, 550 million short tons of coal would be required annually to produce the necessary hydrogen (not including coal necessary for generation of the electricity used within the pathways), and 550 million short tons is 49% of the total coal consumption in 2008. The demand calculation is based on a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from coal of 7.85 kg coal/kg hydrogen (54% efficiency for Pittsburgh #8 coal on an LHV basis). This calculation and coal supply scenarios for lower fuel cell vehicle penetration rates are shown in Section 9.7.

Resource Cost

Electric utility plants paid an average of \$36.06 (2007 dollars) per short ton in 2007 (Energy Information Administration, 2008b). As was the case for coal production, no price data were available for 2008.

Characteristics

Approximate composition for the general ranks of coal (anthracite, bituminous, subbituminous, and lignite) used in electricity generation as well as their calorific values (Avallone and Baumeister, 1996) are shown in Table 3.4.1. The 2007 U.S. production volume (Energy Information Administration, 2008d) and 2007 U.S. average open-market sales price (Energy Information Administration, 2008a) for the coal ranks are shown in Table 3.4.2. Coal rank depends on the volatile matter, fixed carbon, inherent moisture, and oxygen. Typically, coal rank increases as the amount of fixed carbon increases and the amount of volatile matter and moisture decreases. For this analysis, Pittsburgh #8 coal is assumed.

Table 3.4.1. Approximate Composition and Calorific Value of General Ranks of Coal

	% of Combustible				Calorific Value, Btu/lb
	Moisture	Volatile Matter	Fixed Carbon	Oxygen	
Anthracite	4.3	5.1	81.0	6.1	12,880
Bituminous[1]	8.4	36.1	46.9	14.4	12,177
Subbituminous[2]	21.4	32.8	40.9	32.1	9,607
Lignite	36.8	27.8	29.5	45.1	7,000

[1] Average of high-volatile bituminous A, B, and C coals.
[2] Average of subbituminous A, B, and C coals.

Table 3.4.2. U.S. Production Volume and Average Open-Market Sales Price for General Ranks of Coal

	2007 U.S. Production, thousand short tons	2007 U.S. Average Open-Market Sales Price
Anthracite	1,568	\$52.24
Bituminous	542,758	\$40.80
Subbituminous	523,724	\$10.69
Lignite	78,585	\$14.89

3.5 Carbon Sequestration

Carbon sequestration entails the capturing and storing of CO_2 that would otherwise be released into the atmosphere. It is of particular interest in commercial-scale plants using fossil energy because economies of scale are needed to make it practical and affordable. Carbon sequestration is assumed only for the central coal pathway in this report.

Two carbon dioxide capture methods—geological and terrestrial sequestration—are being explored by DOE (see Figure 3.5.1). Geological sequestration involves the separation and capture of CO_2 at the point of emissions from stationary sources followed by storage in underground geological formations (i.e., deep salt formations or depleted oil and gas reservoirs). Terrestrial sequestration involves the net removal of CO_2 from the atmosphere by plants during photosynthesis and its capture in vegetative biomass and in soils. Carbon dioxide uptake takes place in both land and in aquatic environments.

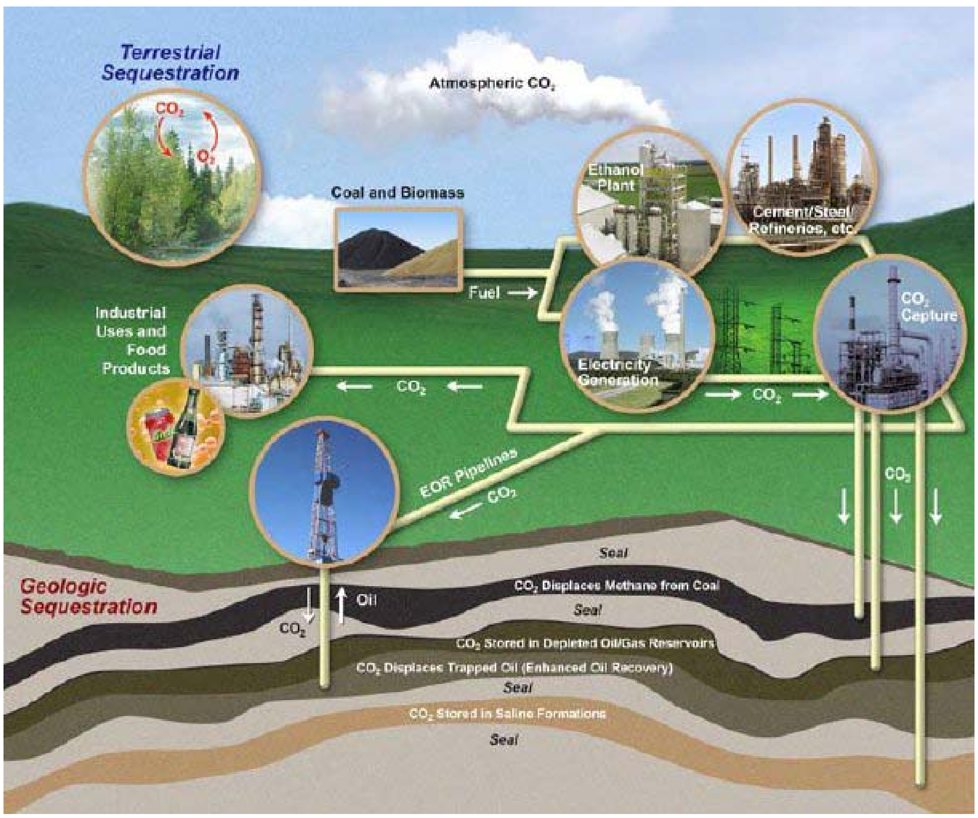


Figure 3.5.1. Geological and terrestrial sequestration (National Energy Technology Laboratory, 2008)

DOE formed Regional Carbon Sequestration Partnerships, public/private cooperative efforts to develop guidelines for the most suitable technologies, regulations and infrastructure needs for carbon capture, and storage for different regions of the U.S. and Canada. Seven partnerships exist and include: 1) Big Sky Carbon Sequestration Partnership (BSCSP); 2) Midwest Geological Sequestration Consortium (MGSC); 3) Midwest Regional Carbon Sequestration Partnership (MRCSP); 4) Plains CO_2 Reduction

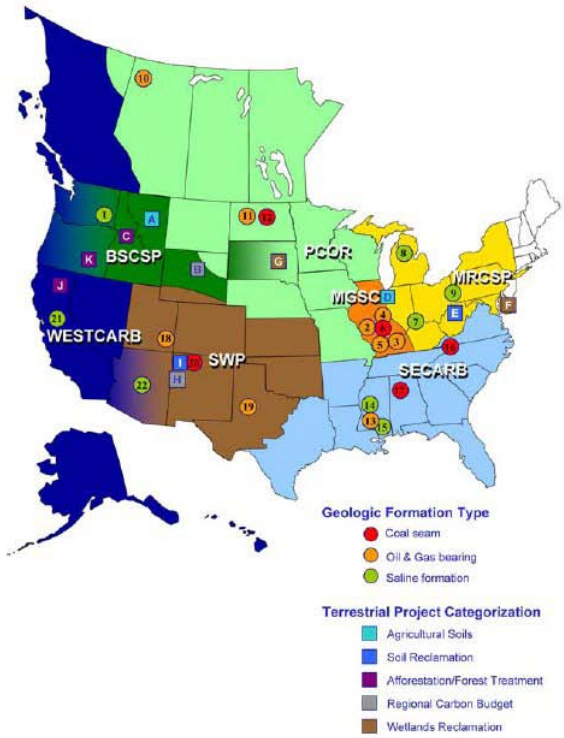
(PCOR) Partnership; 5) Southeast Regional Carbon Sequestration Partnership (SECARB); 6) Southwest Regional Partnership (SWP); and 7) West Coast Regional Carbon Sequestration Partnership (WESTCARB). A map depicting the partnership locations can be seen in Figure 3.5.2.

The partnerships began in 2003 with a characterization phase to develop the framework to validate and deploy carbon capture and storage technologies. During this phase, the partnerships identified potential geological storage basins across North America. The conservative estimate of storage potential in North America can be found in Table 3.5.1 (National Energy Technology Laboratory, 2008).

Table 3.5.1. Conservative Geological Carbon Storage Potential in Gigatonnes

Reservoir Type	Low	High
Deep saline formations	3,300	12,600
Unmineable coal seams	160	180
Oil and gas fields	140	140

Currently, the partnerships are nearing the end of the validation phase, which as implied, validates the most promising regional carbon-sequestration opportunities. Eleven terrestrial sequestration projects were implemented during this phase on abandoned mine land, wetlands, agricultural fields, prairie lands, and forests. Figure 3.5.2 shows the validation-phase CO_2 storage products being developed as well as their locations across the U.S. and Canada (National Energy Technology Laboratory, 2008). The development phase, estimated to extend to 2018, involves utilizing either geological or terrestrial sequestration of one million tons or more of CO_2 by each partnership.



	Partnership	Geologic Province / Project Location	Geologic: Total CO_2 Injection (tons CO_2)	Geologic: Approximate Depth (feet)	Terrestrial: Estimated CO_2 Capacity
1	BIG SKY CARBON	Columbia Basin	3,000	2,500 – 4,000	
A		North Central MT			60 Mt over 20 years
B		Eastern WY			30 Mt over 10 years
C		Region-wide			640 - 1,040 Mt over 50 yrs
2	MGSC	Illinois Basin	50	1,550	
3		Illinois Basin	1,000	1,549	
4		Illinois Basin	3,000	1,548	
5		Illinois Basin	3,000	1,551	
6		Illinois Basin	200	1,000	
7	MRCSP	Cincinnati Arch	3,000	3,200 – 3,500	
8		Michigan Basin	10,000	3,200 – 3,500	
9		Appalachian Basin	3,000	6,900 – 8,300	
D		Region-wide			25 Mt over 20 years
E		Region-wide			100 Mt over 20 years
F		Cambridge, MD			TBD
10	PCOR	Keg River Formation	100,000	5,000	
11		Duperow Formation	<1,000	10,000 – 10,500	
12		Williston Basin	<1,000	1,600 – 1,800	
G		Great Plains wetlands complex (PPR)			14.4 Mt
13	SECARB	Gulf Coast (stacked test)	500,000	10,304	
14		Gulf Coast (stacked test)		10,400	
15		Mississippi Coastal Plain	3,000	8,500	
16		Central Appalachian	1,000	1,600 – 2,300	
17		Black Warrior Basin	1,000	1,500 – 2,500	
18	SWP	Paradox Basin, Aneth Field	450,000	5,600 – 5,800	
19		Permian Basin	900,000	5,800	
20		San Juan Basin	75,000	3,000	
H		Region-wide			TBD
I		San Juan Basin Coal Fairway (Navajo City, NM)			TBD
21	westcarb.org	Sacramento Basin	2,000	8,000	
22		Colorado Plateau	2,000	4,000	
J		Shasta County, CA			4,600 Mt over 80 years (CA)
K		Lake County, OR			900 Mt over 80 years (OR)

Figure 3.5.2. Regional carbon sequestration partnerships and their respective validation carbon storage projects (National Energy Technology Laboratory, 2008)

4.0 Status of Supporting Infrastructure

4.1 Natural Gas Supply Infrastructure

The natural gas supply infrastructure in the U.S. consists of more than 210 natural gas pipeline systems, more than 1,400 compressor stations to maintain pressure on the natural gas pipeline network, more than 11,000 delivery points, 5,000 receipt points, 1,400 interconnection points, 24 hubs, 400 underground natural gas storage facilities, 49 import/export locations, 8 liquefied natural gas (LNG) import facilities, and 100 LNG peaking facilities (Energy Information Administration, 2008e). Table 4.1.1 estimates the natural gas pipeline mileage for the regions listed in Figure 4.1.1. As can be seen from the table, over 305,000 miles of pipeline exist in the United States; the Southwest region comprises over 109,000 miles of that total while the Western region has the least amount at fewer than 25,000 miles.

Table 4.1.1. Natural Gas Pipeline Mileage (Energy Information Administration, 2008e)

Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage
Central		Midwest		Northeast		Southeast		Southwest		Western	
Colorado	7,803	Illinois	11,911	Connecticut	628	Alabama	4,818	Arkansas	6,267	Arizona	5,989
Iowa	5,421	Indiana	4,704	Delaware	280	Florida	4,971	Louisiana	18,900	California	11,770
Kansas	15,386	Michigan	9,722	Maine	609	Georgia	3,483	New Mexico	6,756	Idaho	1,567
Missouri	3,944	Minnesota	4,447	Maryland/DC	1,022	Kentucky	6,892	Oklahoma	18,539	Nevada	1,469
Montana	3,861	Ohio	7,670	Massachusetts	972	Mississippi	9,784	Texas	58,588	Oregon	1,823
Nebraska	5,697	Wisconsin	3,471	New Hampshire	291	North Carolina	2,484	.	109,050	Washington	2,072
North Dakota	1,873		41,925	New Jersey	1,520	South Carolina	2,265				24,690
South Dakota	1,242			New York	5,018	Tennessee	4,304				
Utah	3,175			Pennsylvania	8,680		39,001	Gulf Mexico[1]	9,458		
Wyoming	7,902			Rhode Island	100						
	56,304			Vermont	71						
				Virginia	2,577			Total US Pipeline Mileage			305,954
				West Virginia	3,758			Total Interstate[1]			217,306
					25,526			Total Non-interstate[2]			88,648

[1] In the Gulf of Mexico some large-scale gathering systems are FERC jurisdictional and are therefore counted as interstate.
[2] Includes intrastate transmission and non-FERC jurisdictional large diameter gathering systems or headers. Local distribution company (LDC) mileage excluded.
Note: All mileage is approximate. Includes looped pipeline segments. Approximately 73 percent of Interstate pipeline systems are made up of pipeline diameters exceeding 16 inches while only 34 percent of non-interstate pipeline systems are 16 inches or larger.
Source: Energy Information Administration, Gas Transportation Information System, Pipeline Map Files and Pipeline Projects Database.

Ideally, natural gas pipelines would be utilized at or as close as possible to 100%. In reality, however, that rarely occurs. Several factors contribute to less-than-perfect utilization such as scheduled or unscheduled maintenance, decreases in demand, and weather disturbances. Figure 4.1.1 shows the interregional natural gas pipeline capacity levels with arrows indicating the direction of the interregional pipelines. Utilization rates below 100% do not necessarily mean that additional capacity is available for use. For instance, in the summer months, average utilization rates will be low compared to winter months. Additionally, rates can exceed 100% of the certified capacity (minimum level of service over an extended period of time) in periods of high demand. This rate can be accomplished by temporarily increasing compression within safety limits.

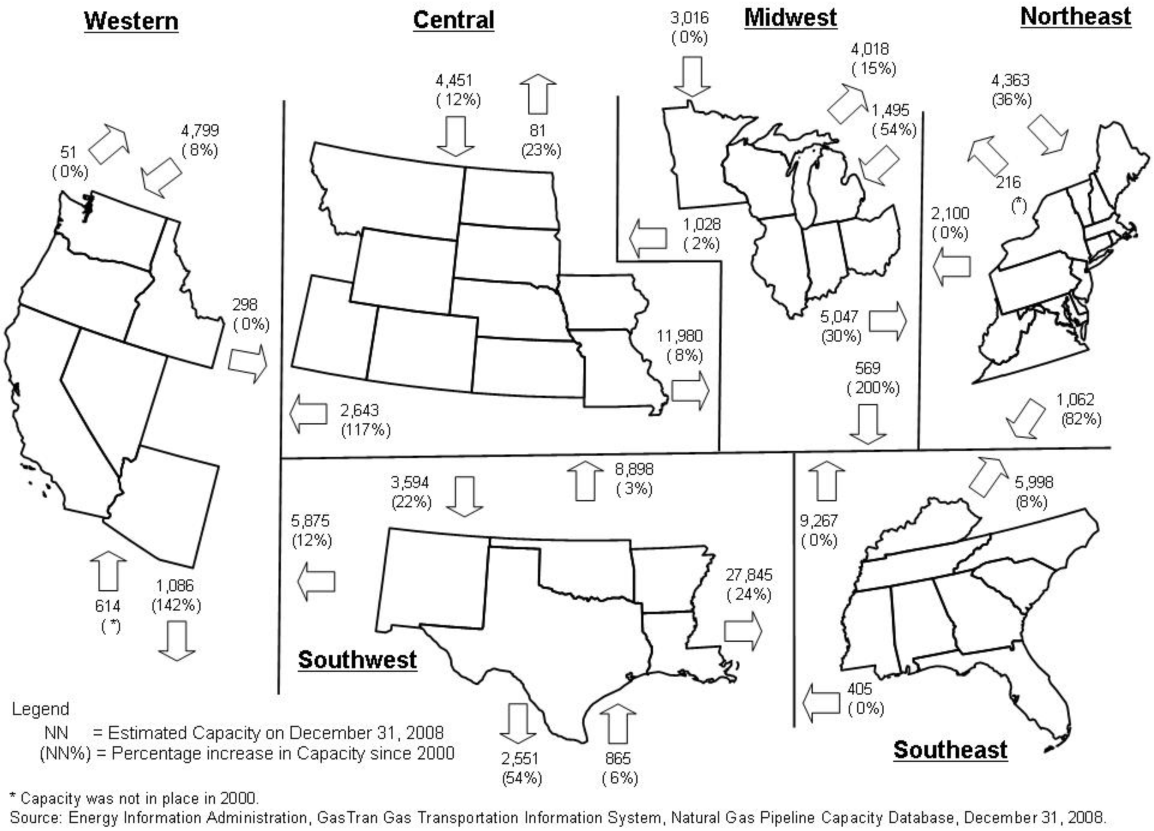


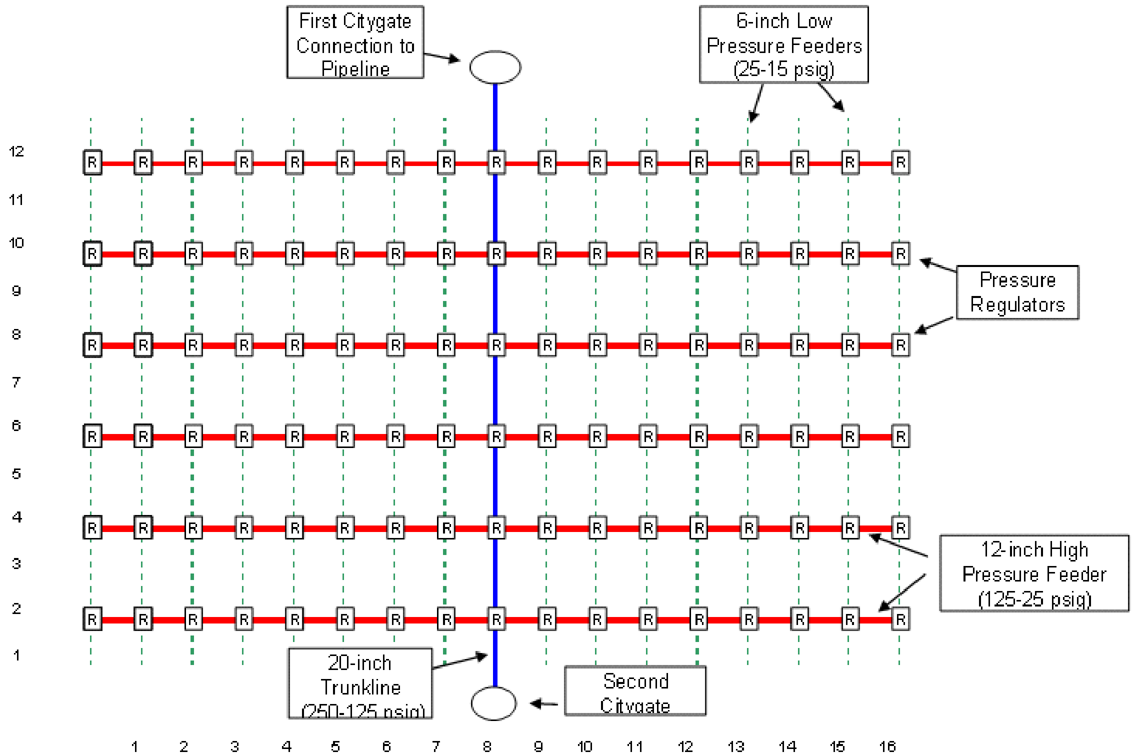
Figure 4.1.1. Interregional natural gas pipeline capacity levels (Energy Information Administration, 2008e)

Energy and Environmental Analysis (EEA), an ICF International Company, analyzed natural gas infrastructure requirements for hydrogen production for the U.S. Department of Energy (Vidas, 2007). The premise of the study was that hydrogen transportation fuel will be supplied to early adopters of hydrogen-fueled vehicles by distributed natural gas–fueled steam methane reformers co-located with refueling stations. EEA sought to determine how much natural gas would be required for hydrogen production, how the natural gas demand would be distributed geographically, whether the existing or expected future natural gas transmission system could accommodate the anticipated demand, whether physical constraints would prevent local distribution companies (LDCs) from being able to supply natural gas to refueling stations, and how much needed natural gas infrastructure improvements would cost. It was assumed that 15% of light-duty vehicles in 27 largest U.S. cities (11.7 million vehicles) would be fueled by hydrogen, and that all of the hydrogen would be produced at 1,500 kg/day refueling stations using natural gas. At this penetration rate, almost 6,400 refueling stations (with a utilization factor of 75%) would be required in the 27 cities. Assuming that 170 cubic feet of natural gas is required to produce 1 kg of hydrogen, each station will require 255,000 cubic feet of natural gas per day. This volume of natural gas is considered a large load for an LDC, equivalent to the average load of 1,200 homes or two to three industrial plants.

EEA compared the natural gas needs for hydrogen against the total load for each city (all sectors) to determine the impact on transmission systems and estimated that hydrogen would increase total (all-sector) peak natural gas demand by an average of 1.7% (ranging from 0.6% to 5.8%) over projected demand in 2025 for the 27 cities. Only 3 of the 27 cities would experience a natural gas demand increase of more than 3% as a result of hydrogen production: Miami, Seattle, and Orlando.

The natural gas needs for hydrogen were also compared against residential and commercial loads to determine the impact on distribution systems. Hydrogen would increase residential/commercial peak natural gas demand by an average of 2.6% (ranging from 1.4% to over 45%) over projected demand in 2025 for the 27 cities. Four cities would experience a residential/commercial natural gas demand increase of more than 5% as a result of hydrogen production: Los Angeles, Miami, Phoenix, and Orlando.

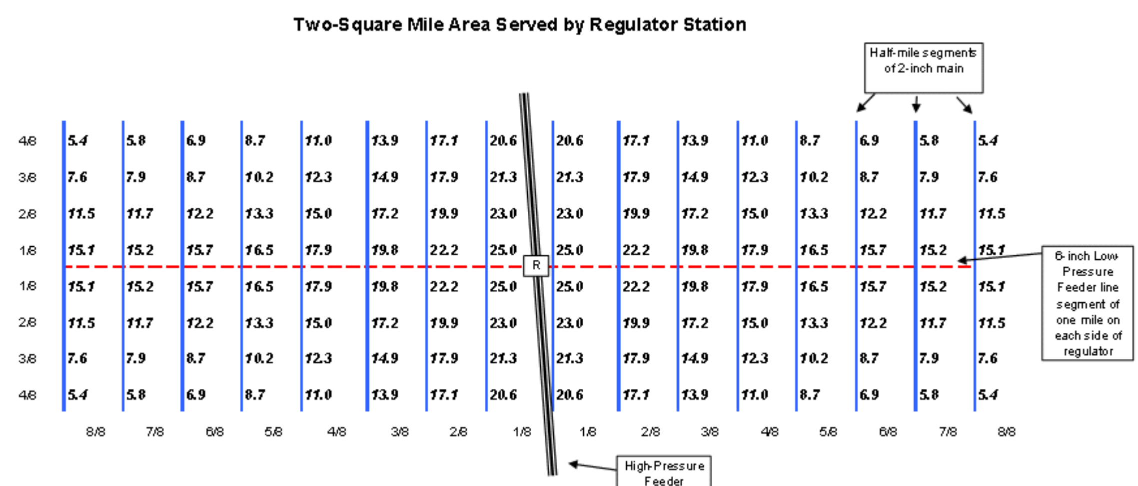
Natural gas is delivered to city gates in interstate transmission pipelines that are 20–36 inches in diameter and flow at pressures between 1,000 and 750 psig. At the city gate, the pressure is stepped down to ~400 psig or lower. LDCs deliver the gas from the city gate to the end user through smaller-diameter trunk lines (>125 psig, ~20-inch diameter), high-pressure feeders (125–25 psig, ~12-inch diameter), low-pressure feeders (25–15 psig, ~6-inch diameter), and mains (15–5 psig, ~2-inch diameter). Figure 4.1.2 shows a hypothetical 12-mile by 16-mile city-wide gas distribution grid. Figure 4.1.3 shows hypothetical pressures in distribution mains serving a two-square mile area.



Note: Two-inch mains are not shown on this diagram.

Total square miles	192
Max flow per square mile (scf/hour)	164,386
Max flow for city (scf/hour)	31,562,042
Max flow per citygate (scf/hour)	15,781,021

Figure 4.1.2. Hypothetical 12 x 16-mile city-wide gas distribution grid (Vidas, 2007)



Maximum flow through each regulator (scf/hour)	328,771
City blocks served by each regulator	128
Maximum flow per city block (scf/hour)	2,569

Figure 4.1.3. Hypothetical pressures (psig) in distribution mains at maximum design flows (Vidas, 2007)

EEA concluded that the changes to transmission pipeline capacities needed to accommodate the hydrogen production will depend on what LNG terminals, pipeline, and storage assets are built in the coming years to meet overall natural gas demand growth. Required hydrogen-related gas transmission expenditures were estimated to cost $1 to $1.5 billion, roughly 2% of the gas transmission expenditures expected in the next 20 years. Assuming gradual growth of hydrogen, EEA did not anticipate that gas transmission pipelines would represent a barrier to hydrogen production.

New service lines will have to be installed to accommodate refueling stations with natural gas loads of 255,000 cubic feet per day because a station of this size will require more gas than can be supplied through a typical 2-inch-diameter main. Initial stations may be sited on streets with feeder lines to minimize the cost to LDCs. Steward et al. (2009) asserted that 1,500 kg/day hydrogen stations with on-site hydrogen production from natural gas using SMR would need to tie into 4-inch or larger natural gas feeder lines.

One strategy under consideration for implementing early hydrogen fueling infrastructure is to establish networks of fueling stations in a limited number of urban centers, beginning with Southern California and the area surrounding New York City (Greene et al., 2008). Because existing gasoline stations are potential sites for future hydrogen fuel stations, the Fuel Pathway Integration Technical Team (Steward et al., 2009) assessed the proximity of existing gasoline fueling stations in Los Angeles to natural gas feeder lines. As shown in Figure 4.1.4, there are around 1,500 gasoline stations within a half mile of a feeder line in Los Angeles.

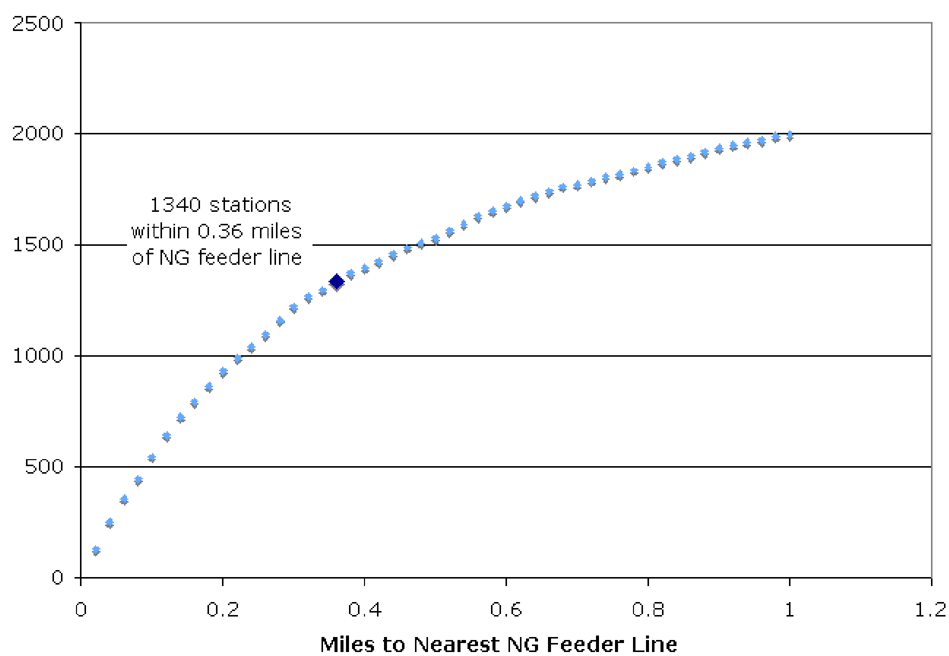


Figure 4.1.4 Number of refueling stations within one mile of natural gas feeder line in Los Angeles (Steward et al., 2009)

In HDSAM, the cost of installed pipelines with diameters less than 6 inches is estimated using the following equation:

$$\$/mile=5280*(5.6822*D^2-15.767*D+66.212)$$

where D is the pipeline diameter in inches. Using this equation, a 4-inch feeder line will cost $496,600 per mile (installed). The average distance of refueling stations in the Los Angeles metropolitan area to a feeder line is 0.73 miles, correlating to a cost of $362,500 (installed) (Steward et al., 2009).

EEA (Vidas, 2007) estimated that required hydrogen-related gas distribution expenditures will cost $1 to $2.5 billion, about 1.5% of the gas distribution expenditures expected in the next 20 years. LDCs in warm locations with relatively low natural gas loads will be impacted most severely by the addition of natural gas–derived hydrogen.

4.2 Electricity Transmission Grid

The North American electricity transmission system is composed of three major interconnected power systems: the Eastern Interconnections, the Western Interconnections, and the Electric Reliability Council of Texas. Within each system, disturbances or reliability events are felt nearly instantaneously throughout the system. This transmission system was built over the past 100 years by vertically integrating utilities that produced electricity at large generation stations located close to fuel supplies. Over 150,000 miles of high-voltage transmission lines (both alternating current and direct current) link generators to load centers across the states and along the borders with Mexico and Canada. A 2002 U.S. Department of Energy report found that the U.S.'s transmission system was under stress (Abraham, 2002). Findings of that report attributed the stress to growth in electricity demand and new generation, lack of investment in new transmission facilities, and the incomplete transition to fully efficient and competitive wholesale markets. These factors allow for transmission bottlenecks, which lead to increased electricity costs to consumers as well as increased risk of blackouts.

Transmission bottlenecks occur when there is not enough transmission capability to accommodate all requests to ship power over existing lines and maintain adequate safety margins for reliability. Because electricity cannot be stored economically as of yet, transmission-system operators must deny requests for transmission service when they receive too many to prevent lines from becoming overloaded. Bottlenecking is managed through Transmission Loading Relief (TLR), also known as "calls," which determines which requests will be denied. The DOE report (Abraham, 2002) shows that the number of TLR calls increased between 1997 and 2001 (see Figure 4.2.1). More recent data are unavailable at this time. Frequent TLR calls increase consumer electricity costs by denying low-cost transactions in favor of high-cost transactions.

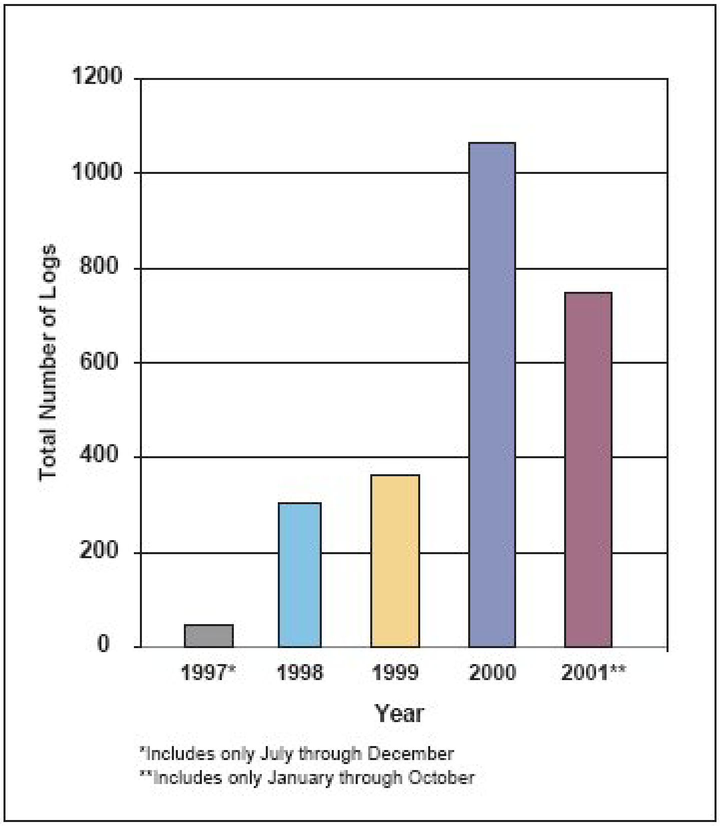


Figure 4.2.1. Transmission loading relief calls for 1997-2001 (Abraham, 2002)

Out of 186 transmission paths for the Eastern Interconnection, 50 were used to their maximum capacity at some point during the year, and 21 paths were congested more than 10% of the hours during the year studied in the 2002 DOE report. Figure 4.2.2 shows a map of the congestion for the Eastern Interconnection. The highest levels of congestion were found to be transmissions from Minnesota to Wisconsin, from the Midwest to the Mid-Atlantic, from the Mid-Atlantic to New York, and from the Southeast to Florida. Of the 106 transmission paths for the Western Interconnection, 37 were congested at some point during the year, half of these are congested less than 10% of the time, and no path is congested more than 60% of the hours during the year studied in the 2002 DOE report (see Figure 4.2.3). The Western Interconnection was built primarily to carry power over long distances, unlike that of the Eastern Interconnection, which may account for the differences between the two.

Construction of new transmission facilities would alleviate the stress of bottlenecking. However, investment in new transmission facilities (see Figure 4.2.4) is lagging behind investment in new generation and growth in electricity demand. Construction of high-voltage transmission facilities is expected to increase by 6% (in line miles) by 2012 in contrast to the expected 20% increase in electricity demand and generation capacity (in MW). This projected growth, which does not include impacts of potential transportation technologies such as plug-in hybrid electric vehicles (PHEVs), was deemed inadequate to ensure grid reliability (Abraham, 2002). The North American Electric Reliability

Corporation asserts that PHEVs have the potential to support grid reliability by supplementing electricity generation capacity during times of peak usage and drawing charging power from the grid during off-peak hours (North American Electric Reliability Corporation, 2009). FCVs may also have potential to support grid reliability; however, examination of grid effects of electric vehicles (PHEVs or FCVs) is beyond the scope of this study.

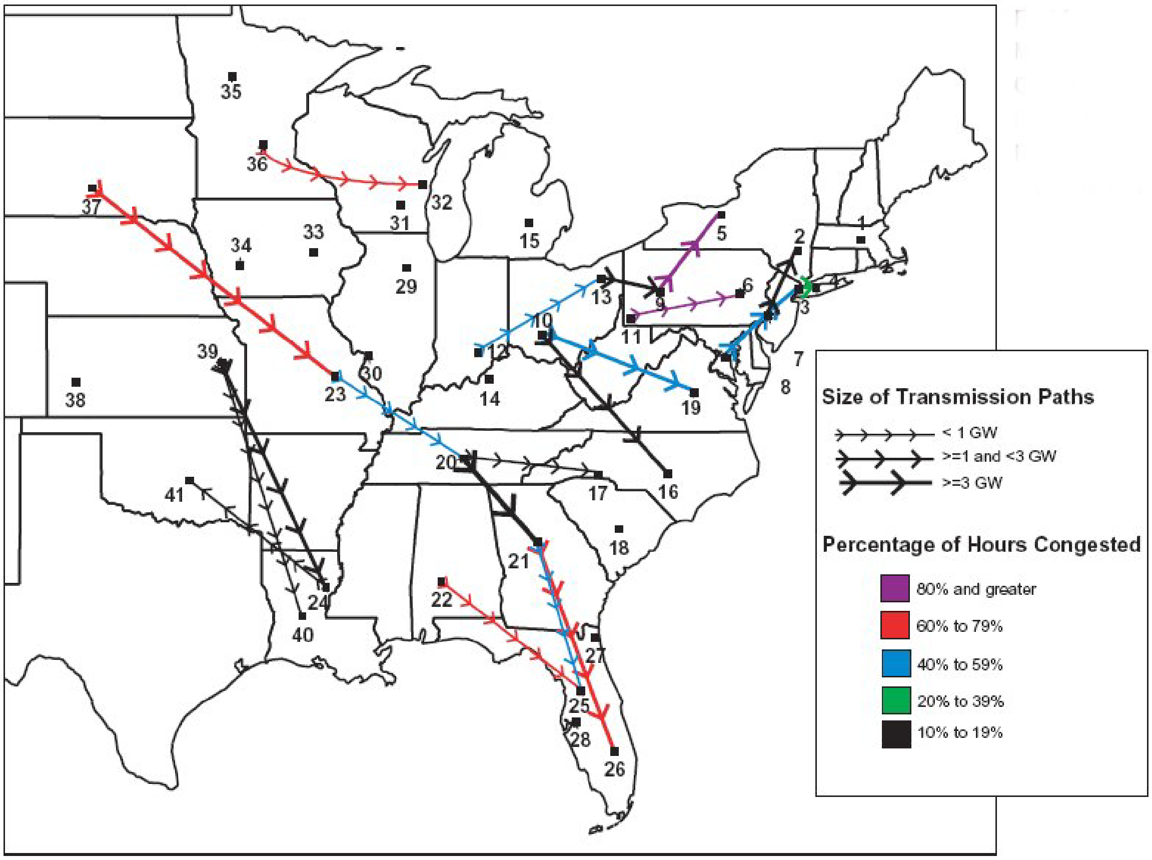


Figure 4.2.2. Map of Eastern Interconnection Congestion (Abraham, 2002)

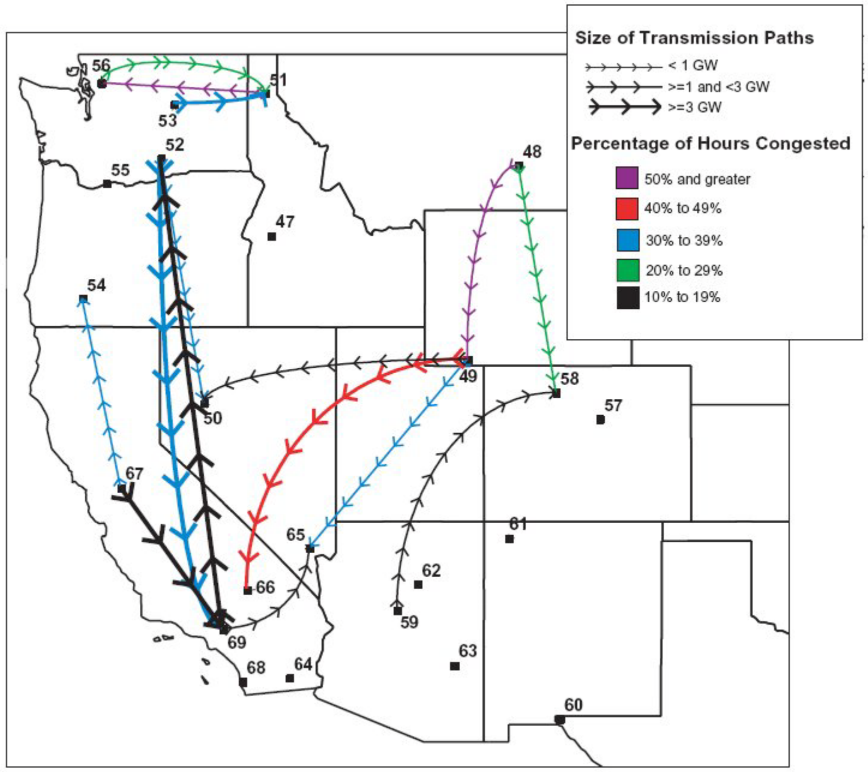


Figure 4.2.3. Map of Western Interconnection Congestion (Abraham, 2002)

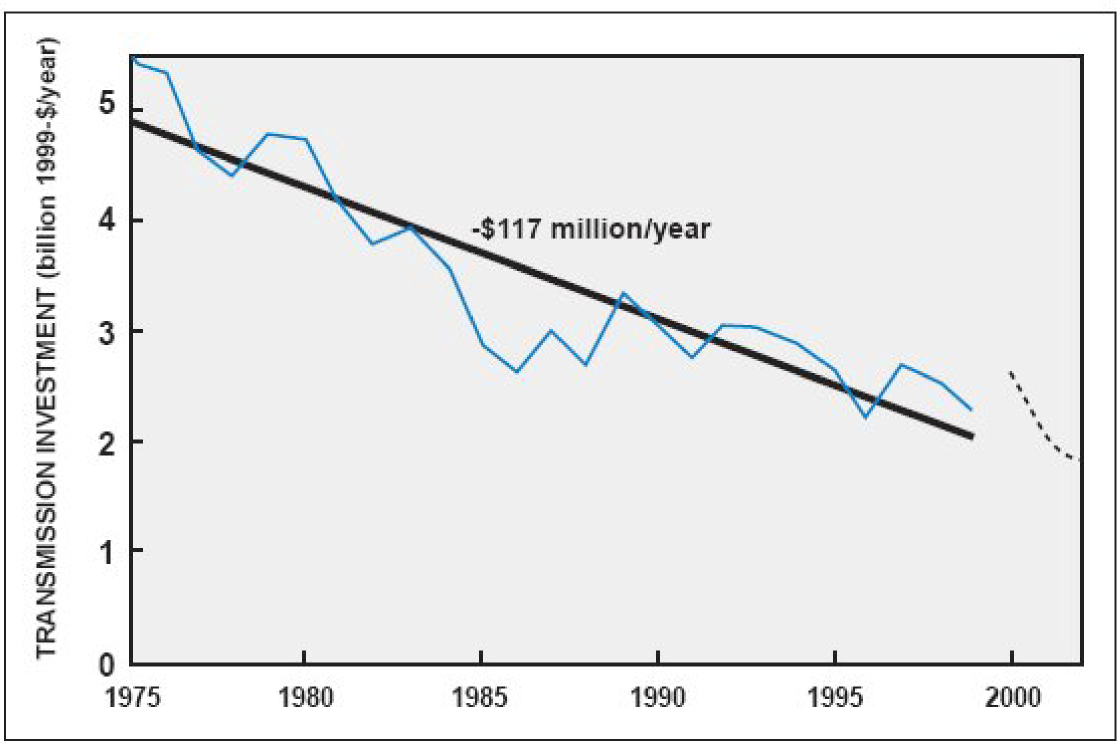


Figure 4.2.4. New transmission facility investment for the period 1975–2000 (Abraham, 2002)

4.3 Biomass Truck Transportation and Delivery

Delivery of biomass can be accomplished in multiple ways with rail or truck being the most common. The form of the truck is typically that of a tractor-trailer. Trailers can come in several varieties: log trailer, container trailer, or bulk van. Regardless of the tractor and trailer setup, an over-the-road truck of this combination is limited to a gross vehicle weight of 80,000 lbs. As an example and depending on the type of tractor (sleeper cab or non-sleeper), a bulk van will have a legal payload in the range of 42,000 to 52,000 lbs (20 to 25 tons), which translates to between 97 and 131 cubic yards of biomass (Hubbard, Biles, Mayfield, and Ashton, 2007). The capital cost of a tractor is approximately $75,000; a trailer costs approximately $35,000 (Harris et al., 2004).

Using the assumptions in this study, if the entire fleet of U.S. passenger vehicles were run on hydrogen produced from biomass, 890 million dry tons of biomass would be required annually to produce the necessary hydrogen (see Section 3.3). If all of this biomass were delivered by trucks with a payload of 20–25 tons, and each truck delivered three payloads per day on average, approximately 32,000–41,000 trucks would be needed.

The total number of Class 8 trucks (gross vehicle weight 33,001 lbs and more) in 2002 was estimated to be over 2.15 million. Annual retail sales of new Class 8 trucks ranged from 140,000 to 284,000 for the years 1998–2007 and averaged 200,000 over that 10-year timeframe (Davis et al., 2009). Truck availability is therefore not likely to limit implementation of biomass-gasification-based hydrogen production plants.

Perlack et al. (2005) estimated that 368 million dry tons of woody biomass is available from U.S. forest lands. Thus, to produce enough hydrogen to fuel all U.S. passenger vehicles, herbaceous biomass from agricultural lands would also be needed. Issues that impact biomass delivery distances and costs for woody and herbaceous biomass are described below.

Woody Biomass

In whatever form it takes (slash, small trees with limbs, or tree sections), woody biomass has an inherently low bulk density. Transportation costs are high due to this low bulk density because air is a major component of the transported biomass volume. Bulk density can be increased by processing (chipping, grinding, or shredding), which allows for the biomass to be compacted (see Figure 4.3.1). Processing, however, decreases biomass storage durability and longevity (Hubbard, Biles, Mayfield, and Ashton, 2007).

Additionally, woody biomass has a low energy density when compared to other fossil fuels (coal). For example, wood chips have approximately three times the bulk per unit energy than coal does and as a result need three times the storage space (Harris et al., 2004). Therefore, when compared to fossil fuels, biomass has a high transportation cost.

Figure 4.3.1. Bulk volume of woody biomass in different processed forms with the same weight (Hubbard, Biles, Mayfield, and Ashton, 2007)

A tradeoff between feedstock transportation and plant efficiency has resulted in an optimum electricity-generating power plant size of about 40–50 MW (1,750 tons woody biomass per day). This sized plant operating at full capacity would typically receive 70 truckloads per business day, requiring 140 daily truck trips (Timmons, Damery, Allen, and Petraglia, 2007). Processed (chipped) woody biomass can be accomplished at a cost of approximately $12 per ton in-woods cost. Assuming a freight cost of $2 per mile, a 25 ton payload of chipped biomass and a 50-mile delivery distance to the plant, the biomass can be transported at the cost of approximately $16 per ton (Harris et al., 2004) for a feedstock cost of $28 per wet ton or $37.33 per dry ton. The 2012 industry initiation/low demand cost target, which was used in the analysis, is $35 per dry ton in 2002 dollars or $37.96 per dry ton in 2005 dollars (Hess, Denney, Wright, Radtke, and Perlack, 2007).

Herbaceous Biomass

The National Renewable Energy Laboratory conducted a tradeoff analysis (Aden et al., 2002) to determine the effect of ethanol production plant size on the required radius of corn stover collection. A maximum corn stover yield of 2 metric tons (MT) was assumed. It was also assumed that the ethanol plant would be located in the middle of the farmland from which the corn stover would be collected and that 75% of the total surrounding land area is farm land that can be planted. In Figure 4.3.2, 100% access represents a scenario in which all farmers are growing corn continuously and are willing to sell their stover, a highly unlikely scenario. A 50% access represents a scenario in which farmers split their land between soybean and corn. It was found that this scenario is also unlikely because a soybean/corn rotation would not likely produce 2 MT per acre. A 10% access is a more realistic scenario. Aden et al. assumed that plants would not collect corn stover outside a 50-mile radius around the ethanol plant. The plant size from Figure 4.3.2 corresponding to 10% access, and a 50-mile radius is 2,000 MT stover per day (1,823 tons stover per day). This sized ethanol plant is comparable to the 1,750-ton-per-day power plant discussed in the woody biomass section.

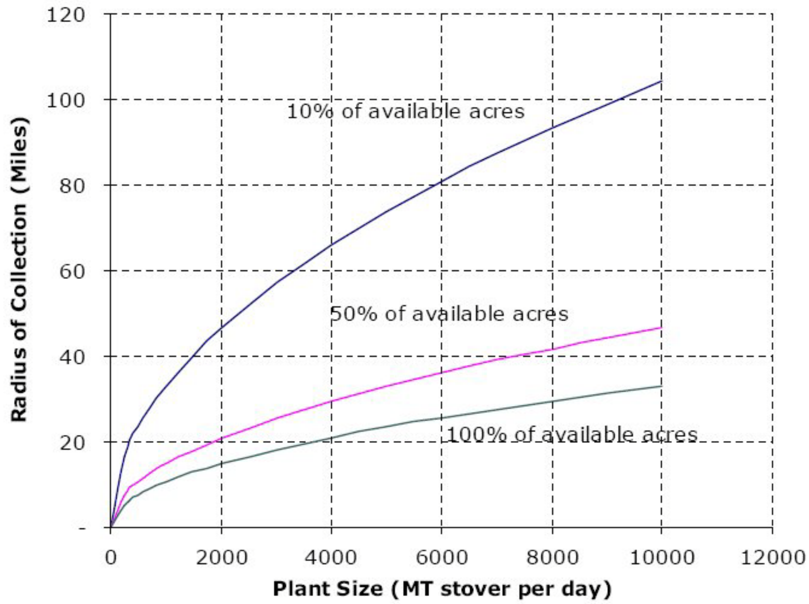


Figure 4.3.2. Effect of plant size on collection distance (Aden et al., 2002)

Figure 4.3.3 shows the relative contribution of the sources of costs for stover collection and delivery based on analyses done by Oak Ridge National Laboratory. The figure shows that 23% of the total delivered stover cost ($62 per dry MT/$56 per dry ton) is transportation cost. This $13-per-ton stover transport cost agrees favorably with the $16-per-ton woody biomass transport cost, both of which assume a 50-mile delivery distance.

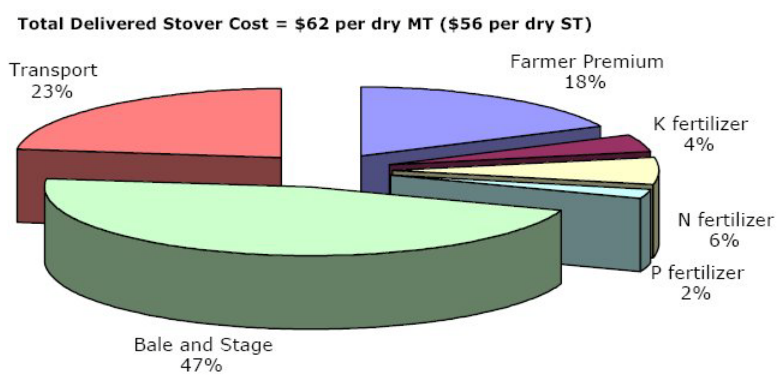


Figure 4.3.3. Breakdown of corn stover costs (Aden et al., 2002)

4.4 Coal Moved by Railway

For 2007, EIA reported that 1,138,529 thousand short tons of coal were moved via railroad from 18 states for electric-generation purposes (Energy Information Administration, 2008c). In November 2007, the U.S. Department of Transportation conducted research to determine future rail capacity to deliver increasing amounts of coal and the amount of investment that might be needed to fulfill that capacity (McCollum, Ogden, and Chernicoff, 2007). The study looked at several different scenarios (see Table 4.4.1) for coal demand growth (see Figure 4.4.1) and considered the tradeoff between pulverized coal (PC) or IGCC power plants, as well as an additional amount of coal to produce hydrogen for fuel cell vehicles.

Table 4.4.1. Various Scenarios for Coal Demand Growth

Scenario	Description
BAU1	Baseline scenario using EIA projection for coal power demand and assuming that all new coal plants will be PC
BAU2	BAU2a and BAU2b: A similar scenario to BAU1 but assuming that all new coal plants will be IGCC. BAU2b only: In addition to building new IGCC plants, all old PC plants are gradually retrofitted to IGCC.
BAU2+LowH2	A similar scenario to BAU2b except that in addition to IGCC plants being built, extra coal is used to supply a fleet of hydrogen fuel cell vehicles that obtain a 50% share of the total vehicle market by the year 2050
BAU2+HighH2	A similar scenario to BAU2b except that in addition to IGCC plants being built, extra coal is used to supply a fleet of hydrogen fuel cell vehicles that obtain a 100% share of the total vehicle market by the year 2050

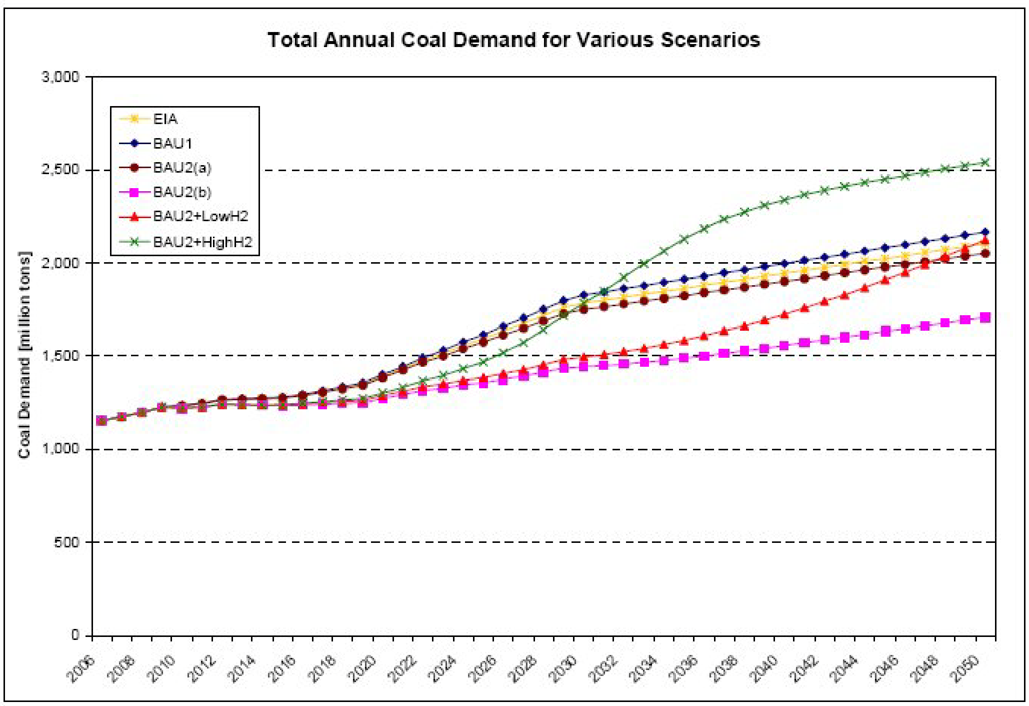


Figure 4.4.1. Total annual coal demand for various scenarios (McCollum, Ogden, and Chernicoff, 2007)

Coal traffic on each rail line was modeled using a confidential set of data known as the Carload Waybill Sample. Waybill sample data from 2004 (see Figure 4.4.2) were used in conjunction with the projections of the Freight Analysis Framework 2 (FAF2) program, which provides estimates of freight commodity flows. Projections were divided into coal (modified for the various scenarios) and non-coal (taken directly from FAF2) categories. Hypothetical waybill for future years for the various scenarios was then routed onto the rail network. Forty-two routes were identified that will likely carry the bulk of the coal demand in the future (see Figure 4.4.3). These routes represent approximately 5% of all route mileage in the North American rail network but are responsible for transporting more than 80% of the coal shipped by rail.

Four different capacity enhancement strategies were analyzed: 1) upgrading the signaling system to centralized traffic control; 2) upgrading the signaling system to positive train control; 3) adding new mainline track; and 4) upgrading the quality of mainline track, allowing heavier-capacity rail cars to be transported over them. It was determined that the incremental capital costs of adding capacity to all 42 routes is on the order of \$0.5–\$5.5 billion (in discounted terms, over the timeframe 2004–2050). The report also concluded that it did not seem likely that the incremental costs of adding new capacity will markedly increase coal transportation rates or the delivered price of coal, even under aggressive scenarios of coal demand growth.

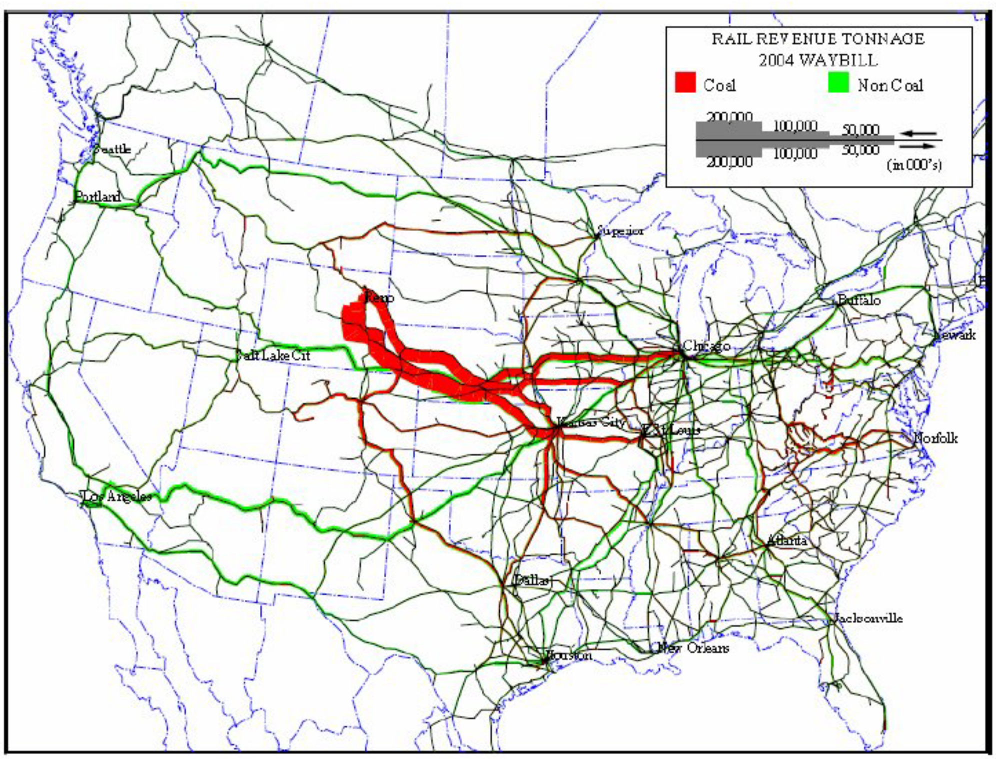


Figure 4.4.2. Rail traffic on the rail network for 2004 waybill sample data (McCollum, Ogden, and Chernicoff, 2007)

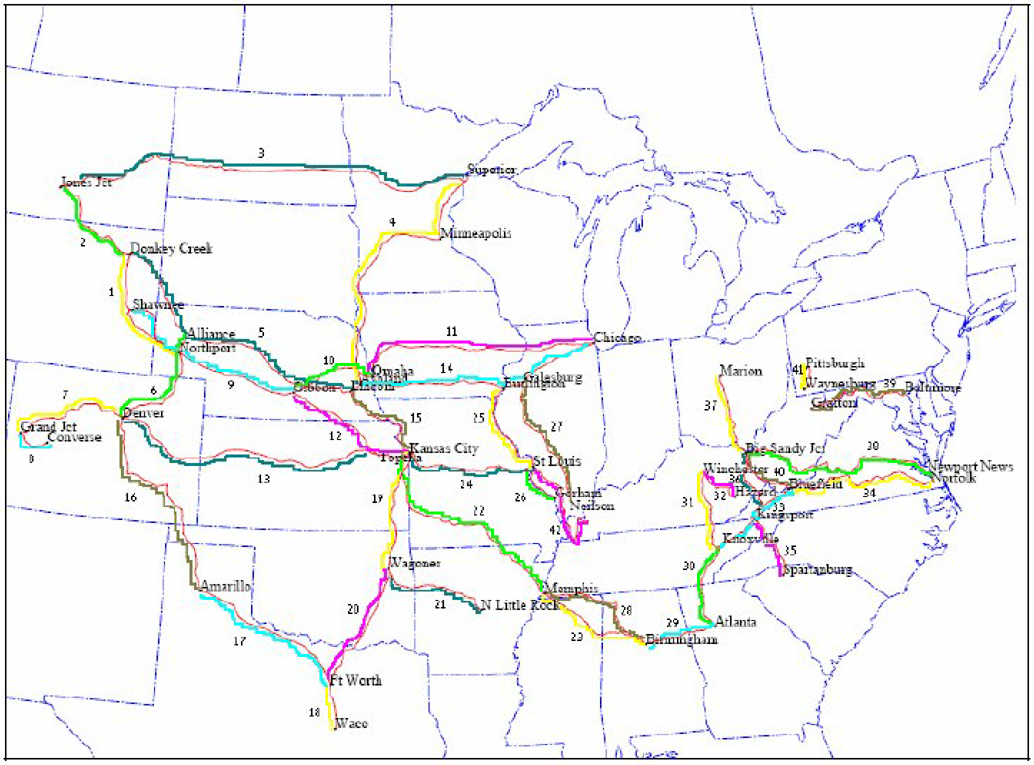


Figure 4.4.3. Coal rail routes (McCollum, Ogden, and Chernicoff, 2007)

5.0 Production Technology Description and Assumptions

The hydrogen production technologies used in each of the seven pathways examined in this study are described below. Note that this study assumes that energy used in the production facility for lighting, control systems, etc. is small relative to the energy used directly in the production process; these items are therefore not included in the cost, energy use, and emissions calculations.

5.1 Distributed Natural Gas Reforming

The H2A distributed natural gas model (James, 2008) determines a baseline delivered cost of hydrogen for the forecourt production of hydrogen from natural gas steam reforming. The natural gas reforming process is based on an ASPEN simulation of a 20-atm conventional tube-in-shell SMR with hydro-desulfurization pre-treatment and PSA gas cleanup. The PSA is based on a four-bed Batta cycle achieving 75% hydrogen recovery (single pass). Multiple passes are used to increase recovery. The unit is assumed to be factory built (as opposed to on-site construction) and skid-mounted for easy and rapid installation.

Reforming ($C_nH_m + nH_2O \rightarrow (n+m/2)H_2 + nCO$) and water-gas shift ($CO + H_2O \rightarrow CO_2 + H_2$) are the main reactions in the steam-reforming process. The reformer heat is supplied by the PSA offgas; a small amount of natural gas is added for burner control. The amount of natural gas added is equal to 10% of the heating value of the PSA offgas. The high-temperature-shift and low-temperature-shift reactors convert the majority of the CO into CO_2 and H_2 through the water-gas shift reaction.

A PSA unit is used to separate the hydrogen from the other components in the shifted gas stream, mainly CO_2 and unreacted CO, CH_4, and other hydrocarbons. The hydrogen purity achieved from a PSA unit can be greater than 99.99%. For this analysis, the concentration of hydrogen in the shifted stream prior to the PSA is between 60 and 65 mol%. Therefore, part of the PSA hydrogen product stream is recycled back into the PSA feed to increase the hydrogen concentration to 70 mol%. For a 70-mol% hydrogen PSA feed, an overall hydrogen recovery rate of 85% is typical with a product purity of 99.9 vol%.

A single 1,500 kg/day unit is assumed (as opposed to the previous H2A assumption of parallel 750 kg/day units). The system is assumed to be air cooled (and thus requires no cooling water flow). The product hydrogen exits the PSA at 300 psi and is compressed for storage in metal cylinder storage tanks (2,500 psi max pressures). The hydrogen is next compressed to 6,250 psi (maximum) for transfer into a four-bed, high-pressure cascade system to allow rapid filling of 5,000-psi onboard hydrogen vehicular tanks. A process flow diagram is shown in Figure 5.1.1.

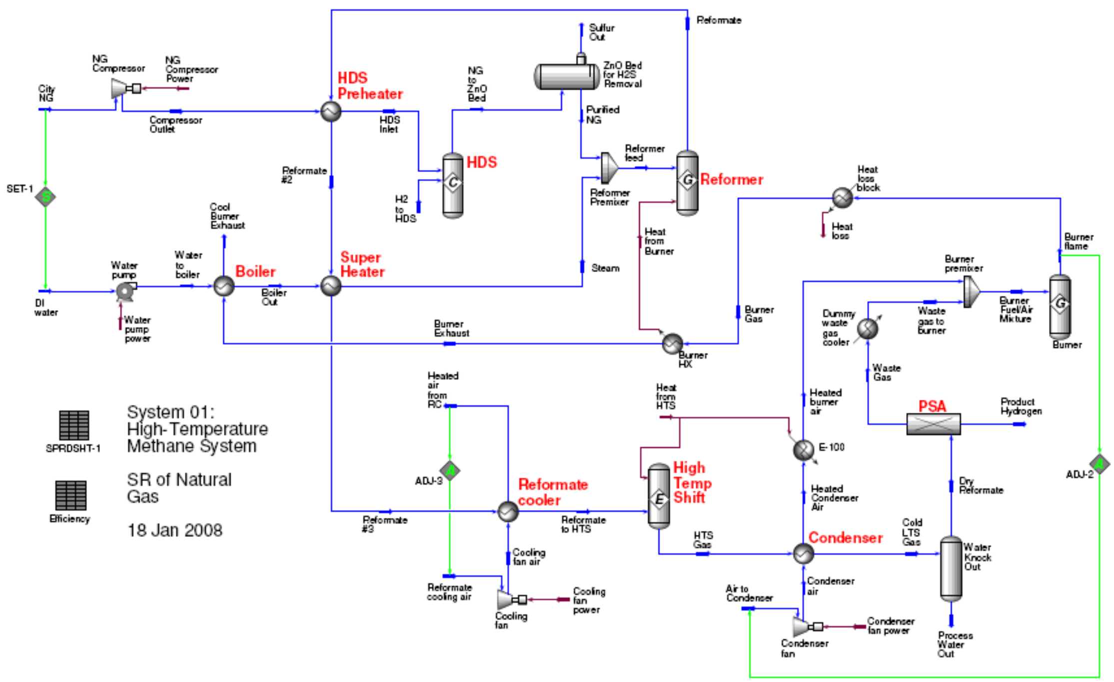


Figure 5.1.1. Distributed natural gas reforming process flow diagram (James, 2008)

5.2 Distributed Electrolysis

The system modeled in the H2A distributed electrolysis model (Ramsden, 2008b) is a standalone, grid-powered electrolyzer system with a total hydrogen production capacity of 1,500 kg/day. The system is based on the hydro bi-polar alkaline electrolyzer system [Atmospheric Type No.5040–5150 amp direct current (DC)]. The electrolyzer system modeled is a skid-mounted unit, including the electrolyzer system and necessary auxiliary subsystems. The electrolyzer units use process water for electrolysis and cooling water. KOH is the electrolyte in the system. The system includes the following equipment: transformer, thyristor, electrolyzer unit, lye tank, feed water demineralizer, hydrogen scrubber, gas holder, two compressor units to 30 bar (435 psig), deoxidizer, and twin tower dryer. A process flow chart and a mass balance diagram are shown in Figure 5.2.1 and Figure 5.2.2, respectively.

The electrolyzer system receives alternating current (AC) grid electricity, which is converted via transformer and rectifier sub-systems into DC electricity for use by the electrolyzer stack. The transformer subsystem is an oil-immersed, ambient air-cooled unit, manufactured to IEC-76. The rectifier sub-system converts the AC voltage to DC voltage using thyristors. Cooling is generally accomplished via forced air cooling achieved by fan(s) on the bottom of the rectifier cabinet but can also be accomplished with cooling water. The electrolyzer system uses 4.8 kWh of electricity per Nm^3 of hydrogen produced (53.4 kWh per kilogram of hydrogen produced) with the electrolyzer stack requiring 4.3 kWh and the remainder used by the balance of plant.

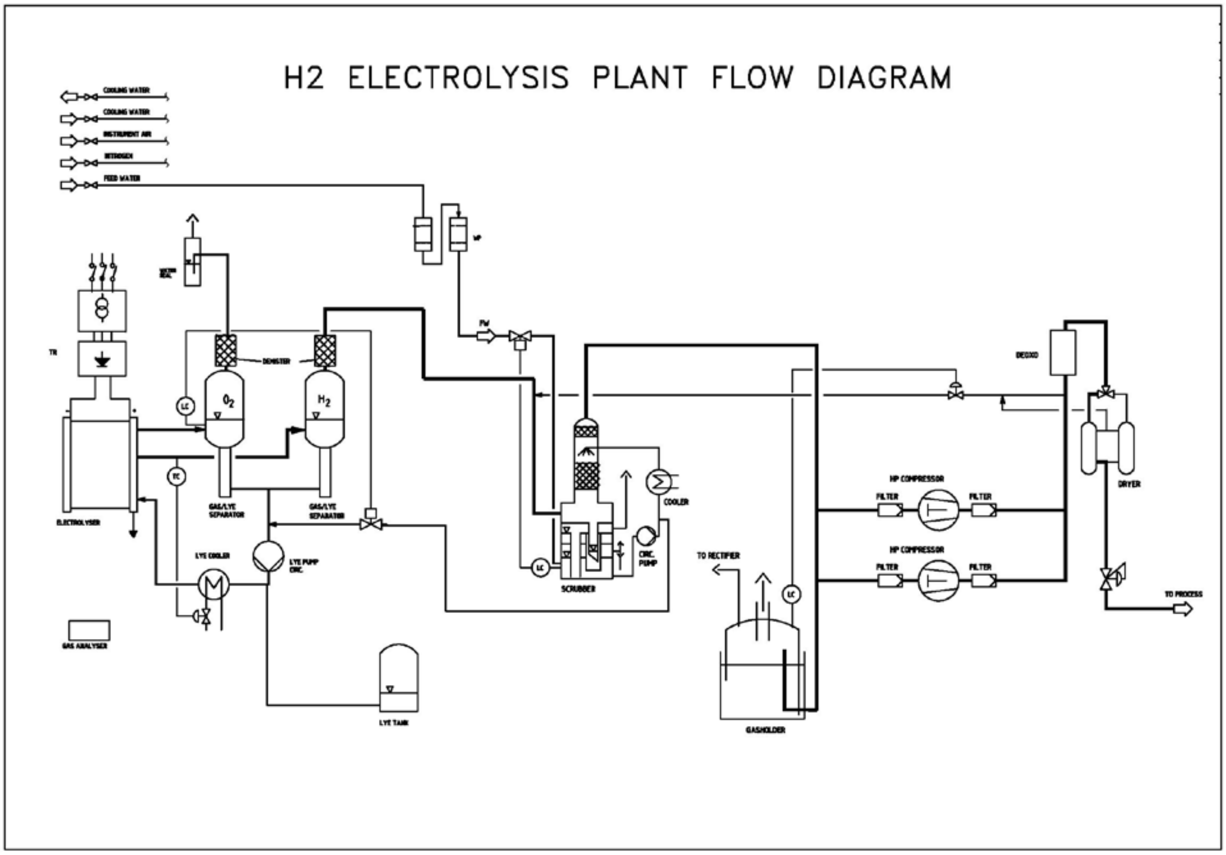


Figure 5.2.1. Distributed electrolysis process flow diagram (Ramsden, 2008b)

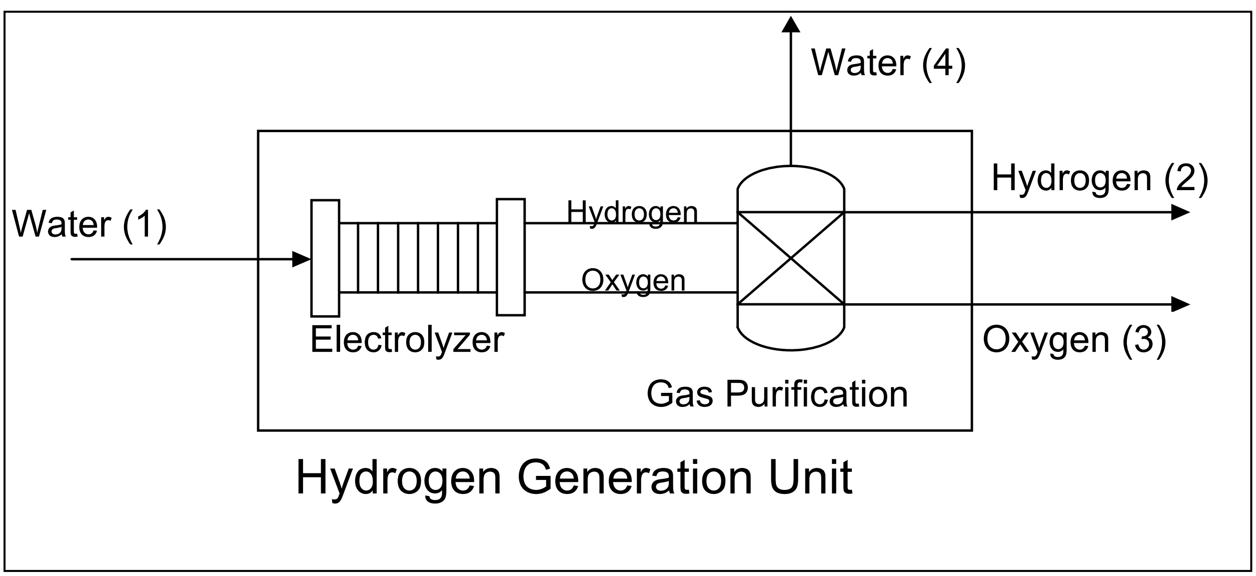


Figure 5.2.2. Distributed electrolysis mass balance diagram (Ramsden, 2008b)

The electrolyzer system requires high-purity water to avoid deterioration of electrolyzer performance. Process water is demineralized and softened to a specific resistance of 1 to 2 megaohm/cm in the demineralizer unit. The system requires 1 L of process water per Nm^3 of hydrogen produced (2.939 gal/kg H_2).

The system requires 100 L of cooling water per Nm^3 of hydrogen produced (293.9 gal/kg H_2 produced). It is assumed that the cooling water system is a closed water loop (see Figure 5.2.3), which is maintained at approximately 30°C via a water evaporative spray cooler. The spray cooler requires approximately 611 kg/day of water (0.41 L/kg H_2 – 0.11 gal/kg H_2).

The electrolyzer system produces hydrogen and oxygen from the electrolysis of feed water. The gas from each cell in the electrolyzer stack is collected in the hydrogen and oxygen flow channels and is fed into the gas/lye (KOH) separators. The lye, separated from the produced gas, is recycled through the lye pump, through the lye cooler, and back into the lye tank. Excess heat in the electrolyzer is removed by the lye cooler. Oxygen is removed from the lye in the oxygen/lye separator. The system modeled does not capture the oxygen gas, but capture of the high-purity oxygen gas is a possibility. Saturated hydrogen gas from the hydrogen/lye separator is fed to the gas scrubber subsystem, which purifies the hydrogen. The hydrogen gas is held in a small gas holder unit and then is compressed to 435 psig (30 bar). Following compression, residual oxygen is removed from the hydrogen gas by the deoxidizer unit, and the hydrogen gas is then dried in the twin-tower dryer. The purity of the hydrogen gas coming off the electrolyzer stack is 99.9 %. Following the gas purifier, deoxidizer, and dryer stages, the purity of hydrogen increases to 99.9998% (2 ppm impurities).

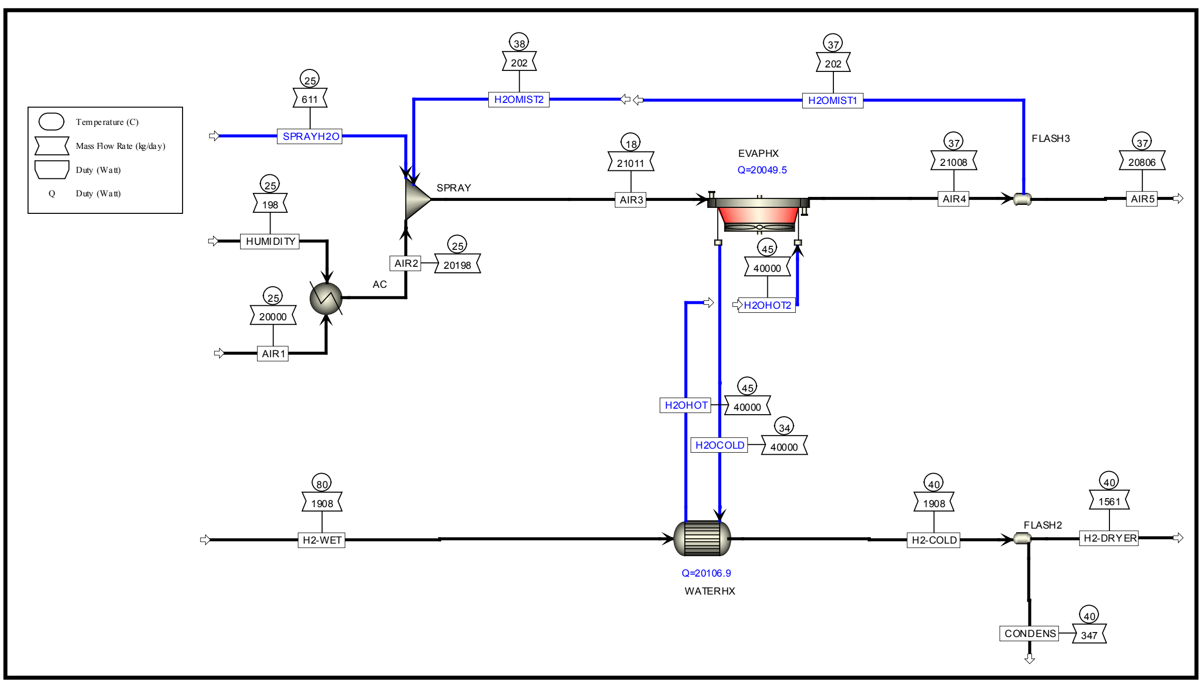


Figure 5.2.3. Distributed electrolysis process flow diagram cooling water detail (Ramsden, 2008b)

5.3 Central Biomass Gasification

The systems examined in the H2A central biomass gasification model (Mann and Steward, 2008) are based on the Battelle/FERCO indirectly heated biomass gasifier, conventional catalytic steam reforming, WGS, and PSA purification. The indirectly heated biomass gasifier uses hot sand circulating between the char combustor and the gasifier to provide the heat necessary for gasification. Steam is used as the fluidizing gas; no oxygen (as pure oxygen or air) is fed to the gasifier. The biomass feedstock is assumed to be a woody biomass, represented as hybrid poplar. A process flow chart is shown in Figure 5.3.1. The as-received wood is dried from 50 wt% moisture to 12% employing a rotary dryer. The dryer uses gas from the char combustor as the drying medium. Conveyors and hoppers are used to feed the wood to the low-pressure, indirectly heated entrained flow gasifier. Heat for the endothermic gasification reactions is supplied by circulating hot synthetic olivine, which is calcined magnesium silicate [primarily enstatite ($MgSiO_3$), forsterite (Mg_2SiO_3), and hematite (Fe_2O_3)] used as a sand for applications between the gasifier and a char combustor vessel. A small amount of MgO is added to the fresh olivine to keep it from forming glass-like bed agglomerations that would result from biomass potassium interacting with the silicate compounds. The gasification medium is steam. The char that is formed in the gasifier is burned in the combustor to reheat the olivine. Particulate removal is performed through cyclone separators. Ash and any sand particles are landfilled.

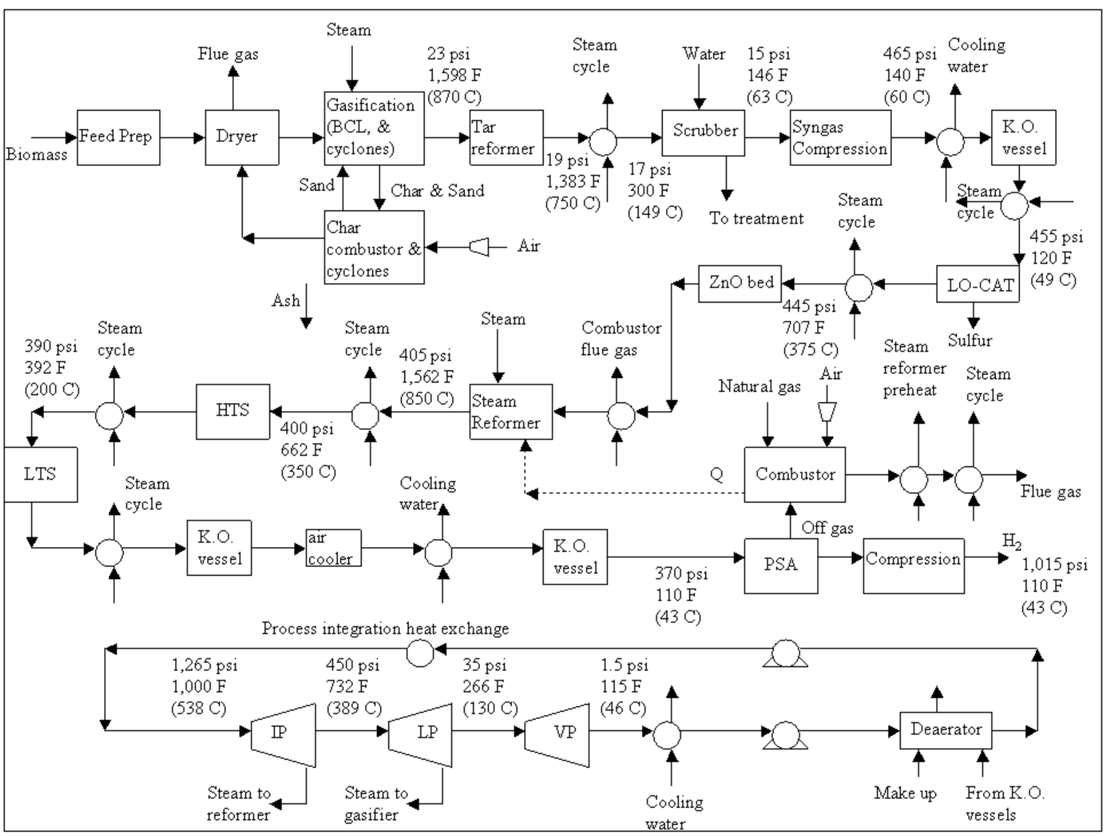


Figure 5.3.1. Central biomass gasification flow diagram (Mann and Steward, 2008)

Reforming ($C_nH_m + nH_2O \rightarrow (n+m/2)H_2 + nCO$) and water-gas shift ($CO + H_2O \rightarrow CO_2 + H_2$) are the main reactions in the steam-reforming process. The reformer heat is supplied by PSA offgas; a small amount of natural gas is added for burner control. The amount of natural gas added is equal to 10% of the heating value of the PSA offgas. The high-temperature-shift and low-temperature-shift reactors convert the majority of the CO into CO_2 and H_2 through the water-gas shift reaction.

A PSA unit is used to separate the hydrogen from the other components in the shifted gas stream, mainly CO_2 and unreacted CO, CH_4, and other hydrocarbons. The hydrogen purity achieved from a PSA unit can be greater than 99.99%. For this analysis, the concentration of hydrogen in the shifted stream prior to the PSA is between 60 and 65 mol%. Therefore, part of the PSA hydrogen product stream is recycled back into the PSA feed to increase the hydrogen concentration to 70 mol%. For a 70-mol% hydrogen PSA feed, an overall hydrogen recovery rate of 85% is typical with a product purity of 99.9 vol%.

The steam-cycle produces power in addition to providing steam for the gasifier and reformer operations. The steam cycle is integrated with the biomass-to-hydrogen production process. There is an extraction steam turbine/generator, and steam is supplied to the reformer and gasifer from the intermediate and low pressure turbine sections, respectively. Superheated steam enters the intermediate pressure turbine at 1,000ºF and 1,265 psia and is expanded to a pressure of 450 psia. The steam then enters a low-pressure turbine and is expanded to a pressure of 35 psia. Finally, the steam enters a condensing turbine and is expanded to a pressure of 1.5 psia. Preheaters, steam generators, and superheaters are integrated within the process design. The condensate from the syngas compressor and the condensate from the cooled shifted-gas stream prior to the PSA are sent to the steam cycle, de-gassed, and combined with the make-up water. A pinch analysis was performed to determine the heat integration of the system.

A cooling water system is also included in the Aspen Plus® model to determine the requirements of each cooling-water heat exchanger within the hydrogen production system as well as the requirements of the cooling tower. The cooling water supply temperature is 90°F, and the return temperature is 110°F.

5.4 Central Natural Gas Reforming

Steam reforming of hydrocarbons continues to be the most efficient, economical, and widely used process for production of hydrogen and mixtures of hydrogen and carbon monoxide (CO). The H2A central natural gas reforming model (Steward, 2008) assesses the economic production of hydrogen by steam reforming of natural gas.

A process flow chart is shown in Figure 5.4.1, and the stream summaries are shown in Table 5.4.1. Natural gas is fed to the plant from the pipeline at a pressure of 450 psia. The gas is generally sulfur-free, but odorizers with mercaptans must be cleaned from the gas to prevent contamination of the reformer catalyst. The desulfurized natural gas feedstock is mixed with process steam to be reacted over a nickel-based catalyst contained inside a system of high alloy steel tubes. The reforming reaction, which converts the methane to a mixture of CO and H_2, is strongly endothermic, and the metallurgy of the tubes usually limits the reaction temperature to 1,400°F–1,700°F.

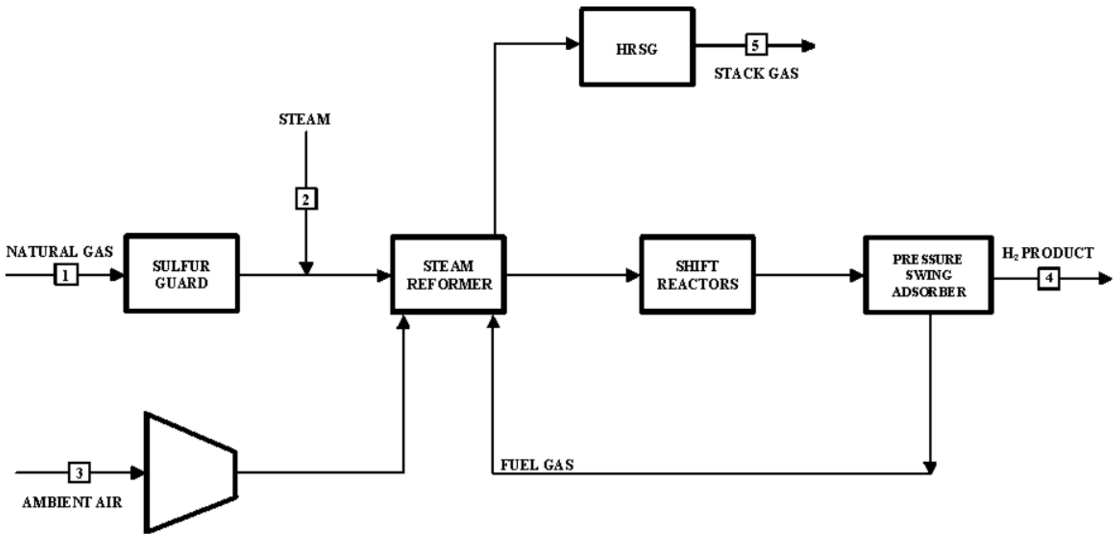


Figure 5.4.1. Central natural gas process flow diagram (Steward, 2008)

Table 5.4.1. Central Natural Gas Stream Summary (Steward, 2008)

STREAM NUMBER	1	2	3	4	5
	Natural Gas	Steam	Air	Hydrogen	Stack Gas
Mole Fraction					
Ar	0.0000	0.0000	0.0093	0.0000	0.0073
CH_4	0.9000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0500	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0004	0.0013	0.1677
H_2	0.0000	0.0000	0.0000	0.9947	0.0000
H_2O	0.0000	1.0000	0.0101	0.0000	0.1835
N_2	0.0500	0.0000	0.7724	0.0040	0.6115
O_2	0.0000	0.0000	0.2078	0.0000	0.0301
NO_x	----	----	----	----	20 ppm
Total Flow (lbmol/hr)	6,981	24,432	29,489	16,102	37,697
Total Flow (lb/hr)	121,060	440,145	851,008	35,008	1,095,760
Temperature (°F)	59	750	60	108	280
Pressure (psia)	450.0	450.0	14.7	346.0	14.7

Reforming ($C_nH_m + nH_2O \rightarrow (n+m/2)H_2 + nCO$) and water-gas shift ($CO + H_2O \rightarrow CO_2 + H_2$) are the main reactions in the steam-reforming process. The reformer heat is supplied by the PSA offgas; a small amount of natural gas is added for burner control. The amount of natural gas added is equal to 10% of the heating value of the PSA offgas. The high-temperature-shift and low-temperature-shift reactors convert the majority of the CO into CO_2 and H_2 through the water-gas shift reaction.

A PSA unit is used to separate the hydrogen from the other components in the shifted gas stream, mainly CO_2 and unreacted CO, CH_4, and other hydrocarbons. The hydrogen purity achieved from a PSA unit can be greater than 99.99%. For this analysis, the concentration of hydrogen in the shifted stream prior to the PSA is between 60 and 65 mol%. Therefore, part of the PSA hydrogen product stream is recycled back into the PSA feed to increase the hydrogen concentration to 70 mol%. For a 70-mol% hydrogen PSA feed, an overall hydrogen recovery rate of 85% is typical with a product purity of 99.9 vol%.

The flue gas path of the fired reformer is integrated with additional boiler surfaces to produce about 700,000 lb/hour steam. Of this, about 450,000 lb/hour is superheated to 450 psia and 750°F to be added to the incoming natural gas. Additional steam from the boiler is sent off-site; however, revenue from the steam is not factored into the economic assessment. After the reformer, the process gas mixture of CO and H_2 passes through a heat recovery step and is fed into a water-gas shift reactor to produce additional H_2.

5.5 Central Electrolysis

The system modeled in the H2A central electrolysis model (Ramsden, 2008a) is a standalone grid-powered electrolyzer system with a total hydrogen production capacity of 52,300 kg/day. The technology is identical to that used for distributed electrolysis even though it is 35 times larger, which provides economies-of-scale for the auxiliary components. As such, the process description for distributed electrolysis in Section 5.2 describes this production process as well.

The H2A central electrolysis model is not based on wind-power, so this analysis assumed that a single facility is buying electricity from the grid and wind-power credits for all the electricity purchased. Because the facility is using grid power, the operating capacity factor is 97%. If the facility were co-sited with the wind turbines, it is likely to have a lower operating capacity because the turbines will not be generating electricity much of the time. The optimal location and the capacity factor were not included in this analysis.

5.6 Central Coal with Carbon Capture and Sequestration

The H2A central coal with carbon capture and sequestration model (Rutkowski, 2008a) uses capital and operating cost data to be used to arrive at a plant gate cost for hydrogen produced from coal gasification. Hydrogen cost was determined by first preparing a plant design for hydrogen production based on currently available process technology and then meeting current permitting regulations for environmental compliance. This baseline plant captures CO_2.

To arrive at a cost estimate for hydrogen, the design includes commercially available process technology obtained from verifiable sources. The plant utilizes a Wabash River-scale ConocoPhillips (EGas^{TM}) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial PSA. A steam turbine supplies the electricity needed for the process except that required to compress the CO_2. Two-stage Selexol® is used to remove CO_2. Carbon dioxide is compressed to 2,200 psi for sequestration using electricity purchased from the grid (U.S. grid mix). The EGas^{TM} gasifier is the gasifier of choice for this study because it has been operated on both bituminous and subbituminous coals. Simulations of hydrogen from coal in central plants are based on the use of Pittsburgh No. 8 bituminous coal while GREET simulations are based on generic coal. Table 5.6.1 presents the properties of Pittsburgh No. 8 coal used in the H2A analysis. A process flow chart is shown in Figure 5.6.1, and the energy efficiencies are shown in Table 5.6.2.

Table 5.6.1. Pittsburgh No. 8 Coal Properties (Rutkowski, 2008a)

Coal Constituents

Component	**Air Dry, %**	**Dry, %**	**As Received, %**
Carbon	71.88%	73.79%	69.36%
Hydrogen	4.97%	4.81%	5.18%
Nitrogen	1.26%	1.29%	1.22%
Sulfur	2.99%	3.07%	2.89%
Ash	10.30%	10.57%	9.94%
Oxygen	8.60%	6.47%	11.41%
Total	100.00%	100.00%	100.00%
Moisture			6.00%
Volatile matter		38.20%	35.91%
Fixed carbon		51.23%	48.15%
Total (including ash)		100.00%	100.00%

Heating Values, standard units

Value	**Dry, Btu/English ton**	**As Received, Btu/English ton**
High heating value	26,488,000	24,900,000
High heating value free of moisture and ash	29,620,000	
Low heating value		23,806,000

Heating Values, SI units

Value	**Dry, MJ/kg**	**As Received, MJ/kg**
High heating value	30.804	28.957
High heating value free of moisture and ash	34.446	
Low heating value		27.685

Ash Constituents of Coal: Dry Coal-Based

Component	**Dry, %**
Silica, SiO_2	48.10%
Aluminum oxide, Al_2O_3	22.00%
Iron oxide, Fe_2O_3	24.00%
Titanium dioxide, TiO_2	1.30%
Calcium oxide, CaO	1.30%
Magnesium oxide, MgO	0.60%
Sodium oxide, Na_2O	0.30%
Potassium oxide, K_2O	1.50%
Sulfur trioxide, SO_3	0.80%
Phosphorous pentoxide, P_2O_5	0.10%
Total	100.00%

Ash Fusion Temperature, degrees F

Item	**Reducing Atmosphere**	**Oxidizing Atmosphere**
Initial deformation	2,015	2,570
Spherical	2,135	2,614
Hemispheric	2,225	2,628
Fluid	2,450	2,685

Ash Fusion Temperature, degrees C

Item	**Reducing Atmosphere**	**Oxidizing Atmosphere**
Initial deformation	1,087	1,396
Spherical	1,154	1,420
Hemispheric	1,204	1,428
Fluid	1,329	1,460

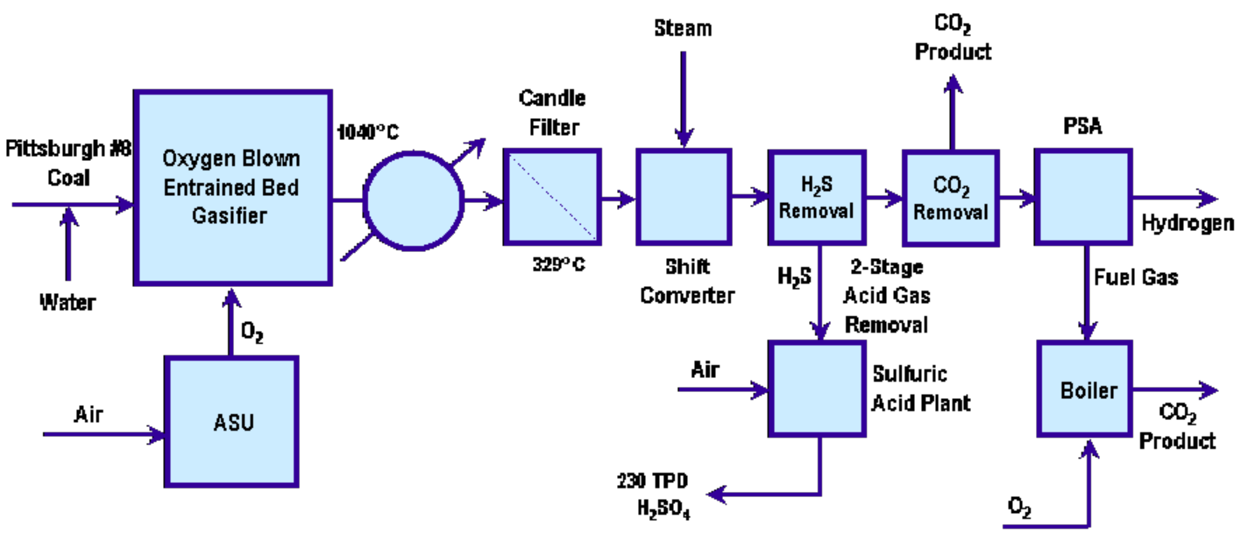


Figure 5.6.1. Central coal with carbon capture process flow diagram (Rutkowski, 2008a)

Table 5.6.2. Energy Efficiencies of Process Components of the Central Coal with Carbon Capture and Sequestration Pathway (Rutkowski, 2008a)

Energy efficiencies for individual process steps (add rows as appropriate)	**Value**	**Basis**	**Reference**
Gasifier Cold Gas Effieiency	72%	LHV efficiency of energy in gasifier product gas coming out of gasifier divided by energy in coal fed to gasifier.	Aspen Plus Model
Carbon Conversion	99%	Percent of carbon in coal converted to gaseous product	ConocoPhillips gasifier spec.
Shift Reactor Conversion	90%	Molar percent of CO converted to CO2	Haldor Topsoe commercial catalyst spec.
PSA Hydrogen Separation	80%	Percent hydrogen rercovered from PSA feed gas	UOP commercial PSA design spec.

6.0 Delivery Technology Description and Assumptions

The hydrogen delivery and distribution technologies used in each of the seven pathways examined in this study are described below. Note that this study assumes that energy used in the hydrogen refueling station for lighting, cryogenic pumping, security cameras, etc. is small relative to the total delivery and distribution energy use; these items are therefore not included in the cost, energy use, and emissions calculations.

6.1 Liquid Hydrogen Delivery

The components for the liquid hydrogen pathway include: central production → liquefier → liquid hydrogen (including liquid storage for plant outages) → liquid hydrogen truck transmission and distribution → and liquid hydrogen fuel station. For liquid hydrogen truck transmission and distribution, HDSAM calculates the number and cost of the trucks and trailers required to deliver the fuel to fuel stations as well as distances traveled. The capital and operating costs of the delivery trucks, including the amount of diesel fuel required, are computed. Additionally, the cost of appropriately sized liquefiers, terminal storage, liquid pumps, vaporizers, etc. are calculated.

Peak demand is used to determine the design capacity of the terminal or depot where hydrogen is stored and loaded onto trailers for delivery to stations. Cryogenic storage tanks are used to mitigate production outages and demand surges and are assumed to be sited immediately adjacent to the production facility. The terminal's storage requirement is determined by the following factors: peak daily demand, days of summer peak demand, and expected days per year that the production plant is off-line. The amount of required storage determines the number of truck-filling bays required at the terminal, the capacities of storage tanks, and the resulting capital and operating costs associated with the terminal. Liquefier design is also linked to peak demand.

6.1.1 Liquid Hydrogen Truck

A typical liquid hydrogen trailer can carry up to 3,900 kg of hydrogen. HDSAM calculates the amount of hydrogen that is loaded on a trailer when it leaves the terminal. The equation is as follows:

$$H2(kg) = V_{\tan k}\,\rho_{LH2}\,A_{LH2truck}$$

Where:
V_{tank} = water volume of the trailer (m^3)
ρ_{LH2} = density of liquid hydrogen (g/L)
$A_{LH2Truck}$ = availability of the liquid truck

The amount of hydrogen loaded on the trailer is then used to calculate the amount of boil-off losses during delivery to a station, using the following equation:

$$H_{2,boil-off} = H_{2,prev} B_r T$$

Where:
$H_{2,prev}$ = hydrogen in trailer from previous station
B_r = boil-off rate (fraction of a day)
T = travel time (days)

HDSAM assumes there are only combinations of one tractor and one trailer. Additionally, it is assumed that the stations are the same distance from the terminal and that the same amount of hydrogen is delivered to each station.

Total fuel cost is determined by multiplying the HDSAM fuel cost value by the fuel consumption by trip, which is calculated based on truck fuel economy and distance traveled. Total capital (truck and trailer), labor and other operational and maintenance costs are added together so a cost for hydrogen can be determined.

6.1.2 Liquefier

For the pathways analysis, HDSAM is able to cost a single liquefier unit based on an idealized liquefier power equation and an energy requirement based on literature data. The actual power requirement is calculated using the curve in Figure 6.1.1. Figure 6.1.1 shows how the energy requirement of a liquefier decreases as the design capacity or hydrogen flow rate drops below 5 tonnes/day.

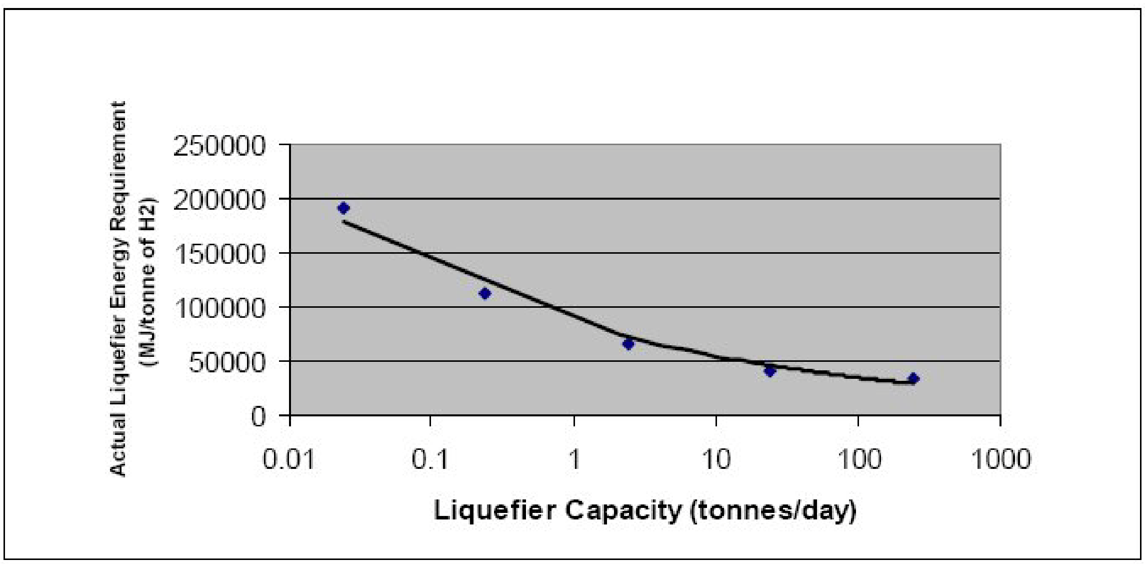


Figure 6.1.1. Liquefier energy requirement versus hydrogen flow rate (National Renewable Energy Laboratory, 2006)

The formula for the actual power requirement is as follows:

$$P_{liq} = P_{req} \frac{F_{avg}}{1 - loss}$$

Where:
P_{req} = curve fit from Figure 6.1.1
F_{avg} = average hydrogen flow rate out
loss = hydrogen loss during liquefaction

The thermodynamically ideal system for liquefaction assumes reversible isothermal compression and a reversible isentropic expansion. The theoretical power requirement is calculated using the following formula:

$$-\frac{\dot{W}_{net}}{\dot{m}} = T_1\ (s_{in} - s_{out}) - (h_{in} - h_{out})$$

Where:
W_{net} = idealized net work required by the liquefier [kWh / (kg/day)]
m = design capacity of the liquefier (kg/day)
T_1 = inlet temperature to the liquefier (K)
s_m = hydrogen entropy at the inlet temperature [kWh / K(kg/day)]
s_{out} = hydrogen entropy at the outlet temperature [kWh / K(kg/day)]
h_{in} = hydrogen enthalpy at the inlet temperature [kWh / (kg/day)]
h_{out} = hydrogen enthalpy at the outlet temperature [kWh / (kg/day)]

The liquefier efficiency is then just the theoretical power divided by the actual power requirement.

It is assumed that the inlet and outlet pressures for the liquefier are both 1 atm and that the feed to the system is pure hydrogen.

A cost curve has been developed based on several literature sources that estimate the capital cost of a liquefier. Figure 6.1.2 displays the costs for a liquefier only and does not include other direct and indirect costs such as installation, contingencies, property taxes and engineering. The costs in Figure 6.1.2 were determined from reports published from 1986 to 2002 and were scaled to 2005 dollars using the GDP Deflator Price Index found in EIA's Short Term Energy Outlook.

It is assumed that a 30 tonne/day liquefier will require approximately 25,000 m^2 of land. The land required for other sizes of liquefiers is calculated by taking the ratio of the design capacity to 30 tonnes/day; the result is then raised to the 0.6 power. That result is multiplied by 25,000 to give the amount of land required.

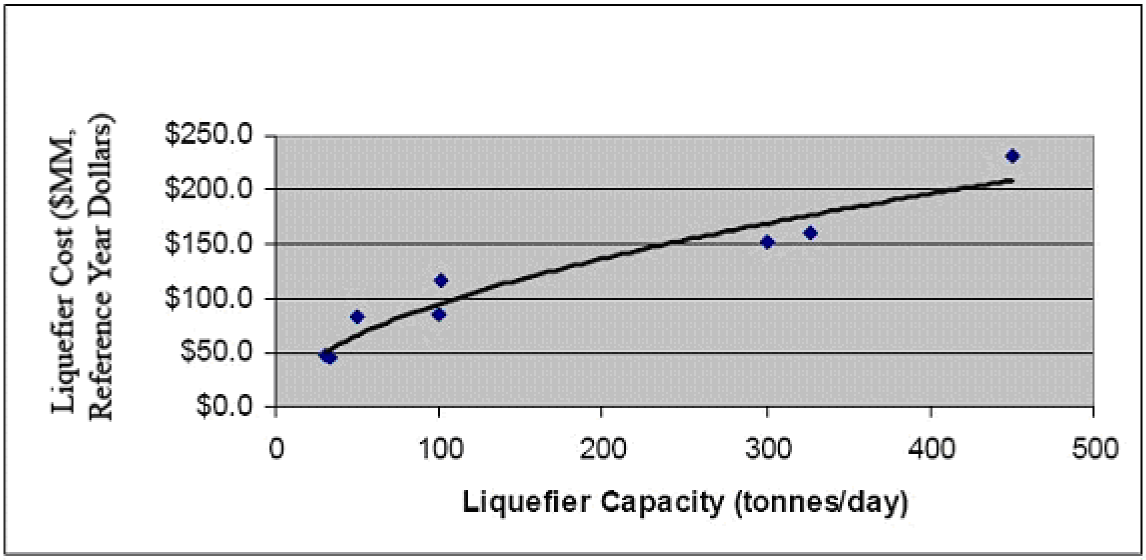


Figure 6.1.2. Liquefier cost versus design capacity (National Renewable Energy Laboratory, 2006)

The annual energy requirement is calculated using the following formula:

$$E_{ann} = 8760 P_{liq}$$

Where:
E_{ann} = annual energy requirement
P_{liq} = actual power requirement

The total utility cost is then determined by multiplying the H2A fuel/utility cost by the annual energy requirement. Total capital, labor, and other operational and maintenance costs (not inclusive to what is presented here) are added together so a cost for hydrogen can be determined.

6.2 Gaseous Hydrogen Delivery

The components for gaseous hydrogen pathways include: central production → compressor → geologic storage for plant outages → transmission and distribution pipeline → and gaseous hydrogen fuel station. The largest diameter pipe of those in each scenario is the transmission pipeline. It extends from the production facility to the city gate. The diameter of the transmission pipeline is a function of its length, peak hydrogen demand, and the pressure differential between the pipeline inlet at the production end and the pipeline outlet at the city gate. An intermediate diameter pipe (trunk line) creates one or more rings within an area and is used to carry hydrogen from the transmission line to the individual service pipelines that connect to each individual hydrogen fuel station. HDSAM finds the least-cost combination of trunk and service lines and in doing so determines the number of trunk lines, their location, lengths, and diameters.

The pipeline system requires a compressor to increase hydrogen pressure from its production level to the pressure at the terminus of the transmission line. Design requirements for the pipeline central compressor can be calculated as a function of change in pressure and the peak hydrogen throughput (after accounting for losses in the pathway).

6.2.1 Pipeline

Pipeline diameter is calculated using the Panhandle B pipeline equation and is used to simulate compressible flow. The equation is as follows:

$$q_{sc} = 737\left(\frac{T_{sc}}{P_{sc}}\right)^{1.02}\left(\frac{(P_1^2 - P_2^2)d^{4.961}}{\gamma^{0.961} L T_m Z_m}\right)^{0.51} E$$

Where:
q_{sc} = gas rate at standard conditions (scf / day)
T_{sc} = temperature at standard conditions (°R)
P_{sc} = pressure at standard conditions (psia)
P_1 = inlet pressure (psia)
P_2 = outlet pressure (psia)
d = inside pipe diameter (in)
γ = mean gas relative density (air = 1)
L = pipeline length (mile)
T_m = mean temperature of pipeline (°R)
Z_m = mean compressibility factor
E = pipeline efficiency

T_{sc}, P_{sc}, and E are assumed to be 530 R, 14.7 psia, and 0.92, respectively. It is assumed that no energy is required by the pipeline.

The H2A Delivery Components model uses a cost curve to estimate the capital cost of a hydrogen pipeline system. Data from the curve are based on a University of California, Davis study and is broken down into four parts: pipeline material cost, labor cost, miscellaneous cost and right-of-way cost. It is assumed that the cost of hydrogen pipeline will be 10% higher than that of natural gas pipeline given that materials and weld-types may be different. Total capital, labor, and other operational and maintenance costs for each part of the pipeline (transmission, trunk, and service) are added together so a cost for hydrogen can be determined (National Renewable Energy Laboratory, 2006).

6.2.2 Compressor

A compressor is required to raise the pressure of the hydrogen produced at a central facility to the pressure in a pipeline. These compressors are integral parts of the pipeline delivery network. HDSAM is designed to cost a centralized compressor that can raise the pressure of a defined flow rate from one pressure to another. Spare compressor units are included in the model to ensure a high level of operational availability.

It is assumed that there are no pressure drops in the after-cooler or interstage coolers. Also, an electrical-powered compressor is assumed.

A cost curve has been developed to estimate the capital cost of a compressor. Data for the cost curve were acquired from an article published in the *Oil and Gas Journal* in the year 2000. Costs include the purchase costs for natural gas compressors, the cost of an aftercooler, and other direct and indirect capital costs (installation, contingencies, property taxes, and engineering). The data were adapted to that of a hydrogen compressor (1.3 times the cost of a natural gas compressor) and inflated to 2005 dollars using the GDP Implicit Deflator Price Index in EIA's Short Term Energy Outlook. Figure 6.2.1 shows the cost of a compressor versus power draw.

The capital cost of the compressor needs to be based on a unit that is capable of processing the peak hydrogen flow rate. During a typical operating year, however, the feed flow rate will fluctuate. Therefore, an average hydrogen flow rate is used as a basis to calculate the annual energy requirement. The equation is as follows:

$$E_{ann} = 8760 \frac{F_{avg}}{\eta_{isentrop}} ZRT_1 N_{st} \left(\frac{k}{k-1} \right) \left[\left(\frac{p_2}{p_1} \right)^{\frac{k-1}{kN_{st}}} - 1 \right]$$

Where:
$\eta_{isentrop}$ = isentropic compressor efficiency
F_{avg} = average hydrogen flow rate
R = gas constant
T_1 = inlet gas temperature
N_{st} = number of compression stages
k = ratio of specific heats
p_2 = outlet pressure
p_1 = inlet pressure

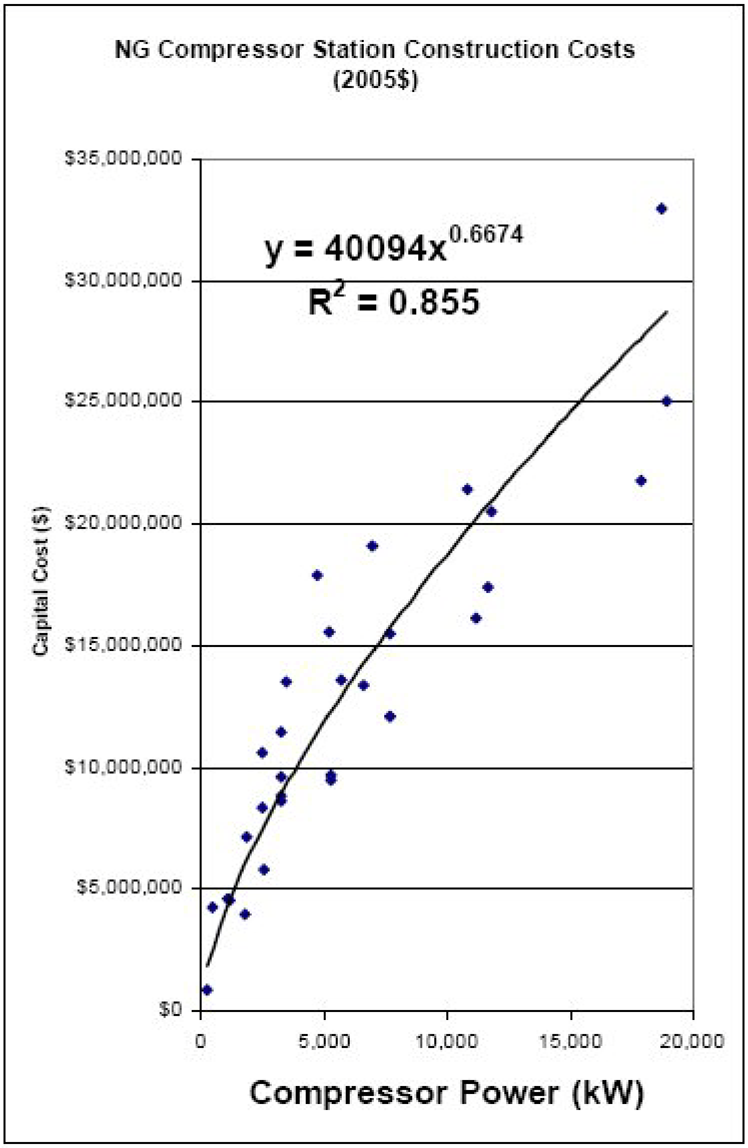


Figure 6.2.1. Compressor cost as a function of power draw (National Renewable Energy Laboratory, 2006)

The total utility cost is determined by multiplying the HDSAM fuel/utility cost by the annual energy requirement. Total capital, labor, and other operational and maintenance costs (not inclusive to what is presented here) are added together so a cost for hydrogen can be determined.

6.3 Compression, Storage, and Dispensing

Hydrogen distribution requires compression, storage, and dispensing at the fueling station to transfer hydrogen at 6250 psi to vehicles in the required fill-up time.

Much like gasoline stations, hydrogen stations will experience seasonal demand. Summer demand is assumed in HDSAM to be approximately 10% higher than the average demand whereas winter demand is 10% lower. During early infrastructure development especially, a long-term storage system will be needed to store the 10% production excess in production during the winter for release to supplement production in the summer months (Nexant 2008). Figure 6.3.1 shows the annual schedule of production and demand used in the H2A models.

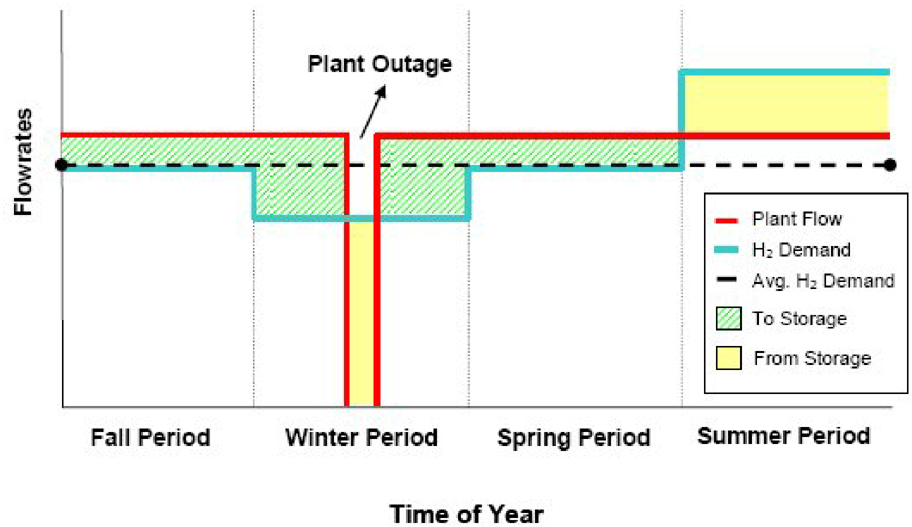


Figure 6.3.1. Hydrogen demand and required annual storage (Nexant 2008)

H2A appropriately sizes the storage capacity to handle the maximum of the two green shaded areas in Figure 6.3.1 and to handle any losses that may occur during the storage period. The daily design flow rate for the production plant is determined by calculating the annual hydrogen demand (area under the black or blue lines in Figure 6.3.1), adding all of the annual losses, and dividing by 365 days minus scheduled production outage days. Storage capacity is based on: 1) plant-outage period; 2) 10% increase in summer demand; 3) length of the summer period; and 4) length of the winter period. H2A assumes a plant-outage period of 10 days.

In addition to seasonal demand, demand variation occurs daily during the week as well as hourly during the day. Peak demand occurs on Fridays between 4:00 and 6:00 p.m. (Nexant, 2008). Figure 6.3.2 shows the hourly Friday demand profile at a refueling station over 24 hours. The area under the curve above the daily average hourly demand represents the minimum storage requirement to satisfy the station demand during peak hours (approximately 30% of daily demand).

The refueling site is the best location to handle daily and hourly fluctuations in demand and takes the form of low-pressure storage (2,500 psi). This eliminates the need for scaling upstream components to handle daily and hourly demand variations. For distributed hydrogen production facilities and stations supplied by pipeline, the low-pressure storage at the refueling station is sized at 30% of the total daily demand (472 kg

H_2 for distributed facilities and 470 kg H_2 for pipeline-supplied facilities). For liquid trucks, the liquid storage tank (6,920 kg H_2) would satisfy the increase in additional storage. Because truck deliveries do not exceed two deliveries per day, the truck would carry half the daily demand plus the 30% excess.

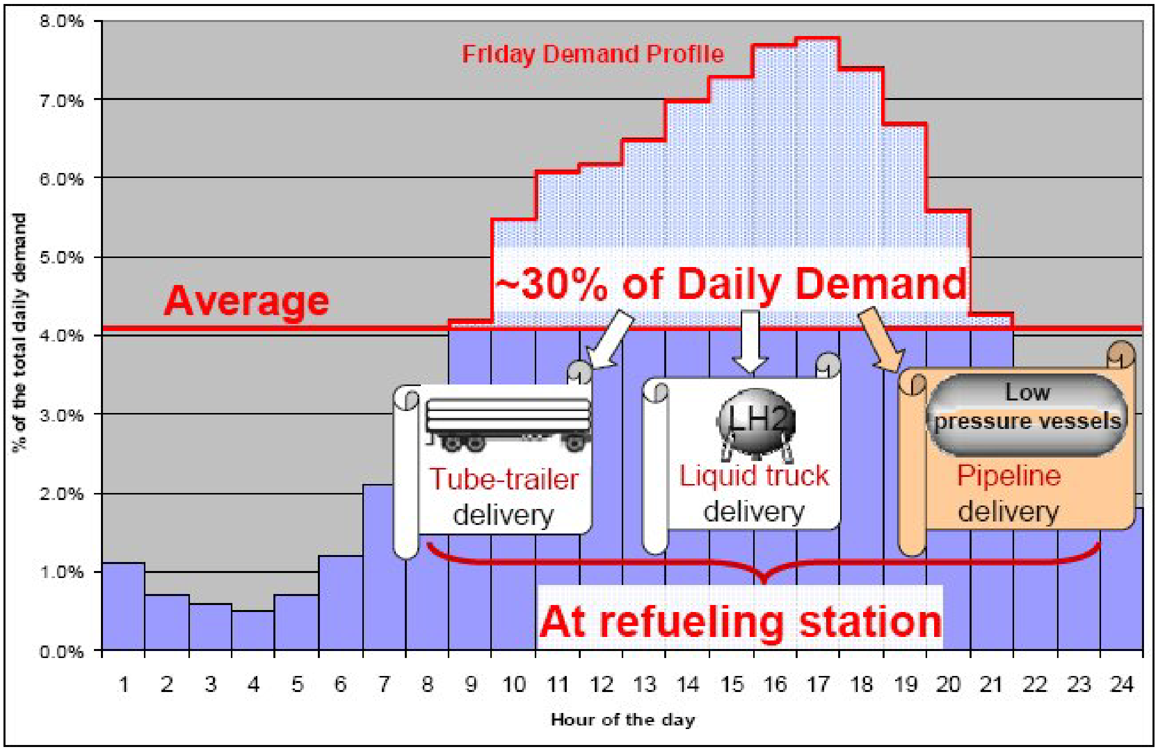


Figure 6.3.2. Hydrogen daily average demand (Nexant, 2008)

Refueling stations also include a cascade charging system with at least one bank of three pressure vessels operating under different pressures (6,000, 4,350, and 2,000 psi) to satisfy vehicle refueling requirements. Each vessel holds 21.3 kg hydrogen at a maximum pressure of 6,250 psi. For distributed hydrogen production facilities, the refueling station modeled includes cascade storage for 325 kg H_2. For stations receiving liquid hydrogen, the cascade storage volume is 453 kg H_2, and for stations supplied by pipeline, the cascade storage is sized for 582 kg H_2.

The number of dispensers is determined by the metric utilized in gasoline stations known as hose-occupied fraction (HOF). The HOF is the average fraction of time that each hose is occupied during the peak hour of the day. By determining the HOF of a gasoline station, the number of dispensers at a hydrogen station can be selected such that the HOF is approximately equal to that of a gasoline station. Figure 6.3.3 shows the number of dispensers for a range of refueling station daily demands in kg/day (Nexant, 2008).

An equation, based on Figure 6.3.3, can also be used to determine the number of dispensers given a daily capacity (kg/day):

$$\#\text{ of Dispensers} = \text{Daily Capacity}/(305.85*\text{Daily Capacity}^{0.0763})$$

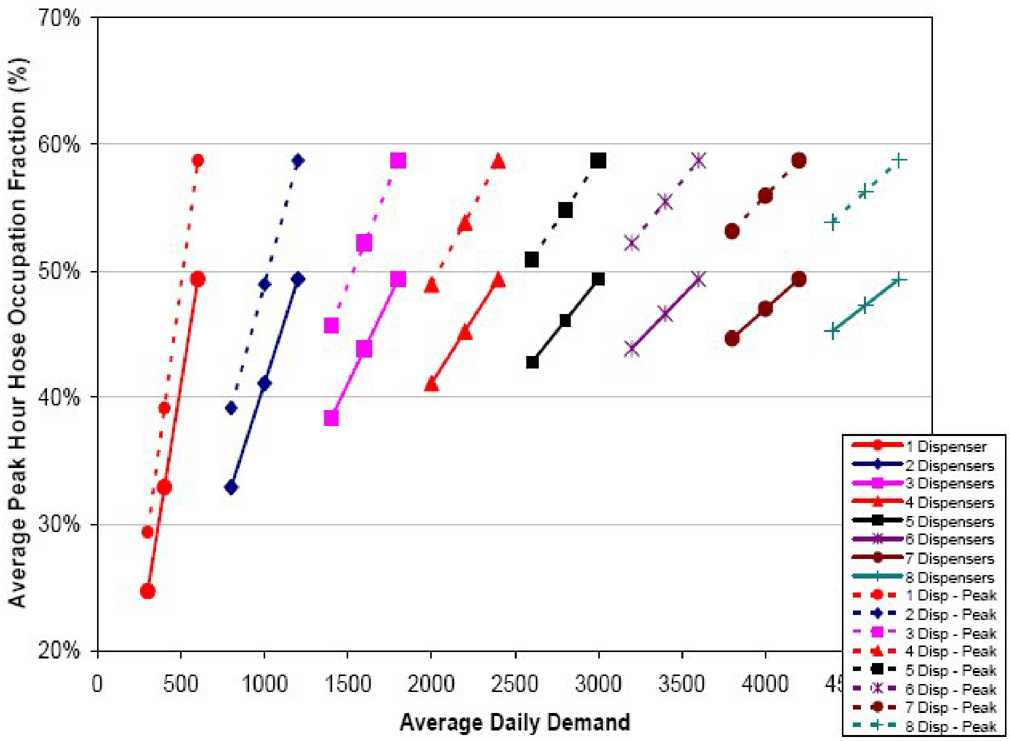


Figure 6.3.3. Recommended number of refueling station dispensers (Nexant 2008)

Once the number of dispensers is known, the maximum flow rate can be determined. This flow rate is integral in determining the required size of the refueling station compressor and cascade charging system.

The dispensing pressure is assumed to be 6,250 psi. A conservative assumption and worst-case scenario of occupying all the dispensing hoses during the first three minutes of each hour simultaneously is made to ensure adequate sizing of the refueling station components (see Section 2.3.2, Nexant, 2008). In addition, a small amount of 2,500-psi storage (1 day) is provided for in H2A at the liquid terminal to ensure smooth loading of liquid hydrogen trucks.

Dispensers are unlikely to use a significant amount of energy for operation, so there are no costs associated to fuel or utilities related to the dispenser. Capital, labor, and other operational and maintenance costs for compressed hydrogen storage are pooled together so the total hydrogen cost can be determined.

7.0 Vehicle Assumptions

Vehicle assumptions are engineering estimates based on both simulation and performance of the current generation of vehicles being tested under the Program's technology validation function.

7.1 Vehicle Fuel Economy

Vehicle fuel economy is a primary parameter for these analyses because it has an inversely proportional effect on cost per mile as well as energy use and emissions per mile. For this study, the estimated fuel economy is 45 miles per gallon gasoline equivalent (mpgge)

The fuel economy of 45 mpgge was estimated by running simulations using the Powertrain Simulation Analysis Toolkit (PSAT) V6.2 SP1, which was developed by Argonne National Laboratory. Simulations were run for both mid-size passenger cars and light trucks. The on-road adjusted fuel economies of the mid-size passenger car and light truck were estimated to be 53.6 mpgge and 37.8 mpgge, respectively. For a light-duty vehicle that is the composite of a car and a light truck, the two fuel economies were averaged using a weighting factor that reflects the ratio of new light truck sales to new car sales. Using the EIA-estimated light truck sales share of 46.4% for 2008, the on-road fuel economy of a new light-duty vehicle was estimated to be 45 mpgge (Singh and Nguyen, 2009).

In PSAT simulations, vehicle weight is specified because it is a crucial factor in determining a vehicle's fuel economy. Additional vehicle glider assumptions used in this analysis are listed in Table 7.1.1 (Rousseau and Wallner, 2008), and light truck parameters can be found in Delorme, Pagerit, Sharer, and Rousseau (2009). A wide variety of data sources were used to characterize the PSAT mid-size passenger car and fuel cell propulsion system. These sources include vehicle tear-down data, various automotive models, personal communications, and literature reviews.

Table 7.1.1. PSAT Mid-Size Passenger Car Assumptions

Parameter	Unit	Value
Glider mass	kg	990
Frontal area	m^2	2.1
Drag coefficient		0.29
Wheel radius	m	0.137
Rolling resistance		0.008
0–60 mph	S	9 ± 0.1
0–30 mph	S	3
Grade at 60 mph	%	6
Maximum speed	mph	>100[1]

[1] Two-gear transmission used for series

Table 7.1.2 shows the PSAT fuel cell system assumptions while Figure 7.1.1 shows the fuel cell power versus system efficiency used for PSAT simulations (Rousseau and Wallner, 2008).

Table 7.1.2. PSAT Fuel Cell System Assumptions

Parameter	Unit	Current Status	FreedomCAR Goal
Specific power	W/kg	500	650
Peak efficiency	%	55	60

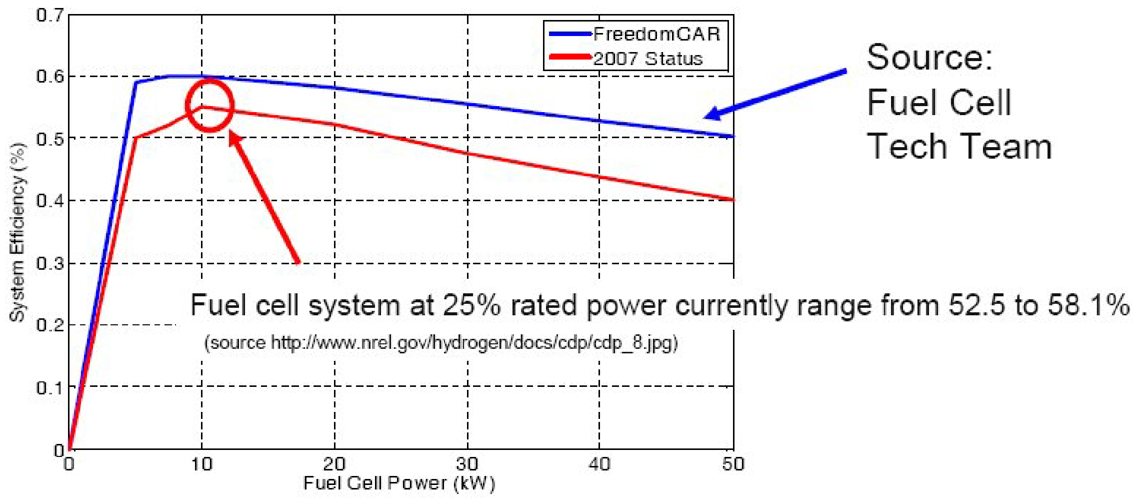


Figure 7.1.1. Fuel cell power versus system efficiency (Rousseau and Wallner, 2008)

Other studies on fuel economy have taken place. In another study that was based on the assumptions above, PSAT estimated that the overall [2008 Environmental Protection Agency (EPA) adjusted] vehicle fuel economy for fuel cell hybrid electric vehicles (HEVs) is 50.7 mpgge with an error bar of 7.5 mpgge (Rousseau and Wallner, 2008). The mid-size vehicle fuel economy used in this study (53.6 mpgge) is within that range.

Another simulated analysis was conducted in 2005 by the National Renewable Energy Laboratory (NREL) (National Renewable Energy Laboratory, 2005). Its fuel economy versus fuel cell size results are shown in Figure 7.1.2. The fuel cell HEV fuel economy shown in Figure 7.1.2 (52.5 mpgge) reflects EPA-combined fuel economy. Forty-five mpgge is equivalent to discounting the 52.5 mpgge by 15%, which is an approximation of EPA's pre-2008 reduction factor used to calculate on-road fuel economy from dynamometer test results. (The EPA reduction factor was equivalent to adjusting the city-driving test result downward by 10% and the highway-driving test result downward by 22%.)

NREL also collects fuel economy data under the Hydrogen Fleet and Infrastructure Demonstration and Validation Project (Wipke, Sprik, Kurtz, and Ramsden, 2009). Results from 2009 for that project are shown in Figure 7.1.3, and the upper range of those results includes 45 mpgge, which is the fuel economy used for this analysis.

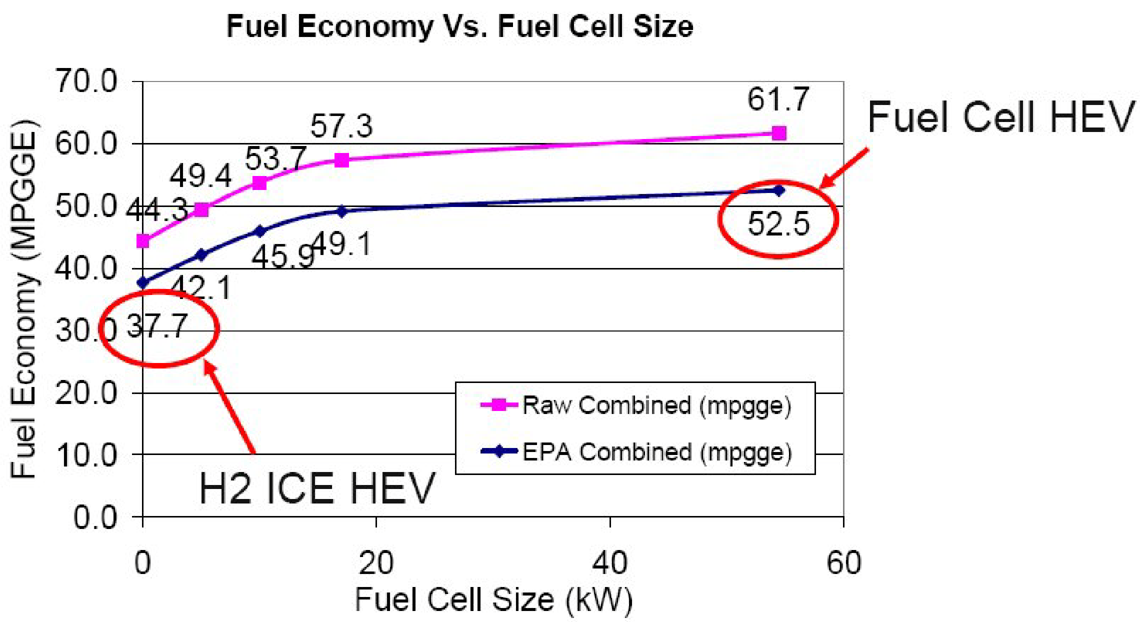


Figure 7.1.2. Fuel economy versus fuel cell size (Rousseau and Wallner, 2008)

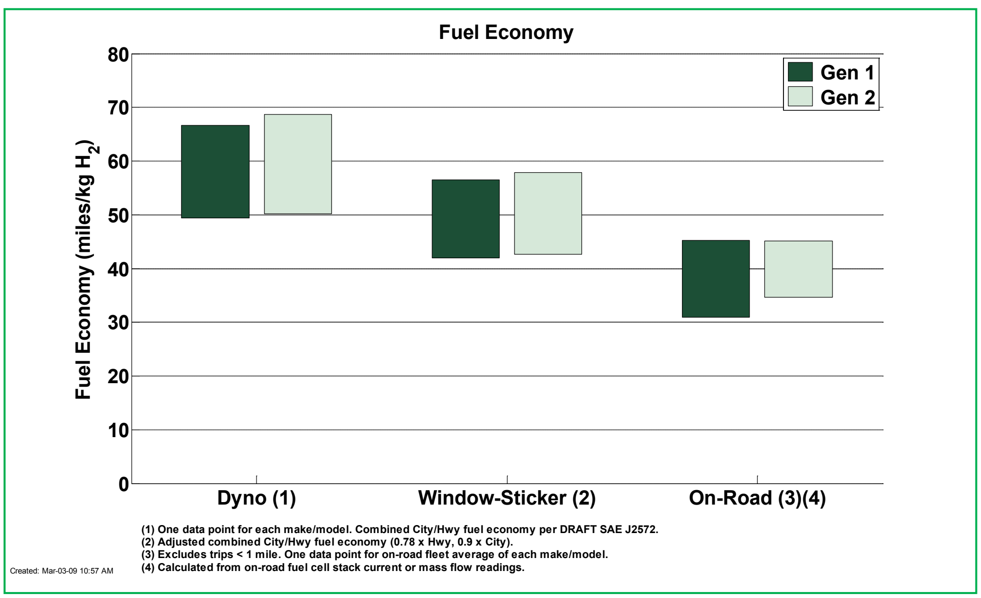


Figure 7.1.3. NREL hydrogen fleet and infrastructure demonstration and validation project fuel economy (Wipke, Sprik, Kurtz, and Ramsden, 2009)

7.2 Vehicle Criteria Pollutant Emissions

Table 7.2.1 presents the default values of emission change rates used in the GREET model for a hydrogen fuel cell vehicle as compared to the modeled gasoline vehicle. Those values were used for this study.

Hydrogen FCVs run on hydrogen instead of combustible carbon compounds, so there are no volatile organic carbon compounds (VOC) to either evaporate or be exhausted due to incomplete emissions. Likewise, there are no CO or methane (CH_4) emissions. Because these vehicles run on fuel cells instead of combustion engines, combustion-caused pollutants are also avoided; therefore, there are no PM_{10}, NOx, or N_2O emissions.

Vehicles within the same class (mid-size passenger car), whether powered by a gasoline internal combustion engine or a hydrogen fuel cell, are assumed to have similar tire- and brake-wear (TBW) particulate matter (PM) emissions (Wang, 1999).

Table 7.2.1. Change in Exhaust as Compared to a Gasoline Vehicle

Vehicle	Exhaust VOC	Evap. VOC	CO	NOx	Exhaust PM	CH_4	N_2O	TBW PM
H_2 FCV	-100%	-100%	-100%	-100%	-100%	-100%	-100%	0%

8.0 Financial Assumptions

The H2A model uses a common set of economic assumptions to allow for consistent and comparable results across technology options. Table 8.0.1 provides a set of key economic parameters selected by H2A analysts and discussed with industry collaborators who participated in the H2A effort.

Table 8.0.1. H2A Key Economic Parameters

Parameter	Value
Reference year	2005 dollars
Percentage equity financing	100%
After-tax internal rate of return	10% real
Inflation rate	1.9%
Effective corporate income tax rate	38.9%
Depreciation schedule	Modified Accelerated Cost Recovery System
Economic analysis period Central plant production Forecourt production	 40 years 20 years

In cases where the capital cost component is a large fraction of the levelized cost of producing hydrogen, the assumed after-tax internal rate of return (IRR) strongly affects the results calculated by H2A. As seen in Table 8.0.1, H2A uses an IRR of 10% real. The 10% real value was derived from return on equity statistics (adjusted for inflation) for large company stocks over the period from 1926–2002. Because returns already account for corporate taxes, this value is an after-tax return. The use of a 10% real IRR is intended to reflect a steady-state situation in the future in which hydrogen is a familiar and publicly accepted fuel and in which a significant demand for hydrogen for transportation exists (Pacific Northwest National Laboratory, 2004).

This 10% after-tax IRR is linked to the H2A assumption of 100% equity financing. Actual projects would probably be financed with a combination of debt and equity, but H2A analysts have been told that firms typically assume 100% equity financing for paper studies and analyses. When debt financing is used, a higher after-tax IRR can be achieved with the same levelized cost. The increase is dependent upon the fraction of debt financing and the interest rate on that debt. Figure 8.0.1 shows the after-tax IRR for multiple combinations of equity to debt financing at three different interest rates for production of hydrogen from coal in central facilities (see section 9.7 for details); delivery costs were not included in the data shown. Technologies with different ratios of capital to operating cost will result in slightly different curves.

Figure 8.0.1 also shows the before-tax IRR for the same equity to debt ratios. Corporate income tax can be considered a reduction in profits, so a pre-tax IRR is always greater than an after-tax IRR. Pre-tax IRRs are shown in Figure 8.0.1 because they are often easier to compare to performance of stocks or bonds, which are reported on a pre-tax basis.

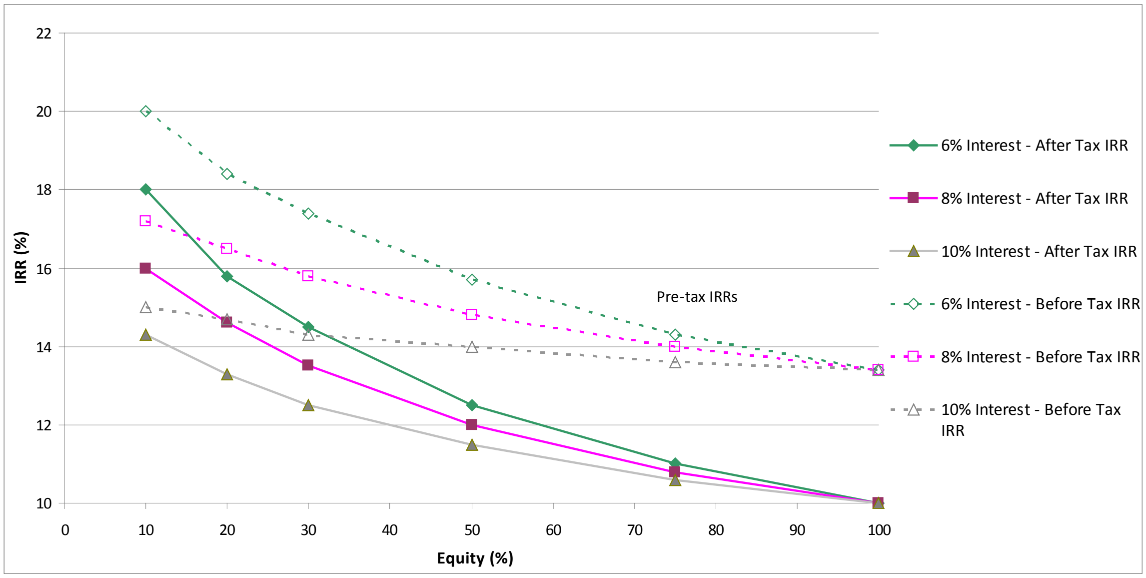


Figure 8.0.1. Post-tax and pre-tax IRRs that result in the same levelized cost for multiple equity to debt ratios (Central Production of Hydrogen from Coal with CCS)

9.0 Pathway Results

This study assessed the WTW cost, energy use, and GHG emissions of each of the seven pathways listed in Table 9.0.1 (see detailed descriptions of each pathway in Section 2.4).

Table 9.0.1. Seven Hydrogen Production, Delivery, and Distribution Pathways

	Central or Distributed Production	Feedstock	Delivery Method	Carbon Capture and Sequestration	Hydrogen Distribution for Fueling
1	Distributed	Natural Gas	Not applicable	No	350 bar compressed gas
2	Distributed	Electricity	Not applicable	No	350 bar compressed gas
3	Central	Biomass	Liquid H_2 in trucks	No	350 bar compressed gas
4	Central	Biomass	Gaseous H_2 in pipelines	No	350 bar compressed gas
5	Central	Natural Gas	Gaseous H_2 in pipelines	No	350 bar compressed gas
6	Central	Wind Electricity	Gaseous H_2 in pipelines	No	350 bar compressed gas
7	Central	Coal	Gaseous H_2 in pipelines	Yes	350 bar compressed gas

The hydrogen production technologies are described in Section 5.0, and the delivery technologies are detailed in Section 6.0. This section presents the results of the WTW cost, energy use, and GHG emissions analysis for each pathway.

9.1 Distributed Natural Gas

Figure 9.1.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. The complete set of assumptions is detailed in Appendix A.

The well-to-pump and well-to-wheels cost of hydrogen, energy use, and emissions for the distributed natural gas pathway are summarized in Table 9.1.1.

9.1.1 Cost Breakdown

Figure 9.1.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the distributed natural gas pathway. The financial assumptions used in this analysis are detailed in Section 8.0.

Figure 9.1.3 shows the contributions of hydrogen production, distribution (compression, storage, and dispensing—CSD), and losses to the levelized cost of hydrogen shown in Figure 9.1.2.

Figure 9.1.4 and Table 9.1.2 show the breakdown of levelized costs for the distributed natural gas pathway.

Inputs		Graphic Depiction & Assumptions		Outputs	
		NG Recovery, Processing, & Transport		NG Delivery Pressure	Average of gas companies
		NG Recovery Efficiency	97.2%	NG Quality at Delivery	Average of gas companies
		NG emitted & combusted during recovery	0.35%		
		NG processing energy efficiency	97.2%	NG Cost	$0.243 2005 $ / Nm^3
		NG emitted & combusted during processin	0.15%	NG Cost	$0.907 2005$ / kg H2 distributed
		NG emitted & combusted during transport	0.14 g / MMBtu		
		NG transport distance	500 miles	WTG CO2 Emissions	5,485 g / 116000Btu to Pump
Coal Input from "Well"	322 Btu / 116000Btu to Pump			WTG CH4 Emissions	239 g / 116000Btu to Pump
Natural Gas Input from "Well"	124,113 Btu / 116000Btu to Pump	Compression Reqs (stages & eff) average of gas companies		WTG N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	497 Btu / 116000Btu to Pump			WTG GHG Emissions	11,475 g CO2 eq./ 116000 Btu

Inputs		Graphic Depiction & Assumptions		Outputs	
Natural Gas consumption	4.5 N m^3/kg H2 produced	**Hydrogen Production**		Hydrogen Output Pressure	300 psi
Electricity consumption	1.11 kWh / kg H2			Hydrogen Outlet Quality	1
Process Water Consumption	5.77 L / kg H2				
Electricity price	$0.0816 2005 $/kWh	Design Capacity	1,500 kg/day	Total capital investment	$2.44 2005$ / annual kg H2 (effective capacity)
		Capacity factor	85%	Electricity cost	$0.09 2005$ / kg H2 produced
		Process energy efficiency	71.3%	Other operating costs	$0.36 2005$ / kg H2 produced
Total Capital Investment	$1,138,995 2005$	Electricity Mix	US Mix	Levelized Cost of Prod (excl feedst	$0.71 2005$ / kg H2 distributed
		After-tax IRR	10%		
		Assumed Plant Life	20 years		
				SMR CO2 Emissions	10,523 g / 116000Btu to Pump
Coal Input from "Well"	6,572 Btu / 116000Btu to Pump			SMR CH4 Emissions	11 g / 116000Btu to Pump
Natural Gas Input from "Well"	47,754 Btu / 116000Btu to Pump			SMR N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	664 Btu / 116000Btu to Pump			SMR GHG Emissions	10,815 g CO2 eq./ 116000 Btu

Inputs		Graphic Depiction & Assumptions		Outputs	
Electricity consumption	1.96 kWh / kg H2	**Compression, Storage, & Dispensing**		Hydrogen outlet pressure	6,250 psi
				Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
				Total capital investment	$8.56 2005$ / annual kg H2 (effective capacity)
		Number of Distribution Stations	270	Electricity cost	$0.16 2005$ / kg H2
Total Capital Investment	$3,993,763 2005$	Energy efficiency	94%		
		Number of Compression Stages	6	Levelized Cost of Distribution	$1.88 2005$ / kg H2 distributed
		Isentropic Efficiency	65%		
		Site storage	62% capacity	CSD CO2 Emissions	1,502 g / 116000Btu to Pump
Coal Input from "Well"	11,382 Btu / 116000Btu to Pump			CSD CH4 Emissions	2 g / 116000Btu to Pump
Natural Gas Input from "Well"	3,269 Btu / 116000Btu to Pump			CSD N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	848 Btu / 116000Btu to Pump			CSD GHG Emissions	1,558 g CO2 eq./ 116000 Btu

Figure 9.1.1. Summary of distributed natural gas pathway major inputs, assumptions, and outputs by subsystem

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

Table 9.1.1. Well-to-Pump and Well-to-Wheels Results for Distributed Natural Gas Pathway

	Well-to-Pump		Well-to-Wheels	
Coal Input from "Well"*	18,300	Btu / 116,000 Btu	410	Btu / mi
Natural Gas Input from "Well"*	175,100	Btu / 116,000 Btu	3,900	Btu / mi
Petroleum Input from "Well"*	2,000	Btu / 116,000 Btu	45	Btu / mi
Fossil Energy Input from "Well"*	195,400	Btu / 116,000 Btu	4,350	Btu / mi
WTP CO_2 Emissions*,**	12,700	g / 116,000 Btu	280	g / mi
WTP CH_4 Emissions	41	g / 116,000 Btu	1	g / mi
WTP N_2O Emissions	0	g / 116,000 Btu	0	g / mi
WTP GHG Emissions*	13,700	g CO_2 eq. / 116,000 Btu	310	g / mi
Levelized Cost of Hydrogen ($/kg)	$3.50	2005 $/kg	$0.0777	2005 $/mi

* Well-to-pump results are rounded to the nearest hundred; well-to-wheels results are rounded to the nearest ten.

** Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

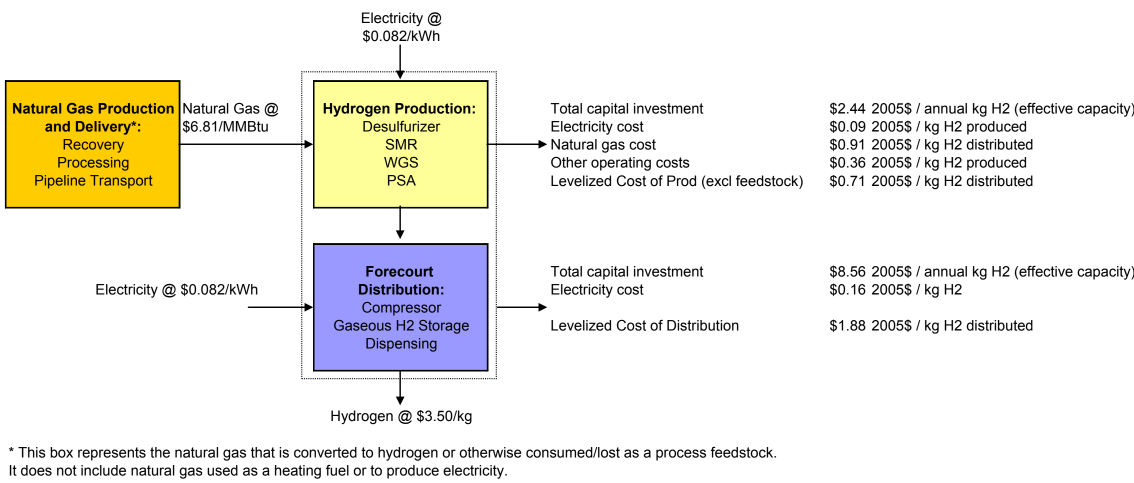


Figure 9.1.2. Cost analysis inputs and high-level results for distributed natural gas pathway

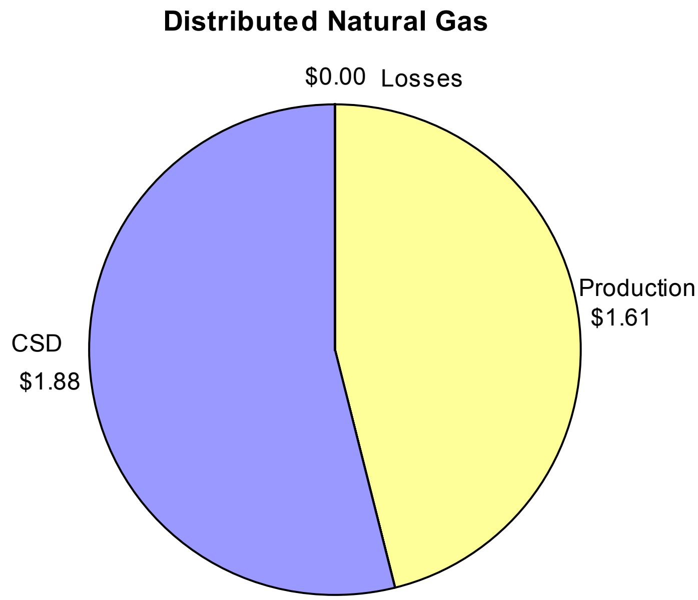


Figure 9.1.3. Contribution of hydrogen production, CSD, and losses to the levelized cost of hydrogen for distributed natural gas pathway

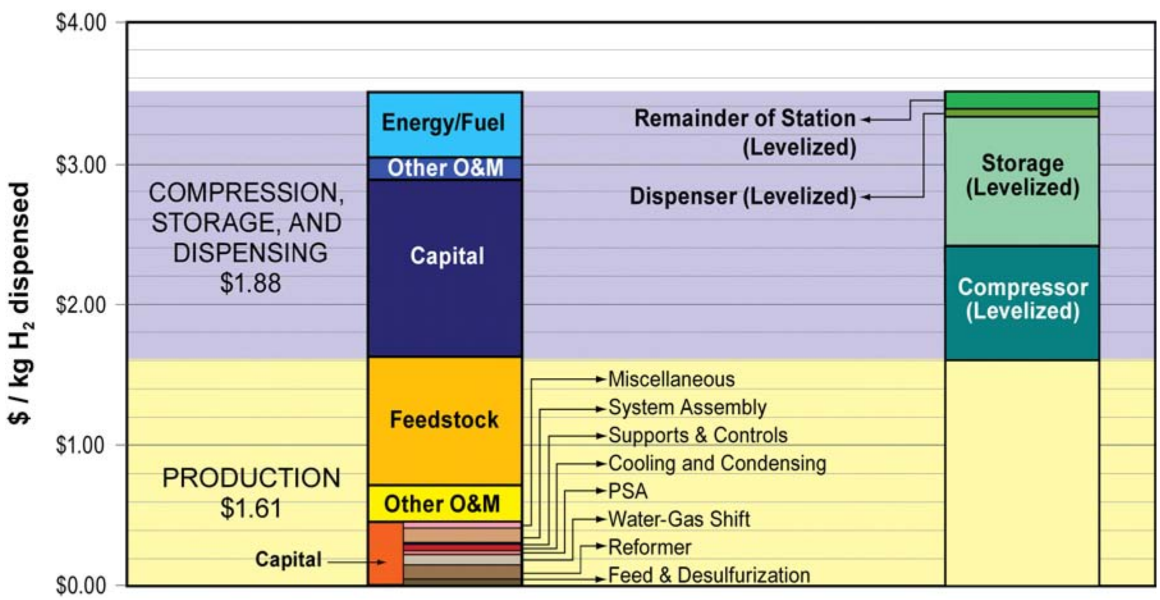


Figure 9.1.4. Breakdown of levelized costs for distributed natural gas pathway

Table 9.1.2. Contribution of Production and CSD Processes to Levelized Hydrogen Cost for Distributed Natural Gas Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.45	$0.26	$0.91		$1.61
Feed & Desulfurization	$0.05				
Reformer	$0.09				
Water-Gas Shift	$0.08				
PSA	$0.03				
Cooling & Condensing	$0.03				
Supports & Controls	$0.03				
System Assembly	$0.10				
Miscellaneous	$0.04				
Compression, Storage, & Dispensing	$1.26	$0.16		$0.46	$1.88
Compressor (Levelized)					$0.80
Storage (Levelized)					$0.94
Dispenser (Levelized)					$0.03
Remainder of Station (Levelized)					$0.11
Losses					$0.00
Total	**$1.71**	**$0.42**	**$0.91**	**$0.46**	**$3.50**

9.1.2 Energy Use and Emissions Breakdown

Figures 9.1.5 and 9.1.6 show the WTW energy inputs and losses for the distributed natural gas pathway. The WTW energy inputs to natural gas production and delivery include those necessary to produce 116,000 Btu of natural gas for reforming. Additional WTW energy inputs for natural gas needed for heating and lost in reforming are reported as inputs to hydrogen production.

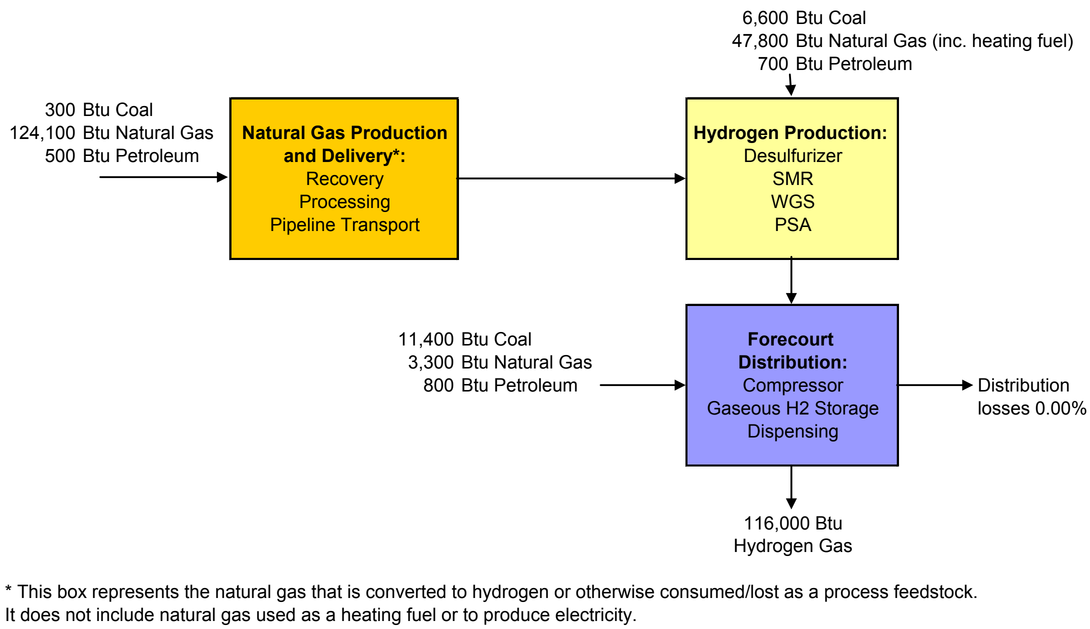


Figure 9.1.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using distributed natural gas pathway

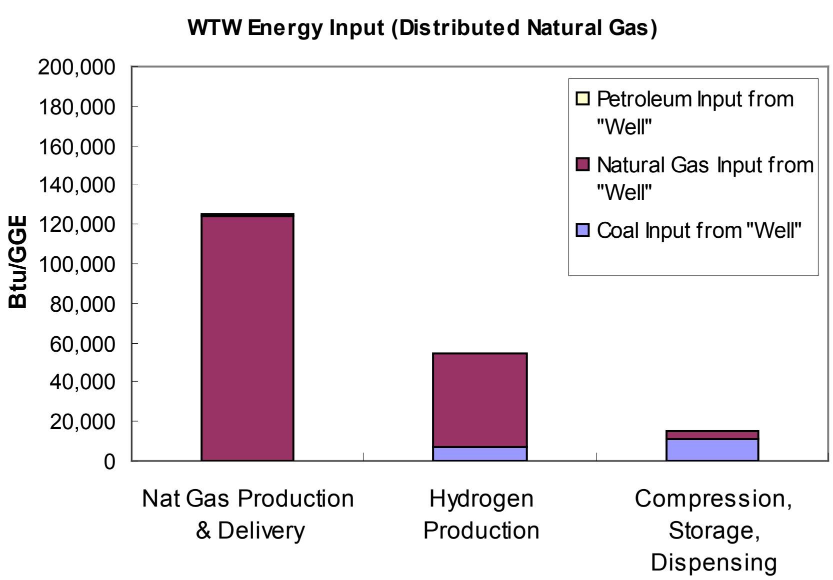
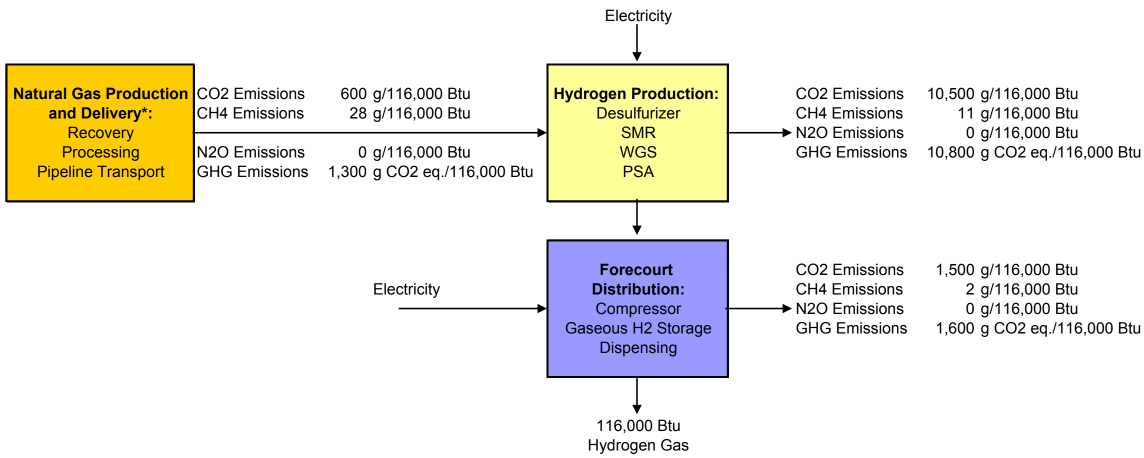


Figure 9.1.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using distributed natural gas pathway

Figures 9.1.7 and 9.1.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the distributed natural gas pathway.



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include natural gas used as a heating fuel or to produce electricity.

Figure 9.1.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using distributed natural gas pathway

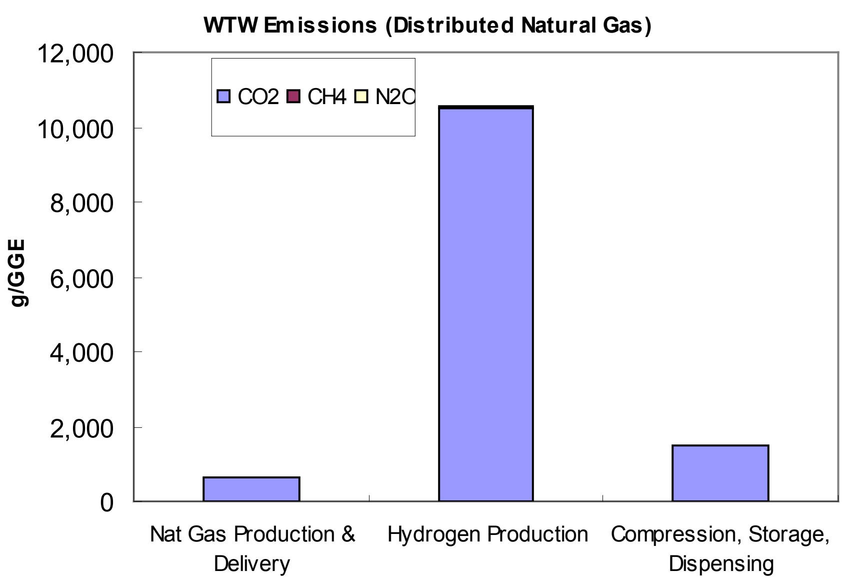


Figure 9.1.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using distributed natural gas pathway

9.1.3 Natural Gas Supply Scenarios

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from natural gas of 4.5 Nm^3 natural gas/kg H_2 (159 Nft^3 natural gas/kg H_2), the amount of natural gas required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with natural gas–derived hydrogen fuel was calculated and compared to the U.S. natural gas reserves and consumption estimates shown in Section 3.1 (Table 9.1.3).

Table 9.1.3. Natural Gas Supply Scenarios for Distributed Natural Gas Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Current Technology – 45 mpgge FCV, hydrogen production yield 4.5 $Nm^3/kg\ H_2$[1]			
Natural Gas Required (trillion ft^3/yr)	10.0	7.5	5.0	2.5
Percent of Estimated U.S. Reserves (237.7 trillion ft^3, dry)[2]	4%	3%	2%	1%
Percent of Annual U.S. Consumption (23.2 trillion ft^3/yr)[3]	43%	32%	22%	11%

[1] Calculation does not include energy or hydrogen losses.
[2] Energy Information Administration (2009i)
[3] Energy Information Administration (2009b)

No sample scenarios for domestic hydrogen production from natural gas are included in the Hydrogen Posture Plan (United States Department of Energy, 2006).

9.1.4 Sensitivities

Production Sensitivities

The parameters used for this analysis are not known absolutely, so sensitivity analyses were performed to better understand the potential effects of that lack of knowledge on the final results. Several sensitivities were run on this pathway. They focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.1.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.1.4 shows the effect of production energy efficiency on WTW energy use and emissions.

The assumed electrical grid mix also affects the energy use and emissions. Table 9.1.5 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

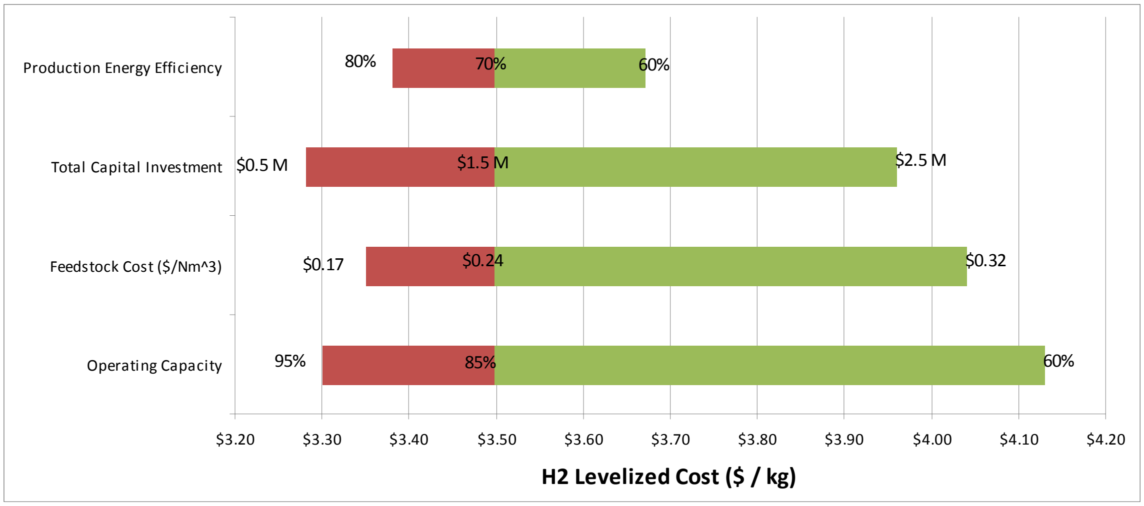


Figure 9.1.9. Production sensitivities for distributed natural gas pathway

Table 9.1.4. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Distributed Natural Gas Pathway (current technology)

	60% Efficiency	70% Efficiency	80% Efficiency
WTW GHG Emissions (g/mile)	350	310	270
WTW Fossil Energy (Btu/mile)	5,030	4,350	3,850
WTW Petroleum Energy (Btu/mile)	47	45	43
WTW Total Energy (Btu/mile)	5,120	4,430	3,930

Table 9.1.5. The Effects of Grid Mix on Use of Primary Energy and Emissions from Distributed Natural Gas Pathway (current technology)

	U.S. Average Grid Mix	"Green" Grid Mix
WTW GHG Emissions (g/mile)	310	250
WTW Fossil Energy (Btu/mile)	4,350	3,790
WTW Petroleum Energy (Btu/mile)	45	14
WTW Total Energy (Btu/mile)	4,430	4,060

9.1.5 Advanced Conversion and Delivery/Distribution Technology

For advanced technology analysis, parameters were changed to future projections. The "Future" H2A production case was used, and HDSAM was modified to include achievement of delivery targets as defined in the Hydrogen, Fuel Cells and Infrastructure Technologies (HFCIT) Multi-Year Program Plan (MYPP). The vehicle fuel economy was increased to 65 mpgge. In addition, the electricity grid mix was updated to match EIA's projection for technology success in 2020 (51.1% coal, 19.2% natural gas, 18.5% nuclear, 1.9% residual oil, 1.0% biomass, and 8.3% zero-carbon). WTW results from cases with those modifications are shown in Table 9.1.6. The results match those in Hydrogen Program Record 9002 (2009).

Table 9.1.6. Well-to-Wheels Results for Distributed Natural Gas Pathway with Advanced Technology

Coal Input from "Well"	370	Btu / mi
Natural Gas Input from "Well"	2440	Btu / mi
Petroleum Input from "Well"	29	Btu / mi
Fossil Energy Input from "Well"	2840	Btu / mi
WTW CO_2 Emissions	190	g / mi
WTW CH_4 Emissions	0.58	g / mi
WTW N_2O Emissions	0.001	g / mi
WTW GHG Emissions	200	g / mi
Levelized Cost of Hydrogen ($ / kg)	$3.23	2005 $ / kg
Levelized Cost of Hydrogen ($ / mi)	$0.0496	2005 $ / mi

Several sensitivities were run on this pathway. They focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.1.10 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.1.7 shows the effect of varying production energy efficiency on WTW energy use and emissions.

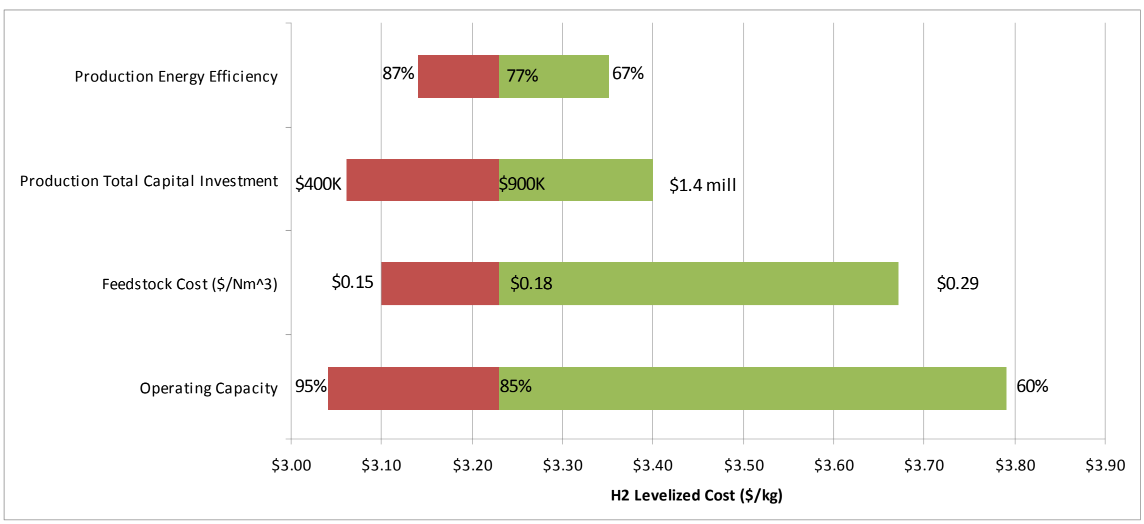


Figure 9.1.10. Production sensitivities for distributed natural gas pathway with advanced technology

Table 9.1.7. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Distributed Natural Gas Pathway (advanced technology)

	67% Efficiency	77% Efficiency	87% Efficiency
WTW GHG Emissions (g/mile)	230	200	190
WTW Fossil Energy (Btu/mile)	3,230	2,840	2,550
WTW Petroleum Energy (Btu/mile)	31	29	28
WTW Total Energy (Btu/mile)	3,300	2,910	2,630

The assumed electrical grid mix also affects the energy use and emissions. Table 9.1.8 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 9.1.8. The Effects of Grid Mix on Use of Primary Energy and Emissions from Distributed Natural Gas Pathway (advanced technology)

	Projected U.S. Average Grid Mix	"Green" Grid Mix
WTW GHG Emissions (g/mile)	200	150
WTW Fossil Energy (Btu/mile)	2,840	2,330
WTW Petroleum Energy (Btu/mile)	29	9
WTW Total Energy (Btu/mile)	2,910	2,580

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy for advanced FCVs used in this study (65 mpgge), and a yield of hydrogen from natural gas of 4.0 Nm^3 natural gas/kg H_2 (140 Nft^3 natural gas/kg H_2), the amount of natural gas required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with natural gas–derived hydrogen fuel was calculated and compared to the U.S. natural gas reserves and consumption estimates shown in Section 3.1 (Table 9.1.9).

Table 9.1.9. Natural Gas Supply Scenarios for Advanced Distributed Natural Gas Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Advanced Technology – 65 mpgge FCV, hydrogen production yield 4.0 Nm^3/kg H_2[1]			
Natural Gas Required (trillion ft^3/yr)	6.1	4.6	3.1	1.5
Percent of Estimated U.S. Reserves (237.7 trillion ft^3, dry)[2]	3%	2%	1%	0.6%
Percent of Annual U.S. Consumption (23.2 trillion ft^3/yr)[3]	26%	20%	13%	7%

[1] Calculation does not include energy or hydrogen losses.
[2] Energy Information Administration (2009i)
[3] Energy Information Administration (2009b)

9.2 Distributed Electricity

Figure 9.2.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. The complete set of assumptions is detailed in Appendix B.

The well-to-pump and well-to-wheels cost of hydrogen, energy use, and emissions for the distributed electricity pathway are summarized in Table 9.2.1.

9.2.1 Cost Breakdown

Figure 9.2.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the distributed electricity pathway. The financial assumptions used in this analysis are detailed in Section 8.0.

Figure 9.2.3 shows the contributions of hydrogen production, distribution (CSD), and losses to the levelized cost of hydrogen shown in Figure 9.2.2.

Figure 9.2.4 and Table 9.2.2 show the breakdown of levelized costs for the distributed electricity pathway.

Inputs | Graphic Depiction & Assumptions | Outputs

Electrolysis Electricity Generation & Transport
Includes Resource Recovery, Processing, & Transport

Inputs

Coal Input from "Well"	310,710 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	89,250 Btu / 116000Btu to Pump
Petroleum Input from "Well"	23,152 Btu / 116000Btu to Pump

Grid Mix

Biomass Fraction	1.20%
Coal Fraction	51.70%
Natural Gas Fraction	15.70%
Nuclear Fraction	20.30%
Residual Oil Fraction	2.90%
Others (Carbon Neutral)	8.20%

Outputs

Electricity Cost	$0.055 2005 $ / kWh
Electricity Cost	$2.804 2005$ / kg H2 distributed
WTG CO2 Emissions	353,525 g / 116000Btu to Pump
WTG CH4 Emissions	464 g / 116000Btu to Pump
WTG N2O Emissions	5 g / 116000Btu to Pump
WTG GHG Emissions	366,556 g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Natural Gas consumption	0.0 N m^3/kg H2 produced
Electricity consumption	53.48 kWh / kg H2
Process Water Consumption	0.00 L / kg H2
Total Capital Investment	$2,738,292 2005$
Coal Input from "Well"	0 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	0 Btu / 116000Btu to Pump
Petroleum Input from "Well"	0 Btu / 116000Btu to Pump

Assumptions

Design Capacity	1,500 kg/day
Capacity factor	85%
Process energy efficiency	62.3%
After-tax IRR	10%
Assumed Plant Life	20

Outputs

Hydrogen Output Pressure	435 psi
Hydrogen Outlet Quality	1
Total capital investment	$5.87 2005$ / annual kg H2 (effective capacity)
Other operating costs	$0.60 2005$ / kg H2 produced
Levelized Cost of Prod (excl feedstock)	$1.42 2005$ / kg H2 distributed
SMR CO2 Emissions	0 g / 116000Btu to Pump
SMR CH4 Emissions	0 g / 116000Btu to Pump
SMR N2O Emissions	0 g / 116000Btu to Pump
SMR GHG Emissions	0 g CO2 eq./ 116000 Btu

Compression, Storage, & Dispensing

Inputs

Electricity consumption	1.73 kWh / kg H2
Total Capital Investment	$3,989,011 2005$
Coal Input from "Well"	12,477 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	3,584 Btu / 116000Btu to Pump
Petroleum Input from "Well"	930 Btu / 116000Btu to Pump

Assumptions

Number of Distribution Stations	270
Energy efficiency	95%
Number of Compression Stages	5
Isentropic Efficiency	65%
Site storage	62% capacity

Outputs

Hydrogen outlet pressure	6,250 psi
Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$8.55 2005$ / annual kg H2 (effective capacity)
Electricity cost	$0.10 2005$ / kg H2
Levelized Cost of Distribution	$1.82 2005$ / kg H2 distributed
CSD CO2 Emissions	1,647 g / 116000Btu to Pump
CSD CH4 Emissions	2 g / 116000Btu to Pump
CSD N2O Emissions	0 g / 116000Btu to Pump
CSD GHG Emissions	1,707 g CO2 eq./ 116000 Btu

Figure 9.2.1. Distributed electricity pathway summary of major inputs, assumptions, and outputs by subsystem

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

Table 9.2.1. Well-to-Pump and Well-to-Wheels Results for Distributed Electricity Pathway

	Well-to-Pump		Well-to-Wheels	
Coal Input from "Well"*	323,200	Btu / 116,000 Btu	7,190	Btu / mi
Natural Gas Input from "Well"*	92,800	Btu / 116,000 Btu	2,070	Btu / mi
Petroleum Input from "Well"*	24,100	Btu / 116,000 Btu	540	Btu / mi
Fossil Energy Input from "Well"*	440,100	Btu / 116,000 Btu	9,790	Btu / mi
WTP CO_2 Emissions*,**	42,700	g / 116,000 Btu	950	g / mi
WTP CH_4 Emissions	56	g / 116,000 Btu	1	g / mi
WTP N_2O Emissions	1	g / 116,000 Btu	0	g / mi
WTP GHG Emissions*	44,300	g CO_2 eq./ 116,000 Btu	980	g / mi
Levelized Cost of Hydrogen ($/kg)	$6.05	2005 $/kg	$0.1344	2005 $/mi

* Well-to-pump results are rounded to the nearest hundred; well-to-wheels results are rounded to the nearest ten.

** Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

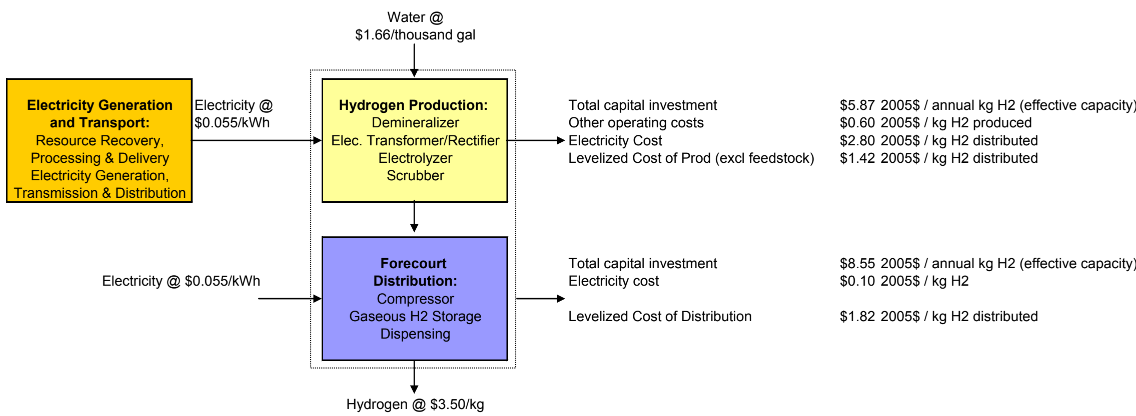


Figure 9.2.2. Cost analysis inputs and high-level results for distributed electricity pathway

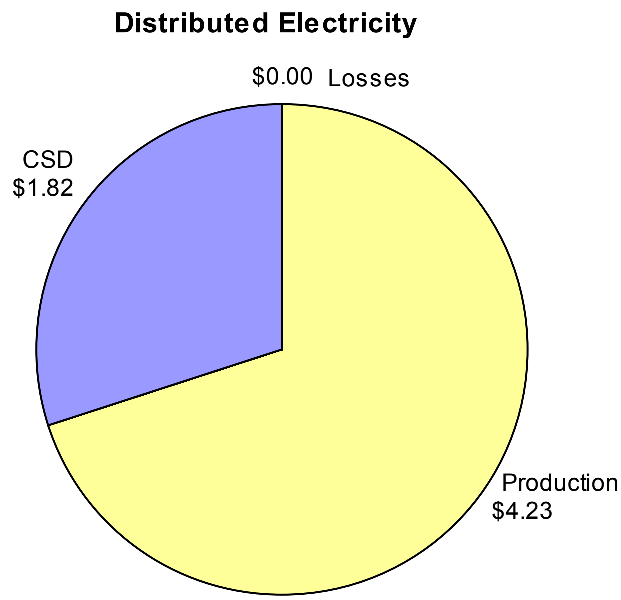


Figure 9.2.3. Contribution of hydrogen production, CSD, and losses to the levelized cost of hydrogen for distributed electricity pathway

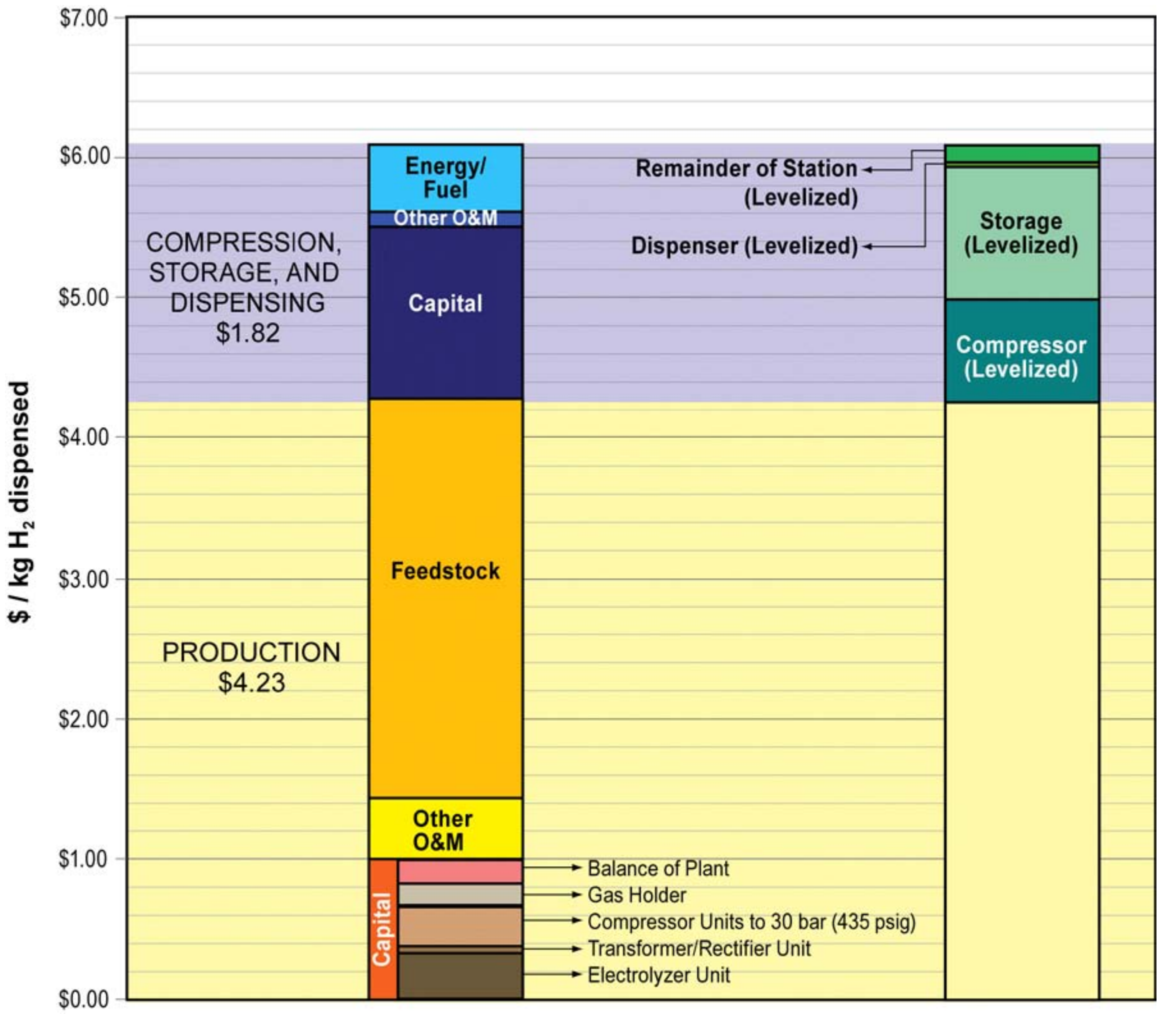


Figure 9.2.4. Breakdown of levelized costs for distributed electricity pathway

Table 9.2.2. Contribution of Production and CSD Processes to Levelized Hydrogen Cost for Distributed Electricity Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.98	$0.45	$2.80		$4.23
Electrolyzer Unit	$0.31				
Transformer/Rectifier Unit	$0.06				
Compressor Units to 30 bar (435 psig)	$0.28				
Gas Holder	$0.15				
Balance of Plant	$0.18				
Compression, Storage, & Dispensing	$1.26	$0.10		$0.46	$1.82
Compressor (Levelized)					$0.73
Storage (Levelized)					$0.94
Dispenser (Levelized)					$0.03
Remainder of Station (Levelized)					$0.11
Losses					$0.00
Total	**$2.24**	**$0.55**	**$2.80**	**$0.46**	**$6.05**

9.2.2 Energy Use and Emissions Breakdown

Figures 9.2.5 and 9.2.6 show the WTW energy inputs and losses for the distributed electricity pathway.

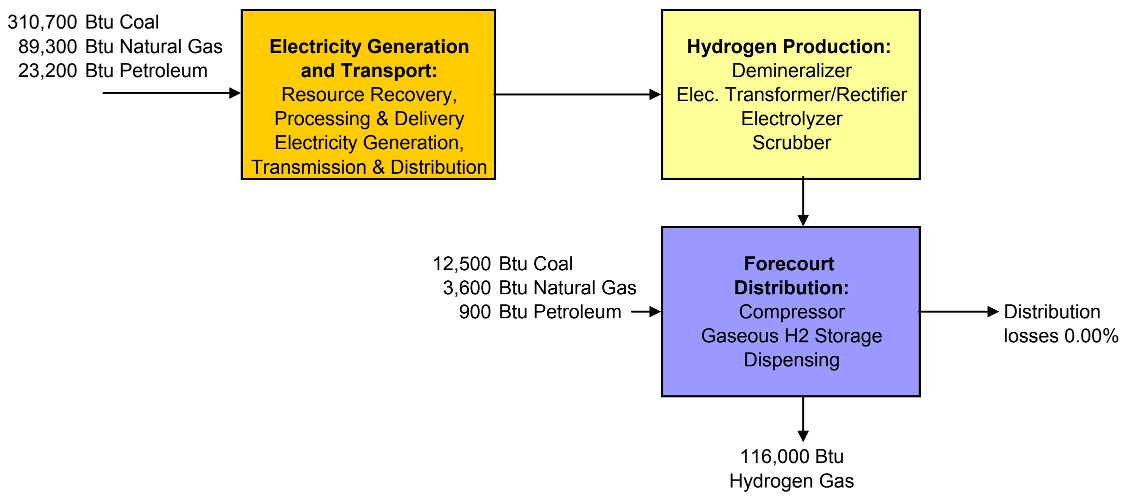


Figure 9.2.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using distributed electricity pathway

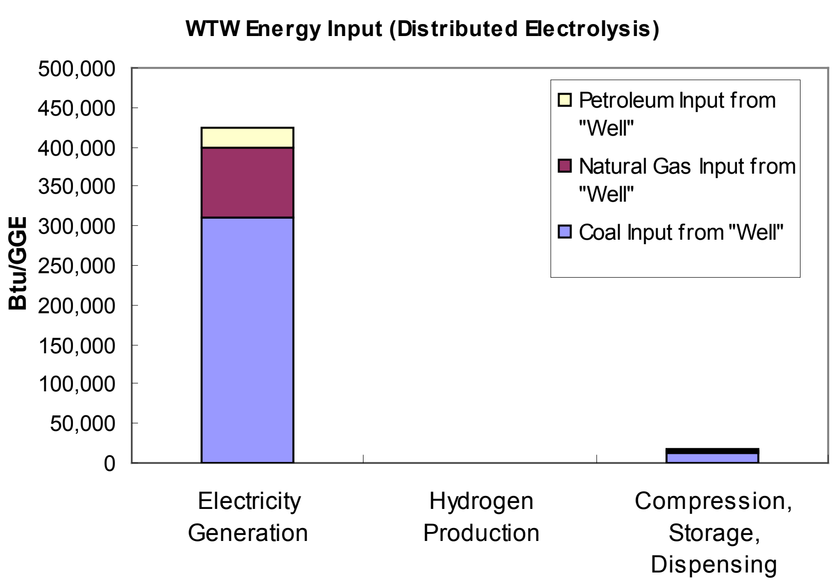


Figure 9.2.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using distributed electricity pathway

Figures 9.2.7 and 9.2.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the distributed electricity pathway.

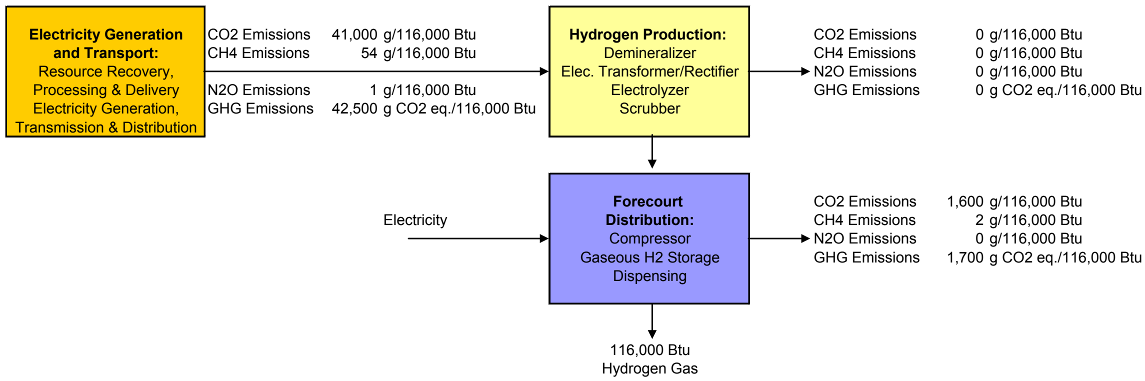


Figure 9.2.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using distributed electricity pathway

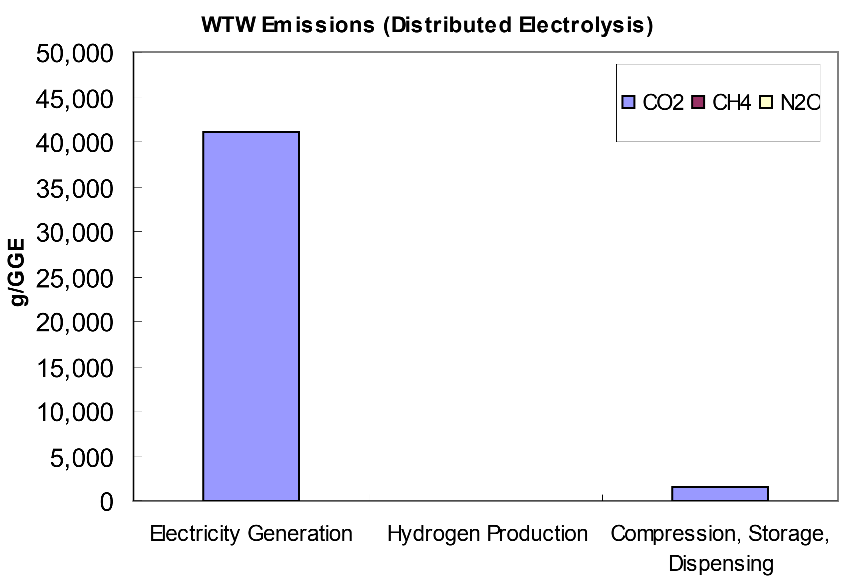


Figure 9.2.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using distributed electricity pathway

9.2.3 Electricity Supply Scenarios

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from electricity of 55 kWh electricity/kg H_2, the amount of electricity required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with electrolysis-derived hydrogen fuel was calculated and compared to the projected 2030 U.S. electricity demand (United States Department of Energy, 2009), the 2008 U.S. electricity generation, and the 2008 U.S. electricity consumption estimates shown in Section 3.2 (Table 9.2.3).

Table 9.2.3. Electricity Supply Scenarios for Distributed Electricity Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Current Technology - 45 mpgge FCV, hydrogen production yield 55 kWh/kg H_2[1]			
Electricity Required (trillion kWh/yr)	3.5	2.6	1.7	0.9
Percent of Projected 2030 U.S. Electricity Demand (5.8 trillion kWh)[2]	60%	45%	30%	15%
Percent of 2008 U.S. Net Electricity Generation (4.1 trillion kWh)[3]	85%	64%	42%	21%
Percent of Annual U.S. Consumption (3.7 trillion kWh)[4]	94%	70%	47%	23%

[1] Calculation does not include energy or hydrogen losses.
[2] United States Department of Energy (2008)
[3] Energy Information Administration (2009e)
[4] Energy Information Administration (2009f)

No sample scenarios for domestic hydrogen production from grid electricity are included in the Hydrogen Posture Plan (United States Department of Energy, 2006).

9.2.4 Sensitivities

Production Sensitivities

The parameters used for this analysis are not known absolutely, so sensitivity analyses were performed to better understand the potential effects of that lack of knowledge on the final results. Several sensitivities were run on this pathway. They focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.2.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.2.4 shows the effect of production energy efficiency on WTW energy use and emissions.

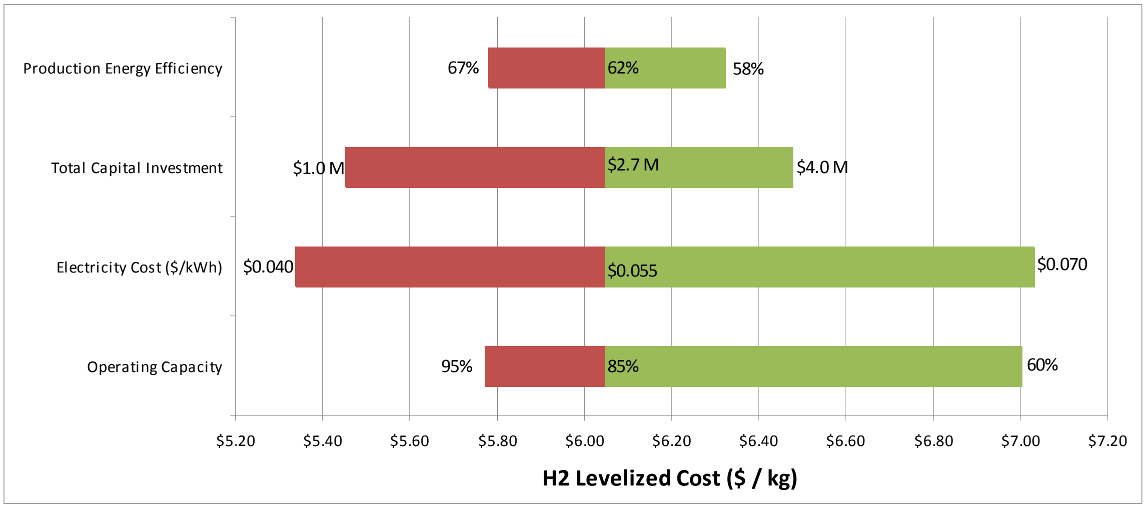


Figure 9.2.9. Production sensitivities for distributed electrolysis pathway

Table 9.2.4. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Distributed Natural Gas Pathway (current technology)

	58% Efficiency	62% Efficiency	67% Efficiency
WTW GHG Emissions (g/mile)	1,050	980	920
WTW Fossil Energy (Btu/mile)	10,400	9,800	9,200
WTW Petroleum Energy (Btu/mile)	570	540	500
WTW Total Energy (Btu/mile)	12,000	11,300	10,600

The assumed electrical grid mix also affects the energy use and emissions. If a hypothetical green grid mix that is 100% renewable energy (solar and wind) is used instead of the average grid mix (which was used for all other sensitivities), no fossil energy is used, nor are there any GHG emissions.

9.2.5 Advanced Conversion and Delivery/Distribution Technology

For advanced technology analysis, parameters were changed to future projections. The "Future" H2A production case was used, and HDSAM was modified to include achievement of delivery targets as defined in the Hydrogen, Fuel Cells and Infrastructure Technologies (HFCIT) Multi-Year Program Plan (MYPP). The vehicle fuel economy was increased to 65 mpgge. In addition, the electricity grid mix was updated to match EIA's projection for technology success in 2020 (51.1% coal, 19.2% natural gas, 18.5% nuclear, 1.9% residual oil, and 1.0% biomass, and 8.3% zero-carbon).

WTW results from cases with those modifications are shown in Table 9.2.5. The results do not match those in Hydrogen Program Record 9002 (2009) because the production yield and cost of electrolyzers were modified in the Program Record case.

Table 9.2.5. Well-to-Wheels Results for Distributed Electrolysis Pathway with Advanced Technology

Coal Input from "Well"	4050	Btu / mi
Natural Gas Input from "Well"	1330	Btu / mi
Petroleum Input from "Well"	220	Btu / mi
Fossil Energy Input from "Well"	5600	Btu / mi
WTW CO_2 Emissions	540	g / mi
WTW CH_4 Emissions	0.72	g / mi
WTW N_2O Emissions	0.008	g / mi
WTW GHG Emissions	560	g / mi
Levelized Cost of Hydrogen ($/kg)	$4.93	2005 $/kg
Levelized Cost of Hydrogen ($/mi)	$0.0759	2005 $/mi

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy for advanced FCVs used in this study (65 mpgge), and a yield of hydrogen from electricity of 45 kWh electricity/kg H_2, the amount of electricity required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with electrolysis-derived hydrogen fuel was calculated and compared to the projected 2030 U.S. electricity demand (United States Department of Energy, 2009), the 2008 U.S. electricity generation, and the 2008 U.S. electricity consumption estimates shown in Section 3.2 (Table 9.2.6).

Table 9.2.6. Electricity Supply Scenarios for Advanced Distributed Electricity Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Advanced Technology – 65 mpgge FCV, hydrogen production yield 45 kWh/kg H_2[1]			
Electricity Required (trillion kWh/yr)	2.0	1.5	1.0	0.5
Percent of Projected 2030 U.S. Electricity Demand (5.8 trillion kWh)[2]	34%	25%	17%	8%
Percent of 2008 U.S. Net Electricity Generation (4.1 trillion kWh)[3]	48%	36%	24%	12%
Percent of Annual U.S. Consumption (3.7 trillion kWh)[4]	52%	39%	26%	13%

[1] Calculation does not include energy or hydrogen losses.
[2] United States Department of Energy (2008)
[3] Energy Information Administration (2009e)
[4] Energy Information Administration (2009f)

9.3 Central Biomass – Liquid Delivery

Figure 9.3.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. The complete set of assumptions is detailed in Appendix C.

The well-to-pump and well-to-wheels cost of hydrogen, energy use, and emissions for the central biomass–liquid truck delivery pathway are summarized in Table 9.3.1.

The GHG emissions include carbon dioxide uptake of 112,500 g CO_2 / dry ton biomass due to direct land use change. That uptake is in addition to carbon dioxide that is converted into plant matter and subsequently released during gasification and reforming. If the land use change had a neutral effect on GHG emissions, the WTP GHG emissions would increase by 1,700 CO_2 eq. / 116,000 Btu H_2, and the WTW GHG emissions would increase by 38 CO_2 eq. / mile.

9.3.1 Cost Breakdown

Figure 9.3.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central biomass–liquid truck delivery pathway. The financial assumptions used in this analysis are detailed in Section 8.0.

Inputs		Graphic Depiction & Assumptions		Outputs	

Biomass Production & Delivery

Inputs

Coal Input from "Well"	269 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	427 Btu / 116000Btu to Pump
Petroleum Input from "Well"	2,832 Btu / 116000Btu to Pump

Assumptions

Fraction of Woody Biomass (Remaining is Herbaceous)	100%
Grams of Nitrogen / dry ton biomass	709
Grams of P2O5 / dry ton biomass	189
Grams of K2O / dry ton biomass	331
Herbicide use	24 g / dry ton
Insecticide use	2 g / dry ton
Average dist from farm to H2 production	40 miles

Outputs

Biomass moisture content	25%
Woody biomass LHV	16,811,019 Btu / dry ton
Biomass price at H2 production	$37.96 2005 $ / dry ton
Levelized Cost of Biomass	$0.61 2005$ / kg H2 distributed
WTG CO2 Emissions	-26,911 g / 116000Btu to Pump
WTG CH4 Emissions	0 g / 116000Btu to Pump
WTG N2O Emissions	0 g / 116000Btu to Pump
WTG GHG Emissions	-26,867 g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Biomass consumption	12.8 kg (dry) / kg H2 produced
Natural gas consumption	0.17 N m^3/kg H2 produced
Electricity consumption	0.98 kWh / kg H2
Process Water Consumption	5.00 L / kg H2
Natural gas price	$0.340 2005$ / N m^3
Electricity price	$0.0555 2005 $/kWh
Total Capital Investment	$154,644,297 2005$
Coal Input from "Well"	6,356 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	9,009 Btu / 116000Btu to Pump
Petroleum Input from "Well"	3,570 Btu / 116000Btu to Pump

Assumptions

Central plant design capacity	155,236 kg/day
Capacity factor	90%
Process energy efficiency	46.0%
Electricity Mix	US Mix
After-tax IRR	0
Assumed Plant Life	40

Outputs

Hydrogen Output Pressure	300 psi
Hydrogen Outlet Quality	98 minimum
Total capital investment	$3.03 2005$ / annual kg H2 (effective capacity)
Levelized Electricity cost	$0.05 2005$ / kg H2 produced
Levelized Natural Gas Cost	$0.06 2005$ / kg H2 produced
Levelized Other operating costs	$0.32 2005$ / kg H2 produced
Levelized Cost of Prod (excl feedstock)	$1.18 2005$ / kg H2 distributed
SMR CO2 Emissions	26,979 g / 116000Btu to Pump
SMR CH4 Emissions	3 g / 116000Btu to Pump
SMR N2O Emissions	0 g / 116000Btu to Pump
SMR GHG Emissions	27,091 g CO2 eq./ 116000 Btu

Liquefaction and Truck-Delivery

Inputs

Liquefaction electricity consumption	8.2 kWh / kg H2
Diesel consumption	7.3 gal / 1000 kg H2
Total Capital Investment	$800,063,746
Coal Input from "Well"	50,184 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	14,462 Btu / 116000Btu to Pump
Petroleum Input from "Well"	4,778 Btu / 116000Btu to Pump

Assumptions

City Population	1,247,364 people
Hydrogen Vehicle Penetration	50%
City hydrogen use	125,810,766 kg / yr
Liquefaction efficiency	80.3%
Terminal Design Capacity	3,532,139 kg H2
Number of truck-trips required	31,009 per year
Truck hydrogen capacity	4,372 kg / truckload
One-way distance for delivery	49 miles
Hydrogen losses	10.1%

Outputs

Total capital investment	$6.37 2005$/annual kg delivered
Levelized Electricity cost	$0.49 2005$ / kg H2 delivered
Levelized Diesel cost	$0.01 2005$ / kg H2 delivered
Levelized Labor cost	$0.13 2005$ / kg H2 delivered
Levelized Other operating costs	$0.28 2005$ / kg H2 delivered
Levelized Cost of Distribution	$2.04 2005$ / kg H2 distributed
Delivery CO2 Emissions	6,708 g / 116000Btu to Pump
Delivery CH4 Emissions	9 g / 116000Btu to Pump
Delivery N2O Emissions	0 g / 116000Btu to Pump
Delivery GHG Emissions	6,955 g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs

Electricity consumption	3.04 kWh / kg H2
Electricity price	$0.082 2005$ / kWh
Coal Input from "Well"	0 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	0 Btu / 116000Btu to Pump
Petroleum Input from "Well"	0 Btu / 116000Btu to Pump

Assumptions

Number of Distribution Stations	270
Energy efficiency	92%
Number of Compression Steps	4
Isentropic Efficiency	65%
Site storage	52% capacity
Hydrogen losses	0.50%
Hydrogen loss factor	1.005

Outputs

Hydrogen outlet pressure	6,250 psi
Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$5.85 2005$/annual kg
Levelized Electricity cost	$0.25 2005$ / kg H2
Levelized Cost of Distribution	$1.05 2005$ / kg H2 distributed
CSD CO2 Emissions	0 g / 116000Btu to Pump
CSD CH4 Emissions	0 g / 116000Btu to Pump
CSD N2O Emissions	0 g / 116000Btu to Pump
CSD GHG Emissions	0 g CO2 eq./ 116000 Btu

Figure 9.3.1. Central biomass–liquid truck delivery pathway summary of major inputs, assumptions, and outputs by subsystem

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

Table 9.3.1. Well-to-Pump and Well-to-Wheels Results for Central Biomass–Liquid Truck Delivery Pathway

	Well-to-Pump		Well-to-Wheels	
Coal Input from "Well"*	56,800	Btu / 116,000 Btu	100	Btu / mi
Natural Gas Input from "Well"*	23,900	Btu / 116,000 Btu	3,910	Btu / mi
Petroleum Input from "Well"*	11,200	Btu / 116,000 Btu	250	Btu / mi
Fossil Energy Input from "Well"*	91,900	Btu / 116,000 Btu	2,040	Btu / mi
WTP CO_2 Emissions*,**	6,800	g / 116,000 Btu	150	g / mi
WTP CH_4 Emissions*	12	g / 116,000 Btu	0	g / mi
WTP N_2O Emissions	0	g / 116,000 Btu	0	g / mi
WTP GHG Emissions*	7,200	g CO_2 eq. / 116,000 Btu	160	g / mi
Levelized Cost of Hydrogen ($/kg)	$4.88	2005 $/kg	$0.1086	2005 $/mi

* Well-to-pump results are rounded to the nearest hundred; well-to-wheels results are rounded to the nearest ten.

** Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

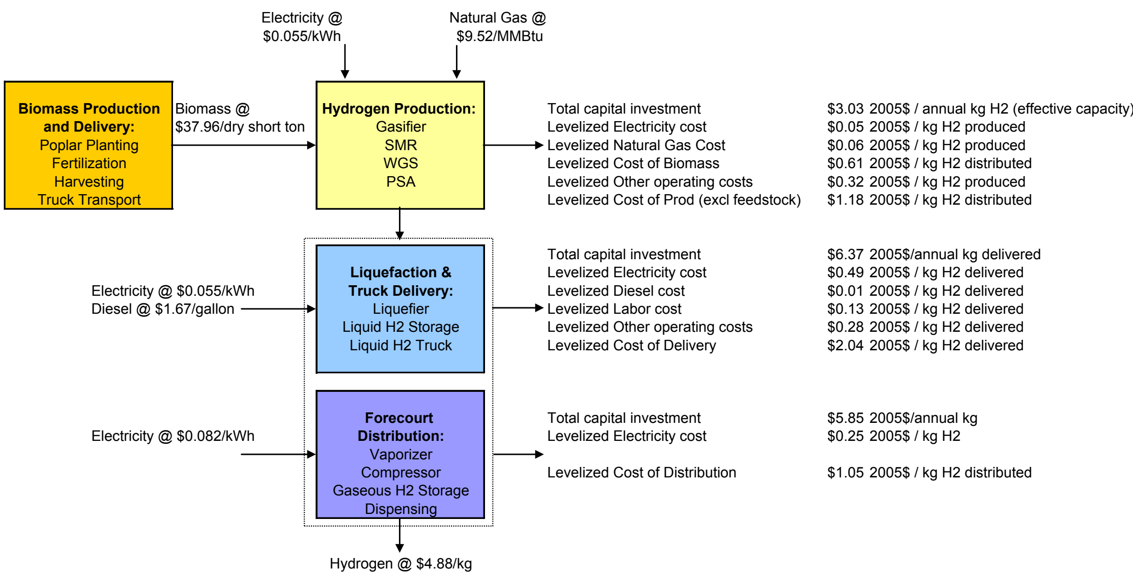


Figure 9.3.2. Cost analysis inputs and high-level results for central biomass–liquid truck delivery pathway

Figure 9.3.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 9.3.2.

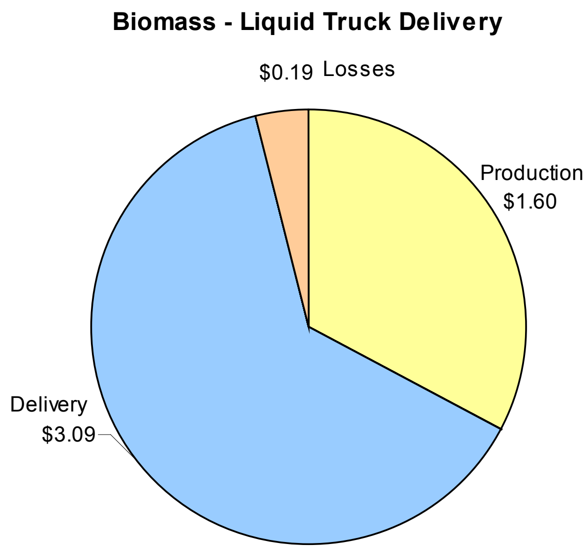


Figure 9.3.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for central biomass–liquid truck delivery pathway

Figure 9.3.4 and Table 9.3.2 show the breakdown of levelized costs for the central biomass–liquid truck delivery pathway.

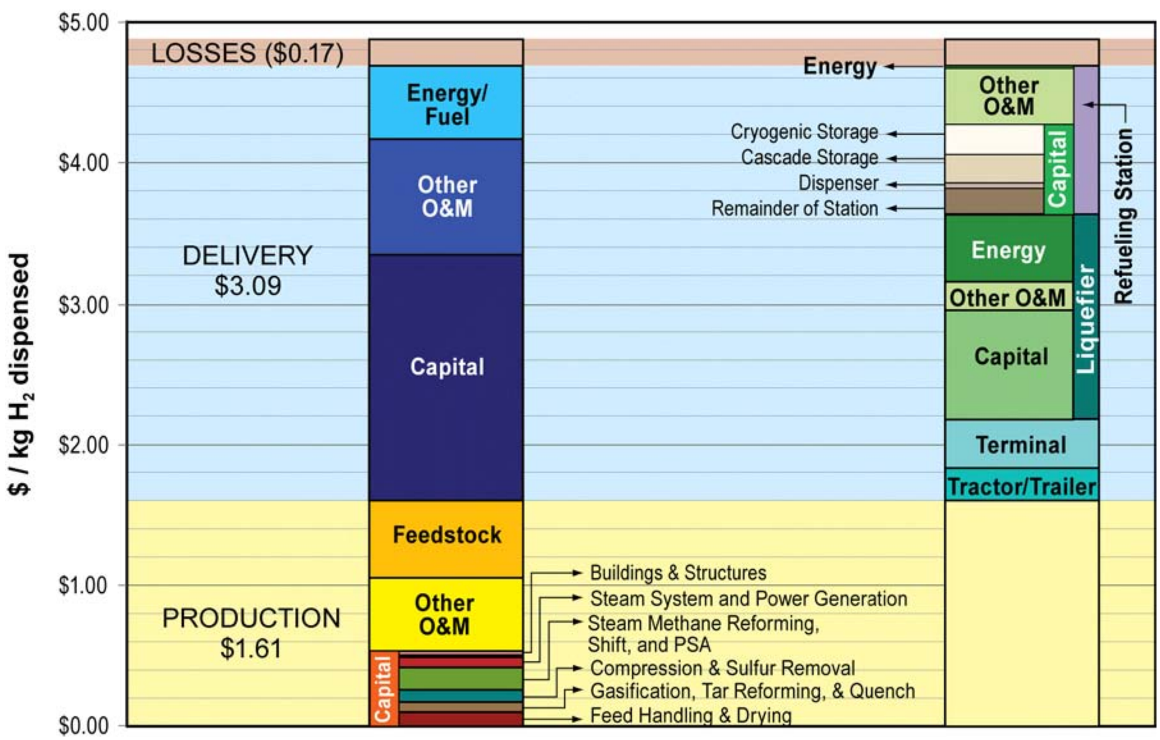


Figure 9.3.4. Breakdown of levelized costs for central biomass–liquid truck delivery pathway

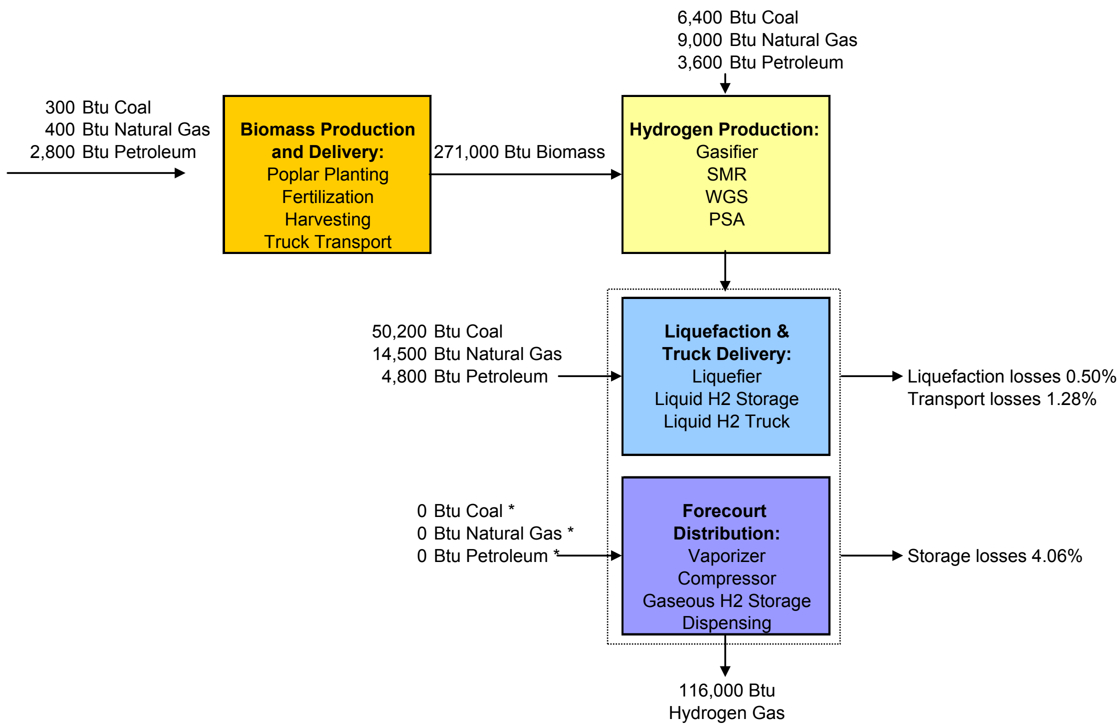
Table 9.3.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for Central Biomass–Liquid Truck Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	\$0.53	\$0.52	\$0.55		\$1.61
Feed Handling & Drying	\$0.10				
Gasification, Tar Reforming, & Quench	\$0.09				
Compression & Sulfur Removal	\$0.08				
SMR, WGS, and PSA	\$0.15				
Steam System and Power Generation	\$0.07				
Cooling Water and Other Utilities	\$0.02				
Buildings & Structures	\$0.03				
Delivery	\$1.76	\$0.82		\$0.52	\$3.09
Tractor/Trailer					\$0.24
Terminal					\$0.34
Liquefier	\$0.79	\$0.19		\$0.50	\$1.46
Gaseous Refueling Station	\$0.64	\$0.40		\$0.02	\$1.05
Cryogenic Storage	\$0.22				
Cascade Storage	\$0.20				
Dispenser	\$0.04				
Remainder of Station	\$0.18				
Losses					\$0.19
Total	**\$2.29**	**\$1.34**	**\$0.55**	**\$0.52**	**\$4.88**

9.3.2 Energy Use and Emissions Breakdown

Figures 9.3.5 and 9.3.6 show the WTW energy inputs and losses for the central biomass–liquid truck delivery pathway.

Figures 9.3.7 and 9.3.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central biomass–liquid truck delivery pathway. As noted above, carbon dioxide uptake within the plant matter and due to direct land use change is included in the biomass production section of the GHG calculations. If the land use change had a neutral effect on GHG emissions, the WTP GHG emissions would increase by 1,700 CO_2 eq. / 116,000 Btu H_2, and the WTW GHG emissions would increase by 38 CO_2 eq. / mile.



* Electricity (1,000 Btu) is used in the distribution of hydrogen to the pump. However, GREET does not model this electricity usage for the case of liquid hydrogen delivery to the station; thus, the coal, natural gas, and petroleum used in the production of the electricity are not shown here.

Figure 9.3.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using central biomass–liquid truck delivery pathway

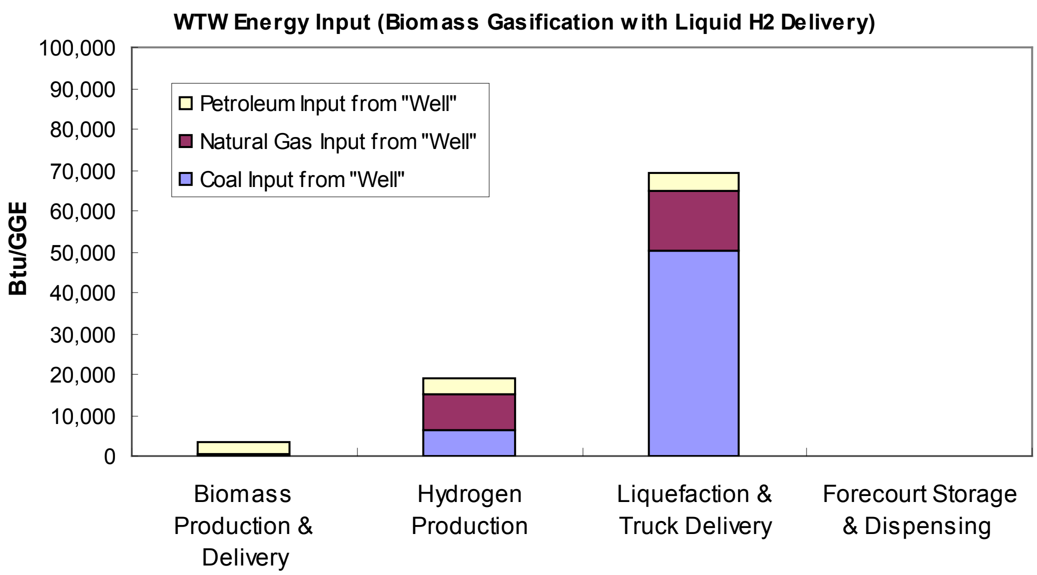


Figure 9.3.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using central biomass–liquid truck delivery pathway

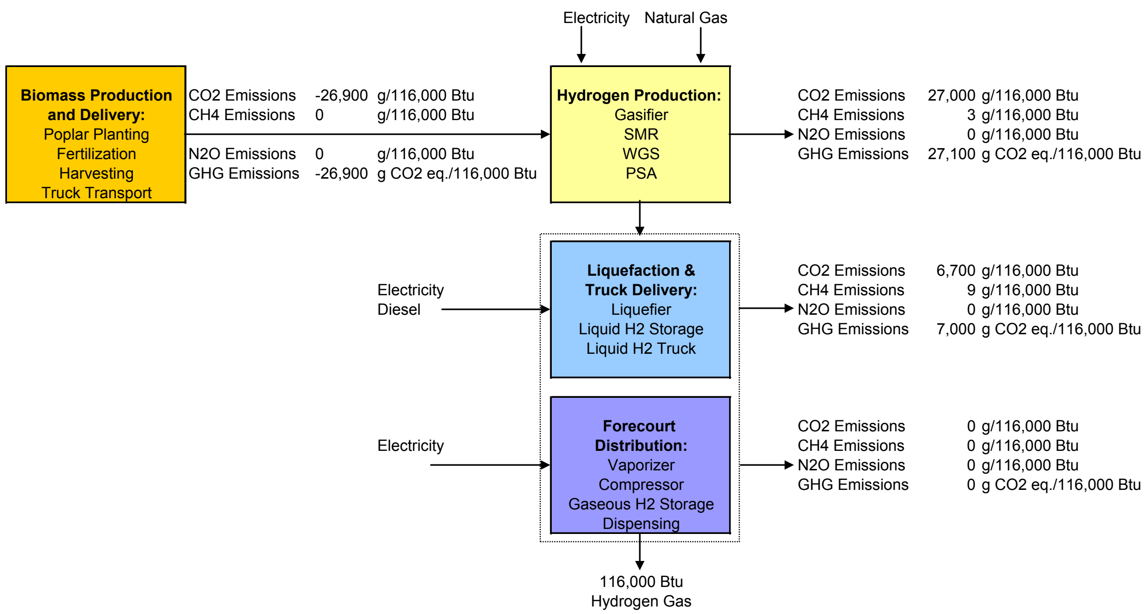


Figure 9.3.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central biomass–liquid truck delivery pathway

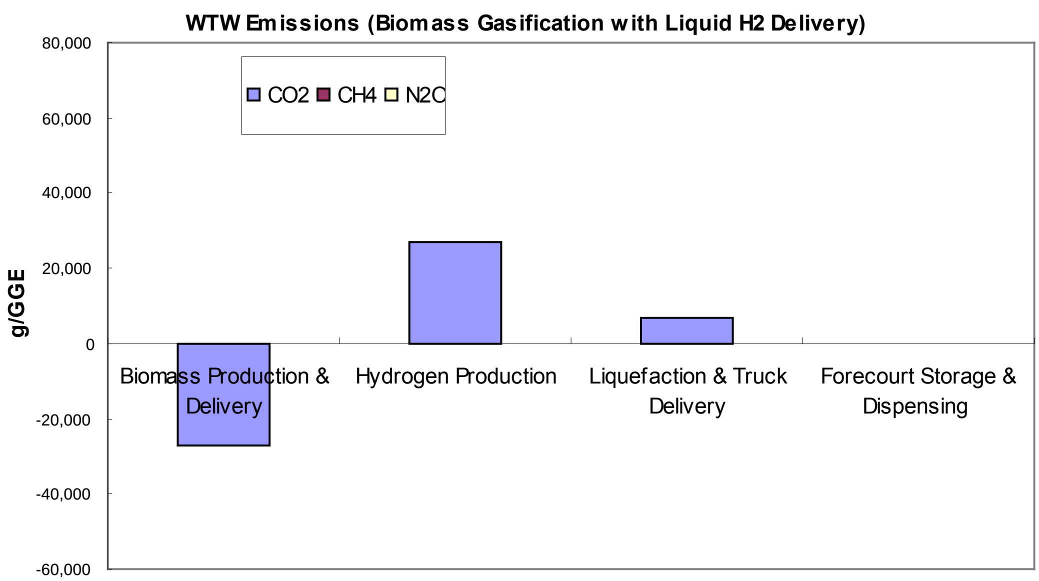


Figure 9.3.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using central biomass–liquid truck delivery pathway

9.3.3 Biomass Supply Scenarios

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from biomass of 13 kg biomass (dry)/kg H_2, the amount of biomass required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with biomass-derived hydrogen fuel was calculated and compared to the projected U.S. biomass potential and the 2008 U.S. biomass consumption estimates shown in Section 3.3 (Table 9.3.3).

Table 9.3.3. Biomass Supply Scenarios for the Central Biomass–Liquid Truck Delivery Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Current Technology – 45 mpgge FCV, hydrogen production yield 13 kg dry biomass/kg H_2 [1]			
Biomass Required (billion dry tons/yr)	0.89	0.67	0.45	0.22
Percent of U.S. Biomass Potential (1.4 billion dry tons) [2]	65%	49%	33%	16%
Percent of 2008 U.S. Wood Derived Fuels Consumption (0.12 billion dry tons) [3]	730%	550%	370%	180%

[1] Calculation does not include energy or hydrogen losses.
[2] Perlack et al. (2005)
[3] Calculated from values in Energy Information Administration (2009k)

Table 9.3.4 compares a sample scenario for hydrogen production from biomass from DOE's Hydrogen Posture Plan (United States Department of Energy, 2006) to a 20% FCV penetration scenario using the assumptions in this study, as described above.

Table 9.3.4. Comparison of Biomass Supply Scenarios to Hydrogen Posture Plan

	DOE Hydrogen Posture Plan (2006)	Hydrogen Pathways Report (2009)*
Total Hydrogen Demand	64 million metric tons/yr	63.1 million metric tons/yr
Amount of Demand to Be Supplied by Resource	13 million metric tons/yr (20%)	12.6 million metric tons/yr (20%)
Biomass Needed for H_2	140-280 million metric tons/yr	162 million metric tons/yr
Biomass Availability	512-1,300 million dry short tons/yr	1,368 million dry short tons/yr
Biomass Consumption (current)	190 million metric tons/yr	110 million metric tons/yr (using 16.8 million Btu/dry short ton LHV for biomass)
Increase in Biomass Consumption with H_2 Production	1.7-2.5 X	2.5 X

* Calculated using the assumptions in Table 9.3.3 with 20% penetration of FCVs in light-duty vehicle market

9.3.4 Sensitivities

Production Sensitivities

Several sensitivities were run on the production portion of the central biomass–liquid truck delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.3.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.3.5 shows the effects of varying production energy efficiency on WTW energy use and emissions.

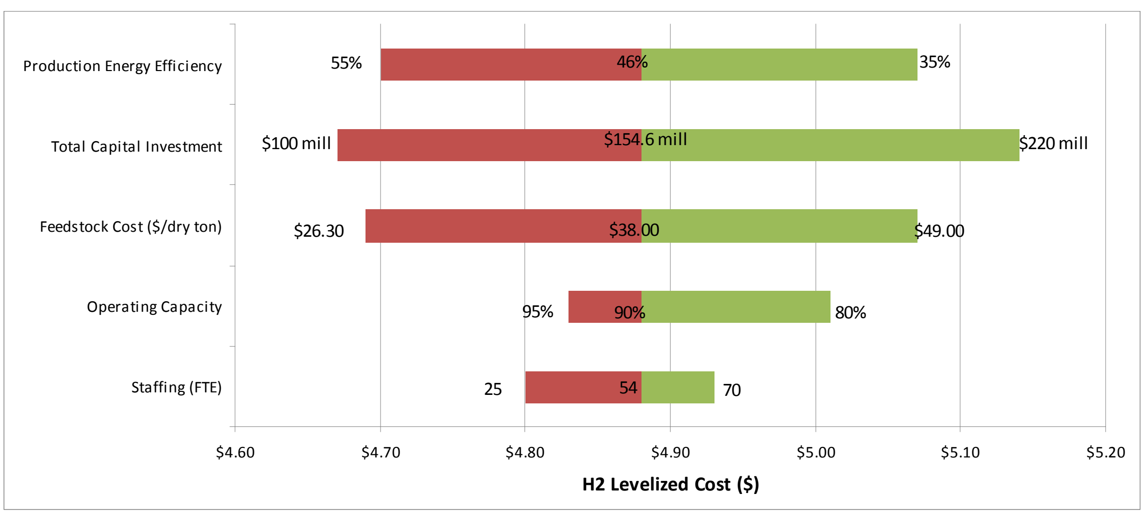


Figure 9.3.9. Production sensitivities for central biomass–liquid truck delivery pathway

Table 9.3.5. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Central Biomass–Liquid Truck Delivery Pathway

	38% Efficiency	48% Efficiency	58% Efficiency
WTW GHG Emissions (g/mile)	150	160	170
WTW Fossil Energy (Btu/mile)	2,090	2,040	2,010
WTW Petroleum Energy (Btu/mile)	290	250	220
WTW Total Energy (Btu/mile)	9,930	8,170	6,980

The assumed electrical grid mix also affects the energy use and emissions. Table 9.3.6 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 9.3.6. The Effects of Grid Mix on Use of Primary Energy and Emissions from Central Biomass–Liquid Truck Delivery Pathway

	U.S. Average Grid Mix	"Green" Grid Mix
WTW GHG Emissions (g/mile)	160	-13
WTW Fossil Energy (Btu/mile)	2,040	330
WTW Petroleum Energy (Btu/mile)	250	160
WTW Total Energy (Btu/mile)	8,170	7,010

Delivery Sensitivities

Delivery cost, energy use, and emissions are strongly dependent upon daily consumption of hydrogen within a city and delivery distance from the central facility to the city gate. Sensitivities were run to show some of those effects. Daily consumption was varied by keeping the city size constant and adjusting the penetration of hydrogen vehicles from the base case of 50%. Resulting consumption is shown in Figure 9.3.10.

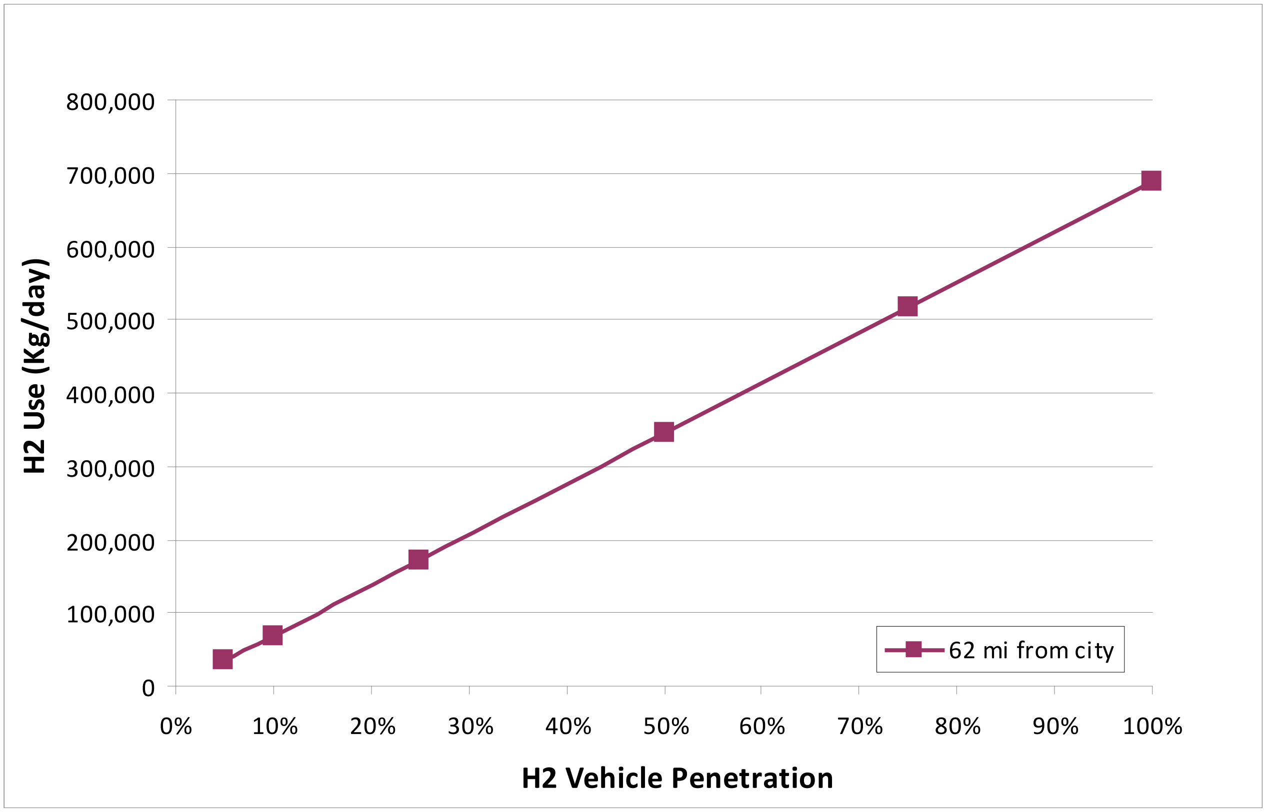


Figure 9.3.10. Daily hydrogen consumption versus hydrogen vehicle penetration for the central biomass–liquid truck delivery pathway

As expected there are economies of scale for higher penetration/hydrogen consumption, and the levelized cost of delivery decreases as the distance from the production plant to the city gate is shortened. Figures 9.3.11 and 9.3.12 show those economic effects (The figures show identical data but are organized differently.).

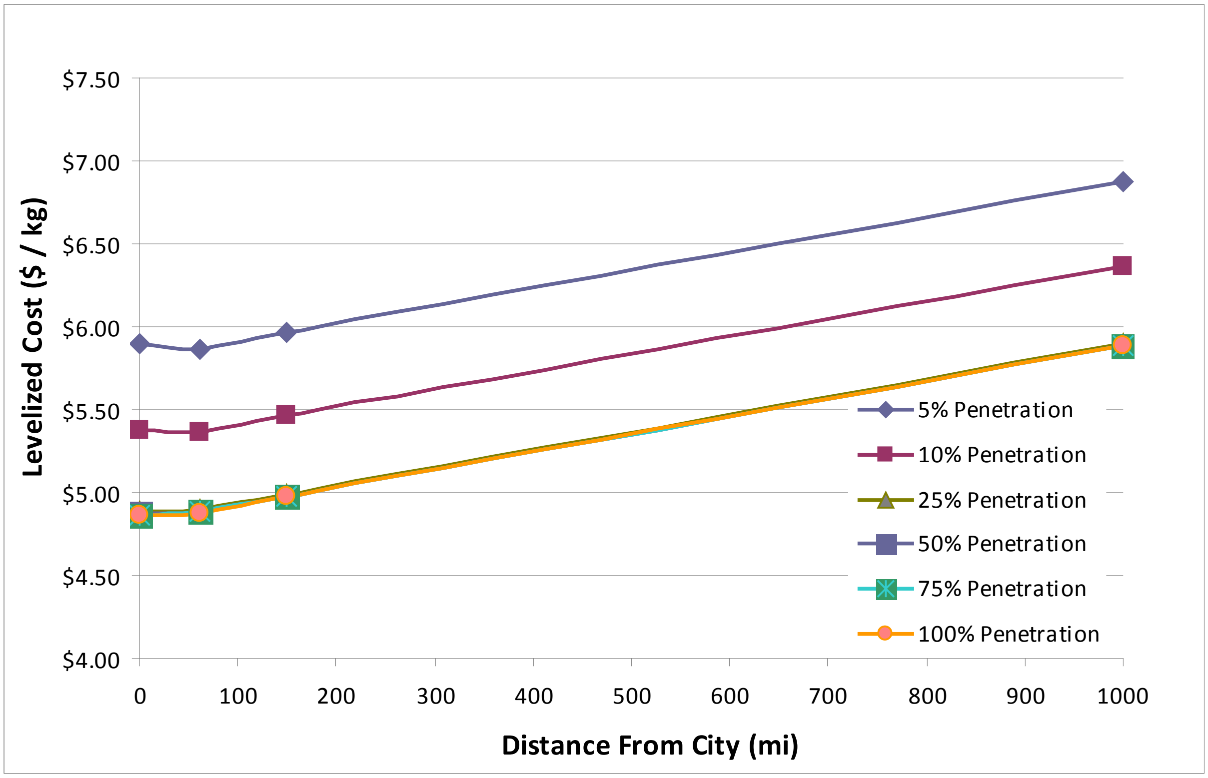


Figure 9.3.11. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass–liquid truck delivery pathway

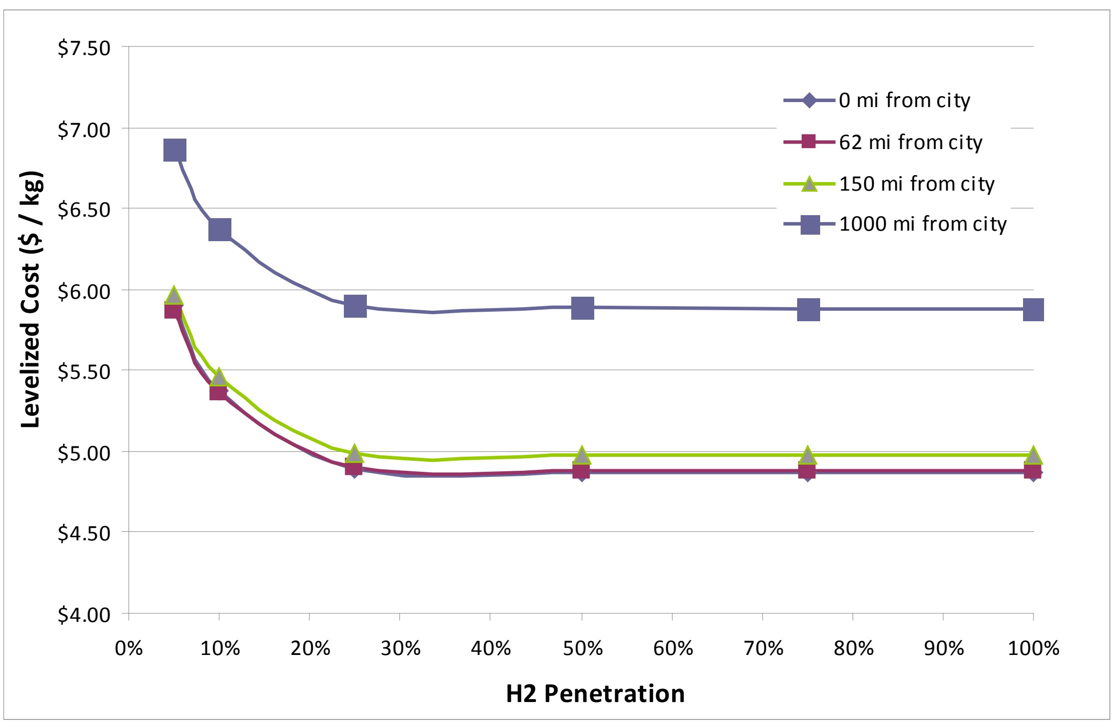


Figure 9.3.12. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass–liquid truck delivery pathway

As Figure 9.3.12 shows, there is a $0.20 increase in levelized cost when the production facility is assumed to be 150 miles from the city gate as compared to being at the city gate. There is a much larger levelized-cost increase when the distance is assumed to be 1,000 miles because the levelized cost of trucking increases with added distance due to additional driver time, additional fuel requirements, and an increased number of trucks and trailers required. Figure 9.3.13 shows the liquid truck portion of the levelized cost; note that the base case distance is 62 miles and that the truck's levelized cost is $0.235 for all penetration levels at that distance. Because the city size is constant and the assumed station size is sufficient to utilize a full truckload at each station, each delivery has the same travel distance and takes the same amount of time within the city regardless of penetration level; therefore, the levelized cost within the city gate is constant for all penetration levels.

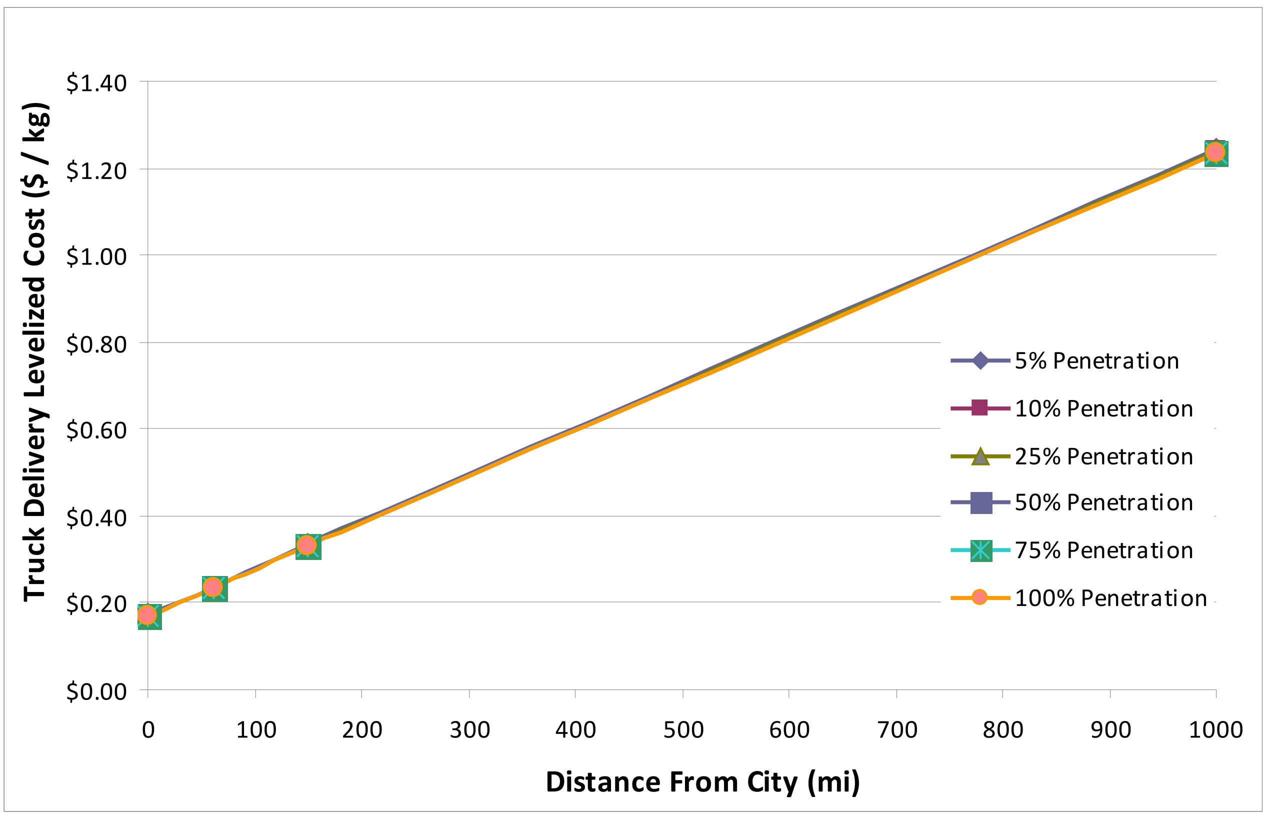


Figure 9.3.13. Truck levelized cost versus distance between production facility and city gate for the central biomass–liquid truck delivery pathway

The most notable feature in Figure 9.3.13 is the reduction in levelized cost as penetration increases to 25%. That levelized cost decrease is due to reduced cost of liquefaction, which is shown in Figure 9.3.14 (Liquefier cost is constant for all distances from the city.).

The majority of the liquefaction system's cost driver is capital (Table 9.3.2 shows that the capital accounts for $0.79/kg H_2 of the $1.47/kg H_2 total liquefaction cost.). As shown in Figure 9.3.15 capital-cost reduction drives the cost decrease as penetration increases.

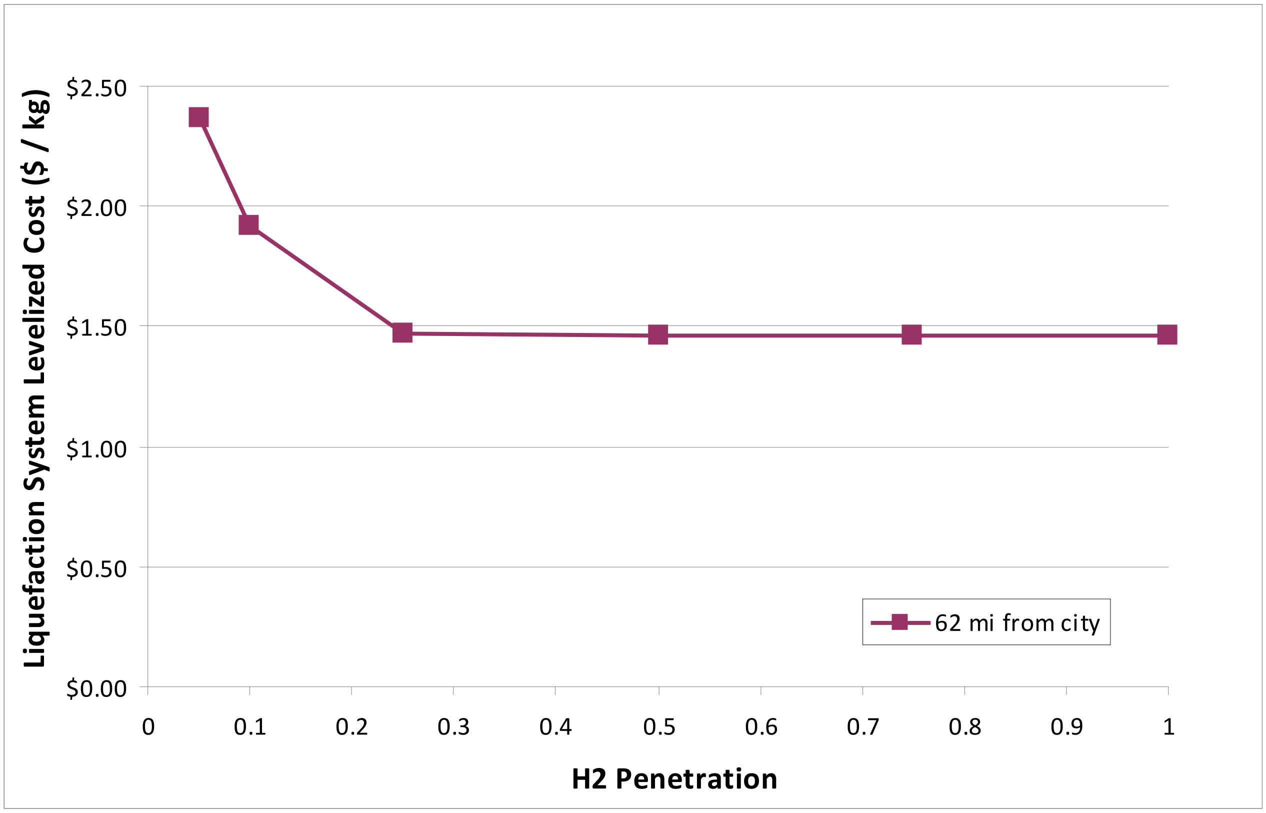


Figure 9.3.14. Liquefaction system levelized cost versus penetration for the central biomass–liquid truck delivery pathway

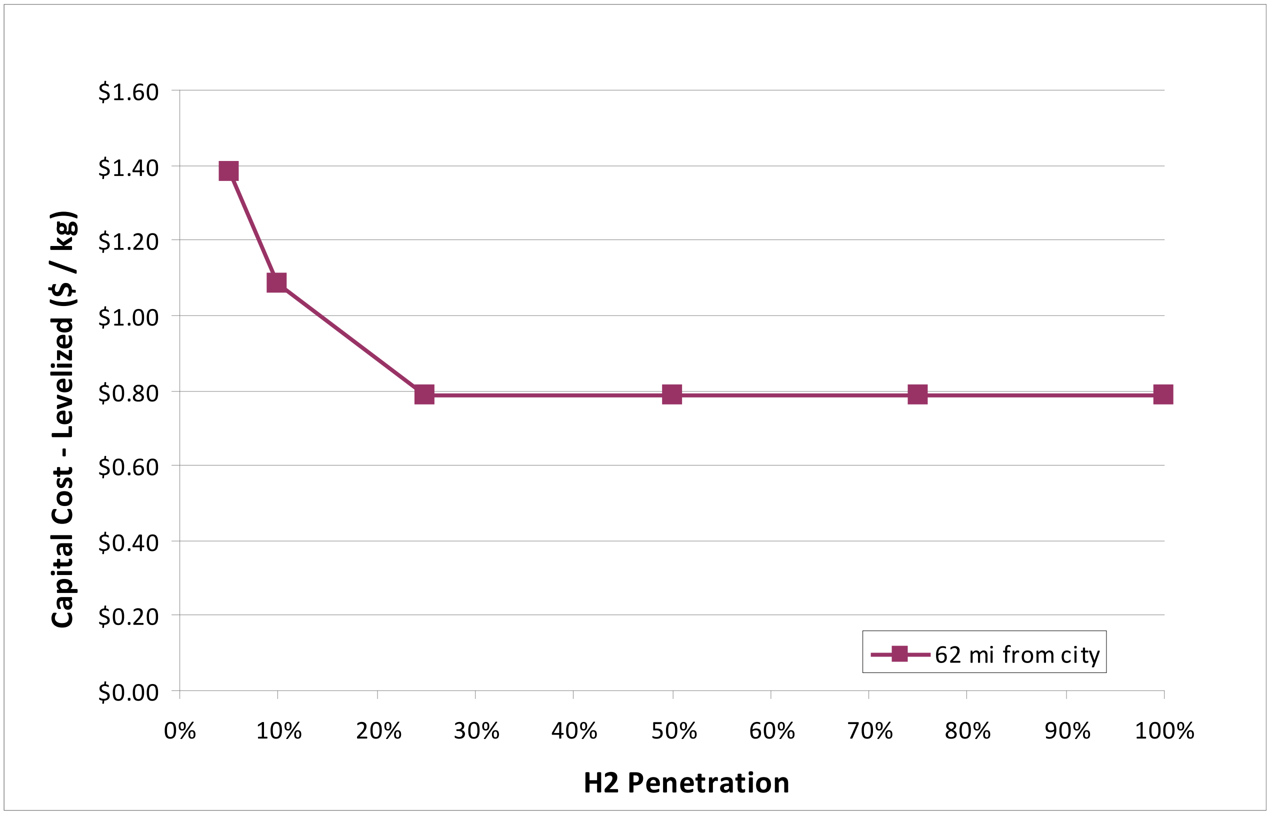


Figure 9.3.15. Liquefaction system capital cost (levelized) versus penetration for the central biomass–liquid truck delivery pathway

The additional cost variable for the liquefaction system levelized cost is the system efficiency because increased efficiency reduces the energy required for liquefaction. Figure 9.3.16 shows the effect of penetration (directly affecting liquefier size) on efficiency.

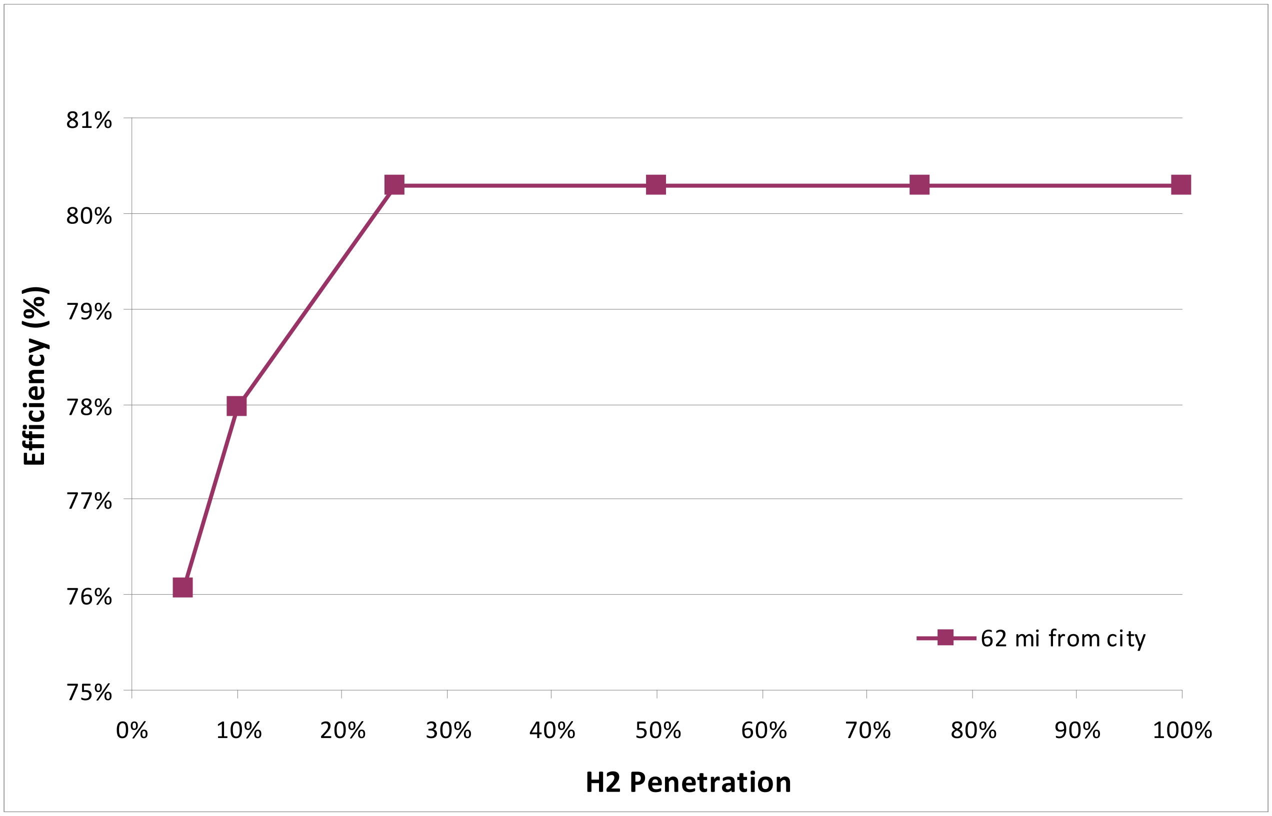


Figure 9.3.16. Liquefaction system efficiency versus penetration for the central biomass–liquid truck delivery pathway

The effects of penetration and distance between production facility and city-gate on WTW greenhouse gas emissions, WTW petroleum use, and WTW fossil energy use are shown in Figures 9.3.17, 9.3.18, and 9.3.19, respectively. In each case, the energy use and emissions decrease as liquefier efficiency increases with penetration and then plateaus as discussed above. Energy use and emissions are also reduced when the production facility is closer to the city gate because of reduced diesel use for trucking.

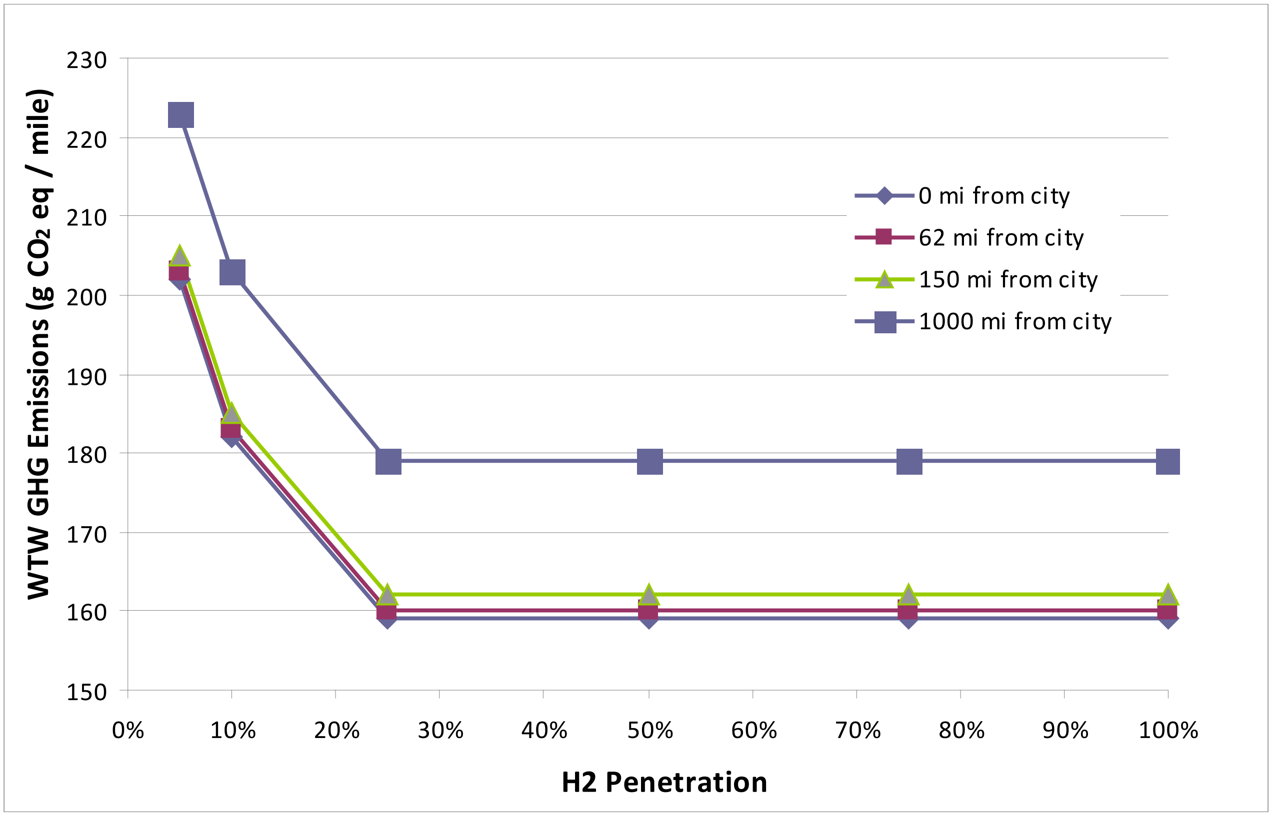


Figure 9.3.17. WTW greenhouse gas emissions versus penetration for the central biomass–liquid truck delivery pathway

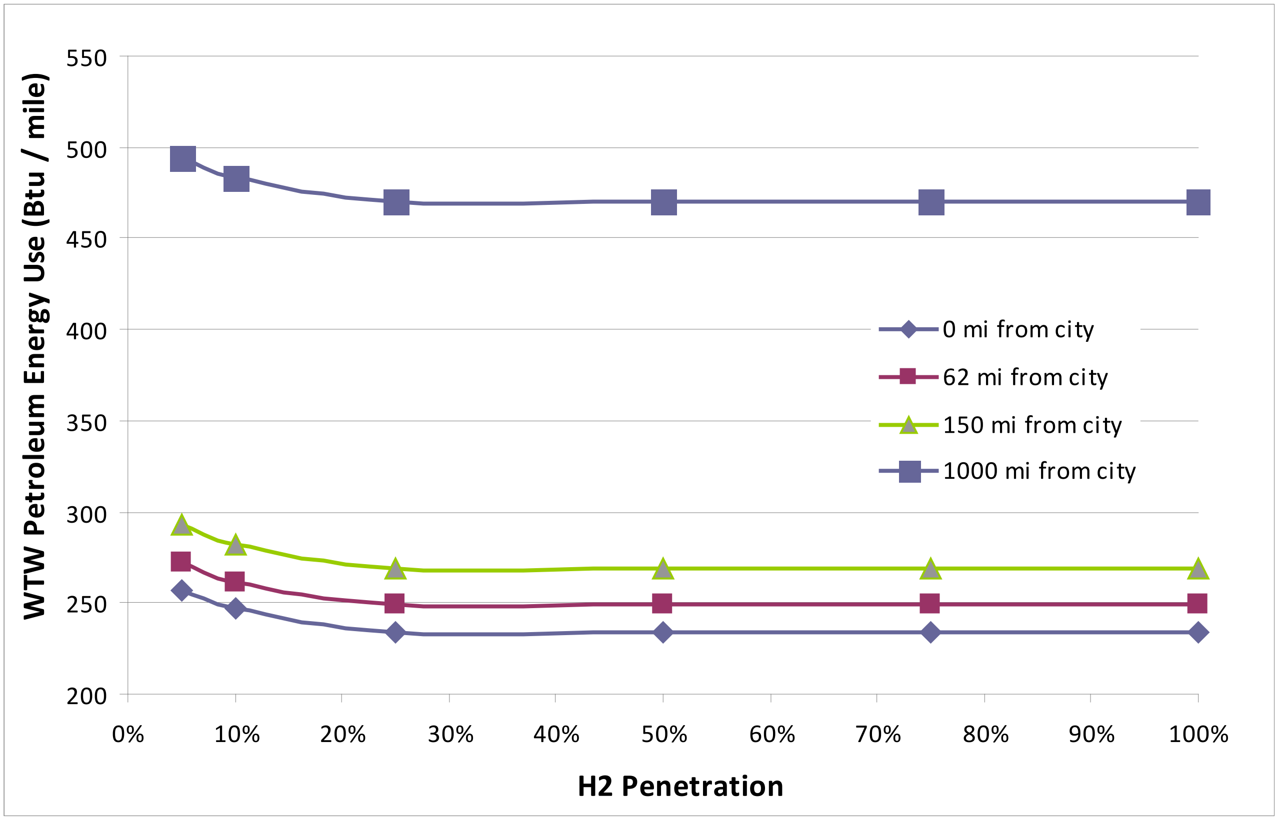


Figure 9.3.18. WTW petroleum use versus penetration for the central biomass–liquid truck delivery pathway

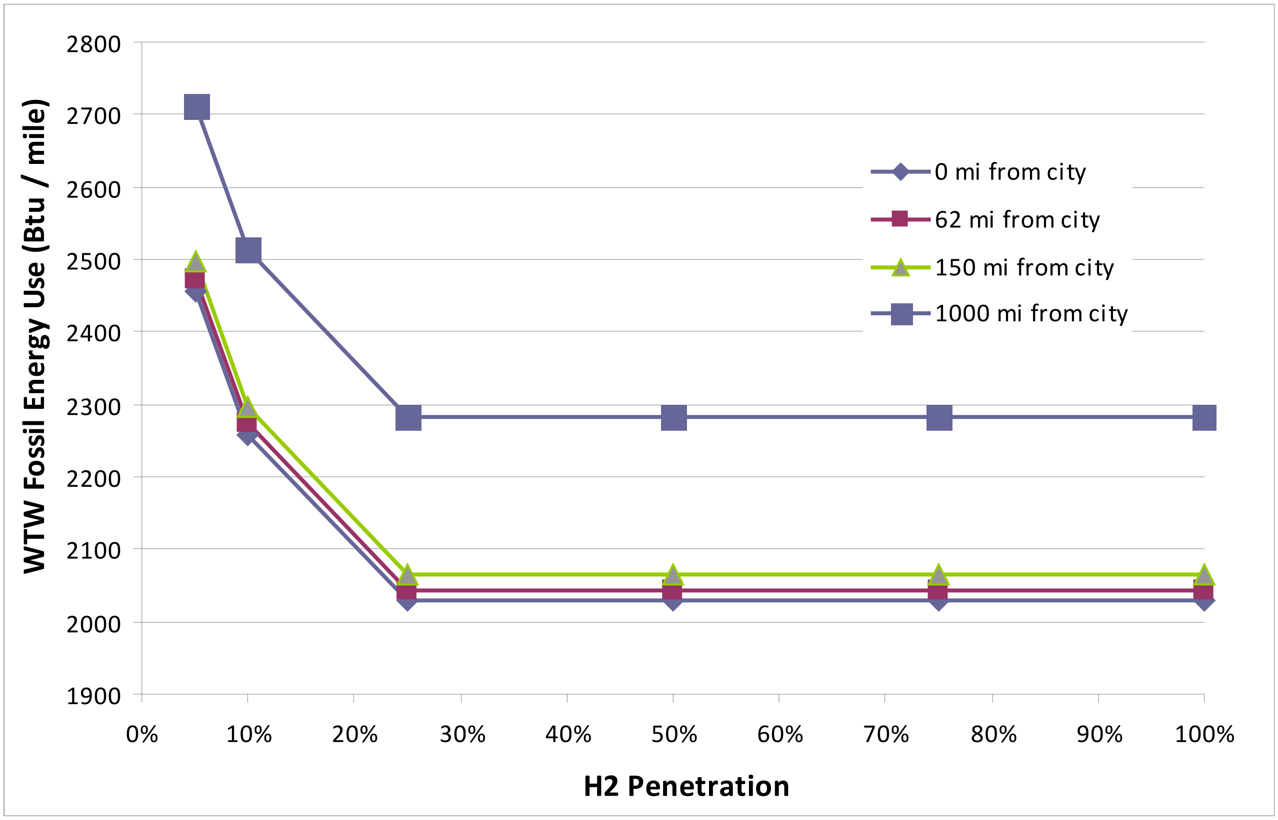


Figure 9.3.19. WTW fossil energy use versus penetration for the central biomass–liquid truck delivery pathway

9.4 Central Biomass – Pipeline Delivery

Figure 9.4.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. The complete set of assumptions is detailed in Appendix D.

The well-to-pump and well-to-wheels cost of hydrogen, energy use, and emissions for the central biomass–pipeline delivery pathway are summarized in Table 9.4.1.

The GHG emissions include carbon dioxide uptake of 112,500 g CO_2 / dry ton biomass due to direct land use change. That uptake is in addition to carbon dioxide that is converted into plant matter and subsequently released during gasification and reforming. If the land use change had a neutral effect on GHG emissions, the WTP GHG emissions would increase by 1,700 CO_2 eq. / 116,000 Btu H_2, and the WTW GHG emissions would increase by 36 CO_2 eq. / mile.

9.4.1 Cost Breakdown

Figure 9.4.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central biomass–pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 8.0.

Figure 9.4.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 9.4.2.

Figure 9.4.4 and Table 9.4.2 show the breakdown of levelized costs for the central biomass–pipeline delivery pathway.

Inputs	Graphic Depiction & Assumptions	Outputs

Biomass Production & Delivery

Inputs

Coal Input from "Well"	261	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	418	Btu / 116000Btu to Pump
Petroleum Input from "Well"	2,900	Btu / 116000Btu to Pump

Assumptions

Fraction of Woody Biomass (Remaining is Herbaceous)	100%	
Grams of Nitrogen / dry ton biomass	709	
Grams of P2O5 / dry ton biomass	189	
Grams of K2O / dry ton biomass	331	
Herbicide use	24	g / dry ton
Insecticide use	2	g / dry ton
Average dist from farm to H2 production	40	miles

Outputs

Biomass moisture content	25%	
Woody biomass LHV	16,811,019	Btu / dry ton
Biomass price at H2 production	$37.96	2005 $ / dry ton
Levelized Cost of Biomass	$0.56	2005$ / kg H2 distributed
WTG CO2 Emissions	-25,632	g / 116000Btu to Pump
WTG CH4 Emissions	0	g / 116000Btu to Pump
WTG N2O Emissions	0	g / 116000Btu to Pump
WTG GHG Emissions	-25,590	g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Biomass consumption	12.8	kg (dry) / kg H2 produced
Natural gas consumption	0.17	N m^3/kg H2 produced
Electricity consumption	0.98	kWh / kg H2
Process Water Consumption	5.00	L / kg H2
Natural gas price	$0.340	2005$ / N m^3
Electricity price	$0.055	2005 $/kWh
Total Capital Investment	$154,644,297	2005$
Coal Input from "Well"	6,063	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	8,598	Btu / 116000Btu to Pump
Petroleum Input from "Well"	3,623	Btu / 116000Btu to Pump

Assumptions

Central plant design capacity	155,236	kg/day
Capacity factor	90%	
Process energy efficiency	46.0%	
Electricity Mix	US Mix	
After-tax IRR	0	
Assumed Plant Life	40	

Outputs

Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	1	
Total capital investment	$3.03	2005$ / annual kg H2 (effective capacity)
Electricity cost	$0.05	2005$ / kg H2 produced
Natural Gas Cost	$0.06	2005$ / kg H2 produced
Other operating costs	$0.38	2005$ / kg H2 produced
Levelized Cost of Prod (excl feedst	$1.07	2005$ / kg H2 distributed
CO2 Emissions	25,733	g / 116000Btu to Pump
CH4 Emissions	3	g / 116000Btu to Pump
N2O Emissions	0	g / 116000Btu to Pump
GHG Emissions	25,839	g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs

Electricity consumption for compressor	0.56	kWh / kg H2
Electricity consumption for geo storage	0.01	kWh / kg H2
Total electricity consumption	0.57	kWh / kg H2
Electricity price for compressor	$0.056	2005$ / kWh
Electricity price for geologic storage	$0.052	2005$ / kWh
Coal Input from "Well"	3,306	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	950	Btu / 116000Btu to Pump
Petroleum Input from "Well"	246	Btu / 116000Btu to Pump

Assumptions

City Population	1,247,364	people
Hydrogen Vehicle Penetration	50%	
City hydrogen use	125,810,766	kg / yr
Distance from City to Production Facility	62	miles
Geologic storage capacity	3,762,787	kg H2
Trunk #1-line length	17	miles
Trunk #2-line length	40	miles
Service-line length	1.1	miles / line
Number of service lines	270	
Hydrogen losses	1.12%	
Hydrogen loss factor	1.011	

Outputs

Total capital investment	$3.51	2005$/annual kg distributed
Electricity cost	$0.03	2005$ / kg H2
Levelized Cost of Delivery	$0.92	2005$ / kg H2 distributed
Delivery CO2 Emissions	436	g / 116000Btu to Pump
Delivery CH4 Emissions	1	g / 116000Btu to Pump
Delivery N2O Emissions	0	g / 116000Btu to Pump
Delivery GHG Emissions	452	g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs

Electricity consumption	3.04	kWh / kg H2
Electricity price	$0.082	2005$ / kWh
Coal Input from "Well"	17,677	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	5,078	Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,317	Btu / 116000Btu to Pump

Assumptions

Number of Distribution Stations	270	
Energy efficiency	92%	
Number of Compression Steps	4	
Isentropic Efficiency	65%	
Site storage	69%	capacity
Hydrogen losses	0.50%	
Hydrogen loss factor	1.005	

Outputs

Hydrogen outlet pressure	6,250	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$6.69	2005$/annual kg
Electricity cost	$0.25	2005$ / kg H2
Levelized Cost of Distribution	$1.69	2005$ / kg H2 distributed
CSD CO2 Emissions	2,333	g / 116000Btu to Pump
CSD CH4 Emissions	3	g / 116000Btu to Pump
CSD N2O Emissions	0	g / 116000Btu to Pump
CSD GHG Emissions	2,419	g CO2 eq./ 116000 Btu

Figure 9.4.1. Central biomass–pipeline delivery pathway summary of major inputs, assumptions, and outputs by subsystem

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

Table 9.4.1. Well-to-Pump and Well-to-Wheels Results for Central Biomass–Pipeline Delivery Pathway

	Well-to-Pump		Well-to-Wheels	
Coal Input from "Well"*	27,300	Btu / 116,000 Btu	610	Btu / mi
Natural Gas Input from "Well"*	15,000	Btu / 116,000 Btu	340	Btu / mi
Petroleum Input from "Well"*	8,100	Btu / 116,000 Btu	180	Btu / mi
Fossil Energy Input from "Well"*	50,400	Btu / 116,000 Btu	1,120	Btu / mi
WTP CO_2 Emissions*,**	2,900	g / 116,000 Btu	60	g / mi
WTP CH_4 Emissions	7	g / 116,000 Btu	0	g / mi
WTP N_2O Emissions	0	g / 116,000 Btu	0	g / mi
WTP GHG Emissions*	3,100	g CO2 eq. / 116000 Btu	70	g / mi
Levelized Cost of Hydrogen ($/kg)	$4.23	2005 $/kg	$0.0941	2005 $/mi

* Well-to-pump results are rounded to the nearest hundred; well-to-wheels results are rounded to the nearest ten.

** Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

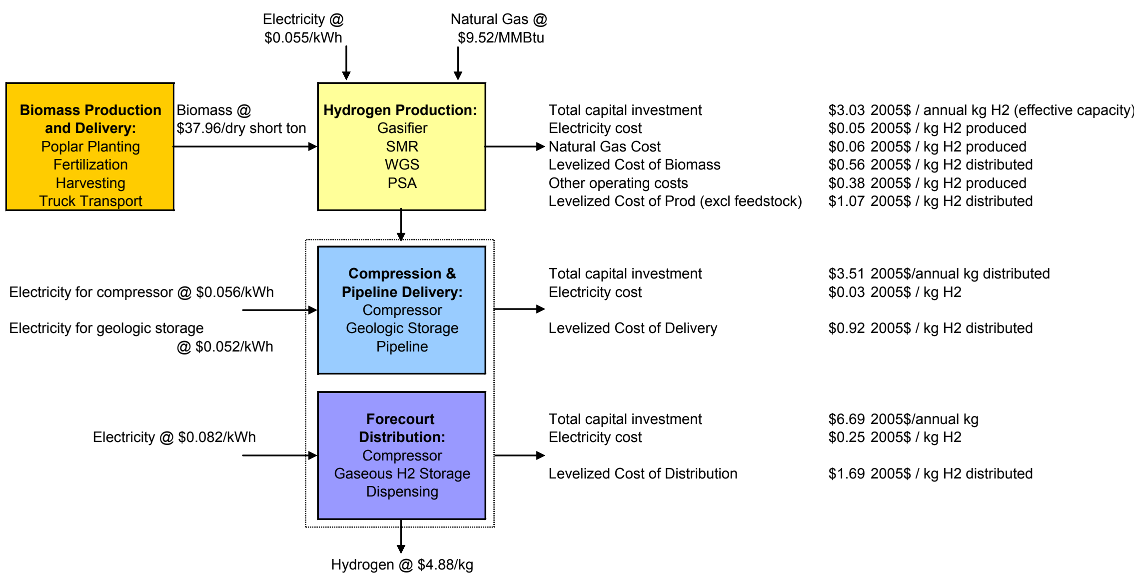


Figure 9.4.2. Cost analysis inputs and high-level results for central biomass–pipeline delivery pathway

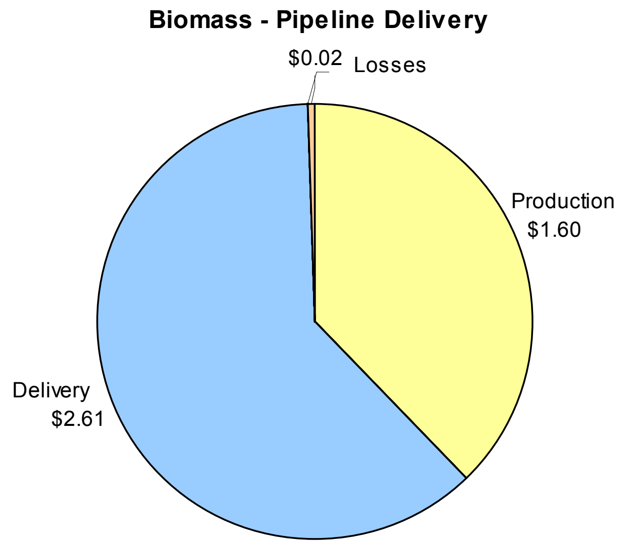


Figure 9.4.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for central biomass–pipeline delivery pathway

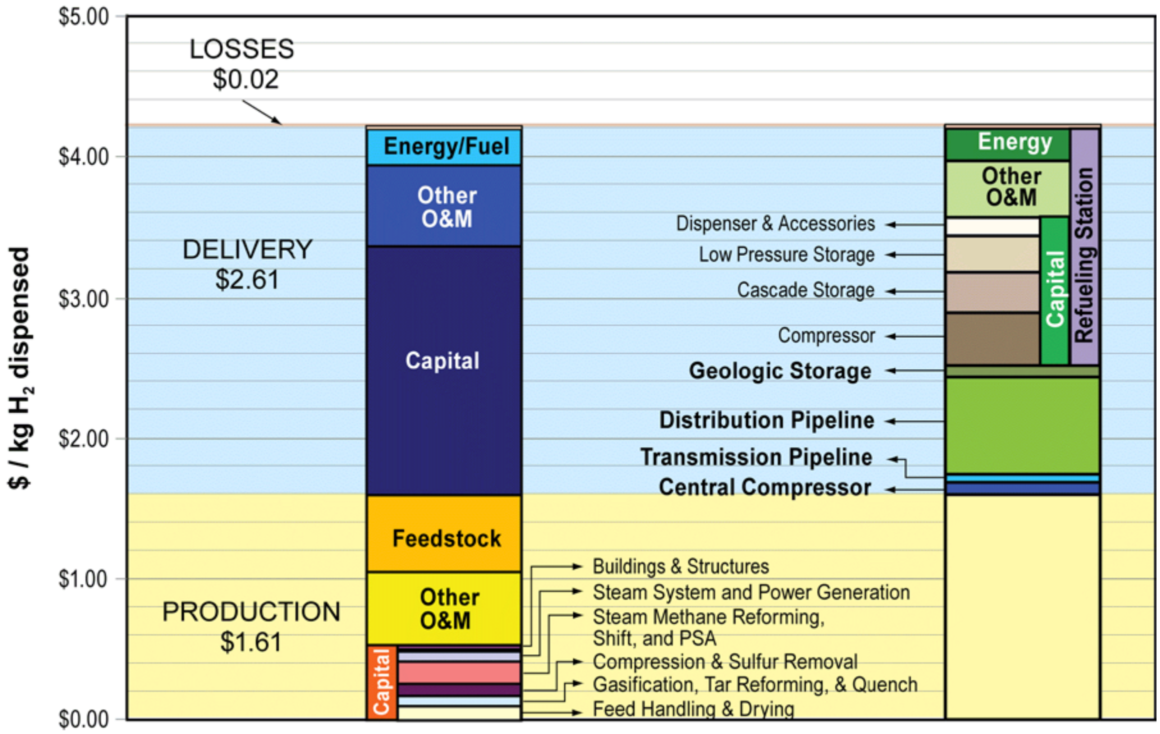


Figure 9.4.4. Breakdown of levelized costs for central biomass–pipeline delivery pathway

Table 9.4.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for Central Biomass–Pipeline Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.53	$0.52	$0.55		$1.61
Feed Handling & Drying	$0.10				
Gasification, Tar Reforming, & Quench	$0.09				
Compression & Sulfur Removal	$0.08				
SMR, WGS, and PSA	$0.15				
Steam System and Power Generation	$0.07				
Cooling Water and Other Utilities	$0.02				
Buildings & Structures	$0.03				
Delivery	$1.77	$0.58		$0.26	$2.61
Central Compressor					$0.08
Transmission Pipeline					$0.07
Distribution Pipeline					$0.70
Geologic Storage					$0.08
Gaseous Refueling Station	$1.06	$0.41		$0.23	$1.69
Compressor	$0.39				
Cascade Storage	$0.29				
Low Pressure Storage	$0.26				
Dispenser & Accessories	$0.12				
Losses					$0.02
Total	**$2.30**	**$1.10**	**$0.55**	**$0.26**	**$4.23**

9.4.2 Energy Use and Emissions Breakdown

Figures 9.4.5 and 9.4.6 show the WTW energy inputs and losses for the central biomass–pipeline delivery pathway.

Figures 9.4.7 and 9.4.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central biomass–pipeline delivery pathway.

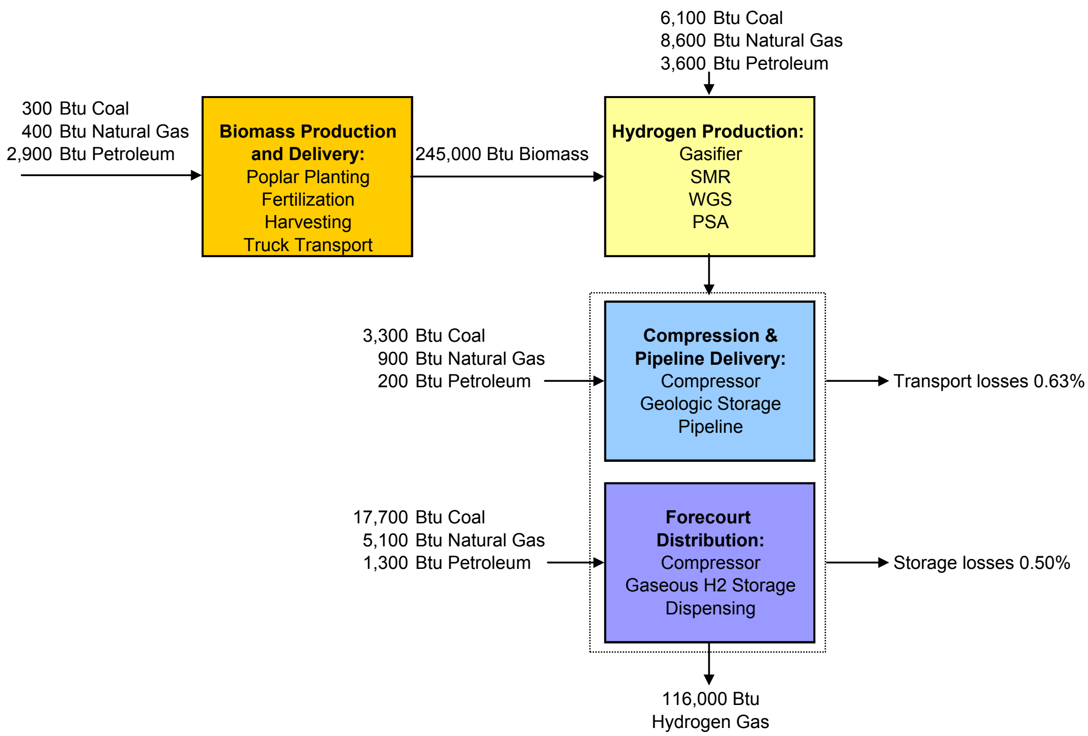


Figure 9.4.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using central biomass–pipeline delivery pathway

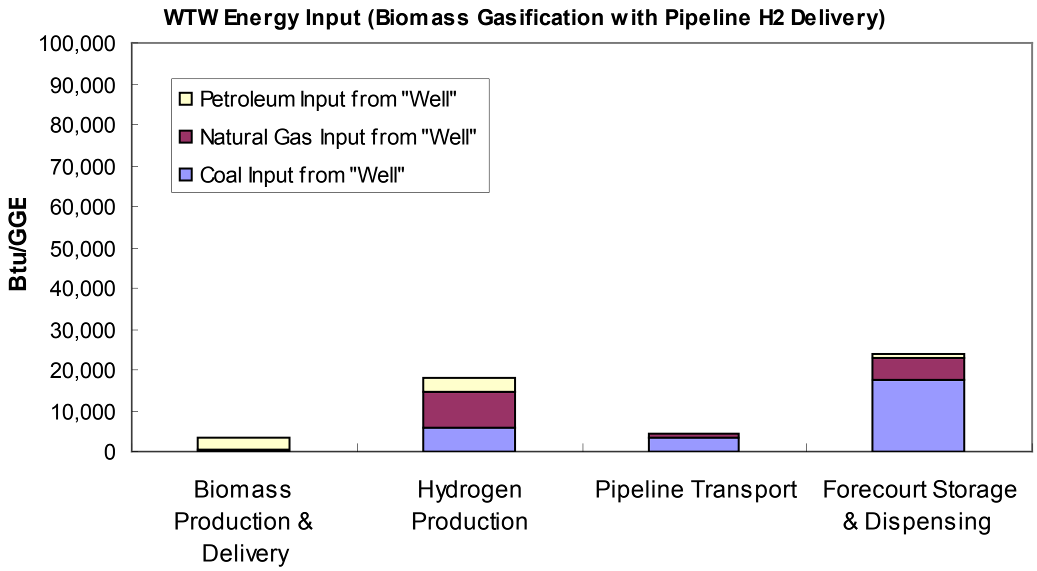


Figure 9.4.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using central biomass–pipeline delivery pathway

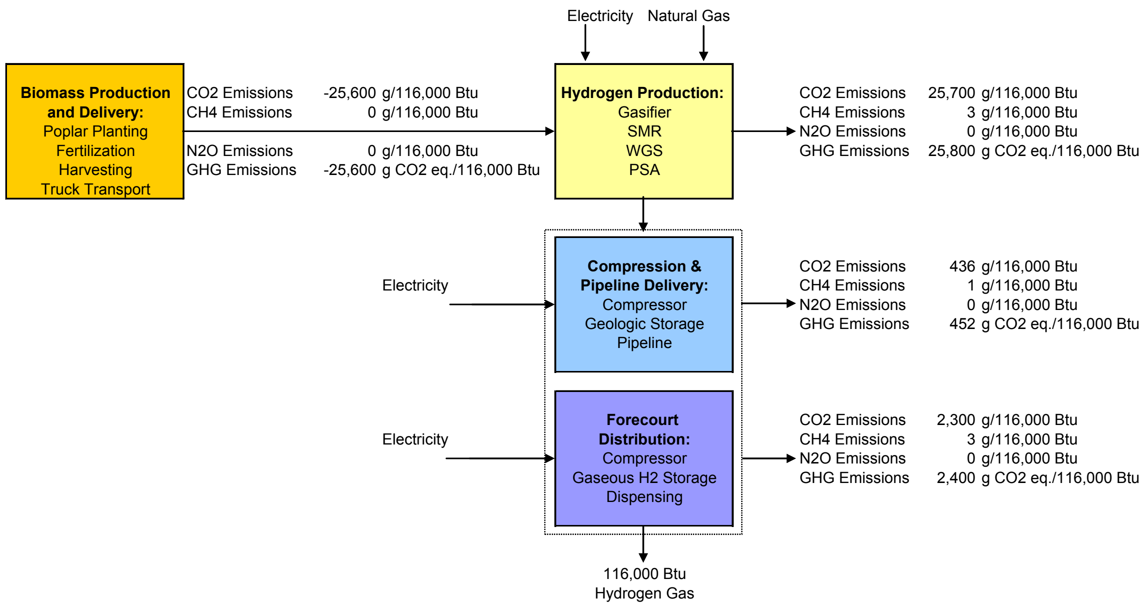


Figure 9.4.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central biomass–pipeline delivery pathway

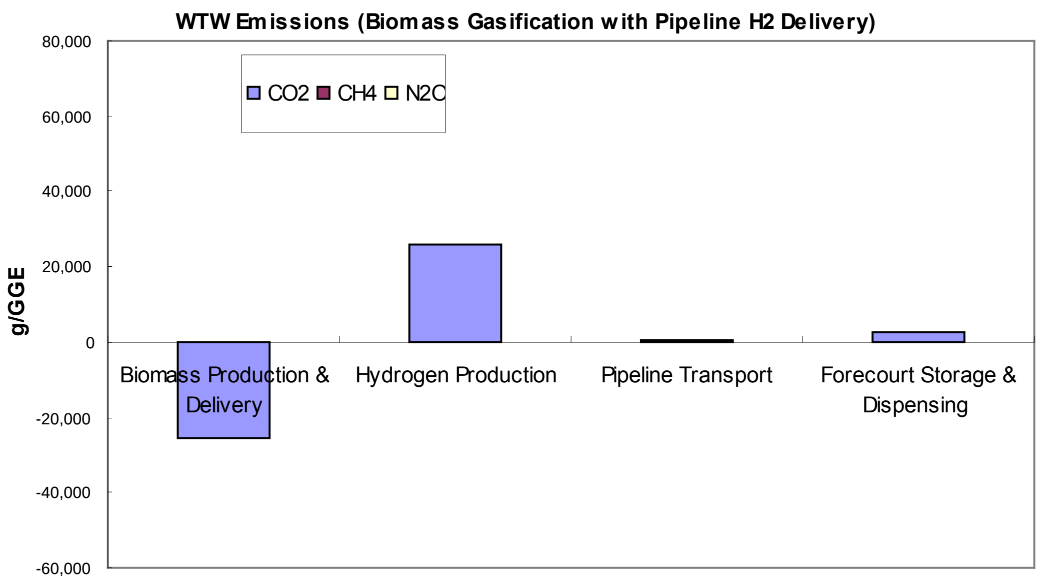


Figure 9.4.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using central biomass–pipeline delivery pathway

9.4.3 Biomass Supply Scenarios

Because the feedstock, calculated yield, and assumed fuel economy for this pathway are the same as those for the central biomass–liquid truck delivery pathway, the supply scenarios are the same as those shown in Section 9.3.3.

9.4.4 Sensitivities

Production Sensitivities

Several sensitivities were run on the production portion of the central biomass–pipeline delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.4.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.4.3 shows the effects of varying production energy efficiency on WTW energy use and emissions.

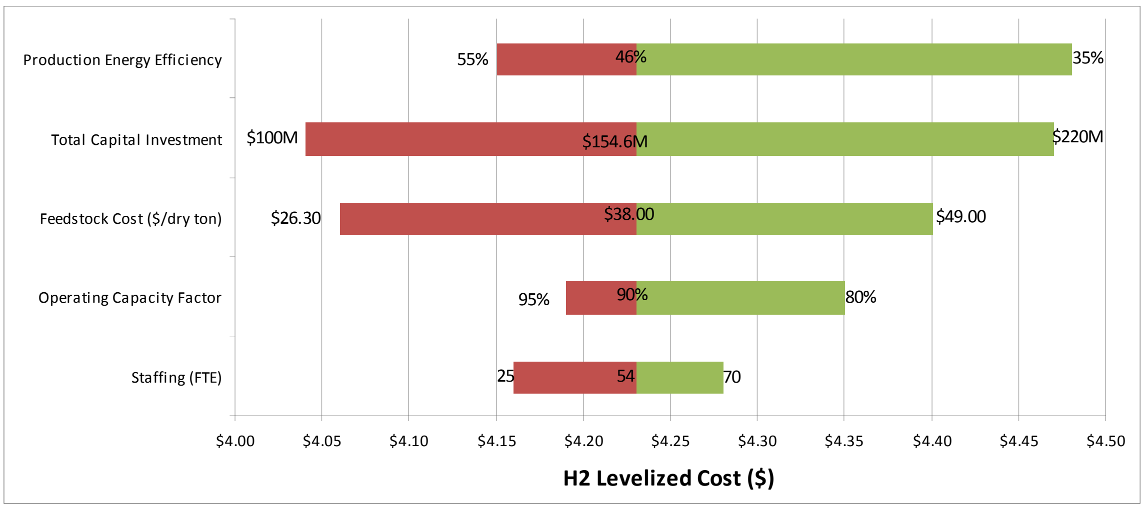


Figure 9.4.9. Production sensitivities for central biomass–pipeline delivery pathway

Table 9.4.3. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Central Biomass–Pipeline Delivery Pathway (current technology)

	35% Efficiency	46% Efficiency	55% Efficiency
WTW GHG Emissions (g/mile)	60	62	73
WTW Fossil Energy (Btu/mile)	1,190	1,040	1,100
WTW Petroleum Energy (Btu/mile)	240	170	160
WTW Total Energy (Btu/mile)	9,100	6,410	5,840

The assumed electrical grid mix also affects the energy use and emissions. Table 9.4.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 9.4.4. The Effects of Grid Mix on Use of Primary Energy and Emissions from Central Biomass–Pipeline Delivery Pathway

	U.S. Average Grid Mix	"Green" Grid Mix
WTW GHG Emissions (g/mile)	62	-17
WTW Fossil Energy (Btu/mile)	1,040	220
WTW Petroleum Energy (Btu/mile)	170	130
WTW Total Energy (Btu/mile)	6,410	5,870

Delivery Sensitivities

Delivery cost, energy use, and emissions are strongly dependent upon daily consumption of hydrogen within a city and delivery distance from the central facility to the city gate. Sensitivities were run to show some of those effects. Daily consumption was varied by keeping the city size constant and adjusting the penetration of hydrogen vehicles from the base case of 50%. Resulting consumption is shown in Figure 9.4.10.

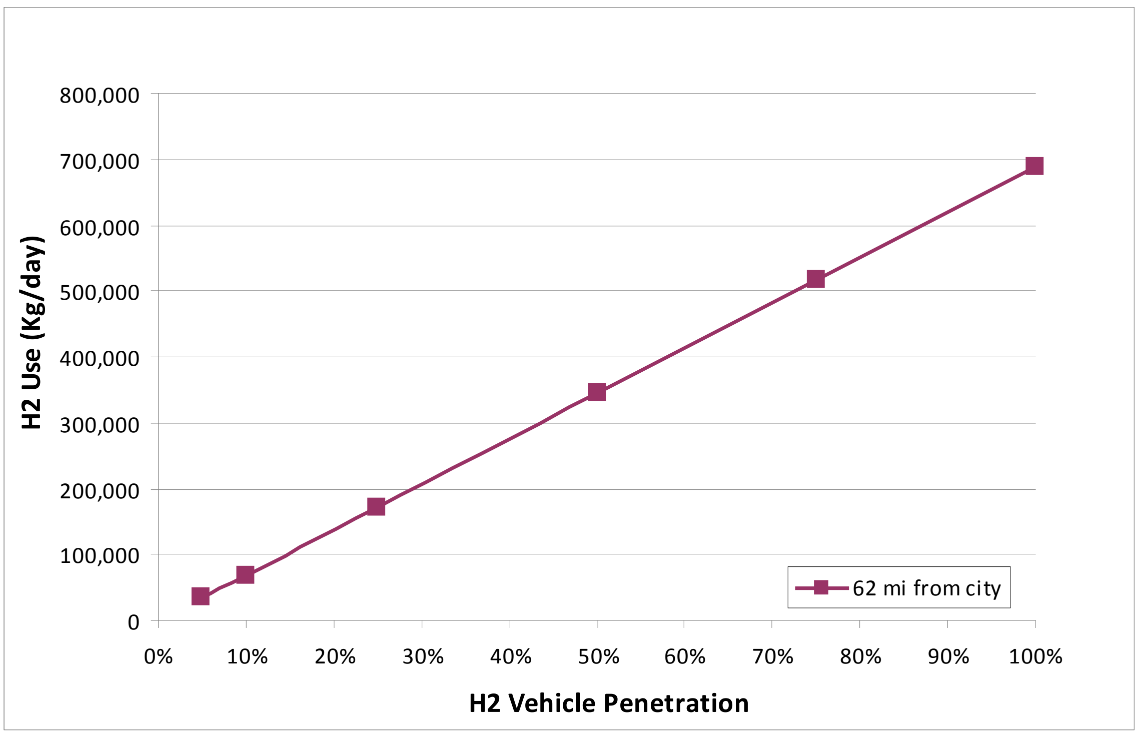


Figure 9.4.10. Daily hydrogen consumption versus hydrogen vehicle penetration for central biomass–pipeline delivery pathway

As expected there are economies of scale for higher penetration/hydrogen consumption, and the levelized cost of delivery decreases as the distance from the production plant to the city gate is shortened. Figures 9.4.11 and 9.4.12 show those economic effects (The figures show identical data but are organized differently.).

As Figure 9.4.12 shows, the cost increase due to distance from the city is more gradual with higher penetration because the cost of the transmission pipeline is shared more fully with increased demand.

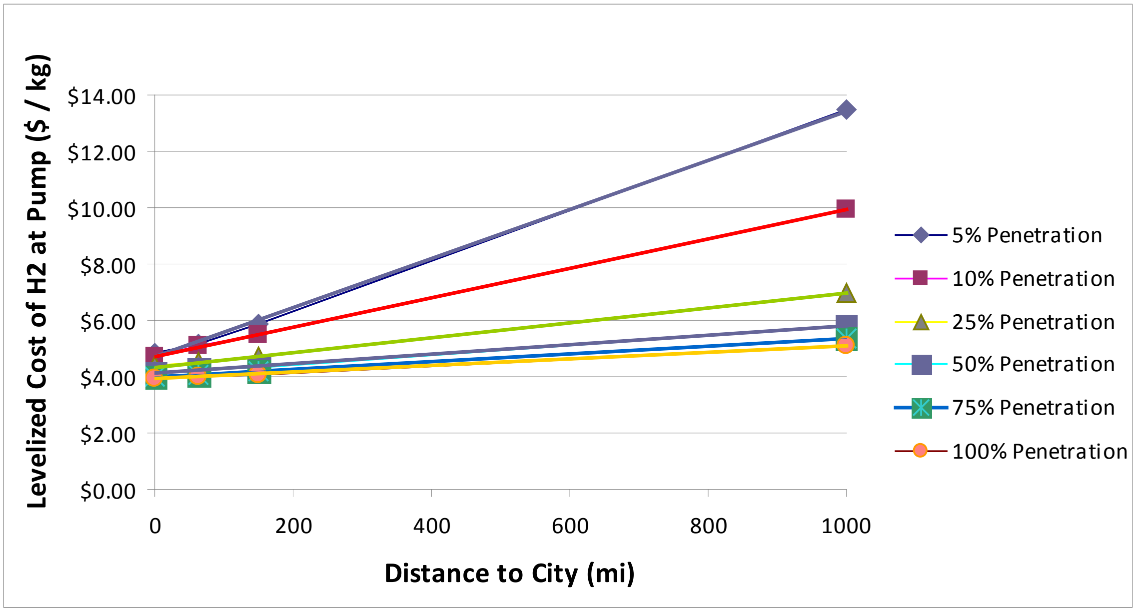


Figure 9.4.11. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for central biomass–pipeline delivery pathway

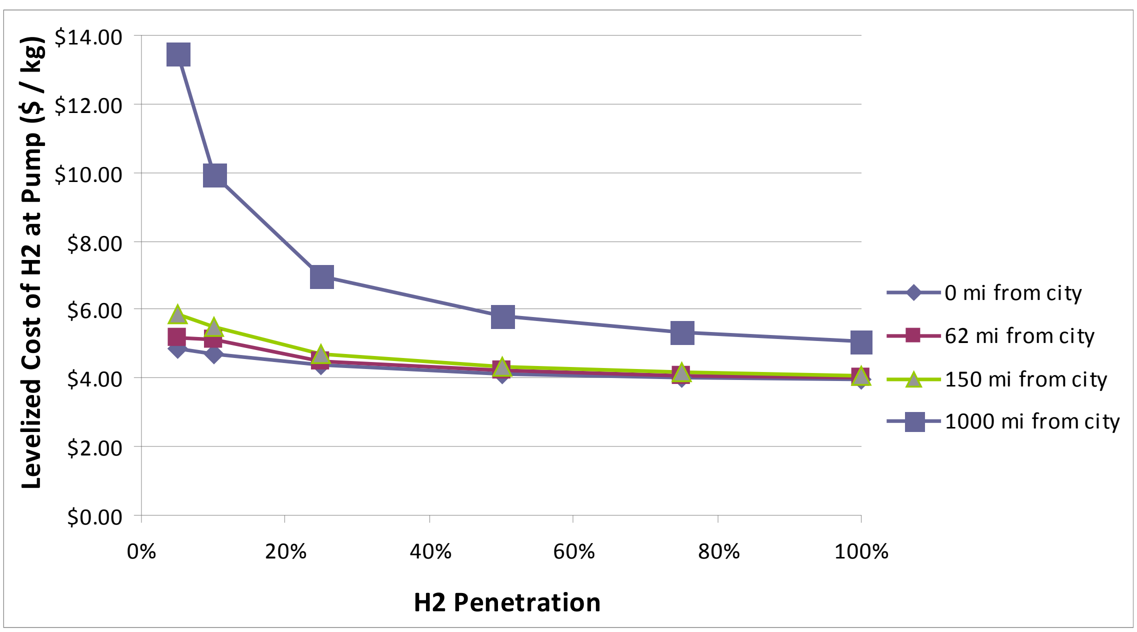


Figure 9.4.12. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for central biomass–pipeline delivery pathway

The effects of penetration and distance between production facility and city gate on WTW greenhouse gas emissions, WTW petroleum use, and WTW fossil energy use are shown in Figures 9.4.13, 9.4.14, and 9.4.15. The overall emissions change little with penetration because the additional energy required for distance is minimal. That additional electricity requirement is for compression over the distance. The total energy required for compression varies little with increased penetration because the total electricity required to compress each kilogram of hydrogen is nearly constant for all penetrations. That is the case because only a small portion of the total energy is needed for compression for the pipelines (see Figure 9.4.1), and much of the pressure drop is in the service pipelines instead of the transmission or trunk pipelines.

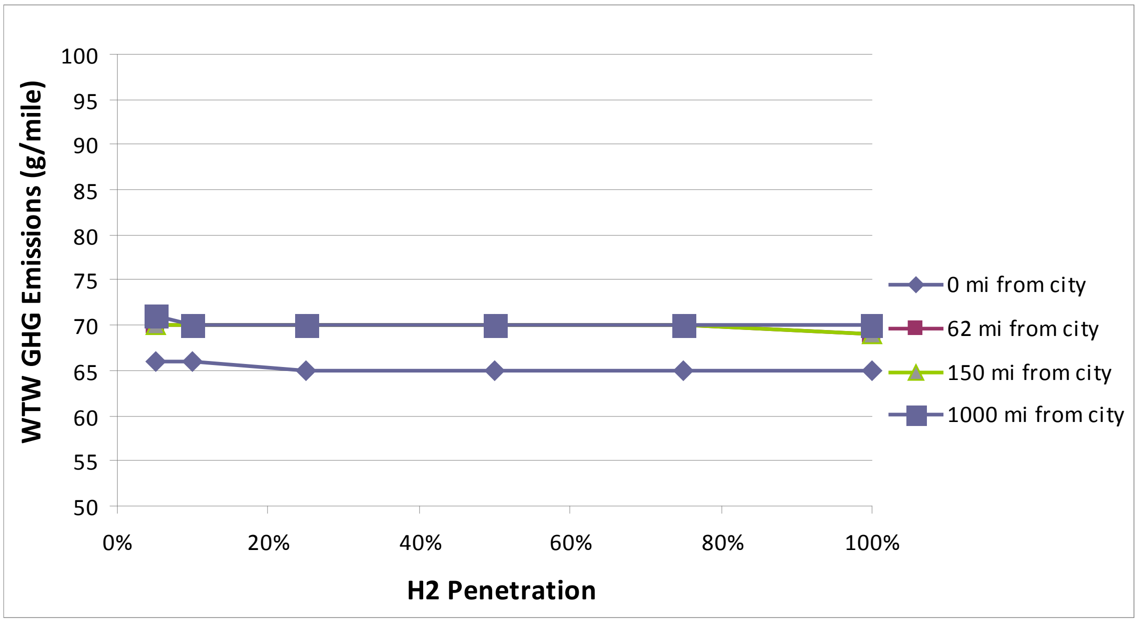


Figure 9.4.13. WTW greenhouse gas emissions versus penetration for central biomass–pipeline delivery pathway

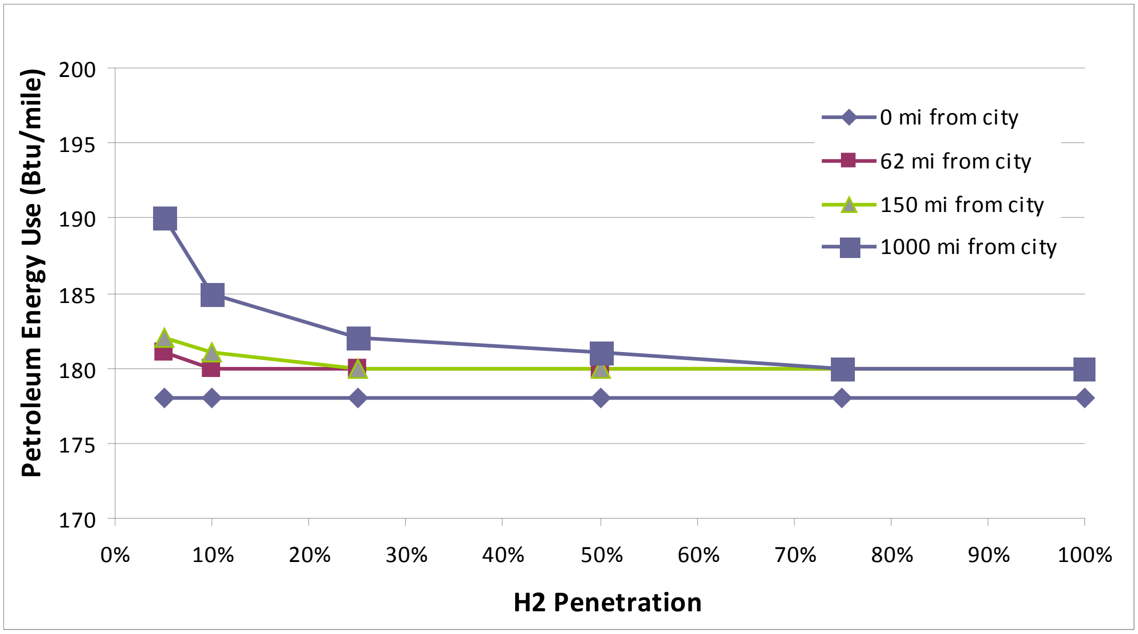


Figure 9.4.14. WTW petroleum use versus penetration for central biomass–pipeline delivery pathway

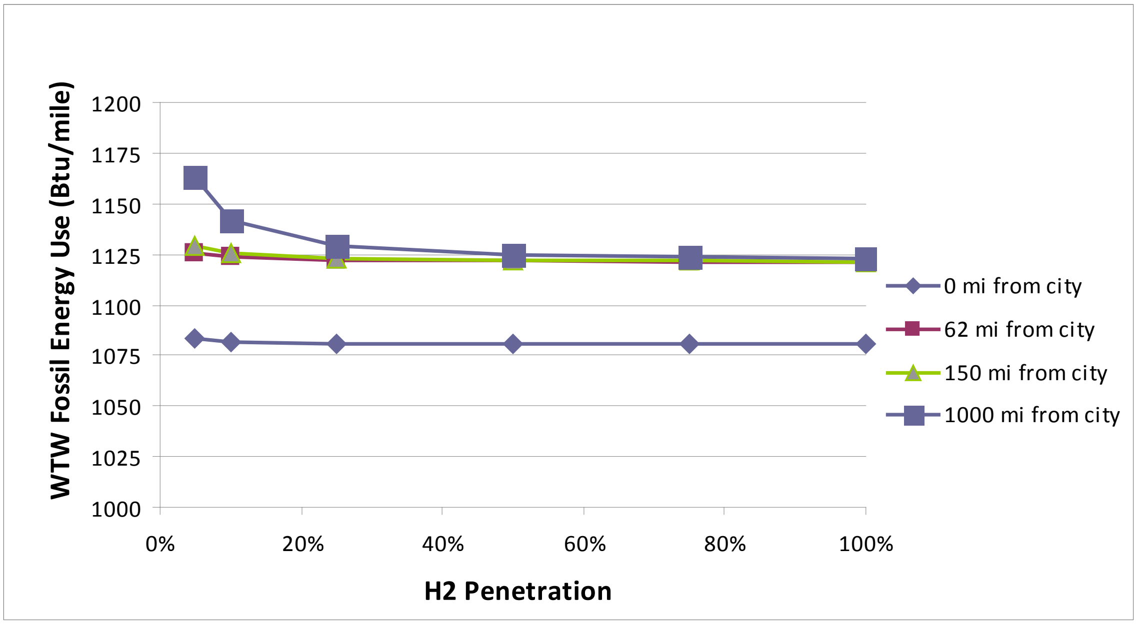


Figure 9.4.15. WTW fossil energy use versus penetration for central biomass–pipeline delivery pathway

9.4.5 Advanced Conversion and Delivery / Distribution Technology

For advanced technology analysis, parameters were changed to future projections. The "Future" H2A production case was used, and HDSAM was modified to include achievement of delivery targets as defined in the HFCIT MYPP. The vehicle fuel economy was increased to 65 mpgge. In addition, the electricity grid mix was updated to match EIA's projection for technology success in 2020 (51.1% coal, 19.2% natural gas, 18.5% nuclear, 1.9% residual oil, 1.0% biomass, and 8.3% zero-carbon). Well-to-wheels results from cases with those modifications are shown in Table 9.4.5. The results match those in Hydrogen Program Record 9002 (2009).

Table 9.4.5. Well-to-Wheels Results for Central Biomass–Pipeline Delivery Pathway with Advanced Technology

Coal Input from "Well"	450	Btu / mi
Natural Gas Input from "Well"	210	Btu / mi
Petroleum Input from "Well"	100	Btu / mi
Fossil Energy Input from "Well"	750	Btu / mi
WTW CO_2 Emissions	49	g / mi
WTW CH_4 Emissions	0.096	g / mi
WTW N_2O Emissions	0.004	g / mi
WTW GHG Emissions	53	g / mi
Levelized Cost of Hydrogen ($/kg)	$3.26	2005 $/kg
Levelized Cost of Hydrogen ($/mi)	$0.0501	2005 $/mi

Several sensitivities were run on the production portion of the central biomass–pipeline pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.4.16 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.4.6 shows the effects of varying production energy efficiency on WTW energy use and emissions.

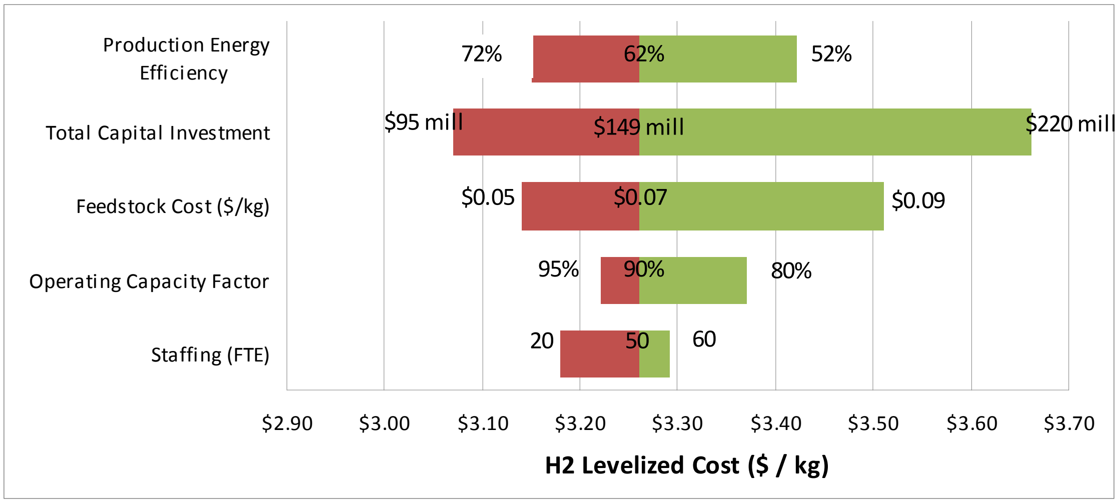


Figure 9.4.16. Production sensitivities for central biomass–pipeline delivery pathway with advanced technology

Table 9.4.6. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Central Biomass–Pipeline Delivery Pathway (advanced technology)

	52% Efficiency	62% Efficiency	72% Efficiency
WTW GHG Emissions (g/mile)	50	53	55
WTW Fossil Energy (Btu/mile)	770	750	730
WTW Petroleum Energy (Btu/mile)	112	96	84
WTW Total Energy (Btu/mile)	4,360	3,710	3,230

The assumed electrical grid mix also affects the energy use and emissions. Table 9.4.7 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind). The advanced conversion pathway has a higher conversion efficiency than the current technology, so less biomass is used; therefore, less carbon is removed from the atmosphere for each kilogram of hydrogen produced, and the "green" grid mix has GHG emissions less negative than that for the current technology.

Table 9.4.7. The Effects of Grid Mix on Use of Primary Energy and Emissions from Central Biomass–Pipeline Delivery Pathway (advanced technology)

	Projected U.S. Average Grid Mix	**"Green" Grid Mix**
WTW GHG Emissions (g/mile)	53	-9
WTW Fossil Energy (Btu/mile)	750	130
WTW Petroleum Energy (Btu/mile)	96	72
WTW Total Energy (Btu/mile)	3,710	3,300

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy for advanced FCVs used in this study (65 mpgge), and a yield of hydrogen from biomass of 9.8 kg biomass (dry)/kg H_2, the amount of biomass required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with biomass-derived hydrogen fuel was calculated and compared to the projected U.S. biomass potential and the 2008 U.S. biomass consumption estimates shown in Section 3.3 (Table 9.4.8).

Table 9.4.8. Biomass Supply Scenarios for the Advanced Central Biomass–Liquid Truck Delivery Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Advanced Technology – 65 mpgge FCV, hydrogen production yield 9.8 kg dry biomass/kg H_2[1]			
Biomass Required (billion dry tons/yr)	0.47	0.35	0.24	0.12
Percent of U.S. Biomass Potential (1.4 billion dry tons)[2]	34%	26%	17%	9%
Percent of 2008 U.S. Wood Derived Fuels Consumption (0.12 billion dry tons)[3]	390%	290%	190%	100%

[1] Calculation does not include energy or hydrogen losses.
[2] Perlack et al. (2005)
[3] Calculated from values in Energy Information Administration (2009k)

Table 9.4.9 compares a sample scenario for hydrogen production from biomass from DOE's Hydrogen Posture Plan (United States Department of Energy, 2006) to a 20% FCV penetration scenario using the advanced technology assumptions in this section, as described above.

Table 9.4.9. Comparison of Biomass Supply Scenarios to Hydrogen Posture Plan for Advanced Hydrogen Technology

	DOE Hydrogen Posture Plan (2006)	Hydrogen Pathways Report (2009)*
Total Hydrogen Demand	64 million metric tons/yr	63.1 million metric tons/yr
Amount of Demand to Be Supplied by Resource	13 million metric tons/yr (20%)	12.6 million metric tons/yr (20%)
Biomass Needed for H_2	140-280 million metric tons/yr	64 million metric tons/yr
Biomass Availability	512-1,300 million dry short tons/yr	1,368 million dry short tons/yr
Biomass Consumption (current)	190 million metric tons/yr	110 million metric tons/yr (using 16.8 million Btu/dry short ton LHV for biomass)
Increase in Biomass Consumption with H_2 Production	1.7-2.5 X	1.6 X

* Calculated using the assumptions in Table 9.4.8 with 20% penetration of FCVs in light-duty vehicle market

9.5 Central Natural Gas – Pipeline Delivery

Figure 9.5.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. The complete set of assumptions is detailed in Appendix E.

The well-to-pump and well-to-wheels cost of hydrogen, energy use, and emissions for the central natural gas–pipeline delivery pathway are summarized in Table 9.5.1.

9.5.1 Cost Breakdown

Figure 9.5.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central natural gas–pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 8.0.

Figure 9.5.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 9.5.2.

Figure 9.5.4 and Table 9.5.2 show the breakdown of levelized costs for the central natural gas–pipeline delivery pathway.

Inputs	Graphic Depiction & Assumptions	Outputs

NG Recovery, Processing, & Transport

Inputs	
Coal Input from "Well"	252 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	122,927 Btu / 116000Btu to Pump
Petroleum Input from "Well"	492 Btu / 116000Btu to Pump

Assumptions	
NG Recovery Efficiency	97.2%
NG emitted & combusted during recovery	0.35%
NG processing energy efficiency	97.2%
NG emitted & combusted during processin	0.15%
NG emitted & combusted during transport	0.14 g / MMBtu
NG transport distance	500 miles
Compression Reqs (stages & eff) average of gas companies	

Outputs	
NG Delivery Pressure	Average of gas companies
NG Quality at Delivery	Average of gas companies
NG Cost	$0.243 2005 $ / Nm^3
NG Cost	$0.958 2005$ / kg H2 distributed
WTG CO2 Emissions	5,079 g / 116000Btu to Pump
WTG CH4 Emissions	139 g / 116000Btu to Pump
WTG N2O Emissions	0 g / 116000Btu to Pump
WTG GHG Emissions	8,571 g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs	
Natural gas consumption	4.50 N m^3/kg H2 produced
Electricity consumption	0.57 kWh / kg H2
Process (De-Ionized) Water Consumption	12.70 L / kg H2
Cooling Water Consumption	5.66 L / kg H2
Electricity price	$0.0555 2005 $/kWh
Total Capital Investment	$180,543,901 2005$
Coal Input from "Well"	3,440 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	47,416 Btu / 116000Btu to Pump
Petroleum Input from "Well"	433 Btu / 116000Btu to Pump

Assumptions	
Central plant design capacity	379,387 kg/day
Capacity factor	90%
Process energy efficiency	71.9%
Electricity Mix	US Mix
After-tax IRR	10%
Assumed Plant Life	40 years

Outputs	
Hydrogen Output Pressure	300 psi
Hydrogen Outlet Quality	98 minimum
	2005$ / annual kg H2
Total capital investment	$1.45 (effective capacity)
Electricity cost	$0.03 2005$ / kg H2 produced
Other operating costs	$0.08 2005$ / kg H2 produced
Levelized Cost of Prod (excl feedst	$0.38 2005$ / kg H2 distributed
SMR CO2 Emissions	10,233 g / 116000Btu to Pump
SMR CH4 Emissions	7 g / 116000Btu to Pump
SMR N2O Emissions	0 g / 116000Btu to Pump
SMR GHG Emissions	10,410 g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs	
Electricity consumption for compressor	0.56 kWh / kg H2
Electricity consumption for geo storage	0.01 kWh / kg H2
Total electricity consumption	0.57 kWh / kg H2
Electricity price for compressor	$0.056 2005$ / kWh
Electricity price for geologic storage	$0.052 2005$ / kWh
Coal Input from "Well"	3,306 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	950 Btu / 116000Btu to Pump
Petroleum Input from "Well"	246 Btu / 116000Btu to Pump

Assumptions	
City Population	1,247,364 people
Hydrogen Vehicle Penetration	50%
City hydrogen use	125,810,766 kg / yr
Distance from City to Production Facility	62 miles
Geologic storage capacity	3,762,787 kg H2
Trunk #1-line length	17 miles
Trunk #2-line length	40 miles
Service-line length	1.1 miles / line
Number of service lines	270
Hydrogen losses	1.12%

Outputs	
Total capital investment	$3.51 2005$/annual kg distributed
Electricity cost	$0.03 2005$ / kg H2
Levelized Cost of Delivery	$0.92 2005$ / kg H2 distributed
Delivery CO2 Emissions	436 g / 116000Btu to Pump
Delivery CH4 Emissions	1 g / 116000Btu to Pump
Delivery N2O Emissions	0 g / 116000Btu to Pump
Delivery GHG Emissions	452 g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs	
Electricity consumption	3.04 kWh / kg H2
Electricity price	$0.082 2005$ / kWh
Coal Input from "Well"	17,677 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	5,078 Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,317 Btu / 116000Btu to Pump

Assumptions	
Number of Distribution Stations	270
Energy efficiency	92%
Number of Compression Steps	4
Isentropic Efficiency	65%
Site storage	69% capacity
Hydrogen losses	0.50%

Outputs	
Hydrogen outlet pressure	6,250 psi
Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$6.69 2005$/annual kg
Electricity cost	$0.25 2005$ / kg H2
Levelized Cost of Distribution	$1.69 2005$ / kg H2 distributed
CSD CO2 Emissions	2,333 g / 116000Btu to Pump
CSD CH4 Emissions	3 g / 116000Btu to Pump
CSD N2O Emissions	0 g / 116000Btu to Pump
CSD GHG Emissions	2,419 g CO2 eq./ 116000 Btu

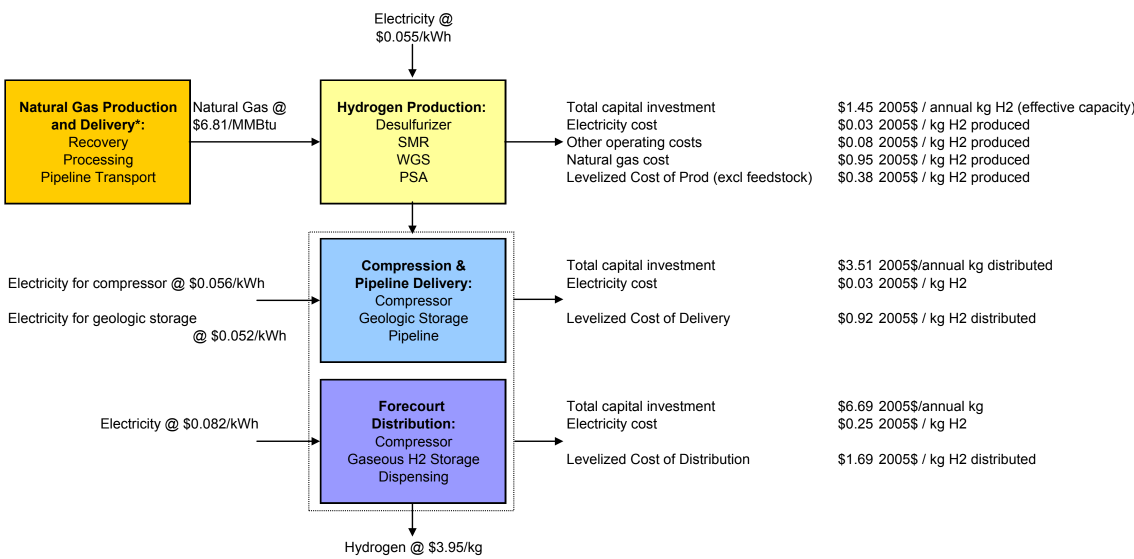
Figure 9.5.1. Central natural gas–pipeline delivery pathway summary of major inputs, assumptions, and outputs by subsystem

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

Table 9.5.1. Well-to-Pump and Well-to-Wheels Results for Central Natural Gas–Pipeline Delivery Pathway

	Well-to-Pump		Well-to-Wheels	
Coal Input from "Well"*	24,700	Btu / 116,000 Btu	550	Btu / mi
Natural Gas Input from "Well"*	176,400	Btu / 116,000 Btu	3,920	Btu / mi
Petroleum Input from "Well"*	2,500	Btu / 116,000 Btu	55	Btu / mi
Fossil Energy Input from "Well"*	203,500	Btu / 116,000 Btu	4,530	Btu / mi
WTP CO_2 Emissions*,**	13,600	g / 116,000 Btu	300	g / mi
WTP CH_4 Emissions	26	g / 116,000 Btu	1	g / mi
WTP N_2O Emissions	0	g / 116,000 Btu	0	g / mi
WTP GHG Emissions*	14,300	g CO2 eq. / 116000 Btu	320	g / mi
Levelized Cost of Hydrogen ($/kg)	$3.95	2005 $/kg	$0.0878	2005 $/mi

* Well-to-pump results are rounded to the nearest hundred; well-to-wheels results are rounded to the nearest ten.
** Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2
Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock. It does not include natural gas used as a heating fuel or to produce electricity.

Figure 9.5.2. Cost analysis inputs and high-level results for central natural gas–pipeline delivery pathway

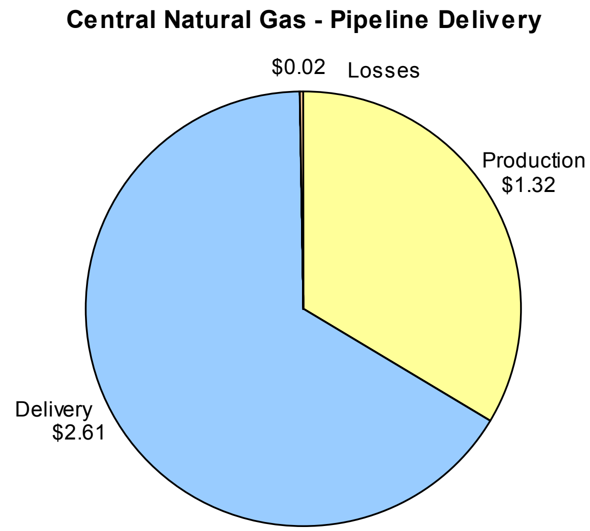


Figure 9.5.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen from central natural gas–pipeline delivery pathway

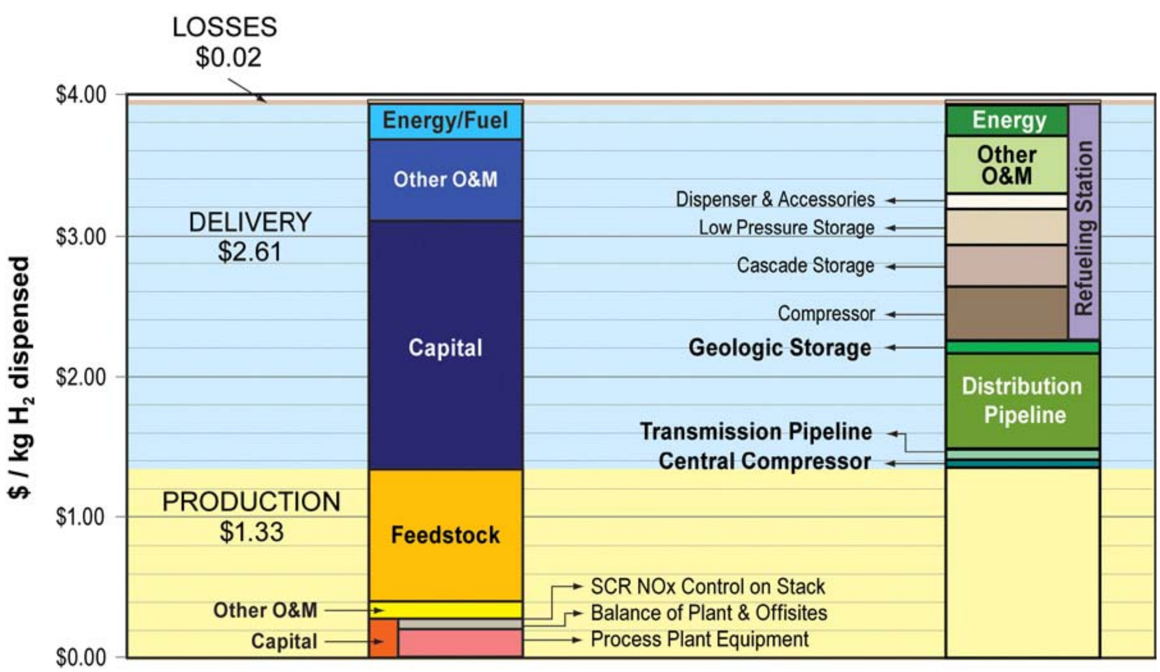


Figure 9.5.4. Breakdown of levelized costs for central natural gas–pipeline delivery pathway

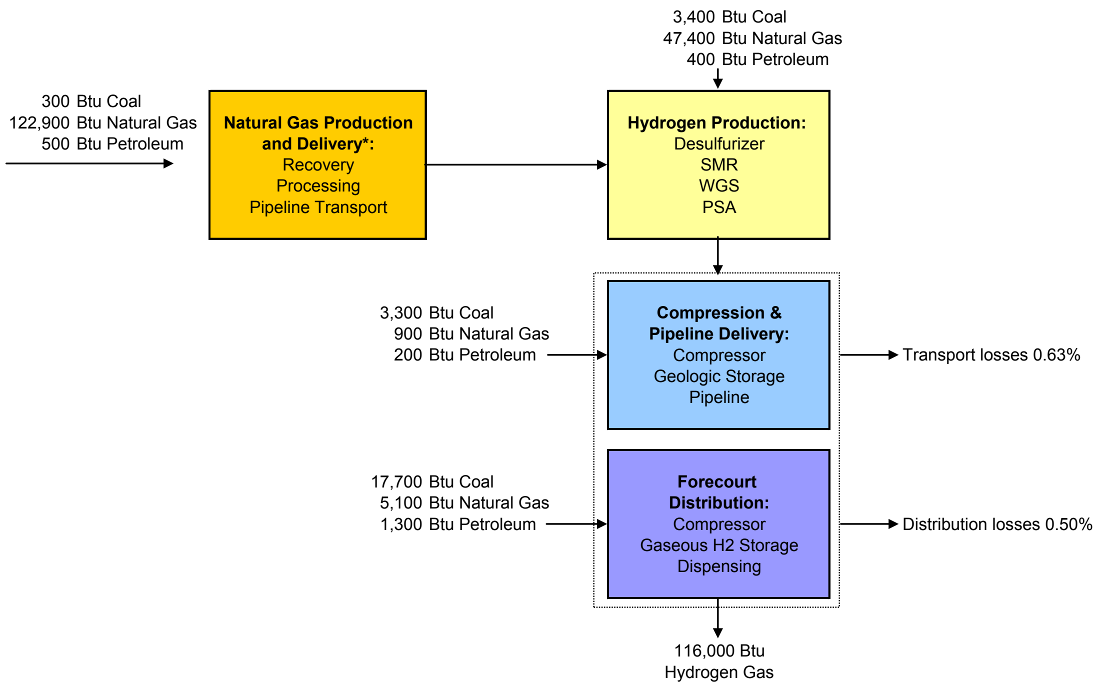
Table 9.5.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for Central Natural Gas–Pipeline Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.26	$0.12	$0.95		$1.33
Process Plant Equipment	$0.18				
Balance of Plant and Offsites	$0.07				
SCR NOx Control on Stack	$0.00				
Delivery	$1.77	$0.58		$0.26	$2.61
Central Compressor					$0.08
Transmission Pipeline					$0.07
Distribution Pipeline					$0.70
Geologic Storage					$0.08
Gaseous Refueling Station	$1.06	$0.41		$0.23	$1.69
Compressor	$0.39				
Cascade Storage	$0.29				
Low Pressure Storage	$0.26				
Dispenser & Accessories	$0.12				
Losses					$0.02
Total	**$2.03**	**$0.70**	**$0.95**	**$0.26**	**$3.95**

9.5.2 Energy Use and Emissions Breakdown

Figures 9.5.5 and 9.5.6 show the WTW energy inputs and losses for the central natural gas–pipeline delivery pathway.

Figures 9.5.7 and 9.5.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central natural gas–pipeline delivery pathway. The WTW energy inputs to natural gas production and delivery include those necessary to produce 116,000 Btu of natural gas for reforming. Additional WTW energy inputs for natural gas needed for heating and lost in reforming are reported as inputs to hydrogen production.



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock. It does not include natural gas used as a heating fuel or to produce electricity.

Figure 9.5.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using central natural gas–pipeline delivery pathway

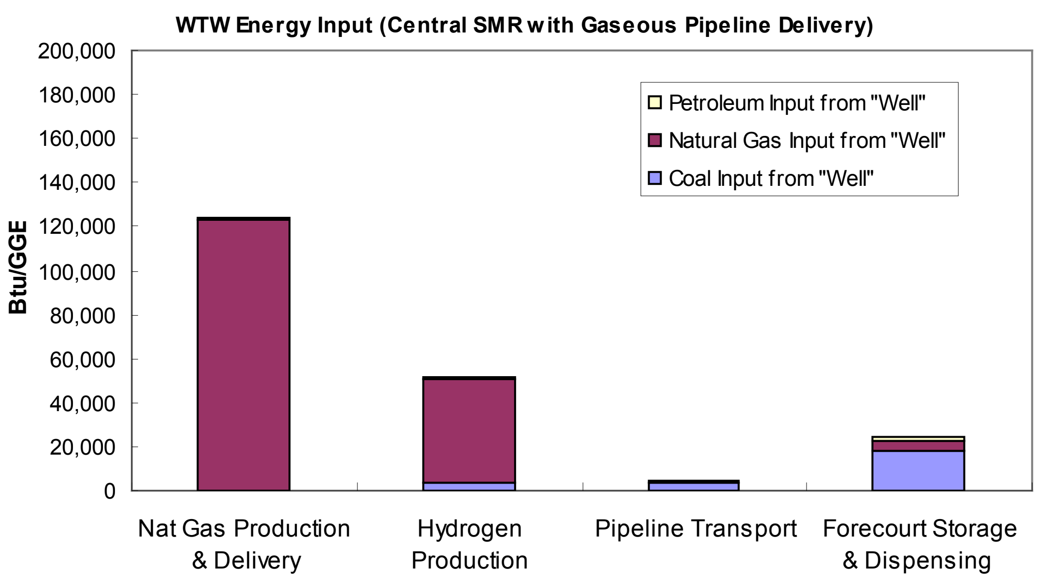
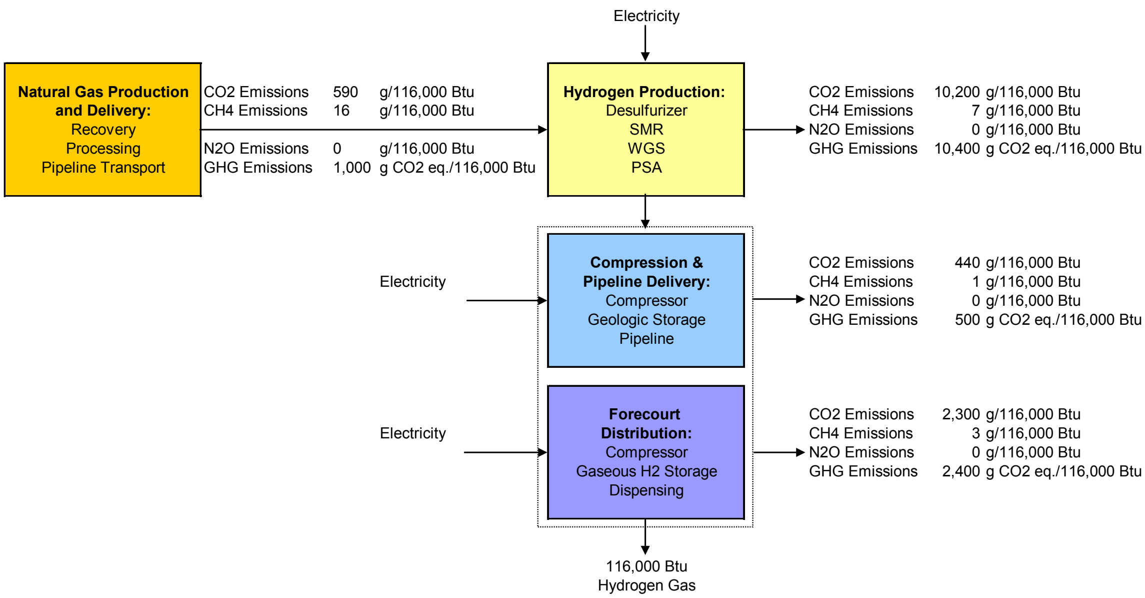


Figure 9.5.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using central natural gas–pipeline delivery pathway



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include natural gas used as a heating fuel or to produce electricity.

Figure 9.5.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central natural gas–pipeline delivery pathway

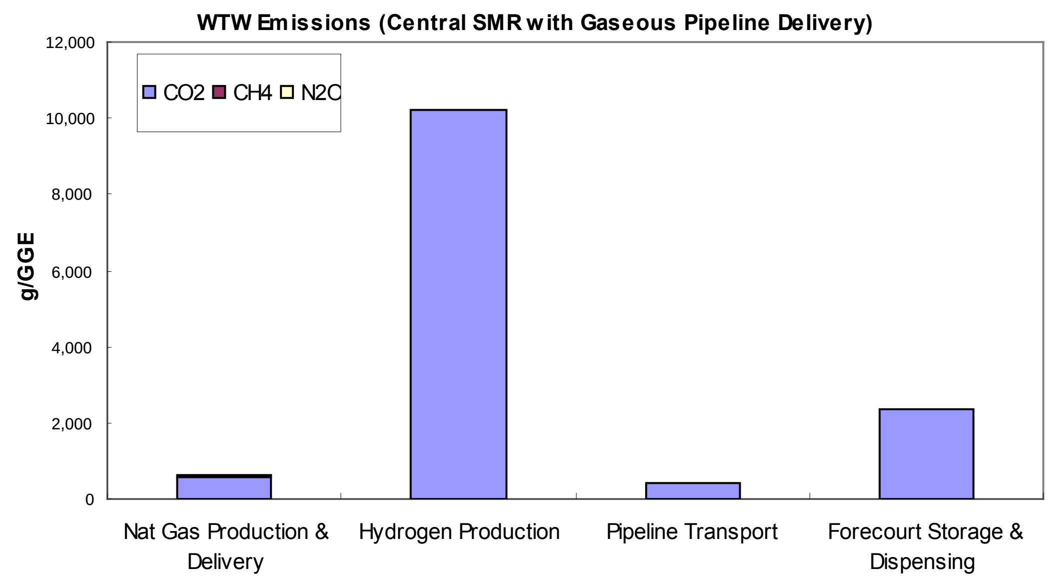


Figure 9.5.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using central natural gas–pipeline delivery pathway

9.5.3 Natural Gas Supply Scenarios

Because the feedstock, calculated yield, and assumed fuel economy for this pathway are the same as those for the distributed natural gas pathway, the supply scenarios are the same as those shown in Section 9.1.3.

9.5.4 Sensitivities

Production Sensitivities

Several sensitivities were run on the production portion of the central biomass–pipeline delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.5.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.5.3 shows the effects of varying production energy efficiency on WTW energy use and emissions.

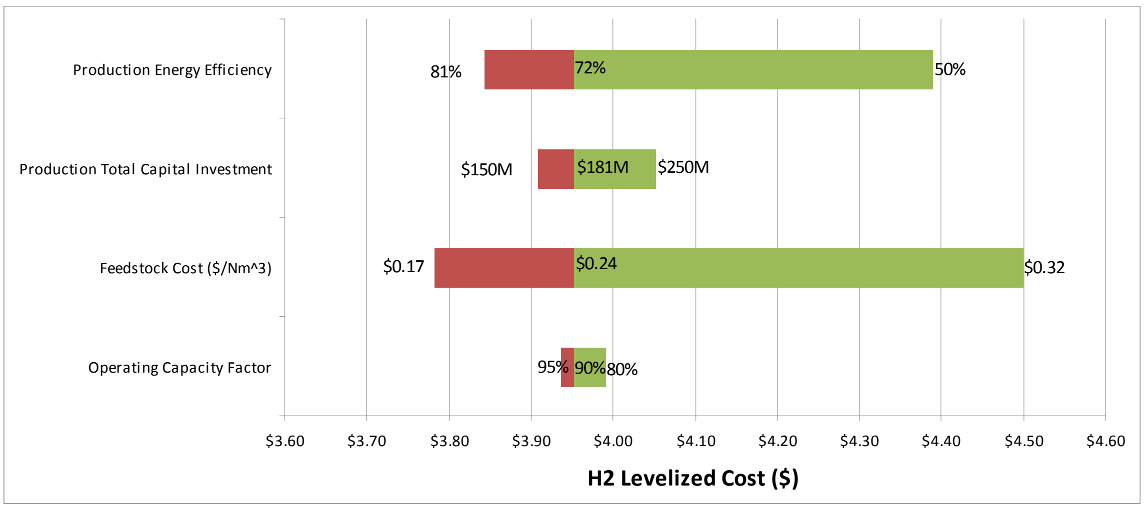


Figure 9.5.9. Production sensitivities for central natural gas–pipeline delivery pathway

Table 9.5.3. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Central Natural Gas–Pipeline Delivery Pathway (current technology)

	50% Efficiency	72% Efficiency	81% Efficiency
WTW GHG Emissions (g/mile)	430	320	290
WTW Fossil Energy (Btu/mile)	6,200	4,500	4,100
WTW Petroleum Energy (Btu/mile)	62	55	54
WTW Total Energy (Btu/mile)	6,400	4,700	4,200

The assumed electrical grid mix also affects the energy use and emissions. Table 9.5.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 9.5.4. The Effects of Grid Mix on Use of Primary Energy and Emissions from Central Natural Gas–Pipeline Delivery Pathway

	U.S. Average Grid Mix	"Green" Grid Mix
WTW GHG Emissions (g/mile)	320	240
WTW Fossil Energy (Btu/mile)	4,500	3,800
WTW Petroleum Energy (Btu/mile)	55	14
WTW Total Energy (Btu/mile)	4,700	4,200

Delivery Sensitivities

Pipeline delivery sensitivities are reported for the biomass production scenario in Section 9.4.4. The effects of the sensitivities will be the same for all pipeline delivery scenarios.

9.5.5 Advanced Conversion and Delivery/Distribution Technology

For advanced technology analysis, parameters were changed to future projections. The "Future" H2A production case was used, and HDSAM was modified to include achievement of delivery targets as defined in the Hydrogen, Fuel Cells and Infrastructure Technologies (HFCIT) Multi-Year Program Plan (MYPP). The vehicle fuel economy was increased to 65 mpgge. In addition, the electricity grid mix was updated to match EIA's projection for technology success in 2020 (51.1% coal, 19.2% natural gas, 18.5% nuclear, 1.9% residual oil, and 1.0% biomass, and 8.3% zero-carbon).

WTW results from cases with those modifications are shown in Table 9.5.5. Corresponding results were not published in Hydrogen Program Record 9002 (2009).

Table 9.5.5. Well-to-Wheels Results for central natural gas–pipeline pathway with advanced technology

Coal Input from "Well"	340	Btu / mi
Natural Gas Input from "Well"	2760	Btu / mi
Petroleum Input from "Well"	40	Btu / mi
Fossil Energy Input from "Well"	3140	Btu / mi
WTW CO_2 Emissions	208	g / mi
WTW CH_4 Emissions	0.41	g / mi
WTW N_2O Emissions	0.001	g / mi
WTW GHG Emissions	220	g / mi
Levelized Cost of Hydrogen ($/kg)	$2.96	2005 $/kg
Levelized Cost of Hydrogen ($/mi)	$0.0456	2005 $/mi

9.6 Central Wind Electricity – Pipeline Delivery

Figure 9.6.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. The complete set of assumptions is detailed in Appendix F.

The well-to-pump and well-to-wheels cost of hydrogen, energy use, and emissions for the central wind electricity–pipeline delivery pathway are summarized in Table 9.6.1.

9.6.1 Cost Breakdown

Figure 9.6.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central wind electricity–pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 8.0.

Figure 9.6.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 9.6.2.

Figure 9.6.4 and Table 9.6.2 show the breakdown of levelized costs for the central wind electricity–pipeline delivery pathway.

Inputs		Graphic Depiction & Assumptions		Outputs	

Wind Electricity

Wind-generated electricity on the grid is assumed.
The electrolyzers are not necessarily co-located with the wind farm.

Inputs

Coal Input from "Well"	0 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	0 Btu / 116000Btu to Pump
Petroleum Input from "Well"	0 Btu / 116000Btu to Pump

Outputs

Electricity price at H2 production	$0.055 2005 $ / short ton
Levelized Cost of Wind Electricity	$2.99 2005$ / kg H2 distributed
WTG CO2 Emissions	0 g / 116000Btu to Pump
WTG CH4 Emissions	0 g / 116000Btu to Pump
WTG N2O Emissions	0 g / 116000Btu to Pump
WTG GHG Emissions	0 g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Electricity consumption	53.48 kWh / kg H2
Process Water Consumption	11.1 L / kg H2
Cooling Water Consumption	1112 L / kg H2
Electrolyzer Cost	675 $ / kW
Total Capital Investment	$110,432,050 2005$
Coal Input from "Well"	0 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	0 Btu / 116000Btu to Pump
Petroleum Input from "Well"	0 Btu / 116000Btu to Pump

Assumptions

Central plant design capacity	52,300 kg/day
Capacity factor	97%
Process energy efficiency	62.3%
Electricity Mix	Wind Electricity
After-tax IRR	10%
Assumed Plant Life	40

Outputs

Hydrogen Output Pressure	300 psi
Total capital investment	$5.96 2005$ / annual kg H2 (effective capacity)
Electricity cost	$2.96 2005$ / kg H2 produced
Other operating costs	$0.38 2005$ / kg H2 produced
Levelized Cost of Prod (excl feedst	$1.56 2005$ / kg H2 distributed
H2 Prod CO2 Emissions	0 g / 116000Btu to Pump
H2 Prod CH4 Emissions	0 g / 116000Btu to Pump
H2 Prod N2O Emissions	0 g / 116000Btu to Pump
H2 Prod GHG Emissions	0 g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs

Electricity consumption for compressor	0.56 kWh / kg H2
Electricity consumption for geo storage	0.01 kWh / kg H2
Total electricity consumption	0.57 kWh / kg H2
Electricity price for compressor	$0.056 2005$ / kWh
Electricity price for geologic storage	$0.052 2005$ / kWh
Coal Input from "Well"	3,307 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	949 Btu / 116000Btu to Pump
Petroleum Input from "Well"	246 Btu / 116000Btu to Pump

Assumptions

City Population	1,247,364 people
Hydrogen Vehicle Penetration	50%
City hydrogen use	125,810,766 kg / yr
Distance from City to Production Facility	62 miles
Geologic storage capacity	3,762,787 kg H2
Trunk #1-line length	17 miles
Trunk #2-line length	40 miles
Service-line length	1.1 miles / line
Number of service lines	270
Hydrogen losses	1.12%
Hydrogen loss factor	1.011

Outputs

Total capital investment	$3.51 2005$/annual kg distributed
Electricity cost	$0.03 2005$ / kg H2
Levelized Cost of Delivery	$0.92 2005$ / kg H2 distributed
Delivery CO2 Emissions	436 g / 116000Btu to Pump
Delivery CH4 Emissions	1 g / 116000Btu to Pump
Delivery N2O Emissions	0 g / 116000Btu to Pump
Delivery GHG Emissions	453 g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs

Electricity consumption	3.04 kWh / kg H2
Electricity price	$0.082 2005$ / kWh
Coal Input from "Well"	17,681 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	5,076 Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,317 Btu / 116000Btu to Pump

Assumptions

Number of Distribution Stations	270
Energy efficiency	92%
Number of Compression Steps	4
Isentropic Efficiency	65%
Site storage	69% capacity
Hydrogen losses	0.50%
Hydrogen loss factor	1.005

Outputs

Hydrogen outlet pressure	6,250 psi
Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$6.69 2005$/annual kg
Electricity cost	$0.25 2005$ / kg H2
Levelized Cost of Distribution	$1.69 2005$ / kg H2 distributed
CSD CO2 Emissions	2,333 g / 116000Btu to Pump
CSD CH4 Emissions	3 g / 116000Btu to Pump
CSD N2O Emissions	0 g / 116000Btu to Pump
CSD GHG Emissions	2,419 g CO2 eq./ 116000 Btu

Figure 9.6.1. Central wind electricity–pipeline delivery pathway summary of major inputs, assumptions, and outputs by subsystem

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

Table 9.6.1. Well-to-Pump and Well-to-Wheels Results for Central Wind Electricity–Pipeline Delivery Pathway

	Well-to-Pump		Well-to-Wheels	
Coal Input from "Well"*	21,000	Btu / 116,000 Btu	470	Btu / mi
Natural Gas Input from "Well"*	6,000	Btu / 116,000 Btu	130	Btu / mi
Petroleum Input from "Well"*	1,600	Btu / 116,000 Btu	35	Btu / mi
Fossil Energy Input from "Well"*	28,600	Btu / 116,000 Btu	640	Btu / mi
WTP CO_2 Emissions*,**	2,800	g / 116,000 Btu	62	g / mi
WTP CH_4 Emissions	4	g / 116,000 Btu	0	g / mi
WTP N_2O Emissions	0	g / 116,000 Btu	0	g / mi
WTP GHG Emissions*	2,900	g CO2 eq. / 116000 Btu	64	g / mi
Levelized Cost of Hydrogen ($/kg)	$7.16	2005 $/kg	$0.1591	2005 $/mi

* Well-to-pump results are rounded to the nearest hundred; well-to-wheels results are rounded to the nearest ten.

** Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

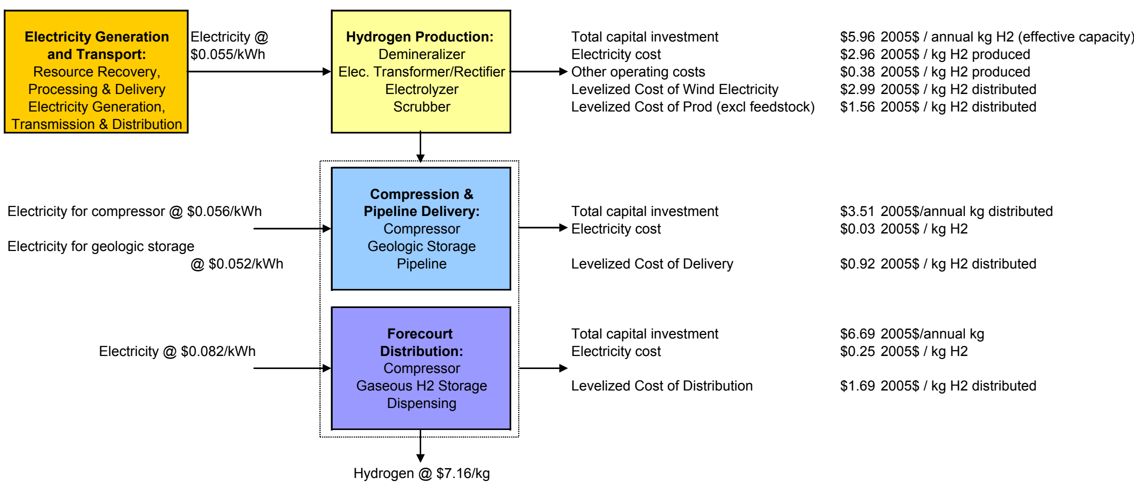


Figure 9.6.2. Cost analysis inputs and high-level results for central wind electricity–pipeline delivery pathway

Central Wind Electricity - Pipeline Delivery

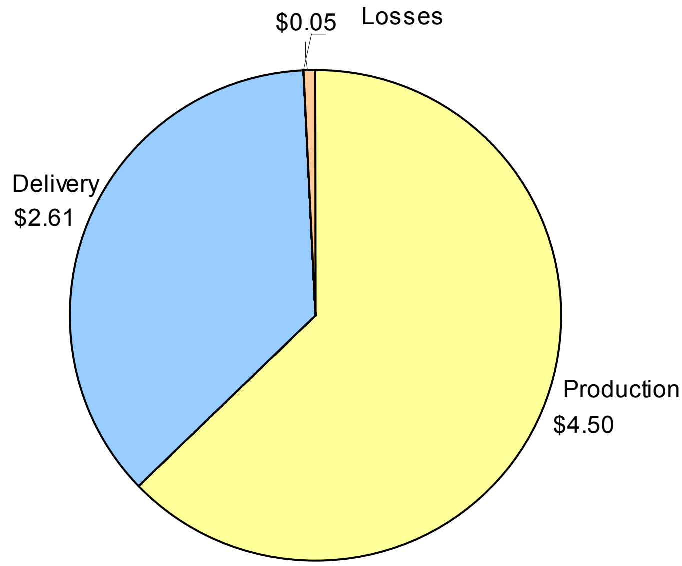


Figure 9.6.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen from central wind electricity–pipeline delivery pathway

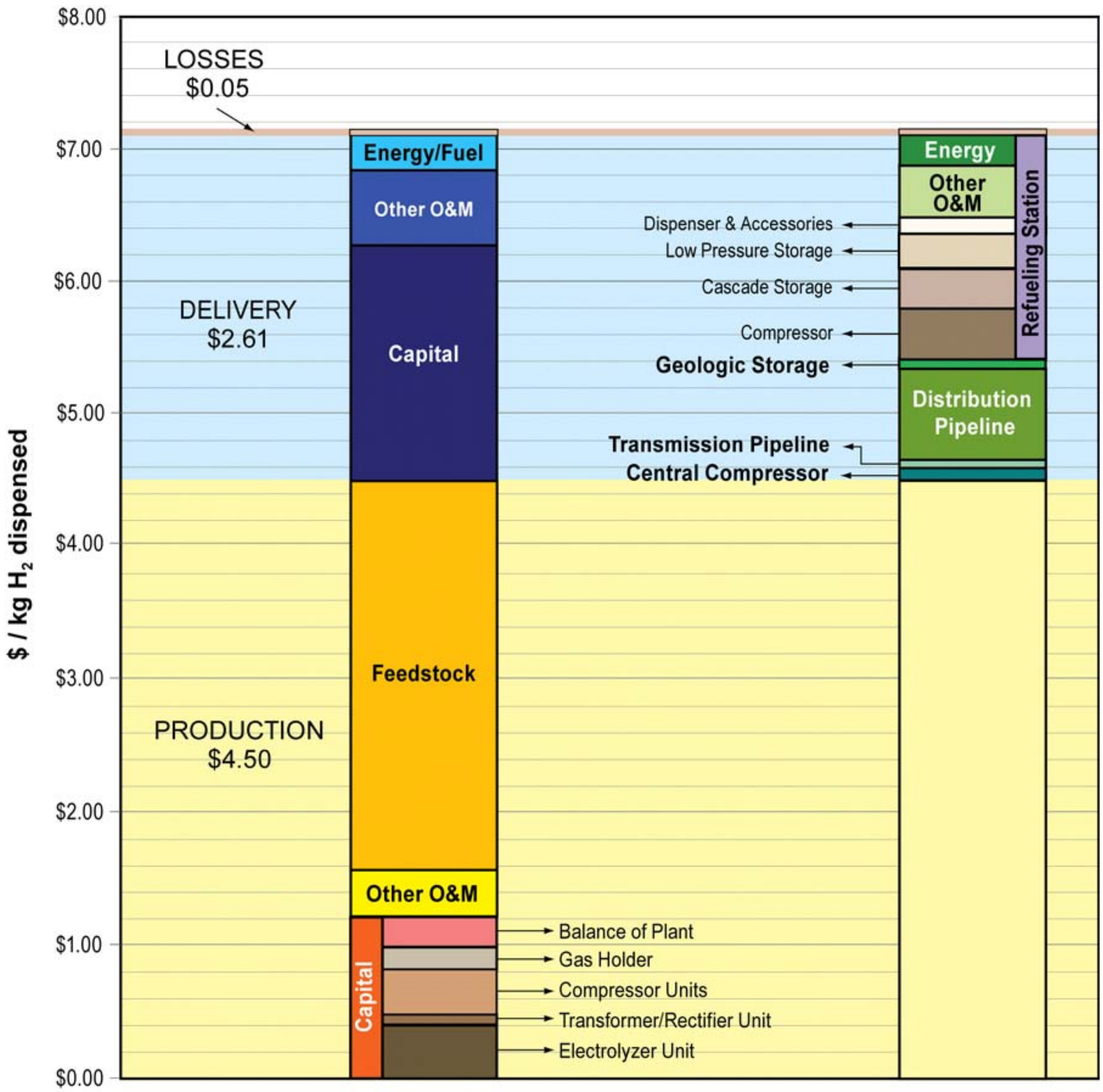


Figure 9.6.4. Breakdown of levelized costs for central wind electricity–pipeline delivery pathway

Table 9.6.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost from Central Wind Electricity–Pipeline Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$1.16	$0.38	$2.96		$4.50
Electrolyzer Units	$0.37				
Transformer/Rectifier Units	$0.07				
Compressor Units	$0.34				
Gas Holders	$0.17				
Balance of Plant	$0.21				
Delivery	$1.77	$0.58		$0.26	$2.61
Central Compressor					$0.08

Transmission Pipeline					$0.07
Distribution Pipeline					$0.70
Geologic Storage					$0.08
Gaseous Refueling Station	$1.06	$0.41		$0.23	$1.69
Compressor	$0.39				
Cascade Storage	$0.29				
Low Pressure Storage	$0.26				
Dispenser & Accessories	$0.12				
Losses					$0.05
Total	**$2.93**	**$0.96**	**$2.96**	**$0.26**	**$7.16**

9.6.2 Energy Use and Emissions Breakdown

Figures 9.6.5 and 9.6.6 show the WTW energy inputs and losses for the central wind electricity–pipeline delivery pathway.

Figures 9.6.7 and 9.6.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central wind electricity–pipeline delivery pathway.

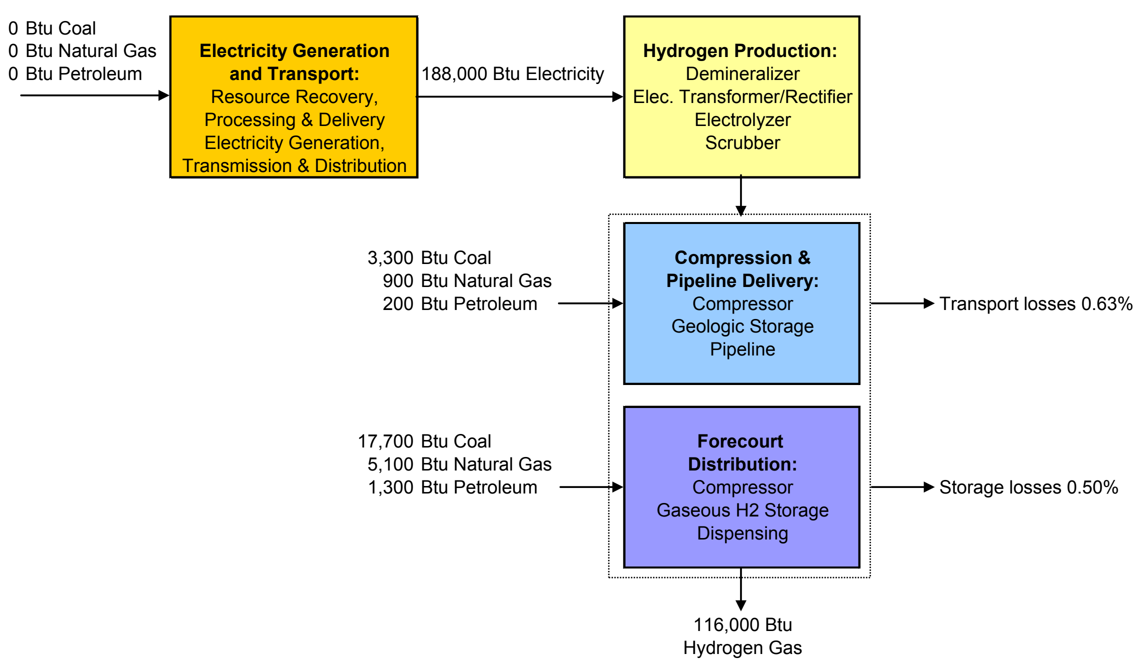


Figure 9.6.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using central wind electricity–pipeline delivery pathway

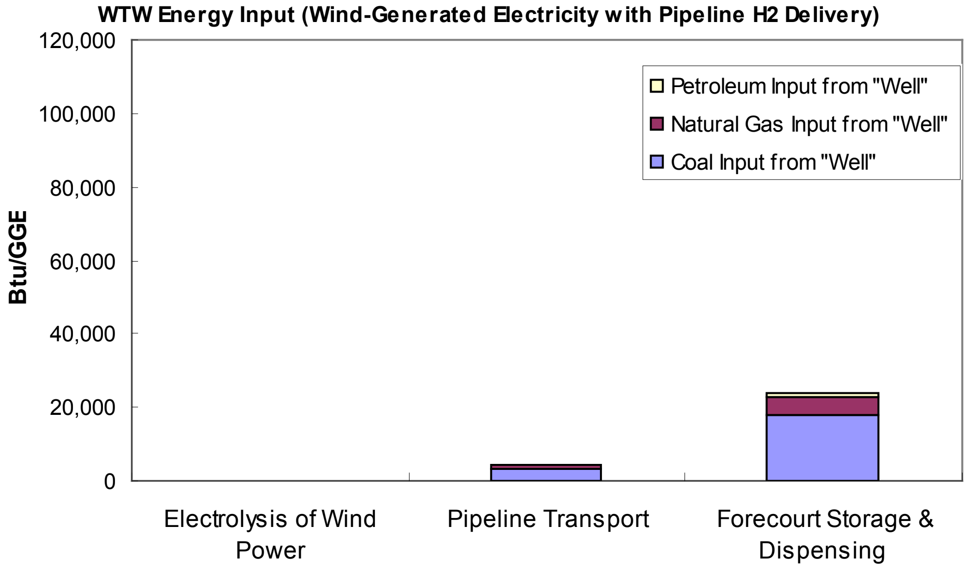


Figure 9.6.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using central wind electricity–pipeline delivery pathway

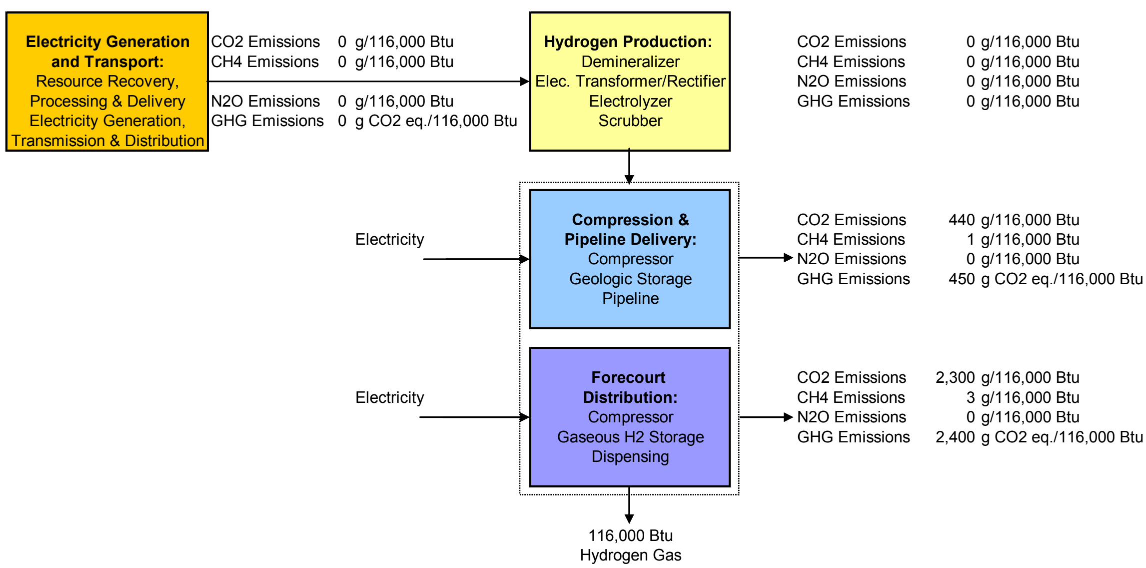


Figure 9.6.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central wind electricity–pipeline delivery pathway

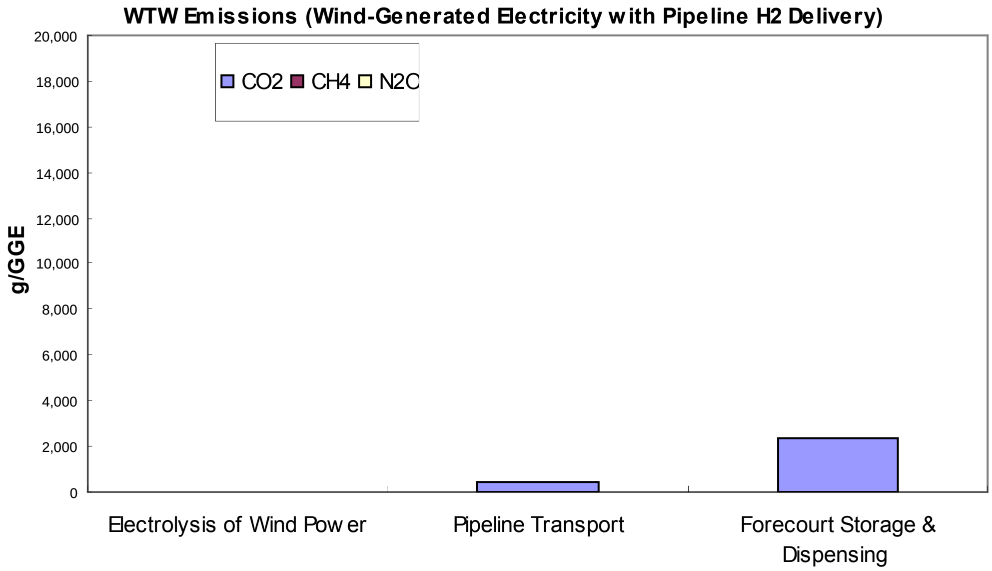


Figure 9.6.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using central wind electricity–pipeline delivery pathway

9.6.3 Wind Electricity Supply Scenarios

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from wind electricity of 53 kWh wind electricity/kg H_2, the amount of wind electricity required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with wind electricity-derived hydrogen fuel was calculated and compared to the potential 2030 U.S. wind electricity generation capacity and the 2008 U.S. wind electricity consumption estimates shown in Section 3.2 (Table 9.6.3).

Table 9.6.3. Wind Electricity Supply Scenarios for the Central Wind Electricity–Pipeline Delivery Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Current Technology – 45 mpgge FCV, hydrogen production yield 53 kWh/kg H_2 [1]			
Wind Electricity Required (trillion kWh/yr)	3.4	2.5	1.7	0.84
Percent of Potential U.S. Capacity in 2030 (1.16 trillion kWh)[2]	290%	220%	150%	70%
Percent of 2008 U.S. Consumption (0.052 trillion kWh)[3]	6,500%	4,900%	3,200%	1,600%

[1] Calculation does not include energy or hydrogen losses.
[2] United States Department of Energy (2008)
[3] Energy Information Administration (2009j)

Table 9.6.4 compares a sample scenario for hydrogen production from wind electricity from DOE's Hydrogen Posture Plan (United States Department of Energy, 2006) to a 20% FCV penetration scenario using the assumptions in this study, as described above.

Table 9.6.4. Comparison of Wind Electricity Supply Scenarios to Hydrogen Posture Plan

	DOE Hydrogen Posture Plan (2006)	**Hydrogen Pathways Report (2009)***
Total Hydrogen Demand	64 million metric tons/yr	63.1 million metric tons/yr
Amount of Demand to Be Supplied by Resource	13 million metric tons/yr (20%)	12.6 million metric tons/yr (20%)
Wind Electricity Needed for H_2	200 GWe	675 billion kWh/yr
Wind Electricity Availability	2,300 GWe nameplate capacity	1,160 billion kWh/yr in 2030
Wind Electricity Consumption (current)	10 GWe installed nameplate capacity	52 billion kWh/yr in 2008
Increase in Wind Electricity Consumption with H_2 Production	28 X	14 X

* Calculated using the assumptions in Table 9.6.3 with 20% penetration of FCVs in light-duty vehicle market

9.6.4 Sensitivities

Production Sensitivities

Several sensitivities were run on the production portion of the central electrolysis of wind-generated electricity–pipeline delivery pathway. These sensitivities focused primarily on cost factors. Figure 9.6.9 shows the effects of several production parameters on the pathway's levelized cost.

Note that the electricity cost is the sensitivity with the greatest potential effect on the levelized cost. The baseline electricity cost is the industrial electricity price estimated in the Annual Energy Outlook 2005 High Case (Energy Information Administration, 2005) and may be too low for wind electricity.

Effects of the sensitivities on WTW energy use and emissions are not shown because, due to the assumption that the electricity feedstock is wind-generated, the production fossil energy use and emissions are zero at all efficiencies.

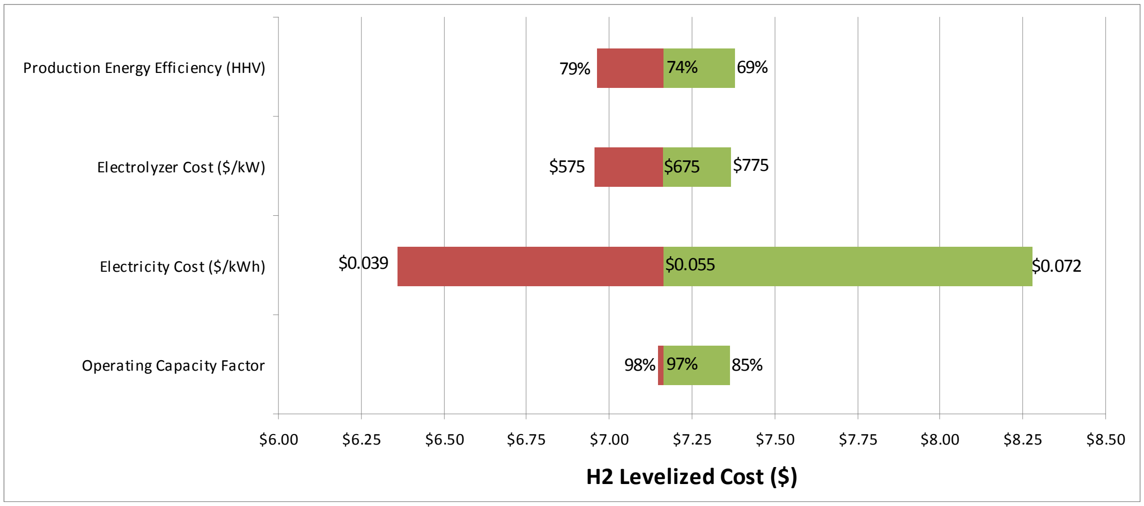


Figure 9.6.9. Production sensitivities for central wind electrolysis–pipeline delivery pathway

Delivery Sensitivities

Pipeline delivery sensitivities are reported for the biomass production scenario in Section 9.4.4. The effects of the sensitivities will be the same for all pipeline delivery scenarios.

9.6.5 Advanced Conversion and Delivery/Distribution Technology

For advanced technology analysis, parameters were changed to future projections. The "Future" H2A production case was used, and HDSAM was modified to include achievement of delivery targets as defined in the Hydrogen, Fuel Cells and Infrastructure Technologies (HFCIT) Multi-Year Program Plan (MYPP). The vehicle fuel economy was increased to 65 mpgge. In addition, the electricity grid mix was updated to match EIA's projection for technology success in 2020 (51.1% coal, 19.2% natural gas, 18.5% nuclear, 1.9% residual oil, and 1.0% biomass, and 8.3% zero-carbon).

WTW results from cases with those modifications are shown in Table 9.6.5. The results do not match those in Hydrogen Program Record 9002 (2009) because the production yield and cost of electrolyzers were modified in the Program Record case.

Table 9.6.5. Well-to-Wheels Results for central wind–pipeline pathway with advanced technology

Coal Input from "Well"	290	Btu / mi
Natural Gas Input from "Well"	130	Btu / mi
Petroleum Input from "Well"	20	Btu / mi
Fossil Energy Input from "Well"	440	Btu / mi
WTW CO_2 Emissions	41	g / mi
WTW CH_4 Emissions	0.06	g / mi
WTW N_2O Emissions	0.0006	g / mi
WTW GHG Emissions	43	g / mi

Levelized Cost of Hydrogen ($/kg)	$4.88	2005 $/kg
Levelized Cost of Hydrogen ($/mi)	$0.0752	2005 $/mi

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy for advanced FCVs used in this study (65 mpgge), and a yield of hydrogen from wind electricity of 45 kWh wind electricity/kg H_2, the amount of wind electricity required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with wind electricity–derived hydrogen fuel was calculated and compared to the potential 2030 U.S. wind electricity generation capacity and the 2008 U.S. wind electricity consumption estimates shown in Section 3.2 (Table 9.6.6).

Table 9.6.6. Wind Electricity Supply Scenarios for the Central Wind Electricity–Pipeline Delivery Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Advanced Technology – 65 mpgge FCV, hydrogen production yield 45 kWh/kg H_2[1]			
Wind Electricity Required (trillion kWh/yr)	2.0	1.5	1.0	0.5
Percent of Potential U.S. Capacity in 2030 (1.16 trillion kWh)[2]	170%	130%	80%	40%
Percent of 2008 U.S. Consumption (0.052 trillion kWh)[3]	3,800%	2,800%	1,900%	900%

[1] Calculation does not include energy or hydrogen losses.
[2] United States Department of Energy (2008)
[3] Energy Information Administration (2009j)

Table 9.6.7 compares a sample scenario for hydrogen production from wind electricity from DOE's Hydrogen Posture Plan (United States Department of Energy, 2006) to a 20% FCV penetration scenario using the advanced technology assumptions in this section, as described above.

Table 9.6.7. Comparison of Wind Electricity Supply Scenarios to Hydrogen Posture Plan for Advanced Hydrogen Technology

	DOE Hydrogen Posture Plan (2006)	Hydrogen Pathways Report (2009)*
Total Hydrogen Demand	64 million metric tons/yr	63.1 million metric tons/yr
Amount of Demand to Be Supplied by Resource	13 million metric tons/yr (20%)	12.6 million metric tons/yr (20%)
Wind Electricity Needed for H_2	200 GWe	390 billion kWh/yr
Wind Electricity Availability	2,300 GWe nameplate capacity	1,160 billion kWh/yr in 2030
Wind Electricity Consumption (current)	10 GWe installed nameplate capacity	52 billion kWh/yr in 2008
Increase in Wind Electricity Consumption with H_2 Production	28 X	8.5 X

* Calculated using the assumptions in Table 9.6.6 with 20% penetration of FCVs in light-duty vehicle market

9.7 Central Coal with Carbon Capture and Sequestration (CCS) – Pipeline Delivery

Figure 9.7.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. The complete set of assumptions is detailed in Appendix G.

The well-to-pump and well-to-wheels cost of hydrogen, energy use, and emissions for the central coal with CCS–pipeline delivery pathway are summarized in Table 9.7.1.

9.7.1 Cost Breakdown

Figure 9.7.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central coal with CCS–pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 8.0.

Figure 9.7.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 9.7.2.

Figure 9.7.4 and Table 9.7.2 show the breakdown of levelized costs for the central coal with CCS–pipeline delivery pathway.

Inputs	Graphic Depiction & Assumptions	Outputs

Coal Mining & Delivery

Inputs	
Coal Input from "Well"	116,427 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	145 Btu / 116000Btu to Pump
Petroleum Input from "Well"	712 Btu / 116000Btu to Pump

Assumptions		
Energy Recovery	99.3%	
Energy Used	7049	Btu / MMBtu Coal Delivered
Diesel Used	3948	Btu / MMBtu Coal Delivered
Electricity Used	1692	Btu / MMBtu Coal Delivered

Outputs	
Coal price at H2 production	$33.98 2005 $ / short ton
Levelized Cost of Coal	$0.31 2005$ / kg H2 distributed
WTG CO2 Emissions	114 g / 116000Btu to Pump
WTG CH4 Emissions	14 g / 116000Btu to Pump
WTG N2O Emissions	0 g / 116000Btu to Pump
WTG GHG Emissions	462 g CO2 eq./ 116000 Btu

Hydrogen Production & CCS

Inputs	
Coal consumption	7.8 kg / kg H2 produced
Natural gas consumption	0.00 N m^3/kg H2 produced
Electricity consumption	1.72 kWh / kg H2
Process Water Consumption	11.02 L / kg H2
Electricity price	$0.0555 2005 $/kWh
Total Capital Investment	$691,377,851 2005$
Coal Input from "Well"	105,782 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	3,022 Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,332 Btu / 116000Btu to Pump

Assumptions		
Central plant design capacity	307,673	kg/day
Capacity factor	90%	
Process energy efficiency	53.6%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	40	
CO2 Captured for sequestration	90%	
CO2 Pipeline Length	100	miles
Number of injection wells	1	
Injection well depth	1524	m

Outputs	
Hydrogen Output Pressure	300 psi
Total capital investment	$6.84 2005$ / annual kg H2 (effective capacity)
Electricity cost	$0.10 2005$ / kg H2 produced
Natural Gas Cost	$0.00 2005$ / kg H2 produced
Other operating costs	$0.38 2005$ / kg H2 produced
Levelized Cost of Prod (excl feedstock)	$1.76 2005$ / kg H2 distributed
H2 Prod CO2 Emissions	3,803 g / 116000Btu to Pump
H2 Prod CH4 Emissions	13 g / 116000Btu to Pump
H2 Prod N2O Emissions	0 g / 116000Btu to Pump
H2 Prod GHG Emissions	4,136 g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs	
Electricity consumption for compressor	0.56 kWh / kg H2
Electricity consumption for geo storage	0.01 kWh / kg H2
Total electricity consumption	0.57 kWh / kg H2
Electricity price for compressor	$0.056 2005$ / kWh
Electricity price for geologic storage	$0.052 2005$ / kWh
Coal Input from "Well"	3,306 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	950 Btu / 116000Btu to Pump
Petroleum Input from "Well"	246 Btu / 116000Btu to Pump

Assumptions		
City Population	1,247,364	people
Hydrogen Vehicle Penetration	50%	
City hydrogen use	125,810,766	kg / yr
Distance from City to Production Facility	62	miles
Geologic storage capacity	3,762,787	kg H2
Trunk #1-line length	17	miles
Trunk #2-line length	40	miles
Service-line length	1.1	miles / line
Number of service lines	270	
Hydrogen losses	1.12%	
Hydrogen loss factor	1.011	

Outputs	
Total capital investment	$3.51 2005$/annual kg distributed
Electricity cost	$0.03 2005$ / kg H2
Levelized Cost of Delivery	$0.92 2005$ / kg H2 distributed
Delivery CO2 Emissions	436 g / 116000Btu to Pump
Delivery CH4 Emissions	1 g / 116000Btu to Pump
Delivery N2O Emissions	0 g / 116000Btu to Pump
Delivery GHG Emissions	452 g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs	
Electricity consumption	3.04 kWh / kg H2
Electricity price	$0.082 2005$ / kWh
Coal Input from "Well"	17,677 Btu / 116000Btu to Pump
Natural Gas Input from "Well"	5,078 Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,317 Btu / 116000Btu to Pump

Assumptions		
Number of Distribution Stations	270	
Energy efficiency	92%	
Number of Compression Steps	4	
Isentropic Efficiency	65%	
Site storage	69%	capacity
Hydrogen losses	0.50%	
Hydrogen loss factor	1.005	

Outputs	
Hydrogen outlet pressure	6,250 psi
Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$6.69 2005$/annual kg
Electricity cost	$0.25 2005$ / kg H2
Levelized Cost of Distribution	$1.69 2005$ / kg H2 distributed
CSD CO2 Emissions	2,333 g / 116000Btu to Pump
CSD CH4 Emissions	3 g / 116000Btu to Pump
CSD N2O Emissions	0 g / 116000Btu to Pump
CSD GHG Emissions	2,419 g CO2 eq./ 116000 Btu

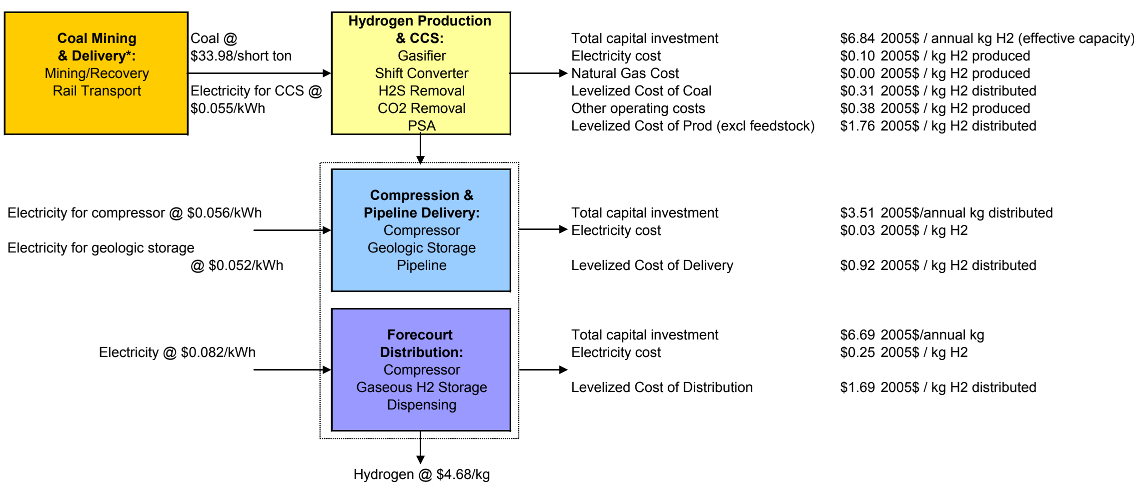
Figure 9.7.1. Central coal with CCS–pipeline delivery pathway summary of major inputs, assumptions, and outputs by subsystem

Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.

Table 9.7.1. Well-to-Pump and Well-to-Wheels Results for Central Coal with CCS–Pipeline Delivery Pathway

	Well-to-Pump		Well-to-Wheels	
Coal Input from "Well"*	243,200	Btu / 116,000 Btu	5,410	Btu / mi
Natural Gas Input from "Well"*	9,200	Btu / 116,000 Btu	200	Btu / mi
Petroleum Input from "Well"*	3,600	Btu / 116,000 Btu	80	Btu / mi
Fossil Energy Input from "Well"*	256,000	Btu / 116,000 Btu	5,690	Btu / mi
WTP CO_2 Emissions*,**	6,700	g / 116,000 Btu	150	g / mi
WTP CH_4 Emissions	31	g / 116,000 Btu	1	g / mi
WTP N_2O Emissions	0	g / 116,000 Btu	0	g / mi
WTP GHG Emissions*	7,500	g CO2 eq. / 116000 Btu	170	g / mi
Levelized Cost of Hydrogen ($/kg)	$4.68	2005 $/kg	$0.1040	2005 $/mi

* Well-to-pump results are rounded to the nearest hundred; well-to-wheels results are rounded to the nearest ten.
** Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2
Coal, natural gas, and petroleum inputs from "well" include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.



* This box represents the coal that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include coal used as a heating fuel or to produce electricity.

Figure 9.7.2. Cost analysis inputs and high-level results for central coal with CCS–pipeline delivery pathway

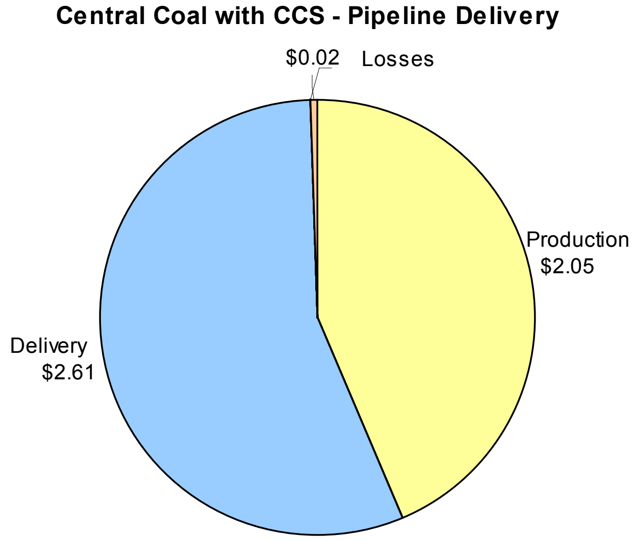


Figure 9.7.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for the central coal with CCS–pipeline delivery pathway

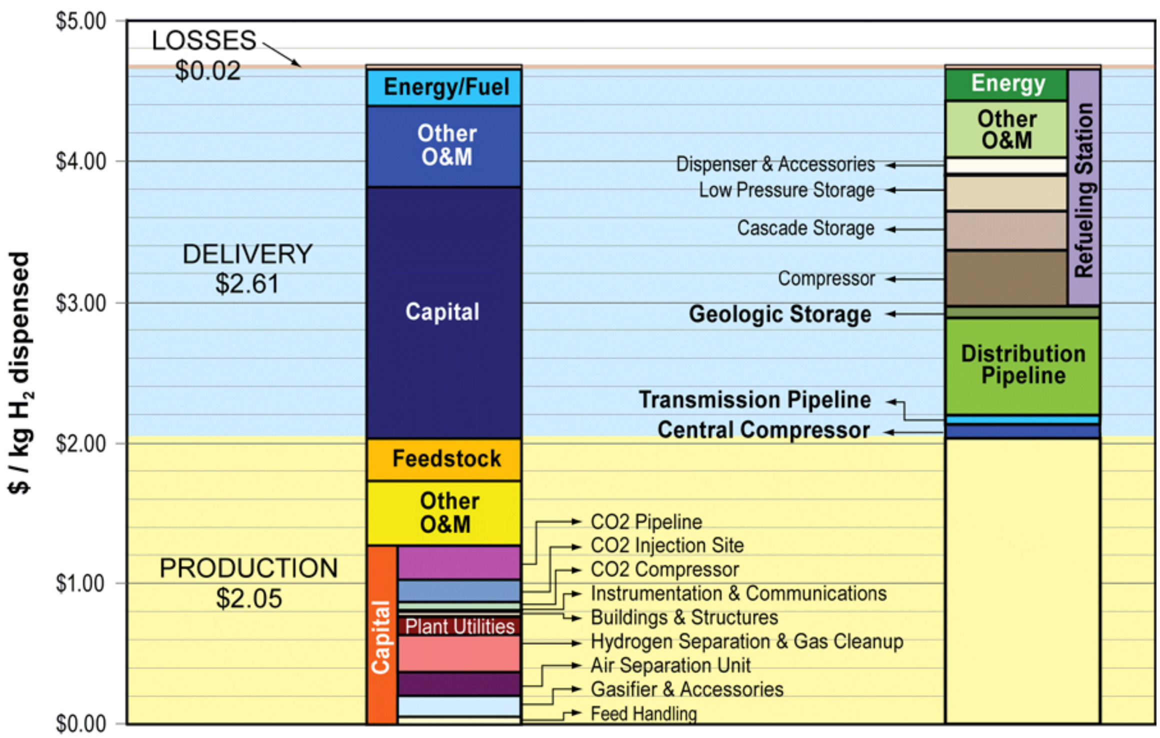


Figure 9.7.4. Breakdown of levelized costs for central coal with CCS–pipeline delivery pathway

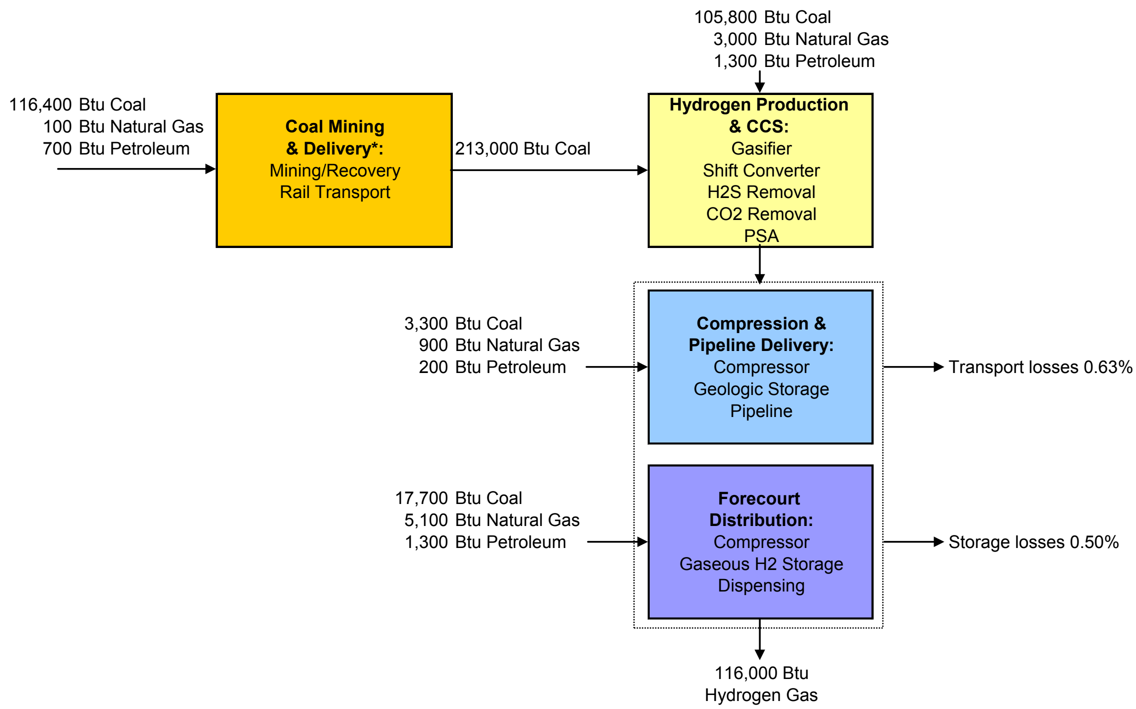
Table 9.7.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost from Central Coal with CCS–pipeline Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$1.27	$0.47	$0.31		$2.05
Feed Handling	$0.06				
Gasifier & Accessories	$0.15				
Air Separation Unit	$0.16				
Hydrogen Separation & Gas Cleanup	$0.27				
Plant Utilities	$0.13				
Buildings & Structures	$0.01				
Instrumentation & Communications	$0.02				
CO_2 Compressor	$0.07				
CO_2 Injection Site	$0.16				
CO_2 Pipeline	$0.24				
Delivery	$1.77	$0.58		$0.26	$2.61
Central Compressor					$0.08
Transmission Pipeline					$0.07
Distribution Pipeline					$0.70
Geologic Storage					$0.08
Gaseous Refueling Station	$1.06	$0.41		$0.23	$1.69
Compressor	$0.39				
Cascade Storage	$0.29				
Low Pressure Storage	$0.26				
Dispenser & Accessories	$0.12				
Losses					$0.02
Total	**$3.04**	**$1.05**	**$0.31**	**$0.26**	**$4.68**

9.7.2 Energy Use and Emissions Breakdown

Figures 9.7.5 and 9.7.6 show the WTW energy inputs and losses for the central coal with CCS–pipeline delivery pathway. The WTW energy inputs to coal mining and delivery include those necessary to produce 116,000 Btu of coal for gasifying. Additional WTW energy inputs for coal needed for heating, electricity, and process-inefficiency are reported as inputs to hydrogen production.

Figures 9.7.7 and 9.7.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central coal with CCS–pipeline delivery pathway.



* This box represents the coal that is converted to hydrogen or otherwise consumed/lost as a process feedstock. It does not include coal used as a heating fuel or to produce electricity.

Figure 9.7.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using central coal with CCS–pipeline delivery pathway

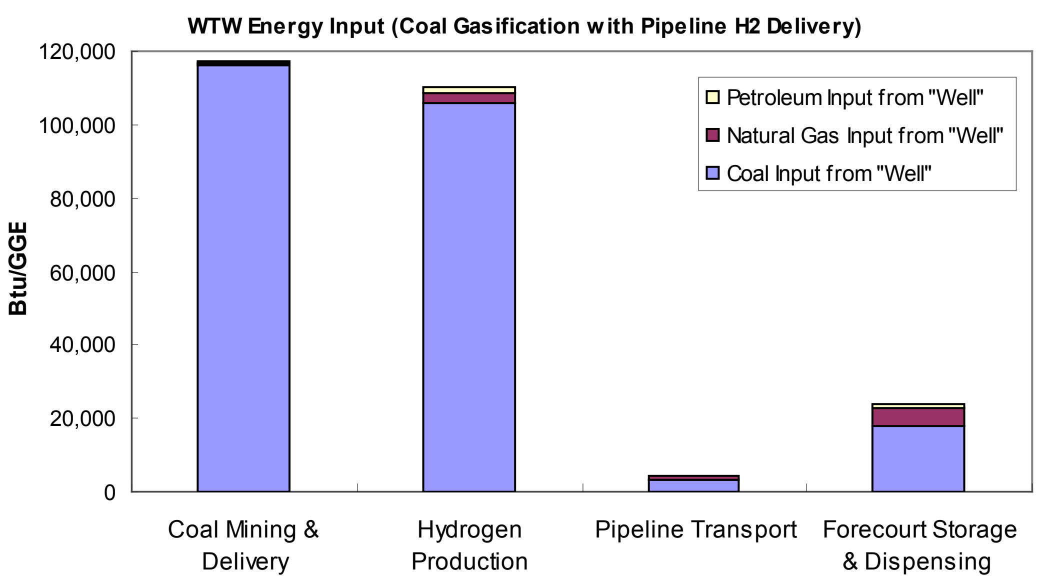
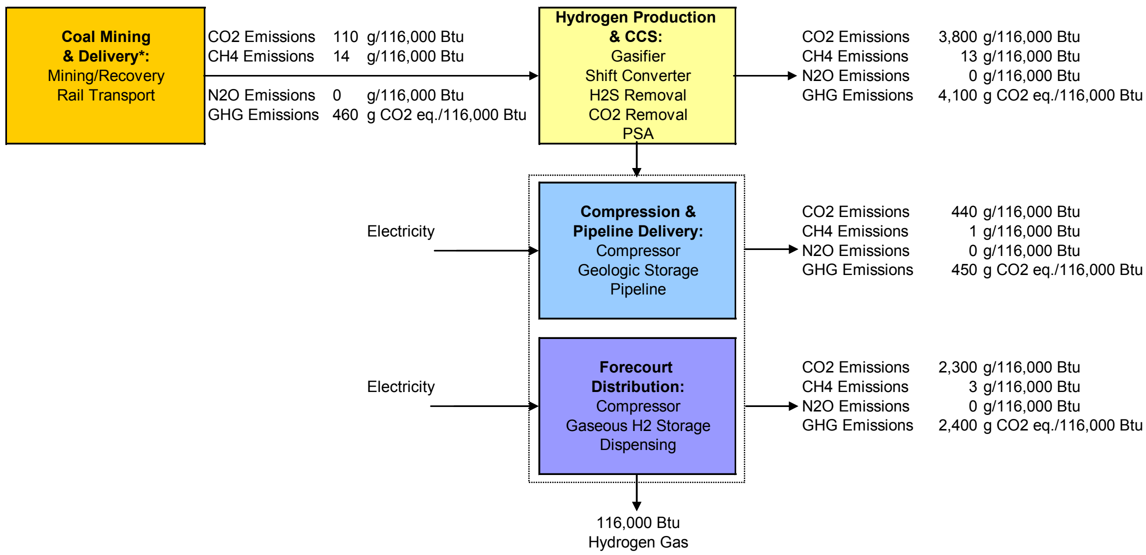


Figure 9.7.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using central coal with CCS–pipeline delivery pathway



* This box represents the coal that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include coal used as a heating fuel or to produce electricity.

Figure 9.7.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central coal with CCS–pipeline delivery pathway

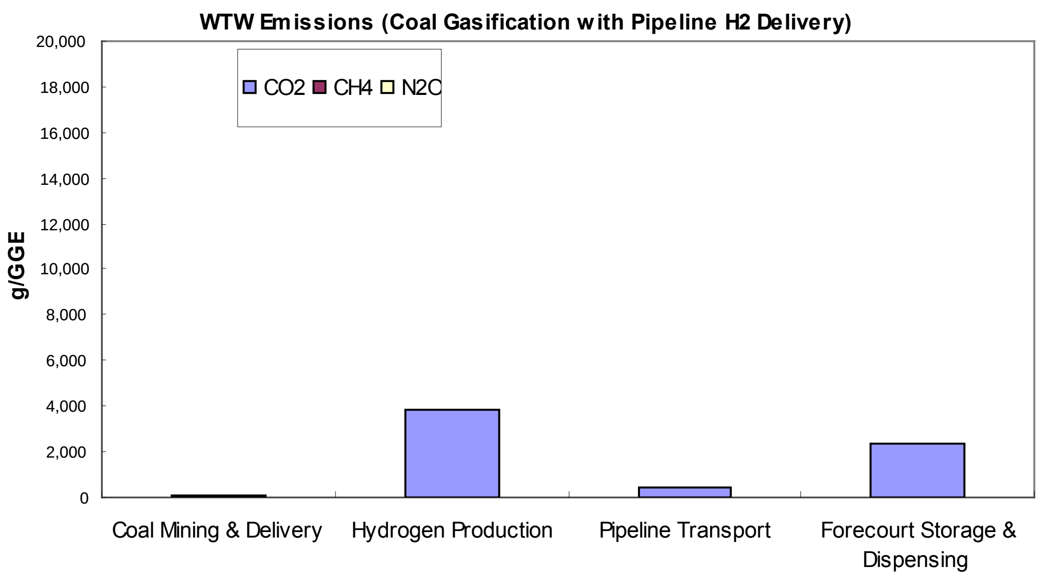


Figure 9.7.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using central coal with CCS–pipeline delivery pathway

9.7.3 Coal Supply Scenarios

Assuming a total vehicle miles traveled in passenger vehicles of 2.78 trillion (Bureau of Transportation Statistics, 2007), the vehicle fuel economy used in this study (45 mpgge), and a yield of hydrogen from coal of 7.9 kg coal/kg H_2, the amount of coal required to supply 100%, 75%, 50%, or 25% of light-duty vehicles with coal-derived hydrogen fuel was calculated and compared to the U.S. coal reserves, 2007 U.S. coal production, and 2008 U.S. coal consumption estimates shown in Section 3.4 (Table 9.7.3).

Table 9.7.3. Coal Supply Scenarios for the Central Coal with CCS–Pipeline Delivery Pathway

	100% Penetration	75% Penetration	50% Penetration	25% Penetration
	Current Technology – 45 mpgge FCV, hydrogen production yield 7.85 kg coal/kg H_2[1]			
Coal Required (million short tons)	550	410	270	140
Percent of U.S. Reserves (489,000 million short tons)[2]	0.11%	0.08%	0.06%	0.03%
Percent of 2007 U.S. Production (1,171 million short tons)[3]	47%	35%	23%	12%
Percent of 2008 U.S. Consumption (1,122 million short tons)[4]	49%	37%	24%	12%

[1] Calculation does not include energy or hydrogen losses.
[2] United States Department of Energy (2008)
[3] Energy Information Administration (2008d)
[4] Energy Information Administration (2009j)

Table 9.7.4 compares a sample scenario for hydrogen production from biomass from DOE's Hydrogen Posture Plan (United States Department of Energy, 2006) to a 20% FCV penetration scenario using the assumptions in this study, as described above.

Table 9.7.4. Comparison of Coal Supply Scenarios to Hydrogen Posture Plan

	DOE Hydrogen Posture Plan (2006)	Hydrogen Pathways Report (2009)*
Total Hydrogen Demand	64 million metric tons/yr	63.1 million metric tons/yr
Amount of Demand to Be Supplied by Resource	13 million metric tons/yr (20%)	12.6 million metric tons/yr (20%)
Coal Needed for H_2	110 million metric tons/yr	99 million metric tons/yr
Coal Availability	268 billion tons estimated recoverable reserves, 493 billion tons demonstrated coal base	489 billion short tons
Coal Consumption (current)	1,100 million metric tons/yr (all grades)	1,017 million metric tons/yr
Increase in Coal Consumption with H_2 Production	1.1 X	1.1 X

* Calculated using the assumptions in Table 9.7.3 with 20% penetration of FCVs in light-duty vehicle market

9.7.4 Sensitivities

Production Sensitivities

Several sensitivities were run on the production portion of the central coal with CCS – pipeline delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 9.7.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 9.7.5 shows the effect of varying production efficiency on the WTW results.

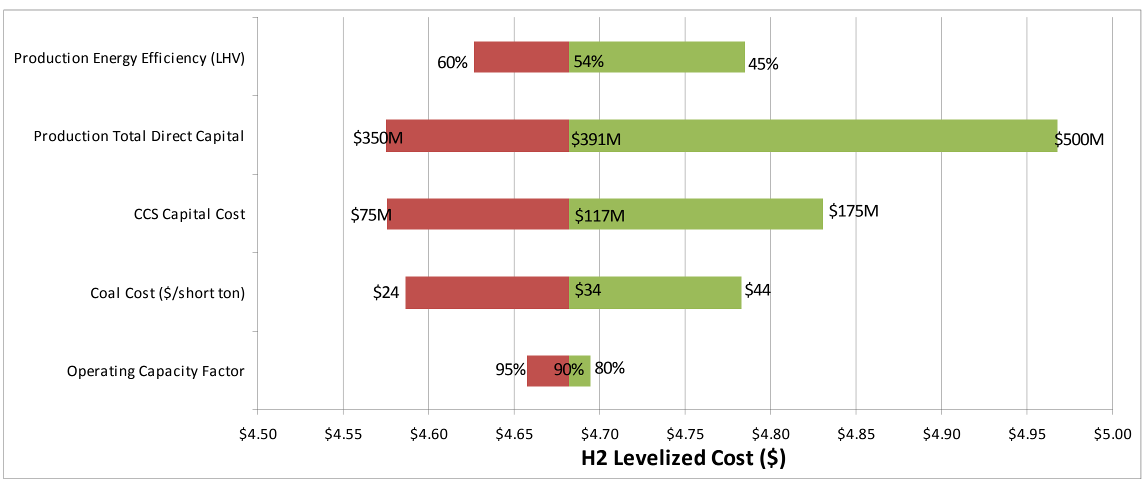


Figure 9.7.9. Production sensitivities for central coal with CCS–pipeline delivery pathway

Table 9.7.5. The Effects of Production Energy Efficiency on Primary Energy and Emissions from Central Coal with CCS–Pipeline Delivery Pathway (current technology)

	45% Efficiency	54% Efficiency	60% Efficiency
WTW GHG Emissions (g/mile)	190	170	160
WTW Fossil Energy (Btu/mile)	6,700	5,700	5,200
WTW Petroleum Energy (Btu/mile)	89	80	76
WTW Total Energy (Btu/mile)	6,900	5,900	5,300

The assumed electrical grid mix also affects the energy use and emissions because grid electricity is needed for delivery and distribution. Electricity for the production facility is generated internally and can be considered a parasitic loss. Table 9.7.6 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 9.7.6. The Effects of Grid Mix on Use of Primary Energy and Emissions from Central Coal with CCS–pipeline Delivery Pathway

	U.S. Average Grid Mix	"Green" Grid Mix
WTW GHG Emissions (g/mile)	170	70
WTW Fossil Energy (Btu/mile)	5,700	4,700
WTW Petroleum Energy (Btu/mile)	80	28
WTW Total Energy (Btu/mile)	5,900	5,200

Delivery Sensitivities

Pipeline delivery sensitivities are reported for the biomass production scenario in Section 9.4.4. The effects of the sensitivities will be the same for all pipeline delivery scenarios.

9.7.5 Advanced Conversion and Delivery/Distribution Technology

For advanced technology analysis, parameters were changed to future projections. The "Future" H2A production case was used, and HDSAM was modified to include achievement of delivery targets as defined in the Hydrogen, Fuel Cells and Infrastructure Technologies (HFCIT) Multi-Year Program Plan (MYPP). The vehicle fuel economy was increased to 65 mpgge. In addition, the electricity grid mix was updated to match EIA's projection for technology success in 2020 (51.1% coal, 19.2% natural gas, 18.5% nuclear, 1.9% residual oil, and 1.0% biomass, and 8.3% zero-carbon).

WTW results from cases with those modifications are shown in Table 9.7.7. The results do not match those in Hydrogen Program Record 9002 (2009) because the H2A case with advanced technology has a larger electricity byproduct than the case used for the Program

Record. Carbon dioxide and GHG emissions are negative because 50,400 Btu (14.8 kWh) electricity is produced for every GGE hydrogen distributed, and that electricity displaces grid electricity with higher GHG emissions. Electricity displacement is also the reason why WTW natural gas and petroleum use are negative.

Table 9.7.7. Well-to-Wheels Results for central coal with CCS–pipeline pathway with advanced technology

Coal Input from "Well"	2330	Btu / mi
Natural Gas Input from "Well"	-360	Btu / mi
Petroleum Input from "Well"	-40	Btu / mi
Fossil Energy Input from "Well"	1900	Btu / mi
WTW CO_2 Emissions	-79	g / mi
WTW CH_4 Emissions	0.21	g / mi
WTW N_2O Emissions	-0.002	g / mi
WTW GHG Emissions	-74	g / mi
Levelized Cost of Hydrogen ($/kg)	$3.53	2005 $/kg
Levelized Cost of Hydrogen ($/mi)	$0.0543	2005 $/mi

10.0 Pathway Results Comparison

In this section, results from the individual pathways are compared. Each pathway's current estimated levelized cost, WTW petroleum use, and WTW GHG emissions are shown for comparison to the other pathways, several crude oil-based transportation options, and ethanol as E85. The crude oil–based options are gasoline in a standard spark-ignition ICE; gasoline in a spark-ignition HEV; and diesel in a compression-ignition direct-injection ICE.

Fuel economies used for each option are shown in Table 10.0.1. GREET-default fuel economies and upstream parameters were used for the crude oil–based transportation options and E85 from corn grain. The gasoline ICE fuel economy is based on data presented by the Environmental Protection Agency (2005). The fuel economies for other, non-hydrogen vehicles are based on PSAT results (Elgowainy, 2009). The GREET yield for corn stover–based E85 was modified to 72.6 gal / dry ton to match the 2008 status in Table B-5 of the Biomass Program Plan (Office of the Biomass Program, 2009). Other key parameters are shown in Table 10.0.2.

Table 10.0.1. Fuel Economies for Vehicle Options

Vehicle Type	Fuel Economy
Hydrogen FCV	45 mpgge
Gasoline ICE	23.2 mpg
Gasoline HEV	34.3 mpg
Diesel ICE	27.8 mpgge (equivalent to 30.8 mpg diesel)
E85 Flex-Fuel FCV	23.2 mpgge (equivalent to 16.4 mpg E85)

Table 10.0.2. Key Analysis Parameters

Parameter	Value and Section with Description
Technology status	Current technology (Section 2.2). Technology is described in Sections 6.0 and 7.0, and parameters are shown in the appendices.
City size	553 mi^2 and 1,247,364 people (equivalent to Indianapolis, IN) (Section 2.2)
Market penetration	50% of hydrogen vehicles (Section 2.2)
Analysis boundaries	Includes feedstock recovery, transportation, and storage; fuel production, transportation, storage, and distribution; and vehicle operation (Section 2.3)
Monetary value	2005 dollars (Section 8.0)
Equity financing	100% (Section 8.0)
After tax internal rate of return	10% (Section 8.0)
Effective total tax rate	38.9%
Carbon capture efficiency in coal with CCS case	90% (Section 9.7)

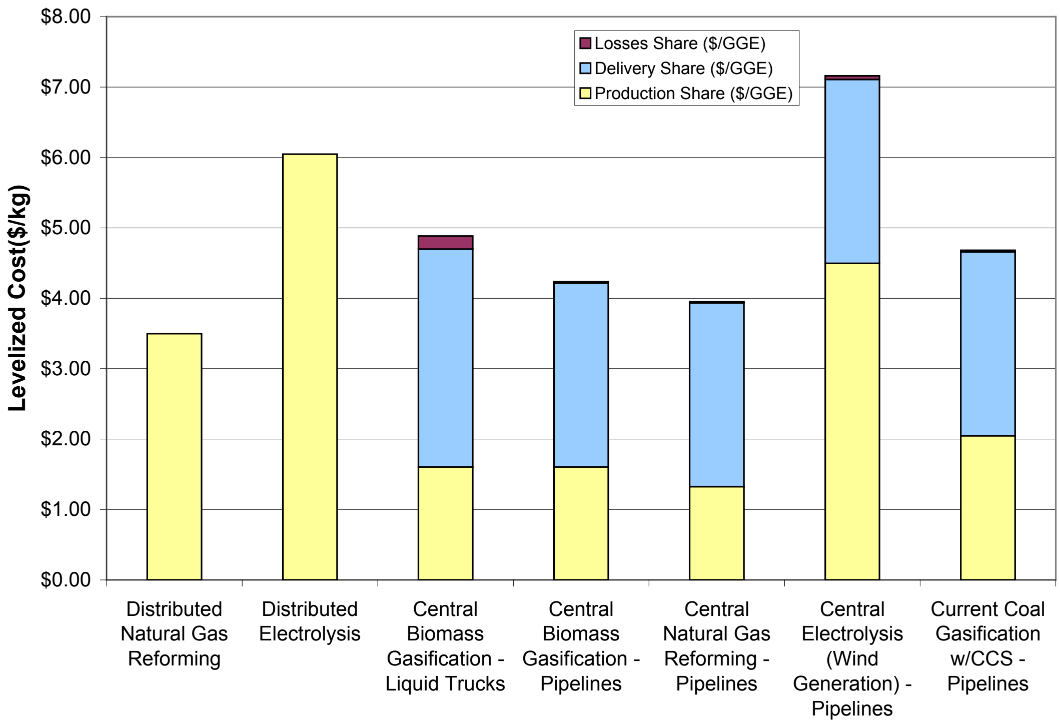


Figure 10.0.1. Levelized cost of hydrogen for seven pathways

Figure 10.0.1 shows the levelized cost of hydrogen for all seven hydrogen pathways with the parameters described in Section 9 and referenced in Appendices A–G. Some of the most important parameters are shown in Table 10.0.2, and additional parameters are in sections 2–8. Sensitivities on parameters in each hydrogen pathway are reported in Section 9.

The levelized cost of hydrogen is calculated directly in the H2A model for the distributed hydrogen production cases because the H2A distributed hydrogen production model includes the forecourt station capital and operating costs. For central production cases, the levelized cost of hydrogen is the sum of levelized production cost, levelized delivery cost, and the cost of excess production due to losses in delivery.

The Program has set a hydrogen levelized cost target of $2.00–$3.00/gge delivered at the pump (Hydrogen, Fuel Cells and Infrastructure Technology Program, 2007), and the comparison in Figure 10.0.1 shows that the target has not been met. Niche opportunities with low-cost feed or capital costs, different financing options, or higher capacities may meet the target. Otherwise, additional research is necessary to meet them. Other analysts have used different parameters and reached slightly different levelized costs of hydrogen in their studies. One example of an analysis that showed that the $2.00–$3.00/gge levelized cost has been met for the distributed natural gas reforming pathway is Fletcher and Callaghan (2007). The primary difference between their analysis and this one is a lower cost for CSD (They estimated \$0.88/kg, and the estimate in this study is \$1.88/kg.).

Figure 10.0.2 shows a comparison hydrogen pathway energy use. Pathway energy includes only the energy used directly by the pathway. It differs from the WTW energy in that WTW energy includes upstream energy requirements. For example, while electricity is reported as a pathway energy source, the primary energy sources used to generate the electricity (coal, natural gas, etc.) are included in the WTW calculations. As expected, the dominant pathway energy source is the one named in the title of each pathway.

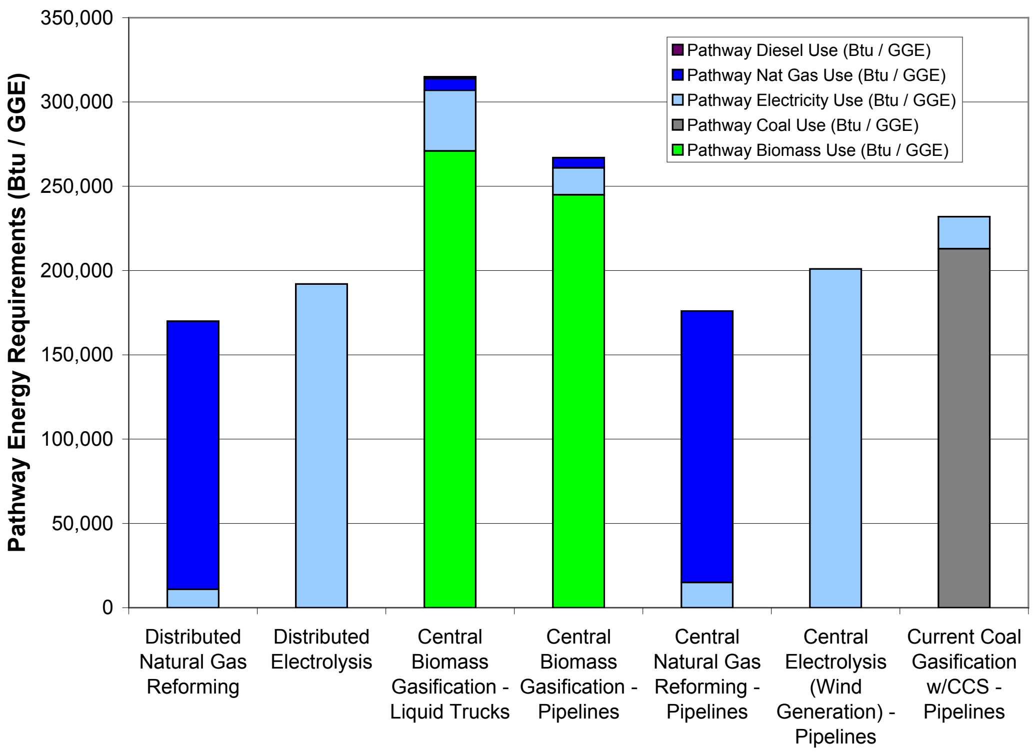


Figure 10.0.2. Pathway energy use for seven pathways

The pathway efficiency can be considered the inverse of the energy use; Figure 10.0.3 shows those efficiencies. The yellow bars show the production efficiencies that are calculated as the LHV of the hydrogen produced divided by the LHV of all the production inputs reported in Section 9. The blue bars show the pathway efficiencies that are calculated as the LHV of the hydrogen delivered divided by the LHV of all the pathway inputs, which are shown in Figure 10.0.2. The red bars show the WTP efficiencies that are calculated as the LHV of the hydrogen delivered divided by the LHV of all the primary energy inputs (coal, natural gas, crude oil, and biomass) that are used directly or indirectly by the pathway.

As an example, Figure 10.0.3 shows that the production efficiency of the distributed natural gas reforming pathway is 71% (i.e., 71% of all of the energy delivered to the hydrogen production plant is contained in the hydrogen product). Because the pathway includes both the production plant and CSD, the pathway efficiency must account for hydrogen lost and energy required for compression; thus, the pathway efficiency is somewhat lower at 68% for the distributed natural gas reforming pathway. Some additional energy is required to produce and delivery the natural gas and electricity to the facility, so the WTP efficiency is lower yet at 58% for the distributed natural gas reforming pathway.

The pathways with the highest efficiency are the natural gas pathways followed by electrolysis and coal, and those with the lowest efficiency are the biomass pathways.

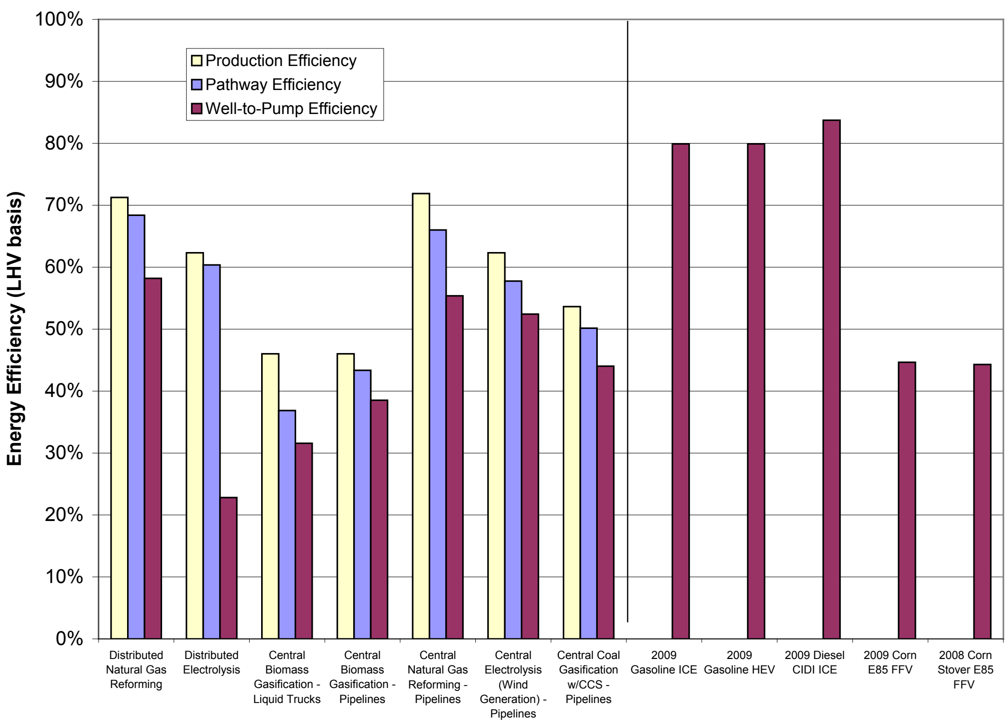


Figure 10.0.3. WTW, pathway, and production efficiencies for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

Figure 10.0.4 shows the WTW petroleum use for the seven hydrogen pathways, the three crude oil–based pathways, and two E85 pathways. Because the petroleum use is so high for the crude oil pathway, Figure 10.0.5 shows the WTW petroleum use for the seven hydrogen pathways alone. Most of the petroleum use is for electricity generation for the pathways' grid electricity requirements (2.9% of the grid mix is electricity generated from residual oil.). The largest grid-electricity user is distributed electrolysis (requiring 55 kWh/kg H_2 produced), and if the grid mix did not include residual oil, its WTW petroleum use would be reduced by 410 Btu/mile.

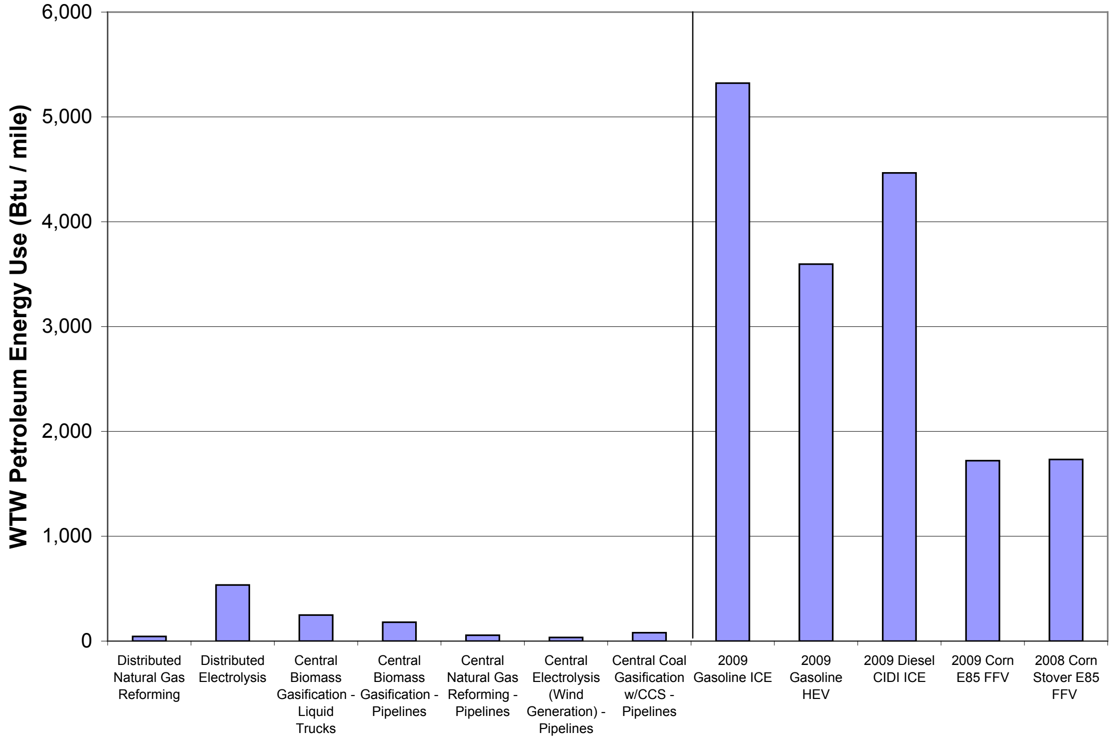


Figure 10.0.4. WTW petroleum energy use for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

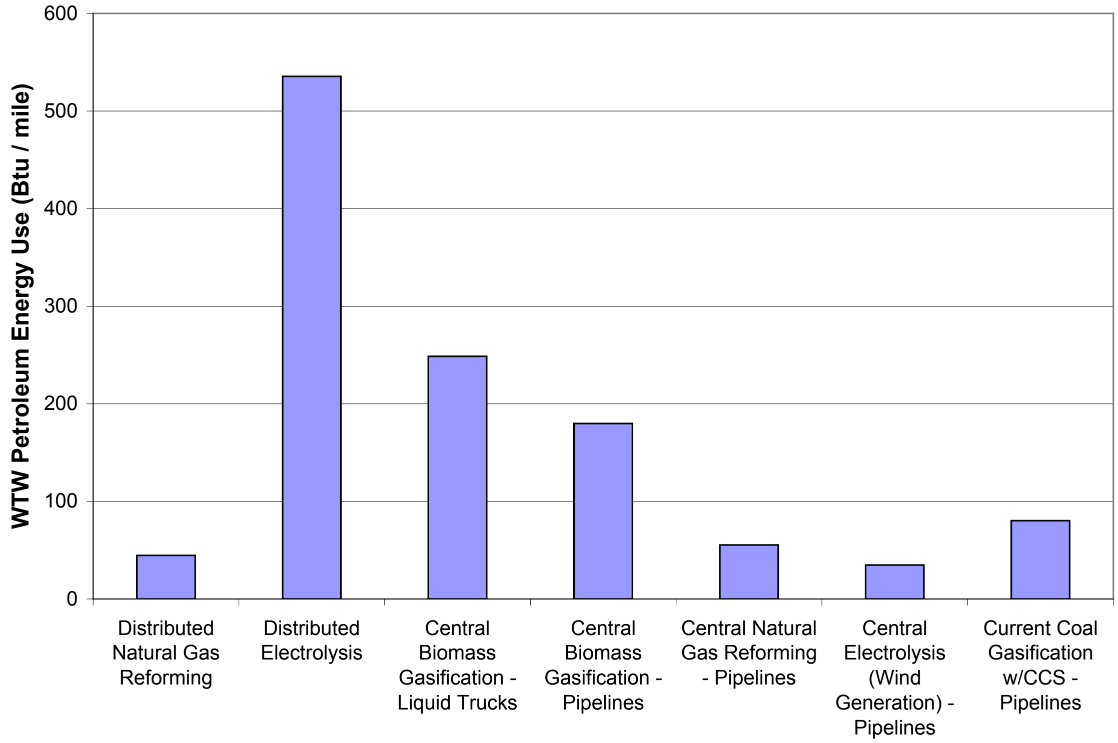


Figure 10.0.5. WTW petroleum energy use for seven hydrogen pathways

Figure 10.0.6 shows the comparative WTW GHG emissions for the seven pathways, the crude oil–based pathways, and two E85 pathways. Well-to-pump (WTP) emissions are colored green, and pump-to-wheels (i.e., tailpipe) emissions are colored blue. Hydrogen FCVs have no tailpipe GHG emissions because reacting hydrogen forms water. The corn stover E85 FFV pathway has negative WTP emissions because more carbon dioxide is removed from the atmosphere while the plants are growing than is released in growing the plants, harvesting and transporting the biomass, producing ethanol, and delivering ethanol.

All the hydrogen pathways except distributed electrolysis have estimated GHG emissions lower than the crude oil options. The primary source (89%) of GHG emissions for the distributed natural gas reforming pathway is generation of hydrogen with some additional GHGs generated to produce electricity for CSD and in natural gas recovery and delivery. Distributed electrolysis requires 55 kWh electricity per kg H_2 produced, and the current grid mix produces 800 g CO_2 eq./kWh, so electricity generation is the primary emitter of its 980 g CO_2 eq./mile traveled. In the biomass / liquid pathway, the GHGs removed from the atmosphere to grow biomass are essentially equivalent to the GHGs generated in producing hydrogen (see Section 9.3 for details). In that pathway, most of the net GHGs emitted (97%) are from liquefaction and transport of the liquid hydrogen. Likewise, in the biomass pipeline pathway, most of the net GHGs emitted (92%) are from electricity generation for CSD of the hydrogen. Central natural gas reforming generates GHGs in both hydrogen production and in CSD. All the GHGs emitted from the central electrolysis of wind electricity are from electricity generation for CSD, which is assumed to be purchased from the grid without wind energy credits. Fifty-five percent of the GHGs emitted from the central coal with CCS and pipeline delivery pathway are GHGs that were not sequestered in the hydrogen production process with the remainder emitted during coal mining, transport and hydrogen CSD.

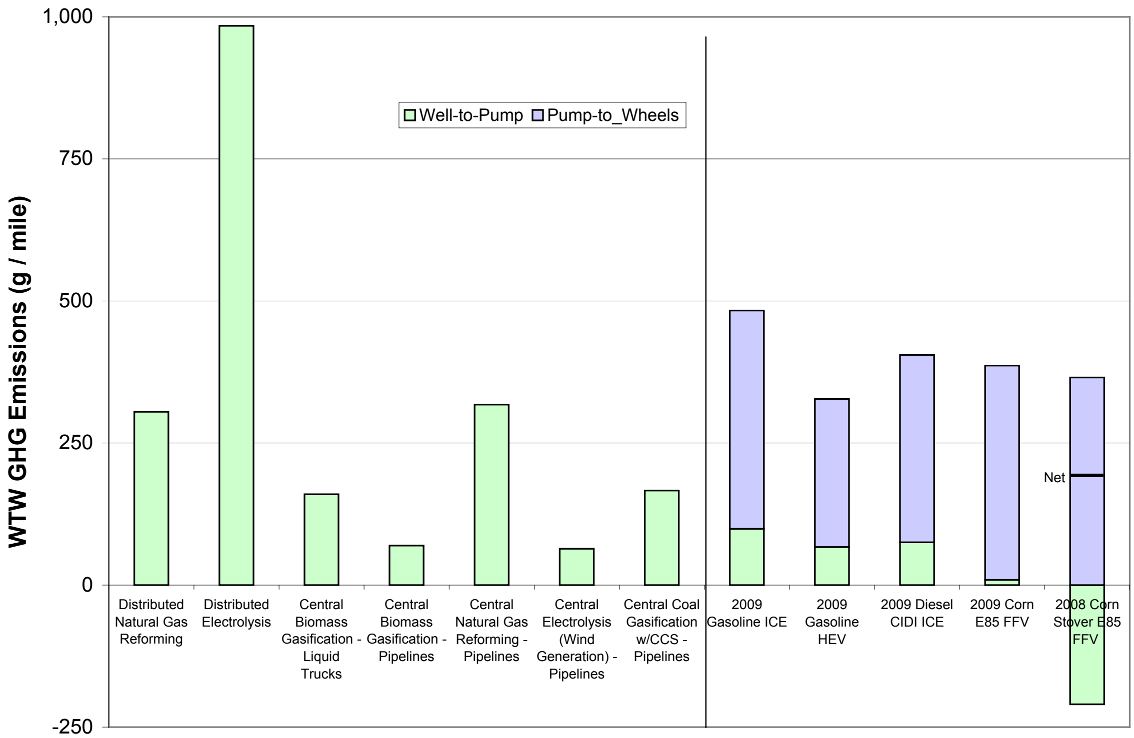


Figure 10.0.6. WTW GHG emissions for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

As seen in Figure 10.0.6, all the pathways except distributed electrolysis result in lower GHG emissions (on a g/mile basis) than a comparable ICE vehicle fueled by gasoline because of the increased efficiency fuel cells provide. Distributed electrolysis has both high GHG emissions and high petroleum use when compared to the other hydrogen pathways because of the electricity grid mix. The pathways that use natural gas as a feedstock use little petroleum but have high GHG emissions compared to most of the other pathways due to the GHGs released in producing hydrogen from natural gas. The coal pathway has a slightly higher petroleum use than the natural gas pathways because petroleum-fueled rail is used to deliver coal to the hydrogen production facility and has lower GHG emissions because of the efficient sequestration system that is assumed. The biomass cases have higher petroleum use than all but the distributed electrolysis pathway because the biomass is delivered using trucks.

Because using hydrogen as a transportation fuel has an effect on both WTW GHG emissions and WTW petroleum use and because that effect varies depending upon the hydrogen production/delivery pathway, Figure 10.0.7 shows both.

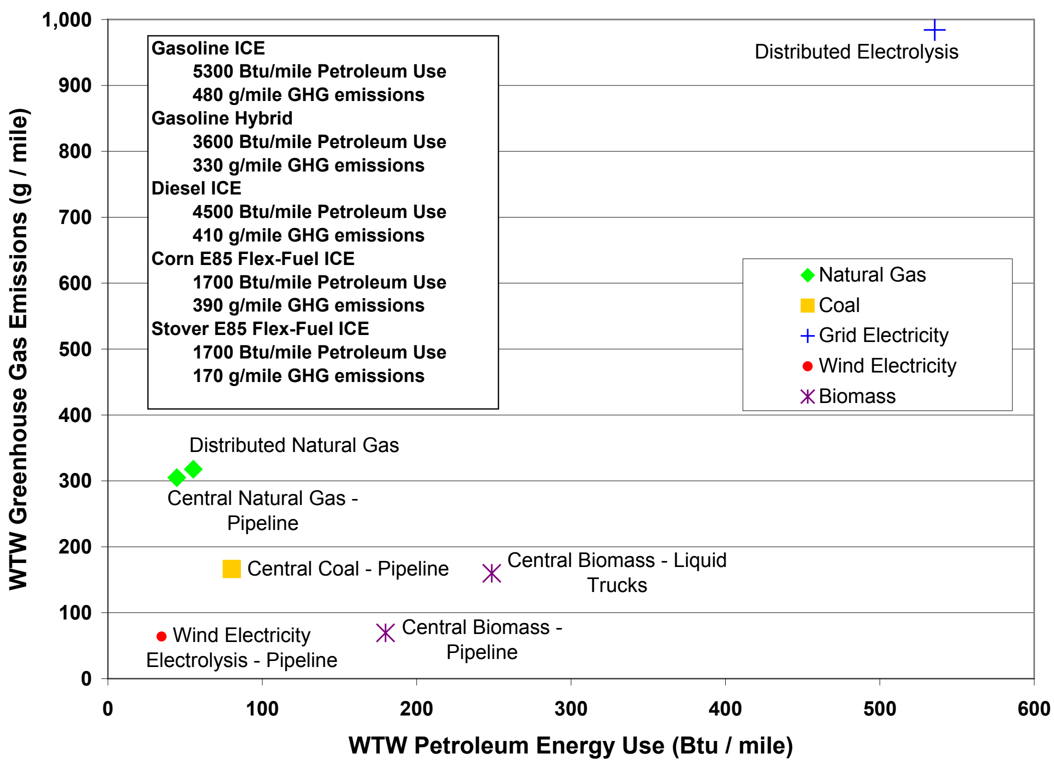


Figure 10.0.7. Comparison of pathways' petroleum use and GHG emissions

Figure 10.0.8 shows the levelized fuel cost per mile and the WTW GHG emissions. For comparison, it also shows the market price per mile and GHG emissions for gasoline and diesel vehicles. The levelized fuel cost was put onto a per-mile basis to simplify the comparison with other fuel/vehicle combinations that have different vehicle fuel economies. Ideally, the vehicle's purchase, maintenance, and insurance costs would also be put onto a per-mile basis, and the totals would be summed; however, those values are outside the scope of this analysis.

Gasoline, diesel, and corn-based E85 prices are based on projected market prices unlike the reported costs for hydrogen- and stover-based E85, which are based on calculated levelized costs. Projected market prices are used because they are available for technologies that are mature and commercialized. Levelized costs are not available for most of those technologies because capital and operating costs are separated for long-term commercial products with multiple improvements. For gasoline, the projected market price used in this analysis is \$2.535/gal based on the 2009 high-energy case in the 2007 Annual Energy Outlook (Energy Information Administration, 2007). The estimated taxes are \$0.391/gal (Federal Highway Administration, 2009), so a tax-free price of

$2.14/gal is used. For diesel, the reported market price is $2.536/gal (Energy Information Administration, 2007) with taxes of $0.452/gal (Federal Highway Administration, 2009), resulting in a tax-free price of $2.08/gal. The diesel price was converted to $1.88/gge using the lower heating values reported in GREET (Wang, 1999) because the vehicles' fuel economy is on a gge basis. The corresponding projected crude oil prices that match the gasoline and diesel prices are $67.70/bbl for imported low-sulfur light crude oil and $60.71/bbl for imported crude oil (Energy Information Administration, 2007). The crude oil prices include delivery to refineries. Corn grain–based E85 is also based on the 2009 high-energy case in the 2007 Annual Energy Outlook (Energy Information Administration, 2007). It is $2.505/gal ethanol and is reported to have 74% ethanol. Reduction by the gasoline tax of $0.391/gal and conversion to the common basis bring the price to $2.83/gge.

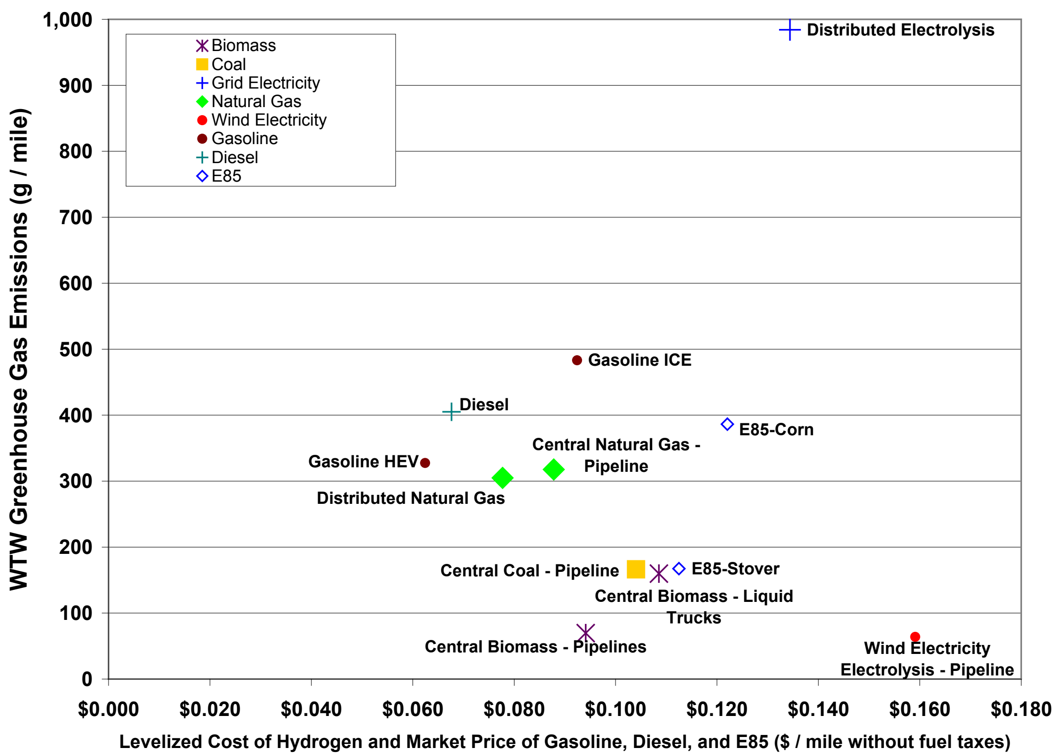


Figure 10.0.8. Comparison of pathways' levelized costs/market and GHG emissions

Figure 10.0.9 shows the levelized cost of hydrogen and the gasoline and diesel market prices on a per-mile-traveled basis with two possible levels of carbon taxation. The tops of the red bars indicate the wholesale, levelized costs including a $50/ton CO_2-equivalent tax, and the tops of the yellow bars indicate the wholesale, levelized costs including a $100/ton CO_2-equivalent tax. The tax calculation is based on WTW GHG emissions, so it includes increased costs due to upstream emissions as well as those generated while producing the hydrogen. A $100/ton CO_2 equivalent tax increases the per-mile levelized cost of hydrogen from electrolysis by 81%, the central and distributed natural gas cases by 40% and 43%, respectively, and all the other cases by less than 20%.

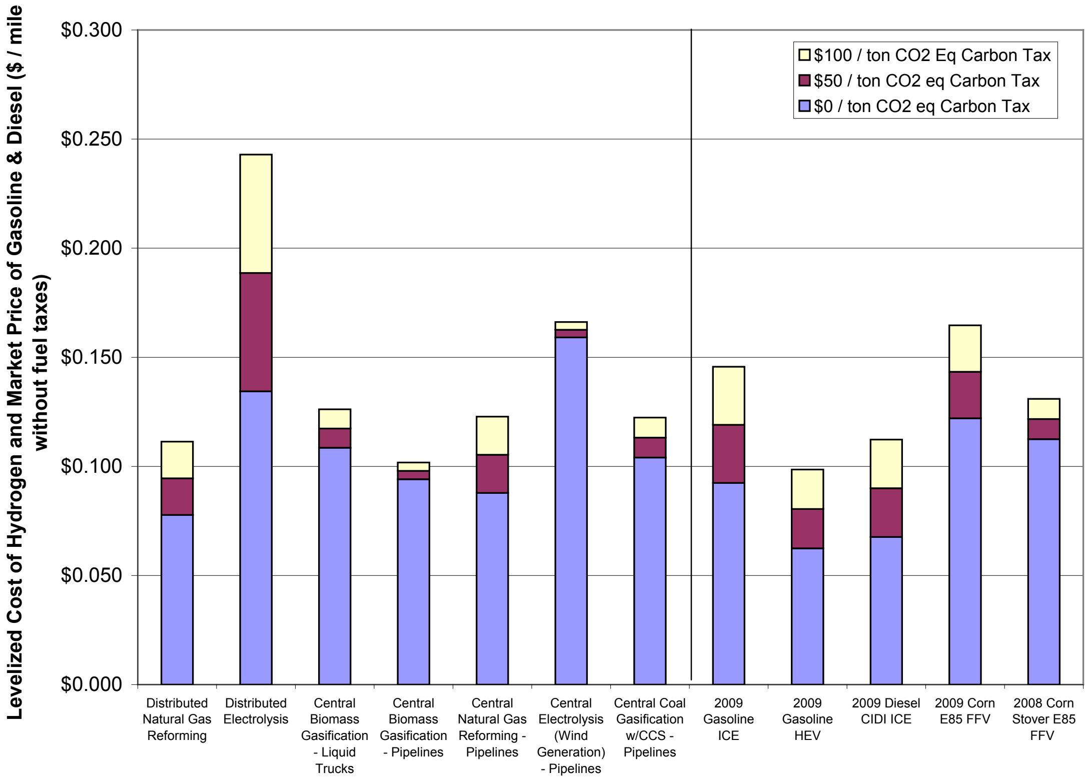


Figure 10.0.9. Levelized costs/market prices with possible carbon taxes for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

11.0 Analysis Gaps

FPITT of the FreedomCAR and Fuel Partnership is composed of representatives of four energy companies (ConocoPhillips, ExxonMobil, Chevron, and Shell), NREL, and the Hydrogen Systems Analyst of the U.S. Department of Energy. The energy company representatives on this team have conducted peer reviews of the hydrogen pathway analyses with the intention of identifying gaps in the analysis and opportunities for additional analysis. Some of the gaps that were identified have been addressed in analyses performed to date, and the results are incorporated in this report. Some gaps, however, have not yet been addressed or are beyond the scope of this effort; these gaps are noted below.

All Pathways

- One gap that was identified was the lack of consensus on the amount of hydrogen storage required at the forecourt site. Since identification of this gap, considerable effort has been directed toward understanding the on-site hydrogen storage needs for forecourt hydrogen stations. The amount of on-site storage assumed in this study for the distributed hydrogen production cases is 797 kg H_2 (62% of the design distribution capacity of the station). For the central hydrogen production pathways with gaseous hydrogen delivery via pipeline, on-site storage is assumed to be 1,052 kg H_2 (69% of the design distribution capacity of the station). For the central biomass–liquid truck delivery pathway, on-site storage is assumed to be 6,920 kg liquid H_2 plus 453 kg gaseous H_2 (486% of the design distribution capacity of the station).
- Additional analysis is needed to determine the ideal size and siting of hydrogen distribution stations.
- The on-board storage pressure for all the analyses in this report is 5,000 psi, which requires a pressure at distribution of 6,250 psi. Some organizations are considering on-board storage of compressed hydrogen at 10,000 psi and are interested in the effect of higher pressure on pathway cost, energy use, and emissions.
- The tradeoffs between hydrogen quality and fuel cell performance (i.e., durability, reliability, and efficiency) are not well understood.

Distributed Natural Gas and Distributed Electrolysis Pathways

- The hydrogen storage in the distributed electrolysis pathway is not optimized for peak power requirements. To optimize the pathway, the tradeoffs between the effects of full-time operation on the grid (transmission and distribution congestion and peaking power dispatch) and the costs of running the electrolyzers at less-than-full-time need to be understood, and a study over 8,760 hours/year is needed.
- The cascade storage volumes may need to be different for distributed production than for central production cases. The necessary volumes need more investigation.

All Centralized Production Pathways

- Hydrogen losses during both pipeline and liquid hydrogen delivery as estimated by HDSAM appear to be higher than those for natural gas delivery and may be higher than actual losses. Additional analysis is necessary to determine if the loss estimates are appropriate.
- Caverns may not be available in most locations for hydrogen storage; thus, alternative options for storing volumes of hydrogen necessary for seasonal variations, including storage as a liquid, need to be identified and characterized. The potential storage capacity for hydrogen should be compared to that for the current natural gas infrastructure.
- The need for hydrogen gas clean-up after the hydrogen is extracted from caverns or other geologic storage is not well understood and requires study. Gas clean-up requirements and costs are a gap in the analysis for all of the pathways employing hydrogen delivery by pipeline.
- The contribution of hydrogen distribution (service) pipelines to the cost of hydrogen is uncertain. The sensitivity of the hydrogen cost to the length of the distribution pipelines should be examined.
- Geologic storage is modeled currently with variable pressure; however, constant pressure is required in salt caverns. The pressure requirements for non-salt geologic structures are not well understood and require study.

Central Biomass Pathways

- Only woody biomass has been included in the analysis. The H2A production models do not currently include data to model herbaceous biomass feedstocks. The theoretical yields of hydrogen from herbaceous biomass should be compared with woody biomass. Empirical kinetic models on biomass gasification exist and may be used.
- The accuracy of the GREET default value for CO_2 emissions from gasification of woody biomass needs to be determined.
- There does not appear to be consensus in the scientific community on the best way to determine and communicate CO_2 emissions/absorption resulting from biomass production. Thus, this analysis does not include representation of the emissions from biomass production.
- The low-pressure gasifier currently used in the analysis may not be the optimal technology for hydrogen production. The results may be significantly different if a high-pressure gasifier is used because a high-pressure gasifier may increase conversion efficiency enough to overcome additional capital costs. A better understanding of the optimal gasifier technology for hydrogen production from biomass is needed.
- The effects of land use changes are not captured in this analysis.
- The land area required to support a specific size of gasifier needs to be calculated to determine if biomass transportation distance is a constraint to hydrogen production plant size. Road capacity is a potential constraint as well. While corn can be barged to some ethanol plants sited on rivers, not all crops and/or geographies will be

amenable to large-scale import of biomass feedstock. A statistical analysis is needed to evaluate the sensitivity of the hydrogen cost to transport distance.

- Using trucks to deliver biomass requires more petroleum than other potential options. Investigations of smaller conversion facilities, distributed gasification facilities with centralized hydrogen production and purification, and other conversion technologies (e.g., cold pyrolysis) are warranted.
- The sensitivity of the biomass/pipeline and biomass/truck pathway costs to power purchase prices should be examined. Producing power on-site using biomass feedstock would reduce the requirement for natural gas and electricity, as well as GHG emissions, to the extent that sufficient biomass is available at a viable cost. It may be worthwhile to configure the model to represent power production from biomass for internal gasification plant use (including liquefaction).

Central Natural Gas Pathway

- Natural gas costs may be different for central natural gas reforming facilities than for distributed reforming facilities. These costs should be compared. The cost of natural gas for the central natural gas pathway should also be compared to the price that utilities pay for natural gas at power plants.

Central Electrolysis Using Wind-Generated Electricity

- The actual price of wind-generated electricity is time-dependent and different than a grid-electricity price. This analysis used a single price of electricity that matched the grid price. Using the time-dependent price is a gap in this analysis.
- This analysis was based on a central electrolysis facility with an operating capacity factor of 97%. A facility may be co-sited with the wind turbines and have a lower operating capacity factor. The optimal location and capacity factor were not included in this analysis.

Central Coal with CCS Pathway

- The availability of carbon sequestration sites and the cost of monitoring at and upkeep of those sites were not included in this analysis. A single cost for sequestration was included.

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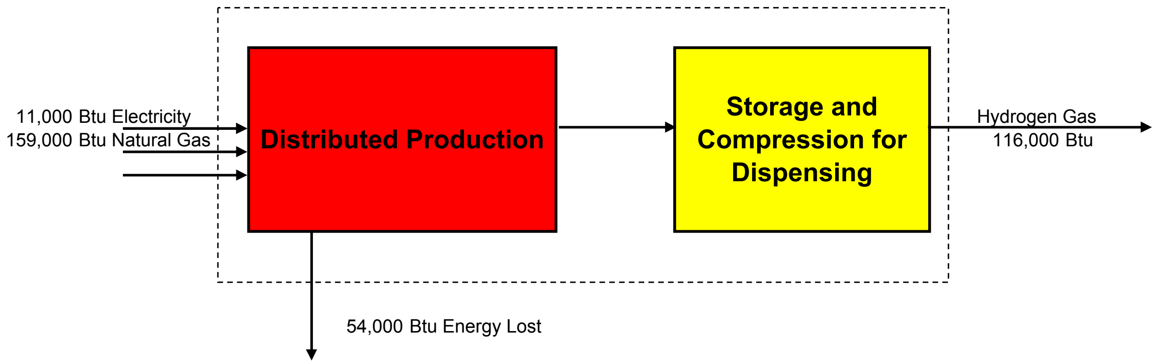
Appendix A — Distributed Natural Gas Supporting Tables and Figures

Table A.1. Worldwide Distributed SMR Hydrogen Fueling Stations

Location	Name	Date Opened
Auburn, CA	PG&E Service Center and Division Office	2004
Chino, CA	Kia-Hyundai America Technical Center	2006
Oakland, CA	AC Transit Oakland	2005
Torrance, CA	Honda Home Energy	2003
Orlando, FL	Orlando International Airport	2006
Selfridge, MI	Selfridge Air National Guard Base (Chevron)	2007
Las Vegas, NV	Las Vegas Energy Station	2002
Latham, NY	Home Energy Station	2004
Topton, PA	East Penn Manufacturing Distribution Center	2007
Austin, TX	University of Texas	2007
Perth, Australia	Sustainable Transport Energy for Perth	2004
Berlin, Germany	Second Clean Energy Partnership Project	2006
Stuttgart, Germany	CUTE Bus Demonstration	2003
Mantova, Italy	AGIP MultiEnergy Public Service Station	2007
Milan, Italy	Milan-Bicocca Project	2004
Nagoya, Japan	Central Japan International Airport	2006
Osaka, Japan	WE-NET Hydrogen Refueling Station	2002
Senju, Japan	Senju Hydrogen Station	2002
Takamatsu, Japan	WE-NET Hydrogen Refueling Station	2002
Tokai, Japan	Toho Gas Research Laboratory	2002
Stavanger, Norway	HyNor Stavangar Hydrogen Station	2006
Porto, Portugal	CUTE Bus Demonstration	2003
Daejeon, S. Korea	Korean Gas Technology Corporation	2006
Madrid, Spain	CUTE Bus Demonstration	2003

Distributed Hydrogen Production



Well-to-Wheels Total Energy Use (Btu/mile)	4,432
Well-to-Wheels Petroleum Energy Use (Btu/mile)	45
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	305
Levelized Cost of H2 at Pump ($/kg)	3.50

Production Process Energy Efficiency	71%
Pathway Efficiency	68%
WTP Efficiency	58%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	30

Case Definition
Year: 2005
Hydrogen as Gas
Forecourt Production
Natural Gas Feedstock
Sequestration: No
Transport for Delivery: None
Vehicle Efficiency: 45.0 mile / GGE
City Hydrogen Use: 344451 kg/day

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Inputs	Graphic Depiction & Assumptions	Outputs

NG Recovery, Processing, & Transport

Inputs

Coal Input from "Well"	322	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	124,113	Btu / 116000Btu to Pump
Petroleum Input from "Well"	497	Btu / 116000Btu to Pump

NG Recovery, Processing, & Transport

NG Recovery Efficiency	97.2%	
NG emitted & combusted during recovery	0.35%	
NG processing energy efficiency	97.2%	
NG emitted & combusted during processin	0.15%	
NG emitted & combusted during transport	0.14	g / MMBtu
NG transport distance	500	miles
Compression Reqs (stages & eff)	average of gas companies	

Outputs

NG Delivery Pressure	Average of gas companies	
NG Quality at Delivery	Average of gas companies	
NG Cost	$0.243	2005 $ / Nm^3
NG Cost	$0.907	2005$ / kg H2 distributed
WTG CO2 Emissions	636	g / 116000Btu to Pump
WTG CH4 Emissions	28	g / 116000Btu to Pump
WTG N2O Emissions	0	g / 116000Btu to Pump
WTG GHG Emissions	1,331	g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Natural Gas consumption	4.5	N m^3/kg H2 produced
Electricity consumption	1.11	kWh / kg H2
Process Water Consumption	5.77	L / kg H2
Electricity price	$0.0816	2005 $/kWh
Total Capital Investment	$1,138,995	2005$
Coal Input from "Well"	6,572	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	47,754	Btu / 116000Btu to Pump
Petroleum Input from "Well"	664	Btu / 116000Btu to Pump

Hydrogen Production

Design Capacity	1,500	kg/day
Capacity factor	85%	
Process energy efficiency	71.3%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	20	years

Outputs

Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	1	
Total capital investment	$2.44	2005$ / annual kg H2 (effective
Electricity cost	$0.09	2005$ / kg H2 produced
Other operating costs	$0.36	2005$ / kg H2 produced
Levelized Cost of Prod (excl feedst	$0.71	2005$ / kg H2 distributed
SMR CO2 Emissions	10,523	g / 116000Btu to Pump
SMR CH4 Emissions	11	g / 116000Btu to Pump
SMR N2O Emissions	0	g / 116000Btu to Pump
SMR GHG Emissions	10,815	g CO2 eq./ 116000 Btu

Compression, Storage, & Dispensing

Inputs

Electricity consumption	1.96	kWh / kg H2
Total Capital Investment	$3,993,763	2005$
Coal Input from "Well"	11,382	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	3,269	Btu / 116000Btu to Pump
Petroleum Input from "Well"	848	Btu / 116000Btu to Pump

Compression, Storage, & Dispensing

Number of Distribution Stations	270	
Energy efficiency	94%	
Number of Compression Stages	6	
Isentropic Efficiency	65%	
Site storage	62%	capacity

Outputs

Hydrogen outlet pressure	6,250	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxyg
Total capital investment	$8.56	2005$ / annual kg H2 (effective
Electricity cost	$0.16	2005$ / kg H2
Levelized Cost of Distribution	$1.88	2005$ / kg H2 distributed
CSD CO2 Emissions	1,502	g / 116000Btu to Pump
CSD CH4 Emissions	2	g / 116000Btu to Pump
CSD N2O Emissions	0	g / 116000Btu to Pump
CSD GHG Emissions	1,558	g CO2 eq./ 116000 Btu

Well-to-Pump Results

Coal Input from "Well"	18,276	Btu / 116000 Btu
Natural Gas Input from "Well"	175,136	Btu / 116000 Btu
Petroleum Input from "Well"	2,009	Btu / 116000 Btu
Fossil Energy Input from "Well"	195,421	Btu / 116000 Btu
WTP CO2 Emissions	12,667	g / 116000 Btu
WTP CH4 Emissions	41	g / 116000 Btu
WTP N2O Emissions	0	g / 116000 Btu
WTP GHG Emissions	13,710	116000 Btu
Levelized Cost of Hydrogen ($/kg)	$3.50	2005 $/ kg

Vehicle

Fuel Economy	45.0	mi / GGE
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%	
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%	
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%	

Well-to-Wheel Results

Coal Input from "Well"	406	Btu / mi
Natural Gas Input from "Well"	3,895	Btu / mi
Petroleum Input from "Well"	45	Btu / mi
Fossil Energy Input from "Well"	4,346	Btu / mi
WTW CO2 Emissions	282	g / mi
WTW CH4 Emissions	1	g / mi
WTW N2O Emissions	0	g / mi
WTW GHG Emissions	305	g / mi
Levelized Cost of Hydrogen ($/mi)	$0.0777	2005 $/mi

Conversion

Coal	6,572	Btu/116000 Btu
Natural Gas	47,754	Btu/116000 Btu
Petroleum	664	Btu/116000 Btu
Total Energy	56,381	Btu/116000 Btu
CO2 Emissions	10,523	g/116000 Btu
CH4 Emissions	11	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	10,815	g/116000 Btu

Distribution

Coal	11,382	Btu/116000 Btu
Natural Gas	3,269	Btu/116000 Btu
Petroleum	848	Btu/116000 Btu
Total Energy	17,910	Btu/116000 Btu
CO2 Emissions	1,502	g/116000 Btu
CH4 Emissions	2	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	1,558	g/116000 Btu

Feedstock

Coal	322	Btu/116000 Btu
Natural Gas	124,113	Btu/116000 Btu
Petroleum	497	Btu/116000 Btu
Total Energy	124,998	Btu/116000 Btu
CO2 Emissions	636	g/116000 Btu
CH4 Emissions	28	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	1,331	g/116000 Btu

Conversion

Compression, Storage, & Dist

Distribution Losses 0.00%

	Total to Deliver 116000 Btu Fuel	Check
Coal	18,276	18,276
Natural Gas	175,136	175,136
Petroleum	2,009	2,009
Total Energy	199,290	199,290
CO2 Emissions	12,661	12,667
CH4 Emissions	41	41
N2O Emissions	0	0
GHG Emissions	13,703	13,710

Parameter	Value	Units	Reference	Comments
Case Definition				
Base Year	2005		None	Default for Dist-SMR Pathway study
Production Technology	Woody Biomass		None	Default for Dist-SMR Pathway study
Form of H2 During Delivery	Liquid		None	Default for Dist-SMR Pathway study
Delivery Mode	Liquid Truck		None	Default for Dist-SMR Pathway study
Forecourt Station Size	1278	kg/day	James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C23
Vehicle Type	passenger cars		None	Default for Dist-SMR Pathway study
Vehicles' Fuel Economy	45.0	mile / gge	Rousseau, A. & Wallner, T. (2008, October 7). *Prospects on Fuel Efficiency Improvements for Hydrogen Powered Vehicles*. Argonne National Laboratory presentation, Chicago, IL. Retreived from http://www.transportation.anl.gov/pdfs/HV/530.pdf	Calculated from data in the presentation. The fuel economy for today's average mid-size vehicle was estimated by the Powertrain Simulation Analysis Toolkit V 6.2 SP1, Summer 2008 (PSAT - http://www.transportation.anl.gov/modeling_simulation/PSAT/index.html). 45 mile/gge is the estimated on-road fuel economy which was determined by multiplying the projected EPA lab-rated fuel economy of 52.5 mile/gge by 0.85.
Market Definition				
City Population	1,247,364	people	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM City Selection; Scenario tab; Indianapolis, IN, cell B9
Market penetration	50%	(% vehicles in city)	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Pla*.	Basis for posture plan
Number of H2 vehicles in city	462,772	H2 vehicles / city	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model*	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 vehicles in city, cell F17
Miles driven per vehicle	12,000	mile / vehicle year	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model*	Key delivery input in HDSAM version 2.02; Scenario tab; Miles driven per year/ vehicle, cell C19
City hydrogen use	344,451	kg / d	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; City H2 daily use, cell F18
Number of H2 refueling stations in city	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 fueling stations in city, cell F19
Number of H2 stations/Number of gasoline stations	41%		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 stations/Number of gasoline stations, cell F2
Average distance between stations (mi)	1.46	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Average distance between stations, cell F22
Feedstock Recovery, Processing, & Transport				
Biomass				
Percentage of Woody Biomass (Remainder is Herbaceous)	100%		Mann, M & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratory	Current central H2A production via biomass gasification version 2.1.2 basis
Biomass Moisture Content	25%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	Page 66
Grams of Nitrogen / short ton biomass	709	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 75 lb N / ac in the maintenance year Year 3 or 4) which is reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre, and harvesting once every 8 years. App 3.1 is for planting on cropland that was used for traditional crops.
Grams of P2O5 / short ton biomass	189	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 20 lb P / ac in the maintenance year (Year 3) which is in the range of 15-50 lb P / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years
Grams of K2O / short ton biomass	331	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 35 lb K / ac in the maintenance year (Year 3) which is in the range of 15-50 lb K / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years)
Grams of herbicide / short ton biomass	24	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 2.0 lb herbicide / ac in the planting year which similar to the 2.0 lb glyphosate / ac reported by De La Torre Ugarte, 2000, App 3.2, assuming 6 dry tons biomass per acre and harvesting once every 8 years. Booth reported Trifluralin (5 L/ha) and Metribuzin (395 g/ha). App 3.2 is for planting on currently idled cropland or cropland that was just used for pasture.
Grams of insecticide / short ton biomass	2	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	As a check, looked at Chastagner: Up to 56% of acreage annually sprayed with Dimethoate (Digon 400, 2-3 pints per acre); up to 56% of acreage annually sprayed with Permethrin 2LB (Ambush, 6.4 ounces per acre); Up to 12% of acreage annually sprayed with Endosulfan 3 EC (24c WA-990025, 2 qts per acre).
Grams of CO2 removed from atmosphere per dry ton woody biomass produced	-112,500	g / dry ton		GREET model default based on ANL personal communications
Average distance from farm to hydrogen production facility	40	miles	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET basis: distance could be limited by transport costs?
Natural Gas				
NG recovery efficiency	97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET uses 97% which is comparable to several other models (Table 4.11)
NG used & lost during recovery	0.35%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET basis
NG processing energy efficiency	97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
NG used & lost during processing	0.15%		Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996) *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.p	Volume lost from EPA/GRI paper and DOE/EIA-0573; future marginal increase is assumed to be less than current average.
NG used & lost during transport	0.14	g / (MM Btu mil)	Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996) *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.p	Volume lost from EPA/GRI paper and DOE/EIA-0573; future marginal increase is assumed to be less than current average.
NG transport distance	500	miles	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET basis
Electricity				
Grid mix for production	US Mix			Default
Biomass Fraction	1.2%		Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Coal Fraction	51.7%		Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Natural Gas Fraction	15.7%		Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Nuclear Fraction	20.3%		Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Residual Oil Fraction	2.9%		Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category

Parameter	Value	Units	Reference	Comments
Others (Carbon Neutral)	8.2%		Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Grid mix for liquefaction with biomass production	US Mix		None	Default for Bio-Liquid Pathway study
Grid mix for liquefaction with coal production	US Mix		None	Default for Bio-Liquid Pathway study
Grid mix for liquefaction with central natural gas production	NGCC		None	Default for Bio-Liquid Pathway study
Grid mix for liquefaction with nuclear production	Nuclear Power		None	Default for Bio-Liquid Pathway study
Grid mix for pipeline compressors	US Mix		None	Default for Bio-Liquid Pathway study
Grid mix for compression at distribution	US Mix		None	Default for Bio-Liquid Pathway study
H2 Production				
CO2 Captured for Sequestration	0%			Not available in this case study
Production Facility Average Output	139,712	kg / facility d (after capacity factor is included)	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Section 3.0. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Design feed rate for current design plant of 2000 bone dry metric tonne biomass per day (see Section 3.0)
Corresponding capacity factor	90%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Operating Capacity Factor, cell C21
Total Capital Investment	$154,644,297	2005 $	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Table 10. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Total installed capital cost of $102M ($2002) (see Table 10, Current Design) was escalated to $2005 dollars. Capital cost for additional compression was removed to maintain consistency with H2A central model assumptions.
Biomass feedstock consumption	12.8	kg (dry) / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Appendex A. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Biomass usage calculated from plant efficiency of 45.6%. The LHV for woody biomass is taken from HyARC, and is high (8406 Btu/lb v. 8060 Btu/lb) than used in Spath. Appendix A - Design Report: Current Case; Hydrogen Yield = 70.4 kg/ dry US ton feedstock
Biomass feedstock cost	$37.96	2005$ / dry short ton	Hess, R., Denney, K., Wright, C., Radtke, C., Perlack, W. (2007, April 18-19). *Cellulosic Biomass Feedstocks for Renewable Bioenergy*. EERE presentation to the National Academy of Sciences Commettee on Resource Needs for Fuel Cell and Hydrogen, Washington, D.C.	Feedstock price is taken from the Biomass Program 2012 Target price of $35/ton ($2002) escalated to $2005
Natural gas feedstock consumption	0.00	normal m^3 / kg H2 produced	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Results tab; Energy Data
Natural Gas feedstock cost	N/A		None	N/A
Natural Gas LHV	34,714	Btu / normal m^3.	Hydrogen Analysis Resource Center. (2008, September 5) *Lower and Higher Heating Values of Hydrogen and Fuels*. Retrieved from http://hydrogen.pnl.gov/cocoon/morf/hydrogen/article/401	LHV of Natural Gas; 983 Btu/ft3
Natural gas utility consumption	0.17	normal m^3 / kg H2 produced	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Appendex A. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Natural gas usage from overall energy balance; Appendix C, A401: stream 427 = 1669 lb/hr; Appendix C, A501: stream 424 = 14260 lb/hr; conversion yields 0.15 (not 0.17)
Natural gas utility price	$0.340	2005$ / Nm^3	Energy Information Administation. (2005, February) *Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	AEO 2005 High A Case - Commercial price; Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Natural gas utility pressure	N/A	kPa	None	Not in H2A or GREET
	#VALUE!	psi	Conversion calculation	conversion calculation
Electricity feedstock consumption	0.00	kWh / kg H2	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Results tab; Energy Data
Electricity utility consumption (both production and compression)	0.98	kWh / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Electricity usage from overall energy balance with energy usage for hydrogen compression (3899 kW) removed. Appendix A, Total Plant Electricity = 5.54 kWh/kg H2 -
Electricity utility consumption (production only)	0.98	kWh / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Electricity usage from overall energy balance with energy usage for hydrogen compression (3899 kW) removed. Appendix A, Total Plant Electricity = 5.54 kWh/kg H2. Electricity consumption reduced in H2A because Spath has hydrogen produ at 360 psi and H2A's standard is 300 psi.
Electricity Utility Price	0.0555	2005 $/kWh	Energy Information Administation. (2005, February) *Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	AEO 2005 High A Case - Industrial price; Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Process Water Consumption	1.32	gal / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Appendix C, A202: stream 218 = 738 lb/hr; Appendix C, A601: stream 620 = 102749 lb/hr; Appendix C, A701: stream 710 = 131921 lb/hr
Water Consumption for Cooling	0.00008	gal / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Assume all make-up water is process water
Electricity co-product production	0.00	kWh / kg H2	None	All electricity co-product used internally
Oxygen co-product production	0.0	kg / kg H2	None	N/A
Steam co-product production	0.0	kg / kg H2	None	N/A
Total Annual Fixed Operating Costs	$10,391,486	2005$ / yr	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Section 9.2. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Section 9.2 Fixed Operating Costs. Costs were escalated from $2002 to $2005 dollars.
Total Annual Variable Operating Costs	$43,162,900	2005$ / yr	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Table 13. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Table 13: Variable Operating Costs. Costs were escalated from $2002 to $2005 dollars.
Total Annual Operating Costs	$53,554,386	2005$ / yr	None	Addtion of Annual Total Fixed Operating Costs and Total Annual Variable Operating Costs
Production energy efficiency (does not include electricity for forecourt compress	46.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - biomass	93.1%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - coal	0.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - natural gas	2.5%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - ethanol	0.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - electricity	4.4%		Calculated from H2A values	Calculated from H2A values

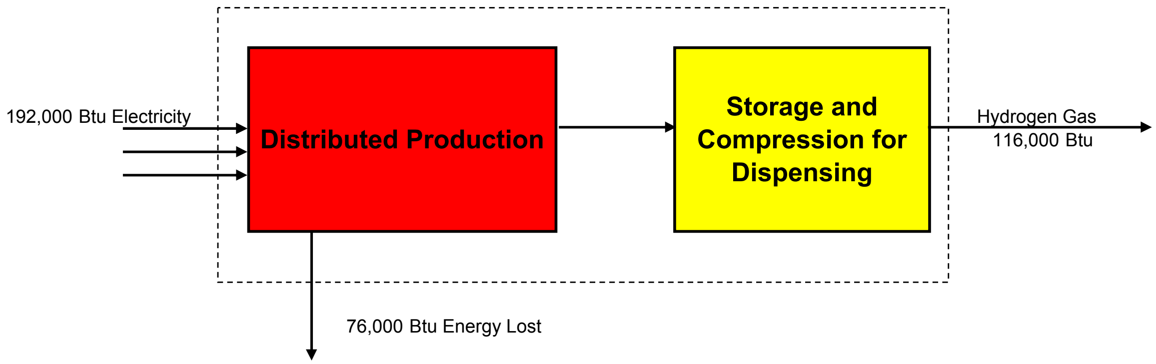
Parameter	Value	Units	Reference	Comments
Hydrogen outlet pressure (before CSD)	300	psi	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Final compression step modeled in the analysis was removed for the H2A case study to maintain consistency with H2A default value. Spath's compression was to 360 psi and H2A standard is 300 psi. Reducing the compression reduced the electricity use.
Hydrogen quality before transport	98 minimum	% H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Page 5, product purity of 99.9 vol%
Financial Parameters				
After-tax Real IRR	10%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; After-tax Real IRR, cell C47
Plant Life	40	years	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Plant life, cell C34
Federal Tax Rate	35.0%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Federal taxes, cell C49
State Tax Rate	6.0%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; State taxes, cell C48
Total Tax Rate	38.9%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Total tax Rate, cell C50
Frection Equity	100%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming* Golden, CO: National Renewable Energy Laboratoty	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Equity Financing, cell C38
Transport, Delivery, and Storage Energy Requirements				
Liquid Truck Delivery				
Hydrogen entering liquefaction	382,396	kg / day	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameters: city selection, market penetration, dispensing rate
Liquefaction electricity requirement	1,136,394,945	kW hr / yr	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Sections 2.2.7.3 and 2.2.7.5. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland (Nexant Report - Sections 2.2.7.3 and 2.2.7.5)
Liquefaction electricity requirement	8.2	kW hr / kg H2	None	Calculation
Hydrogen lost in liquefier	0.5%		Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.2. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland (Nexant Report - Section 2.2.7.2)
Liquefaction efficiency	80.3%		Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.2. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland and Praxair (Nexant Report-Section 2.2.7.2)
Liquefaction System total capital investment	$559,414,686	2005$	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.4. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland and Praxair (Nexant Report - Section 2.2.7.4)
Liquefaction System electricity cost	$60,690,228	2005$ / yr	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.4. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland and Praxair (Nexant Report - Section 2.2.7.4)
Liquefaction System labor cost	$592,895	2005$ / yr	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Liquefaction System total operating cost	$83,647,930	2005$ / yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, H2 Liquifer tab, cell B135: sum of total labor cost, total electricity cost and total other fixed costs
Terminal Storage Design Capacity	3,532,139	kg H2	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Liquid H2 Terminal tab, cell B73: based on liquid storage capacity, terminal average flow
Hydrogen lost in terminal	2.8%		Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report- Section 2.2.14)
Terminal total capital investment	$191,649,060	2005$	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.11.1. DE-FG36-05GO15032.	CB&I (Nexant Report - Section 2.2.11.1)
Terminal electricity cost	$565,492	2005$ / yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Liquid H2 Terminal tab, cell B187: electricity prices are from EIA AEO 2005 and 2007
Terminal labor cost	$588,708	2005$ / yr	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Terminal total operating cost	$8,842,213	2005$ / yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Liquid H2 Terminal tab, cell B201: sum of total labor cost, total electricity cost and total other fixed costs
Truck Payload leaving terminal	4,372	kg / truckload	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.8. DE-FG36-05GO15032.	HDSAM calculation; default value (Nexant Report- Section 2.1.8)
Truck Trips	31,009	per year	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B66: city yearly use(kg)*ref.station.mass efficiency(H2out/H2 in) / H2 delivered per trip (kg)
One-way distance per trip	49	miles / trip (one way)	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B39: distance to the city gate + 1.5 * sqrt(city area)
Diesel for Truck Trips	3,837	m^3 / yr	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.8. DE-FG36-05GO15032.	HDSAM calculation, fuel consumption data from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report - Section 2.1.8)
Hydrogen Losses during loading / transport / unloading	6.1%		Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report- Section 2.2.14)
Hydrogen Losses during liquefaction/loading / transport / unloading	10.08%		Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report- Section 2.2.14)
Truck/trailer total capital investment	$49,000,000	2005$	Nexant, Inc. et al. (2008, May) *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report. DE-FG36-05GO15032.	$625,000 per each tank trailer and $75,00 per each truck cab; recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL
Truck/trailer electricity cost	$0	2005$ / yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation, electricity prices are from EIA AEO 2005 and 2007

Parameter	Value	Units	Reference	Comments
Truck/trailer Diesel cost	$1,692,270	2005$ / yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B116: default milage - 6 mpg; diesel cost data are from E AEO 2005 and 2007
Truck/trailer labor cost	$15,193,193	2005$ / yr	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Truck/trailer total operating cost	$21,691,089	2005$ / yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B137: sum of total labor cost, total fuel cost and total other fixed costs
Distribution Station				
Liquid Receiving/Distributing Stations				
Hydrogen Dispensed at Forecourt Station	465,647	kg / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input: dispensing rate
Electricity Required by Forecourt Station	116,673	kWh / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on pump power requirement (see equation in Design Data tab)
Design Capacity	1,516	kg H2 / day	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.4. DE-FG36-05GO15032.	HDSAM calculation based on Chevron fueling profiles (Nexant Report-Section 2.1.4): = adjusted disp. Rate*(1+summer surge)*(1+Friday surge)
Operating Capacity	1,278	kg H2 / day	James, B.D. (2008, May 23).*Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C23
Capacity Factor	84%		None	Calculation
Site storage (liquid)	6,920	kg H2	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.11.2. DE-FG36-05GO15032.	HDSAM calculation based on number of deliveries per day (Nexant Report-Section 2.2.11.2)
Site storage (gaseous)	453	kg H2	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.3.2.4. DE-FG36-05GO15032.	HDSAM calculation (Nexant Report - Section 2.3.2.4)
Site storage	486%	% of design H2 distribution	None	Calculation
Dispensing Pressure	6,250	psi	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.3.2. DE-FG36-05GO15032.	HDSAM default (see Nexant Report-Section 2.3.2)
Hydrogen Losses due to leaks	1.34%		Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report - Section 2.2.14)
Distribution System total capital investment	$2,073,185	2005$ / station	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.4.2. DE-FG36-05GO15032.	Data from CP Industries, McMaster-Carr, Bechtel, Nexant manufacturer survey, Nexant recommendations (Nexant Rep Section 2.2.4.2)
Distribution System electricity cost	$9,512	2005$ / station yr	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.4.2. DE-FG36-05GO15032.	Data from CP Industries, McMaster-Carr, Bechtel, Nexant manufacturer survey, Nexant recommendations (Nexant Rep Section 2.2.4.2)
Distribution Labor Required	3,951	hr / station yr	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	HDSAM calculation (Nexant Report -Section 2.2.1.3)
Distribution System labor cost	$39,513	2005$ / station yr	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Distribution System total O&M cost	$189,192	2005$ / station yr	Nexant, Inc. et al. (2008, May)*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.2. DE-FG36-05GO15032.	HDSAM calculations (Nexant Report - Section 2.2.1.2)
Other Assumptions for WTW Calculations				
Share of RFG in Total Gasoline Use	100%		U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Pla*.	Basis for posture plan
Type of Oxygenate in RFG	None		U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Pla*.	Basis for posture plan
O2 Content in RFG	0%	wt %	U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Pla*.	Basis for posture plan
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, page 197: vehicles within the same weight class have similar tire and brake wear emissions
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (2008, September 5).*The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory	GREET default:well-known fuel cell emissions (no PM2.5)
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (2008, September 5).*The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory	GREET default:reasonable to assume FCV has same driving pattern as GV
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Result*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Marginal Electricity Generation Mix for Transportation Use	US Mix		U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Pla*.	Basis for posture plan
Results				
Levelized Cost	$4.88	$ / kg	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Coal Input	100	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results

Parameter	Value	Units	Reference	Comments
WTW Natural Gas Input	3,911	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Petroleum Input	249	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Fossil Energy Input	2,044	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Total Energy Input	8,170	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CO2 Emissions	151	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CH4 Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW N2O Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW GHG Emissions	160	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-4479 Golden, CO: National Renewable Energy Laboratory.	MSM Results

Appendix B — Distributed Electrolysis Supporting Tables and Figures

Distributed Hydrogen Production



Well-to-Wheels Total Energy Use (Btu/mile)	11,310
Well-to-Wheels Petroleum Energy Use (Btu/mile)	536
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	984
Levelized Cost of H2 at Pump ($/kg)	6.05

Production Process Energy Efficiency	62%
Pathway Efficiency	60%
WTP Efficiency	23%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	98

Case Definition
Year: 2005
Hydrogen as Gas
Forecourt Production
Electrolysis Feedstock
Sequestration: No
Transport for Delivery: None
Vehicle Efficiency: 45.0 mile / GGE
City Hydrogen Use: 344451 kg/day

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Inputs		Graphic Depiction & Assumptions		Outputs	
		Electrolysis Electricity Generation & Transport Includes Resource Recovery, Processing, & Transport			
		Grid Mix			
		Biomass Fraction	1.20%	Electricity Cost	$0.055 2005 $ / kWh
		Coal Fraction	51.70%	Electricity Cost	$2.804 2005$ / kg H2 distributed
		Natural Gas Fraction	15.70%		
		Nuclear Fraction	20.30%	WTG CO2 Emissions	41,009 g / 116000Btu to Pump
Coal Input from "Well"	310,710 Btu / 116000Btu to Pump	Residual Oil Fraction	2.90%	WTG CH4 Emissions	54 g / 116000Btu to Pump
Natural Gas Input from "Well"	89,250 Btu / 116000Btu to Pump	Others (Carbon Neutral)	8.20%	WTG N2O Emissions	1 g / 116000Btu to Pump
Petroleum Input from "Well"	23,152 Btu / 116000Btu to Pump			WTG GHG Emissions	42,520 g CO2 eq./ 116000 Btu
Natural Gas consumption	0.0 N m^3/kg H2 produced			Hydrogen Output Pressure	435 psi
Electricity consumption	53.48 kWh / kg H2	**Hydrogen Production**		Hydrogen Outlet Quality	1
Process Water Consumption	2.94 L / kg H2				
		Design Capacity	1,500 kg/day	Total capital investment	$5.87 2005$ / annual kg H2 (effective
		Capacity factor	85%	Other operating costs	$0.60 2005$ / kg H2 produced
		Process energy efficiency	62.3%	Levelized Cost of Prod (excl feedst	$1.42 2005$ / kg H2 distributed
Total Capital Investment	$2,738,292 2005$	After-tax IRR	10%		
		Assumed Plant Life	20		
				SMR CO2 Emissions	0 g / 116000Btu to Pump
Coal Input from "Well"	0 Btu / 116000Btu to Pump			SMR CH4 Emissions	0 g / 116000Btu to Pump
Natural Gas Input from "Well"	0 Btu / 116000Btu to Pump			SMR N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	0 Btu / 116000Btu to Pump			SMR GHG Emissions	0 g CO2 eq./ 116000 Btu
Electricity consumption	1.73 kWh / kg H2			Hydrogen outlet pressure	6,250 psi
		Compression, Storage, & Dispensing		Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxyg
				Total capital investment	$8.55 2005$ / annual kg H2 (effective
		Number of Distribution Stations	270	Electricity cost	$0.10 2005$ / kg H2
Total Capital Investment	$3,989,011 2005$	Energy efficiency	95%		
		Number of Compression Stages	5	Levelized Cost of Distribution	$1.82 2005$ / kg H2 distributed
		Isentropic Efficiency	65%		
		Site storage	62% capacity	CSD CO2 Emissions	1,647 g / 116000Btu to Pump
Coal Input from "Well"	12,477 Btu / 116000Btu to Pump			CSD CH4 Emissions	2 g / 116000Btu to Pump
Natural Gas Input from "Well"	3,584 Btu / 116000Btu to Pump			CSD N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	930 Btu / 116000Btu to Pump			CSD GHG Emissions	1,707 g CO2 eq./ 116000 Btu

Well-to-Pump Results

Coal Input from "Well"	323,186 Btu / 116000 Btu
Natural Gas Input from "Well"	92,834 Btu / 116000 Btu
Petroleum Input from "Well"	24,082 Btu / 116000 Btu
Fossil Energy Input from "Well"	440,102 Btu / 116000 Btu
WTP CO2 Emissions	42,684 g / 116000 Btu
WTP CH4 Emissions	56 g / 116000 Btu
WTP N2O Emissions	1 g / 116000 Btu
WTP GHG Emissions	44,256 116000 Btu
Levelized Cost of Hydrogen ($/kg)	$6.05 2005 $/ kg

Vehicle	
Fuel Economy	45.0 mi / GGE
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%

Well-to-Wheel Results

Coal Input from "Well"	7,187 Btu / mi
Natural Gas Input from "Well"	2,065 Btu / mi
Petroleum Input from "Well"	536 Btu / mi
Fossil Energy Input from "Well"	9,788 Btu / mi
WTW CO2 Emissions	949 g / mi
WTW CH4 Emissions	1 g / mi
WTW N2O Emissions	0 g / mi
WTW GHG Emissions	984 g / mi
Levelized Cost of Hydrogen ($/mi)	$0.1344 2005 $/mi

Distribution

Coal	12,477	Btu/116000 Btu
Natural Gas	3,584	Btu/116000 Btu
Petroleum	930	Btu/116000 Btu
Total Energy	19,633	Btu/116000 Btu
CO2 Emissions	1,647	g/116000 Btu
CH4 Emissions	2	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	1,707	g/116000 Btu

Feedstock

Coal	310,710	Btu/116000 Btu
Natural Gas	89,250	Btu/116000 Btu
Petroleum	23,152	Btu/116000 Btu
Total Energy	488,927	Btu/116000 Btu
CO2 Emissions	41,009	g/116000 Btu
CH4 Emissions	54	g/116000 Btu
N2O Emissions	1	g/116000 Btu
GHG Emissions	42,520	g/116000 Btu

Conversion

Compression, Storage, & Dist

Distribution Losses 0.00%

	Total to Deliver 116000 Btu Fuel	Check
Coal	323,186	323,186
Natural Gas	92,834	92,834
Petroleum	24,082	24,082
Total Energy	508,560	508,560
CO2 Emissions	42,656	42,684
CH4 Emissions	56	56
N2O Emissions	1	1
GHG Emissions	44,228	44,256

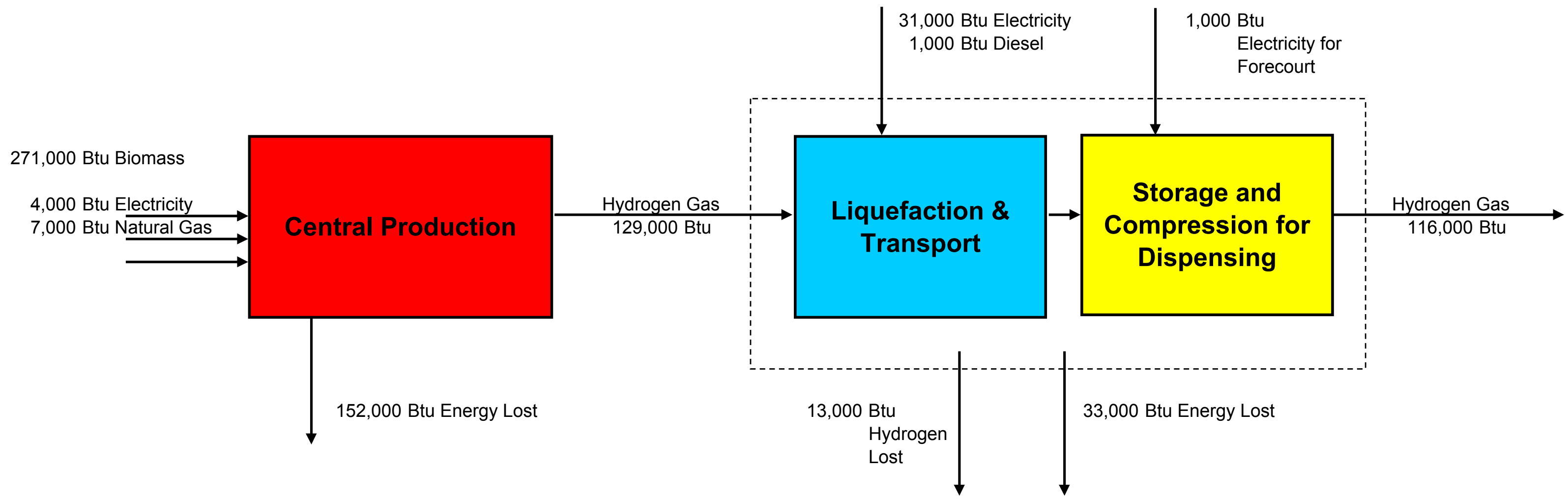
Parameter	Value	Units	Referenced Value	Reference	Comments
Case Definition					
Base Year	2005		2005	None	Default for Dist-Elec Pathway study
Production Technology	Electrolysis		Woody Biomass	None	Default for Dist-Elec Pathway study
Form of H2 During Delivery	Gas		Gas	None	Default for Dist-Elec Pathway study
Delivery Mode	None		Pipeline	None	Default for Dist-Elec Pathway study
Forecourt Station Size	1278	kg/day	1278	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Plant Output, cell C23
Vehicle Type	passenger cars		passenger cars	None	Default for Dist-Elec Pathway study
Vehicles' Fuel Economy	45.0	mile / gge	45.0	Rousseau, A. & Wallner, T. (2008, October 7). *Prospects on Fuel Efficiency Improvements for Hydrogen Powered Vehicles*. Argonne National Laboroatory presentation, Chicago, IL. Retreived from http://www.transportation.anl.gov/pdfs/HV/530.pdf	Calculated from data in the presentation. The fuel economy for today's average mid-size vehicle was estimated by the Powertrain Simulation Analysis Toolkit V 6.2 SP1, Summer 2008 (PSAT - http://www.transportation.anl.gov/modeling_simulation/PSAT/index.html). 45 mile/gge is the estimated on-road fuel economy which was determined by multiplying the projected EPA lab-rated fuel economy of 52.5 mile/gge by 0.85.
Market Definition					
City Population	1,247,364	people	1,247,364	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM City Selection; Scenario tab; Indianapolis, IN, cell B9
Market penetration	50%	(% vehicles in city)	50%	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*.	Basis for posture plan
Number of H2 vehicles in city	462,772	H2 vehicles / city	462,772	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 vehicles in city, cell F17
Miles driven per vehicle	12,000	mile / vehicle year	12,000	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Key delivery input in HDSAM version 2.02; Scenario tab; Miles driven per year/ vehicle, cell C19
City hydrogen use	344,451	kg / d	344,451	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; City H2 daily use, cell F18
Number of H2 refueling stations in city	270		270	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 fueling stations in city, cell F19
Number of H2 stations/Number of gasoline stations	41%		41%	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 stations/Number of gasoline stations, cell F21
Average distance between stations (mi)	1.46	miles	1.46	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Average distance between stations, cell F22
Feedstock Recovery, Processing, & Transport					
Electricity					
Grid mix for production	US Mix		US Mix	None	Default for Dist-Elec Pathway study
Biomass Fraction	1.2%		1.2%	Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htm	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Coal Fraction	51.7%		51.7%	Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htm	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Natural Gas Fraction	15.7%		15.7%	Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htm	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Nuclear Fraction	20.3%		20.3%	Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htm	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Residual Oil Fraction	2.9%		2.9%	Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htm	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Others (Carbon Neutral)	8.2%		8.2%	Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htm	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
H2 Production					
Production Facility Average Output	1,278	kg / facility d (after capacity factor is included)	1,278	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory. And Nexant, Inc. et al. (2008, May). H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results. Interim Report Section 2.1.5. DE-FG36-05GO15032	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Plant Output, cell C23. Calculated based on 1500kg/day and capacity factor; Nexant report only looks filling station, not production, but in forecourt is linked, so daily production related to daily dispensing profile.
Corresponding capacity factor	85%		85%	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Plant Design Capacity, cell C21
Total Capital Investment (both production and CSD)	$6,727,303	2005 $	$6,727,303	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Sum of row 63 and row 227
Total Capital Investment (production only)	$2,738,292		2,738,292	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Total Capital Costs, cell C71
Electricity feedstock consumption	53.48	kWh / kg H2	53.48	None	62% Efficiency on LHV basis from Norsk Hydro Quote
Electricity Feedstock Price (if Industrial Electricity is used)	$0.0555	2005 $/kWh	$0.0555	Energy Information Administation. (2005, February). *Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	Industrial electricity price from AEO 2005 "High A" case for startup year (2005). Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Electricity utility consumption (both production and compression)	1.73	kWh / kg H2	1.73	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory. And Nexant, Inc. et al. (2008, May). H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results. Interim Report Section 2.2.5. DE-FG36-05GO15032	Compression elec use based on H2A Delivery Components and H2A Delivery Scenario Analysis Model, using onsite H2 production, default compressor values are from Nexant, et al, (2008), section 2.2.5
Electricity utility consumption (production only)	0.00	kWh / kg H2	0.00	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	All electricity for production is considered "feedstock." Current central H2A production from grid electrolysis basis version 2.1.2; Results tab; Energy Data
Process Water Consumption	2.94	gal / kg H2	2.94	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Cell D134. Value from Norsk Hydro Quote (2002) 1L per Nm3 H2 At 89.9 g H2/Nm3 and 3.785L/gal, this equals 2.939 gal/kg
Water Consumption for Cooling	0.10832	gal / kg H2	0.11	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Cell D136; ASPEN modeling - see ProcessFlow sheet for details (Mike Penev) in Ramsden, 2008.
Compressed Inert Gas	0.023	Nm^3 / kg H2	0.023	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Cell D138
Total Annual Fixed Operating Costs	$183,949	2005$ / yr	$183,949	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	
Total Annual Variable Operating Costs	$1,404,888	2005$ / yr	$1,404,888	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	
Total Annual Operating Costs	$1,588,838	2005$ / yr	$1,588,838	None	Total Annual Fixed Operating Costs plus Total Annual Variable Operating Cost
Production energy efficiency (does not include electricity for forecourt compress	62.3%		62.3%	Calculated from H2A values	Calculated from H2A values based on Electricity requirement which was stated in Norsk Hydro Quote
Share of process fuel - biomass	0.0%		0.0%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - coal	0.0%		0.0%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - natural gas	100.0%		100.0%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - ethanol	0.0%		0.0%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - electricity	0.0%		0.0%	Calculated from H2A values	Calculated from H2A values

Parameter	Value	Units	Referenced Value	Reference	Comments
Hydrogen outlet pressure (before CSD)	435	psi	435	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Final compression step modeled in the analysis was removed for the H2A case study to maintain consistency with H2A default value.
Hydrogen quality before transport	99.990%	% H2	99.990%	D. Steward (personal communication).	
Financial Parameters					
After-tax Real IRR	10%		10%	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; After-tax Real IRR, cell C47
Plant Life	20	years	40	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Plant life, cell C34
Federal Tax Rate	35.0%		35.0%	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Federal taxes, cell C49
State Tax Rate	6.0%		6.0%	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; State taxes, cell C48
Total Tax Rate	38.9%		38.9%	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Total tax Rate, cell C50
Frection Equity	100%		100%	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Input_Sheet_Template tab; Equity Financing, cell C38
Distribution Station					
Distribution Stations for Forecourt Production					
Compressor Efficiency at Forecourt production stations	94.8%		94.8%	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; cell B41 includes hydrogen loss. This calculation only includes electricity
Electricity Required by Forecourt Station	808,030	kWh / station year	808,030	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; cell B212
Electricity required for forecourt compressors	1.73	kWh / kg H2	1.96	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; cell B213 divided by B212
Number of Compressor Stages	5	Stages in compressor	4	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; Number of Stages, cell B205
Compressor Isentropic Efficiency	65%		65%	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; cell B88
Site storage (Low Pressure - includes heel)	472	kg H2	472	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM calculation, see description in Nexant Report - Section 2.2.3. Case study includes storage for supplying compressor suction side to meet hourly demand (including heel) + 14 hrs of storage based on daily demand for unplanned outages.
Site storage (Cascade)	325	kg H2	325	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.3.2.4. DE-FG36-05GO15032.	HDSAM calculations, see description in Nexant Report - Section 2.3.2.4
Site storage	62%	% of design H2 distribution per day	62%	Calculation	Calculation of total storage (LP + cascade) divided by design hydrogen distribution per da
Dispensing Pressure	6,250	psi	6,250	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM default, see Nexant Report - Section 2.3.2
Hydrogen Losses due to leaks in forecourt production station	0.50%		0.00%	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; Hydrogen Lost During Compression, cell B90
Distribution System total capital investment	$3,989,011	2005 $ / station	$3,993,763	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; Total Capital Investment, cell B162
Distribution System electricity cost	$44,770	2005$ / station yr	$74,512	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; Yearly energy cost, cell F35
Distribution Labor Required	3,958	hr / station yr	3,951	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory	Current forecourt H2A production from grid electrolysis basis version 2.1.2; Refueling Station tab; Labor Cost, cell B166
Distribution System labor cost	$39,583	2005$ / station yr	$39,513	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics, Nexant Report - Section 2.2.1.3
Distribution System total O&M cost	$215,265	2005$ / station yr	$215,353	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.2. DE-FG36-05GO15032.	HDSAM calculations, see recommendations in Nexant Report -Section 2.2.1.2
Other Assumptions for WTW Calculations					
Share of RFG in Total Gasoline Use	100%		100%	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Type of Oxygenate in RFG	None		None	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
O2 Content in RFG	0%	wt %	0%	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		100%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, page 197: vehicles within the same weight class have similar tire and brake wear emissions
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory	GREET default:well-known fuel cell emissions (no PM2.5)
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		100%	Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory	GREET default:reasonable to assume FCV has same driving pattern as GV
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Marginal Electricity Generation Mix for Transportation Use	US Mix		US Mix	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Results					
Levelized Cost	$6.05	$ / kg	$6.05	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Coal Input	7,187	Btu / mile	7,187	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Natural Gas Input	2,065	Btu / mile	2,065	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results

Parameter		Value	Units	Referenced Value	Reference	Comments
WTW Petroleum Input		536	Btu / mile	536	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Fossil Energy Input		9,788	Btu / mile	9,788	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Total Energy Input		11,310	Btu / mile	11,310	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CO2 Emissions		949	g / mile	949	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CH4 Emissions		1	g / mile	1	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW N2O Emissions		0	g / mile	0	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW GHG Emissions		984	g / mile	984	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results

Appendix C — Biomass–Liquid Truck Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Liquid via Truck



Known Issue: Forecourt electricity in HDSAM but not in GREET

Well-to-Wheels Total Energy Use (Btu/mile)	8,170
Well-to-Wheels Petroleum Energy Use (Btu/mile)	249
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	160
Levelized Cost of H2 at Pump ($/kg)	4.88

Production Process Energy Efficiency	46%
Pathway Efficiency	37%
WTP Efficiency	32%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	16

Case Definition
Year: 2005
Hydrogen as Liquid
Central Production
Woody Biomass Feedstock
Sequestration: No
Transport for Delivery: Liquid Truck
Vehicle Efficiency: 45.0 mile / GGE
City Hydrogen Use: 344451 kg/day

R090219B_Figure.xls

Inputs / Graphic Depiction & Assumptions / Outputs

Biomass Production & Delivery

Inputs

Coal Input from "Well"	269	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	427	Btu / 116000Btu to Pump
Petroleum Input from "Well"	2,832	Btu / 116000Btu to Pump

Biomass Production & Delivery

Fraction of Woody Biomass (Remaining is Herbaceous)	100%	
Grams of Nitrogen / dry ton biomass	709	
Grams of P2O5 / dry ton biomass	189	
Grams of K2O / dry ton biomass	331	
Herbicide use	24	g / dry ton
Insecticide use	2	g / dry ton
Average dist from farm to H2 production	40	miles

Outputs

Biomass moisture content	25%	
Woody biomass LHV	16,811,019	Btu / dry ton
Biomass price at H2 production	$37.96	2005 $ / dry ton
Levelized Cost of Biomass	$0.61	2005$ / kg H2 distributed
WTG CO2 Emissions	-26,911	g / 116000Btu to Pump
WTG CH4 Emissions	0	g / 116000Btu to Pump
WTG N2O Emissions	0	g / 116000Btu to Pump
WTG GHG Emissions	-26,867	g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Biomass consumption	12.8	kg (dry) / kg H2 produced
Natural gas consumption	0.17	N m^3/kg H2 produced
Electricity consumption	0.98	kWh / kg H2
Process Water Consumption	5.00	L / kg H2
Natural gas price	$0.340	2005$ / N m^3
Electricity price	$0.0555	2005 $/kWh
Total Capital Investment	$154,644,297	2005$
Coal Input from "Well"	6,356	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	9,009	Btu / 116000Btu to Pump
Petroleum Input from "Well"	3,570	Btu / 116000Btu to Pump

Hydrogen Production

Central plant design capacity	155,236	kg/day
Capacity factor	90%	
Process energy efficiency	46.0%	
Electricity Mix	US Mix	
After-tax IRR	0	
Assumed Plant Life	40	

Outputs

Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	98	minimum
Total capital investment	$3.03	2005$ / annual kg H2 (effective
Levelized Electricity cost	$0.05	2005$ / kg H2 produced
Levelized Natural Gas Cost	$0.06	2005$ / kg H2 produced
Levelized Other operating costs	$0.32	2005$ / kg H2 produced
Levelized Cost of Prod (excl feedst	$1.18	2005$ / kg H2 distributed
SMR CO2 Emissions	26,979	g / 116000Btu to Pump
SMR CH4 Emissions	3	g / 116000Btu to Pump
SMR N2O Emissions	0	g / 116000Btu to Pump
SMR GHG Emissions	27,091	g CO2 eq./ 116000 Btu

Liquefaction and Truck-Delivery

Inputs

Liquefaction electricity consumption	8.2	kWh / kg H2
Diesel consumption	7.3	gal / 1000 kg H2
Total Capital Investment	$800,063,746	
Coal Input from "Well"	50,184	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	14,462	Btu / 116000Btu to Pump
Petroleum Input from "Well"	4,778	Btu / 116000Btu to Pump

Liquefaction and Truck-Delivery

City Population	1,247,364	people
Hydrogen Vehicle Penetration	50%	
City hydrogen use	125,810,766	kg / yr
Liquefaction efficiency	80.3%	
Terminal Design Capacity	3,532,139	kg H2
Number of truck-trips required	31,009	per year
Truck hydrogen capacity	4,372	kg / truckload
One-way distance for delivery	49	miles
Hydrogen losses	10.1%	

Outputs

Total capital investment	$6.37	2005$/annual kg delivered
Levelized Electricity cost	$0.49	2005$ / kg H2 delivered
Levelized Diesel cost	$0.01	2005$ / kg H2 delivered
Levelized Labor cost	$0.13	2005$ / kg H2 delivered
Levelized Other operating costs	$0.28	2005$ / kg H2 delivered
Levelized Cost of Distribution	$2.04	2005$ / kg H2 distributed
Delivery CO2 Emissions	6,708	g / 116000Btu to Pump
Delivery CH4 Emissions	9	g / 116000Btu to Pump
Delivery N2O Emissions	0	g / 116000Btu to Pump
Delivery GHG Emissions	6,955	g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs

Electricity consumption	3.04	kWh / kg H2
Electricity price	$0.082	2005$ / kWh
Coal Input from "Well"	0	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	0	Btu / 116000Btu to Pump
Petroleum Input from "Well"	0	Btu / 116000Btu to Pump

Forecourt Distribution

Number of Distribution Stations	270	
Energy efficiency	92%	
Number of Compression Steps	4	
Isentropic Efficiency	65%	
Site storage	52%	capacity
Hydrogen losses	0.50%	
Hydrogen loss factor	1.005	

Outputs

Hydrogen outlet pressure	6,250	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxyg
Total capital investment	$5.85	2005$/annual kg
Levelized Electricity cost	$0.25	2005$ / kg H2
Levelized Cost of Distribution	$1.05	2005$ / kg H2 distributed
CSD CO2 Emissions	0	g / 116000Btu to Pump
CSD CH4 Emissions	0	g / 116000Btu to Pump
CSD N2O Emissions	0	g / 116000Btu to Pump
CSD GHG Emissions	0	g CO2 eq./ 116000 Btu

Well-to-Pump Results

Coal Input from "Well"	56,809	Btu / 116000 Btu
Natural Gas Input from "Well"	23,898	Btu / 116000 Btu
Petroleum Input from "Well"	11,180	Btu / 116000 Btu
Fossil Energy Input from "Well"	91,887	Btu / 116000 Btu
WTP CO2 Emissions	58,489	g / 116000 Btu
WTP CH4 Emissions	101	g / 116000 Btu
WTP N2O Emissions	3	g / 116000 Btu
WTP GHG Emissions	61,963	116000 Btu
Levelized Cost of Hydrogen ($/kg)	$4.88	2005 $/ kg

Vehicle

Fuel Economy	45.0	mi / GGE
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%	
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%	
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%	

Well-to-Wheel Results

Coal Input from "Well"	100	Btu / mi
Natural Gas Input from "Well"	3,911	Btu / mi
Petroleum Input from "Well"	249	Btu / mi
Fossil Energy Input from "Well"	2,044	Btu / mi
WTW CO2 Emissions	151	g / mi
WTW CH4 Emissions	0	g / mi
WTW N2O Emissions	0	g / mi
WTW GHG Emissions	160	g / mi
Levelized Cost of Hydrogen ($/mi)	$0.1086	2005 $/mi

Basis	**116000**	**Btu**

Gasification

Coal	6,356	Btu/mmBtu
Natural Gas	9,009	Btu/mmBtu
Petroleum	3,570	Btu/mmBtu
CO2 Emissions	26,979	g/mmBtu
CH4 Emissions	3	g/mmBtu
N2O Emissions	0	g/mmBtu
GHG Emissions	27,091	g/mmBtu

Liquefaction

Coal	50,159	Btu/mmBtu
Natural Gas	14,408	Btu/mmBtu
Petroleum	3,735	Btu/mmBtu
CO2 Emissions	6,620	g/mmBtu
CH4 Emissions	9	g/mmBtu
N2O Emissions	0	g/mmBtu
GHG Emissions	6,864	g/mmBtu

Transport

Coal	26	Btu/mmBtu
Natural Gas	54	Btu/mmBtu
Petroleum	1,042	Btu/mmBtu
CO2 Emissions	88	g/mmBtu
CH4 Emissions	0	g/mmBtu
N2O Emissions	0	g/mmBtu
GHG Emissions	91	g/mmBtu

Storage

Coal	0	Btu/mmBtu
Natural Gas	0	Btu/mmBtu
Petroleum	0	Btu/mmBtu
CO2 Emissions	0	g/mmBtu
CH4 Emissions	0	g/mmBtu
N2O Emissions	0	g/mmBtu
GHG Emissions	0	g/mmBtu

Feedstock

Coal	269	Btu/mmBtu
Natural Gas	427	Btu/mmBtu
Petroleum	2,832	Btu/mmBtu
CO2 Emissions	-26,911	g/mmBtu
CH4 Emissions	0	g/mmBtu
N2O Emissions	0	g/mmBtu
GHG Emissions	-26,867	g/mmBtu

Gasification & Conversion → **Liquefaction** (Liquefaction Losses 0.50%) → **Transport** (Transport Losses 1.28%) → **Storage** (Storage Losses 4.06%) →

Total to Deliver 116000 Btu Fuel		Check
Coal	56,809	56,809
Natural Gas	23,898	23,898
Petroleum	11,180	11,180
CO2 Emissions	6,776	6,785
CH4 Emissions	12	12
N2O Emissions	0	0
GHG Emissions	7,179	7,188

Parameter	Value	Units	Referenced Value	Reference	Comments
Case Definition					
Base Year	2005		2005	None	Default for Dist-SMR Pathway study
Production Technology	Woody Biomass		Woody Biomass	None	Default for Dist-SMR Pathway study
Form of H2 During Delivery	Liquid		Gas	None	Default for Dist-SMR Pathway study
Delivery Mode	Liquid Truck		Pipeline	None	Default for Dist-SMR Pathway study
Forecourt Station Size	1278	kg/day	1278	James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C23
Vehicle Type	passenger cars		passenger cars	None	Default for Dist-SMR Pathway study
Vehicles' Fuel Economy	45.0	mile / gge	45.0	Rousseau, A. & Wallner, T. (2008, October 7). *Prospects on Fuel Efficiency Improvements for Hydrogen Powered Vehicles*. Argonne National Laboroatory presentation, Chicago, IL. Retreive from http://www.transportation.anl.gov/pdfs/HV/530.pdf	Calculated from data in the presentation. The fuel economy for today's average mid-size vehicle was estimated by the Powertrain Simulation Analysis Toolkit V 6.2 SP1, Summer 2008 (PSAT - http://www.transportation.anl.gov/modeling_simulation/PSAT/index.html). 45 mile/gge is the estimated on-road fuel economy which was determined by multiplying the projected EPA lab-rated fuel economy of 52.5 mile/gge by 0.85.
Market Definition					
City Population	1,247,364	people	1,247,364	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM City Selection; Scenario tab; Indianapolis, IN, cell B9
Market penetration	50%	(% vehicles in city)	50%	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Number of H2 vehicles in city	462,772	H2 vehicles / city	462,772	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model*	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 vehicles in city, cell F17
Miles driven per vehicle	12,000	mile / vehicle year	12,000	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model*	Key delivery input in HDSAM version 2.02; Scenario tab; Miles driven per year/ vehicle, cell C19
City hydrogen use	344,451	kg / d	267,247	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	Demand calculation by HDSAM version 2.02; Scenario tab; City H2 daily use, cell F18
Number of H2 refueling stations in city	270		210	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 fueling stations in city, cell F19
Number of H2 stations/Number of gasoline stations	41%		32%	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 stations/Number of gasoline stations, cell F21
Average distance between stations (mi)	1.46	miles	1.65	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	Demand calculation by HDSAM version 2.02; Scenario tab; Average distance between stations, cell F22
Feedstock Recovery, Processing, & Transport					
Biomass					
Percentage of Woody Biomass (Remainder is Herbaceous)	100%		100%	Mann, M & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratory	Current central H2A production via biomass gasification version 2.1.2 basis
Biomass Moisture Content	25%		25%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	Page 66
Grams of Nitrogen / short ton biomass	709	g / dry ton	709	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 75 lb N / ac in the maintenance year Year 3 or 4) which is reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre, and harvesting once every 8 years. App 3.1 is for planting on cropland that was just used for traditional crops.
Grams of P2O5 / short ton biomass	189	g / dry ton	189	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 20 lb P / ac in the maintenance year (Year 3) which is in the range of 15-50 lb P / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years
Grams of K2O / short ton biomass	331	g / dry ton	331	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 35 lb K / ac in the maintenance year (Year 3) which is in the range of 15-50 lb K / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years)
Grams of herbicide / short ton biomass	24	g / dry ton	24	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	Equivalent to 2.0 lb herbicide / ac in the planting year which similar to the 2.0 lb glyphosate / ac reported by De La Torre Ugarte, 2000, App 3.2, assuming 6 dry tons biomass per acre and harvesting once every 8 years. Booth reported Trifluralin (5 L/ha) and Metribuzin (395 g/ha). App 3.2 is for planting on currently idled cropland or cropland that was just used for pasture.
Grams of insecticide / short ton biomass	2	g / dry ton	2	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh 1998).	As a check, looked at Chastagner: Up to 56% of acreage annually sprayed with Dimethoate (Digon 400, 2-3 pints per acre); up to 56% of acreage annually sprayed with Permethrin 2LB (Ambush, 6.4 ounces per acre); Up to 12% of acreage annually sprayed with Endosulfan 3 EC (24c WA-990025, 2 qts per acre).
Grams of CO2 removed from atmosphere per dry ton woody biomass produced	-112,500	g / dry ton	-112,500		
Average distance from farm to hydrogen production facility	40	miles	40	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET basis: distance could be limited by transport costs?
Natural Gas					
NG recovery efficiency	97.2%			Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET uses 97% which is comparable to several other models (Table 4.11)
NG used & lost during recovery	0.35%			Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET basis
NG processing energy efficiency	97.2%			Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET uses 97.5% which is comparable to several other models (Table 4.11)
NG used & lost during processing	0.15%			Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996). *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.pdf	Volume lost from EPA/GRI paper and DOE/EIA-0573; future marginal increase is assumed to be less than current average.
NG used & lost during transport	0.14	g / (MM Btu mil)		Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996). *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.pdf	Volume lost from EPA/GRI paper and DOE/EIA-0573; future marginal increase is assumed to be less than current average.
NG transport distance	500	miles		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET basis
Electricity					
Grid mix for production	US Mix		US Mix		Default
Biomass Fraction	1.2%		1.2%	Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Coal Fraction	51.7%		51.7%	Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Natural Gas Fraction	15.7%		15.7%	Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Nuclear Fraction	20.3%		20.3%	Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Residual Oil Fraction	2.9%		2.9%	Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Others (Carbon Neutral)	8.2%		8.2%	Annual Energy Outlook 2007 -- www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Grid mix for liquefaction with biomass production	US Mix		US Mix	None	Default for Bio-Liquid Pathway study
Grid mix for liquefaction with coal production	US Mix		US Mix	None	Default for Bio-Liquid Pathway study
Grid mix for liquefaction with central natural gas production	NGCC		NGCC	None	Default for Bio-Liquid Pathway study
Grid mix for liquefaction with nuclear production	Nuclear Power		Nuclear Power	None	Default for Bio-Liquid Pathway study
Grid mix for pipeline compressors	US Mix		US Mix	None	Default for Bio-Liquid Pathway study

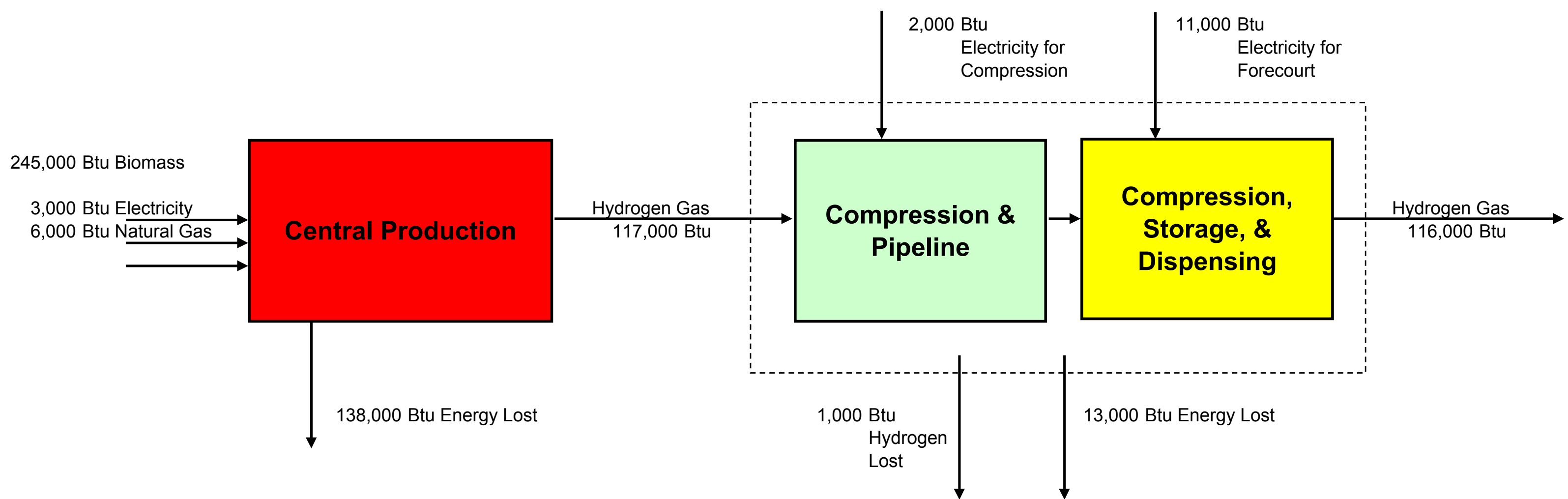
Parameter	Value	Units	Referenced Value	Reference	Comments
Grid mix for compression at distribution	US Mix		US Mix	None	Default for Bio-Liquid Pathway study
H2 Production					
CO2 Captured for Sequestration	0%		0%		Not available in this case study
Production Facility Average Output	139,712	kg / facility d (after capacity factor is included)	139,712	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Section 3.0. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Design feed rate for current design plant of 2000 bone dry metric tonne biomass per day (see Section 3.0)
Corresponding capacity factor	90%		90%	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Operating Capacity Facto cell C21
Total Capital Investment	$154,644,297	2005 $	$154,644,297	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Table 10. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Total installed capital cost of $102M ($2002) (see Table 10, Current Design) was escalated to $2005 dollars. Capital cost for additional compression was removed to maintain consistency with H2A central model assumptions.
Biomass feedstock consumption	12.8	kg (dry) / kg H2	12.8	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Appendex A. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Biomass usage calculated from plant efficiency of 45.6%. The LHV for woody biomass is taken from HyARC, and is higher (8406 Btu/lb v. 8060 Btu/lb) than used in Spath. Appendix A - Design Report: Current Case; Hydrogen Yield = 70.4 kg/ dry US ton feedstock
Biomass feedstock cost	$37.96	2005$ / dry short ton	$37.96	Hess, R., Denney, K., Wright, C., Radtke, C., Perlack, W. (2007, April 18-19). *Cellulosic Biomass Feedstocks for Renewable Bioenergy*. EERE presentation to the National Academy of Sciences Commettee on Resource Needs for Fuel Cell and Hydrogen, Washington, D.C.	Feedstock price is taken from the Biomass Program 2012 Target price of $35/ton ($2002) escalated to $2005
Natural gas feedstock consumption	0.00	normal m^3 / kg H2 produced	0.00	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Results tab; Energy Data
Natural Gas feedstock cost	N/A		N/A	None	N/A
Natural Gas LHV	34,714	Btu / normal m^3.	36,692	Hydrogen Analysis Resource Center. (2008, September 5) *Lower and Higher Heating Values of Hydrogen and Fuels*. Retrieved from http://hydrogen.pnl.gov/cocoon/morf/hydrogen/article/401	LHV of Natural Gas; 983 Btu/ft3
Natural gas utility consumption	0.17	normal m^3 / kg H2 produced	0.17	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Appendex A. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Natural gas usage from overall energy balance; Appendix C, A401: stream 427 = 1669 lb/hr; Appendix C, A501: stream 424 = 14260 lb/hr; conversion yields 0.15 (not 0.17)
Natural gas utility price	$0.340	2005$ / Nm^3	$0.340	Energy Information Administation. (2005, February). *Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	AEO 2005 High A Case - Commercial price; Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Natural gas utility pressure	N/A	kPa	N/A	None	Not in H2A or GREET
	#VALUE!	psi	#VALUE!	Conversion calculation	conversion calculation
Electricity feedstock consumption	0.00	kWh / kg H2	0.00	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Results tab; Energy Data
Electricity utility consumption (both production and compression)	0.98	kWh / kg H2	0.98	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Electricity usage from overall energy balance with energy usage for hydrogen compression (3899 kW) removed. Appendix A, Total Plant Electricity = 5.54 kWh/kg H2 -
Electricity utility consumption (production only)	0.98	kWh / kg H2	0.98	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Electricity usage from overall energy balance with energy usage for hydrogen compression (3899 kW) removed. Appendix A, Total Plant Electricity = 5.54 kWh/kg H2
Electricity Utility Price	0.0555	2005 $/kWh	0.0555	Energy Information Administation. (2005, February). *Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	AEO 2005 High A Case - Industrial price; Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Process Water Consumption	1.32	gal / kg H2	1.32	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Appendix C, A202: stream 218 = 738 lb/hr; Appendix C, A601: stream 620 = 102749 lb/hr; Appendix C, A701: stream 710 = 131921 lb/hr
Water Consumption for Cooling	0.00008	gal / kg H2	0.00	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Assume all make-up water is process water
Electricity co-product production	0.00	kWh / kg H2	0.00	None	All electricity co-product used internally
Oxygen co-product production	0.0	kg / kg H2	0.0	None	N/A
Steam co-product production	0.0	kg / kg H2	0.0	None	N/A
Total Annual Fixed Operating Costs	$10,391,486	2005$ / yr	$10,391,486	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Section 9.2. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Section 9.2 Fixed Operating Costs. Costs were escalated from $2002 to $2005 dollars.
Total Annual Variable Operating Costs	$43,162,900	2005$ / yr	$44,917,200	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Table 13. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Table 13: Variable Operating Costs. Costs were escalated from $2002 to $2005 dollars.
Total Annual Operating Costs	$53,554,386	2005$ / yr	$55,308,686	None	Addtion of Annual Total Fixed Operating Costs and Total Annual Variable Operating Costs
Production energy efficiency (does not include electricity for forecourt compress	46.0%		45.6%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - biomass	93.1%		91.4%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - coal	0.0%		0.0%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - natural gas	2.5%		4.0%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - ethanol	0.0%		0.0%	Calculated from H2A values	Calculated from H2A values
Share of process fuel - electricity	4.4%		4.6%	Calculated from H2A values	Calculated from H2A values
Hydrogen outlet pressure (before CSD)	300	psi	300	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Final compression step modeled in the analysis was removed for the H2A case study to maintain consistency with H2A default value.
Hydrogen quality before transport	98 minimum	% H2	98 minimum	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Page 5, product purity of 99.9 vol%
Financial Parameters					
After-tax Real IRR	10%		10%	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; After-tax Real IRR, cell C47
Plant Life	40	years	40	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Plant life, cell C34

Parameter	Value	Units	Referenced Value	Reference	Comments
Federal Tax Rate	35.0%		35.0%	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Federal taxes, cell C49
State Tax Rate	6.0%		6.0%	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; State taxes, cell C48
Total Tax Rate	38.9%		38.9%	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Total tax Rate, cell C50
Frection Equity	100%		100%	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Equity Financing, cell C38
Transport, Delivery, and Storage Energy Requirements					
Liquid Truck Delivery					
Hydrogen entering liquefaction	382,396	kg / day	382,396	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation based on input parameters: city selection, market penetration, dispensing rate
Liquefaction electricity requirement	1,136,394,945	kW hr / yr	1,136,394,945	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Sections 2.2.7.3 and 2.2.7.5. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland (Nexant Report - Sections 2.2.7.3 and 2.2.7.5)
Liquefaction electricity requirement	8.2	kW hr / kg H2	1,136,394,945	None	Calculation
Hydrogen lost in liquefier	0.5%		0.5%	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.2. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland (Nexant Report - Section 2.2.7.2)
Liquefaction efficiency	80.3%		80.3%	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.2. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland and Praxair (Nexant Report-Section 2.2.7.2)
Liquefaction System total capital investment	$559,414,686	2005$	$559,414,686	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.4. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland and Praxair (Nexant Report - Section 2.2.7.4)
Liquefaction System electricity cost	$60,690,228	2005$ / yr	$60,690,228	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.7.4. DE-FG36-05GO15032.	Discussions with Linde Kryotechnic AG, Switzerland and Praxair (Nexant Report - Section 2.2.7.4)
Liquefaction System labor cost	$592,895	2005$ / yr	$592,895	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Liquefaction System total operating cost	$83,647,930	2005$ / yr	$83,647,930	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, H2 Liquifer tab, cell B135: sum of total labor cost, total electricity cost and total other fixed costs
Terminal Storage Design Capacity	3,532,139	kg H2	3,532,139	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, Liquid H2 Terminal tab, cell B73: based on liquid storage capacity, terminal average flow
Hydrogen lost in terminal	2.8%		2.8%	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report- Section 2.2.14)
Terminal total capital investment	$191,649,060	2005$	$191,649,060	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.11.1. DE-FG36-05GO15032.	CB&I (Nexant Report - Section 2.2.11.1)
Terminal electricity cost	$565,492	2005$ / yr	$565,492	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, Liquid H2 Terminal tab, cell B187: electricity prices are from EIA AEO 2005 and 2007
Terminal labor cost	$588,708	2005$ / yr	$588,708	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Terminal total operating cost	$8,842,213	2005$ / yr	$8,842,213	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, Liquid H2 Terminal tab, cell B201: sum of total labor cost, total electricity cost and total other fixed costs
Truck Payload leaving terminal	4,372	kg / truckload	4,372	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.8. DE-FG36-05GO15032.	HDSAM calculation; default value (Nexant Report- Section 2.1.8)
Truck Trips	31,009	per year	31,009	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B66: city yearly use(kg)*ref.station.mass efficiency(H2out/H2 in) / H2 delivered per trip (kg)
One-way distance per trip	49	miles / trip (one way)	157,840	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B39: distance to the city gate + 1.5 * sqrt(city area)
Diesel for Truck Trips	3,837	m^3 / yr	3,837	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.8. DE-FG36-05GO15032.	HDSAM calculation, fuel consumption data from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report - Section 2.1.8)
Hydrogen Losses during loading / transport / unloading	6.1%		6.1%	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report- Section 2.2.14)
Hydrogen Losses during liquefaction/loading / transport / unloading	10.08%		10.08%	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report- Section 2.2.14)
Truck/trailer total capital investment	$49,000,000	2005$	$49,000,000	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report. DE-FG36-05GO15032.	$625,000 per each tank trailer and $75,00 per each truck cab; recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL
Truck/trailer electricity cost	$0	2005$ / yr	$0	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM calculation, electricity prices are from EIA AEO 2005 and 2007
Truck/trailer Diesel cost	$1,692,270	2005$ / yr	$1,692,270	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B116: default milage - 6 mpg; diesel cost data are from EIA AEO 2005 and 2007
Truck/trailer labor cost	$15,193,193	2005$ / yr	$15,193,193	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Truck/trailer total operating cost	$21,691,089	2005$ / yr	$21,691,089	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation, Truck - LH2 Delivery tab, cell B137: sum of total labor cost, total fuel cost and total other fixed costs
Distribution Station					
Liquid Receiving/Distributing Stations					
Hydrogen Dispensed at Forecourt Station	465,647	kg / station year	465,647	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation based on input: dispensing rate
Electricity Required by Forecourt Station	116,673	kWh / station year	116,673	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laborator	HDSAM version 2.02 calculation based on pump power requirement (see equation in Design Data tab)
Design Capacity	1,516	kg H2 / day	1,516	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.4. DE-FG36-05GO15032.	HDSAM calculation based on Chevron fueling profiles (Nexant Report-Section 2.1.4): = adjusted disp. Rate*(1+summer surge)*(1+Friday surge)
Operating Capacity	1,278	kg H2 / day	1,278	James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C23
Capacity Factor	84%		84%	None	Calculation

Parameter	Value	Units	Referenced Value	Reference	Comments
Site storage (liquid)	6,920	kg H2	6,920	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.11.2. DE-FG36-05GO15032.	HDSAM calculation based on number of deliveries per day (Nexant Report-Section 2.2.11.2)
Site storage (gaseous)	453	kg H2	323	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.3.2.4. DE-FG36-05GO15032.	HDSAM calculation (Nexant Report - Section 2.3.2.4)
Site storage	486%	% of design H2 distribution		None	Calculation
Dispensing Pressure	6,250	psi	6,250	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.3.2. DE-FG36-05GO15032.	HDSAM default (see Nexant Report-Section 2.3.2)
Hydrogen Losses due to leaks	1.34%		1.34%	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	HDSAM parameter, recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Report - Section 2.2.14)
Distribution System total capital investment	$2,073,185	2005$ / station	$2,073,185	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.4.2. DE-FG36-05GO15032.	Data from CP Industries, McMaster-Carr, Bechtel, Nexant manufacturer survey, Nexant recommendations (Nexant Repo Section 2.2.4.2)
Distribution System electricity cost	$9,512	2005$ / station yr	$9,621	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.4.2. DE-FG36-05GO15032.	Data from CP Industries, McMaster-Carr, Bechtel, Nexant manufacturer survey, Nexant recommendations (Nexant Repo Section 2.2.4.2)
Distribution Labor Required	3,951	hr / station yr	3,942	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	HDSAM calculation (Nexant Report -Section 2.2.1.3)
Distribution System labor cost	$39,513	2005$ / station yr	$39,416	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3)
Distribution System total O&M cost	$189,192	2005$ / station yr	$181,989	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.2. DE-FG36-05GO15032.	HDSAM calculations (Nexant Report - Section 2.2.1.2)
Other Assumptions for WTW Calculations					
Share of RFG in Total Gasoline Use	100%		100%	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plar*.	Basis for posture plan
Type of Oxygenate in RFG	None		None	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plar*.	Basis for posture plan
O2 Content in RFG	0%	wt %	0%	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plar*.	Basis for posture plan
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		100%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, page 197: vehicles within the same weight class have similar tire and brake wear emissions
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory	GREET default:well-known fuel cell emissions (no PM2.5)
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		100%	Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory	GREET default:reasonable to assume FCV has same driving pattern as GV
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%		0%	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory	GREET default, Table 4.45 FCV: H2
Marginal Electricity Generation Mix for Transportation Use	US Mix		US Mix	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plar*.	Basis for posture plan
Results					
Levelized Cost	$4.88	$ / kg	$4.38	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Coal Input	100	Btu / mile	534	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Natural Gas Input	3,911	Btu / mile	284	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Petroleum Input	249	Btu / mile	144	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Fossil Energy Input	2,044	Btu / mile	963	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Total Energy Input	8,170	Btu / mile	5,302	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CO2 Emissions	151	g / mile	58	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CH4 Emissions	0	g / mile	0	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW N2O Emissions	0	g / mile	0	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW GHG Emissions	160	g / mile	63	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1 44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results

Appendix D — Biomass–Pipeline Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline



Known Issue: Hydrogen losses are estimated in HDSAM but are not included in GREET

Well-to-Wheels Total Energy Use (Btu/mile)	6,695
Well-to-Wheels Petroleum Energy Use (Btu/mile)	180
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	70
Levelized Cost of H2 at Pump ($/kg)	4.23

Production Process Energy Efficiency	46%
Pathway Efficiency	43%
WTP Efficiency	39%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	7

Case Definition
Year: 2005
Hydrogen as Gas
Central Production
Woody Biomass Feedstock
Sequestration: No
Transport for Delivery: Pipeline
Vehicle Efficiency: 45.0 mile / GGE
City Hydrogen Use: 344451 kg/day

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Inputs | Graphic Depiction & Assumptions | Outputs

Biomass Production & Delivery

Inputs

Coal Input from "Well"	261	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	418	Btu / 116000Btu to Pump
Petroleum Input from "Well"	2,900	Btu / 116000Btu to Pump

Biomass Production & Delivery

Fraction of Woody Biomass (Remaining is Herbaceous)	100%	
Grams of Nitrogen / dry ton biomass	709	
Grams of P2O5 / dry ton biomass	189	
Grams of K2O / dry ton biomass	331	
Herbicide use	24	g / dry ton
Insecticide use	2	g / dry ton
Average dist from farm to H2 production	40	miles

Outputs

Biomass moisture content	25%	
Woody biomass LHV	16,811,019	Btu / dry ton
Biomass price at H2 production	$37.96	2005 $ / dry ton
Levelized Cost of Biomass	$0.56	2005$ / kg H2 distributed
WTG CO2 Emissions	-25,632	g / 116000Btu to Pump
WTG CH4 Emissions	0	g / 116000Btu to Pump
WTG N2O Emissions	0	g / 116000Btu to Pump
WTG GHG Emissions	-25,590	g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Biomass consumption	12.8	kg (dry) / kg H2 produced
Natural gas consumption	0.17	N m^3/kg H2 produced
Electricity consumption	0.98	kWh / kg H2
Process Water Consumption	5.00	L / kg H2
Natural gas price	$0.340	2005$ / N m^3
Electricity price	$0.055	2005 $/kWh
Total Capital Investment	$154,644,297	2005$
Coal Input from "Well"	6,063	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	8,598	Btu / 116000Btu to Pump
Petroleum Input from "Well"	3,623	Btu / 116000Btu to Pump

Hydrogen Production

Central plant design capacity	155,236	kg/day
Capacity factor	90%	
Process energy efficiency	46.0%	
Electricity Mix	US Mix	
After-tax IRR	0	
Assumed Plant Life	40	

Outputs

Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	1	
Total capital investment	$3.03	2005$ / annual kg H2 (effective
Electricity cost	$0.05	2005$ / kg H2 produced
Natural Gas Cost	$0.06	2005$ / kg H2 produced
Other operating costs	$0.38	2005$ / kg H2 produced
Levelized Cost of Prod (excl feedst	$1.07	2005$ / kg H2 distributed
SMR CO2 Emissions	25,733	g / 116000Btu to Pump
SMR CH4 Emissions	3	g / 116000Btu to Pump
SMR N2O Emissions	0	g / 116000Btu to Pump
SMR GHG Emissions	25,839	g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs

Electricity consumption for compressor	0.56	kWh / kg H2
Electricity consumption for geo storage	0.01	kWh / kg H2
Total electricity consumption	0.57	kWh / kg H2
Electricity price for compressor	$0.056	2005$ / kWh
Electricity price for geologic storage	$0.052	2005$ / kWh
Coal Input from "Well"	3,306	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	950	Btu / 116000Btu to Pump
Petroleum Input from "Well"	246	Btu / 116000Btu to Pump

Pipelines for Delivery

City Population	1,247,364	people
Hydrogen Vehicle Penetration	50%	
City hydrogen use	125,810,766	kg / yr
Distance from City to Production Facility	62	miles
Geologic storage capacity	3,762,787	kg H2
Trunk #1-line length	17	miles
Trunk #2-line length	40	miles
Service-line length	1.1	miles / line
Number of service lines	270	
Hydrogen losses	1.12%	
Hydrogen loss factor	1.011	

Outputs

Total capital investment	$3.51	2005$/annual kg distributed
Electricity cost	$0.03	2005$ / kg H2
Levelized Cost of Delivery	$0.92	2005$ / kg H2 distributed
Delivery CO2 Emissions	436	g / 116000Btu to Pump
Delivery CH4 Emissions	1	g / 116000Btu to Pump
Delivery N2O Emissions	0	g / 116000Btu to Pump
Delivery GHG Emissions	452	g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs

Electricity consumption	3.04	kWh / kg H2
Electricity price	$0.082	2005$ / kWh
Coal Input from "Well"	17,677	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	5,078	Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,317	Btu / 116000Btu to Pump

Forecourt Distribution

Number of Distribution Stations	270	
Energy efficiency	92%	
Number of Compression Steps	4	
Isentropic Efficiency	65%	
Site storage	69%	capacity
Hydrogen losses	0.50%	
Hydrogen loss factor	1.005	

Outputs

Hydrogen outlet pressure	6,250	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxyg
Total capital investment	$6.69	2005$/annual kg
Electricity cost	$0.25	2005$ / kg H2
Levelized Cost of Distribution	$1.69	2005$ / kg H2 distributed
CSD CO2 Emissions	2,333	g / 116000Btu to Pump
CSD CH4 Emissions	3	g / 116000Btu to Pump
CSD N2O Emissions	0	g / 116000Btu to Pump
CSD GHG Emissions	2,419	g CO2 eq./ 116000 Btu

Well-to-Pump Results

Coal Input from "Well"	27,308	Btu / 116000 Btu
Natural Gas Input from "Well"	15,043	Btu / 116000 Btu
Petroleum Input from "Well"	8,087	Btu / 116000 Btu
Fossil Energy Input from "Well"	50,437	Btu / 116000 Btu
WTP CO2 Emissions	2,875	g / 116000 Btu
WTP CH4 Emissions	7	g / 116000 Btu
WTP N2O Emissions	0	g / 116000 Btu
WTP GHG Emissions	3,127	116000 Btu
Levelized Cost of Hydrogen ($/kg)	$4.23	2005 $/ kg

Vehicle

Fuel Economy	45.0	mi / GGE
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%	
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%	
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%	

Well-to-Wheel Results

Coal Input from "Well"	607	Btu / mi
Natural Gas Input from "Well"	335	Btu / mi
Petroleum Input from "Well"	180	Btu / mi
Fossil Energy Input from "Well"	1,122	Btu / mi
WTW CO2 Emissions	64	g / mi
WTW CH4 Emissions	0	g / mi
WTW N2O Emissions	0	g / mi
WTW GHG Emissions	70	g / mi
Levelized Cost of Hydrogen ($/mi)	$0.0941	2005 $/mi

Gasification

Coal	6,063	Btu/116000 Btu
Natural Gas	8,598	Btu/116000 Btu
Petroleum	3,623	Btu/116000 Btu
Total Energy	147,677	Btu/116000 Btu
CO2 Emissions	25,733	g/116000 Btu
CH4 Emissions	3	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	25,839	g/116000 Btu

Transport

Coal	3,306	Btu/116000 Btu
Natural Gas	950	Btu/116000 Btu
Petroleum	246	Btu/116000 Btu
Total Energy	5,938	Btu/116000 Btu
CO2 Emissions	436	g/116000 Btu
CH4 Emissions	1	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	452	g/116000 Btu

Distribution

Coal	17,677	Btu/116000 Btu
Natural Gas	5,078	Btu/116000 Btu
Petroleum	1,317	Btu/116000 Btu
Total Energy	27,816	Btu/116000 Btu
CO2 Emissions	2,333	g/116000 Btu
CH4 Emissions	3	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	2,419	g/116000 Btu

Feedstock

Coal	261	Btu/116000 Btu
Natural Gas	418	Btu/116000 Btu
Petroleum	2,900	Btu/116000 Btu
Total Energy	3,628	Btu/116000 Btu
CO2 Emissions	-25,632	g/116000 Btu
CH4 Emissions	0	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	-25,590	g/116000 Btu

Gasification & Conversion

Transport

Transport Losses 0.63%

Distribution

Distribution Losses 0.50%

	Total to Deliver 116000 Btu Fuel	Check
Coal	27,308	27,308
Natural Gas	15,043	15,043
Petroleum	8,087	8,087
Total Energy	185,059	185,059
CO2 Emissions	2,870	2,875
CH4 Emissions	7	7
N2O Emissions	0	0
GHG Emissions	3,121	3,127

Parameter	Value	Units	Reference	Comments
Case Definition				
Base Year	2005		N/A	Default for Bio-Pipe Pathway study
Production Technology	Woody Biomass		N/A	Default for Bio-Pipe Pathway study
Form of H2 During Delivery	Gas		N/A	Default for Bio-Pipe Pathway study
Delivery Mode	Pipeline		N/A	Default for Bio-Pipe Pathway study
Forecourt Station Size	1278	kg/day	James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C28
Vehicle Type	passenger cars		N/A	Default for Bio-Pipe Pathway study
Vehicles' Fuel Economy	45.0	mile / gge	Rousseau, A. & Wallner, T. (2008, October 7). *Prospects on Fuel Efficiency Improvements for Hydrogen Powered Vehicles*. Argonne National Laboratory presentation, Chicago, IL. Retreived from http://www.transportation.anl.gov/pdfs/HV/530.pdf	Calculated from data in the presentation. The fuel economy for today's average mid-size vehicle was estimated by the Powertrain Simulation Analysis Toolkit V 6.2 SP1, Summer 2008 (PSAT - http://www.transportation.anl.gov/modeling_simulation/PSAT/index.html). 45 mile/gge is the estimated on-road fuel economy which was determined by multiplying the projected EPA lab-rated fuel economy of 52.5 mile/gge by 0.85.
Market Definition				
City Population	1,247,364	people	U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	HDSAM City Selection; Scenario tab; Indianapolis, IN, cell B9
Market penetration	50%	(% vehicles in city)	U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Number of H2 vehicles in city	462,772	H2 vehicles / city	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model*	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 vehicles in city, cell F17
Miles driven per vehicle	12,000	mile / vehicle year	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model*	Key delivery input in HDSAM version 2.02; Scenario tab; Miles driven per year/ vehicle, cell C19
City hydrogen use	344,451	kg / d	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; City H2 daily use, cell F18 - based on number of hydrogen vehicles and miles/veh yr.
Number of H2 refueling stations in city	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 fueling stations in city, cell F19
Number of H2 stations/Number of gasoline stations	41%		Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 stations/Number of gasoline stations, cell F21
Average distance between stations (mi)	1.46	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Average distance between stations, cell F22
Feedstock Recovery, Processing, & Transport				
Biomass				
Percentage of Woody Biomass (Remainder is Herbaceous)	100%		Mann, M & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production via biomass gasification version 2.1.2 basis
Biomass Moisture Content	25%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	Page 66
Grams of Nitrogen / short ton biomass	709	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh, 1998).	Equivalent to 75 lb N / ac in the maintenance year Year 3 or 4) which is reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre, and harvesting once every 8 years. App 3.1 is for planting on cropland that was just used for traditional crops.
Grams of P2O5 / short ton biomass	189	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh, 1998).	Equivalent to 20 lb P / ac in the maintenance year (Year 3) which is in the range of 15-50 lb P / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years
Grams of K2O / short ton biomass	331	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh, 1998).	Equivalent to 35 lb K / ac in the maintenance year (Year 3) which is in the range of 15-50 lb K / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years)
Grams of herbicide / short ton biomass	24	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh, 1998).	Equivalent to 2.0 lb herbicide / ac in the planting year which similar to the 2.0 lb glyphosate / ac reported by De La Torre Ugarte, 2000, App 3.2, assuming 6 dry tons biomass per acre and harvesting once every 8 years. Booth reported Triflura (5 L/ha) and Metribuzin (395 g/ha). App 3.2 is for planting on currently idled cropland or cropland that was just used for pasture.
Grams of insecticide / short ton biomass	2	g / dry ton	M. Walsh (personal communication via telephone and meeting between M. Wang and M. Walsh, 1998).	As a check, looked at Chastagner: Up to 56% of acreage annually sprayed with Dimethoate (Digon 400, 2-3 pints per ac up to 56% of acreage annually sprayed with Permethrin 2LB (Ambush, 6.4 ounces per acre); Up to 12% of acreage annually sprayed with Endosulfan 3 EC (24c WA-990025, 2 qts per acre).
Grams of CO2 removed from atmosphere per dry ton woody biomass produced	-112,500	g / dry ton		GREET model default based on ANL personal communications
Average distance from farm to hydrogen production facility	40	miles	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET basis: distance could be limited by transport costs?
Natural Gas				
NG recovery efficiency	97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97% which is comparable to several other models (Table 4.11)
NG used & lost during recovery	0.35%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET basis
NG processing energy efficiency	97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
NG used & lost during processing	0.15%		Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996). *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.p	Volume lost from EPA/GRI paper and DOE/EIA-0573; future marginal increase is assumed to be less than current average.
NG used & lost during transport	0.137	g / (MM Btu mil)	Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996). *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.p	Volume lost from EPA/GRI paper and DOE/EIA-0573; future marginal increase is assumed to be less than current average.
NG transport distance	500	miles	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET basis
Electricity				
Grid mix for production	US Mix			Default
Biomass Fraction	1.20%		Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Coal Fraction	51.70%		Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Natural Gas Fraction	15.70%		Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Nuclear Fraction	20.30%		Energy Information Administration. (2007, February). *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category

Parameter	Value	Units	Reference	Comments
Residual Oil Fraction	2.90%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Others (Carbon Neutral)	8.20%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
H2 Production				
Production Facility Average Output	139,712	kg / facility d (after capacity factor is included)	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Section 3.0. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Design feed rate for current design plant of 2000 bone dry metric tonne biomass per day (see Section 3.0)
Corresponding capacity factor	90%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Operating Capacity Factor, cell C21
Total Capital Investment	$154,644,297	2005 $	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Table 10. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Total installed capital cost of $102M ($2002) (see Table 10, Current Design) was escalated to $2005 dollars. Capital cost for additional compression was removed to maintain consistency with H2A central model assumptions.
Biomass feedstock consumption	12.8	kg (dry) / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Appendex A. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Biomass usage calculated from plant efficiency of 45.6%. The LHV for woody biomass is taken from HyARC, and is higher (8406 Btu/lb v. 8060 Btu/lb) than used in Spath. Appendix A - Design Report: Current Case; Hydrogen Yield = 70.4 kg/ dry US ton feedstock
Biomass feedstock cost	$37.96	2005$ / dry short ton	Hess, R., Denney, K., Wright, C., Radtke, C., Perlack, W. (2007, April 18-19) *Cellulosic Biomass Feedstocks for Renewable Bioenergy*. EERE presentation to the National Academy of Sciences Commettee on Resource Needs for Fuel Cell and Hydrogen, Washington, D.C.	Feedstock price is taken from the Biomass Program 2012 Target price of $35/ton ($2002) escalated to $2005
Biomass LHV	16,811,019	Btu / dry ton	Hydrogen Analysis Resource Center. (2008, September 5) *Lower and Higher Heating Values of Hydrogen and Fuels*. Retrieved from http://hydrogen.pnl.gov/cocoon/morf/hydrogen/article/401	LHV of Farmed Trees (dry basis); 19.551 MJ/kg
Natural gas feedstock consumption	0.00	normal m^3 / kg H2 produced	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Results tab; Energy Data
Natural Gas LHV	34,714	Btu / normal m^3	Hydrogen Analysis Resource Center. (2008, September 5) *Lower and Higher Heating Values of Hydrogen and Fuels*. Retrieved from http://hydrogen.pnl.gov/cocoon/morf/hydrogen/article/401	LHV of Natural Gas; 983 Btu/ft3
Natural gas utility consumption	0.17	normal m^3 / kg H2 produced	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Appendex A. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Natural gas usage from overall energy balance; Appendix C, A401: stream 427 = 1669 lb/hr; Appendix C, A501: stream 424 = 14260 lb/hr; conversion yields 0.15 (not 0.17)
Natural gas utility price	$0.340	2005$ / Nm^3	Energy Information Administation. (2005, February) *Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	Commercial natural gas price from AEO 2005 "High A" case for startup year (2005). Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Natural gas utility pressure	N/A	kPa	None	Not in H2A or GREET
	#VALUE!	psi		conversion calculation
Electricity feedstock consumption	0.00	kWh / kg H2	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Results tab; Energy Data
Electricity utility consumption (both production and compression)	0.98	kWh / kg H2		Sum of feedstock + utility
Electricity utility consumption (production only)	0.98	kWh / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory.	Electricity usage from overall energy balance with energy usage for hydrogen compression (3899 kW) removed. Appendix A, Total Plant Electricity = 5.54 kWh/kg H2. Electricity consumption reduced in H2A because Spath has hydrogen product at 360 psi and H2A's standard is 300 psi.
Electricity Utility Price	0.0555	2005 $/kWh	Energy Information Administation. (2005, February) *Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	Industrial electricity price from AEO 2005 "High A" case for startup year (2005). Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Process Water Consumption	1.32	gal / kg H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory.	Appendix C, A202: stream 218 = 738 lb/hr; Appendix C, A601: stream 620 = 102749 lb/hr; Appendix C, A701: stream 710 = 131921 lb/hr
Water Consumption for Cooling	0.00008		Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory.	Assume all make-up water is process water
Electricity co-product production	0.00	kWh / kg H2	None	All electricity co-product used internally
Oxygen co-product production	0.0	kg / kg H2	None	N/A
Steam co-product production	0.0	kg / kg H2	None	N/A
Total Annual Fixed Operating Costs	$10,391,486	2005$ / yr	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Section 9.2. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Section 9.2 Fixed Operating Costs. Costs were escalated from $2002 to $2005 dollars.
Total Annual Variable Operating Costs	$43,162,900	2005$ / yr	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Table 13. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Table 13: Variable Operating Costs. Costs were escalated from $2002 to $2005 dollars.
Total Annual Operating Costs	$53,554,386	2005$ / yr	N/A	Addition of Annual Total Fixed Operating Costs and Total Annual Variable Operating Costs
Production energy efficiency (does not include electricity for forecourt compressio	46.0%		N/A	Calculated from H2A values
Share of process fuel - biomass	93.1%		N/A	Calculated from H2A values
Share of process fuel - coal	0.0%		N/A	Calculated from H2A values
Share of process fuel - natural gas	2.5%		N/A	Calculated from H2A values
Share of process fuel - ethanol	0.0%		N/A	Calculated from H2A values
Share of process fuel - electricity	4.4%		N/A	Calculated from H2A values
Hydrogen outlet pressure (before CSD)	300	psi	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May) *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory.	Final compression step modeled in the analysis was removed for the H2A case study to maintain consistency with H2A default value. Spath's compression was to 360 psi and H2A standard is 300 psi. Reducing the compression reduced the electricity use.

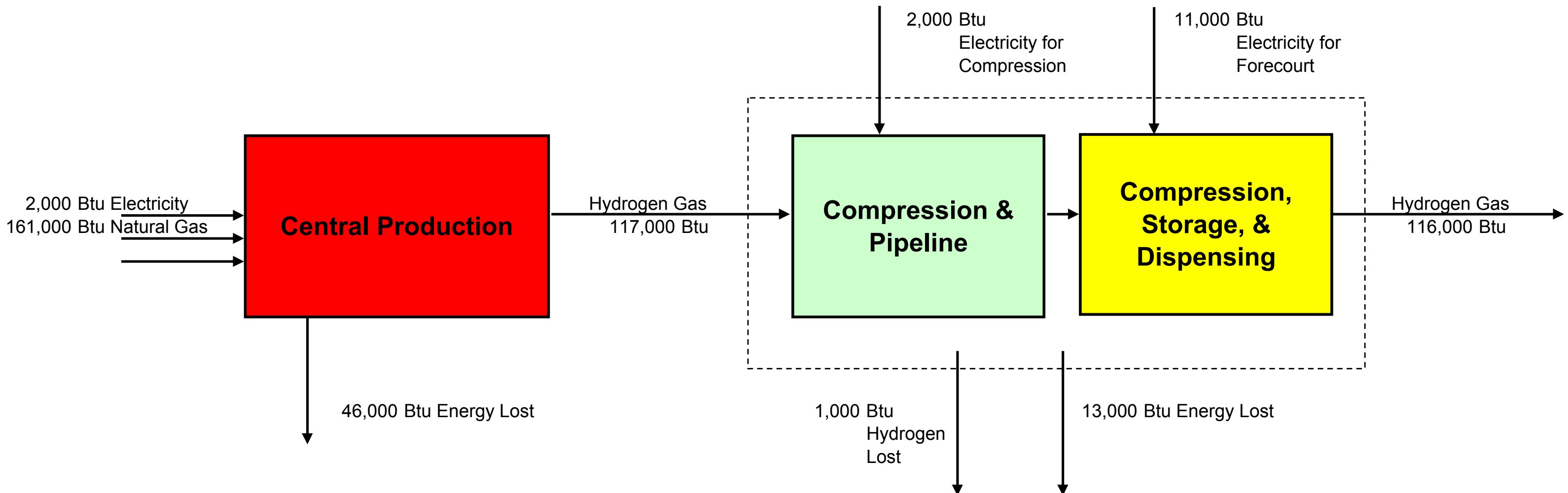
Parameter	Value	Units	Reference	Comments
Hydrogen quality before transport	99.9%	% H2	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May). *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory.	Page 5, product purity of 99.9 vol%
Financial Parameters				
After-tax Real IRR	10%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; After-tax Real IRR, cell C47
Plant Life	40	years	Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Plant life, cell C34
Federal Tax Rate	35.0%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Federal taxes, cell C49
State Tax Rate	6.0%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; State taxes, cell C48
Total Tax Rate	38.9%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Total tax Rate, cell C50
Fraction Equity	100%		Mann, M., & Steward, D.M. (2008, May 28). *Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Equity Financing, cell C38
Transport, Delivery, and Storage Energy Requirements				
Pipeline Delivery				
Average Hydrogen Flowrate (Entering System)	348,364	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOW RATE THRU TRANSMISSION SYSTEM=CITY PEAK DEMAND/TRANSMISIION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Average Hydrogen Flowrate (Distributed)	344,451	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameters: city, market penetration, dispensing rate (Ave. daily use=CITY DAILY USE/TOTAL PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Summer Surge: % above the System Average Daily Demand	10%	% above Average Daily Demand	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM default, Scenario Parameters tab, cell B90
Friday Peak	8%	% above Average Daily Demand	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM default, Scenario Parameters tab, cell B92
Peak Hydrogen Flowrate	381,192	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOWRATE THRU DISTRIBUTION SYSTEM=CITY PEAK DEMAND/DISTRIBUTION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Total Capital Investment for Compressors	$27,199,794		Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	Disscussions with Bechtel and Air Liquide (Nexant report - Section 2.2.5)
Hydrogen Losses from Compressors	0.50%		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM default, Refueling Station - Gaseous H2 tab, cell B79
Compressor Electricity Demand	70,343,075	kWh / year	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	Based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand (Nexant report - Section 2.2.5)
Compressor Electricity Demand	0.5591	kWh / kg H2	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	Based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand (see Nexant report - Section 2.2.5)
Compressor Electricity Cost	$0.056	2005$ / kWh	Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	EIA AEO 2005 and 2007
Total Capital Investment for Pipeline System	$377,283,372		Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.2. DE-FG36-05GO15032.	HDSAM version 2.02 calculations based on data from GTI, Bechtel, Air Liquide, UC Davis (Nexant Report -Section 2.2.2)
Hydrogen Losses from Pipelines	0.10%		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	
Number of transmission pipelines	1		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Default in HDSAM version 2.02
Transmission pipeline diameter	11.00	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B83
Transmission pipeline inlet pressure	999	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Transmission pipeline outlet pressure	705	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Transmission pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Transmission pipeline length	62	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameter: city, Scenario Parameters tab, cell F167
Number of trunk pipelines	4		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input data and HDSAM distribution model - not documented, H2 Pipeline tab, cell B58
Trunk #1 pipeline diameter	7.25	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B84
Trunk #1 pipeline inlet pressure	603	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #1 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #1 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #1 pipeline length	17	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco), Scenario Parameters tab, cell F168

Parameter	Value	Units	Reference	Comments
Trunk #2 pipeline diameter	10.25	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B85
Trunk #2 pipeline inlet pressure	588	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #2 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #2 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #2 pipeline length	40	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model - not documented, Scenario Parameters tab, cell F169
Trunk #3 pipeline diameter	12.25	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B86
Trunk #3 pipeline inlet pressure	573	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #3 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #3 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #3 pipeline length	65	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model - not documented, Scenario Parameters tab, cell F170
Trunk #4 pipeline diameter	10.75	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B87
Trunk #4 pipeline inlet pressure	558	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #4 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #4 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #4 pipeline length	90	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model - not documented, Scenario Parameters tab, cell F171
Number of service pipelines	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco), H2 Pipeline tab, cell B67
Service pipeline diameter	1	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B88
Service pipeline inlet pressure	382	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Service pipeline outlet pressure	294	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Service pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Service pipeline length	1.1	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco), H2 Pipeline tab, cell B68
Pipeline Geologic Storage Total Capital Investment	$36,988,376		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase (Nexant Report - Section 2.2.12)
Hydrogen Losses from Geologic Storage	0.02%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	
Geologic Storage Capacity	41,864,765	m^3	Calculation	
Geologic Storage Design Capacity	3,762,787	kg H2	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Gaseous H2 Geological Stroage tab, cell B105
Geologic Storage Electricity Demand	961,465	kWh / year	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase (Nexant Report- Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Demand	0.0076	kWh / kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase (Nexant Report- Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Cost	$0.052	2005$ / kWh	Energy Information Administration. (2005, January)*Annual Energy Outlook 2005 with Projections to 2025* . DOE/EIA-0383(2005). Washington, D.C. Retreived from http://www.eia.doe.gov/oiaf/archive/aeo05/index.htı	EIA AEO 2005
Distribution Station				
Gaseous Receiving/Distributing Stations				
Hydrogen Dispensed at Forecourt Station	465,647	kg / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B138
Electricity Required by Forecourt Station	1,416,755	kWh / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B263
Number of Compressor Stages	4	Stages in compressor	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B67
Compressor Isentropic Efficiency	65%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B69
Design Capacity	1,516	kg H2 / day	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.4. DE-FG36-05GO15032.	HDSAM version 2.02 calculation based on Chevron fueling profiles (Nexant Report - Section 2.1.4): = adjusted disp. Rate*(1+summer surge)*(1+Friday surge), Refueling Station - Gaseous H2 tab, cell B32
Operating Capacity	1,278	kg H2 / day	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Adjusted dispensing rate=city use/number of stations/utilization factor, Refueling Station - Gaseous H2 tab, cell B33

Parameter	Value	Units	Reference	Comments
Capacity Factor	84%		N/A	calculation
Site storage (Low Pressure)	470	kg H2	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM version 2.02 calculation (Nexant Report - Section 2.2.3), Refueling Station - Gaseous H2 tab, cell B123
Site storage (Cascade)	582	kg H2	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.3.2.4 DE-FG36-05GO15032.	HDSAM calculations (Nexant Report - Section 2.3.2.4), Refueling Station - Gaseous H2 tab, cell B122
Site storage	69%	% of design H2 distribution	N/A	calculation
Dispensing Pressure	6,250	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM version 2.02 default (see Nexant Report-Section 2.3.2), Refueling Station - Gaseous H2 tab, cell B58
Hydrogen Losses due to leaks	0.50%		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B79
Electrical Voltage Supply Requirement	480	Volts	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM version 2.02 calculation (see Nexant Report - Sections 2.2.5 and 2.2.6), Refueling Station - Gaseous H2 tab, cell B137
Distribution System total capital investment	$3,117,483	2005$ / station	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5.2. DE-FG36-05GO15032.	Nexant Report - Section 2.2.5.2
Distribution System electricity cost	$115,508	2005$ / station yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B267
Distribution Labor Required	3,951	hr / station yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B259
Distribution System labor cost	$39,513	2005$ / station yr	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3), Refueling Station - Gaseous H2 tab, cell B260
Distribution System total O&M cost	$298,898	2005$ / station yr	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.1.2. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (Nexant Report - Section 2.2.1.2), Refueling Station - Gaseous H2 tab, cell B283
Other Assumptions for WTW Calculations				
Share of RFG in Total Gasoline Use	100%		U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan.* .	Basis for posture plan
Type of Oxygenate in RFG	None		U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan.* .	Basis for posture plan
O2 Content in RFG	0%	wt %	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan.* .	Basis for posture plan
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, page 197: vehicles within the same weight class have similar tire and brake wear emissions
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b* . Argonne, IL: Argonne National Laboratory.	GREET default:well-known fuel cell emissions (no PM2.5)
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b* . Argonne, IL: Argonne National Laboratory.	GREET default:reasonable to assume FCV has same driving pattern as GV
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Marginal Electricity Generation Mix for Transportation Use	US Mix		U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan.* .	Basis for posture plan
Results				
Levelized Cost	$4.23	$ / kg	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Coal Input	607	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Natural Gas Input	335	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Petroleum Input	180	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Fossil Energy Input	1,122	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Total Energy Input	6,695	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CO2 Emissions	64	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CH4 Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW N2O Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW GHG Emissions	70	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results

Appendix E — Natural Gas–Pipeline Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline



Known Issue: Hydrogen losses are estimated in HDSAM but are not included in GREET

Well-to-Wheels Total Energy Use (Btu/mile)	4,659
Well-to-Wheels Petroleum Energy Use (Btu/mile)	55
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	318
Levelized Cost of H2 at Pump ($/kg)	3.95

Production Process Energy Efficiency	72%
Pathway Efficiency	66%
WTP Efficiency	55%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	31

Case Definition
Year: 2005
Hydrogen as Gas
Central Production
Natural Gas Feedstock
Sequestration: No
Transport for Delivery: Pipeline
Vehicle Efficiency: 45.0 mile / GGE
City Hydrogen Use: 344451 kg/day

Inputs		Graphic Depiction & Assumptions		Outputs	
		NG Recovery, Processing, & Transport		NG Delivery Pressure	Average of gas companies
		NG Recovery Efficiency	97.2%	NG Quality at Delivery	Average of gas companies
		NG emitted & combusted during recovery	0.35%		
		NG processing energy efficiency	97.2%	NG Cost	$0.243 2005 $ / Nm^3
		NG emitted & combusted during processin	0.15%	NG Cost	$0.958 2005$ / kg H2 distributed
		NG emitted & combusted during transport	0.14 g / MMBtu		
		NG transport distance	500 miles	WTG CO2 Emissions	589 g / 116000Btu to Pump
Coal Input from "Well"	252 Btu / 116000Btu to Pump			WTG CH4 Emissions	16 g / 116000Btu to Pump
Natural Gas Input from "Well"	122,927 Btu / 116000Btu to Pump	Compression Reqs (stages & eff) average of gas companies		WTG N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	492 Btu / 116000Btu to Pump			WTG GHG Emissions	994 g CO2 eq./ 116000 Btu

Natural gas consumption	4.50 N m^3/kg H2 produced	**Hydrogen Production**		Hydrogen Output Pressure	Not Available psi
Electricity consumption	0.57 kWh / kg H2			Hydrogen Outlet Quality	1
Process (De-Ionized) Water Consumptio	12.70 L / kg H2				
Cooling Water Consumption	5.66 L / kg H2	Central plant design capacity	379,387 kg/day	Total capital investment	$1.45 2005$ / annual kg H2 (effective
		Capacity factor	90%	Electricity cost	$0.03 2005$ / kg H2 produced
Electricity price	$0.0555 2005 $/kWh	Process energy efficiency	71.9%	Other operating costs	$0.08 2005$ / kg H2 produced
Total Capital Investment	$180,543,901 2005$	Electricity Mix	US Mix	Levelized Cost of Prod (excl feedst	$0.38 2005$ / kg H2 distributed
		After-tax IRR	10%		
		Assumed Plant Life	40 years		
				SMR CO2 Emissions	10,233 g / 116000Btu to Pump
Coal Input from "Well"	3,440 Btu / 116000Btu to Pump			SMR CH4 Emissions	7 g / 116000Btu to Pump
Natural Gas Input from "Well"	47,416 Btu / 116000Btu to Pump			SMR N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	433 Btu / 116000Btu to Pump			SMR GHG Emissions	10,410 g CO2 eq./ 116000 Btu

Electricity consumption for compressor	0.56 kWh / kg H2			Total capital investment	$3.51 2005$/annual kg distributed
Electricity consumption for geo storage	0.01 kWh / kg H2	**Pipelines for Delivery**		Electricity cost	$0.03 2005$ / kg H2
Total electricity consumption	0.57 kWh / kg H2				
Electricity price for compressor	$0.056 2005$ / kWh	City Population	1,247,364 people		
Electricity price for geologic storage	$0.052 2005$ / kWh	Hydrogen Vehicle Penetration	50%	Levelized Cost of Delivery	$0.92 2005$ / kg H2 distributed
		City hydrogen use	125,810,766 kg / yr		
		Distance from City to Production Facility	62 miles		
		Geologic storage capacity	3,762,787 kg H2		
		Trunk #1-line length	17 miles		
		Trunk #2-line length	40 miles		
		Service-line length	1.1 miles / line	Delivery CO2 Emissions	436 g / 116000Btu to Pump
Coal Input from "Well"	3,306 Btu / 116000Btu to Pump	Number of service lines	270	Delivery CH4 Emissions	1 g / 116000Btu to Pump
Natural Gas Input from "Well"	950 Btu / 116000Btu to Pump	Hydrogen losses	1.12%	Delivery N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	246 Btu / 116000Btu to Pump			Delivery GHG Emissions	452 g CO2 eq./ 116000 Btu

Electricity consumption	3.04 kWh / kg H2			Hydrogen outlet pressure	6,250 psi
Electricity price	$0.082 2005$ / kWh	**Forecourt Distribution**		Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxyg
				Total capital investment	$6.69 2005$/annual kg
		Number of Distribution Stations	270	Electricity cost	$0.25 2005$ / kg H2
		Energy efficiency	92%		
		Number of Compression Steps	4	Levelized Cost of Distribution	$1.69 2005$ / kg H2 distributed
		Isentropic Efficiency	65%		
		Site storage	69% capacity	CSD CO2 Emissions	2,333 g / 116000Btu to Pump
Coal Input from "Well"	17,677 Btu / 116000Btu to Pump	Hydrogen losses	0.50%	CSD CH4 Emissions	3 g / 116000Btu to Pump
Natural Gas Input from "Well"	5,078 Btu / 116000Btu to Pump			CSD N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	1,317 Btu / 116000Btu to Pump			CSD GHG Emissions	2,419 g CO2 eq./ 116000 Btu

Well-to-Pump Results

Coal Input from "Well"	24,676 Btu / 116000 Btu
Natural Gas Input from "Well"	176,371 Btu / 116000 Btu
Petroleum Input from "Well"	2,489 Btu / 116000 Btu
Fossil Energy Input from "Well"	203,535 Btu / 116000 Btu
WTP CO2 Emissions	13,599 g / 116000 Btu
WTP CH4 Emissions	26 g / 116000 Btu
WTP N2O Emissions	0 g / 116000 Btu
WTP GHG Emissions	14,283 116000 Btu
Levelized Cost of Hydrogen ($/kg)	$3.95 2005 $/ kg

Vehicle

Fuel Economy	45.0 mi / GGE
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%

Well-to-Wheel Results

Coal Input from "Well"	549 Btu / mi
Natural Gas Input from "Well"	3,922 Btu / mi
Petroleum Input from "Well"	55 Btu / mi
Fossil Energy Input from "Well"	4,527 Btu / mi
WTW CO2 Emissions	302 g / mi
WTW CH4 Emissions	1 g / mi
WTW N2O Emissions	0 g / mi
WTW GHG Emissions	318 g / mi
Levelized Cost of Hydrogen ($/mi)	$0.0878 2005 $/mi

Gasification

Coal	3,440	Btu/116000 Btu
Natural Gas	47,416	Btu/116000 Btu
Petroleum	433	Btu/116000 Btu
Total Energy	52,018	Btu/116000 Btu
CO2 Emissions	10,233	g/116000 Btu
CH4 Emissions	7	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	10,410	g/116000 Btu

Transport

Coal	3,306	Btu/116000 Btu
Natural Gas	950	Btu/116000 Btu
Petroleum	246	Btu/116000 Btu
Total Energy	5,938	Btu/116000 Btu
CO2 Emissions	436	g/116000 Btu
CH4 Emissions	1	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	452	g/116000 Btu

Distribution

Coal	17,677	Btu/116000 Btu
Natural Gas	5,078	Btu/116000 Btu
Petroleum	1,317	Btu/116000 Btu
Total Energy	27,816	Btu/116000 Btu
CO2 Emissions	2,333	g/116000 Btu
CH4 Emissions	3	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	2,419	g/116000 Btu

Feedstock

Coal	252	Btu/116000 Btu
Natural Gas	122,927	Btu/116000 Btu
Petroleum	492	Btu/116000 Btu
Total Energy	7,723	Btu/116000 Btu
CO2 Emissions	589	g/116000 Btu
CH4 Emissions	16	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	994	g/116000 Btu

Reforming & Purification

Transport

Transport Losses 0.63%

Distribution

Distribution Losses 0.50%

Total to Deliver 116000 Btu Fuel		Check
Coal	24,676	24,676
Natural Gas	176,371	176,371
Petroleum	2,489	2,489
Total Energy	93,495	93,495
CO2 Emissions	13,591	13,599
CH4 Emissions	26	26
N2O Emissions	0	0
GHG Emissions	14,276	14,283

Parameter	Value	Units	Reference	Comments
Case Definition				
Base Year	2005		None	Default for NG-Pipe Pathway study
Production Technology	Natural Gas		None	Default for NG-Pipe Pathway study
Form of H2 During Delivery	Gas		None	Default for NG-Pipe Pathway study
Delivery Mode	Pipeline		None	Default for NG-Pipe Pathway study
Forecourt Station Size	1278	kg/day	James, B.D. (2008, May 23).*Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day* . Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C23
Vehicle Type	passenger cars		None	Default for NG-Pipe Pathway study
Vehicles' Fuel Economy	45.0	mile / gge	Rousseau, A. & Wallner, T. (2008, October 7).*Prospects on Fuel Efficiency Improvements for Hydrogen Powered Vehicles* . Argonne National Laboroatory presentation, Chicago, IL. Retreived from http://www.transportation.anl.gov/pdfs/HV/530.pdf	Calculated from data in the presentation. The fuel economy for today's average mid-size vehicle was estimated by the Powertrain Simulation Analysis Toolkit V 6.2 SP1, Summer 2008 (PSAT - http://www.transportation.anl.gov/modeling_simulation/PSAT/index.html). 45 mile/gge is the estimated on-road fuel economy which was determined by multiplying the projected EPA lab-rated fuel economy of 52.5 mile/gge by 0.85.
Market Definition				
City Population	1,247,364	people	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM City Selection; Scenario tab; Indianapolis, IN, cell B9
Market penetration	50%	(% vehicles in city)	U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Number of H2 vehicles in city	462,772	H2 vehicles / city	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 vehicles in city, cell F17
Miles driven per vehicle	12,000	mile / vehicle year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Key delivery input in HDSAM version 2.02; Scenario tab; Miles driven per year/ vehicle, cell C19
City hydrogen use	344,451	kg / d	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; City H2 daily use, cell F18
Number of H2 refueling stations in city	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 fueling stations in city, cell F19
Number of H2 stations/Number of gasoline stations	41%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 stations/Number of gasoline stations, cell F21
Average distance between stations (mi)	1.46	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Average distance between stations, cell F22
Feedstock Recovery, Processing, & Transport				
Natural Gas				
NG recovery efficiency	97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	Table 4.11
NG used & lost during recovery	0.35%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	
NG processing energy efficiency	97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	
NG used & lost during processing	0.15%		Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996)*Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.pdf.	Volume lost from EPA/GRI paper by Kirchgessner er al (1996) and DOE/EIA-0573; future marginal increase is assumed to less than current average
NG used & lost during transport	0.14	g / (MM Btu mil)	Kirchgessner, D. A., Lott, R. A., Cowgill, R. M., Harrison, M. R. & Shires, T. M. (1996)*Estimate of Methane Emissions from the U.S. Natural Gas Industry*, EPA/Gas Research Institute paper. Retrieved from http://www.epa.gov/ttn/chief/ap42/ch14/related/methane.pdf.	GREET 97% is comparable to several other models; volume lost from EPA/GRI paper by Kirchgessner et al (1996) and DOE/EIA-0573; future marginal increase is assumed to be less than current average
NG transport distance	500	miles	Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results* . Argonne, IL: Argonne National Laboratory.	
Electricity				
Grid mix for production	US Mix		None	Default for NG-Pipe Pathway study
Biomass Fraction	1.2%		Energy Information Administration. (2007, February)*Annual Energy Outlook 2007 with Projections to 2030* . DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Coal Fraction	51.7%		Energy Information Administration. (2007, February)*Annual Energy Outlook 2007 with Projections to 2030* . DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Natural Gas Fraction	15.7%		Energy Information Administration. (2007, February)*Annual Energy Outlook 2007 with Projections to 2030* . DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Nuclear Fraction	20.3%		Energy Information Administration. (2007, February)*Annual Energy Outlook 2007 with Projections to 2030* . DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Residual Oil Fraction	2.9%		Energy Information Administration. (2007, February)*Annual Energy Outlook 2007 with Projections to 2030* . DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Others (Carbon Neutral)	8.2%		Energy Information Administration. (2007, February)*Annual Energy Outlook 2007 with Projections to 2030* . DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Grid mix for pipeline compressors	US Mix		None	Default for NG-Pipe Pathway study
Grid mix for compression at distribution	US Mix		None	Default for NG-Pipe Pathway study
H2 Production				
Production Facility Average Output	341,448	kg / facility d (after capacity factor is included)	Rutkowski, M. (2008, Sept 22).*Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration* . Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell C23
Corresponding capacity factor	90%		H2A Production model default	
Total Capital Investment	$180,543,901	2005 $	Rutkowski, M. (2008, Sept 22).*Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration* . Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell C98; SMR Costs based on turnkey quotation from Krupp-Uhde, updated to 2005

Parameter	Value	Units	Reference	Comments
Natural gas feedstock consumption	4.50	normal m^3 / kg H2 produced	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell E66; AspenPlus modelling for energy/material balances; "To arrive at a cost estimate for hydrogen, the design included commercially available process technology obtained from verifiable sources. The plant utilized commercially available technology including a Wabash River-scale Conoco-Phillips (EGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial pressure swing adsorption (PSA). The EGas gasifier is the gasifier of choice for this study since it has been operated on both bituminous and sub-bituminous coals." Uses Aspen Plus® Model, Haldor Topsoe commercial catalyst spec., UOP commercial PSA design spec.
Natural Gas feedstock cost	$ 0.243	2005$ / Nm^3	Industrial natural gas price from AEO 2005 "High A" case for startup year (2005). Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)	AEO 2005 High A Case - Industrial price; Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Natural Gas LHV	34,714	Btu / normal m^3 - review units	Hydrogen Analysis Resource Center. (2008, September 5) *Lower and Higher Heating Values of Hydrogen and Fuels*. Retrieved from http://hydrogen.pnl.gov/cocoon/morf/hydrogen/article/401	LHV of Natural Gas; 983 Btu/ft3
Natural gas utility consumption	0.00	normal m^3 / kg H2 produced	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	
Electricity feedstock consumption	0.00	kWh / kg H2	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	
Electricity utility consumption (both production and compression)	0.57	kWh / kg H2	Calculation	Sum of production and CSD consumption of "utility" electricity (does not include "feedstock" electricity)
Electricity utility consumption (production only)	0.57	kWh / kg H2	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell E69
Electricity Utility Price	0.0555	2005 $/kWh	Industrial electricity price from AEO 2005 "High A" case for startup year (2005). Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)	AEO 2005 High A Case - Industrial price; Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Process Water Consumption	3.36	gal / kg H2	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell D128
Water Consumption for Cooling	1.50	gal / kg H2	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell D130
Electricity co-product production	0.00	kWh / kg H2	N/A	
Oxygen co-product production	0.0	kg / kg H2	N/A	
Steam co-product production	0.0	kg / kg H2	N/A	
Total Annual Fixed Operating Costs	$6,916,975	2005$ / yr	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell C114
Total Annual Variable Operating Costs	$144,393,400	2005$ / yr	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from NG basis version 2.1.1; Input Sheet Template tab; cell C153
Total Annual Operating Costs	$151,310,375	2005$ / yr	None	Addtion of Annual Total Fixed Operating Costs and Total Annual Variable Operating Costs
Production energy efficiency (does not include electricity for forecourt compressio	71.9%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - biomass	0.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - coal	0.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - natural gas	4.4%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - ethanol	0.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - electricity	95.6%		Calculated from H2A values	Calculated from H2A values
Hydrogen outlet pressure (before CSD)	Not Available	psi	None	
Hydrogen quality before transport	99.6%	% H2	Rutkowski, M. (2008, Sept 22). *Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration*. Golden, CO: National Renewable Energy Laboratoty.	discussed in the process description
Financial Parameters				
After-tax Real IRR	10%		James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current central H2A production from SMR basis version 2.0.1; Input_Sheet_Template tab; After-tax Real IRR, cell C47
Plant Life	40	years	James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current central H2A production from SMR basis version 2.0.1; Input_Sheet_Template tab; Plant life, cell C34
Federal Tax Rate	35.0%		James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current central H2A production from SMR basis version 2.0.1; Input_Sheet_Template tab; Federal taxes, cell C49
State Tax Rate	6.0%		James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current central H2A production from SMR basis version 2.0.1; Input_Sheet_Template tab; State taxes, cell C48
Total Tax Rate	38.9%		James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current central H2A production from SMR basis version 2.0.1; Input_Sheet_Template tab; Total tax Rate, cell C50
Frection Equity	100%		James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current central H2A production from SMR basis version 2.0.1; Input_Sheet_Template tab; Equity Financing, cell C38
Transport, Delivery, and Storage Energy Requirements				
Pipeline Delivery				
Average Hydrogen Flowrate (Entering System)	348,364	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOW RATE THRU TRANSMISIIION SYSTEM=CITY PEAK DEMAND/TRANSMISIION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Average Hydrogen Flowrate (Distributed)	344,451	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation based on input parameters: city, market penetration, dispensing rate (Ave. daily use=CITY DAILY USE/TOTAL PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Summer Surge: % above the System Average Daily Demand	10%	% above Average Daily Demand	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.9. DE-FG36-05GO15032.	Nexant Report - Section 2.1.9
Friday Peak	8%	% above Average Daily Demand	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.9. DE-FG36-05GO15032.	Nexant Report - Section 2.1.9
Peak Hydrogen Flowrate	381,192	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOWRATE THRU DISTRIBUTION SYSTEM=CITY PEAK DEMAND/DISTRIBUTION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Total Capital Investment for Compressors	$27,199,794		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculations, data from disscussions with Bechtel and Air Liquide (see ref. in Nexant report - Section 2.2.5)
Hydrogen Losses from Compressors	0.50%		Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	Table 2.26
Compressor Electricity Demand	70,343,075	kWh / year	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM calculations - data from Nexant recommendations (based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand - see Nexant report - Section 2.2.5)
Compressor Electricity Demand	0.5591	kWh / kg H2	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM calculations - data from Nexant recommendations (based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand - see Nexant report - Section 2.2.5)

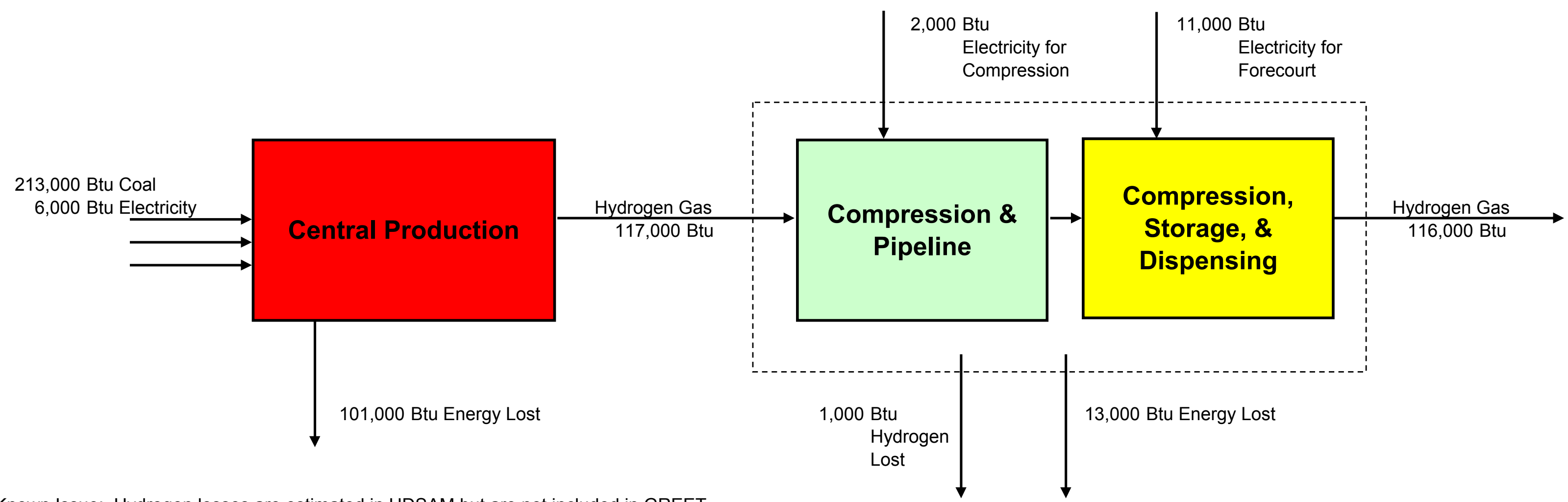
Parameter	Value	Units	Reference	Comments
Compressor Electricity Cost	$0.056	2005$ / kWh	Energy Information Administration. (2005, January)*Annual Energy Outlook 2005 with Projections to 2025* . DOE/EIA-0383(2005). Washington, D.C. Retrieved from http://www.eia.doe.gov/oiaf/archive/aeo05/index.htı	EIA AEO 2005 and 2007
Total Capital Investment for Pipeline System	$377,283,372		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.2. DE-FG36-05GO15032.	HDSAM calculations based on data from GTI, Bechtel, Air Liquide, UC Davis (Nexant Report -Section 2.2.2)
Hydrogen Losses from Pipelines	0.10%		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.14. DE-FG36-05GO15032.	Calculated based upon natural gas pipelines; Nexant report - Section 2.2.14
Number of transmission pipelines	1		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Default in HDSAM
Transmission pipeline diameter	11.00	in	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Transmission pipeline inlet pressure	999	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Transmission pipeline outlet pressure	705	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Transmission pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Transmission pipeline length	62	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Based on input parameter: city
Number of trunk pipelines	4		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . DE-FG36-05GO15032.	HDSAM calculations based on input data and HDSAM distribution model - not documented; "The pipeline model includes up to four trunk lines within a given metropolitan area with service lines extending from the trunk lines to the refueling stations. The model iterates on the number and location of trunk lines within a given metropolitan area until an optimum distribution configuration is obtained at a minimum cost." Nexant (2008) sect 2.4.3, 2.1.6, 2.2.2
Trunk #1 pipeline diameter	7.25	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Trunk #1 pipeline inlet pressure	603	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #1 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #1 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #1 pipeline length	17	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco)
Trunk #2 pipeline diameter	10.25	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Trunk #2 pipeline inlet pressure	588	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #2 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #2 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #2 pipeline length	40	miles	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2	HDSAM calculations based on input data and HDSAM distribution model - not documented
Trunk #3 pipeline diameter	12.25	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Trunk #3 pipeline inlet pressure	573	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #3 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #3 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Repor t- Section 2.1.6)
Trunk #3 pipeline length	65	miles	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2	HDSAM calculations based on input data and HDSAM distribution model - not documented
Trunk #4 pipeline diameter	10.75	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Trunk #4 pipeline inlet pressure	558	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #4 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #4 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #4 pipeline length	90	miles	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2	HDSAM calculations based on input data and HDSAM distribution model - not documented
Number of service pipelines	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco)
Service pipeline diameter	1	in	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Service pipeline inlet pressure	382	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)

Parameter	Value	Units	Reference	Comments
Service pipeline outlet pressure	294	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Service pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Service pipeline length	1.1	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco)
Pipeline Geologic Storage Total Capital Investment	$36,988,376		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase Nexant Report-Section 2.2.12)
Hydrogen Losses from Geologic Storage	0.02%		H2A Components Model User Guide, Section 6.5; Duke Energy, 2005; US EPA, 2003; Natural Resources Canada	
Geologic Storage Capacity	41,864,765	m^3	H2A Components Model User Guide, Section 6.5; Duke Energy, 2005; US EPA, 2003; Natural Resources Canada	
Geologic Storage Design Capacity	3,762,787	kg H2	H2A Components Model User Guide, Section 6.5; Duke Energy, 2005; US EPA, 2003; Natural Resources Canada	
Geologic Storage Electricity Demand	961,465	kWh / year	Nexant (2008) Section 2.2.12, 2.2.5	HDSAM calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase Nexant Report-Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Demand	0.0076	kWh / kg H2	Nexant (2008) Section 2.2.12, 2.2.5	HDSAM calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase Nexant Report-Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Cost	$0.052	2005$ / kWh	Energy Information Administration. (2005, January)*Annual Energy Outlook 2005 with Projections to 2025* . DOE/EIA-0383(2005). Washington, D.C. Retreived from http://www.eia.doe.gov/oiaf/archive/aeo05/index.htı	EIA AEO 2005
Distribution Station				
Gaseous Receiving/Distributing Stations				
Hydrogen Dispensed at Forecourt Station	465,647	kg / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B138
Electricity Required by Forecourt Station	1,416,755	kWh / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B263
Number of Compressor Stages	4	Stages in compressor	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B67
Compressor Isentropic Efficiency	65%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B69
Design Capacity	1,516	kg H2 / day	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.4. DE-FG36-05GO15032.	HDSAM version 2.02 calculation based on Chevron fueling profiles (Nexant Report - Section 2.1.4): = adjusted disp. Rate*(1+summer surge)*(1+Friday surge), Refueling Station - Gaseous H2 tab, cell B32
Operating Capacity	1,278	kg H2 / day	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Adjusted dispensing rate=city use/number of stations/utilization factor, Refueling Station - Gaseous H2 tab, cell B33
Capacity Factor	84%			calculation
Site storage (Low Pressure)	470	kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM version 2.02 calculation (Nexant Report - Section 2.2.3), Refueling Station - Gaseous H2 tab, cell B123
Site storage (Cascade)	582	kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.3.2.4 DE-FG36-05GO15032.	HDSAM calculations (Nexant Report - Section 2.3.2.4), Refueling Station - Gaseous H2 tab, cell B122
Site storage	69%	% of design H2 distribution		calculation
Dispensing Pressure	6,250	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM version 2.02 default (see Nexant Report-Section 2.3.2), Refueling Station - Gaseous H2 tab, cell B58
Hydrogen Losses due to leaks	0.50%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B79
Electrical Voltage Supply Requirement	480	Volts	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM version 2.02 calculation (see Nexant Report - Sections 2.2.5 and 2.2.6), Refueling Station - Gaseous H2 tab, cell B137
Distribution System total capital investment	$3,117,483	2005$ / station	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5.2. DE-FG36-05GO15032.	Nexant Report - Section 2.2.5.2
Distribution System electricity cost	$115,508	2005$ / station yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B267
Distribution Labor Required	3,951	hr / station yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B259
Distribution System labor cost	$39,513	2005$ / station yr	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3), Refueling Station - Gaseous H2 tab, cell B260
Distribution System total O&M cost	$298,898	2005$ / station yr	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.1.2. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (Nexant Report - Section 2.2.1.2), Refueling Station - Gaseous H2 tab, cell B283
Other Assumptions for WTW Calculations				
Share of RFG in Total Gasoline Use	100%		U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*. .	Basis for posture plan
Type of Oxygenate in RFG	None		U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*. .	Basis for posture plan
O2 Content in RFG	0%	wt %	U.S. Department of Energy & U.S. Department of Transportation. (2006, December)*Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*. .	Basis for posture plan
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2

Parameter	Value	Units	Reference	Comments
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, page 197: vehicles within the same weight class have similar tire and brake wear emissions
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory.	GREET default:well-known fuel cell emissions (no PM2.5)
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory.	GREET default:reasonable to assume FCV has same driving pattern as GV
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Marginal Electricity Generation Mix for Transportation Use	US Mix		U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*.	Basis for posture plan
Results				
Levelized Cost	$3.95	$ / kg	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Coal Input	549	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Natural Gas Input	3,922	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Petroleum Input	55	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Fossil Energy Input	4,527	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Total Energy Input	4,659	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CO2 Emissions	302	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CH4 Emissions	1	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW N2O Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW GHG Emissions	318	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799 Golden, CO: National Renewable Energy Laboratory.	MSM Results

Appendix F — Coal–Pipeline with Carbon Capture and Sequestration Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline



Known Issue: Hydrogen losses are estimated in HDSAM but are not included in GREET

Well-to-Wheels Total Energy Use (Btu/mile)	5,859
Well-to-Wheels Petroleum Energy Use (Btu/mile)	80
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	166
Levelized Cost of H2 at Pump ($/kg)	4.68

Production Process Energy Efficiency	54%
Pathway Efficiency	50%
WTP Efficiency	44%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	16

Case Definition
Year: 2005
Hydrogen as Gas
Central Production
Coal Feedstock
Sequestration: Yes
Transport for Delivery: Pipeline
Vehicle Efficiency: 45.0 mile / GGE
City Hydrogen Use: 344451 kg/day

R090819G2C_Figure.xls

Inputs	Graphic Depiction & Assumptions	Outputs

Coal Mining & Delivery

Inputs		
Coal Input from "Well"	116,427	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	145	Btu / 116000Btu to Pump
Petroleum Input from "Well"	712	Btu / 116000Btu to Pump

Coal Mining & Delivery		
Energy Recovery	99.3%	
Energy Used	7049	Btu / MMBtu Coal Delivered
Diesel Used	3948	Btu / MMBtu Coal Delivered
Electricity Used	1692	Btu / MMBtu Coal Delivered

Outputs		
Coal price at H2 production	$33.98	2005 $ / short ton
Levelized Cost of Coal	$0.31	2005$ / kg H2 distributed
WTG CO2 Emissions	114	g / 116000Btu to Pump
WTG CH4 Emissions	14	g / 116000Btu to Pump
WTG N2O Emissions	0	g / 116000Btu to Pump
WTG GHG Emissions	462	g CO2 eq./ 116000 Btu

Hydrogen Production & CCS

Inputs		
Coal consumption	7.8	kg / kg H2 produced
Natural gas consumption	0.00	N m^3/kg H2 produced
Electricity consumption	1.72	kWh / kg H2
Process Water Consumption	11.02	L / kg H2
Electricity price	$0.0555	2005 $/kWh
Total Capital Investment	$691,377,851	2005$
Coal Input from "Well"	105,782	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	3,022	Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,332	Btu / 116000Btu to Pump

Hydrogen Production & CCS		
Central plant design capacity	307,673	kg/day
Capacity factor	90%	
Process energy efficiency	53.6%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	40	
CO2 Captured for sequestration	90%	
CO2 Pipeline Length	100	miles
Number of injection wells	1	
Injection well depth	1524	m

Outputs		
Hydrogen Output Pressure	300	psi
Total capital investment	$6.84	2005$ / annual kg H2 (effective
Electricity cost	$0.10	2005$ / kg H2 produced
Natural Gas Cost	$0.00	2005$ / kg H2 produced
Other operating costs	$0.38	2005$ / kg H2 produced
Levelized Cost of Prod (excl feedst	$1.76	2005$ / kg H2 distributed
H2 Prod CO2 Emissions	3,803	g / 116000Btu to Pump
H2 Prod CH4 Emissions	13	g / 116000Btu to Pump
H2 Prod N2O Emissions	0	g / 116000Btu to Pump
H2 Prod GHG Emissions	4,136	g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs		
Electricity consumption for compressor	0.56	kWh / kg H2
Electricity consumption for geo storage	0.01	kWh / kg H2
Total electricity consumption	0.57	kWh / kg H2
Electricity price for compressor	$0.056	2005$ / kWh
Electricity price for geologic storage	$0.052	2005$ / kWh
Coal Input from "Well"	3,306	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	950	Btu / 116000Btu to Pump
Petroleum Input from "Well"	246	Btu / 116000Btu to Pump

Pipelines for Delivery		
City Population	1,247,364	people
Hydrogen Vehicle Penetration	50%	
City hydrogen use	125,810,766	kg / yr
Distance from City to Production Facility	62	miles
Geologic storage capacity	3,762,787	kg H2
Trunk #1-line length	17	miles
Trunk #2-line length	40	miles
Service-line length	1.1	miles / line
Number of service lines	270	
Hydrogen losses	1.12%	
Hydrogen loss factor	1.011	

Outputs		
Total capital investment	$3.51	2005$/annual kg distributed
Electricity cost	$0.03	2005$ / kg H2
Levelized Cost of Delivery	$0.92	2005$ / kg H2 distributed
Delivery CO2 Emissions	436	g / 116000Btu to Pump
Delivery CH4 Emissions	1	g / 116000Btu to Pump
Delivery N2O Emissions	0	g / 116000Btu to Pump
Delivery GHG Emissions	452	g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs		
Electricity consumption	3.04	kWh / kg H2
Electricity price	$0.082	2005$ / kWh
Coal Input from "Well"	17,677	Btu / 116000Btu to Pump
Natural Gas Input from "Well"	5,078	Btu / 116000Btu to Pump
Petroleum Input from "Well"	1,317	Btu / 116000Btu to Pump

Forecourt Distribution		
Number of Distribution Stations	270	
Energy efficiency	92%	
Number of Compression Steps	4	
Isentropic Efficiency	65%	
Site storage	69%	capacity
Hydrogen losses	0.50%	
Hydrogen loss factor	1.005	

Outputs		
Hydrogen outlet pressure	6,250	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxyg
Total capital investment	$6.69	2005$/annual kg
Electricity cost	$0.25	2005$ / kg H2
Levelized Cost of Distribution	$1.69	2005$ / kg H2 distributed
CSD CO2 Emissions	2,333	g / 116000Btu to Pump
CSD CH4 Emissions	3	g / 116000Btu to Pump
CSD N2O Emissions	0	g / 116000Btu to Pump
CSD GHG Emissions	2,419	g CO2 eq./ 116000 Btu

Well-to-Pump Results

Coal Input from "Well"	243,192	Btu / 116000 Btu
Natural Gas Input from "Well"	9,194	Btu / 116000 Btu
Petroleum Input from "Well"	3,608	Btu / 116000 Btu
Fossil Energy Input from "Well"	255,994	Btu / 116000 Btu
WTP CO2 Emissions	6,694	g / 116000 Btu
WTP CH4 Emissions	31	g / 116000 Btu
WTP N2O Emissions	0	g / 116000 Btu
WTP GHG Emissions	7,477	116000 Btu
Levelized Cost of Hydrogen ($/kg)	$4.68	2005 $/ kg

Vehicle

Fuel Economy	45.0	mi / GGE
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%	
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%	
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%	
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%	
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%	

Well-to-Wheel Results

Coal Input from "Well"	5,408	Btu / mi
Natural Gas Input from "Well"	204	Btu / mi
Petroleum Input from "Well"	80	Btu / mi
Fossil Energy Input from "Well"	5,693	Btu / mi
WTW CO2 Emissions	149	g / mi
WTW CH4 Emissions	1	g / mi
WTW N2O Emissions	0	g / mi
WTW GHG Emissions	166	g / mi
Levelized Cost of Hydrogen ($/mi)	$0.1040	2005 $/mi

Gasification

Coal	105,782	Btu/116000 Btu
Natural Gas	3,022	Btu/116000 Btu
Petroleum	1,332	Btu/116000 Btu
Total Energy	112,337	Btu/116000 Btu
CO2 Emissions	3,803	g/116000 Btu
CH4 Emissions	13	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	4,136	g/116000 Btu

Transport

Coal	3,306	Btu/116000 Btu
Natural Gas	950	Btu/116000 Btu
Petroleum	246	Btu/116000 Btu
Total Energy	5,938	Btu/116000 Btu
CO2 Emissions	436	g/116000 Btu
CH4 Emissions	1	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	452	g/116000 Btu

Distribution

Coal	17,677	Btu/116000 Btu
Natural Gas	5,078	Btu/116000 Btu
Petroleum	1,317	Btu/116000 Btu
Total Energy	27,816	Btu/116000 Btu
CO2 Emissions	2,333	g/116000 Btu
CH4 Emissions	3	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	2,419	g/116000 Btu

Feedstock

Coal	116,427	Btu/116000 Btu
Natural Gas	145	Btu/116000 Btu
Petroleum	712	Btu/116000 Btu
Total Energy	1,357	Btu/116000 Btu
CO2 Emissions	114	g/116000 Btu
CH4 Emissions	14	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	462	g/116000 Btu

Gasification, Conversion, & CCS

Transport

Transport Losses 0.63%

Distribution

Distribution Losses 0.50%

Total to Deliver 116000 Btu Fuel		Check
Coal	243,192	243,192
Natural Gas	9,194	9,194
Petroleum	3,608	3,608
Total Energy	147,448	147,448
CO2 Emissions	6,687	6,694
CH4 Emissions	31	31
N2O Emissions	0	0
GHG Emissions	7,470	7,477

Parameter		Value	Units	Reference	Comments
Case Definition					
	Base Year	2005		None	Default for Coal-Pipe Pathway study
	Production Technology	Coal		None	Default for Coal-Pipe Pathway study
	Form of H2 During Delivery	Gas		None	Default for Coal-Pipe Pathway study
	Delivery Mode	Pipeline		None	Default for Coal-Pipe Pathway study
	Forecourt Station Size	1278	kg/day	James, B.D. (2008, May 23). *Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day*. Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C28
	Vehicle Type	passenger cars		None	Default for Coal-Pipe Pathway study
	Vehicles' Fuel Economy	45.0	mile / gge	Rousseau, A. & Wallner, T. (2008, October 7). *Prospects on Fuel Efficiency Improvements for Hydrogen Powered Vehicles*. Argonne National Laboratory presentation, Chicago, IL. Retreived from http://www.transportation.anl.gov/pdfs/HV/530.pdf	Calculated from data in the presentation. The fuel economy for today's average mid-size vehicle was estimated by the Powertrain Simulation Analysis Toolkit V 6.2 SP1, Summer 2008 (PSAT - http://www.transportation.anl.gov/modeling_simulation/PSAT/index.html). 45 mile/gge is the estimated on-road fuel economy which was determined by multiplying the projected EPA lab-rated fuel economy of 52.5 mile/gge by 0.85.
Market Definition					
	City Population	1,247,364	people	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM City Selection; Scenario tab; Indianapolis, IN, cell B9
	Market penetration	50%	(% vehicles in city)	U.S. Department of Energy & U.S. Department of Transportation. (2006, December) *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan.*.	Basis for posture plan
	Number of H2 vehicles in city	462,772	H2 vehicles / city	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model*	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 vehicles in city, cell F17
	Miles driven per vehicle	12,000	mile / vehicle year	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model*	Key delivery input in HDSAM version 2.02; Scenario tab; Miles driven per year/ vehicle, cell C19
	City hydrogen use	344,451	kg / d	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; City H2 daily use, cell F18
	Number of H2 refueling stations in city	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 fueling stations in city, cell F19
	Number of H2 stations/Number of gasoline stations	41%		Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 stations/Number of gasoline stations, cell F21
	Average distance between stations (mi)	1.46	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006) *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Average distance between stations, cell F22
Feedstock Recovery, Processing, & Transport					
Electricity					
	Grid mix for production	US Mix		None	Default for Coal-Pipe Pathway study
	Biomass Fraction	1.2%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
	Coal Fraction	51.7%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
	Natural Gas Fraction	15.7%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
	Nuclear Fraction	20.3%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
	Residual Oil Fraction	2.9%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
	Others (Carbon Neutral)	8.2%		Energy Information Administration. (2007, February) *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
	Grid mix for pipeline compressors	US Mix		None	Default for Coal-Pipe Pathway study
	Grid mix for compression at distribution	US Mix		None	Default for Coal-Pipe Pathway study
Coal					
	Energy efficiency of coal mining and delivery	99.3%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Coal Tab B18
	Energy requirement for coal mining and delivery	7049	Btu / MMBtu	None	Calculated from energy efficiency of coal mining and delivery, cell D53
	Share of Resid Oil for coal mining & delivery	7.0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Coal Tab B22
	Share of Diesel for coal mining & delivery	56.0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Coal Tab B23
	Share of Gasoline for coal mining & delivery	3.0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Coal Tab B24
	Share of Natural Gas for coal mining & delivery	1.0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Coal Tab B25
	Share of Coal for coal mining & delivery	9.0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Coal Tab B26
	Share of Electricity for coal mining & delivery	24.0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Coal Tab B27
	Resid Oil requirement for coal mining and delivery	493	Btu / MMBtu	None	Calculated from share of reisd oil for coal mining and delivery (cell D55) times energy requirement for coal mining and delivery (cell D54)
	Diesel requirement for coal mining and delivery	3948	Btu / MMBtu	None	Calculated from share of diesel for coal mining & delivery (cell D56) times energy requirement for coal mining and delivery (cell D54)
	Gasoline requirement for coal mining and delivery	211	Btu / MMBtu	None	Calculated from share of gasoline for coal mining and delivery (cell D57) times energy requirement for coal mining and delivery (cell D54)
	Natural Gas requirement for coal mining and delivery	70	Btu / MMBtu	None	Calculated from share of reisd oil for natural gas mining and delivery (cell D58) times energy requirement for coal mining and delivery (cell D54)
	Coal requirement for coal mining and delivery	634	Btu / MMBtu	None	Calculated from share of coal for coal mining and delivery (cell D59) times energy requirement for coal mining and delivery (cell D54)
	Electricity requirement for coal mining and delivery	1692	Btu / MMBtu	None	Calculated from share of electricity for coal mining and delivery (cell D60) times energy requirement for coal mining and delivery (cell D54)
H2 Production					

Parameter	Value	Units	Reference	Comments
Production Facility Average Output	276,906	kg / facility d (after capacity factor is included)	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input_Sheet_Template tab; C23
Corresponding capacity factor	90%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input_Sheet_Template tab; Operating Capacity Factor, cell C21
Total Capital Investment	$691,377,851	2005 $	Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B. & Jechura, J. (2005, May). *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. Table 10. NREL/TP-510-37408. Golden, CO: National Renewable Energy Laboratory	Total installed capital cost of $102M ($2002) (see Table 10, Current Design) was escalated to $2005 dollars. Capital cost for additional compression was removed to maintain consistency with H2A central model assumptions.
Pittsburgh #8 coal feedstock consumption	7.8	kg / kg H2	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Results tab; Energy Data
Pittsburgh #8 coal feedstock cost	$33.98	2005 $/ton	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	
Pittsburgh #8 coal LHV	23,824,506	Btu / ton	Coal Composition for Coal Gasification to Hydrogen in Central Plants: Pittsburgh No. 8 Bituminous Coal (from M. Rutkowski of Parsons, December 2003).	
Natural gas feedstock consumption	0.00	normal m^3 / kg H2 produced	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Results tab; Energy Data
Natural gas utility consumption	0.00	normal m^3 / kg H2 produced	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	
Electricity feedstock consumption	0.00	kWh / kg H2	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Results tab; Energy Data
Electricity utility consumption (both production, carbon capture & transport, and co	1.72	kWh / kg H2	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Results tab; Energy Data
Electricity utility consumption (production only)	0.00	kWh / kg H2	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Results tab; Energy Data
Process Water Consumption	2.91	gal / kg H2	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input Sheet Template: D126
Water Consumption for Cooling	0.00000		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	N/A
Electricity co-product production	0.00	kWh / kg H2	None	N/A
Oxygen co-product production	0.0	kg / kg H2	None	N/A
Steam co-product production	0.0	kg / kg H2	None	N/A
Total Annual Fixed Operating Costs	$28,653,073	2005$ / yr	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input Sheet Template tab; Total Fixed Cost Data
Total Annual Variable Operating Costs	$37,340,700	2005$ / yr	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input Sheet Template tab; Other Variable Operating Costs Data
Total Annual Operating Costs (includes CCS)	$79,129,540	2005$ / yr	None	Addtion of Annual Total Fixed Operating Costs and Total Annual Variable Operating Costs
Production energy efficiency (does not include electricity for forecourt compressio	53.6%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - biomass	0.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - coal	94.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - natural gas	6.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - ethanol	0.0%		Calculated from H2A values	Calculated from H2A values
Share of process fuel - electricity	0.0%		Calculated from H2A values	Calculated from H2A values
Hydrogen outlet pressure (before CSD)	300	psi	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	From comments in Current central H2A production from coal basis version 2.1.1; Process Flow tab; E13
Hydrogen quality before transport	99.8%	% H2	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	From comments in Current central H2A production from coal basis version 2.1.1; Process Flow tab; E14
Carbon Capture and Sequestration				
CO_2 Captured for Sequestration	90%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C28
Electricity utility consumption (carbon capture, transport, & sequestration only)	1.72	kWh / kg H2	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C25
Electricity Utility Price for carbon capture and transport	$0.055	2005 $/kWh	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C24
Total Annual Fixed Operating Costs	$3,492,544	2005$ / yr	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell J37
Total Annual Variable Operating Costs	$9,643,224	2005$ / yr	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell J31
Compressor electricity requirement	22,044	kW	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C47
Pressure required to flow to sequestration site and be sequestered	15.0	Mpa	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C51
Isentropic Efficiency	74.0%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C54
CO_2 Pipeline Length	100	miles	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C39
Terrain Type for Pipeline	<20% Mountainous		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C37
Number of injection wells	1		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C34
Well depth	1524	m	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Carbon Sequestration tab; cell C35
Financial Parameters				
After-tax Real IRR	10%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input_Sheet_Template tab; After-tax Real IRR, cell C47
Plant Life	40	years	Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input_Sheet_Template tab; Plant life, cell C34
Federal Tax Rate	35.0%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from biomass basis version 2.1.1; Input_Sheet_Template tab; Federal taxes, cell C49
State Tax Rate	6.0%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.2; Input_Sheet_Template tab; State taxes, cell C48
Total Tax Rate	38.9%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input_Sheet_Template tab; Total tax Rate, cell C50
Frection Equity	100%		Rutkowski, M. (2008, May 28). *Current (2005) Hydrogen from Coal with CO_2 Capture and Storage*. Golden, CO: National Renewable Energy Laboratoty.	Current central H2A production from coal basis version 2.1.1; Input_Sheet_Template tab; Equity Financing, cell C38
Transport, Delivery, and Storage Energy Requirements				
Pipeline Delivery				

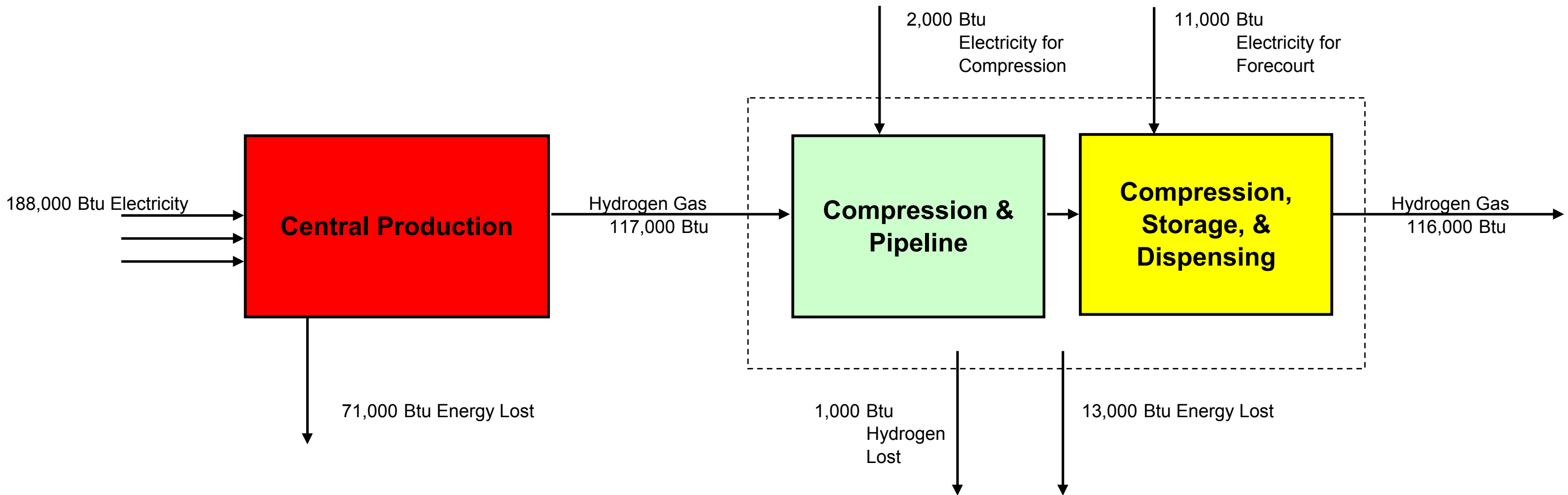
Parameter	Value	Units	Reference	Comments
Average Hydrogen Flowrate (Entering System)	348,364	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOW RATE THRU TRANSMISSION SYSTEM=CITY PEAK DEMAND/TRANSMISIION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Average Hydrogen Flowrate (Distributed)	344,451	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameters: city, market penetration, dispensing rate (Ave. daily use=CITY DAILY USE/TOTAL PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Summer Surge: % above the System Average Daily Demand	10%	% above Average Daily Demand	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM default, Scenario Parameters tab, cell B90
Friday Peak	8%	% above Average Daily Demand	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM default, Scenario Parameters tab, cell B92
Peak Hydrogen Flowrate	381,192	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOWRATE THRU DISTRIBUTION SYSTEM=CITY PEAK DEMAND/DISTRIBUTION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Total Capital Investment for Compressors	$27,199,794		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5. DE-FG36-05GO15032.	Disscussions with Bechtel and Air Liquide (Nexant report - Section 2.2.5)
Hydrogen Losses from Compressors	0.50%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM default, Refueling Station - Gaseous H2 tab, cell B79
Compressor Electricity Demand	70,343,075	kWh / year	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5. DE-FG36-05GO15032.	Based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand (Nexant report - Section 2.2.5)
Compressor Electricity Demand	0.5591	kWh / kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5. DE-FG36-05GO15032.	Based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand (see Nexant report - Section 2.2.5)
Compressor Electricity Cost	$0.056	2005$ / kWh	Energy Information Administration. (2007, February)*Annual Energy Outlook 2007 with Projections to 2030* . DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.htr	EIA AEO 2005 and 2007
Total Capital Investment for Pipeline System	$377,283,372		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.2. DE-FG36-05GO15032.	HDSAM version 2.02 calculations based on data from GTI, Bechtel, Air Liquide, UC Davis (Nexant Report -Section 2.2.2)
Hydrogen Losses from Pipelines	0.10%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	
Number of transmission pipelines	1		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Default in HDSAM version 2.02
Transmission pipeline diameter	11.00	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B83
Transmission pipeline inlet pressure	999	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Transmission pipeline outlet pressure	705	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Transmission pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Transmission pipeline length	62	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input parameter: city, Scenario Parameters tab, cell F167
Number of trunk pipelines	4		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input data and HDSAM distribution model - not documented, H2 Pipeline tab, cell B58
Trunk #1 pipeline diameter	7.25	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B84
Trunk #1 pipeline inlet pressure	603	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #1 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #1 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #1 pipeline length	17	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco), Scenario Parameters tab, cell F168
Trunk #2 pipeline diameter	10.25	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B85
Trunk #2 pipeline inlet pressure	588	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #2 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #2 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #2 pipeline length	40	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model - not documented, Scenario Parameters tab, cell F169
Trunk #3 pipeline diameter	12.25	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B86
Trunk #3 pipeline inlet pressure	573	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #3 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #3 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #3 pipeline length	65	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model - not documented, Scenario Parameters tab, cell F170

Parameter	Value	Units	Reference	Comments
Trunk #4 pipeline diameter	10.75	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B87
Trunk #4 pipeline inlet pressure	558	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #4 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #4 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Trunk #4 pipeline length	90	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model - not documented, Scenario Parameters tab, cell F171
Number of service pipelines	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco), H2 Pipeline tab, cell B67
Service pipeline diameter	1	in	Gas Processors Supplier Association. (2004). GPSA Engineering Data Book, 12th Edition. Tulsa, OK. Retrieved from http://gpaglobal.org/gpsa/book.php	HDSAM version 2.02 calculation: Panhandle B equation, H2 Pipeline tab, cell B88
Service pipeline inlet pressure	382	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Service pipeline outlet pressure	294	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Service pipeline temperature	25	C	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL (Nexant Repo Section 2.1.6)
Service pipeline length	1.1	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco), H2 Pipeline tab, cell B68
Pipeline Geologic Storage Total Capital Investment	$36,988,376		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase (Nexant Report - Section 2.2.12)
Hydrogen Losses from Geologic Storage	0.02%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	
Geologic Storage Capacity	41,864,765	m^3	Calculation	
Geologic Storage Design Capacity	3,762,787	kg H2	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model*	HDSAM version 2.02 calculation, Gaseous H2 Geological Stroage tab, cell B105
Geologic Storage Electricity Demand	961,465	kWh / year	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase (Nexant Report- Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Demand	0.0076	kWh / kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase (Nexant Report- Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Cost	$0.052	2005$ / kWh	Energy Information Administration. (2005, January)*Annual Energy Outlook 2005 with Projections*	EIA AEO 2005
Distribution Station				
Gaseous Receiving/Distributing Stations				
Hydrogen Dispensed at Forecourt Station	465,647	kg / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B138
Electricity Required by Forecourt Station	1,416,755	kWh / station year	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B263
Number of Compressor Stages	4	Stages in compressor	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B67
Compressor Isentropic Efficiency	65%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B69
Design Capacity	1,516	kg H2 / day	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.1.4. DE-FG36-05GO15032.	HDSAM version 2.02 calculation based on Chevron fueling profiles (Nexant Report - Section 2.1.4): = adjusted disp. Rate*(1+summer surge)*(1+Friday surge), Refueling Station - Gaseous H2 tab, cell B32
Operating Capacity	1,278	kg H2 / day	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	Adjusted dispensing rate=city use/number of stations/utilization factor, Refueling Station - Gaseous H2 tab, cell B33
Capacity Factor	84%			calculation
Site storage (Low Pressure)	470	kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM version 2.02 calculation (Nexant Report - Section 2.2.3), Refueling Station - Gaseous H2 tab, cell B123
Site storage (Cascade)	582	kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.3.2.4 DE-FG36-05GO15032.	HDSAM calculations (Nexant Report - Section 2.3.2.4), Refueling Station - Gaseous H2 tab, cell B122
Site storage	69%	% of design H2 distribution		calculation
Dispensing Pressure	6,250	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM version 2.02 default (see Nexant Report-Section 2.3.2), Refueling Station - Gaseous H2 tab, cell B58
Hydrogen Losses due to leaks	0.50%		Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 default, Refueling Station - Gaseous H2 tab, cell B79
Electrical Voltage Supply Requirement	480	Volts	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM version 2.02 calculation (see Nexant Report - Sections 2.2.5 and 2.2.6), Refueling Station - Gaseous H2 tab, cell B137
Distribution System total capital investment	$3,117,483	2005$ / station	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.5.2. DE-FG36-05GO15032.	Nexant Report - Section 2.2.5.2
Distribution System electricity cost	$115,508	2005$ / station yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B267
Distribution Labor Required	3,951	hr / station yr	Elgowainy, A., Mintz, M. & Gillette, J. (2006)*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0* . Argonne, IL: Argonne National Laboratory	HDSAM version 2.02 calculation, Refueling Station - Gaseous H2 tab, cell B259
Distribution System labor cost	$39,513	2005$ / station yr	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics (Nexant Report - Section 2.2.1.3), Refueling Station - Gaseous H2 tab, cell B260
Distribution System total O&M cost	$298,898	2005$ / station yr	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results* . Interim Report Section 2.2.1.2. DE-FG36-05GO15032.	HDSAM version 2.02 calculations (Nexant Report - Section 2.2.1.2), Refueling Station - Gaseous H2 tab, cell B283

Parameter	Value	Units	Reference	Comments
Other Assumptions for WTW Calculations				
Share of RFG in Total Gasoline Use	100%		U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*.	Basis for posture plan
Type of Oxygenate in RFG	None		U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*.	Basis for posture plan
O2 Content in RFG	0%	wt %	U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*.	Basis for posture plan
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, page 197: vehicles within the same weight class have similar tire and brake wear emissions
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory.	GREET default:well-known fuel cell emissions (no PM2.5)
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory.	GREET default:reasonable to assume FCV has same driving pattern as GV
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Marginal Electricity Generation Mix for Transportation Use	US Mix		U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Ingrated Research, Development and Demonstration Plan*.	Basis for posture plan
Results				
Levelized Cost	$4.68	$ / kg	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	
WTW Coal Input	5,408	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Natural Gas Input	204	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Petroleum Input	80	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Fossil Energy Input	5,693	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Total Energy Input	5,859	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CO2 Emissions	149	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CH4 Emissions	1	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW N2O Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW GHG Emissions	166	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results

Appendix G — Wind Electrolysis–Pipeline Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline



Known Issue: Hydrogen losses are estimated in HDSAM but are not included in GREET

Well-to-Wheels Total Energy Use (Btu/mile)	4,921
Well-to-Wheels Petroleum Energy Use (Btu/mile)	35
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	64
Levelized Cost of H2 at Pump ($/kg)	7.16

Production Process Energy Efficiency	62%
Pathway Efficiency	58%
WTP Efficiency	52%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	6

Case Definition
Year: 2005
Hydrogen as Gas
Central Production
Wind Feedstock
Sequestration: No
Transport for Delivery: Pipeline
Vehicle Efficiency: 45.0 mile / GGE
City Hydrogen Use: 344451 kg/day

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Inputs		Graphic Depiction & Assumptions		Outputs	

Wind Electricity

Wind-generated electricity on the grid is assumed.
The electrolyzers are not necessarily co-located with the wind farm.

Inputs		Outputs	
Coal Input from "Well"	0 Btu / 116000Btu to Pump	Electricity price at H2 production	$0.055 2005 $ / short ton
Natural Gas Input from "Well"	0 Btu / 116000Btu to Pump	Levelized Cost of Wind Electricity	$2.99 2005$ / kg H2 distributed
Petroleum Input from "Well"	0 Btu / 116000Btu to Pump	WTG CO2 Emissions	0 g / 116000Btu to Pump
		WTG CH4 Emissions	0 g / 116000Btu to Pump
		WTG N2O Emissions	0 g / 116000Btu to Pump
		WTG GHG Emissions	0 g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs		Assumptions		Outputs	
Electricity consumption	53.48 kWh / kg H2	Central plant design capacity	52,300 kg/day	Hydrogen Output Pressure	450 psi
Process Water Consumption	11.1 L / kg H2	Capacity factor	97%	Total capital investment	$5.96 2005$ / annual kg H2 (effective
Cooling Water Consumption	1112 L / kg H2	Process energy efficiency	62.3%	Electricity cost	$2.96 2005$ / kg H2 produced
Electrolyzer Cost	675 $ / kW	Electricity Mix	Wind Electricity	Other operating costs	$0.38 2005$ / kg H2 produced
Total Capital Investment	$110,432,050 2005$	After-tax IRR	10%	Levelized Cost of Prod (excl feedst	$1.56 2005$ / kg H2 distributed
		Assumed Plant Life	40		
				H2 Prod CO2 Emissions	0 g / 116000Btu to Pump
Coal Input from "Well"	0 Btu / 116000Btu to Pump			H2 Prod CH4 Emissions	0 g / 116000Btu to Pump
Natural Gas Input from "Well"	0 Btu / 116000Btu to Pump			H2 Prod N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	0 Btu / 116000Btu to Pump			H2 Prod GHG Emissions	0 g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs		Assumptions		Outputs	
Electricity consumption for compressor	0.56 kWh / kg H2			Total capital investment	$3.51 2005$/annual kg distributed
Electricity consumption for geo storage	0.01 kWh / kg H2			Electricity cost	$0.03 2005$ / kg H2
Total electricity consumption	0.57 kWh / kg H2				
Electricity price for compressor	$0.056 2005$ / kWh	City Population	1,247,364 people		
Electricity price for geologic storage	$0.052 2005$ / kWh	Hydrogen Vehicle Penetration	50%	Levelized Cost of Delivery	$0.92 2005$ / kg H2 distributed
		City hydrogen use	125,810,766 kg / yr		
		Distance from City to Production Facility	62 miles		
		Geologic storage capacity	3,762,787 kg H2		
		Trunk #1-line length	17 miles		
		Trunk #2-line length	40 miles		
		Service-line length	1.1 miles / line	Delivery CO2 Emissions	436 g / 116000Btu to Pump
Coal Input from "Well"	3,307 Btu / 116000Btu to Pump	Number of service lines	270	Delivery CH4 Emissions	1 g / 116000Btu to Pump
Natural Gas Input from "Well"	949 Btu / 116000Btu to Pump	Hydrogen losses	1.12%	Delivery N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	246 Btu / 116000Btu to Pump	Hydrogen loss factor	1.011	Delivery GHG Emissions	453 g CO2 eq./ 116000 Btu

Forecourt Distribution

Inputs		Assumptions		Outputs	
Electricity consumption	3.04 kWh / kg H2			Hydrogen outlet pressure	6,250 psi
Electricity price	$0.082 2005$ / kWh			Basis -- Hydrogen Quantity	116,000 Btu (116,000 Btu/gal non-oxyg
				Total capital investment	$6.69 2005$/annual kg
		Number of Distribution Stations	270	Electricity cost	$0.25 2005$ / kg H2
		Energy efficiency	92%		
		Number of Compression Steps	4	Levelized Cost of Distribution	$1.69 2005$ / kg H2 distributed
		Isentropic Efficiency	65%		
		Site storage	69% capacity	CSD CO2 Emissions	2,333 g / 116000Btu to Pump
Coal Input from "Well"	17,681 Btu / 116000Btu to Pump	Hydrogen losses	0.50%	CSD CH4 Emissions	3 g / 116000Btu to Pump
Natural Gas Input from "Well"	5,076 Btu / 116000Btu to Pump	Hydrogen loss factor	1.005	CSD N2O Emissions	0 g / 116000Btu to Pump
Petroleum Input from "Well"	1,317 Btu / 116000Btu to Pump			CSD GHG Emissions	2,419 g CO2 eq./ 116000 Btu

Well-to-Pump Results

Coal Input from "Well"	20,988 Btu / 116000 Btu
Natural Gas Input from "Well"	6,026 Btu / 116000 Btu
Petroleum Input from "Well"	1,564 Btu / 116000 Btu
Fossil Energy Input from "Well"	28,577 Btu / 116000 Btu
WTP CO2 Emissions	2,772 g / 116000 Btu
WTP CH4 Emissions	4 g / 116000 Btu
WTP N2O Emissions	0 g / 116000 Btu
WTP GHG Emissions	2,874 116000 Btu
Levelized Cost of Hydrogen ($/kg)	$7.16 2005 $/ kg

Vehicle

Fuel Economy	45.0 mi / GGE
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%

Well-to-Wheel Results

Coal Input from "Well"	467 Btu / mi
Natural Gas Input from "Well"	134 Btu / mi
Petroleum Input from "Well"	35 Btu / mi
Fossil Energy Input from "Well"	636 Btu / mi
WTW CO2 Emissions	62 g / mi
WTW CH4 Emissions	0 g / mi
WTW N2O Emissions	0 g / mi
WTW GHG Emissions	64 g / mi
Levelized Cost of Hydrogen ($/mi)	$0.1591 2005 $/mi

Transport

Coal	3,307	Btu/116000 Btu
Natural Gas	949	Btu/116000 Btu
Petroleum	246	Btu/116000 Btu
Total Energy	5,204	Btu/116000 Btu
CO2 Emissions	436	g/116000 Btu
CH4 Emissions	1	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	453	g/116000 Btu

Distribution

Coal	17,681	Btu/116000 Btu
Natural Gas	5,076	Btu/116000 Btu
Petroleum	1,317	Btu/116000 Btu
Total Energy	27,820	Btu/116000 Btu
CO2 Emissions	2,333	g/116000 Btu
CH4 Emissions	3	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	2,419	g/116000 Btu

Feedstock

Coal	0	Btu/116000 Btu
Natural Gas	0	Btu/116000 Btu
Petroleum	0	Btu/116000 Btu
Total Energy	188,245	Btu/116000 Btu
CO2 Emissions	0	g/116000 Btu
CH4 Emissions	0	g/116000 Btu
N2O Emissions	0	g/116000 Btu
GHG Emissions	0	g/116000 Btu

Electrolysis

Transport

Transport Losses 0.63%

Distribution

Distribution Losses 0.50%

Total to Deliver 116000 Btu Fuel		Check
Coal	20,988	20,988
Natural Gas	6,026	6,026
Petroleum	1,564	1,564
Total Energy	221,268	221,268
CO2 Emissions	2,770	2,772
CH4 Emissions	4	4
N2O Emissions	0	0
GHG Emissions	2,872	2,874

Parameter	Value	Units	Reference	Comments
Case Definition				
Base Year	2005		None	Default for Wind-Pipe Pathway study
Production Technology	Wind		None	Default for Wind-Pipe Pathway study
Form of H2 During Delivery	Gas		None	Default for Wind-Pipe Pathway study
Delivery Mode	Pipeline		None	Default for Wind-Pipe Pathway study
Forecourt Station Size	1278	kg/day	James, B.D. (2008, May 23). Current (2005) Steam Methan Reformer (SMR) at Forecourt 1500kg/day. Arlington, VA: Directed Technologies Inc.	Current forecourt H2A production from natural gas basis version 2.0.1; Input_Sheet_Template tab; Plant Output, cell C23
Vehicle Type	passenger cars		None	Default for Wind-Pipe Pathway study
Vehicles' Fuel Economy	45.0	mile / gge	Rousseau, A. & Wallner, T. (2008, October 7). *Prospects on Fuel Efficiency Improvements for Hydrogen Powered Vehicles*. Argonne National Laboratory presentation, Chicago, IL. Retreived from http://www.transportation.anl.gov/pdfs/HV/530.pdf	Calculated from data in the presentation. The fuel economy for today's average mid-size vehicle was estimated by the Powertrain Simulation Analysis Toolkit V 6.2 SP1, Summer 2008 (PSAT - http://www.transportation.anl.gov/modeling_simulation/PSAT/index.html). 45 mile/gge is the estimated on-road fuel economy which was determined by multiplying the projected EPA lab-rated fuel economy of 52.5 mile/gge by 0.85.
Market Definition				
City Population	1,247,364	people	Elgowainy, A., Mintz, M. & Gillette, J. (2006).*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM City Selection; Scenario tab; Indianapolis, IN, cell B9
Market penetration	50%	(% vehicles in city)	U.S. Department of Energy & U.S. Department of Transportation. (2006, December). Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan.	Basis for posture plan
Number of H2 vehicles in city	462,772	H2 vehicles / city	Elgowainy, A., Mintz, M. & Gillette, J. (2006). Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 vehicles in city, cell F17
Miles driven per vehicle	12,000	mile / vehicle year	Elgowainy, A., Mintz, M. & Gillette, J. (2006). Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0. Argonne, IL: Argonne National Laboratory	Key delivery input in HDSAM version 2.02; Scenario tab; Miles driven per year/ vehicle, cell C19
City hydrogen use	344,451	kg / d	Elgowainy, A., Mintz, M. & Gillette, J. (2006). Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; City H2 daily use, cell F18
Number of H2 refueling stations in city	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006). Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 fueling stations in city, cell F19
Number of H2 stations/Number of gasoline stations	41%		Elgowainy, A., Mintz, M. & Gillette, J. (2006). Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Number of H2 stations/Number of gasoline stations, cell F21
Average distance between stations (mi)	1.46	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006). Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0. Argonne, IL: Argonne National Laboratory	Demand calculation by HDSAM version 2.02; Scenario tab; Average distance between stations, cell F22
Feedstock Recovery, Processing, & Transport				
Electricity (Utility)				
Grid mix for production & delivery utility electricity	US Mix			
Biomass Fraction	1.2%		Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbo Neutral)" category
Coal Fraction	51.7%		Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbo Neutral)" category
Natural Gas Fraction	15.7%		Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbo Neutral)" category
Nuclear Fraction	20.3%		Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbo Neutral)" category
Residual Oil Fraction	2.9%		Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbo Neutral)" category
Others (Carbon Neutral)	8.2%		Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html	US grid mix. National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbo Neutral)" category
Grid mix for pipeline compressors	US Mix		None	Default for Wind-Pipe Pathway study
Grid mix for compression at distribution	US Mix		None	Default for Wind-Pipe Pathway study
Electricity (Feedstock)				
Grid mix for production	Wind Electricity		None	Default for Wind-Pipe Pathway study
H2 Production				
Production Facility Average Output	50,731	kg / facility d (after capacity factor is included)	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen from Central Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell C23
Corresponding capacity factor	97%		Ramsden, T. (2008, May 28). *Current (2005) Hydrogen from Central Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell C21 -- Note that this technology is higher than others due to its simplicity
Total Capital Investment	$110,432,050	2005 $	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen from Central Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell C96
Electricity feedstock consumption	53.5	kWh / kg H2	Ramsden, T. (2008, May 28). *Current (2005) Hydrogen from Central Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell E66; 62% Efficiency on LHV basis from Norsk Hydro Quote
Electricity feedstock cost	$0.055	2005 $/kWh	Energy Information Administation. (2005, February).*Annual Energy Outlook 2005 With Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C.: U.S. Department of Energy.	Assumed that wind electricity price would match industrial electricity price from AEO 2005 "High A" case for startup year (2005). Escalated from 2003 dollars to 2005 dollars. File downloaded from http://www.eia.doe.gov/oiaf/aeo/index.html (file name aeo_hw-3.xls)
Electricity utility consumption (both production, carbon capture & transport, and c	0.00	kWh / kg H2		All electricity is considered feedstock.
Electricity utility consumption (production only)	0.00	kWh / kg H2		All electricity is considered feedstock.
Process Water Consumption	2.94	gal / kg H2	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell D126. Value from Norsk Hydro Quote (2002) 1L per Nm3 H2 At 89.9 g H2/Nm3 and 3.785L/gal, this equals 2.939 gal/kg
Water Consumption for Cooling	294	gal / kg H2	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell D128; ASPEN modeling - see ProcessFlow sheet for details (Mike Penev) in Ramsden, 2008.

Parameter	Value	Units	Reference	Comments
Compressed Inert Gas	0.023	Nm^3 / kg H2	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell D130
Electricity co-product production	0.00	kWh / kg H2		N/A
Oxygen co-product production	0.0	kg / kg H2		N/A
Steam co-product production	0.0	kg / kg H2		N/A
Electrolyzer Equipment Cost (Uninstalled)	$675	$ / kW	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Capital Costs tab; Cell C32 - Taken from a Norsk Hydro Quote
Total Annual Fixed Operating Costs	$5,413,991	2005$ / yr	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell "fixed" = C112
Total Annual Variable Operating Costs	$55,873,500	2005$ / yr	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from electricity basis version 2.1.2; Input_Sheet_Template tab; cell "total_var" = C153
Total Annual Operating Costs	$61,287,491	2005$ / yr	Calculation	Sum of fixed and variable operating costs
Production energy efficiency (does not include electricity for CSD)	62.3%		Calculated from H2A values	Calculated from H2A values based on Electricity requirement which was stated in Norsk Hydro Quote
Hydrogen outlet pressure (before CSD)	450	psi	Ramsden, T. (2008, July 2). *Current (2005) Hydrogen Production from Distributed Grid Electrolysis*. Golden, CO: National Renewable Energy Laboratory.	Discussion on Description tab
Hydrogen quality before transport	99.990%	% H2	D. Steward (personal communication).	
Financial Parameters				
After-tax Real IRR	10%		Mann, M., & Steward, D.M. (2008, May 28). Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; After-tax Real IRR, cell C47
Plant Life	40	years	Mann, M., & Steward, D.M. (2008, May 28). Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Plant life, cell C34
Federal Tax Rate	35.0%		Mann, M., & Steward, D.M. (2008, May 28). Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Federal taxes, cell C49
State Tax Rate	6.0%		Mann, M., & Steward, D.M. (2008, May 28). Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; State taxes, cell C48
Total Tax Rate	38.9%		Mann, M., & Steward, D.M. (2008, May 28). Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Total tax Rate, cell C50
Frection Equity	100%		Mann, M., & Steward, D.M. (2008, May 28). Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming. Golden, CO: National Renewable Energy Laboratory.	Current central H2A production from biomass basis version 2.1.2; Input_Sheet_Template tab; Equity Financing, cell C38
Transport, Delivery, and Storage Energy Requirements				
Pipeline Delivery				
Average Hydrogen Flowrate (Entering System)	348,364	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006).*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOW RATE THRU TRANSMISIIION SYSTEM=CITY PEAK DEMAND/TRANSMISIION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Average Hydrogen Flowrate (Distributed)	344,451	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006).*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation based on input parameters: city, market penetration, dispensing rate (Ave. daily use=CITY DAILY USE/TOTAL PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Summer Surge: % above the System Average Daily Demand	10%	% above Average Daily Demand	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.9. DE-FG36-05GO15032.	Nexant Report - Section 2.1.9
Friday Peak	8%	% above Average Daily Demand	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.9. DE-FG36-05GO15032.	Nexant Report - Section 2.1.9
Peak Hydrogen Flowrate	381,192	kg/hr	Elgowainy, A., Mintz, M. & Gillette, J. (2006).*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation based on input parameters: city, market penetration, dispensing rate (PEAK FLOWRATE THRU DISTRIBUTION SYSTEM=CITY PEAK DEMAND/DISTRIBUTION PIPELINE MASS EFFICIENCY/REF.STATION MASS EFFICIENCY)
Total Capital Investment for Compressors	$27,199,794		Elgowainy, A., Mintz, M. & Gillette, J. (2006).*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculations, data from disscussions with Bechtel and Air Liquide (see ref. in Nexant report - Section 2.2.5)
Hydrogen Losses from Compressors	0.50%		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	Table 2.26
Compressor Electricity Demand	70,343,075	kWh / year	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM calculations - data from Nexant recommendations (based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand - see Nexant report - Section 2.2.5)
Compressor Electricity Demand	0.5591	kWh / kg H2	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM calculations - data from Nexant recommendations (based on vendor data from Neuman&Esser, Burckhardt Compression, Ariel Compressors, Dresser-Rand - see Nexant report - Section 2.2.5)
Compressor Electricity Cost	$0.056	2005$ / kWh	Energy Information Administration. (2005, January).*Annual Energy Outlook 2005 with Projections to 2025*. DOE/EIA-0383(2005). Washington, D.C. Retreived from http://www.eia.doe.gov/oiaf/archive/aeo05/index.html	EIA AEO 2005 and 2007
Total Capital Investment for Pipeline System	$377,283,372		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.2. DE-FG36-05GO15032.	HDSAM calculations based on data from GTI, Bechtel, Air Liquide, UC Davis (Nexant Report -Section 2.2.2)
Hydrogen Losses from Pipelines	0.10%		Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.14. DE-FG36-05GO15032.	Calculated based upon natural gas pipelines; Nexant report - Section 2.2.14
Number of transmission pipelines	1		Elgowainy, A., Mintz, M. & Gillette, J. (2006).*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Default in HDSAM
Transmission pipeline diameter	11.00	in	Elgowainy, A., Mintz, M. & Gillette, J. (2006).*Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Transmission pipeline inlet pressure	999	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Transmission pipeline outlet pressure	705	psi	Nexant, Inc. et al. (2008, May).*H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)

Parameter	Value	Units	Reference	Comments
Transmission pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Transmission pipeline length	62	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	Based on input parameter: city
Number of trunk pipelines	4		Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. DE-FG36-05GO15032.	HDSAM calculations based on input data and HDSAM distribution model - not documented; "The pipeline model includes up to four trunk lines within a given metropolitan area with service lines extending from the trunk lines to the refueling stations. The model iterates on the number and location of trunk lines within a given metropolitan area until an optimum distribution configuration is obtained at a minimum cost." Nexant (2008) sect 2.4.3, 2.1.6, 2.2.2
Trunk #1 pipeline diameter	7.25	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com) Equations and explanations can be found in Component Delivery User Guide.
Trunk #1 pipeline inlet pressure	603	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #1 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #1 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #1 pipeline length	17	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco)
Trunk #2 pipeline diameter	10.25	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com) Equations and explanations can be found in Component Delivery User Guide.
Trunk #2 pipeline inlet pressure	588	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #2 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #2 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #2 pipeline length	40	miles	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2	HDSAM calculations based on input data and HDSAM distribution model - not documented
Trunk #3 pipeline diameter	12.25	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com) Equations and explanations can be found in Component Delivery User Guide.
Trunk #3 pipeline inlet pressure	573	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #3 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #3 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #3 pipeline length	65	miles	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2	HDSAM calculations based on input data and HDSAM distribution model - not documented
Trunk #4 pipeline diameter	10.75	in	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2; H2A Delivery Components User Guide (2006) sect 5.15.4	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com) Equations and explanations can be found in Component Delivery User Guide.
Trunk #4 pipeline inlet pressure	558	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #4 pipeline outlet pressure	397	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #4 pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Trunk #4 pipeline length	90	miles	Nexant (2008) Section 2.4.3, 2.1.6, 2.2.2	HDSAM calculations based on input data and HDSAM distribution model - not documented
Number of service pipelines	270		Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco)
Service pipeline diameter	1	in	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM Calculation: Panhandle B equation (Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com)
Service pipeline inlet pressure	382	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Service pipeline outlet pressure	294	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Service pipeline temperature	25	C	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.6. DE-FG36-05GO15032.	Recommendations from Nexant in conjuction with Air Liquide, GTI, Chevron, TIAX, ANL, PNNL and NREL - see Nexant Report - Section 2.1.6)
Service pipeline length	1.1	miles	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculations based on input data and HDSAM distribution model (discussions with Pacific Gas & Electric Company, San Francisco)
Pipeline Geologic Storage Total Capital Investment	$36,988,376		Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.12. DE-FG36-05GO15032.	HDSAM calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase. Nexant Repor Section 2.2.12)
Hydrogen Losses from Geologic Storage	0.02%		H2A Components Model User Guide, Section 6.5; Duke Energy, 2005; US EPA, 2003; Natural	
Geologic Storage Capacity	41,864,765	m^3	H2A Components Model User Guide, Section 6.5; Duke Energy, 2005; US EPA, 2003; Natural	

Parameter	Value	Units	Reference	Comments
Geologic Storage Design Capacity	3,762,787	kg H2	H2A Components Model User Guide, Section 6.5; Duke Energy, 2005; US EPA, 2003; Natural	
Geologic Storage Electricity Demand	961,465	kWh / year	Nexant (2008) Section 2.2.12, 2.2.5	HDSAM calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase. Nexant Repor Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Demand	0.0076	kWh / kg H2	Nexant (2008) Section 2.2.12, 2.2.5	HDSAM calculations (cost data from ConocoPhilips and Saltville natural gas storage facility in Virginiase. Nexant Repor Sections 2.2.12 and 2.2.5)
Geologic Storage Electricity Cost	$0.052	2005$ / kWh		EIA AEO 2005
Distribution Station				
Gaseous Receiving/Distributing Stations				
Hydrogen Dispensed at Forecourt Station	465,647	kg / station year	Nexant (2008) Section 2.1.3, 2.1.5	HDSAM calculation
Electricity Required by Forecourt Station	1,416,755	kWh / station year	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.6. DE-FG36-05GO15032.	HDSAM calculation
Number of Compressor Stages	4	Stages in compressor	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5. DE-FG36-05GO15032.	HDSAM default
Compressor Isentropic Efficiency	65%		Nexant 2008, Section 2.2.3.3, 2.2.5.2	HDSAM default;small compressor isentropic efficiency 65%, large 88%
Design Capacity	1,516	kg H2 / day	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	HDSAM calculation based on Chevron fueling profiles (see Nexant Report-Section 2.1.4): = adjusted disp. Rate*(1+summer surge)*(1+Friday surge)
Operating Capacity	1,278	kg H2 / day	Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	adjusted dispensing rate=city use/numberof stations/utilization factor
Capacity Factor	84%		Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.1.5. DE-FG36-05GO15032.	Calculation; according to Nexant report the station does not have a capacity factor (did in v1 H2A, not in v2) so not sure what the refers to.
Site storage (Low Pressure)	470	kg H2	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.3. DE-FG36-05GO15032.	HDSAM calculation, see description in Nexant Report-Section 2.2.3
Site storage (Cascade)	582	kg H2	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.3.2.4. DE-FG36-05GO15032.	HDSAM calculations (see description in Nexant Report-Section 2.3.2.4)
Site storage	69%	% of design H2 distribution	Nexant 2008, Section 2.1.9, 2.2.3.4	calculation
Dispensing Pressure	6,250	psi	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.3.2. DE-FG36-05GO15032.	HDSAM Default (see Nexant Report-Section 2.3.2)
Hydrogen Losses due to leaks	0.50%		Elgowainy, A., Mintz, M. & Gillette, J. (2006). *Hydrogen Delivery Scenario Analysis Model (HDSAM) V2.0*. Argonne, IL: Argonne National Laboratory	
Electrical Voltage Supply Requirement	480	Volts	Nexant (2008) Section 2.2.5, 2.2.6	HDSAM calculation (see Nexant Report - Sections 2.2.5 and 2.2.6)
Distribution System total capital investment	$3,117,483	2005$ / station	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.5.2. DE-FG36-05GO15032.	See Nexant Report-Section 2.2.5.2)
Distribution System electricity cost	$115,508	2005$ / station yr	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.6. DE-FG36-05GO15032.	HDSAM calculation
Distribution Labor Required	3,951	hr / station yr	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	HDSAM calculation
Distribution System labor cost	$39,513	2005$ / station yr	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.3. DE-FG36-05GO15032.	Bureau of Labor and Statistics, Nexant Report - Section 2.2.1.3
Distribution System total O&M cost	$298,898	2005$ / station yr	Nexant, Inc. et al. (2008, May). *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. Interim Report Section 2.2.1.2. DE-FG36-05GO15032.	HDSAM calculations - see recommendations in Nexant Report-Section 2.2.1.2
Other Assumptions for WTW Calculations				
Share of RFG in Total Gasoline Use	100%		U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Type of Oxygenate in RFG	None		U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
O2 Content in RFG	0%	wt %	U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Ratio of FCV VOCs (emissions) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV CO emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV NOx emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Ratio of FCV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, page 197: vehicles within the same weight class have similar tire and brake wear emissions
Ratio of FCV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory.	GREET default:well-known fuel cell emissions (no PM2.5)
Ratio of FCV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Wang, M.Q. (2008, September 5). *The Greenhouse Gases, Regualted Emissions, and Energy Use in Transportation (GREET) Model, Version 1.8b*. Argonne, IL: Argonne National Laboratory.	GREET default:reasonable to assume FCV has same driving pattern as GV
Ratio of FCV CH4 emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2

Parameter	Value	Units	Reference	Comments
Ratio of FCV N2O emissions to GVs fueled with CG & RFG	0%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET default, Table 4.45 FCV: H2
Marginal Electricity Generation Mix for Transportation Use	US Mix		U.S. Department of Energy & U.S. Department of Transportation. (2006, December). *Hydrogen Posture Plan An Inegrated Research, Development and Demonstration Plan*.	Basis for posture plan
Results				
Levelized Cost	$7.16	$ / kg	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Coal Input	467	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Natural Gas Input	134	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Petroleum Input	35	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Fossil Energy Input	636	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW Total Energy Input	4,921	Btu / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CO2 Emissions	62	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW CH4 Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW N2O Emissions	0	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results
WTW GHG Emissions	64	g / mile	Ruth, M. et al. (2009, March). Hydrogen Macro System Model User Guide. NREL/TP-6A1-44799. Golden, CO: National Renewable Energy Laboratory.	MSM Results

Appendix H — Platinum Resource Availability and Cost

Although a lot of research is being done to reduce the platinum loading in proton exchange membrane (PEM) fuel cells, platinum catalyst is critical to the performance of current PEM fuel cell technology. Platinum catalyst was projected by TIAX (Kromer et. al, 2009) in 2008 to contribute 31% of the total fuel cell system factory cost. Current Pt loading in fuel cell vehicles (FCVs) is 32–45 g/vehicle. The DOE target is to reduce this loading to 15 g/FCV by 2015. The target for FCVs is still about fivefold greater than the Pt loading for internal combustion engine (ICE) vehicles: 2.5–3.3 g/vehicle (associated with the autocatalyst). At the 2007 average Pt price of $1,300/troy ounce, 15 g Pt will cost ~$750 (Rhodes and Kromer, 2008).

An implicit assumption in this study is that PEM FCVs will achieve cost parity with internal combustion engine vehicles. Although the cost and availability of platinum will not affect the hydrogen cost directly for the pathways studied, it will impact the cost of the FCV and, therefore, the rate at which FCVs can be commercialized. Demand for hydrogen will depend on the rate of FCV deployment, and the viability of various hydrogen production and delivery pathways will depend on hydrogen demand.

Availability and Utilization

The Stillwater and East Boulder mines in Montana are the only primary platinum group metal (PGM) mines in the United States. During 2008, those mines produced 3,700 kg of platinum, which was down from 3,860 kg in 2007. An estimated 26,000 kg of PGMs were recovered from new and old scrap in 2008. Platinum imports for consumption were 181,000 and 195,000 kg for 2007 and 2008, respectively. The United States has a reserve of 900,000 kg and a reserve base of 2,000,000 kg of platinum (United States Geological Survey, 2009). The reserve base is the part of platinum that meets specified minimum physical and chemical criteria related to current mining and production practices, including grade, quality, thickness and depth. Reserves are the part of the reserve base that could be economically extracted or produced at the time of determination.

TIAX, LLC (Rhodes and Kromer, 2008) projected that world resources for all PGMs are ~160,000 Mg; platinum resources are ~76,000 Mg. South Africa produces ~80% of the world's platinum supply of ~200 Mg per year (Figure H.0.1). The historical growth rate of primary Pt demand (from 1960 to 2007) is 3 Mg/yr; recent growth rates (1999–2007) have been closer to 6–7 Mg/yr. (Primary Pt refers to platinum that is directly mined in contrast to secondary Pt, which is recycled.)

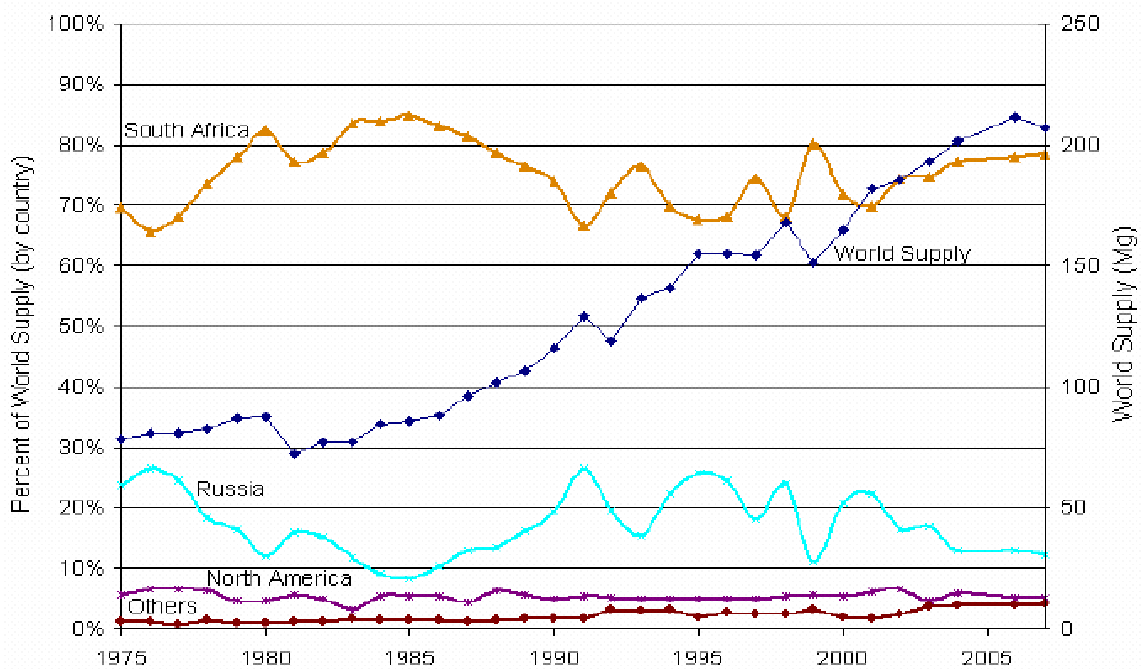


Figure H.0.1. World platinum supply (Rhodes and Kromer, 2008)

TIAX (Rhodes and Kromer, 2008) assessed worldwide platinum availability for FCVs and concluded that platinum resources are sufficient to meet significant FCV demand but that FCV demand growth may be constrained by primary platinum supply. Long-term projections for the global transportation sector were developed based on population projections, vehicle-per-capita scenarios, and projected ICE vehicle and FCV Pt requirements. Population projections and vehicle–per-capita projections were used to develop a total vehicle forecast, which included replacement demand and new demand. The total vehicle forecast and fuel cell and internal combustion powertrain Pt requirements were used to determine the FCV projection, which in turn was used to develop the Pt demand versus time. United Nations forecasts were used for the population projections. The EIA Annual Energy Outlook 2003 provided near-term annual vehicle per capita growth estimates.

Two scenarios were considered: 1) FCVs achieve market share of 50% in the global light-duty vehicle market by 2050, and 2) FCVs achieve market share of 80% in the global light-duty vehicle market by 2050 (Figure H.0.2). A growth rate in primary Pt demand of 12 Mg/yr would be necessary for the 50% scenario, and 23 Mg/yr would be needed to achieve the 80% scenario (Figure H.0.3). Annual primary platinum supply increased by an average of 3 Mg/yr from 1960 to 2007 with average increases of 6.3 Mg/yr from 1999 to 2004. The platinum industry developed plans in 2003 to expand production by 13 Mg/yr. Thus, the lower growth rate is considered achievable while the higher growth rate is considered beyond reasonable growth expectations (Rhodes and Kromer, 2008).

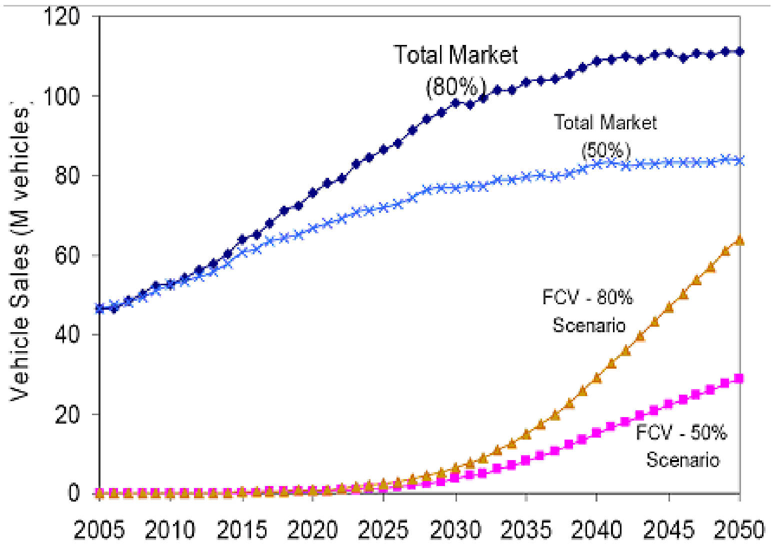


Figure H.0.2. Projected worldwide vehicle sales (Kromer, Rhodes, and Guernsey, 2008)

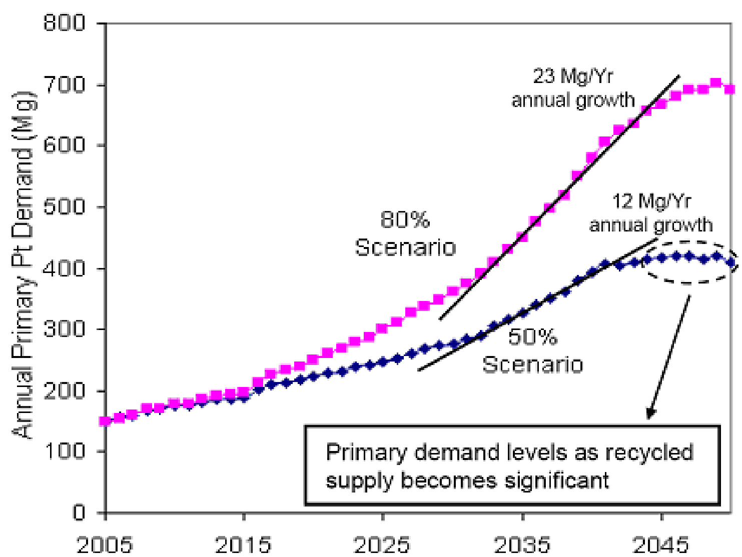


Figure H.0.3. Projected primary platinum demand (Kromer, Rhodes, and Guernsey, 2008)

Resource Cost

In 2008, platinum reached its all-time highest annual average price of $1,680 per troy ounce. That price is up from $1,308 per troy ounce in 2007 (United States Geological Survey, 2009).

Appendix I — Enlarged Graphics

The following figures from the previous sections are enlarged in this section for ease of viewing.

- Figure 3.2.1. Efficiency in electricity generation from various sources (van Aart, 2004)
- Figure 3.2.2. Installed wind capacity as of April 2009 (National Renewable Energy Laboratory, 2009)
- Figure 3.2.3. U.S. wind resource map (National Renewable Energy Laboratory, 2009)
- Figure 3.5.2. Regional carbon sequestration partnerships and their respective validation carbon storage projects (National Energy Technology Laboratory, 2008)
- Table 4.1.1. Natural Gas Pipeline Mileage (Energy Information Administration, 2008e)
- Figure 4.1.3. Hypothetical pressures (psig) in distribution mains at maximum design flows (Vidas, 2007)
- Figure 5.1.1. Distributed natural gas reforming process flow diagram (James, 2008)
- Figure 5.2.1. Distributed electrolysis process flow diagram (Ramsden, 2008b)
- Figure 5.2.3. Distributed electrolysis process flow diagram cooling water detail (Ramsden, 2008b)
- Figure 5.3.1. Central biomass gasification flow diagram (Mann and Steward, 2008)
- Figure 9.1.2. Cost analysis inputs and high-level results for distributed natural gas pathway
- Figure 9.1.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using distributed natural gas pathway
- Figure 9.1.9. Production sensitivities for distributed natural gas pathway
- Figure 9.1.10. Production sensitivities for distributed natural gas pathway with advanced technology
- Figure 9.2.2. Cost analysis inputs and high-level results for distributed electricity pathway
- Figure 9.2.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using distributed electricity pathway
- Figure 9.2.9. Production sensitivities for distributed electrolysis pathway
- Figure 9.3.2. Cost analysis inputs and high-level results for central biomass–liquid truck delivery pathway
- Figure 9.3.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central biomass–liquid truck delivery pathway
- Figure 9.3.9. Production sensitivities for central biomass–liquid truck delivery pathway
- Figure 9.4.2. Cost analysis inputs and high-level results for central biomass–pipeline delivery pathway
- Figure 9.4.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central biomass–pipeline delivery pathway
- Figure 9.4.9. Production sensitivities for central biomass–pipeline delivery pathway

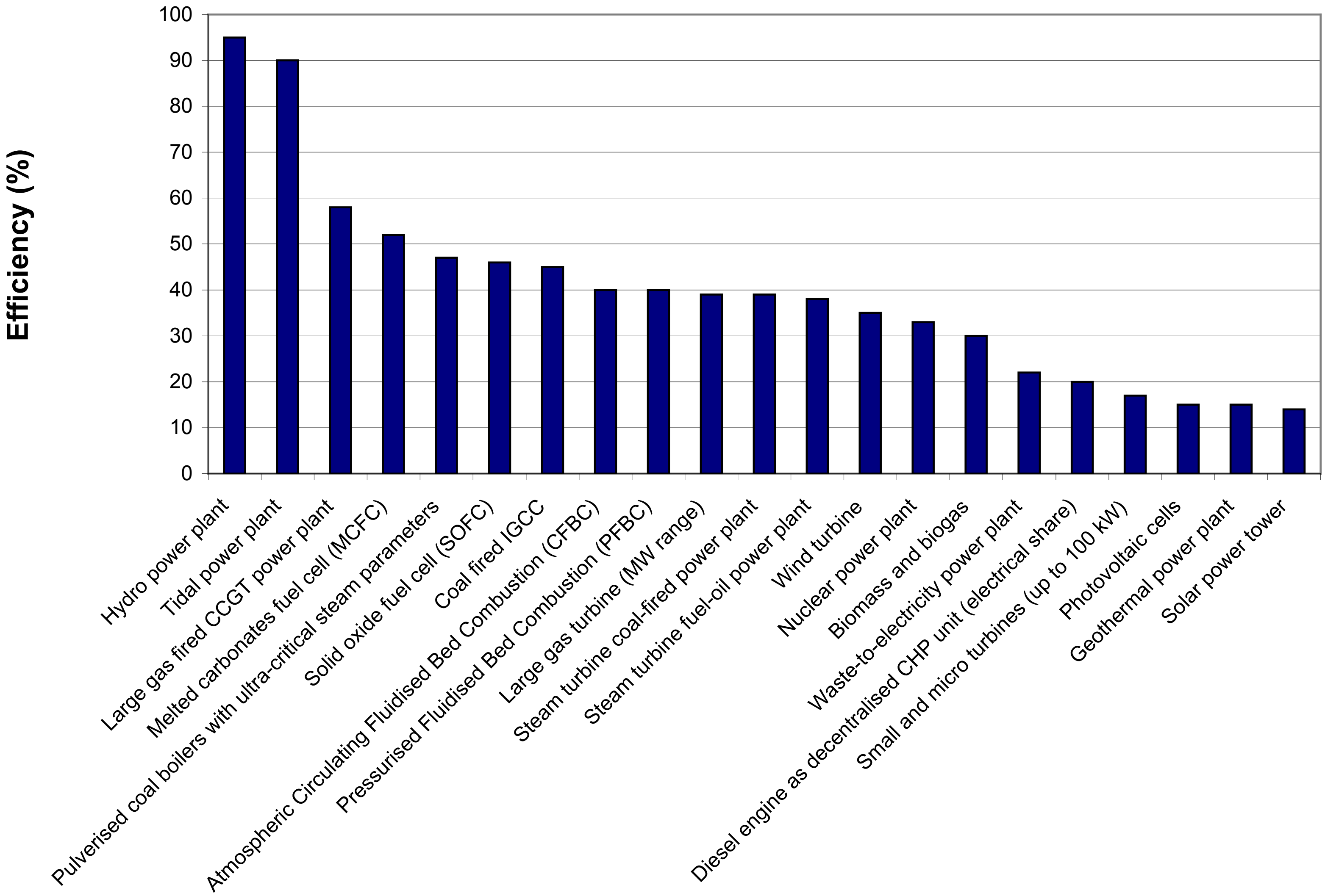


Figure 3.2.1. Efficiency in electricity generation from various sources (van Aart, 2004)

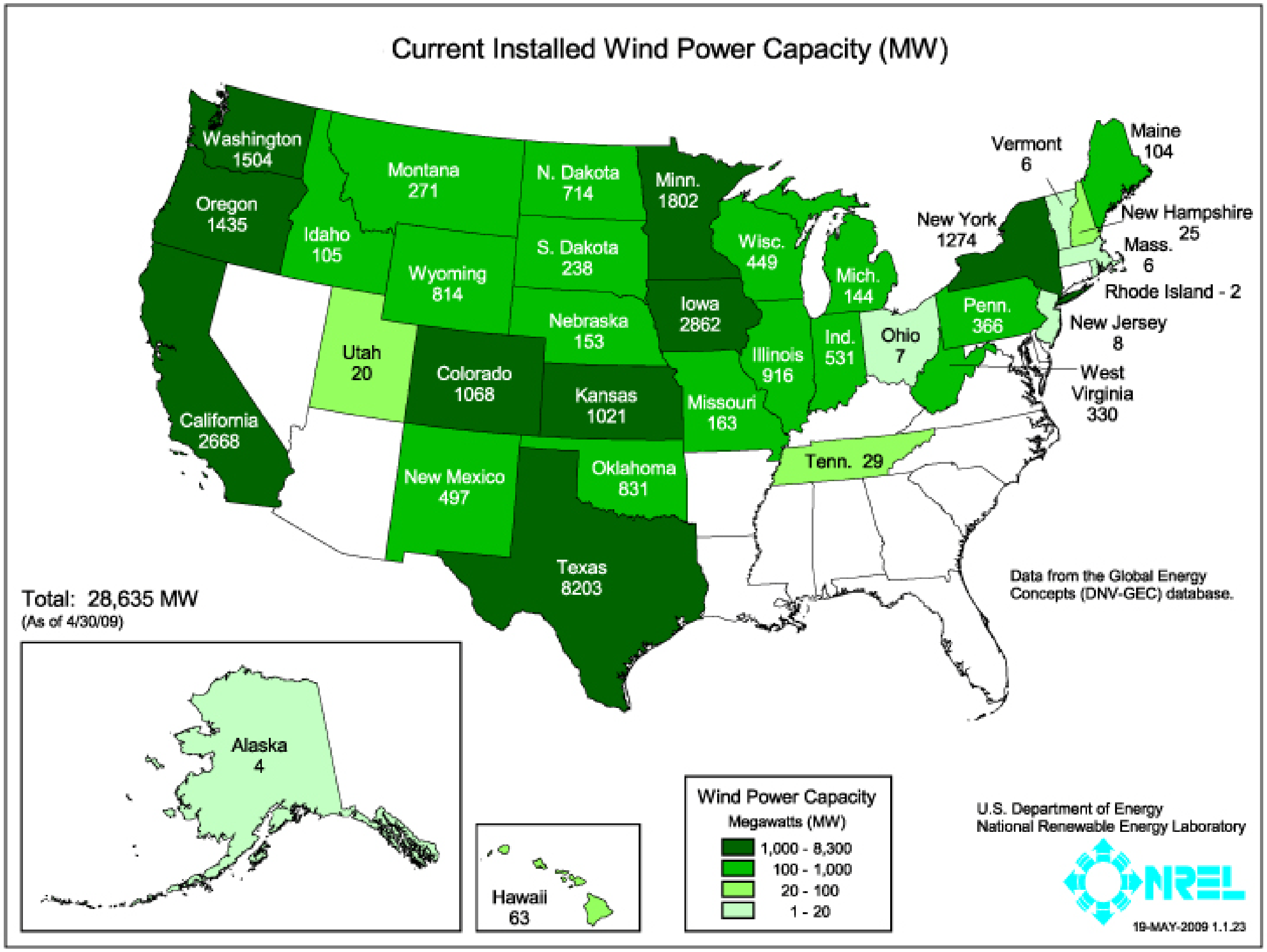


Figure 3.2.2. Installed wind capacity as of April 2009 (National Renewable Energy Laboratory, 2009)

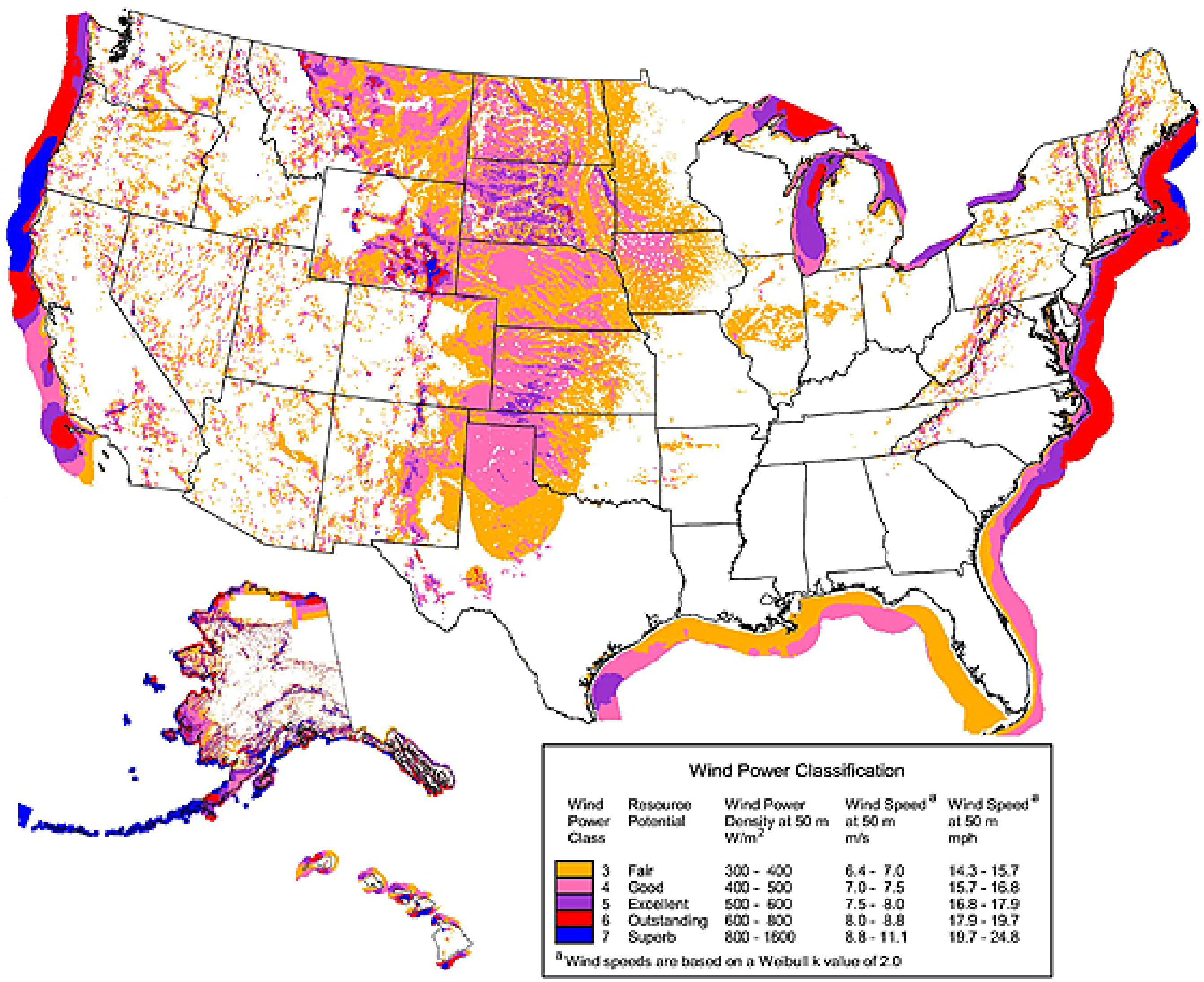
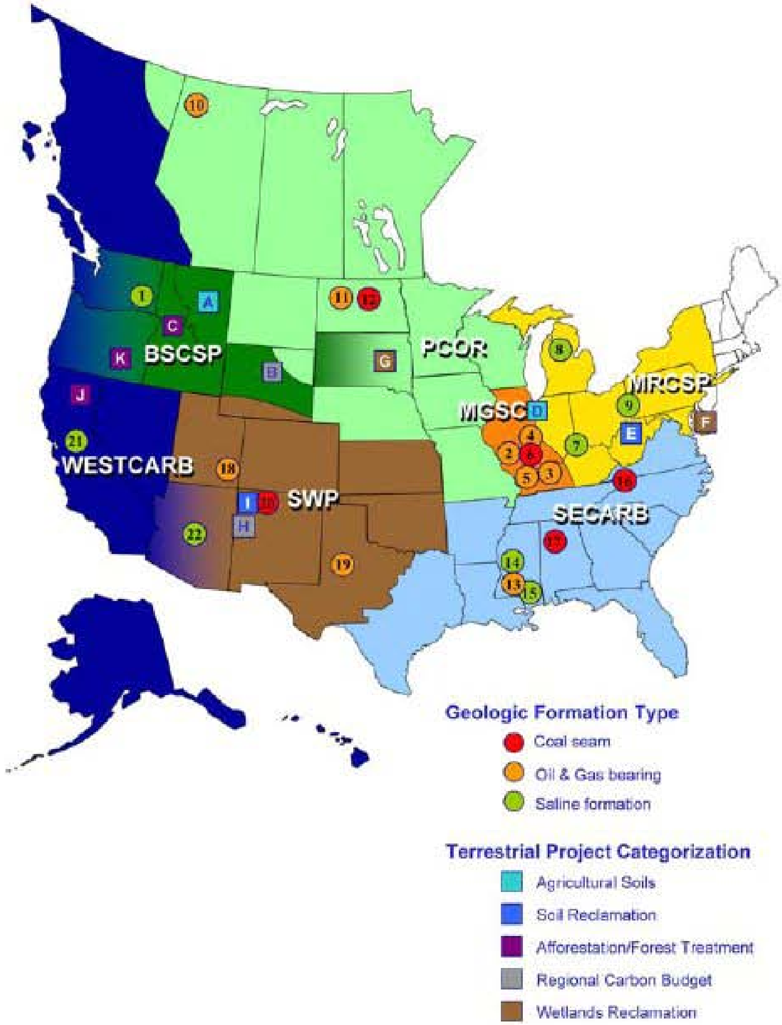


Figure 3.2.3. U.S. wind resource map (National Renewable Energy Laboratory, 2009)



	Partnership	Geologic Province / Project Location	Geologic: Total CO_2 Injection (tons CO_2)	Geologic: Approximate Depth (feet)	Terrestrial: Estimated CO_2 Capacity
1	Big Sky Carbon	Columbia Basin	3,000	2,500 – 4,000	
A		North Central MT			60 Mt over 20 years
B		Eastern WY			30 Mt over 10 years
C		Region-wide			640 - 1,040 Mt over 80 yrs
2	MGSC	Illinois Basin	50	1,550	
3		Illinois Basin	1,000	1,549	
4		Illinois Basin	3,000	1,548	
5		Illinois Basin	3,000	1,551	
6		Illinois Basin	200	1,000	
7	MRCSP	Cincinnati Arch	3,000	3,200 – 3,500	
8		Michigan Basin	10,000	3,200 – 3,500	
9		Appalachian Basin	3,000	6,900 – 8,300	
D		Region-wide			25 Mt over 20 years
E		Region-wide			100 Mt over 20 years
F		Cambridge, MD			TBD
10	PCOR	Keg River Formation	100,000	5,000	
11		Duperow Formation	<1,000	10,000 – 10,500	
12		Williston Basin	<1,000	1,600 – 1,800	
G		Great Plains wetlands complex (PPR)			14.4 Mt
13	SECARB	Gulf Coast (stacked test)	500,000	10,304	
14		Gulf Coast (stacked test)		10,400	
15		Mississippi Coastal Plain	3,000	8,500	
16		Central Appalachian	1,000	1,600 – 2,300	
17		Black Warrior Basin	1,000	1,500 – 2,500	
18	SWP	Paradox Basin, Aneth Field	450,000	5,600 – 5,800	
19		Permian Basin	900,000	5,800	
20		San Juan Basin	75,000	3,000	
H		Region-wide			TBD
I		San Juan Basin Coal Fairway (Navajo City, NM)			TBD
21	WESTCARB	Sacramento Basin	2,000	8,000	
22		Colorado Plateau	2,000	4,000	
J		Shasta County, CA			4,600 Mt over 80 years (CA)
K		Lake County, OR			900 Mt over 80 years (OR)

Figure 3.5.2. Regional carbon sequestration partnerships and their respective validation carbon storage projects (National Energy Technology Laboratory, 2008)

Table 4.1.1. Natural Gas Pipeline Mileage (Energy Information Administration, 2008e)

Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage	Region/ State	Pipeline Mileage
Central		**Midwest**		**Northeast**		**Southeast**		**Southwest**		**Western**	
Colorado	7,803	Illinois	11,911	Connecticut	628	Alabama	4,818	Arkansas	6,267	Arizona	5,989
Iowa	5,421	Indiana	4,704	Delaware	280	Florida	4,971	Louisiana	18,900	California	11,770
Kansas	15,386	Michigan	9,722	Maine	609	Georgia	3,483	New Mexico	6,756	Idaho	1,567
Missouri	3,944	Minnesota	4,447	Maryland/DC	1,022	Kentucky	6,892	Oklahoma	18,539	Nevada	1,469
Montana	3,861	Ohio	7,670	Massachusetts	972	Mississippi	9,784	Texas	58,588	Oregon	1,823
Nebraska	5,697	Wisconsin	3,471	New Hampshire	291	North Carolina	2,484	.	109,050	Washington	2,072
North Dakota	1,873		41,925	New Jersey	1,520	South Carolina	2,265				24,690
South Dakota	1,242			New York	5,018	Tennessee	4,304				
Utah	3,175			Pennsylvania	8,680		39,001	Gulf Mexico[1]	9,458		
Wyoming	7,902			Rhode Island	100						
	56,304			Vermont	71						
				Virginia	2,577			Total US Pipeline Mileage			305,954
				West Virginia	3,758			Total Interstate[1]			217,306
					25,526			Total Non-interstate[2]			88,648

[1] In the Gulf of Mexico some large-scale gathering systems are FERC jurisdictional and are therefore counted as interstate.

[2] Includes intrastate transmission and non-FERC jurisdictional large diameter gathering systems or headers. Local distribution company (LDC) mileage excluded.

Note: All mileage is approximate. Includes looped pipeline segments. Approximately 73 percent of Interstate pipeline systems are made up of pipeline diameters exceeding 16 inches while only 34 percent of non-interstate pipeline systems are 16 inches or larger.

Source: Energy Information Administration, Gas Transportation Information System, Pipeline Map Files and Pipeline Projects Database.

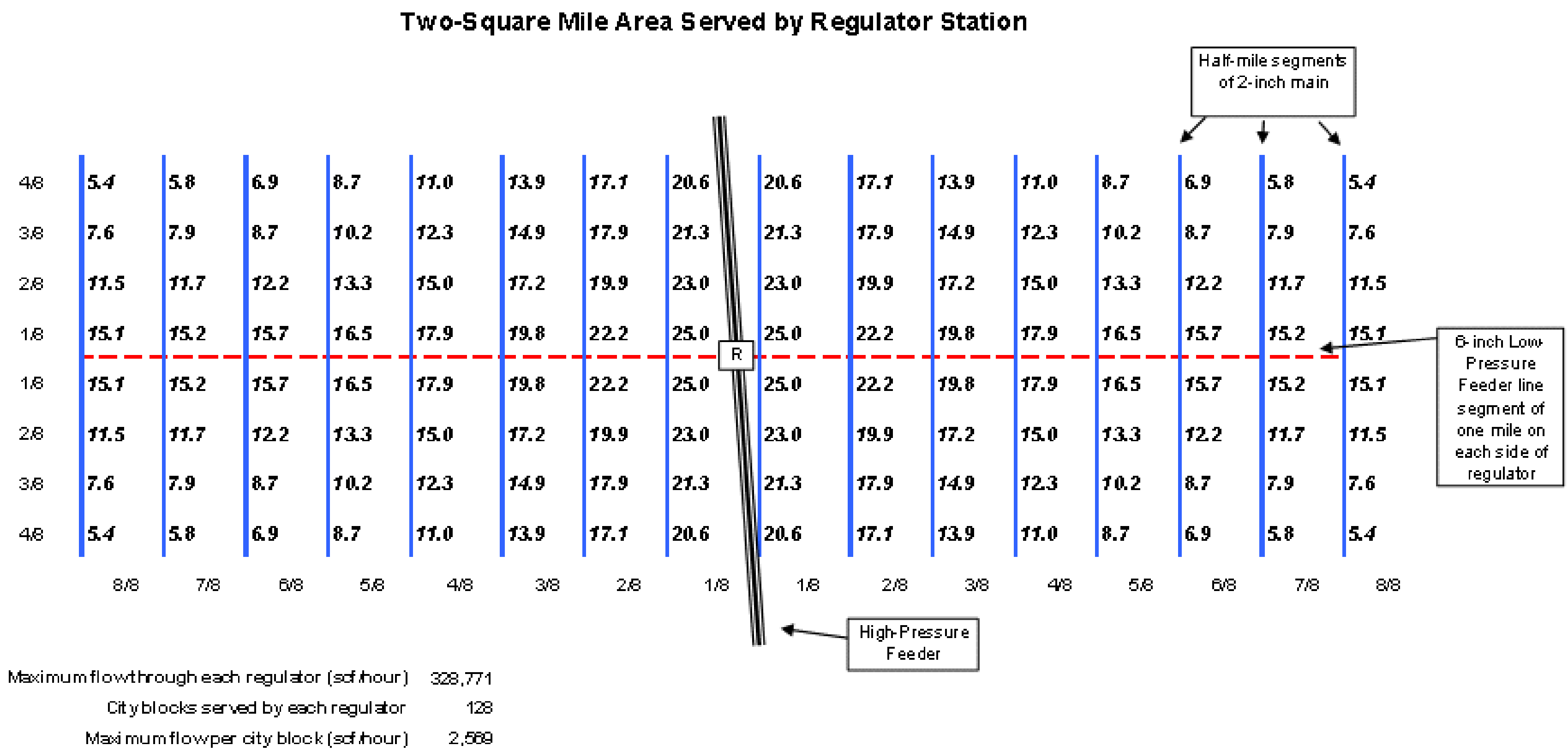


Figure 4.1.3. Hypothetical pressures (psig) in distribution mains at maximum design flows (Vidas, 2007)

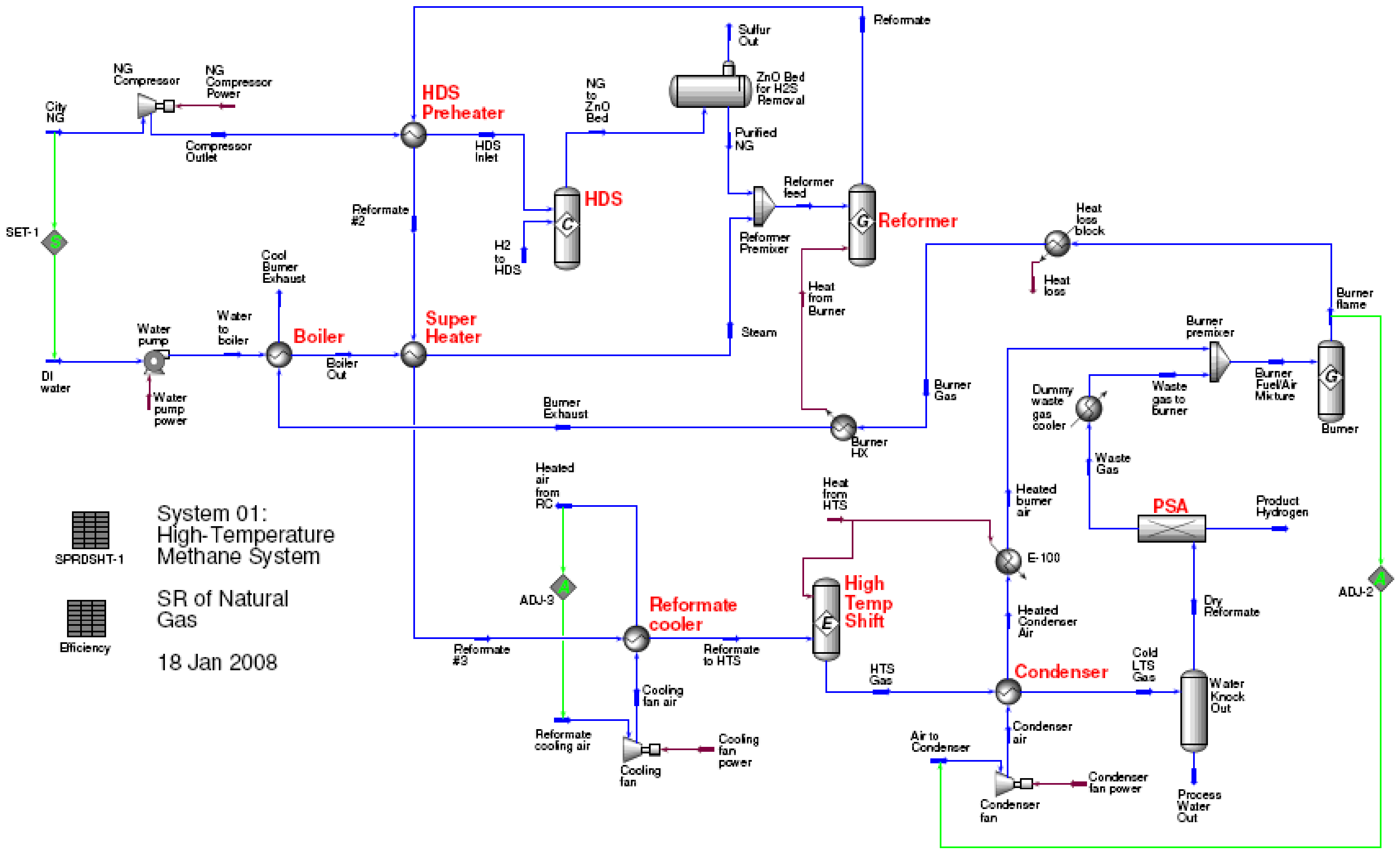


Figure 5.1.1. Distributed natural gas reforming process flow diagram (James, 2008)

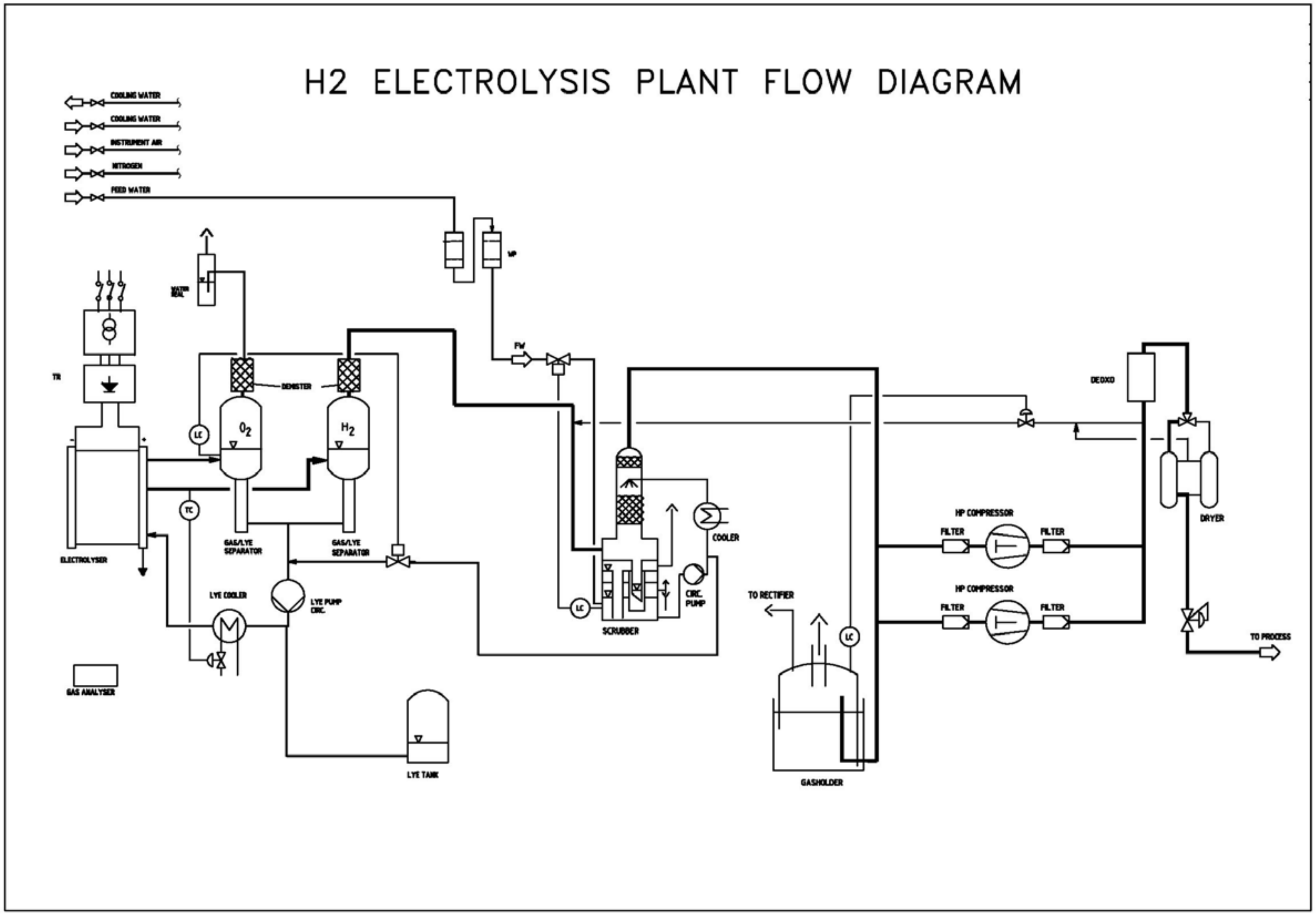


Figure 5.2.1. Distributed electrolysis process flow diagram (Ramsden, 2008b)

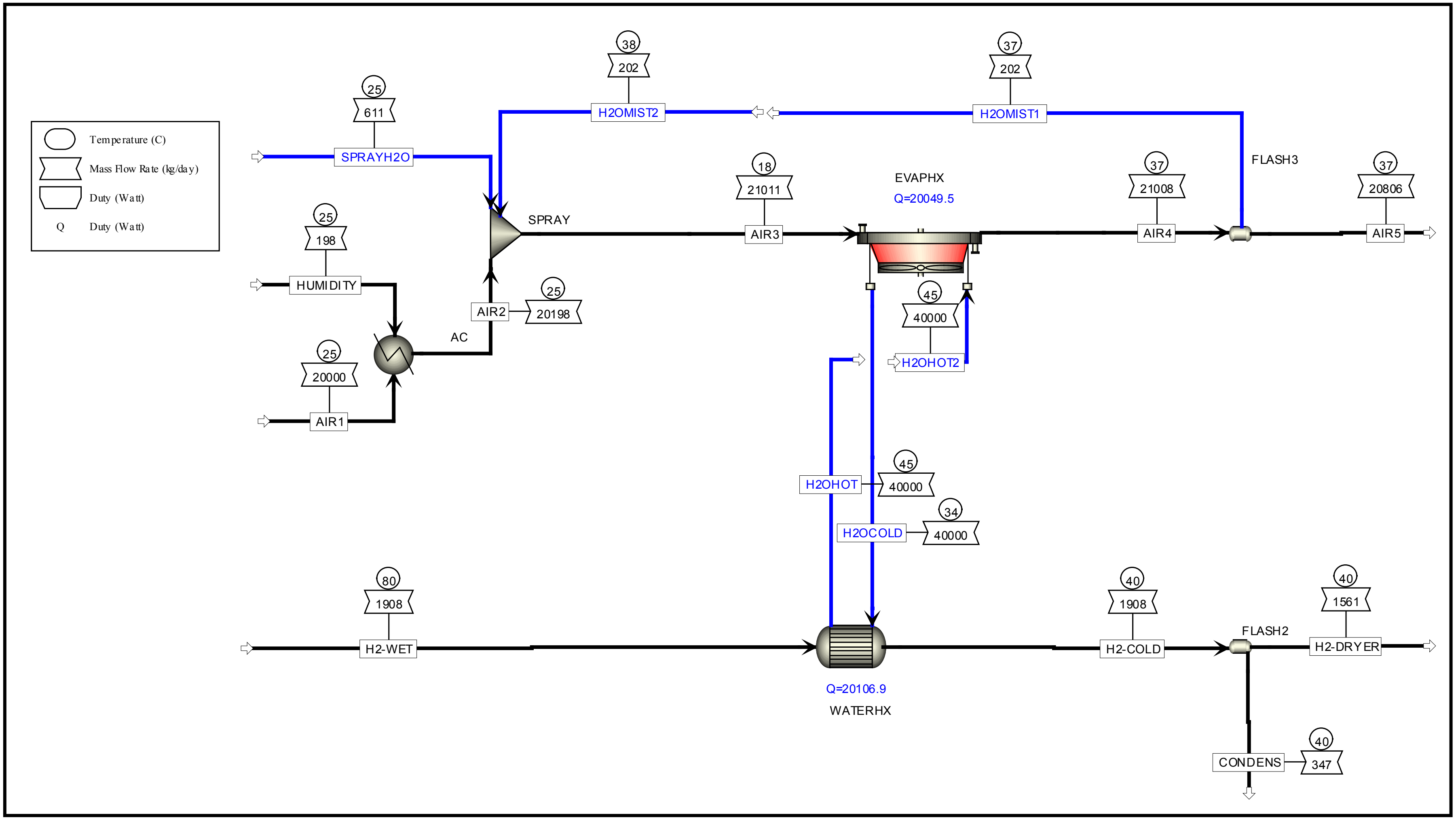


Figure 5.2.3. Distributed electrolysis process flow diagram cooling water detail (Ramsden, 2008b)

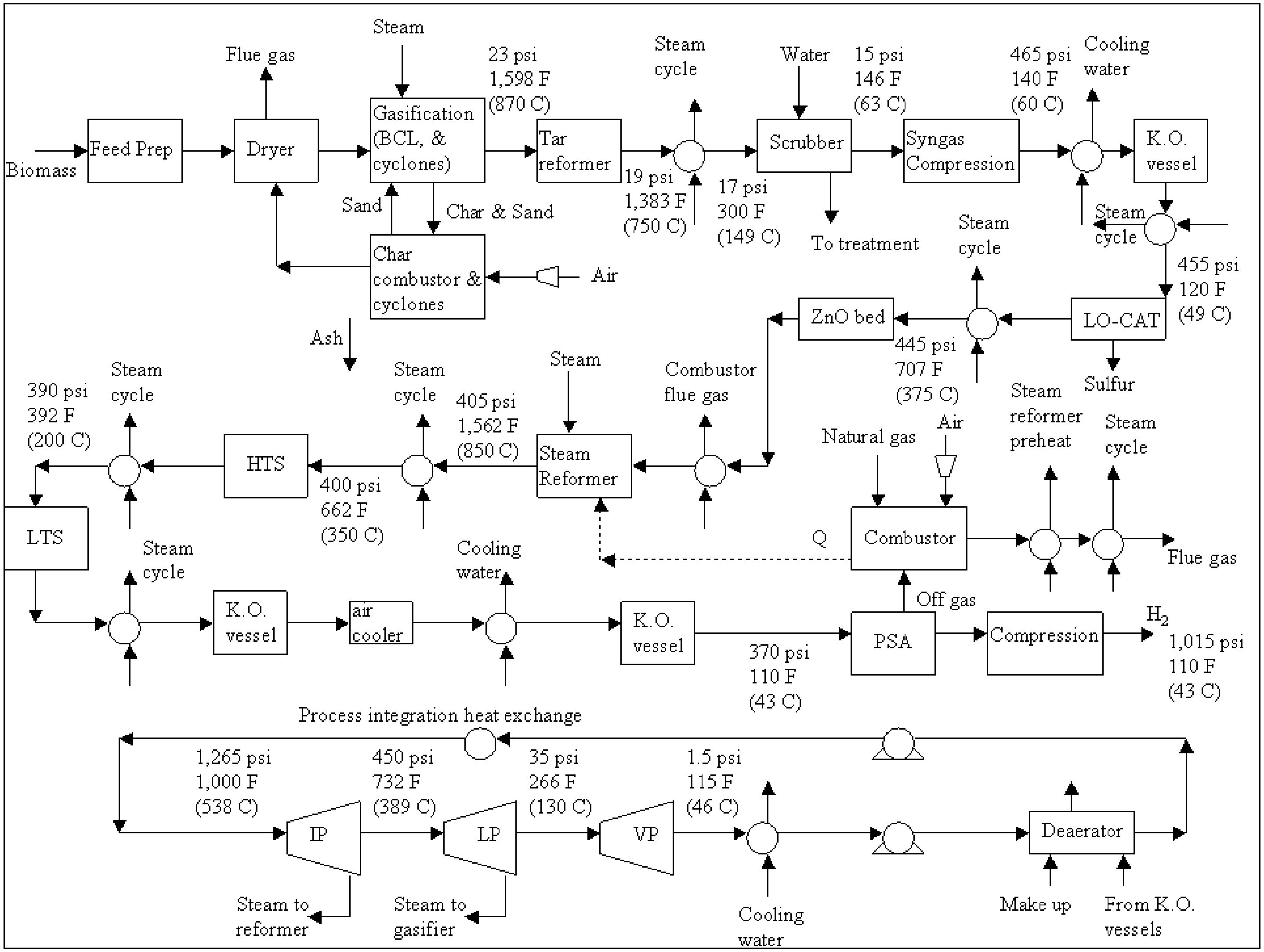
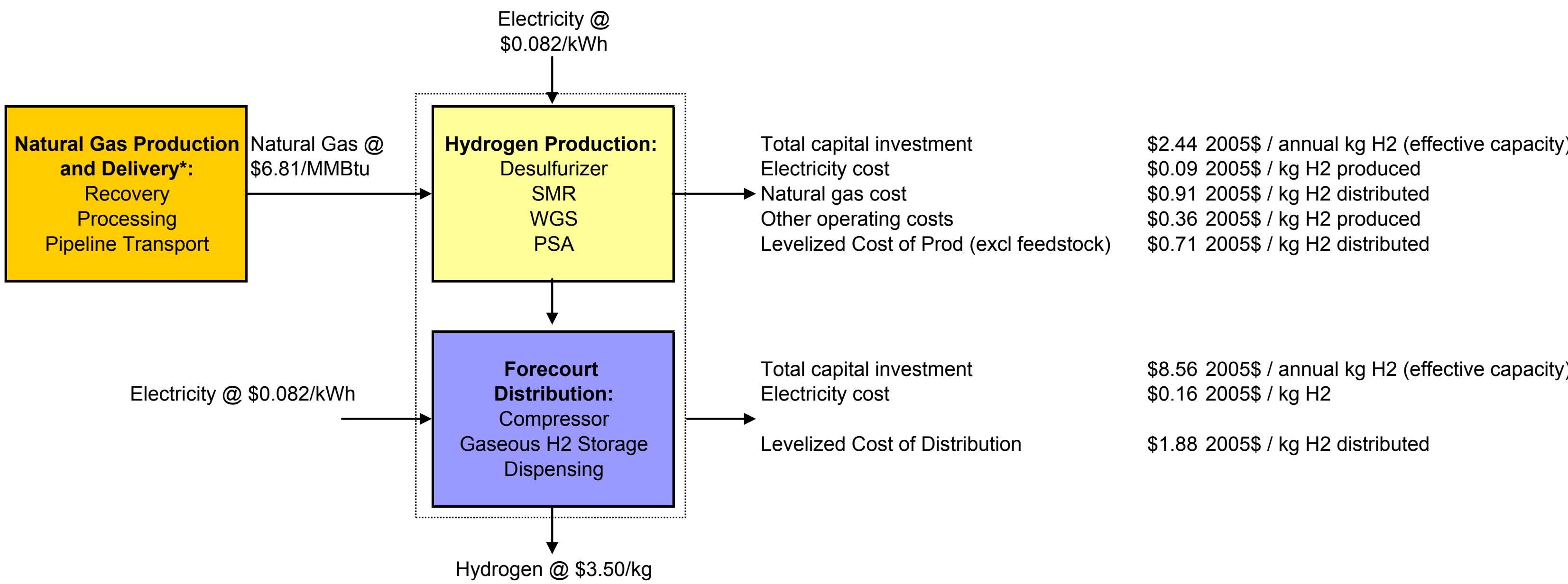
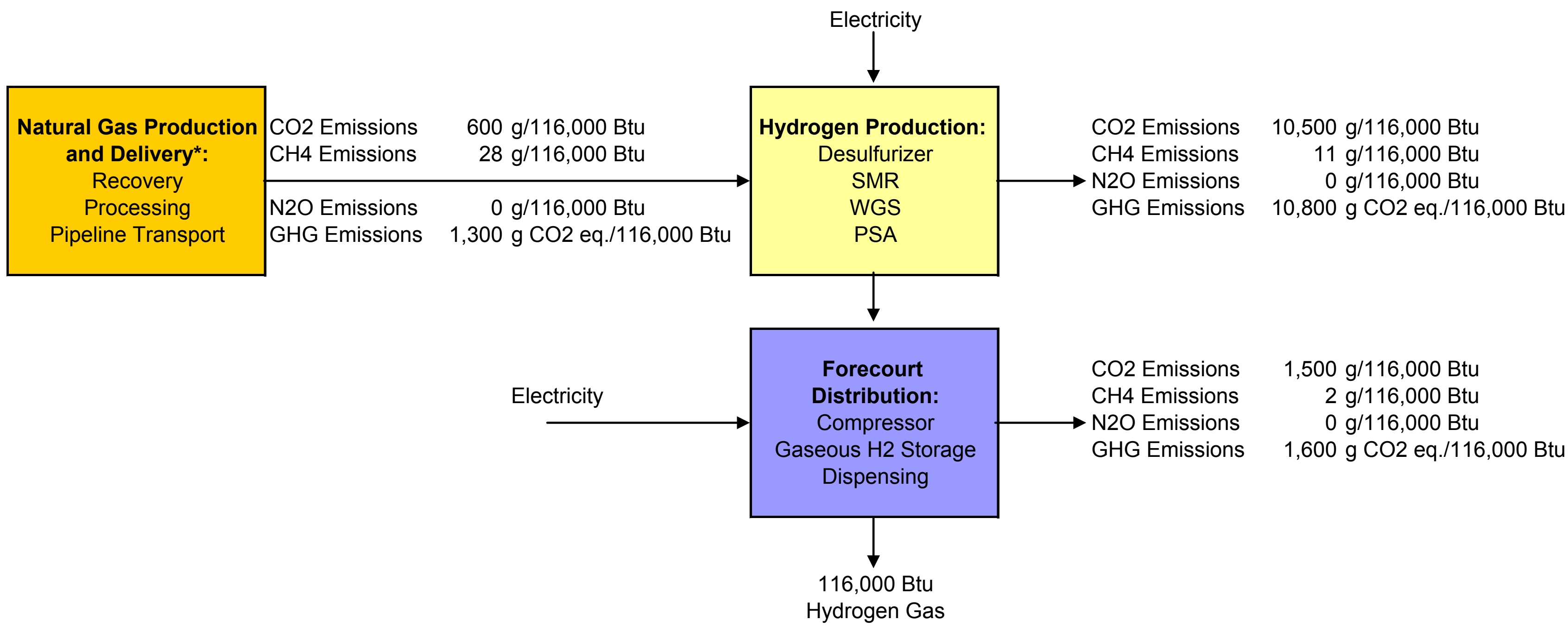


Figure 5.3.1. Central biomass gasification flow diagram (Mann and Steward, 2008)



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include natural gas used as a heating fuel or to produce electricity.

Figure 9.1.2. Cost analysis inputs and high-level results for distributed natural gas pathway



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock. It does not include natural gas used as a heating fuel or to produce electricity.

Figure 9.1.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using distributed natural gas pathway

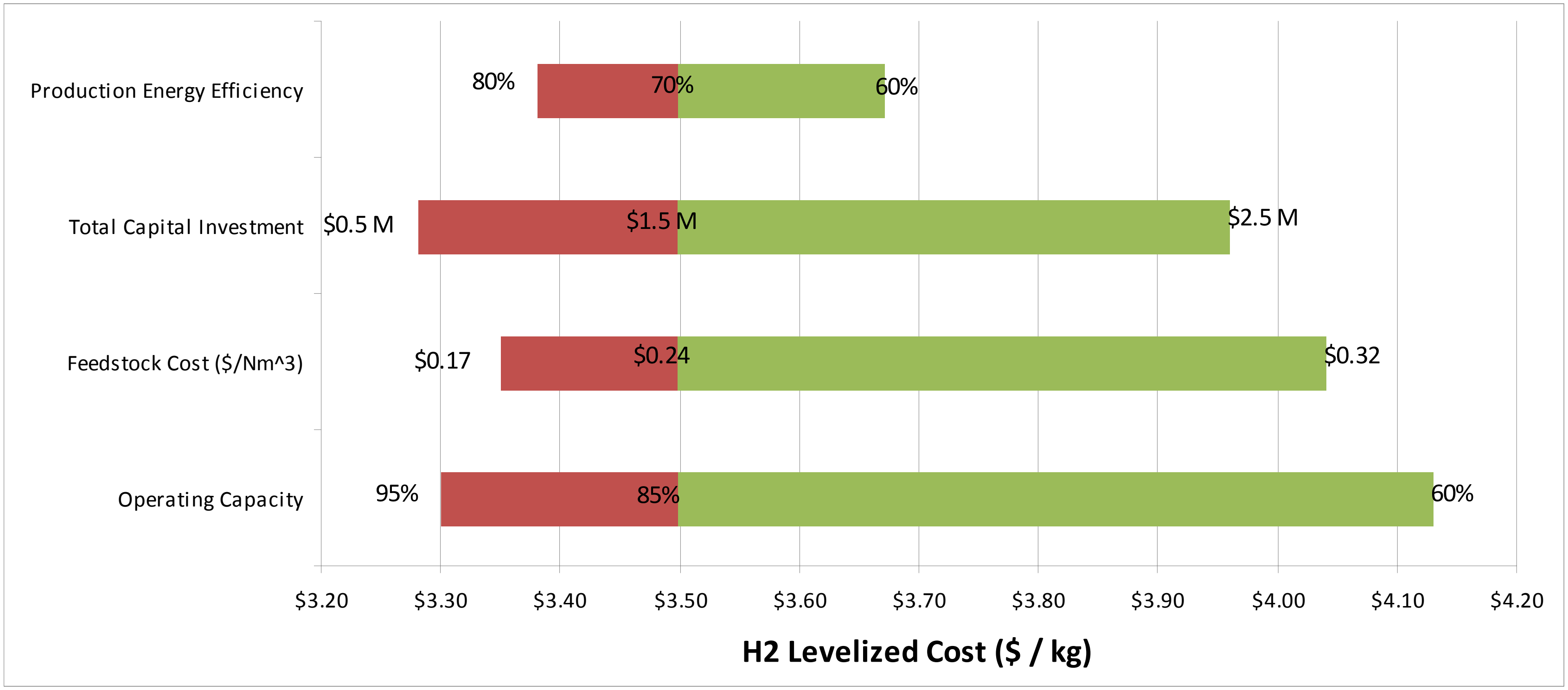


Figure 9.1.9. Production sensitivities for distributed natural gas pathway

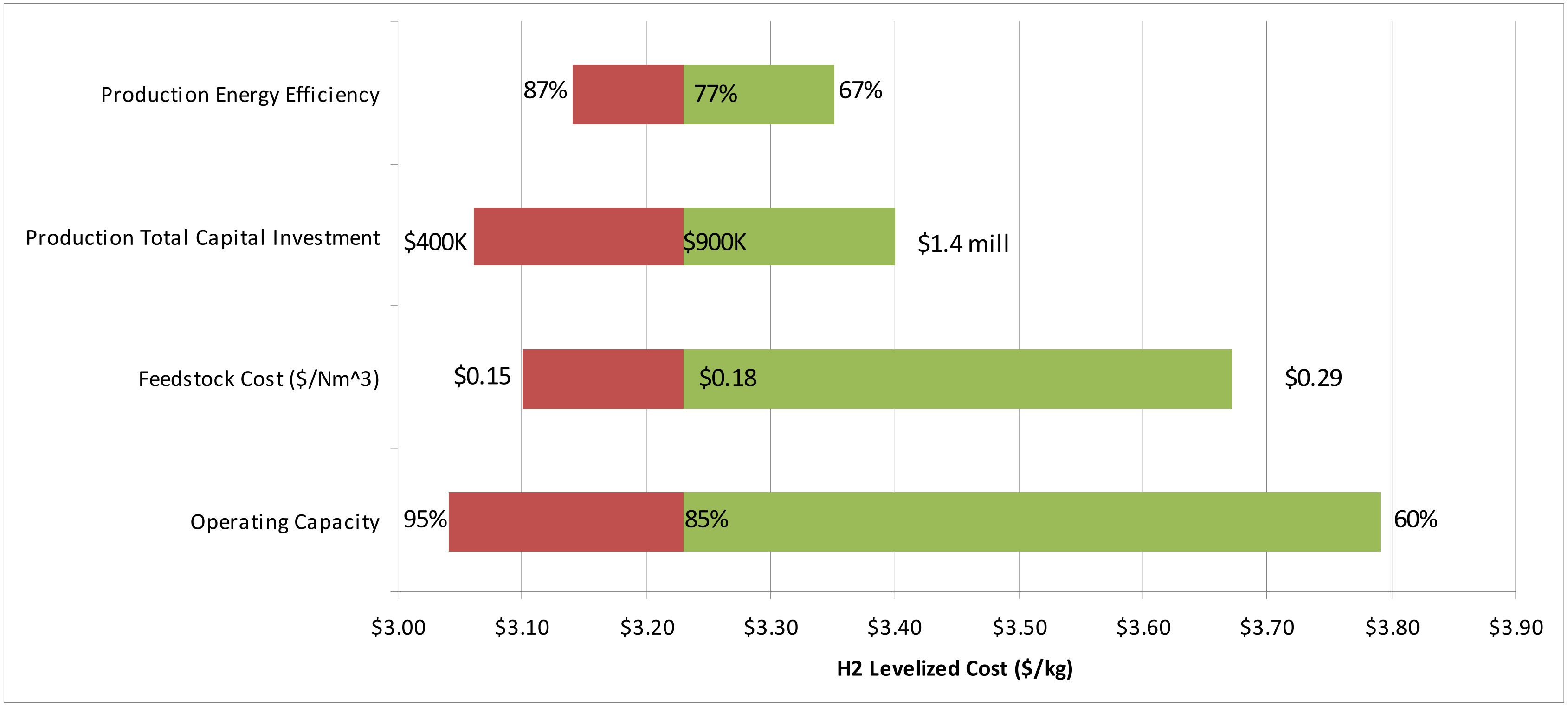


Figure 9.1.10. Production sensitivities for distributed natural gas pathway with advanced technology

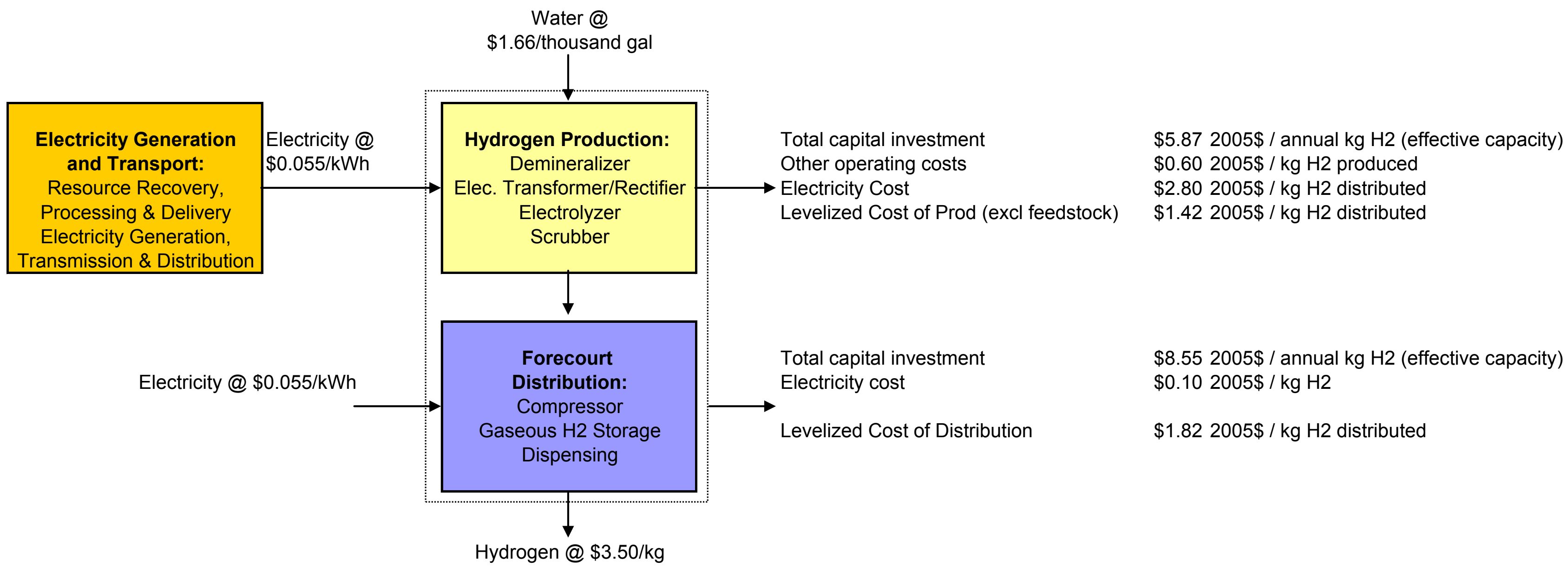


Figure 9.2.2. Cost analysis inputs and high-level results for distributed electricity pathway

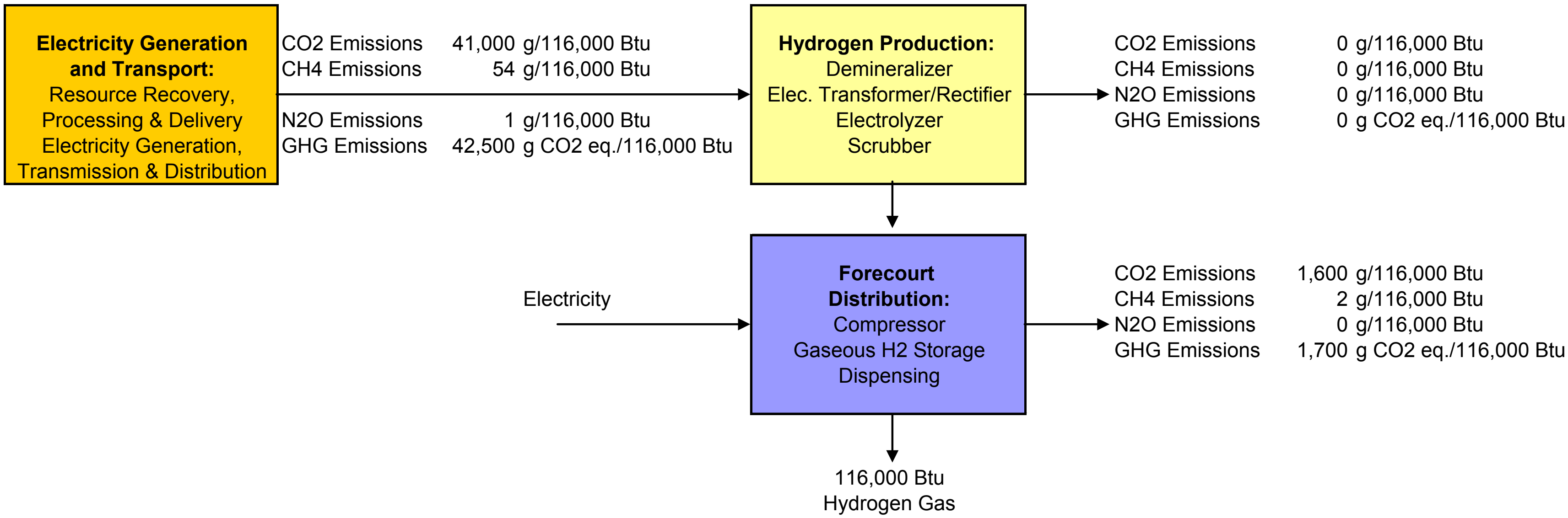


Figure 9.2.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using distributed electricity pathway

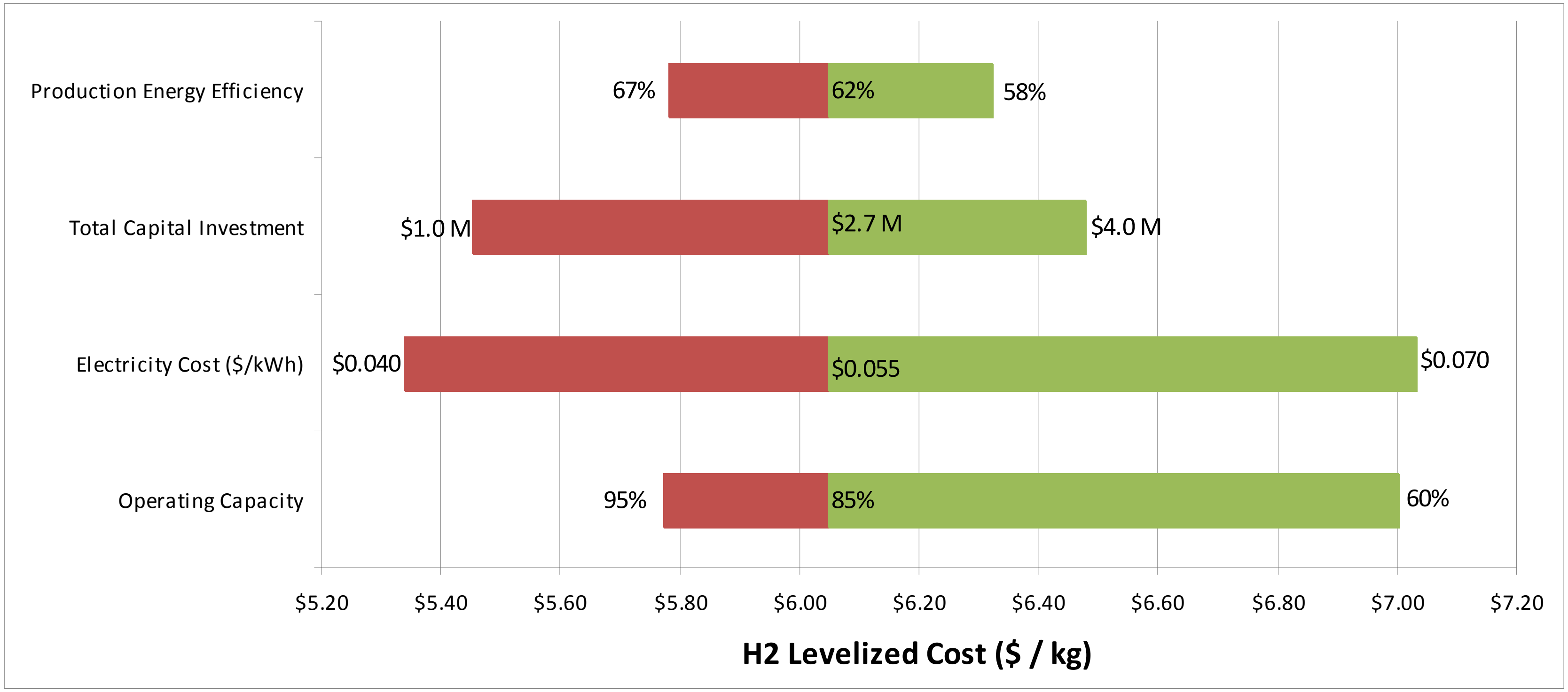


Figure 9.2.9. Production sensitivities for distributed electrolysis pathway

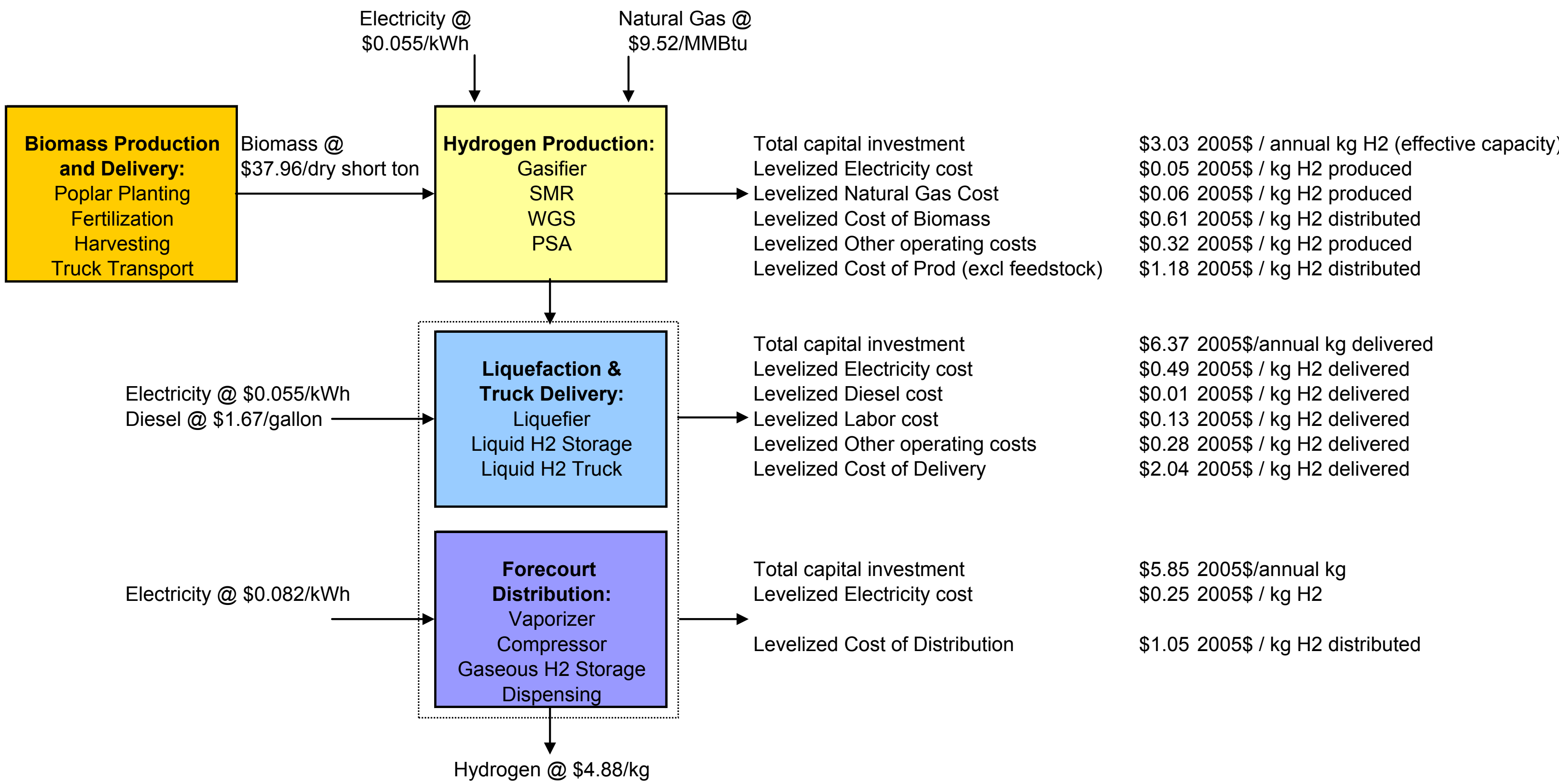


Figure 9.3.2. Cost analysis inputs and high-level results for central biomass–liquid truck delivery pathway

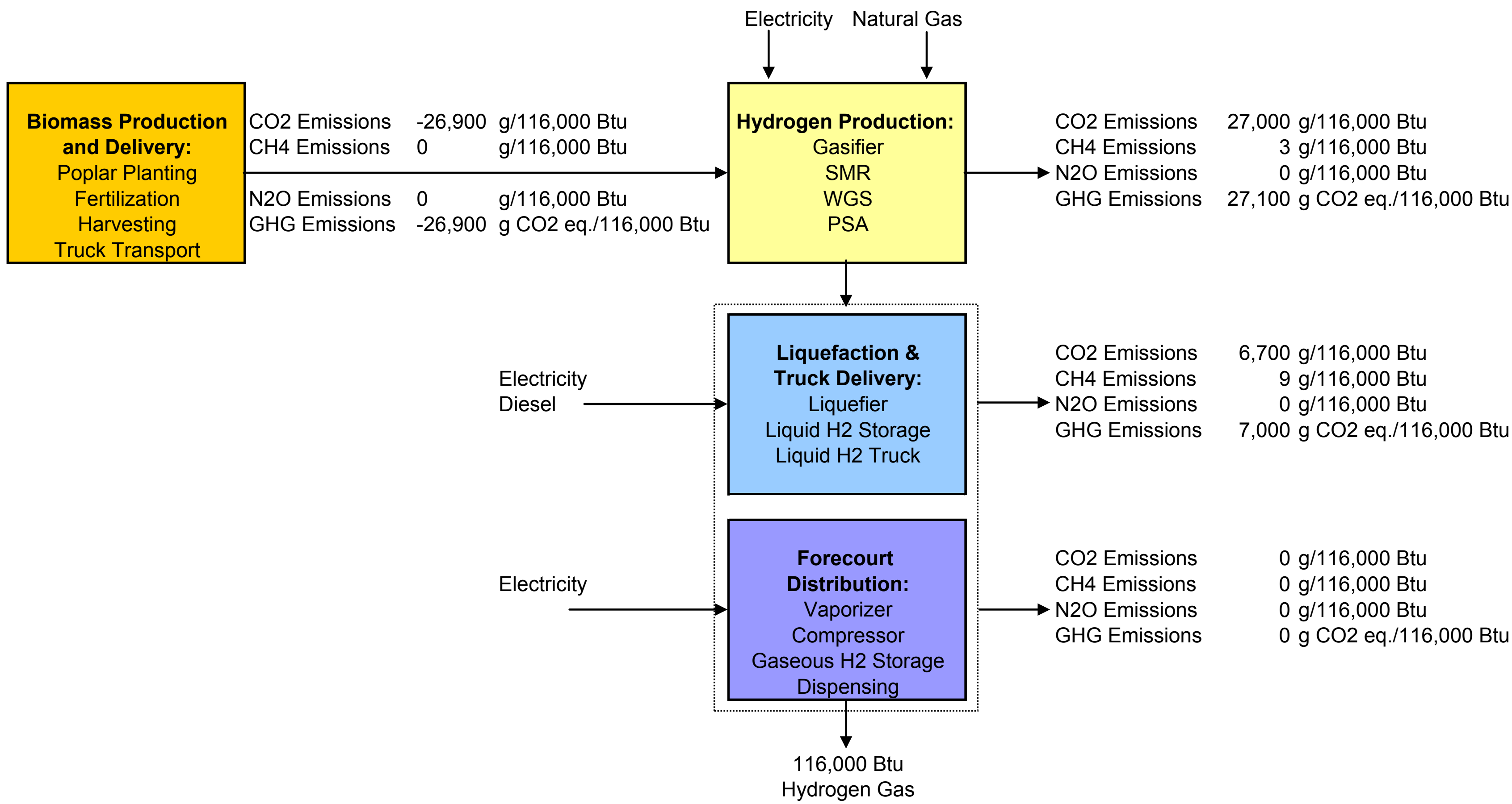


Figure 9.3.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central biomass–liquid truck delivery pathway

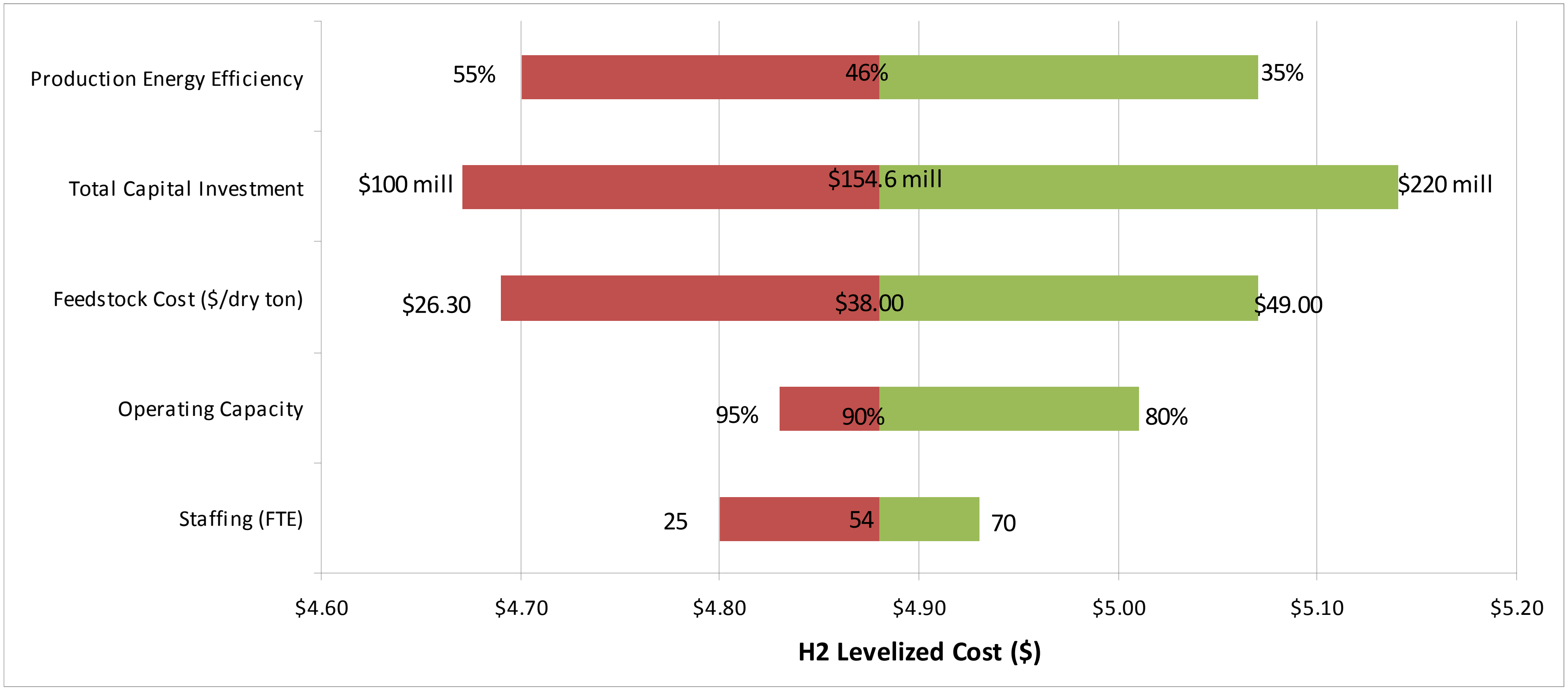


Figure 9.3.9. Production sensitivities for central biomass–liquid truck delivery pathway

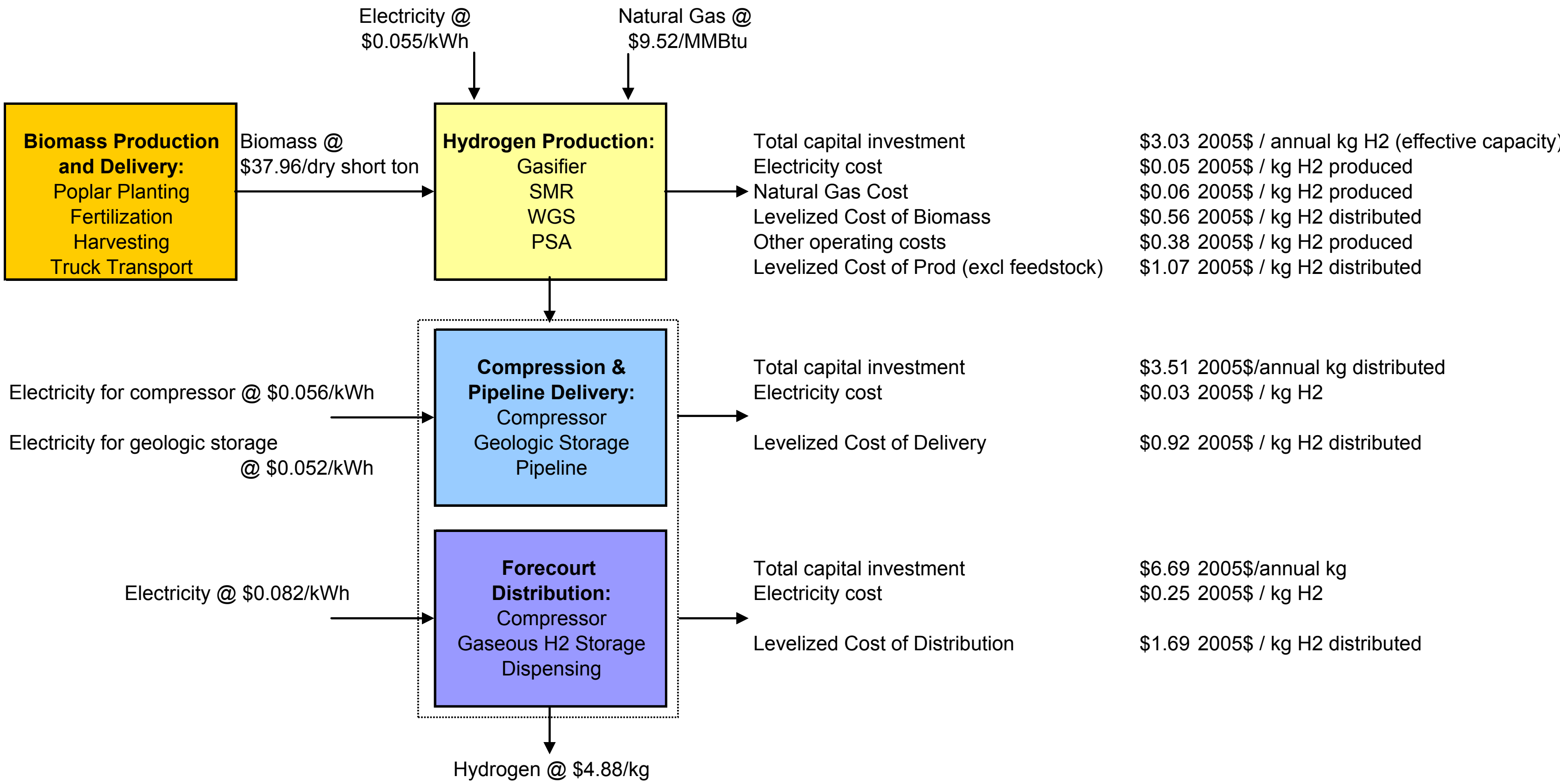


Figure 9.4.2. Cost analysis inputs and high-level results for central biomass–pipeline delivery pathway

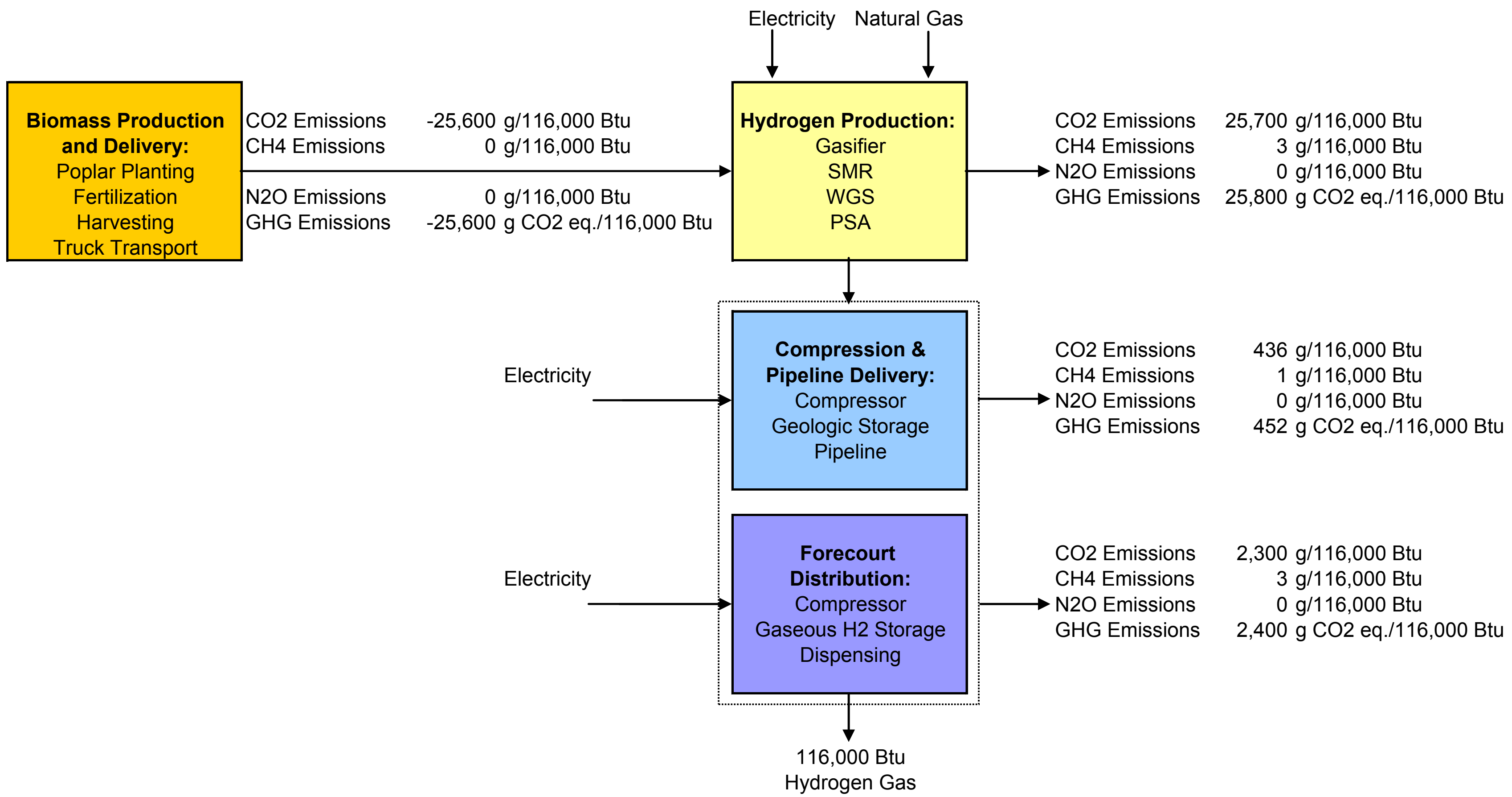


Figure 9.4.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central biomass–pipeline delivery pathway

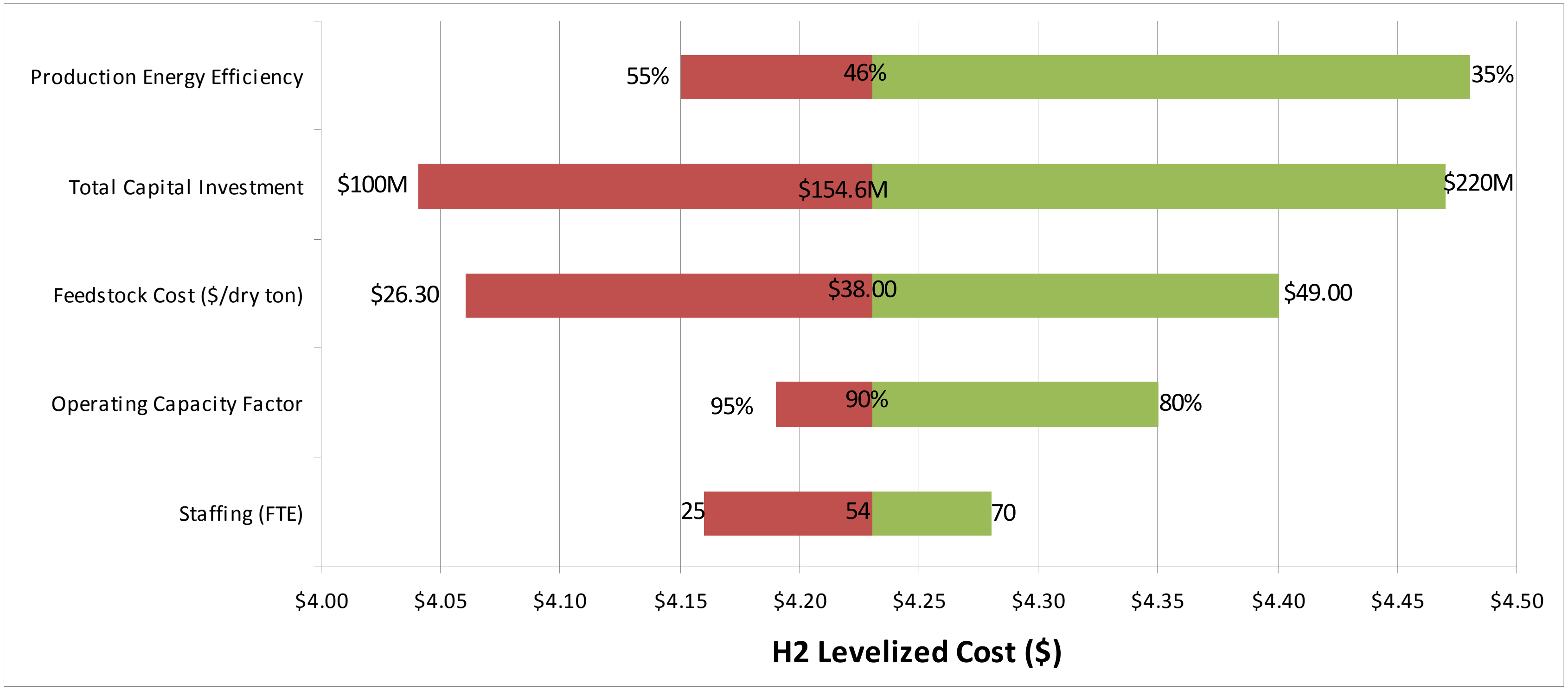
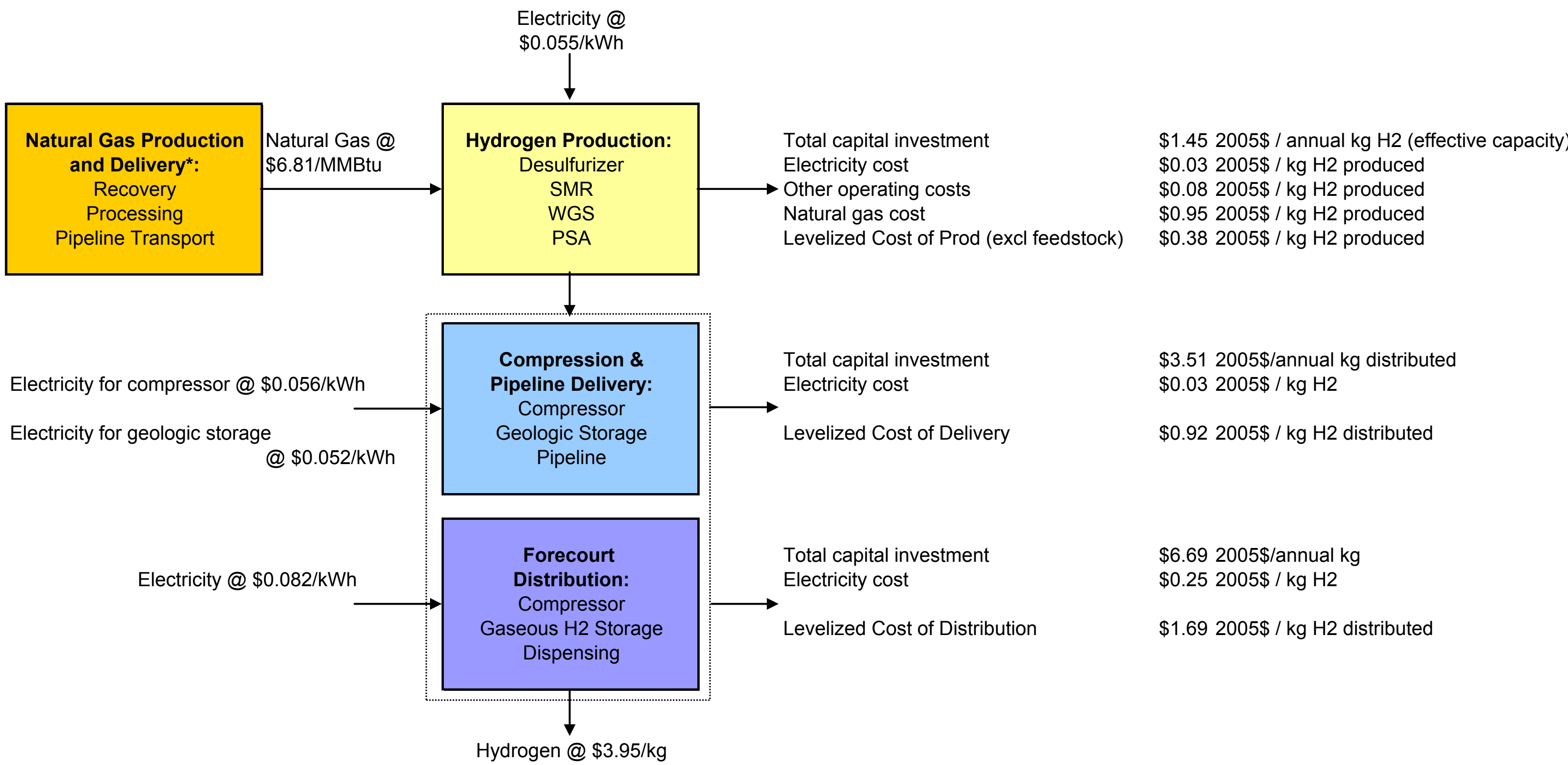
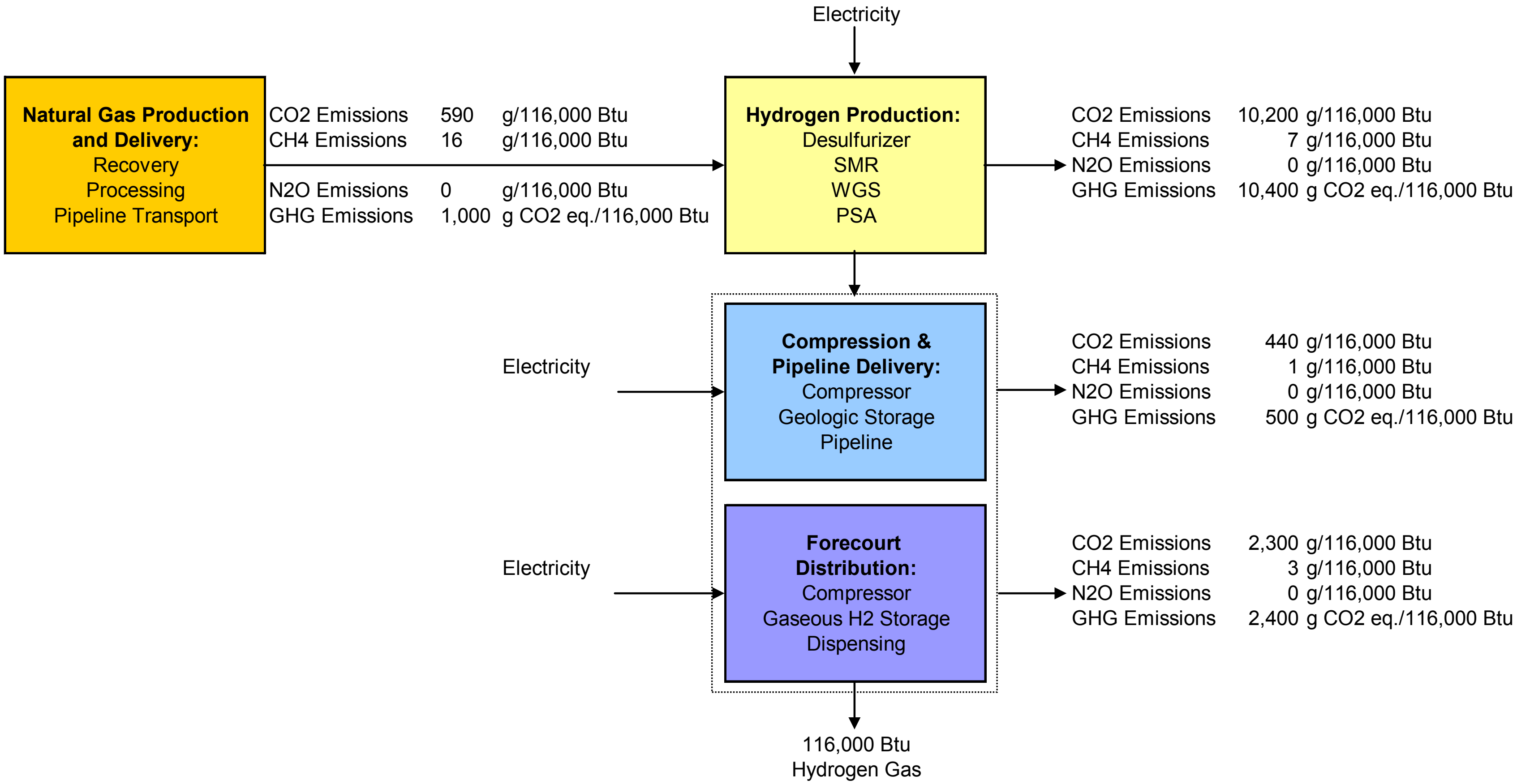


Figure 9.4.9. Production sensitivities for central biomass–pipeline delivery pathway



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include natural gas used as a heating fuel or to produce electricity.

Figure 9.5.2. Cost analysis inputs and high-level results for central natural gas–pipeline delivery pathway



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
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Figure 9.5.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central natural gas–pipeline delivery pathway

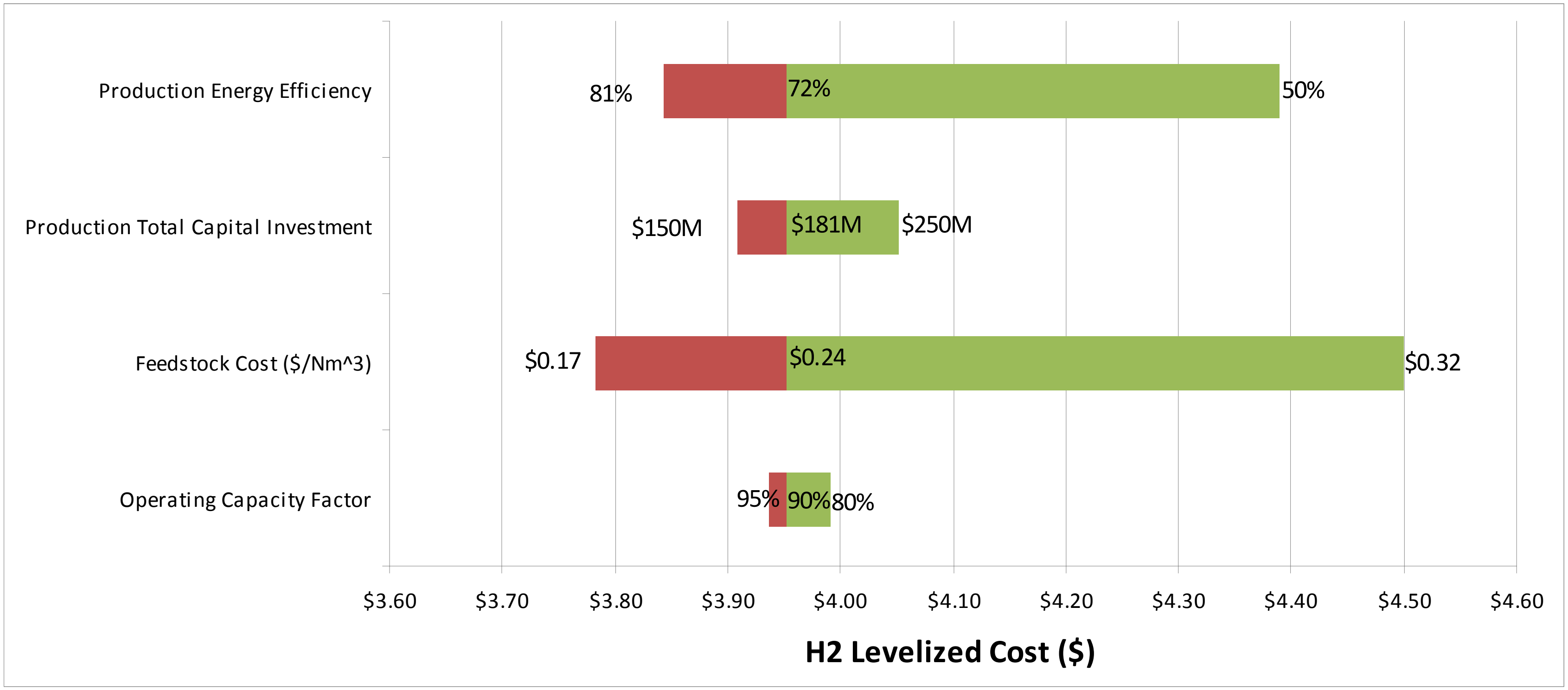


Figure 9.5.9. Production sensitivities for central natural gas–pipeline delivery pathway

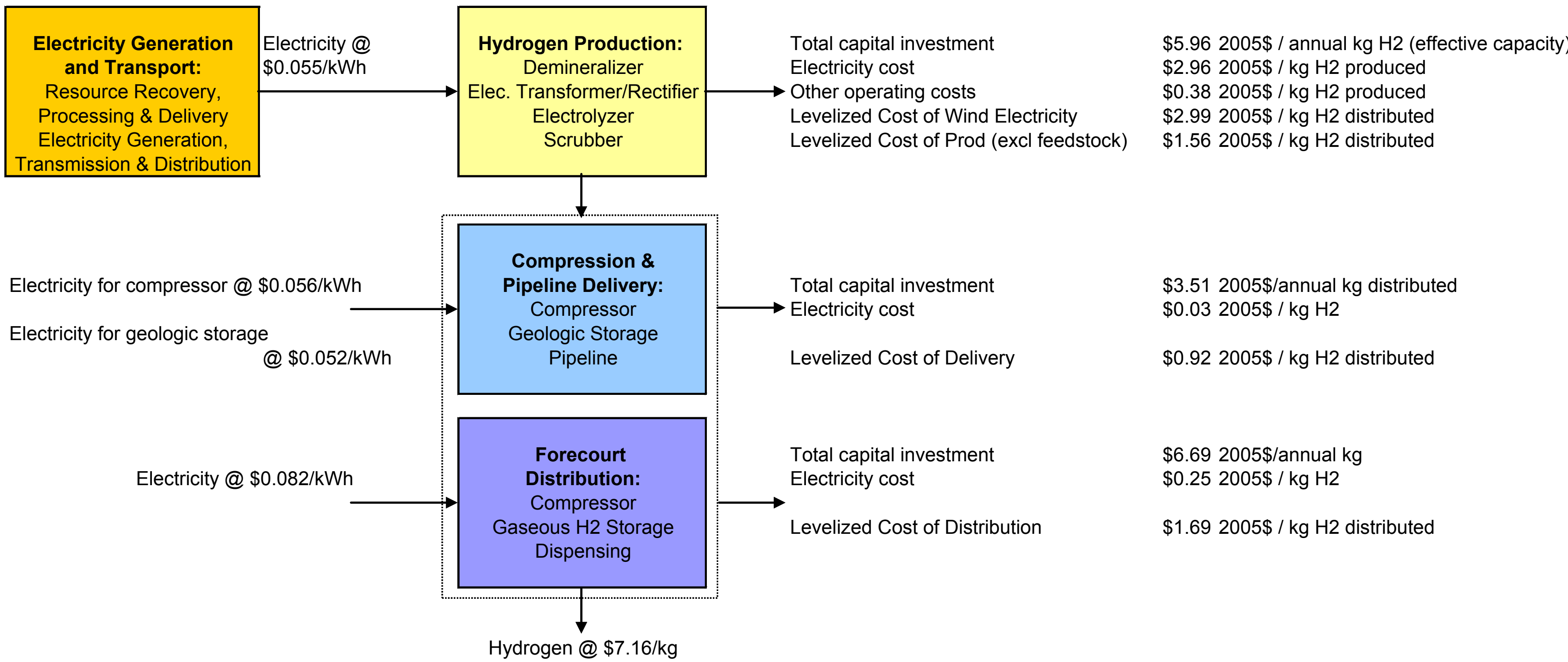


Figure 9.6.2. Cost analysis inputs and high-level results for central wind electricity–pipeline delivery pathway

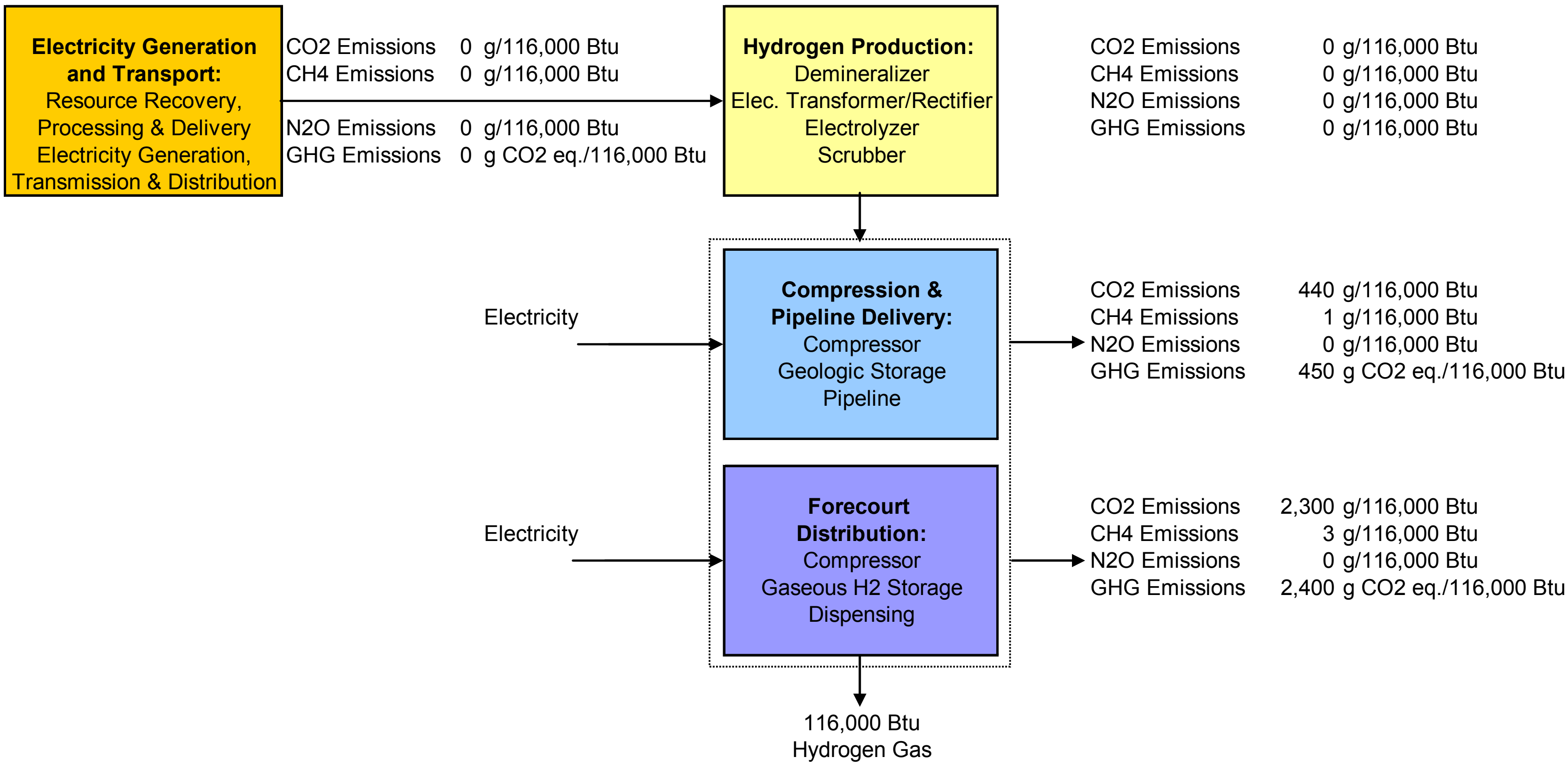


Figure 9.6.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central wind electricity–pipeline delivery pathway

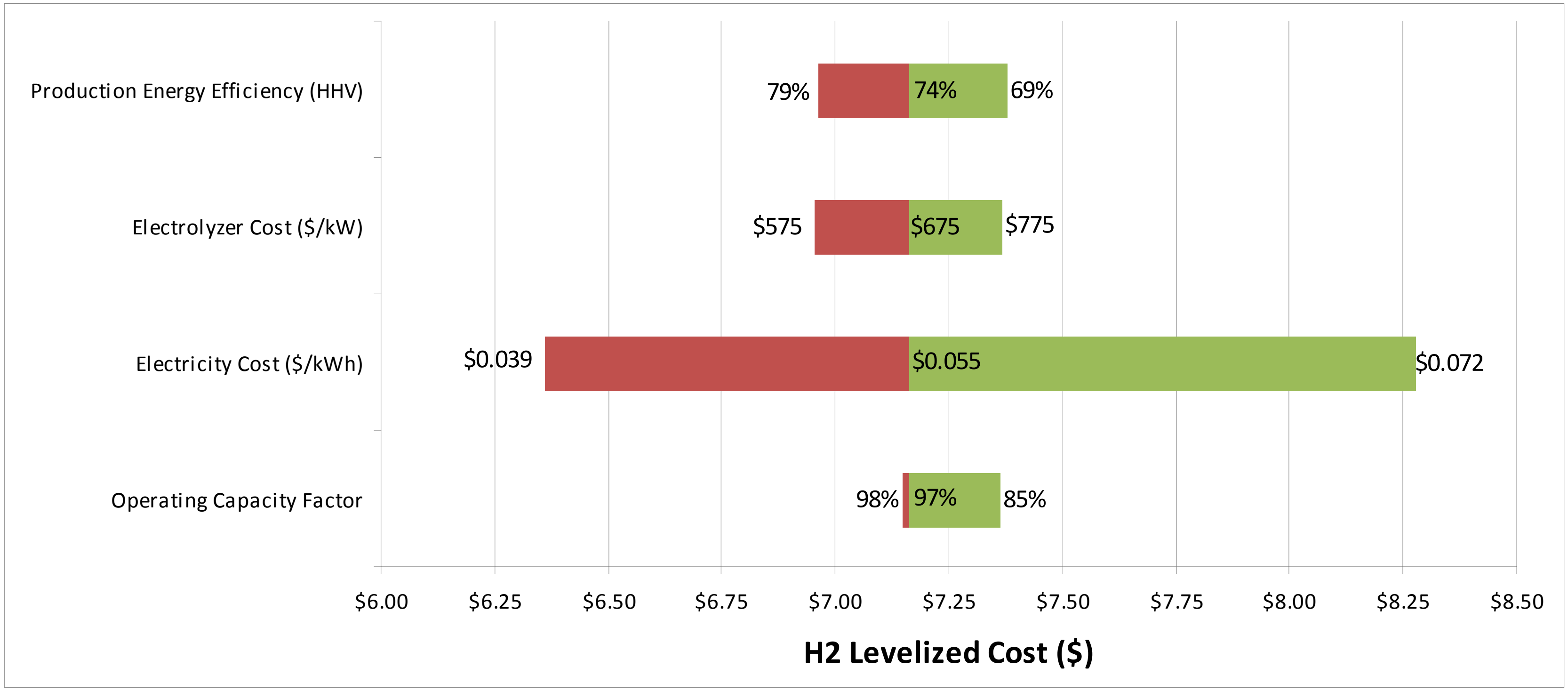
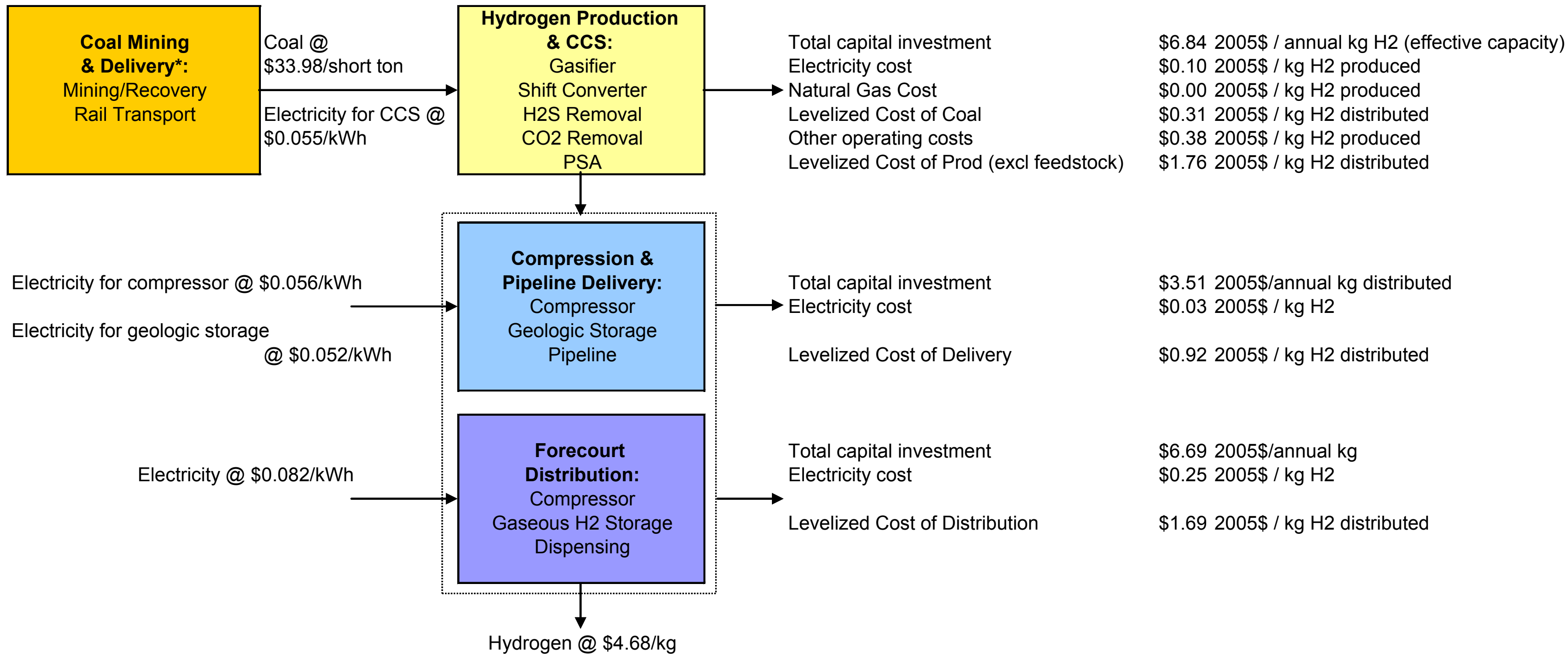
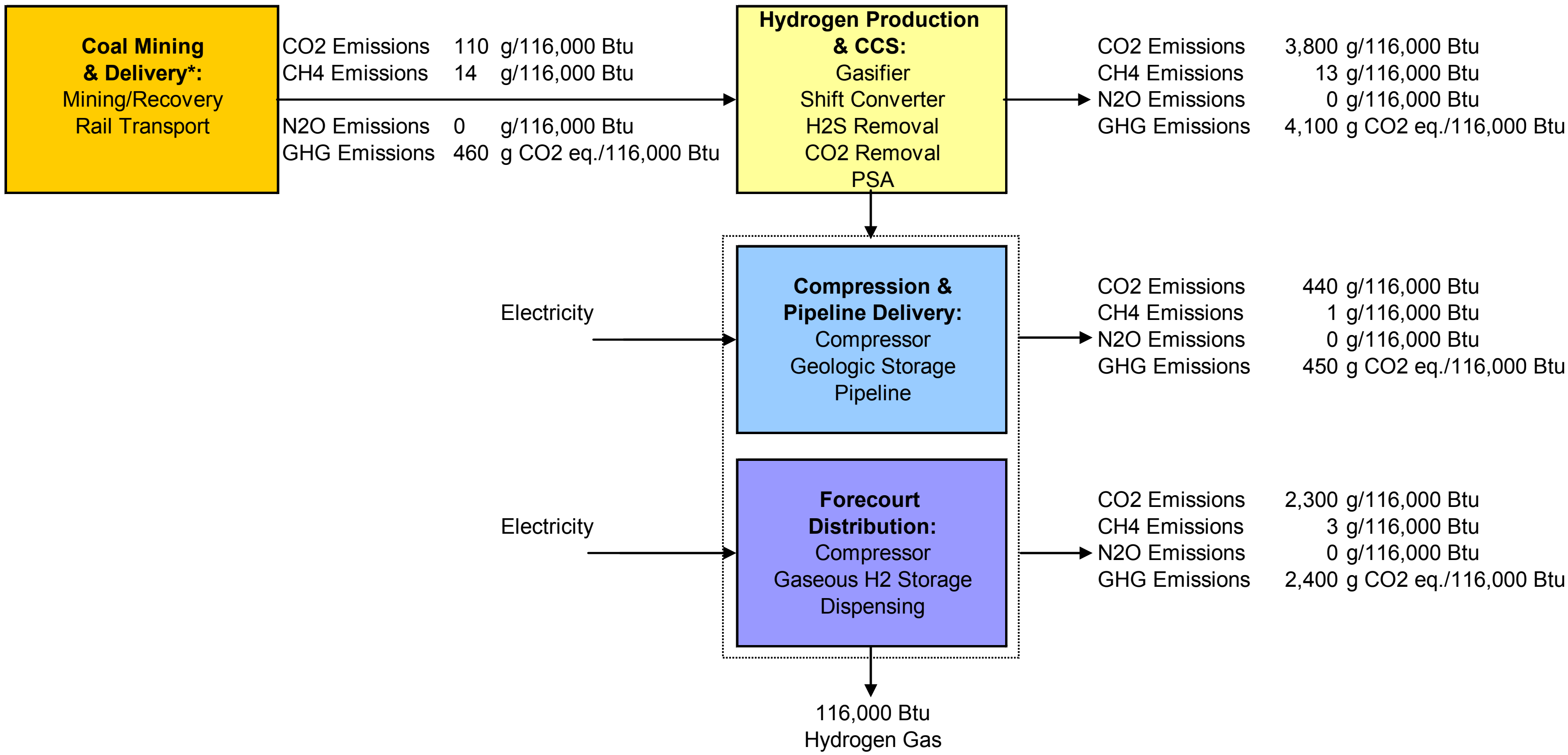


Figure 9.6.9. Production sensitivities for central wind electrolysis–pipeline delivery pathway



* This box represents the coal that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include coal used as a heating fuel or to produce electricity.

Figure 9.7.2. Cost analysis inputs and high-level results for central coal with CCS–pipeline delivery pathway



* This box represents the coal that is converted to hydrogen or otherwise consumed/lost as a process feedstock.
It does not include coal used as a heating fuel or to produce electricity.

Figure 9.7.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using central coal with CCS–pipeline delivery pathway

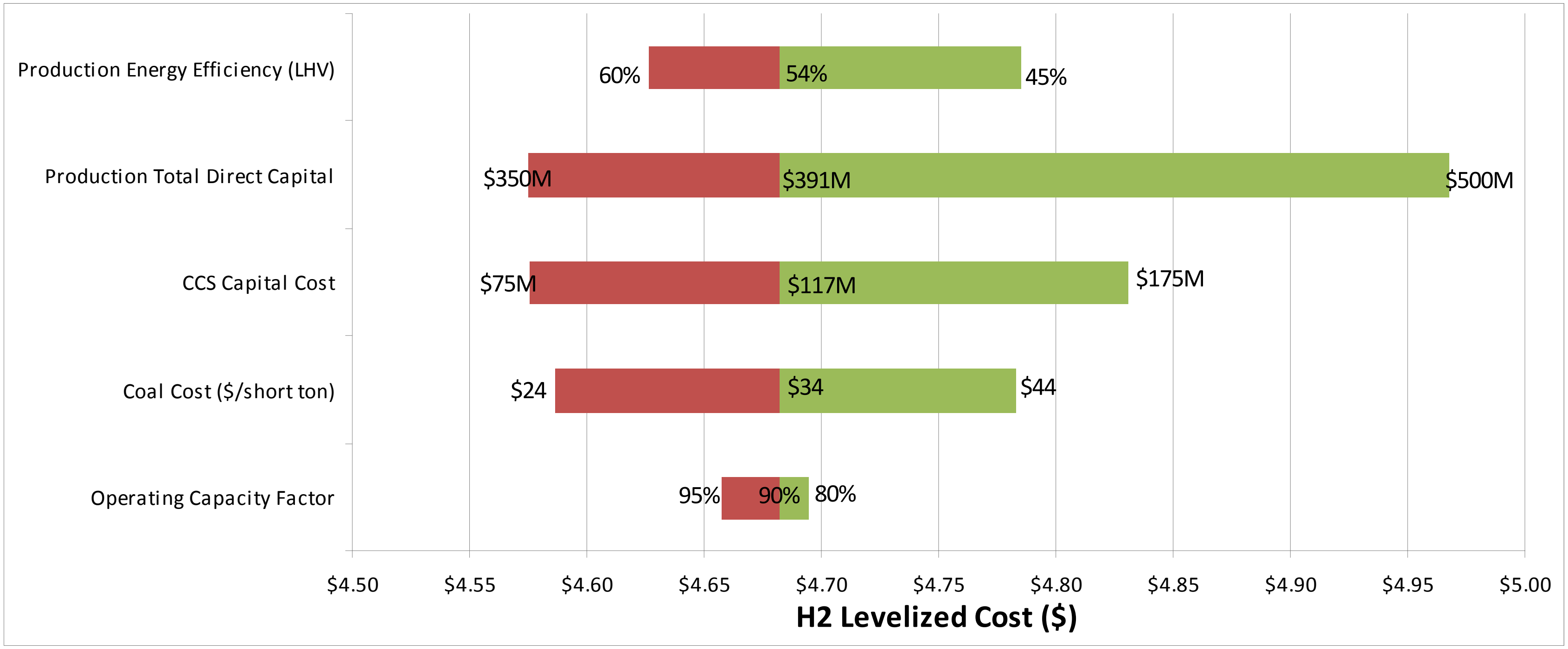


Figure 9.7.9. Production sensitivities for central coal with CCS–pipeline delivery pathway

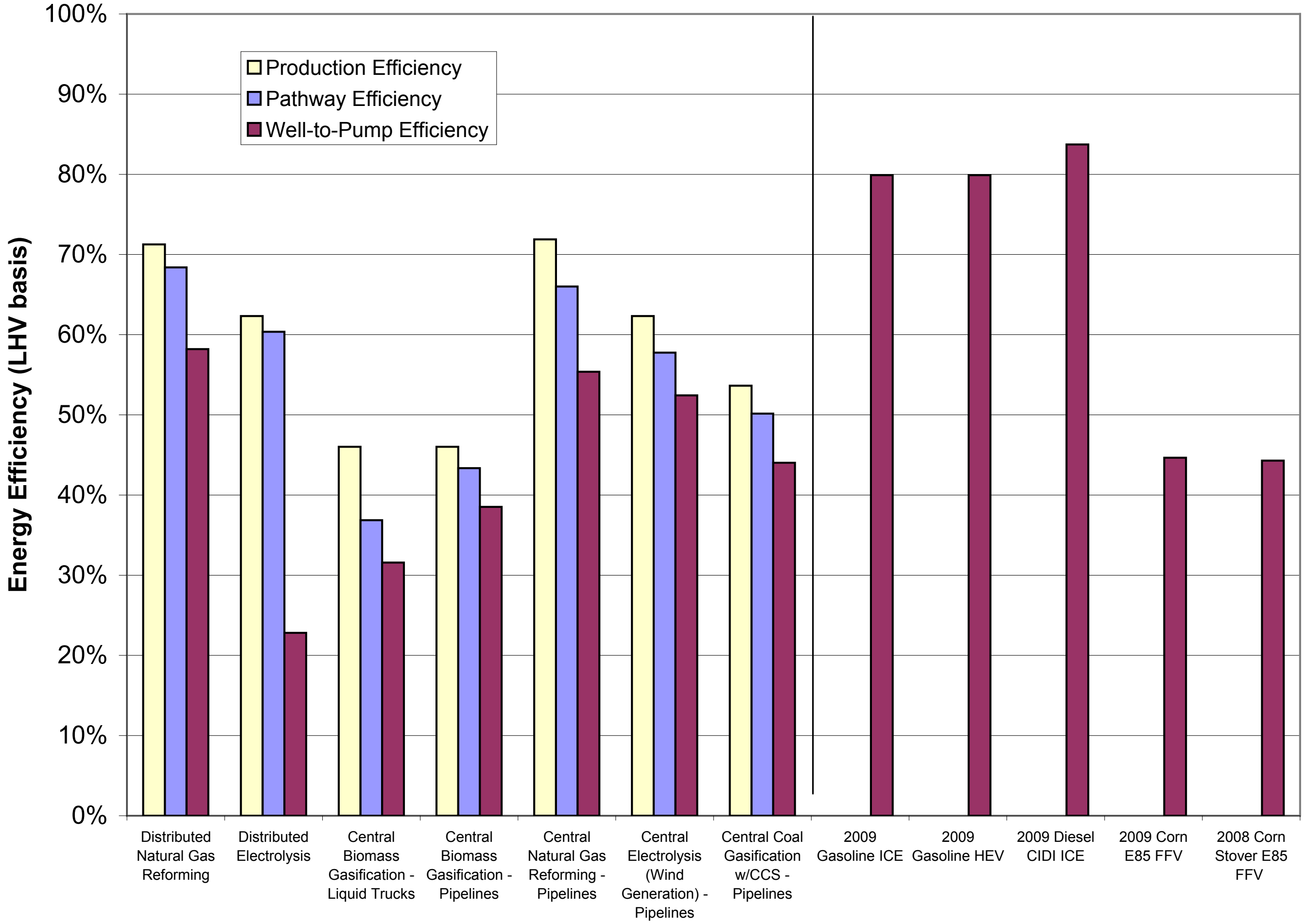


Figure 10.0.3. WTW, pathway, and production efficiencies for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

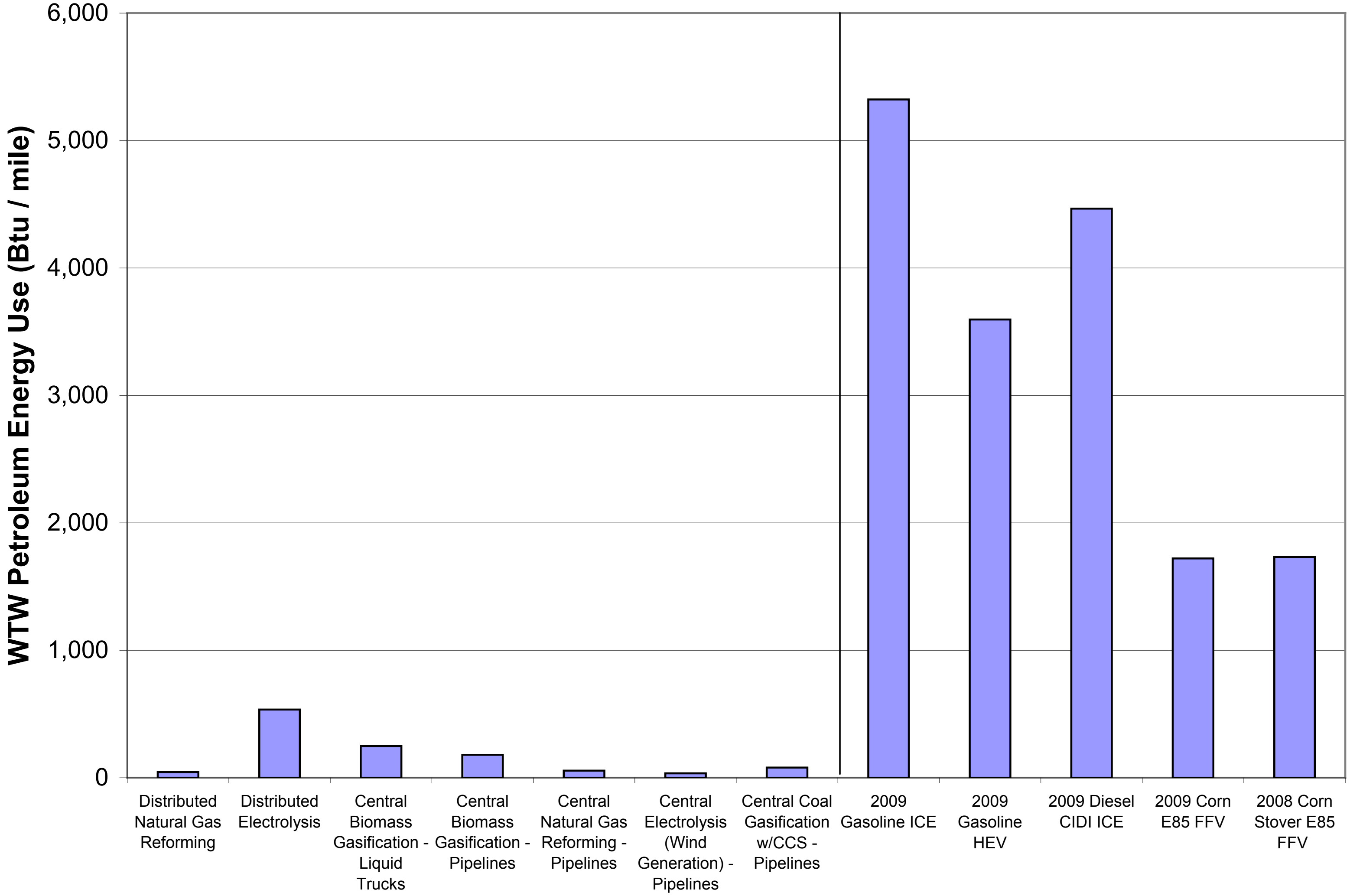


Figure 10.0.4. WTW petroleum energy use for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

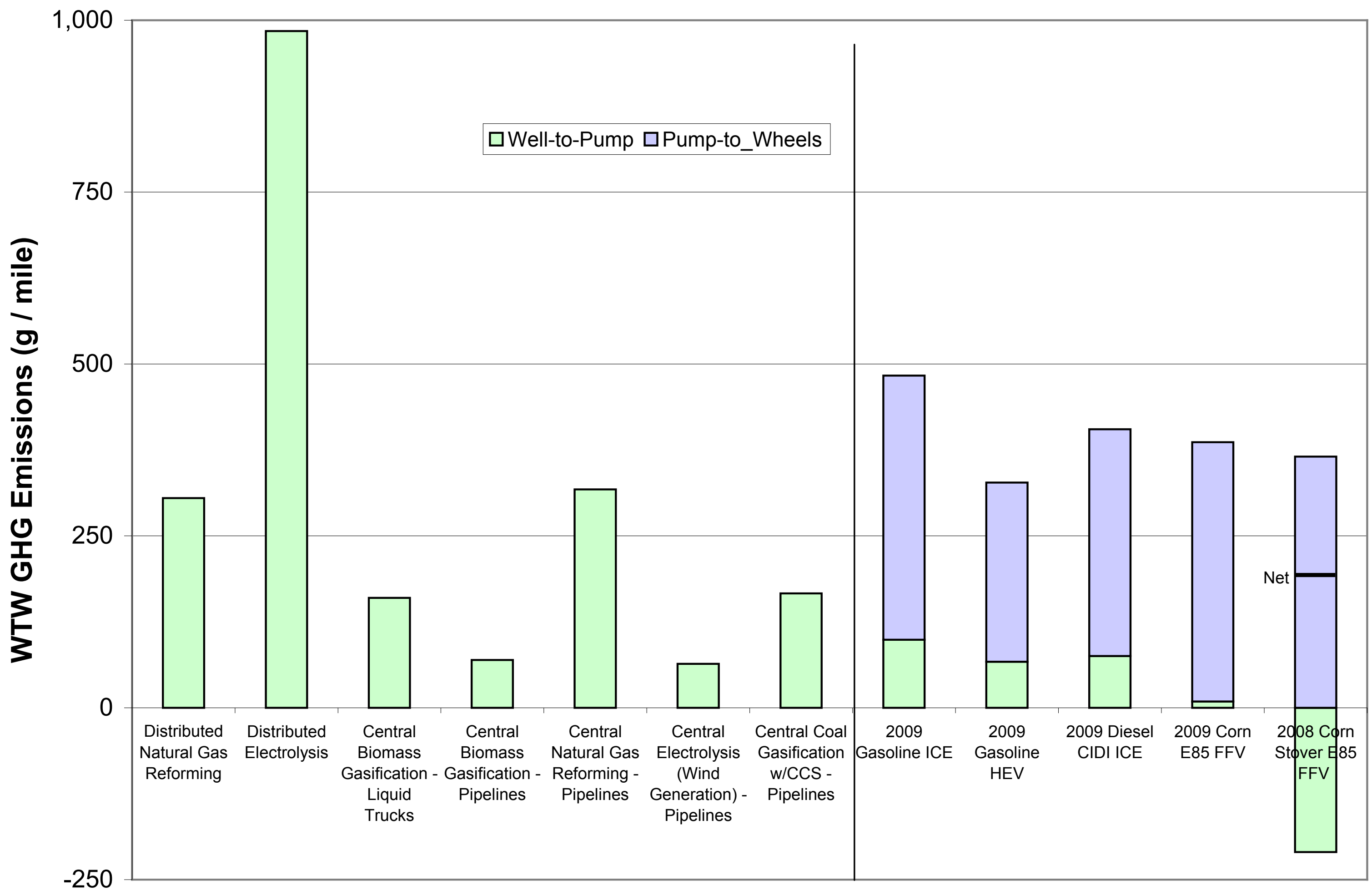


Figure 10.0.6. WTW GHG emissions for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

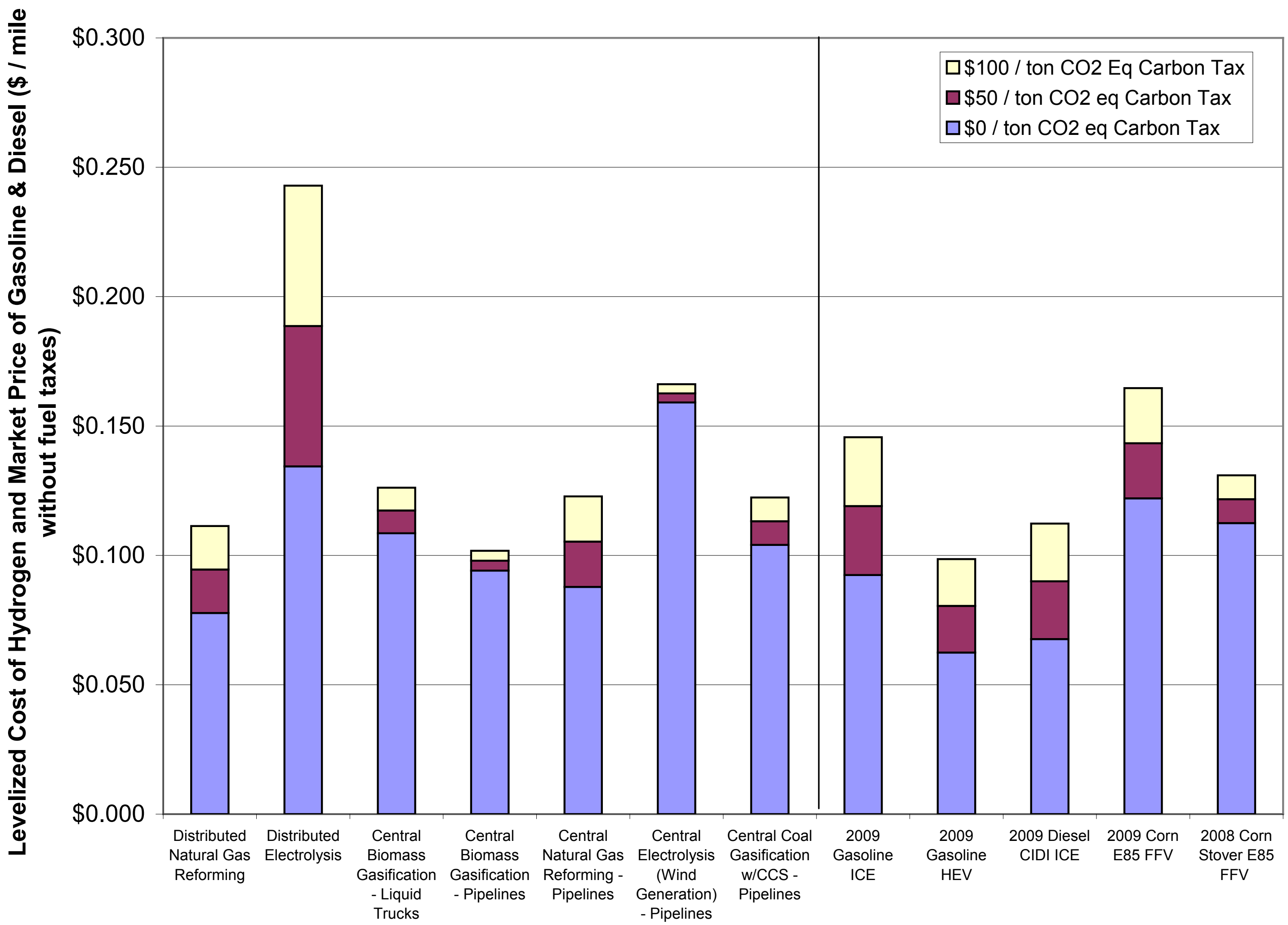


Figure 10.0.9. Levelized costs/market prices with possible carbon taxes for seven hydrogen pathways, three crude oil–based fuel options, and two E85 options

Acronyms

°C	degrees Celsius
°F	degrees Fahrenheit
AC	alternating current
atm	atmosphere
BSCSP	Big Sky Carbon Sequestration Partnership
Btu	British thermal unit
CA	California
CCS	carbon capture and sequestration
CHP	combined heat and power
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
CSD	compression, storage, and dispensing
DC	direct current
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FAF2	Freight Analysis Framework 2
FCV	fuel cell vehicle
FL	Florida
FPITT	Fuel Pathway Integration Tech Team
gal	gallon
gge	gallon gasoline equivalent
GHG	greenhouse gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
H2, H_2	diatomic hydrogen
HEV	hybrid electric vehicle
HDSAM	H2A Delivery Scenario Analysis Model
HFCIT	Hydrogen, Fuel Cells and Infrastructure Technologies
HOF	hose occupied fraction
hr	hour
ICE	internal combustion engine
IGCC	integrated gasification combined cycle
kg	kilogram
kWh	kilowatt-hour
L	liter
lb	pound
MGSC	Midwest Geological Sequestration Consortium
mi	mile
MI	Michigan
MRCSP	Midwest Regional Carbon Sequestration Partnership
MSM	Macro-System Model
MT	metric ton

MW	megaWatt
MYPP	Multi-Year Program Plan
NG	natural gas
NOx	oxides of nitrogen
NREL	National Renewable Energy Laboratory
NV	Nevada
NY	New York
PA	Pennsylvania
PC	pulverized coal
PCOR	Plains CO_2 Reduction
PGM	platinum group metal
PM	particulate matter
ppm	parts per million
PSA	pressure swing adsorption
PSAT	Powertrain Simulation Analysis Toolkit
psi	pound per square inch
psia	pounds per square inch absolute
psig	pound per square inch gauge
SECARB	Southeast Regional Carbon Sequestration Partnership
SMR	steam methane reforming
SWP	Southwest Regional Partnership
TBW	tire and brake wear
TLR	transmission loading relief
TX	Texas
U.S.	United States
VOC	volatile organic compound
WESTCARB	West Coast Regional Carbon Sequestration Partnership
WGS	water-gas shift
wt%	weight percent
WTG	well-to-plant gate
WTP	well-to-pump
WTW	well-to-wheels

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