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Hydrogen Supply: Cost Estimate for Hydrogen Pathways—Scoping Analysis

January 22, 2002—July 22, 2002

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National Renewable Energy Laboratory

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Acronyms and Abbreviations

ASU	air separation unit
ATR	autothermal reforming
BDT	bone-dry ton
Btu	British thermal unit
EOR	enhanced oil recovery
FC	fuel cell
gal	gallon
GPS	global positioning system
H2	molecular hydrogen
ICE	internal combustion engine
IHIG	International Hydrogen Infrastructure Group
kg	kilogram
kg/d	kilograms per day
O&M	operating and maintenance
PO	partial oxidation
PSA	pressure swing adsorption
psig	pounds per square inch gauge
SMR	steam methane reforming

Introduction

The International Hydrogen Infrastructure Group (IHIG) requested a comparative “scoping” economic analysis of 19 pathways for producing, handling, distributing, and dispensing hydrogen for fuel cell (FC) vehicle applications. Of the 19 pathways shown in Table 1, 15 were designated for large-scale central plants and the remaining four pathways focus on smaller modular units suitable for forecourt (fueling station) on-site production. Production capacity is the major determinant for these two pathways. The central hydrogen conversion plant is sized to supply regional hydrogen markets, whereas the forecourt capacity is sized to meet local service station demand.

Table 1
IHIG Hydrogen Pathways

Original Feedstocks	Revised Feedstocks	Location of H_2 Production
Biomass	Biomass	Central
Natural gas	Natural gas	Central and forecourt
Water	Water	Central and forecourt
Coal	Coal	Central
Petroleum coke	Petroleum coke	Central
Methanol	Methanol	Forecourt
Gasoline	Gasoline	Forecourt
H_2 from ethylene or refinery	Residue/pitch	Central

The by-product source of hydrogen defined by IHIG in the original proposal has been replaced with residue/pitch. For all practical purposes, by-product hydrogen from ethylene plants and naphtha reforming is fully utilized by petrochemical and refining processes. In the future, the demand for hydrogen will increase at a higher rate than the growth of by-product production. Since the mid-1990s, the demand for hydrogen in refineries has been growing at an annual rate of 5%-10%. More hydroprocessing treatment of feedstocks and products are required to meet increasingly stringent clean fuel specifications for gasoline and diesel. Meanwhile, by-product hydrogen production has been declining during the same period. Specifically:

- Hydrogen yields from naphtha reforming have been declining as refineries adjust their operational severity downward to reduce the aromatic content in the reformat; a major gasoline blending stock.
- Most of the new ethylene capacities are based on less hydrogen-rich liquid feedstocks such as naphtha.

Hydrogen could be extracted from the eight feedstocks listed in Table 3 using the following five commercially proven technologies.

Steam methane reforming
Methanol reforming
Gasoline reforming
Gasification/partial oxidation
Electrolysis

Table 2 shows feedstocks, associated conversion technologies, and distribution methods for the 14 central facility pathways. For central production plants, there are several intermediate steps before the hydrogen could be dispensed into FC vehicles. The purified hydrogen has to be either liquefied or compressed before it can be transported by cryogenic trucks, pipelines, or tube trailers. In the base case, the delivered hydrogen has to be pressurized to 400 atmospheres (6,000 psig) to be dispensed into FC vehicles outfitted with 340 atmospheres (5,000 psig) on-board cylinders.

Table 5 shows four forecourt hydrogen production pathways. On-site production eliminates the need for intermediate handling steps and distribution infrastructure.

Table 2
Central Hydrogen Production Pathways

Case No.	Feedstock	Conversion Process	Method of Distribution
C4	Natural gas	Steam methane reforming	Liquid H_2 via truck
C11	Natural gas	Steam methane reforming	Gaseous H_2 via tube trailer
C3	Natural gas	Steam methane reforming	Gaseous H_2 via Pipeline
C9	Coal	Partial oxidation	Liquid H_2 via truck
C15	Coal	Partial oxidation	Gaseous H_2 via tube trailer
C8	Coal	Partial oxidation	Gaseous H_2 via Pipeline
C6	Water	Electrolysis	Liquid H_2 via truck
C12	Water	Electrolysis	Gaseous H_2 via tube trailer
C5	Water	Electrolysis	Gaseous H_2 via Pipeline
C2	Biomass	Gasification	Liquid H_2 via truck
C10	Biomass	Gasification	Gaseous H_2 via tube trailer
C1	Biomass	Gasification	Gaseous H_2 via Pipeline
C7	Petroleum coke	Gasification	Gaseous H_2 via Pipeline
C13	Residue	Gasification	Gaseous H_2 via Pipeline

Table 3
Forecourt Hydrogen Production Pathways

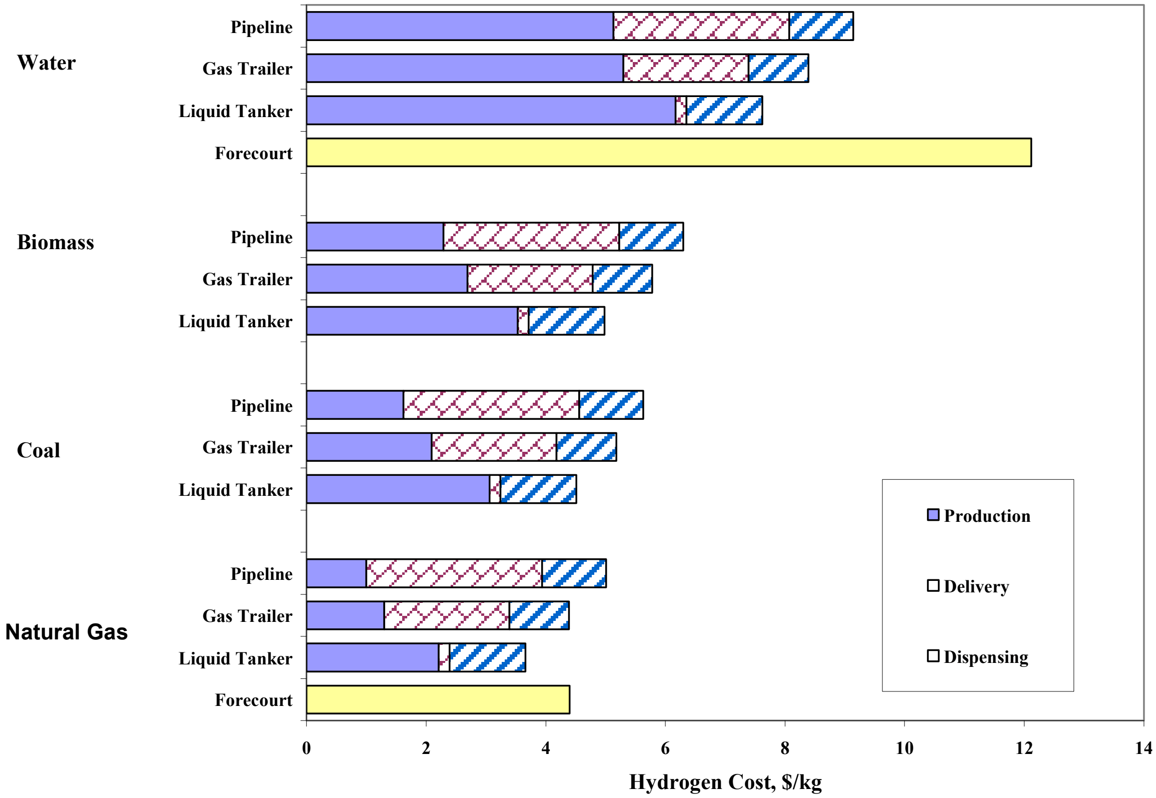
Case No.	Feedstock	Conversion Process
F1	Methanol	Methanol reforming
F2	Natural gas	Steam methane reforming
F3	Gasoline	Gasoline reforming
F4	Water	Electrolysis

Summary

SFA Pacific has developed consistent and transparent infrastructure cost modules for producing, handling, distributing, and dispensing hydrogen from a central plant and forecourt (fueling station) on-site facility for fuel cell (FC) vehicle applications. The investment and operating costs are based on SFA Pacific's extensive database and verified with three industrial gas companies (Air Products, BOC, and Praxair) and hydrogen equipment vendors.

The SFA Pacific cost module worksheets allow users to provide alternative inputs for all the cells that are highlighted in light gray boxes. Flexibilities are provided for assumptions that include production capacity, capital costs, capital build-up, fixed costs, variable costs, distribution distance, carrying capacity, fueling station sales volume, dispensing capacity, and others. Figure 1 compares the costs of hydrogen produced from a 150,000 kg/d central plant based on natural gas, coal, biomass, and water, delivered to forecourt by either liquid truck, gas tube trailer, or pipeline with a 470 kg/d forecourt production based on natural gas and water. The base case capacity was chosen at the beginning of the project to represent infrastructure requirements for the New York/New Jersey region.

Figure 1
Central Plant and Forecourt Hydrogen Costs



Source: SFA Pacific, Inc.

Generally, the higher costs of commercial rates for feedstock and utilities coupled with lower operating rates lead to higher hydrogen costs from forecourt production. Regardless of the source for hydrogen, the above comparison shows the following trends for central plant production.

- The energy intensive liquefaction operation leads to the highest production cost, but incurs the lowest transportation cost
- The high capital investment required for pipeline construction makes it the most expensive delivery method
- The cost for gas tube trailer delivery is also high, slightly less than the pipeline cost, because the low hydrogen density limits each load to about 300 kg.

Other findings from this evaluation could facilitate the formulation of hydrogen infrastructure development strategies from the initial introductory period through ramp-up to a fully developed market.

- Advantages of economy of scale and lower industrial rates for feedstock and power compensate for the additional handling and delivery costs needed for distributing hydrogen to fueling stations from central plants.
- Hydrocarbon feedstock-based pathways have economic advantages in both investment and operating costs over renewable feedstocks such as water and biomass.
- Economics of forecourt production suffer from low utilization rates and higher commercial rates for feedstock and electricity. For natural gas based feedstock, the hydrogen costs from forecourt production are comparable to those of hydrogen produced at a central plant and distributed to fueling stations by tube trailer, and are 20% higher than the liquid tanker truck delivery pathway.
- To meet the increasing demand during the ramp-up period, a “mix and match” of the three delivery systems (tube trailers, tanker trucks, and pipelines) is a likely scenario. Tube trailers, which haul smaller quantities of hydrogen, are probably best suited for the introductory period. As the demand grows, cryogenic tanker trucks could serve larger markets located further from the central plant. As the ramp-up continues, additional production trains would be added to the existing central plants, and ultimately a few strategically placed hydrogen pipelines could connect these plants to selected stations and distribution points.
- On-board liquid (methanol or naphtha) reforming or direct FC technology could leverage the existing liquids infrastructure. It would eliminate costly hydrogen delivery and dispensing infrastructures, as well as avoid regulatory issues regarding hydrogen handling.

Consistency and Transparency

The SFA Pacific cost modules are "living documents." The flexible inputs allow revisions for infrastructure adjustments and future improved capital and operating cost bases.

Ease of Comparison

Table 4 shows that, at comparable capacity, SFA Pacific's models yield cost estimates similar to those developed by Air Products for the Hydrogen Infrastructure Report [1] sponsored by Ford and the U.S. Department of Energy (DOE). Key findings from the Air Products evaluation were also published in the International Journal of Hydrogen Energy [2].

Table 4
Comparison of Hydrogen Costs Developed by SFA Pacific and Air Products

			Investment ($million)		Hydrogen Cost ($/kg)	
Feedstock	H_2 Capacity (t/d)	H_2 Source	SFA Pacific	Air Products	SFA Pacific	Air Products
Natural Gas	27	Liquid	102	63	4.34	3.35
Natural Gas	27	Pipeline [a]	71	82	3.08	2.91
Natural Gas	2.7	Forecourt	6.2	9.6	3.30	3.57
Methanol	2.7	Forecourt	6.0	6.8	3.46	3.76

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[a] To be consistent with the estimates from Air Products, SFA Pacific excluded fueling state investment and operating costs in this comparison.

Source: SFA Pacific, Inc.

The differences between SFA Pacific and Air Products costs for hydrogen delivered by cryogenic tanker trucks could be attributed to a large discrepancy shown in the capital investment for fueling station infrastructure (Table 5).

Table 5
Capital Investment Allocations for Methane Based Liquefied Hydrogen
($Million)

	SFA Pacific	Air Products
Steam Methane Reformer	21	19
Liquefier	44	41
Tanker Trucks	7	n/a
Fueling Stations	30	3
Total	102	63

Source: SFA Pacific, Inc.

Flexibility Improvements

Currently, the central plant storage matches the form of hydrogen for a designated delivery option. A separate and independent module for handling and storing purified gaseous hydrogen would increase the model's flexibility in evaluating mix-match storage and delivery options to meet the rising demand during the ramp-up period.

Potential Improvements for Hydrogen Economics

All hydrogen pathways were developed based on conventional technology and infrastructure deployment. However, new technologies and novel operating options could potentially reduce the cost of hydrogen, thus making it a more attractive fuel option.

Central Plant Hydrogen Production

- Polygeneration (a term referring to the co-production of electric power for sale to the grid) would improve the hydrogen economics. Central gasification units have advantages of economy of scale and lower marginal operating and maintenance costs compared with the same option for forecourt production.
- Installing a liquefaction unit would lower the central storage costs and provide greater flexibility. It is more practical to store large amounts of liquid than gaseous hydrogen. More storage capacity would allow the hydrogen plant to operate at a higher utilization rate. If the hydrogen is to be transported either by pipelines or tube trailers, a slipstream from the boil-off could supply the gaseous hydrogen for distribution.
- Using a hybrid technology or heat-exchange design improves steam reforming operation and increases conversion. Autothermal reforming (ATR), which combines partial oxidation with reforming, improves heat and temperature management. Instead of a single-step process, ATR is a two-step process in hydrogen plants—the partially reformed gases from the primary reformer feed a secondary oxygen blown reformer with additional methane. The exothermic heat release from the oxidation reaction supplies the endothermic heat needs of the reforming reactions. Including reforming reactions allows co-feeding of CO_2 or steam to achieve a wider range of H_2/CO ratios in the syngas.
- Capturing CO_2 for enhanced oil recovery (EOR) or for future CO_2 trading could improve the economics of hydrogen production if CO_2 mitigation is mandated and supported by trading.

Hydrogen Distribution

- Hydrogen pipeline costs could be reduced by placing the pipelines in sewers, securing utility status, or converting existing natural gas pipelines to carry a mixture of hydrogen/natural gas (town gas).
- Using ultra high-pressure (10,000 psig) tube trailers could potentially triple the carrying load.

Hydrogen Fueling Stations

The infrastructure investment for fueling stations could reach 60% of the total capital costs. By using the global positioning system (GPS), which has gained wide consumer acceptance, we could significantly lower the traditional strategy of 25% urban and 50% rural area hydrogen service station penetration. The GPS system would enable FC vehicle drivers to locate fueling stations more efficiently. Additional strategies for reducing infrastructure investment include:

- Using ultra high-pressure (about 800 to 900 atmospheres) vessels to increase forecourt hydrogen storage capacity. It may be possible to have large vertical vessels underground or to use them as canopy supports to minimize land usage.
- Replacing on-board hydrogen cylinders with pre-filled ones instead of the traditional fill-up option could eliminate fueling station infrastructure investment.
- Dispensing liquid hydrogen into FC vehicles (an idea brought up by BMW during the April 4, 2002 meeting) could eliminate the need for expensive compression and storage costs at forecourts. However, an innovative on-board liquid hydrogen storage design is needed to prevent boil-off when the FC vehicle is not in use.

Hydrogen Economic Module Basis

SFA Pacific developed simplified energy, material balance, capital investment, and operating costs to achieve transparency and consistency. Cost estimates are presented in five workbooks (Appendix A) include central plant, distribution, fueling station, forecourt, and overall summary. Each worksheet includes a simplified block flow diagram and major line items for capital and operating costs. Capital investment and operating costs are based on an extensive proprietary SFA Pacific database, which has been verified with industrial gas producers and hydrogen equipment vendors. The database contains reliable data for large and small-scale steam methane reforming and gasification units. Although SFA has confirmed the estimates for electrolyzers with industrial gas companies, they could probably be improved further. There are many advocates and manufacturers giving quotes that are significantly lower than those used in this analysis. Some of these discrepancies could be attributed to the manufacturers' exclusion of a processing step to remove contaminants, and others could result from optimistic estimates based on projected future breakthroughs.

The investment and operating costs modules are developed based upon commonly accepted cost estimating practices. Capital build-up is based on percentages of battery limit process unit costs. Variable non-fuel and fixed operating and maintenance (O&M) costs are estimated based on percentages of total capital per year. Capital charges are also estimated as percentages of total capital per year assumptions for capital investment. Operating costs (variable and fixed) and capital charges are listed in Table 6. For ease of comparison, all unit costs are shown in \$/million Btu, \$/1,000 scf, and \$/kg (\$/gal gasoline energy equivalent).

The capital cost estimates are based on U.S. Gulf Coast costs. A location factor adjustment is provided to facilitate the evaluation of costs for three targeted states: high cost urban areas such as New York/New Jersey and California and low-cost lower population density Texas. Two provisions are made at forecourt/fueling stations to allow "what-if" analysis: (1) road tax input accommodates possible government subsidies to jump-start the hydrogen economy and (2) gas station mark-ups permit incentives for lower revenue during initial stages of low hydrogen demand.

Table 6
Capital and Operating Costs Assumptions

Capital Build-up	% of Process Unit	Typical Range
General Facilities	20	20-40 [a]
Engineering, Permitting, and Startup	15	10-20
Contingencies	10	10-20
Working Capital, Land, and Others	7	5-10

Operating Costs Build-up	%/yr of Capital	Typical Range
Variable Non-Fuel O&M	1.0	0.5-0.5
Fixed O&M	5.0	4-7
Capital Charges	18.0	20-25 for refiners 14-20 for utilities

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[a] 20%-40% for steam methane reformer and an additional 10% for gasification.

Source: SFA Pacific, Inc.

Hydrogen Production Technology

Three distinct types of commercially proven technologies were selected to extract hydrogen from the eight feedstocks. Fundamental principles for each technology apply regardless of the unit size. A brief technical review of reforming, gasification, and electrolysis describes the major processing steps required for each hydrogen production pathway.

- Reforming is the technology of choice for converting gaseous and light liquid hydrocarbons
- Gasification or partial oxidation (PO) is more flexible than reforming—it could process a range of gaseous, liquid, and solid feedstocks.
- Electrolysis splits hydrogen from water.

Reforming

Steam methane reforming (SMR), methanol reforming, and gasoline reforming are based on the same fundamental principles with modified operating conditions depending on the hydrogen-to-carbon ratio of the feedstock.

SMR is an endothermic reaction conducted under high severity; the typical operating conditions are 30 atmospheres and temperatures exceeding 870°C (1,600°F). Conventional SMR is a fired heater filled with multiple tubes to ensure uniform heat transfer.

$$CH_4 + H_2O <=> 3H_2 + CO \tag{1}$$

Typically the feedstock is pretreated to remove sulfur, a poison which deactives nickel reforming catalysts. Guard beds filled with zinc oxide or activated carbon are used to pretreat natural gas and hydrodesulfurization is used for liquid hydrocarbons. Commercially, the steam to carbon ratio is between 2 and 3. Higher stoichiometric amounts of steam promote higher conversion rates and minimize thermal cracking and coke formation.

Because of the high operating temperatures, a considerable amount of heat is available for recovery from both the reformer exit gas and from the furnace flue gas. A portion of this heat is used to preheat the feed to the reformer and to generate the steam for the reformer. Additional heat is available to produce steam for export or to preheat the combustion air.

Methane reforming produces a synthesis gas (syngas) with a 3:1 H_2/CO ratio. The H_2/CO ratio decreases to 2:1 for less hydrogen-rich feedstocks such as light naphtha. The addition of a CO shift reactor could further increase hydrogen yield from SMR according to Equation 2.

$$CO + H_2O => H_2 + CO_2 \tag{2}$$

The shift conversion may be conducted in either one or two stages operating at three temperature levels. High temperature (660°F or 350°C) shift utilizes an iron-based catalyst, whereas medium and low (400°F or 205°C) temperature shifts use a copper based catalyst. Assuming 76% SMR efficiency coupled with CO shift, the hydrogen yield from methane on a volume is 2.4:1.

There are two options for purifying crude hydrogen. Most of the modern plants use multi-bed pressure swing adsorption (PSA) to remove water, methane, CO_2, N_2, and CO from the shift reactor to produce a high purity product (99.99%+). Alternatively, CO_2 could be removed by chemical absorption followed by methanation to convert residual CO_2 in the syngas.

Gasification

Traditionally, gasification is used to produce syngas from residual oil and coal. More recently, it has been extended to process petroleum coke. Although not as economical as SMR, there are a number of natural gas-based gasifiers. Other feedstocks include refinery wastes, biomass, and municipal solid waste. Gasification of 100% biomass feedstock is the most speculative technology used in this project. Total biomass based gasification has not been practiced commercially. However, a 25/75 biomass/coal has been commercially demonstrated by Shell at their Buggenm refinery. The biomass is dried chicken waste.

In addition to the primary reaction shown by Equation 3, a variety of secondary reactions such as hydrocracking, steam gasification, hydrocarbon reforming, and water-gas shift reactions also take place.

$$C_aH_b + a/2O_2 \Rightarrow b/2H_2 + aCO \qquad (3)$$

For liquid and solids gasification, the feedstocks react with oxygen or air under severity operating conditions (1,150°C -1,425°C or 2,100°F -2,600°F at 400-1,200 psig). In hydrogen production plant, there is an air separation unit (ASU) upstream of the gasifier. Using oxygen rather than air avoids downstream nitrogen removal steps.

In some designs, the gasifiers are injected with steam to moderate operating temperatures and to suppress carbon formation. The hot syngas could be cooled directly with a water quench at the bottom of the gasifier or indirectly in a waste heat exchanger (often referred to as a syngas cooler) or a combination of the two. Facilitating the CO shift reaction, a direct quench design maximizes hydrogen production. The acid gas (H_2S and CO_2) produced has to be removed from the hydrogen stream before it enters the purification unit.

When gasifying liquids, it is necessary to remove and recover soot (i.e., unconverted feed carbon), ash, and any metals (typically vanadium and nickel) that are present in the feed. The recovered soot can be recycled to the gasifier, although such recycling may be limited when the levels of ash and metals in the feed are high. Additional feed preparation and handling steps beyond the basic gasification process are needed for coal, petroleum coke, and other solids such as biomass.

Electrolysis

Electrolysis is decomposition of water into hydrogen and oxygen, as shown in Equation 4.

$$H_2O + \text{electricity} \Rightarrow H_2 + \tfrac{1}{2}\ O \qquad (4)$$

Alkaline water electrolysis is the most common technology used in larger production capacity units (0.2 kg/day). In an alkaline electrolyzer, the electrolyte is a concentrated solution of KOH in water, and charge transport is through the diffusion of OH^- ions from cathode to anode. Hydrogen is produced at the cathode with almost 100% purity at low pressures. Oxygen and water by-products have to be removed before dispensing.

Electrolysis is an energy intensive process. The power consumption at 100% efficiency is about 40 kWh/kg hydrogen; however, in practice it is closer to 50 kWh/kg. Since electrolysis units operate at relatively low pressures (10 atmospheres), higher compression is needed to distribute the hydrogen by pipelines or tube trailers compared to other hydrogen production technologies.

Central Plant Hydrogen Production

Figure 2 shows that each central production hydrogen pathway consists of four steps: hydrogen production, handling, distribution, and dispensing.

Figure 2
Central Plant Hydrogen Production Pathway

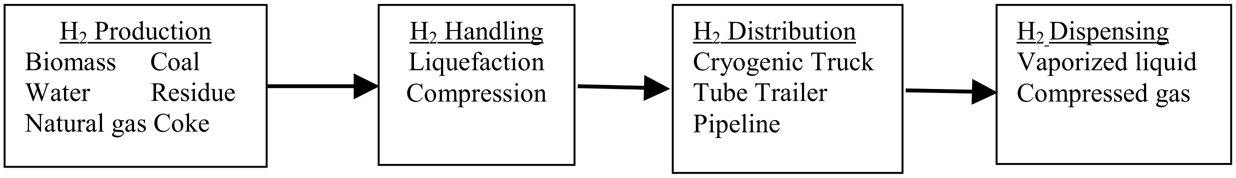


Table 7 lists feedstocks and utility costs used in this analysis. Central plant hydrogen production benefits from lower industrial rates, whereas the fueling stations are charged with the higher commercial rates.

Table 7
Central Hydrogen Production Feedstock and Utility Costs

	Unit Cost
Natural gas (industrial)	\$3.5/MMBtu HHV
Electricity (industrial)	\$0.045/kW
Electricity (commercial)	\$0.070/kW
Biomass	\$57/bone dry ton
Coal	\$1.1/MMBtu dry HHV
Petroleum coke	\$0.2/MMBtu dry HHV
Residue (Pitch)	\$1.5/MMBtu dry HHV

Source: Annual Energy Outlook 2002 Reference Case Tables, EIA.

The design production capacity for each central plant ranges from 20,000 kg/d to 200,000 kg/d hydrogen with a 90% utilization rate. An arbitrary design capacity of 150,000 kg/d has been chosen for discussion purposes. Table 8 shows that the cost of hydrogen for hydrocarbon based feedstock is lower than renewables. For each feedstock, the cost of hydrogen via cryogenic liquid tanker truck delivery pathway is 10%-25% lower than by tube trailer and 15%-30% less than by pipeline. Since the cost of liquid delivery is relatively small (less than 5%), the costs for hydrocarbon based feedstock, production, and fueling account for close to 67% and 33% of the total hydrogen costs, respectively. For renewables (biomass and water), the production cost accounts for 70%-80% of the total hydrogen cost. With high investment costs, the tube trailer and pipeline delivery account for 50% of the total cost.

Table 8
Summary of Central Plant Based Hydrogen Costs
(1,000 kg/d hydrogen)

Delivery Pathway	Liquid Tanker Truck, $/kg	Gas Tube Trailer, $/kg	Pipeline, $/kg
Natural Gas			
Production	2.21	1.30	1.00
Delivery	0.18	2.09	2.94
Dispensing	1.27	1.00	1.07
Total	3.66	4.39	5.00
Coal			
Production	3.06	2.09	1.62
Delivery	0.18	2.09	2.94
Dispensing	1.27	1.00	1.07
Total	4.51	5.18	5.62
Biomass			
Production	3.53	2.69	2.29
Delivery	0.18	2.09	2.94
Dispensing	1.27	1.00	1.07
Total	4.98	5.77	6.29
Water			
Production	6.17	5.30	5.13
Delivery	0.18	2.09	2.94
Dispensing	1.27	1.00	1.07
Total	7.62	8.39	9.13
Petroleum Coke			
Production			1.35
Delivery			2.94
Dispensing			1.07
Total			5.35
Residue			
Production			1.27
Delivery			2.94
Dispensing			1.07
Total			5.27

Source: SFA Pacific, Inc.

Numerous studies have been conducted to evaluate the economics of using renewable feedstocks to produce energy and fuels. Waste biomass and co-product biomass are very seasonal and have high moisture content, except for field-dried crop residues. As a result, they require more expensive storage and extensive drying before gasification. Furthermore, very limited supplies are available and quantities are not large or consistent enough to make them a viable feedstock for large-scale hydrogen production. Cultivated biomass is the only guaranteed source of biomass feedstock, and as a crop, the yield is relatively low (10 ton/hectare). As a result, large land mass is required to provide a steady supply of feedstock. This dedicated renewable biomass comes at a cost of $57/bone dry ton (BDT), which includes $500/hectare/yr and $7/BTD delivery cost. However, available biomass could supplement other solid feeds to maximize the utilization of the gasification unit. Finally, biomass gasification processes are not effective for pure hydrogen production due to their air-blown operations or a product gas that is high in methane and requires additional reforming to produce hydrogen.

Water is another feedstock commonly referred to as a renewable energy source. Although hydrogen occurs naturally in water, the extraction costs are still considerably higher than conventional hydrocarbon based energy sources.

Hydrogen Handling and Storage

Purified hydrogen has to be either liquefied for cryogenic tanker trucks or compressed for pipeline or tube trailer delivery to fueling stations.

Hydrogen Liquefaction

Liquefaction of hydrogen is a capital and energy intensive option. The battery limit investment is $700/kg/d for a 100,000 kg/d hydrogen plant, and compressors and brazed aluminum heat exchanger cold boxes account for most of the cost. The total installed capital cost for the liquefier, excluding land and working capital is $1,015 kg/d, which agrees well with the $1,125 estimate from Air Products. Multi-stage compression consumes about 10-13 kWh/kg hydrogen.

Gaseous crude hydrogen from the PSA unit undergoes multiple stages of compression and cooling. Nitrogen is used as the refrigerant to about 195°C (-320°F). Ambient hydrogen is a mixture 75% ortho- and 25% para-hydrogen, whereas liquid hydrogen is almost 100% para-hydrogen. Unless ortho-hydrogen is catalytically converted to para-hydrogen before the hydrogen is liquefied, the heat of reaction from the exothermic conversion of ortho-hydrogen to para-hydrogen, which doubles the latent heat of vaporization, would cause excessive boil-off during storage. The liquefier feed from the PSA unit mixes with the compressed hydrogen and enters a series of ortho/para-hydrogen converters before entering the cold end of the liquefier. Further cooling to about -250°C (-420°F) is accomplished in a vacuum cold box with brazed aluminum flat plate cores. The remaining 20% ortho-hydrogen is converted to achieve 99%+ para-hydrogen in this section.

Gaseous Hydrogen Compression

Gaseous hydrogen compressors are major contributors to capital and operating costs. To deliver high-pressure hydrogen, 3-5 stages of compression are required because water-cooled positive-displacement compressors could only achieve 3 compression ratios per stage. Compression requirements depend on the hydrogen production technology and the delivery requirements. For pipeline delivery, the gas is compressed to 75 atmospheres for 30 atmospheres delivery. Higher pressures are used to compensate for frictional loss in pipelines without booster compressors along the pipeline system. The gaseous hydrogen has to be compressed to 215 atmospheres to fill tube trailers. In this study, the unit capital cost is between $2,000/kW and $3,000/kW and the power requirement ranged from 0.5 kW/kg/hr to 2.0 kW/kg/hr.

Hydrogen Storage

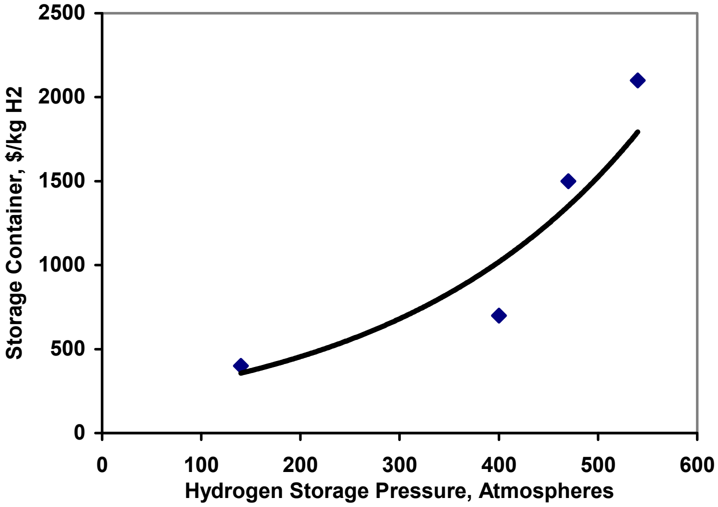
On-site storage allows continuous hydrogen plant operation in order to achieve higher utilization rates. It is more practical to store large amounts of hydrogen as liquid. At less than $5/gallon (physical volume) capital cost, liquid hydrogen storage is relatively inexpensive compared to compressed gaseous hydrogen. Table 9 shows that hydrogen is the lowest energy density fuel on earth. It would take 3.73 gallons of liquid hydrogen to provide equivalent energy of one gallon of gasoline. Gaseous hydrogen has to be pressurized for storage. At the base case pressure of 400 atmospheres (6,000 psig), it would require about 8 gallons of gaseous hydrogen to have the same energy content as one gallon of gasoline. The higher the gas pressure, the lower the storage volume needed. However, the tube becomes weight limited as the thickness of the steel wall increases to prevent embrittlement (cracking caused by hydrogen migrating into the metal).

Table 9
Density of Vehicle Fuel

Fuel Type	Density (kg/l)
Compressed Hydrogen	0.016
Gasoline	0.8
Methanol	0.72

Figure 3 shows how the cost of gaseous storage tubes increases with pressure. The cost could increase from less than $400/kg hydrogen at 140 atmospheres to $2100/kg hydrogen at 540 atmospheres. Companies such as Lincoln Composites and Quantum Technologies are developing new synthetic materials to withstand high pressures at a larger range of temperatures.

Figure 3
Hydrogen Storage Container Costs

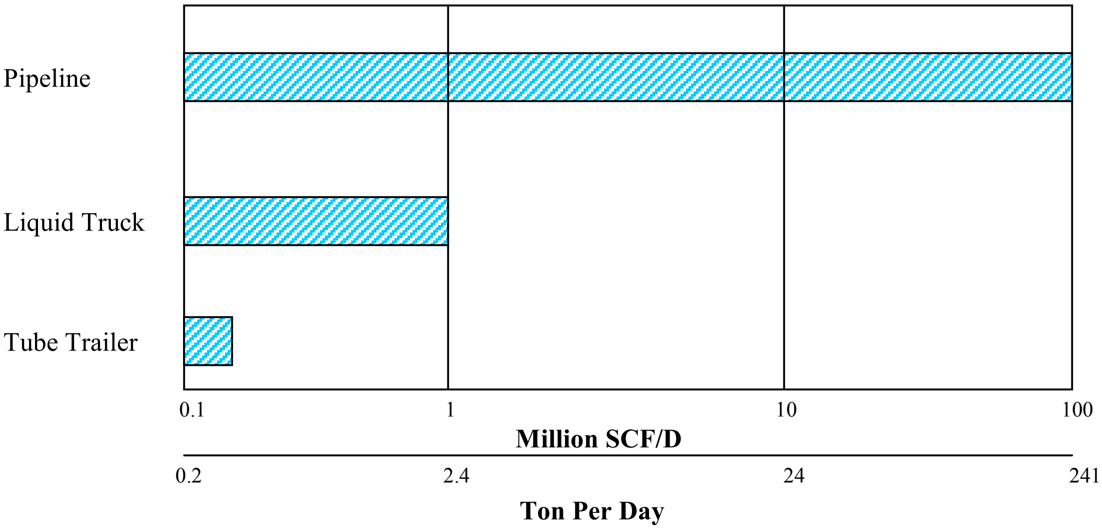


Source: SFA Pacific, Inc.

Hydrogen Distribution

This study includes three hydrogen distribution pathways: cryogenic liquid trucks, compressed tube trailers, and gaseous pipelines. Figure 4 shows that each option has a distinct range of practical application.

Figure 4
Hydrogen Distribution Options



Source: Air Products.

A combination of these three options could be used during various stages of hydrogen fuel market development.

- Tube trailers could be used during the initial introductory period because the demand probably will be relatively small and it would avoid the boil-off incurred with liquid hydrogen storage.
- Cryogenic tanker trucks could haul larger quantities than tube trailers to meet the demands of growing markets.
- Pipelines could be strategically placed to transport hydrogen to high demand areas as more production capacities are placed on-line.

Road Delivery (Tanker Trucks and Tube Trailers)

Based on the assumptions shown in Table 10, the cost of liquid tanker truck delivery is about 10% of tube trailer delivery ($0.18/kg vs. $2.09/kg).

Table 10
Road Hydrogen Delivery Assumptions

	Cryogenic Truck	Tube Trailer
Load, kg	4,000	300
Net delivery, kg	4,000	250
Load/unload, hr/trip	4	2
Boil-off rate, %/day	0.3	na
Truck utilization rate, %	80	80
Truck/tube, $/module	450,000	100,000
Undercarriage, $	60,000	60,000
Cab, $	90,000	90,000

Source: SFA Pacific, Inc.

Delivery by cryogenic liquid hydrogen tankers is the most economical pathway for medium market penetration. They could transport relatively large amounts of hydrogen and reach markets located throughout large geographic areas. Tube trailers are better suited for relatively small market demand and the higher costs of delivery could compensate for losses due to liquid boil-off during storage. However, high-pressure tube trailers are limited to meeting small hydrogen demands. Typically, the tube-to-hydrogen weight ratio is about 100-150:1. A combination of low gaseous hydrogen density and the weight of thick wall, high quality steel tubes (80,000 pounds or 36,000 kilograms) limit each load to 300 kilograms of hydrogen. In reality, only 75%-85% of each load is dispensable, depending on the dispensing compressor configuration. Unlike tanker trucks that discharge their load, the tube and undercarriage are disconnected from the cab and left at the fueling station. Tube trailers are used not only as transport container, but also as on-site storage. As a result, the total number of tubes provided equals the number of tubes left at the fueling stations and those at the central plants to be picked up by the returning cabs.

Liquid hydrogen flows into and out of the tanker truck by gravity and it takes about two hours to load and unload the contents. SFA Pacific estimates the physical delivery distance for truck/trailers is 40% longer than the assumed average distance of 150 kilometers between the central facility and fueling stations.

Pipeline Delivery

Pipelines are most effective for handling large flows. They are best suited for short distance delivery because pipelines are capital intensive ($0.5 to $1.5 million/mile). Much of the cost is associated with acquiring right-of-way. Currently, there are 10,000 miles of hydrogen pipelines in the world. At 250 miles, the longest hydrogen pipeline connects Antwerp and Normandy.

Operating costs for pipelines are relatively low. To deliver hydrogen to the fueling stations at 30 atmospheres, the pressure drop could be compensated with either booster compressors or by compressing the hydrogen at the central plant. In this study, the pipeline investment is based on four pipelines radiating from the central plant.

Hydrogen Fueling Station

The conceptual hydrogen fueling station for this study is designed based on equivalent conventional internal combustion engine (ICE) requirements as shown in Table 11.

Table 11
Assumed FC Vehicle Requirements

	ICE-gasoline	FC requirement
Vehicle mileage	23 km/liter	23 km/liter
Vehicle annual mileage	12,000 miles	218 kg H_2 or 12,000 miles
Fuel sales per station	150,000 gal/month	10,000 kg H_2/monthor 10,000 gal gasoline equivalent

Source: SFA Pacific, Inc.

Table 12 shows that the key fueling station design parameters. At a 70% operating rate, each service station dispenses about 329 kg/d, assuming a daily average of 4.0 kg per fill-up and five fill-ups an hour. Each fueling hose is sized to meet daily peak demand.

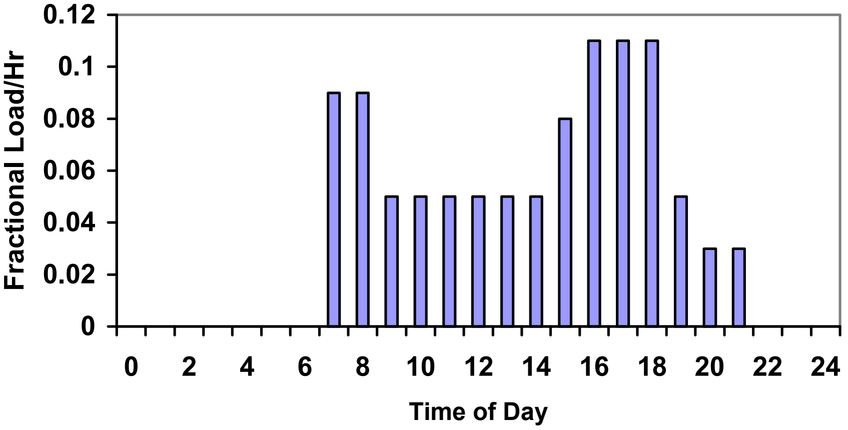
Table 12
Fueling Dispenser Design Basis

Design capacity	470 kg/d
Operating rate	70%
Operating capacity	329 kg/d
Number of dispenser	2
Average fill-up rate	4 kg
Average number of fill-up	5 /hr
Peak fill-up rate (3 times daily average)	48 kg/hr
Dispensing pressure, psig	6,000

Source: SFA Pacific, Inc.

Sizing hydrogen dispensers is no different than sizing gasoline dispensers; they must be designed to meet peak demands. As shown in Figure 5, the peak demand could be triple that of the daily average.

Figure 5
Fueling Station Dispensing Utilization Profile



Source: Praxair.

This study developed analyses for two types of high-pressure gaseous fueling stations: one to handle liquid based hydrogen and the other for gaseous hydrogen. Components handling compressed hydrogen (6,000 psig) are the same regardless of the form of hydrogen delivered to the fueling station. Since positive displacement pumps and compressors cannot provide instantaneous load or meet the high-rate demand for dispensing hydrogen directly to FC vehicles, each filling station is provided with three hours of peak demand high-pressure hydrogen buffer storage. The dispenser meters the hydrogen into a FC vehicle fitted with 5,000 psig cylinders.

Liquid Hydrogen Based Fueling

Liquid hydrogen from storage (15,000 gallons) is pressurized to 6,000 psig with variable speed reciprocating positive displacement pumps. An ambient or natural convection vaporizer, which uses ambient air and condensed water to supply the heat requirement for vaporizing and warming the high-pressure gas, does not incur additional utility costs.

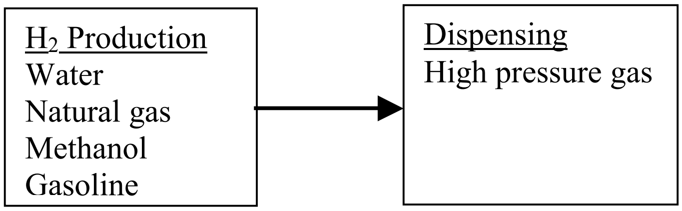
Gaseous Hydrogen Based Fueling

Gaseous hydrogen could be delivered either by pipeline at 30 atmospheres or by tube trailer at 215 atmospheres to the fueling station. To minimize the high cost of hydrogen storage, both pipeline and tube trailer gases are compressed to 6,000 psig and held in a buffer storage. Two other possible options (multi-stage cascade system and booster system) require considerably more expensive hydrogen storage.

Forecourt Hydrogen Production

Forecourt production pathways were developed to evaluate the potential economic advantages of placing small modular units at fueling stations to avoid the initial investment of under utilized large central facilities and delivery infrastructures. The forecourt hydrogen facility is sized to supply and dispense the same amount of hydrogen as each fueling station in the central plant pathways. Each unit is designed to produce 470 kg/d of hydrogen with a 70% utilization rate. Figure 6 shows that forecourt hydrogen production is a self-contained operation. Ideally, hydrogen is compressed to 400 atmospheres (6,000 psig) after purification and dispensed directly into the FC vehicle with 340 atmosphere (5,000 psig) cylinders.

Figure 6
Forecourt Hydrogen Production Pathways



Source: SFA Pacific, Inc.

Table 13 lists commercial rates for feedstocks and power. The commercial rates charged to small local service stations are consistently 50%-70% higher than industrial rates for large production plants. Natural gas delivered to forecourt costs 70% more than that delivered to a central facility ($6/million Btu vs. $3.5/million Btu) and the power cost is 55% higher (7¢/kWh vs. 4.5¢/kWh). Often, proponents of a hydrogen economy provide cost estimates based on off-peak power rates (~$0.04/kWh). Off-peak is only available for 12 hours, after which the forecourt would be charged with peak rates ($0.09/kWh). To circumvent peak power rates, forecourt plants have to be built with oversized units operated at low utilization rates with large amounts of storage. This option would require considerable additional capital investment.

Instead of developing a complete production and delivery infrastructure for methanol, this evaluation uses market prices for methanol. Methanol prices are based on current supplies to chemical markets, and distribution costs per gallon of methanol are twice that of gasoline per gallon or four times that of gasoline on an energy basis.

Table 13
Forecourt Hydrogen Production Feedstock and Utility Costs

	Unit Cost
Natural gas (commercial)	$5.5/MMBtu HHV
Electricity (commercial)	$0.07/kW
Methanol	$7.0/MMBtu HHV
Gasoline	$6.0/MMBtu HHV

Source: Annual Energy Outlook 2002 Reference Case Tables, EIA.
Current Methanol Price, Methanex, February, 2002.

Table 14 shows that the costs for forecourt production of hydrogen from hydrocarbon based feedstocks are within 10%-15% of each other, ranging from $4.40/kg to $5.00/kg hydrogen. The cost for electrolysis based hydrogen is two to three times that of the other three feedstocks. The high cost of electrolytic hydrogen is attributable to high power usage and high capital costs—electricity and capital charges account for 30% and 50% of the total cost, respectively.

Table 14
Summary of Forecourt Hydrogen Costs
(470 kg/d Hydrogen)

Feedstock	$/kg
Methanol	4.53
Natural Gas	4.40
Gasoline	5.00
Water	12.12

Source: SFA Pacific, Inc.

For the two feedstocks common to both the central and forecourt plant, Table 15 shows that the lower infrastructure requirements of forecourt production do not compensate for the higher operating costs.

Table 15
Hydrogen Costs: Central Plant vs. Forecourt
($/kg Hydrogen)

	Central Plant [a]	Forecourt
Natural Gas	3.66	4.40
Water	7.62	12.12

[a] Liquid hydrogen delivery pathway.

Source: SFA Pacific, Inc.

The proposed option of utilizing the hydrogen produced at the forecourt to fuel on-site power generation during initial low hydrogen demand does not make economic sense. Excluding the high capital cost of fuel cell power generation and commercial scale grid connections for exporting electricity, the marginal load dispatch cost of power alone would make this strategy non-competitive. As a result, this pathway was eliminated from our analysis during the kick-off meeting on January 23, 2002.

Sensitivity

SFA Pacific developed a 700 atmospheres (10,000 psig) FC vehicle sensitivity case. This ultra high pressure would allow the vehicle to meet ICE vehicle standards (equal or greater distance between fill ups). Similarly detailed worksheets for the ultra high-pressure case are presented in Appendix B.

Between 1920 and 1950, the process industry had extensive commercial operating experience with 10,000 psig operation in ammonia synthesis and the German coal hydrogenations plants. Improvements in catalytic activity had lowered the operating pressures for these processes, which in turn significantly reduced capital and operating costs. Even though there is less demand for equipment to handle very high-pressure hydrogen, several companies still manufacture ultra high-pressure compressors and vessels. The cost of hydrogen compressors capable of handling 875 atmospheres (13,000 psig) is significantly more than the base case ($4,000/kW vs. $3,000/kW). The higher cost could be attributed mostly to expensive premium-steels to avoid hydrogen stress cracking at ultra high pressures. However, data on these costs are not readily available and are also inconsistent due to the lack of common use, small sizes, and the special fabrication requirements. Until a time when composite material becomes economically viable for high-pressure storage, it is may be best to develop the fueling infrastructure for 5,000 psig FC vehicle cylinders.

Special Acknowledgement

SFA Pacific would like to express our gratitude to the following three industrial gas companies for their insightful discussion and comments after reviewing our draft cost estimates for the hydrogen production, delivery, and dispensing infrastructure.

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BOC
Praxair

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Appendix A

Complete Set of Spreadsheets For Base Case Input

Summary of Natural Gas Based Hydrogen Production

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Design hydrogen production	**150,000**	kg/d H2 and	**90%**	Annual ave. load facor
Supporting	**225,844**	FC Vehicles at	**411**	Filling station
Hydrogen per filling station	**10,000**	kg/mo H2 or	**329**	kg/d H2

Capital Investment	Liquid H2	Pipeline	Tube Trailer
	Million $/yr	Million $/yr	Million $/yr
H2 production	230	79	133
H2 delivery	13	603	141
H2 fueling	279	212	212
Total	**522**	**894**	**486**

Annual Operating Costs	Liquid H2	Pipeline	Tube Trailer
	$ million/yr	$ million/yr	$ million/yr
H2 production	109	49	64
H2 delivery	9	145	103
H2 fueling	63	53	49
Total	**180**	**246**	**216**

Unit H2 Cost in $/kg which is the same as $/gallon gasoline energy equivalent

	Liquid H2	**Pipeline**	**Tube Trailer**	**Forecourt**
	$/kg	**$/kg**	**$/kg**	**$/kg**
H2 production	2.21	1.00	1.30	
H2 delivery	0.18	2.94	2.09	
H2 fueling	1.27	1.07	1.00	
Total	**3.66**	**5.00**	**4.39**	**4.40**

Source: SFA Pacific, Inc.

Summary of Resid Hydrogen Production

Final Version June 2002 **IHIG Confidential**

Design hydrogen production	**150,000**	kg/d H2 and	**90%**	Annual ave. load facor
Supporting	**225,844**	FC Vehicles at	**411**	Filling station
Hydrogen per filling station	**10,000**	kg/mo H2 or	**329**	kg/d H2

Capital Investment	Pipeline Million $/yr
H2 production	185
H2 delivery	603
H2 fueling	212
	1,000

Annual Operating Costs	Pipeline $ million/yr
H2 production	62
H2 delivery	145
H2 fueling	53
Total	**260**

Unit H2 Cost in $/kg which is the same as $/gallon gasoline energy equivalent

	Pipeline **$/kg**
H2 production	1.27
H2 delivery	2.94
H2 fueling	1.07
Total	**5.27**

Source: SFA Pacific, Inc.

Summary of Petroleum Coke Based Hydrogen Production

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Design hydrogen production	**150,000**	kg/d H2 and	**90%**	Annual ave. load facor
Supporting	**225,844**	FC Vehicles at	**411**	Filling station
Hydrogen per filling station	**10,000**	kg/mo H2 or	**329**	kg/d H2

Capital Investment	Pipeline Million $/yr
H2 production	238
H2 delivery	603
H2 fueling	212
	1,053

Annual Operating Costs	Pipeline $ million/yr
H2 production	66
H2 delivery	145
H2 fueling	53
Total	**264**

Unit H2 Cost in $/kg which is the same as $/gallon gasoline energy equivalent

	Pipeline **$/kg**
H2 production	1.35
H2 delivery	2.94
H2 fueling	1.07
Total	**5.35**

Source: SFA Pacific, Inc.

Summary of Coal Based Hydrogen Production

Final Version June 2002 **IHIG Confidential**

Design hydrogen production	**150,000**	kg/d H2 and	**90%**	Annual ave. load facor
Supporting	**225,844**	FC Vehicles at	**411**	Filling station
Hydrogen per filling station	**10,000**	kg/mo H2 or	**329**	kg/d H2

Capital Investment	Liquid H2 Million $/yr	Pipeline Million $/yr	Tube Trailer Million $/yr
H2 production	448	259	339
H2 delivery	13	603	141
H2 fueling	279	212	212
	740	**1,074**	**692**

Annual Operating Costs	Liquid H2 $ million/yr	Pipeline $ million/yr	Tube Trailer $ million/yr
H2 production	151	80	103
H2 delivery	9	145	103
H2 fueling	63	53	49
Total	**222**	**277**	**255**

Unit H2 Cost in $/kg which is the same as $/gallon gasoline energy equivalent

	Liquid H2 $/kg	**Pipeline $/kg**	**Tube Trailer $/kg**
H2 production	3.06	1.62	2.09
H2 delivery	0.18	2.94	2.09
H2 fueling	1.27	1.07	1.00
Total	**4.51**	**5.62**	**5.18**

Source: SFA Pacific, Inc.

Summary of Biomass Based Hydrogen Production

Final Version June 2002 **IHIG Confidential**

Design hydrogen production	**150,000**	kg/d H2 and	**90%**	Annual ave. load facor
Supporting	**225,844**	FC Vehicles at	**411**	Filling station
Hydrogen per filling station	**10,000**	kg/mo H2 or	**329**	kg/d H2

Capital Investment	Liquid H2 Million $/yr	Pipeline Million $/yr	Tube Trailer Million $/yr
H2 production	452	295	362
H2 delivery	13	603	141
H2 fueling	279	212	212
	744	**1,110**	**715**

Annual Operating Costs	Liquid H2 $ million/yr	Pipeline $ million/yr	Tube Trailer $ million/yr
H2 production	174	113	132
H2 delivery	9	145	103
H2 fueling	63	53	49
Total	246	310	284

Unit H2 Cost in $/kg which is the same as $/gallon gasoline energy equivalent

	Liquid H2 **$/kg**	**Pipeline** **$/kg**	**Tube Trailer** **$/kg**
H2 production	3.53	2.29	2.69
H2 delivery	0.18	2.94	2.09
H2 fueling	1.27	1.07	1.00
Total	**4.98**	**6.29**	**5.77**

Source: SFA Pacific, Inc.

Summary of Electrolysis Based Hydrogen Production

Final Version June 2002 **IHIG Confidential**

Design hydrogen production	**150,000**	kg/d H2 and	**90%**	Annual ave. load facor
Supporting	**225,844**	FC Vehicles at	**411**	Filling station
Hydrogen per filling station	**10,000**	kg/mo H2 or	**329**	kg/d H2

Capital Investment	Liquid H2 Million $/yr	Pipeline Million $/yr	Tube Trailer Million $/yr
H2 production	688	566	602
H2 delivery	13	603	141
H2 fueling	279	212	212
	980	**1,382**	**955**

Annual Operating Costs	Liquid H2 $ million/yr	Pipeline $ million/yr	Tube Trailer $ million/yr
H2 production	304	253	261
H2 delivery	9	145	103
H2 fueling	63	53	49
Total	**376**	**450**	**413**

Unit H2 Cost in $/kg which is the same as $/gallon gasoline energy equivalent

	Liquid H2 $/kg	**Pipeline $/kg**	**Tube Trailer $/kg**	**Forecourt $/kg**
H2 production	6.17	5.13	5.30	
H2 delivery	0.18	2.94	2.09	
H2 fueling	1.27	1.07	1.00	
Total	**7.62**	**9.13**	**8.39**	**12.12**

Source: SFA Pacific, Inc.

Forecourt Summary of Inputs and Outputs

Final Version June 2002 **IHIG Confidential**

Inputs **Boxed in yellow** are the key input variables **you** must choose, **current inputs are just an example**

design basis

Key Variables Inputs			**Notes**
Hydrogen Production Inputs			**1 kg H2 is the same energy content as 1 gallon of gasoline**
Design hydrogen production	**470**	**kg/d H2**	194,815 **scf/d H2** 100 to 10,000 kg/d range for forecourt
Annual average load factor	**70%**	/yr of design	10,007 kg/month actual or 120,085 kg/yr actual
High pressure H2 storage	**3**	hr at peak surge rate	"plug & play" 24 hr process unit replacements for availability
FC Vehicle gasoline equiv mileage	**55**	mpg (U.S. gallons) or	23 km/liter 329 kg/d average
FC Vehicle miles per year	**12,000**	mile/yr thereby requires	218 kg/yr H2 for each FC vehicle
Capital Cost Buildup Inputs from process unit costs			**All major utilities included as process units**
General Facilities	**20%**	of process units	20-40% typical, should be low for small forecourt
Engineering, Permitting & Startup	**10%**	of process units	10-20% typical, assume low eng. of multiple standard designs
Contingencies	**10%**	of process units	10-20% typical, should be low after the first few
Working Capital, Land & Misc.	**9%**	of process units	5-10% typical, high land costs for forecourt
Site specific factor	**110%**	above US Gulf Coast	90-130% typical; sales tax, labor rates & weather issues
Product Cost Buildup Inputs			
Road tax or (subsidy)	**$ -**	/gal gasoline equivalent	may need subsidy like EtOH to get it going
Gas Station mark-up	**$ -**	/gal gasoline equivalent	may be needed if H2 sales drops total station revenues
Non-fuel Variable O&M	**1.0%**	/yr of capital	0.5-1.5% is typical
Fuels Methanol	**$ 7.15**	/MM Btu HHV	$7-9/MM Btu typical chemical grade delivered rate
Natural Gas	**$ 5.50**	/MM Btu HHV	$4-7/MM Btu typical **commercial** rate, see www.eia.doe.gov
Gasoline	**$ 6.60**	/MM Btu HHV	$5-7/MM Btu typical tax free rate go to www.eia.doe.gov
Electricity	**$ 0.070**	/kWh	$0.06-.0.09/kWh typical **commercial** rate, see www.eia.doe.gov
Fixed Operating Cost	**5.0%**	/yr of capital	4-7% typical for refiners: labor, overhead, insurance, taxes, G&A
Capital Charges	**18.0%**	/yr of capital	20-25%/yr CC typical for refiners & 14-20%/yr CC for utilities
			20%/yr CC is about 12% IRR DCF on 100% equity where as
			15%/yr CC is about 12% IRR DCF on 50% equity & debt at 7%

Outputs 329 kg/d H2 that supports 550 FC vehicles or 10,007 kg/month for this station

actual annual average 79 fill-ups/d if 1 fill-up/week @ 4.2 kg/fill-up

		Capital Costs			**Operating Cost**		**Product Costs**	
		Absolute	Unit cost	**Unit cost**	**Fixed**	**Variable**	**Including capital charges**	
Case No.	**Description**	$ millions	design rate	design rate	Unit cost	Unit cost	**Unit cost**	**Note**
			$/scf/d H2	**$ kg/d H2**	**$/kg H2**	**$/kg H2**	**$/kg H2**	same as $/gal gaso equiv
F1	**Methanol Reforming**	1.57	8.08	3,350	0.66	1.51	**4.53**	into vehicles at 340 atm
F2	**Natural Gas Reforming**	1.63	8.35	3,460	0.68	1.28	**4.40**	into vehicles at 340 atm
F3	**Gasoline Reforming**	1.78	9.14	3,789	0.74	1.59	**5.00**	into vehicles at 340 atm
F4	**Water Electrolysis**	4.15	21.28	8,821	1.73	4.18	**12.12**	into vehicles at 340 atm

Click on specific Excel worksheet tabs below for details of cost buildups for each case

Source: SFA Pacific, Inc.

Path F1

Forecourt Hydrogen via Steam Reformer of Methanol plus High Pressure Gas Storage

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

Design per station	Design LHV energy equivalent				
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	10,000	10,000	47.422	4,145,000	13.894
This run	**470**	**470**	**2.229**	**194,815**	**0.653**
Minimum	100	100	0.474	41,450	0.139

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming **70%** Annual average load factor

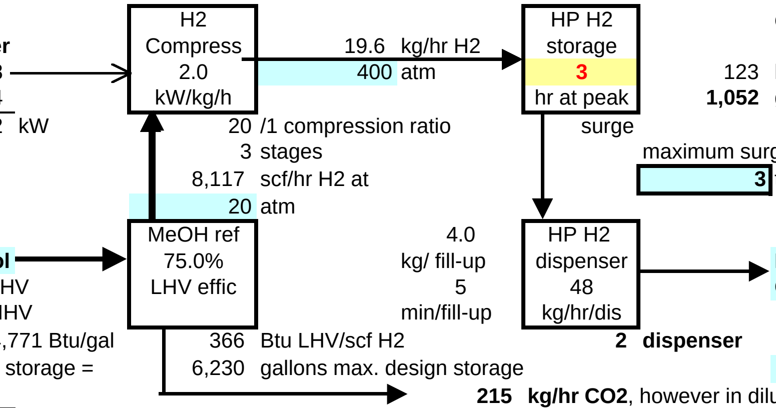
actual H2 120,085 kg/y H2 /station or gal/y gaso equiv

or 10,007 kg/month H2 or gal/mo. gaso equiv

thereby **550** **FC vehicles can be supported at**

79 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week



Electric Power

Compress 38

SMR & misc. 4

Total 42 kW

H2 Compress 2.0 kW/kg/h

19.6 kg/hr H2

400 atm

HP H2 storage **3** hr at peak surge

123 kg H2 max storage or

1,052 gal phy vol at **400** atm

20 /1 compression ratio

3 stages

8,117 scf/hr H2 at

20 atm

maximum surge fill/up rate per hr at

3 times average kg/hr H2 production rate

Methanol

2.972 MM Btu/h LHV

3.363 MM Btu/h HHV

52 gal/hr @ 64,771 Btu/gal

5 day MeOH storage =

MeOH ref 75.0% LHV effic

366 Btu LHV/scf H2

6,230 gallons max. design storage

4.0 kg/ fill-up

5 min/fill-up

HP H2 dispenser 48 kg/hr/dis

2 **dispenser**

High Pressure (340 atm) Hydrogen Gas into Vehicles

470 **design kg/d H2 or gal/d gasoline equivalent**

329 **actual kg/d annual ave.**

215 **kg/hr CO2**, however in dilute N2 rich SMR flue gas

at 0.75 kg CO2/kWh current U.S. average = **32** **kg/hr CO2** equivalent at power plants

12.6 **kgCO2/kg H2**

Capital Costs	**Unit cost basis at 1,000 kg/d H2**	**cost/size factors**	**Unit cost at 470 kg/d H2**	**millions of $ for 1 station**	**Notes**
Methanol storage	5 /gal	70%	$ 6 /gal	0.04	same as gasoline tank cost
Methanol reformer	$ 2.70 /scf/d	75%	$ 3.26 /scf/d	0.64	assume 90% of SMR
H2 Compressor	$ 3,000 /kW	80%	$ 3,489 /kW	0.13	$ 285 /kg/d H2
HP H2 gas storage	$ 100 /gal phy vol	80%	$ 116 /gal phy vol	0.12	$ 991 /kg high press H2 gas
HP H2 gas dispenser	$ 15,000 /dispenser	100%	$ 15,000 /dispenser	0.03	$ 13 /kg/d dispenser design
			Total process units	0.96	
General Facilities	**20%** of process units			0.19	20-40% typical, should be low for this
Engineering Permitting & Startup	**10%** of process units			0.10	10-20% typical, low eng after first few
Contingencies	**10%** of process units			0.10	10-20% typical, low after the first few
Working Capital, Land & Misc.	**9%** of process units			0.09	5-10% typical, high land costs for this
			U.S. Gulf Coast Capital Costs	1.43	
Site specific factor	**110%** above US Gulf Coast		**Total Capital Costs**	**1.57**	
Unit Capital Costs of	**8.08** **/scf/d H2 or**	3,350 /kg/d H2 or	3,350 /gal/d gaso equiv		

Hydrogen Costs at	70% ann load factor	**million $/yr of 1 station**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Road tax or (subsidy)	$ - /gal gaso equiv.	-	-	-	-	can be subsidy like EtOH
Gas Station mark-up	$ - /gal gaso equiv.	-	-	-	-	if H2 drops total station revenues
Non-fuel Variable O&M	**1.0%** /yr of capital	0.016	1.15	0.32	0.13	0.5-1.5% is typical
Methanol	$ **7.15** /MM Btu HHV	0.147	10.79	2.96	1.23	see below - chemical grade
Electricity	$ **0.070** /kWh	0.018	1.33	0.37	0.15	$0.06-.09/kWh EIA **commercial** rate
Variable Operating Cost		**0.181**	**13.27**	**3.64**	**1.51**	
Fixed Operating Cost	**5.0%** /yr of capital	**0.079**	**5.76**	**1.58**	**0.66**	4-7% typical for refining
Capital Charges	**18.0%** /yr of capital	**0.283**	**20.74**	**5.69**	**2.36**	20-25% typical for refining
Total HP Hydrogen Cost from Methanol		**0.544**	**39.77**	**10.92**	**4.53**	including return on investment

in vehicle

$ 0.061	/kWh electricity for **only** H2 fuel **(no capital charges or other O&M)** to high capital cost fuel cell @	60%	LHV effic
$ 0.068	/kWh electricity for **only** MeOH fuel **(no capital charges or other O&M)** to Solar 4 MWe Mercury 50 GT @	40%	LHV effic
$ 0.067	/kWh electricity for **only** MeOH fuel **(no capital charges or other O&M)** to Solar 9 MWe STAC70 CC @	41%	LHV effic

H2-fuel cell power sales during H2 vehicle ramp-up is questionable relative to lower capital & non-fuel O&M of small NG or MeOH fired GT/CC or the much lower NG costs and higher efficiency, 60% of large industrial NGCC

note: **requires $ 0.462 /gal MeOH delivered price back calculated for above $/MM Btu price**

assuming $ 0.100 /gal delivery cost at 2 times assumed special reformer gasoline delivery costs

$ 0.362 /gal Feb. 2002 Methanex U.S. reference price was $ 0.360 /gal

Fuel grade MeOH & large scale GTL with low cost NG, like the new Trinidad 5,000 t/d MeOH unit should be cheaper

Source SFA Pacific, Inc

Path F2

Forecourt Hydrogen via Steam Reformer of Natural Gas plus High Pressure Gas Storage

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

Design for 1 station	**Design LHV energy equivalent**				
	Hydrogen	**gasoline**	**million**		
Size range	**kg/d H2**	**gal/d**	**Btu/hr**	**scf/d H2**	**MW t**
Maximum	10,000	10,000	47.422	4,145,000	13.894
This run	**470**	**470**	**2.229**	**194,815**	**0.653**
Minimum	100	100	0.474	41,450	0.139

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv.

Assuming **70%** Annual average load factor

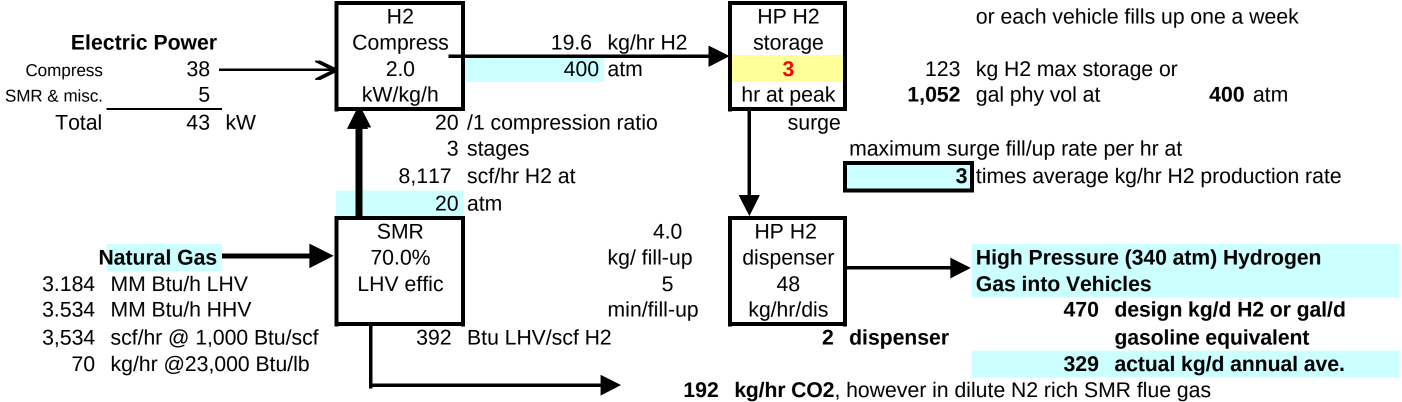
actual H2 120,085 kg/y H2 /station or gal/y gaso equiv.

or 10,007 kg/month H2 or gal/mo. gaso equiv.

thereby **550** **FC vehicles can be supported at**

79 fill-ups/d @ 4.2 kg or gal equiv./fill-up

or each vehicle fills up one a week



192 **kg/hr CO2**, however in dilute N2 rich SMR flue gas

at 0.75 kg CO2/kWh current U.S. average = **32** **kg/hr CO2** equivalent at power plants

11.4 **kgCO2/kg H2**

Capital Costs	**Unit cost basis at 1,000**	**kg/d H2**	**cost/size factors**	**Unit cost at 470**	**kg/d H2**	**millions of $ for 1 station**	**Notes**	
NG Reformer (SMR)	$ 3.00	/scf/d	75%	$ 3.62	/scf/d	0.71	$ 1,502	/kg/d H2
H2 Compressor	$ 3,000	/kW	80%	$ 3,489	/kW	0.13	$ 285	/kg/d H2
HP H2 gas storage	$ 100	/gal phy vol	80%	$ 116	/gal phy vol	0.12	$ 991	/kg high press H2 gas
HP H2 gas dispenser	$ 15,000	/dispenser	100%	$ 15,000	/dispenser	0.03	$ 13	/kg/d dispenser design
				Total process units		0.99		
General Facilities		of process units				0.20	20-40% typical, should be low for this	
Engineering Permitting & Startup	10%	of process units				0.10	10-20% typical, low eng after first few	
Contingencies	10%	of process units				0.10	10-20% typical, low after the first few	
Working Capital, Land & Misc.	9%	of process units				0.09	5-10% typical, high land costs for this	
				U.S. Gulf Coast Capital Costs		1.48		
Site specific factor	110%	above US Gulf Coast		**Total Capital Costs**		**1.63**		
Unit Capital Costs	**8.35**	**/scf/d H2 or**	3,460	/kg/d H2 or	3,460	/gal/d gaso equiv.		

Hydrogen Costs at	70%	ann load factor	**million $/yr of 1 station**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv.**	**Notes**
Road tax or (subsidy)	$ -	/gal gaso equiv.	-	-	-	-	can be subsidy like EtOH
Gas Station mark-up	$ -	/gal gaso equiv.	-	-	-	-	if H2 drops total station revenues
Variable Non-fuel O&M	1%	/yr of capital	0.016	1.19	0.33	0.14	0.5-1.5% is typical
Natural Gas	$ 5.50	/MM Btu HHV	0.119	8.72	2.39	0.99	$4-7/MM Btu EIA **commercial** rate
Electricity	$ 0.070	/kWh	0.019	1.36	0.37	0.15	$0.06-.09/kWh EIA **commercial** rate
Variable Operating Cost			**0.154**	**11.27**	**3.09**	**1.28**	
Fixed Operating Cost	**5%**	/yr of capital	**0.081**	**5.95**	**1.63**	**0.68**	4-7% typical for refining
Capital Charges	**18%**	/yr of capital	**0.293**	**21.42**	**5.88**	**2.44**	20-25% typical of refining
Total HP Hydrogen Costs from Natural Gas			**0.528**	**38.64**	**10.61**	**4.40**	including return on investment

in vehicle

$	**0.050**	/kWh electricity for **only** H2 fuel (**no capital charges or other O&M**) to high capital cost fuel cell @	60% LHV effic
$	**0.052**	/kWh electricity for **only** NG fuel (**no capital charges or other O&M**) to Solar 4 MWe Mercury 50 GT @	40% LHV effic
$	**0.051**	/kWh electricity for **only** NG fuel (**no capital charges or other O&M**) to Solar 9 MWe STAC70 CC @	41% LHV effic

H2-fuel cell power sales during H2 vehicle ramp-up is questionable relative to lower capital & non-fuel O&M of small NG fired GT/CC or the much lower NG costs and higher efficiency, 60% of large industrial NGCC

note: Assume gas station has existing natural gas pipeline infrastructure, if not more capital or higher NG price

Source SFA Pacific, Inc

Path F3

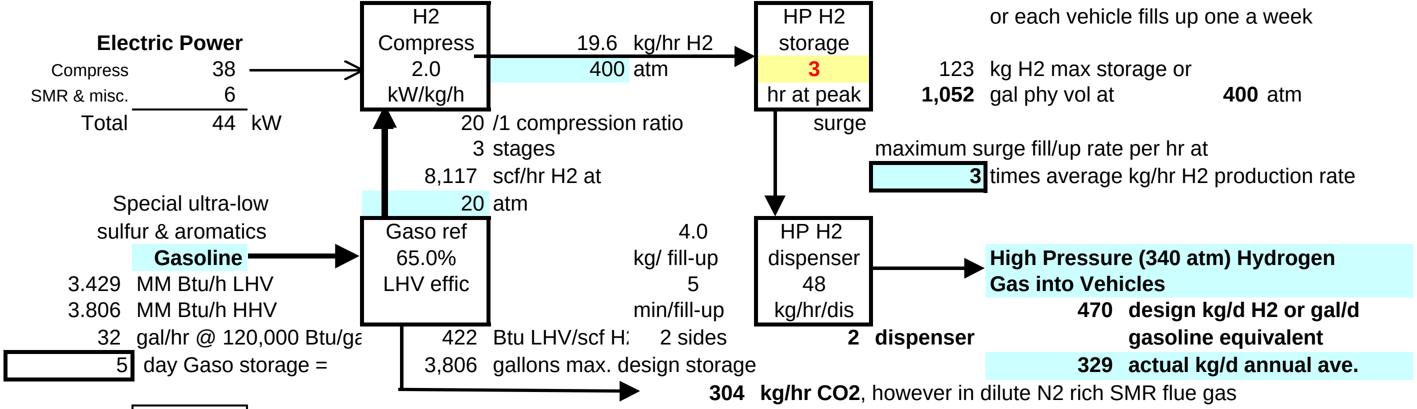
Forecourt Hydrogen via Steam Reformer of Gasoline plus High Pressure Gas Storage

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

Design per station	**Design LHV energy equivalent**				
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	10,000	10,000	47.422	4,145,000	13.894
This run	**470**	**470**	**2.229**	**194,815**	**0.653**
Minimum	100	100	0.474	41,450	0.139

	gasoline equivalent			
Assuming	55	mpg and	12,000	mile/yr
requires	218	kg/yr H2/vehicle or gal/yr gaso equiv		
Assuming	**70%**	Annual average load factor		
actual H2	120,085	kg/y H2 /station or gal/y gaso equiv		
or	10,007	kg/month H2 or gal/mo. gaso equiv		
thereby	**550**	**FC vehicles can be supported at**		
	79	fill-ups/d @ 4.2 kg or gal equiv/fill-up		
		or each vehicle fills up one a week		



Electric Power
Compress 38
SMR & misc. 6
Total 44 kW

H2 Compress 2.0 kW/kg/h

19.6 kg/hr H2
400 atm

HP H2 storage 3 hr at peak surge

123 kg H2 max storage or
1,052 gal phy vol at **400** atm

20 /1 compression ratio
3 stages
8,117 scf/hr H2 at
20 atm

maximum surge fill/up rate per hr at
3 times average kg/hr H2 production rate

Special ultra-low sulfur & aromatics **Gasoline**
3.429 MM Btu/h LHV
3.806 MM Btu/h HHV
32 gal/hr @ 120,000 Btu/ga
5 day Gaso storage = 3,806 gallons max. design storage

Gaso ref 65.0% LHV effic
422 Btu LHV/scf H:

4.0 kg/ fill-up
5 min/fill-up
2 sides

HP H2 dispenser 48 kg/hr/dis
2 dispenser

High Pressure (340 atm) Hydrogen Gas into Vehicles
470 design kg/d H2 or gal/d gasoline equivalent
329 actual kg/d annual ave.

304 kg/hr CO2, however in dilute N2 rich SMR flue gas
at 0.75 kg CO2/kWh current U.S. average = **33 kg/hr CO2** equivalent at power plants
17.2 kgCO2/kg H2

Capital Costs		**Unit cost basis at 1,000**	**kg/d H2**	**cost/size factors**		**Unit cost at 470**	**kg/d H2**	**millions of $ for 1 station**	**Notes**
Special gasoline storage		5	/gal	70%	$	6.27	gal storage	0.02	could use with existing tanks
Gasoline reformer	$	3.30	/scf/d	75%	$	3.99	per scf/d	0.78	assume 110% of SMR
H2 Compressor	$	3,000	/kW	80%	$	3,489	per kW	0.13	$ 285 /kg/d H2
HP H2 gas storage	$	100	/gal phy vol	80%	$	116	/gal phy vol	0.12	$ 991 $/kg high press H2 gas
HP H2 gas dispenser	$	15,000	/dispenser	100%	$	15,000	per dispenser	0.03	$ 13 /kg/d dispenser design
						Total process units		1.09	
General Facilities			of process units					0.22	20-40% typical, should be low for this
Engineering Permitting & Startup		**10%**	of process units					0.11	10-20% typical, low eng after first few
Contingencies		**10%**	of process units					0.11	10-20% typical, low after the first few
Working Capital, Land & Misc.		**9%**	of process units					0.10	5-10% typical, high land costs for this
						U.S. Gulf Coast Capital Costs		1.62	
Site specific factor		**110%**	above US Gulf Coast			**Total Capital Costs**		**1.78**	
Unit Capital Costs of		**9.14**	**/scf/d H2 or**	3,789	/kg/d H2 or	3,789	/gal/d gaso equiv		

Hydrogen Costs at		70%	ann load factor	**million $/yr of 1 station**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Road tax or (subsidy)	$	-	/gal gaso equiv.	-	-	-	-	can be subsidy like EtOH
Gas Station mark-up	$	-	/gal gaso equiv.	-	-	-	-	if H2 drops total station revenues
Non-fuel Variable O&M		1%	/yr of capital	0.018	1.30	0.36	0.15	0.5-1.5% is typical
Special gasoline	$	6.60	/MM Btu HHV	0.154	11.27	3.09	1.28	see below
Electricity	$	0.070	/kWh	0.019	1.38	0.38	0.16	$0.06-.09/kWh EIA **commercial** rate
Variable Operating Cost				**0.191**	**13.96**	**3.83**	**1.59**	
Fixed Operating Cost		**5%**	/yr of capital	**0.089**	**6.52**	**1.79**	**0.74**	4-7% typical for refining
Capital Charges		**18%**	/yr of capital	**0.321**	**23.46**	**6.44**	**2.67**	20-25% typical of refining
Total HP Hydrogen Costs from Gasoline				**0.600**	**43.93**	**12.06**	**5.00**	including return on investment
			in vehicle					

$	**0.064**	/kWh electricity for **only** H2 fuel **(no capital charges or other O&M)** to high capital cost fuel cell @	60% LHV effic
$	**0.059**	/kWh electricity for **only** gaso fuel (**no capital charges or other O&M)** to Solar 4 MWe Mercury 50 GT @	40% LHV effic
$	**0.058**	/kWh electricity for **only** gaso fuel (**no capital charges or other O&M)** to Solar 9 MWe STAC70 CC @	41% LHV effic

H2-fuel cell power sales during H2 vehicle ramp-up is questionable relative to lower capital & non-fuel O&M of small NG or gasoline fired GT/CC or the much lower NG costs and higher efficiency, 60% of large industrial NGCC

note: assume special ultra-low sulfur & aromatics gasoline is 100% of current regular reformulated gasoline price

requires $ 0.792 /gal gasoline delivered price back calculated for above $/MM Btu price input
assuming $ 0.050 /gal delivery cost (assume use of existing delivery system)
$ 0.742 /gal refinery price or 100% of $ 0.742 /gal O&G Journal price in Feb 2002

Source SFA Pacific, Inc

Path F4

Forecourt Hydrogen via Electrolysis of Water plus High Pressure Gas Storage

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

Design per station		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000	1,000	4.742	414,500	1.389
This run	**470**	**470**	**2.229**	**194,815**	**0.653**
Minimum	10	10	0.047	4,145	0.014

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming **70%** Annual average load factor

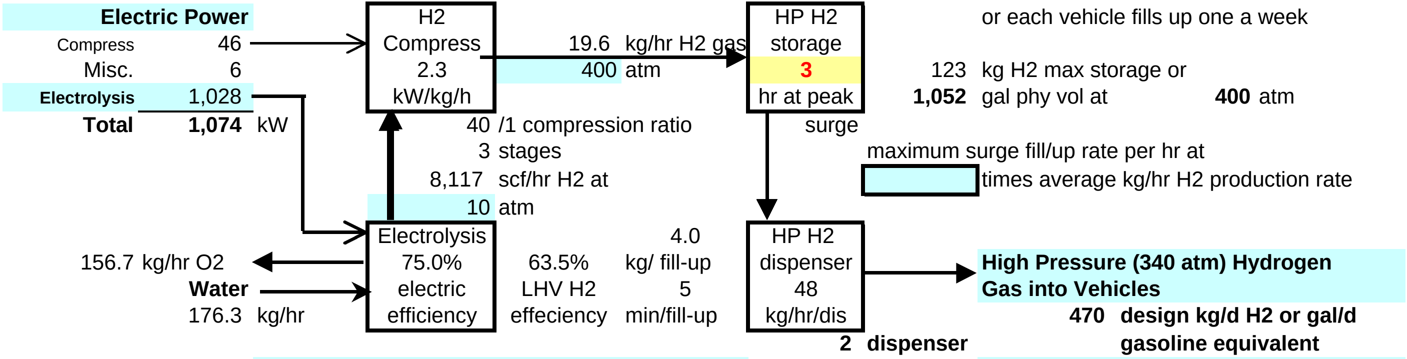
actual H2 120,085 kg/y H2 /station or gal/y gaso equiv

or 10,007 kg/month H2 or gal/mo. gaso equiv

thereby **550** **FC vehicles can be supported at**

79 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week



Electric Power		
Compress	46	
Misc.	6	
Electrolysis	1,028	
Total	**1,074**	kW

H2 Compress 2.3 kW/kg/h

19.6 kg/hr H2 gas

400 atm

HP H2 storage **3** hr at peak surge

123 kg H2 max storage or

1,052 gal phy vol at **400** atm

40 /1 compression ratio

3 stages

8,117 scf/hr H2 at

10 atm

maximum surge fill/up rate per hr at

times average kg/hr H2 production rate

156.7 kg/hr O2

Water

176.3 kg/hr

Electrolysis 75.0% electric efficiency

63.5% LHV H2 effeciency

4.0 kg/ fill-up

5 min/fill-up

HP H2 dispenser 48 kg/hr/dis

2 **dispenser**

High Pressure (340 atm) Hydrogen Gas into Vehicles

470 **design kg/d H2 or gal/d gasoline equivalent**

329 **actual kg/d annual ave.**

theoretical power 39.37 kWh/kg H2 at 100% electric efficiency

actual power 52.49 kWh/kg or 4.73 kWh/Nm3 H2

at 0.75 kg CO2/kWh current U.S. average = **805** **kg/hr CO2** equivalent at power plants

41.1 **kgCO2/kg H2**

Capital Costs		**Unit cost basis at 1,000**	**kg/d H2**	**cost/size factors**		**Unit cost at 470**	**kg/d H2**	**millions of $ for 1 station**		**Notes**	
Electrolyser	$	2,000	/kW	90%	$	2,157	/kW	2.22	$	11.4	/scf/d H2
H2 Compressor	$	3,000	/kW	80%	$	3,489	/kW	0.16	$	340	$/kg/d H2
HP H2 gas storage	$	100	/gal phy vol	80%	$	116	/gal phy vol	0.12	$	991	$/kg high press H2 gas
HP H2 gas dispenser	$	15,000	/dispenser	100%	$	15,000	/dispenser	0.03	$	13	/kg/d dispenser design
						Total process units		2.53			
General Facilities		**20%**	of process units					0.51	20-40% typical, should be low for this		
Engineering Permitting & Startup		**10%**	of process units					0.25	10-20% typical, low eng after first few		
Contingencies		**10%**	of process units					0.25	10-20% typical, low after the first few		
Working Capital, Land & Misc.		**9%**	of process units					0.23	5-10% typical, high land costs for this		
						U.S. Gulf Coast Capital Costs		3.77			
Site specific factor		**110%**	above US Gulf Coast			**Total Capital Costs**		**4.15**			
Unit Capital Costs of		**21.28**	**/scf/d H2 or**	8,821	/kg/d H2 or	8,821	/gal/d gaso equiv				

Hydrogen Costs	**at**	70%	ann load factor	**million $/yr of 1 station**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Road tax or (subsidy)	$	-	/gal gaso equiv.	-	-	-	-	can be subsidy like EtOH
Gas Station mark-up	$	-	/gal gaso equiv.	-	-	-	-	if H2 drops total station revenues
Non-fuel Variable O&M		1.0%	/yr of capital	0.041	3.03	0.83	0.35	0.5-1.5% is typical
Electricity	$	0.070	/kWh	0.461	33.72	9.26	3.84	$0.06-.09/kWh EIA **commercial** rate
Variable Operating Cost				**0.502**	**36.76**	**10.09**	**4.18**	mostly electricity costs
Fixed Operating Cost		5.0%	/yr of capital	**0.207**	**15.17**	**4.16**	**1.73**	4-7% typical for refining
Capital Charges		18.0%	/yr of capital	**0.746**	**54.60**	**14.99**	**6.21**	20-25% typical of refining
Total HP Hydrogen Costs from Electrolysis			in vehicle	**1.456**	**106.52**	**29.25**	**12.12**	including return on investment

Note: if 12 hr/d at $ 0.040 /kWh lower off-peak rate and

12 hr/d at $ 0.090 /kWh higher peak rate

Daliy average rate could be $ 0.065 /kWh

If only operated during low off-peak rate times would have low ann load factor & need more expensive H2 storage

Assume Hydrogn Systems Electrolysis at 150 psig pressure, Norsk Hydro & Stuard systems are low pressure

Assumed oxygen recovery for by-product sales with large central plant case, but only minor economic impact

Source SFA Pacific, Inc

Central Hydrogen Plant Summary of Inputs and Outputs

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Inputs — **Boxed in yellow** are the key input variables **you** must choose, **current inputs are** **just an example**

design basis

Key Variables Inputs				Notes	
Hydrogen Production Inputs				**1 kg H2 is the same energy content as 1 gallon of gasoline**	
Design hydrogen production	150,000	**kg/d H2**		62,175,000 **scf/d H2**	size range of 20,000 to 900,000 kg/d
Annual average load factor	90%	/yr of design	4,106,250	kg/month actual or	49,275,000 kg/yr actual
Distribution distance to forecourt				43 miles average distance	25-200 miles is typical
FC Vehicle gasoline equiv mileage	55	mpg (U.S. gallons) or		23 km/liter	
FC Vehicle miles per year	12,000	mile/yr thereby requires		218 kg/yr H2 for each FC vehicle	
Typical gasoline sales/month/station	150,000	gallons/month per station		100,000 - 250,000 gallons/month is typical or	4,932 gal/d
Hydrogen as % of gasoline/station	6.7%	of gasoline/station or		10,000 kg H2/month per stations or	329 kg/d/station
Capital Cost Buildup Inputs from process unit costs				**All major utilities included as process units**	
General Facilities	20%	of process units		20-40% typical for SMR + 10% more for gasification	
Engineering, Permitting & Startup	15%	of process units		10-20% typical	
Contingencies	10%	of process units		10-20% typical, should be low after the first few	
Working Capital, Land & Misc.	7%	of process units		5-10% typical	
Site specific factor	110%	above US Gulf Coast		90-130% typical; sales tax, labor rates & weather issues	
Product Cost Buildup Inputs					
Non-fuel Variable O&M	1.0%	/yr of capital		0.5-1.5% is typical	
Fuels Natural Gas	$ 3.50	/MM Btu HHV		$2.50-4.50/MM Btu typical **industrial** rate, see www.eia.doe.gov	
Electricity	$ 0.045	/kWh		$0.04-0.05/kWh typical **industrial** rate, see www.eia.doe.gov	
Biomass production costs	$ 500	/ha/yr gross revenues		$400-600/hr/yr typical in U.S. .lower in developing nations or wastes	
Biomass yield	10	tonne/ha/yr bone dry		8-12 ton/hr/yr typical if farmed, 3-5 ton/hr/yr if forestation or wastes	
Coal	$ 1.10	/million Btu dry HHV		$0.75-1.25/million Btu coal utility delivered go to www.eia.doe.gov	
Petroleum Coke	$ 0.20	/million Btu dry HHV		$0.00-0.50/million Btu refinery gate	
Residue (Pitch)	$ 1.50	/million Btu dry HHV		$1.00-2.00/million Btu refinery gate (solid at room temperature)	
Fixed O&M Costs	5.0%	/yr of capital		4-7% typical for refiners: labor, overhead, insurance, taxes, G&A	
Capital Charges	18.0%	/yr of capital		20-25%/yr CC typical for refiners & 14-20%/yr CC typical for utilities	

20%/yr CC is about 12% IRR DCF on 100% equity where as
15%/yr CC is about 12% IRR DCF on 50% equity & debt at 7%

Outputs 135,000 kg/d H2 that supports 225,844 FC vehicles — 10,000 kg H2/month/station supports **411 stations**

actual annual average 32,263 fill-ups/d if 1 fill-up/week @ 4.2 kg/fill-up — 79 fill-ups/d per station or 329 kg/d/station

		Capital Costs			**Operating Cost**		**Product Costs**	
		Absolute	Unit cost	**Unit cost**	**Fixed**	**Variable**	**Including capital charges**	
Case No.	**Description**	$ millions	design rate $/scf/d H2	design rate **$/kg/d H2**	Unit cost **$/kg H2**	Unit cost **$/kg H2**	**Unit cost** **$/kg H2**	**Note** same as $/gal gaso equiv
C1	**Biomass-H2 Pipeline**	295	4.74	1,966	0.30	0.92	**2.29**	216 sq mi land
C2	**Biomass-Liquid H2**	452	7.28	3,017	0.46	1.42	**3.53**	216 sq mi land
C3	**Natural gas-H2 Pipeline**	79	1.27	527	0.08	0.63	**1.00**	into pipeline @ 75 atm
C4	**Natural gas-Liquid H2**	230	3.70	1,534	0.23	1.13	**2.21**	into liquid H2 tanker truck
C5	**Electrolysis-H2 Pipeline**	566	9.11	3,776	0.57	2.49	**5.13**	into pipeline @ 75 atm
C6	**Electrolysis-Liquid H2**	688	11.07	4,586	0.70	2.96	**6.17**	into liquid H2 tanker truck
C7	**Pet Coke-H2 Pipeline**	238	3.82	1,585	0.24	0.24	**1.35**	into pipeline @ 75 atm
C8	**Coal-H2 pipeline**	259	4.16	1,723	0.26	0.42	**1.62**	into pipeline @ 75 atm
C9	**Coal-Liquid H2**	448	7.21	2,989	0.46	0.97	**3.06**	into liquid H2 tanker truck
C10	**Biomass-HP Tube H2**	362	5.82	2,411	0.37	1.00	**2.69**	216 sq mi land
C11	**Natural Gas-HP Tube H2**	133	2.13	884	0.13	0.69	**1.30**	into tube trailer @ 400 atm
C12	**Electrolysis-HP Tube H2**	602	9.67	4,010	0.61	2.49	**5.30**	into tube trailer @ 400 atm
C13	**Residue-H2 Pipeline**	185	2.97	1,231	0.19	0.41	**1.27**	into pipeline @ 75 atm
C15	**Coal-HP Tube H2**	339	5.46	2,263	0.34	0.51	**2.09**	into tube trailer @ 400 atm

Click on specific Excel worksheet tabs below for details of cost buildups for each case

Source: SFA Pacific, Inc.

Path C1
Central Hydrogen via Biomass Gasification, Shipped by Pipeline

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	200,000	200,000	948	82,900,000	278
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming **90%** **annual load factor at**

actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv

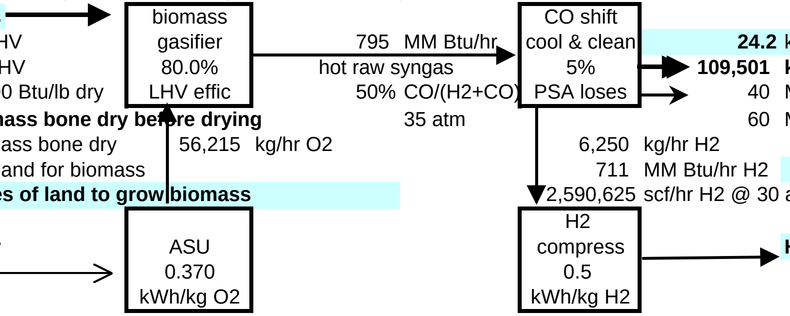
or 4,106,250 kg/month H2 or gal/mo. gaso equiv

thereby **225,844** **vehicles can be serviced at**

32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week

Shell gasifier to avoid high CH4 & secondary SMR or ATR



Biomass

1,169 MM Btu/h LHV

1,239 MM Btu/h HHV

70,268 kg/hr @8,000 Btu/lb dry

1,686 **tons/d biomass bone dry before drying**

553,995 tons/yr biomass bone dry

55,400 hectares of land for biomass

216 **square miles of land to grow biomass**

795 MM Btu/hr

hot raw syngas

50% CO/(H2+CO)

35 atm

56,215 kg/hr O2

24.2 kg CO2/kg H2

109,501 **kg/hr CO2** plus 15 % from dryer

40 MM Btu/hr PSA fuel gas for superheating

60 MM Bur/h CO to H2 shifting LHV loses

6,250 kg/hr H2

711 MM Btu/hr H2

2,590,625 scf/hr H2 @ 30 atm

61% overall effic raw bio to H2

LHV efficiency

Hydrogen in Gas Pipeline @ 75 atm

Electric Power		
ASU	20,799	
H2 compres	3,125	
Misc.	6,253	
Total	**30,177**	**kW**

1,349 metric tons/d O2

0.80 tons O2/ton dry feed

2.5 compression ratio

150,000 **design kg/d H2 or gal/d**

gasoline equivalent

135,000 **actual kg/d annual ave.**

15% of biomass fired in FBC to dry gasifier biomass feed **1,902** Btu/lb water vaporized

1,433 **tons/day bone dry biomass to gasifier** 1,500 Btu/lb water vaporized minimum

at 0.75 kg CO2/kWh current U.S. average for all electricity = **22,633** **kg/hr CO2 equivalent at power plants**

Capital Costs		**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**		**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**			**Notes**	
Biomass handling & drying	$	25	/kg/d dry bio	75%	$	23	/kg/d dry bio	38.1		11	/kg/d green (wet) biomass	
Shell gasifier	$	20	/kg/d dry bio	80%	$	18	/kg/d dry bio	52.9		100%	spare unit	
Air separation unit (ASU)	$	27	/kg/d oxygen	75%	$	24	/kg/d oxygen	32.9	$	1,583	/kW power	
CO shift, cool & cleanup	$	15	/kg/d CO2	75%	$	14	/kg/d CO2	35.6	$	0.6	/scf/d H2	MDEA & PSA
H2 Compressor	$	2,000	/kW	90%	$	1,921	/kW	6.0	$	40	/kg/d H2	
						Total process units		165.5				
General Facilities			of process units					49.7	20-40% typical,		SMR +	10%
Engineering Permitting & Startup		15%	of process units					24.8	10-20% typical			
Contingencies		10%	of process units					16.6	10-20% typical, low after the first few			
Working Capital, Land & Misc.		7%	of process units					11.6	5-10% typical			
						U.S. Gulf Coast Capital Costs		268.1				
Site specific factor		110%	of US Gulf Coast costs			**Total Capital Costs**		**294.9**				
Unit Capital Costs		**4.74**	**/scf/d H2 or**	1,966	/kg/d H2 or	1,966	/gal/d gaso equiv					

Hydrogen Costs at		90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M		1.0%	/yr of capital	2.9	0.53	0.14	0.06	0.5-1.5% typical
Delivered biomass	$	3.22	/MM Btu HHV	31.5	5.61	1.54	0.64	**based on costs below**
Electricity	$	0.045	/kWh	10.7	1.91	0.52	0.22	0.04-0.05/kWh typical **industrial** rates
Variable Operating Cost				**45.1**	**8.05**	**2.21**	**0.92**	
Fixed Operating Cost		5.0%	/yr of capital	**14.7**	**2.63**	**0.72**	**0.30**	4-6% typical for refining
Capital Charges		18%	/yr of capital	**53.1**	**9.47**	**2.60**	**1.08**	20% typical of refining
Total Gaseous Hydrogen Costs from Biomass				**113.0**	**20.14**	**5.53**	**2.29**	including return on investment

into pipeline still requires distribution

Delivered biomass @ **$** **56.82** **/bone dry ton (BDT) or** **$** **3.22** **/million Btu LHV based on below:**

$ 500	/hectare per yr gross total revenues or	$ 200	/acre per yr gross total revenues		If waste bio or coproduct
10	ton biomass/yr per ha - bone dry basic or	4.0	tons biomass/yr per acre - bone dry		lower gross revenue needs
8,000	Btu/lb HHV bone dry and	50%	moisture of green biomass		but much lower yield/ha
$ 2.08	/mile round trip for typical 25 ton truck hauling green biomass				
41	miles round trip haul =	$ 3.41	/ton green or	$	**6.82** **/ton bone dry equivalent transportation**

Source SFA Pacific, Inc

Path C2

Central Hydrogen via Biomass Gasification, Shipped by Cryogenic Tanker Truck

Final Version June 2002 **IHIG Confidential**

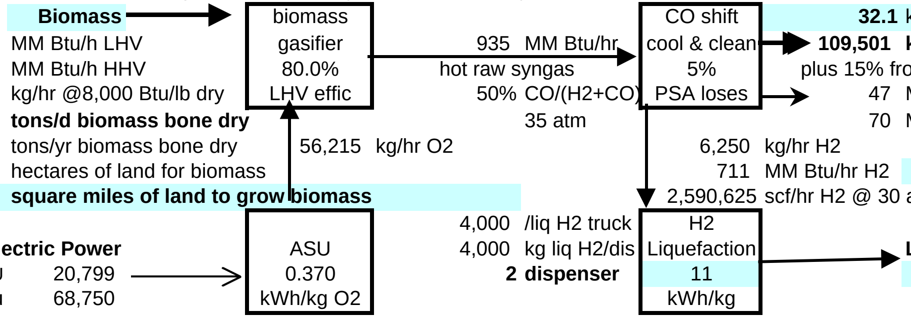
Color codes **variables** via summary inputs key outputs

1 Central Plant Design — **Design LHV energy equivalent**

Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	200,000	200,000	948	82,900,000	278
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent
Assuming 55 mpg and 12,000 mile/yr
requires 218 kg/yr H2/vehicle or gal/yr gaso equiv
Assuming **90%** **annual load factor at**
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv
or 4,106,250 kg/month H2 or gal/mo. gaso equiv
thereby **225,844** **vehicles can be serviced at**
32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up
or each vehicle fills up one a week

Shell gasifier to avoid high CH4 & secondary SMR or ATR



Biomass | biomass gasifier 80.0% LHV effic | CO shift cool & clean 5% PSA loses | **32.1** kg CO2/kg H | 12 hr liq H2 stor
1,169 MM Btu/h LHV | 935 MM Btu/hr | **109,501** **kg/hr CO2** | 75,000 kg liq H2 stor
1,239 MM Btu/h HHV | hot raw syngas | plus 15% from dryer | 279,975 gal phy liq H2
70,268 kg/hr @8,000 Btu/lb dry | 50% CO/(H2+CO) | 47 MM Btu/hr PSA fuel gas
1,686 **tons/d biomass bone dry** | 35 atm | 70 MM Bur/h CO to H2 shifting | storage
553,995 tons/yr biomass bone dry | 56,215 kg/hr O2 | 6,250 kg/hr H2
55,400 hectares of land for biomass | 711 MM Btu/hr H2 | 61% overall effic raw bio to H2
216 **square miles of land to grow biomass** | 2,590,625 scf/hr H2 @ 30 atm

Electric Power | ASU 0.370 kWh/kg O2 | 4,000 /liq H2 truck | 4,000 kg liq H2/dis | **2** **dispenser** | H2 Liquefaction 11 kWh/kg | **Liquid Hydrogen in Tanker Trucks**
ASU 20,799 | **38** **Cryo tanker fill-ups/d at**
H2 Liqu 68,750 | **150,000** **design kg/d H2 or gal/d**
Misc. 6,253 | 1,349 metric tons/d O2 | **gasoline equivalent**
Total **95,802** **kW** | 0.80 tons O2/ton dry feed | **135,000** **actual kg/d annual ave.**

15% of biomass fired in FBC to dry gasifier biomass feed | **1,902** Btu/lb water vaporized
1,433 **tons/day bone dry biomass to gasifier** | 1,500 Btu/lb water vaporized minimum
at 0.75 kg CO2/kWh current U.S. average for all electricity = **71,851** **kg/hr CO2 equivalent at power plants**

Capital Costs	**Unit cost basis at 100,000 kg/d H2**	**cost/size factors**	**Unit cost at 150,000 kg/d H2**	**millions of $ for 1 plant**	**Notes**
Biomass handling & drying	$ 25 /kg/d dry bio	75%	$ 23 /kg/d dry bio	38.1	11 /kg/d green (wet) biomass
Shell gasifer	$ 20 /kg/d dry bio	80%	$ 18 /kg/d dry bio	52.9	100% spare unit H2O quench
Air separation unit (ASU)	$ 27 /kg/d oxygen	75%	$ 24 /kg/d oxygen	32.9	$ 1,583 /kW power
CO shift, cool & cleanup	$ 15 /kg/d CO2	75%	$ 14 /kg/d CO2	35.6	$ 0.6 /scf/d H2 MDEA & PSA
H2 Cryo Liquefaction	$ 700 /kg/d H2	70%	$ 620 /kg/d H2	93.0	$ 1,352 /kW power
Liquid H2 storage	$ 5 /gal phy vol	70%	$ 4 /gal phy vol	1.2	$ 17 kg of H2 liquid storage
Liquid H2 dispenser	$ 100,000 /dispenser	100%	$ 100,000 /dispenser	0.2	$ 1 /kg/d dispenser design
			Total process units	253.9	
General Facilities	30% of process units			76.2	20-40% typical, SMR + 10%
Engineering Permitting & Startup	15% of process units			38.1	10-20% typical
Contingencies	10% of process units			25.4	10-20% typical, low after the first few
Working Capital, Land & Misc.	7% of process units			17.8	5-10% typical
			U.S. Gulf Coast Capital Costs	411.3	
Site specific factor	110% of US Gulf Coast costs		**Total Capital Costs**	**452.5**	

Unit Capital Costs **7.28** **/scf/d H2 or** 3,017 /kg/d H2 or 3,017 /gal/d gaso equiv

Hydrogen Costs at	90% ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0% /yr of capital	4.5	0.81	0.22	0.09	0.5-1.5% typical
Delivered biomass	$ 3.22 /MM Btu HHV	31.5	5.61	1.54	0.64	**based on costs below**
Electricity	$ 0.045 /kWh	34.0	6.06	1.66	0.69	0.04-0.05/kWh typical **industrial** rates
Variable Operating Cost		**70.0**	**12.48**	**3.43**	**1.42**	
Fixed Operating Cost	5.0% /yr of capital	**22.6**	**4.03**	**1.11**	**0.46**	4-7% typical for refining
Capital Charges	18% /yr of capital	**81.4**	**14.52**	**3.99**	**1.65**	20-25% typical for refining
Total Liquid Hydrogen Costs from Biomass		**174.1**	**31.04**	**8.52**	**3.53**	including return on investment

plant gate still requires distribution

Delivered biomass @ **$ 56.82** **/bone dry ton (BDT) or** **$ 3.22** **/million Btu LHV based on below:**
$ 500 /hectare per yr gross total revenues or $ 200 /acre per yr gross total revenues
10 ton biomass/yr per ha - bone dry basic or 4.0 tons biomass/yr per acre - bone dry
8,000 Btu/lb HHV bone dry and 50% moisture of green biomass
$ 2.08 /mile round trip for typical 25 ton truck hauling green biomass
41 miles round trip haul = $ 3.41 /ton green or **$** **6.82** **/ton bone dry equivalent transportation**

If waste bio or coproduct lower gross revenue needs but much lower yield/ha

Source SFA Pacific, Inc

Path C3

Central Hydrogen via Steam Reformer of Natural Gas, Shipped by Gas Pipeline

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design — **Design LHV energy equivalent**

Size range	Hydrogen kg/d H2	gasoline gal/d	million Btu/hr	scf/d H2	MW t
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming 90% **annual load factor at**

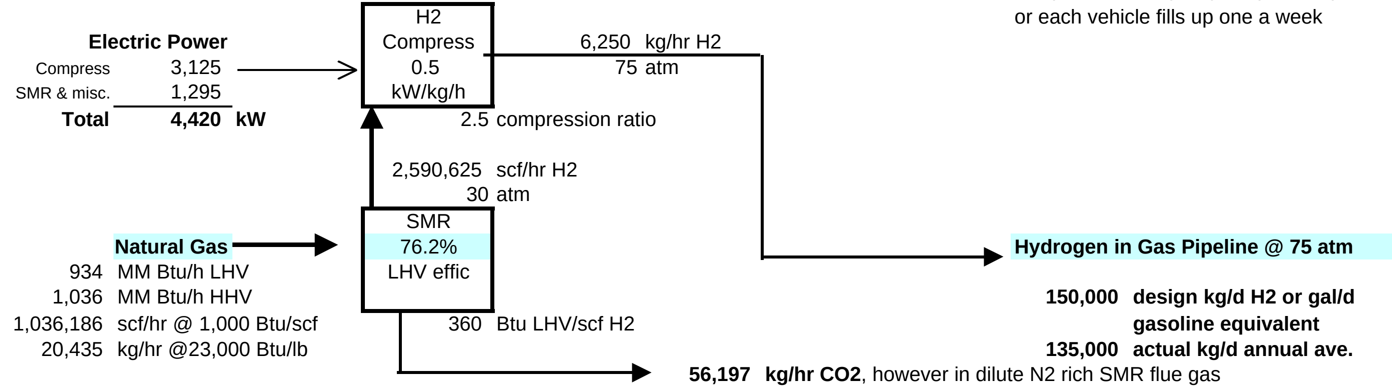
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv

or 4,106,250 kg/month H2 or gal/mo. gaso equiv

thereby **225,844 vehicles can be serviced at**

32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week



Electric Power

Compress	3,125
SMR & misc.	1,295
Total	**4,420 kW**

H2 Compress 0.5 kW/kg/h

6,250 kg/hr H2

75 atm

2.5 compression ratio

2,590,625 scf/hr H2

30 atm

SMR 76.2% LHV effic

360 Btu LHV/scf H2

Natural Gas

934 MM Btu/h LHV

1,036 MM Btu/h HHV

1,036,186 scf/hr @ 1,000 Btu/scf

20,435 kg/hr @23,000 Btu/lb

Hydrogen in Gas Pipeline @ 75 atm

150,000 design kg/d H2 or gal/d gasoline equivalent

135,000 actual kg/d annual ave.

56,197 kg/hr CO2, however in dilute N2 rich SMR flue gas

at 0.75 kg CO2/kWh current U.S. average = **3,315 kg/hr CO2** equivalent at power plants

9.5 kg CO2/kg H2

Capital Costs	**Unit cost basis at 100,000 kg/d H2**		**cost/size factors**	**Unit cost at 150,000 kg/d H2**		**millions of $ for 1 plant**	**Notes**
SMR	$ 0.75	/scf/d	70%	$ 0.66	/scf/d	41.3	$ 275 /kg/d H2
H2 Compressor	$ 2,000	/kW	90%	$ 1,921	/kW	6.0	$ 40 /kg/d H2
				Total process units		47.3	
General Facilities	20%	of process units				9.5	20-40% typical
Engineering Permitting & Startup	15%	of process units				7.1	10-20% typical
Contingencies	10%	of process units				4.7	10-20% typical, low after the first few
Working Capital, Land & Misc.	7%	of process units				3.3	5-10% typical
				U.S. Gulf Coast Capital Costs		71.9	
Site specific factor	110%	of US Gulf Coast costs		**Total Capital Costs**		**79.1**	
Unit Capital Costs	**1.27**	**/scf/d H2 or**	527	/kg/d H2 or	527	/gal/d gaso equiv	

Hydrogen Costs at	90% ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0% /yr of capital	0.8	0.14	0.04	0.02	0.5-1.5% typical
Natural Gas	$ 3.50 /MM Btu HHV	28.6	5.10	1.40	0.58	$2.50-4.50/MM Btu **industrial** rate
Electricity	$ 0.045 /kWh	1.6	0.28	0.08	0.03	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost		**31.0**	**5.52**	**1.52**	**0.63**	
Fixed Operating Cost	5.0% /yr of capital	**4.0**	**0.70**	**0.19**	**0.08**	4-7% typical for refining
Capital Charges	18% /yr of capital	**14.2**	**2.54**	**0.70**	**0.29**	20-25% typical for refining
Total Gaseous Hydrogen Costs from Natural Gas		**49.1**	**8.76**	**2.41**	**1.00**	including return on investment

into pipeline still requires distribution

note: Assume no central plant storage or compression of hydrogen due to pipeline volume & SMR at 30 atm pressure

Source SFA Pacific, Inc

Path C4

Central Hydrogen via Steam Reformer of Natural Gas, Shipped by Cryogenic Liquid Trucks

Final Version June 2002 **IHIG Confidential**

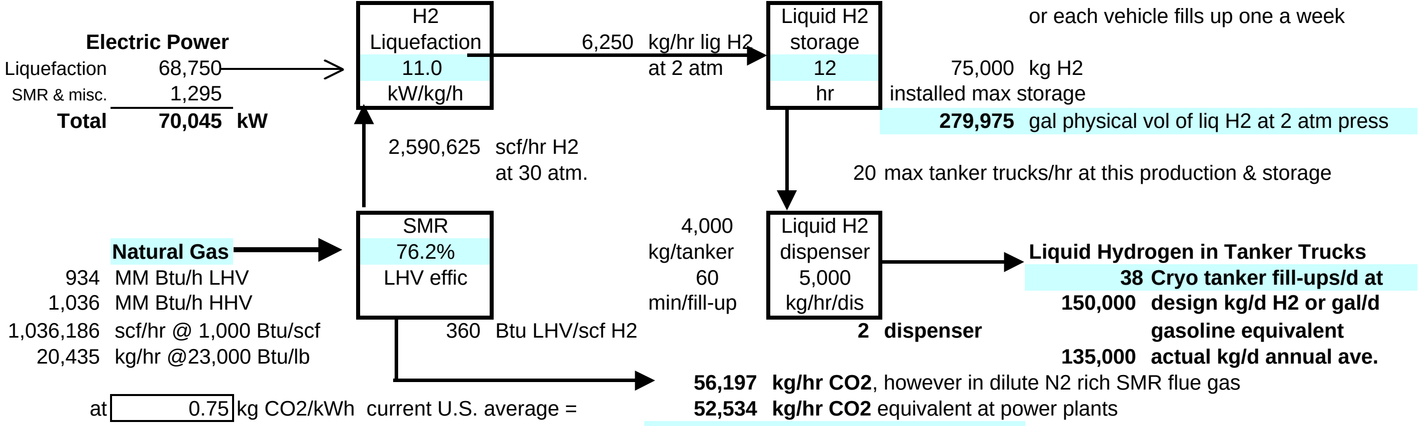
Color codes **variables** via summary inputs key outputs

1 Central Plant Design

Design LHV energy equivalent

Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent
Assuming 55 mpg and 12,000 mile/yr
requires 218 kg/yr H2/vehicle or gal/yr gaso equiv
Assuming **90%** **annual load factor at**
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv
or 4,106,250 kg/month H2 or gal/mo. gaso equiv
thereby **225,844** **vehicles can be serviced at**
32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up
or each vehicle fills up one a week



Electric Power
Liquefaction 68,750
SMR & misc. 1,295
Total **70,045** **kW**

H2 Liquefaction 11.0 kW/kg/h
6,250 kg/hr liq H2 at 2 atm
Liquid H2 storage 12 hr
75,000 kg H2 installed max storage
279,975 gal physical vol of liq H2 at 2 atm press
2,590,625 scf/hr H2 at 30 atm.
20 max tanker trucks/hr at this production & storage

Natural Gas
934 MM Btu/h LHV
1,036 MM Btu/h HHV
1,036,186 scf/hr @ 1,000 Btu/scf
20,435 kg/hr @23,000 Btu/lb

SMR 76.2% LHV effic
360 Btu LHV/scf H2
4,000 kg/tanker
60 min/fill-up
Liquid H2 dispenser 5,000 kg/hr/dis
2 **dispenser**

Liquid Hydrogen in Tanker Trucks
38 **Cryo tanker fill-ups/d at**
150,000 **design kg/d H2 or gal/d**
gasoline equivalent
135,000 **actual kg/d annual ave.**

56,197 **kg/hr CO2**, however in dilute N2 rich SMR flue gas
at 0.75 kg CO2/kWh current U.S. average = **52,534** **kg/hr CO2** equivalent at power plants
17.4 **kg CO2/kg H2**

Capital Costs	**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**	**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**	**Notes**
SMR	$ 0.75	/scf/d H2	70%	$ 0.66	/scf/d H2	41.3	$ 275 /kg/d H2
H2 Cryo Liquefaction	$ 700	/kg/d H2	75%	$ 633	/kg/d H2	94.9	$ 1,380 /kW power
Liquid H2 storage	$ 5	/gal phy vol	70%	$ 4	/gal phy vol	1.2	$ 17 kg of H2 liquid storage
Liquid H2 dispenser	$ 100,000	/dispenser	100%	$ 100,000	/dispenser	0.2	$ 1 /kg/d dispenser design
				Total process units		137.6	
General Facilities			20% of process units			27.5	20-40% typical
Engineering Permitting & Startup			15% of process units			20.6	10-20% typical
Contingencies			10% of process units			13.8	10-20% typical, low after the first few
Working Capital, Land & Misc.			7% of process units			9.6	5-10% typical
				U.S. Gulf Coast Capital Costs		209.2	
Site specific factor	110%	of US Gulf Coast costs		**Total Capital Costs**		**230.1**	
Unit Capital Costs	**3.70**	**/scf/d H2 or**	1,534	/kg/d H2 or	1,534	/gal/d gaso equiv	

Hydrogen Costs at	90% ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0% /yr of capital	2.3	0.41	0.11	0.05	0.5-1.5% typical
Natural Gas	$ 3.50 /MM Btu HHV	28.6	5.10	1.40	0.58	$2.50-4.50/MM Btu **industrial** rate
Electricity	$ 0.045 /kWh	24.9	4.43	1.22	0.50	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost		**55.7**	**9.94**	**2.73**	**1.13**	
Fixed Operating Cost	5.0% /yr of capital	**11.5**	**2.05**	**0.56**	**0.23**	4-7% typical for refining
Capital Charges	18% /yr of capital	**41.4**	**7.38**	**2.03**	**0.84**	20-25% typical for refining
Total Liquid Hydrogen Costs from Natural Gas		**108.7**	**19.38**	**5.32**	**2.21**	including return on investment

plant gate still requires distribution

note: Assuming all storage liquid boil-off is recycled back to hydrogen liquefaction units, thereby no hydrogen losses

Source SFA Pacific, Inc

Path C5

Central Hydrogen via Electrolysis of Water, Shipped by Gas Pipeline

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming **90%** **annual load factor at**

actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv

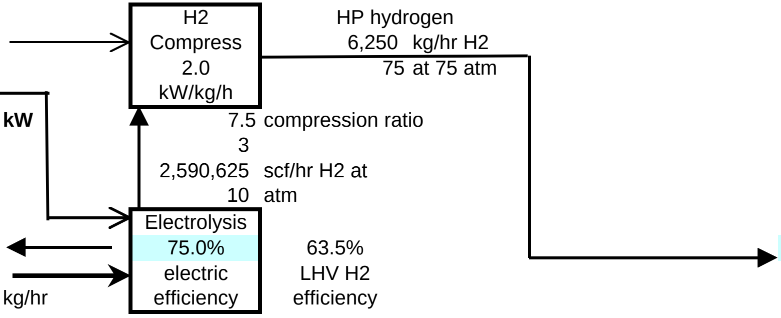
or 4,106,250 kg/month H2 or gal/mo. gaso equiv

thereby **225,844** **vehicles can be serviced at**

32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week

Electric Power	
Compress	12,343
Misc.	1,875
Electrolysis	328,083
Total	**340,427 kW**



50,000 kg/hr O2

Water
56,250 kg/hr

Hydrogen in Gas Pipeline @ 75 atm

150,000 **design kg/d H2 or gal/d gasoline equivalent**

135,000 **actual kg/d annual ave.**

theoretical power 39.37 kWh/kg H2 at 100% electric efficiency

actual power 52.49 kWh/kg or 4.73 kWh/Nm3 H2

at 0.75 kg CO2/kWh current U.S. average for all electricity = **255,320** **kg/hr CO2 equivalent at power plants**

40.9 **kgCO2/kg H2**

Capital Costs	**Unit cost basis at 100,000 kg/d H2**		**cost/size factors**	**Unit cost at 150,000 kg/d H2**	**millions of $ for 1 plant**	**Notes**
Electrolyser	$ 1,000 /kW		90%	$ 960 /kW	315.0	$ 5.1 /scf/d H2
H2 Compressor	$ 2,000 /kW		90%	$ 1,921 /kW	23.7	$ 158 /kg/d H2
				Total process units	338.8	
General Facilities		of process units			67.8	20-40% typical
Engineering Permitting & Startup	**15%**	of process units			50.8	10-20% typical
Contingencies	**10%**	of process units			33.9	10-20% typical, low after the first few
Working Capital, Land & Misc.	**7%**	of process units			23.7	5-10% typical
				U.S. Gulf Coast Capital Costs	514.9	
Site specific factor	**110%**	of US Gulf Coast costs		**Total Capital Costs**	**566.4**	

Unit Capital Costs of **9.11** **/scf/d H2 or** 3,776 /kg/d H2 or 3,776 /gal/d gaso equiv

Hydrogen Costs at	90% ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Non-fuel Variable O&M	**1.0%** /yr of capital	5.664	1.01	0.28	0.11	0.5-1.5% typical
Oxygen byproduct	**$ (10)** /ton O2	(3.942)	(0.70)	(0.19)	(0.08)	large amount could create min. value
Electricity	**$ 0.045** /kWh	120.777	21.54	5.91	2.45	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost		**122.498**	**21.84**	**6.00**	**2.49**	
Fixed Operating Cost	**5.0%** /yr of capital	**28.320**	**5.05**	**1.39**	**0.57**	4-7% typical for refining
Capital Charges	**18%** /yr of capital	**101.951**	**18.18**	**4.99**	**2.07**	20-25% typical for refining
Total Gaseous Hydrogen Costa from Electrolysis		**252.769**	**45.07**	**12.38**	**5.13**	including return on investment

into pipeline still requires distribution

Note: if 12 hr/d at only $ 0.020 /kWh lower off-peak rate and
12 hr/d at $ 0.060 /kWh higher peak rate daily average rate is $ 0.040 /kWh

Assume Hydrogn Systems Electrolysis at 150 psig pressure, Norsk Hydro & Stuard systems are low pressure

Source SFA Pacific, Inc

Path C6

Central Hydrogen via Electrolysis of Water, Shipped by Cryogenic Liquid Tankers

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design	Design LHV energy equivalent				
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming 90% annual load factor at

actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv

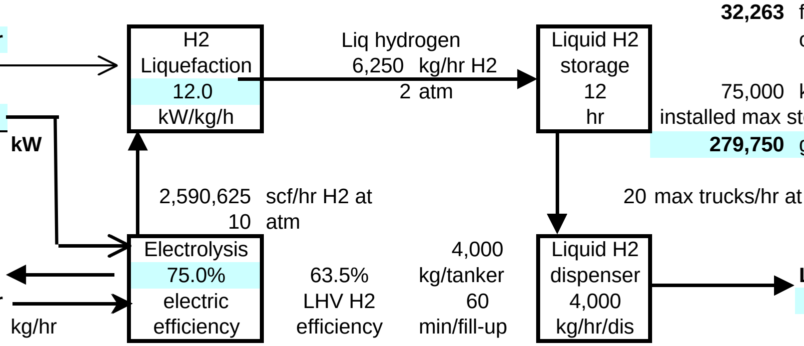
or 4,106,250 kg/month H2 or gal/mo. gaso equiv

thereby **225,844 vehicles can be serviced at**

32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week

Electric Power		
Liquefaction	75,000	
Misc.	1,875	
Electrolysis	328,083	
Total	**403,083**	**kW**



75,000 kg H2

installed max storage

279,750 gal physical vol of liq H2 at 2 atm press

20 max trucks/hr at this production & storage

50,000 kg/hr O2

Water

56,250 kg/hr

2 dispenser

Liquid Hydrogen in Tanker Trucks

38 Cryo tanker fill-ups/d at

150,000 design kg/d H2 or gal/d

gasoline equivalent

135,000 actual kg/d annual ave.

theoretical power 39.37 kWh/kg H2 at 100% electric efficiency

actual power 52.49 kWh/kg or 4.73 kWh/Nm3 H2

at 0.75 kg CO2/kWh current U.S. average for all electricity = **302,313 kg/hr CO2 equivalent at power plants**

48.4 kgCO2/kg H2

Capital Costs	**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**	**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**	**Notes**	
Electrolyser	$ 1,000	/kW	90%	$ 960	/kW	315.0	$ 5.1	/scf/d H2
H2 Cryo Liquefaction	$ 700	/kg/d H2	75%	$ 633	/kg/d H2	94.9	$ 1,265	/kW power
Liquid H2 storage	$ 5	/gal phy vol	70%	$ 4	/gal phy vol	1.2	$ 17	kg of H2 liquid storage
Liquid H2 dispenser	$ 150,000	/dispenser	100%	$ 150,000	/dispenser	0.3	$ 2	/kg/d dispenser design
					Total process units	411.5		
General Facilities		of process units				82.3	20-40% typical	
Engineering Permitting & Startup	15%	of process units				61.7	10-20% typical	
Contingencies	10%	of process units				41.1	10-20% typical, low after the first few	
Working Capital, Land & Misc.	7%	of process units				28.8	5-10% typical	
					U.S. Gulf Coast Capital Costs	625.4		
Site specific factor	110%	of US Gulf Coast costs			**Total Capital Costs**	**$ 688.0**		
Unit Capital Costs of	**11.07**	**/scf/d H2 or**		4,586	/kg/d H2 or	4,586	/gal/d gaso equiv	

Hydrogen Costs at	90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Non-fuel Variable O&M	1.0%	/yr of capital	6.880	1.23	0.34	0.14	0.5-1.5% typical
Oxygen byproduct	$ (10)	/ton O2	(3.942)	(0.70)	(0.19)	(0.08)	large amount could create min. value
Electricity	$ 0.045	/kWh	143.006	25.50	7.00	2.90	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost			**145.944**	**26.02**	**7.15**	**2.96**	
Fixed Operating Cost	5.0%	/yr of capital	**34.398**	**6.13**	**1.68**	**0.70**	4-7% typical for refining
Capital Charges	18%	/yr of capital	**123.834**	**22.08**	**6.06**	**2.51**	20-25% typical for refining
Total Liquid Hydrogen Costs from Electrolysis			**304.176**	**54.24**	**14.89**	**6.17**	including return on investment

plant gate still requires distribution

Note: if 12 hr/d at only $ 0.020 /kWh lower off-peak rate and

12 hr/d at $ 0.060 /kWh higher peak rate daily average rate is $ 0.040 /kWh

Assume Hydrogn Systems Electrolysis at 150 psig pressure, Norsk Hydro & Stuard systems are low pressure

Source SFA Pacific, Inc

Path C7

Central Hydrogen via Petroleum Coke Gasification, Shipped by Pipeline

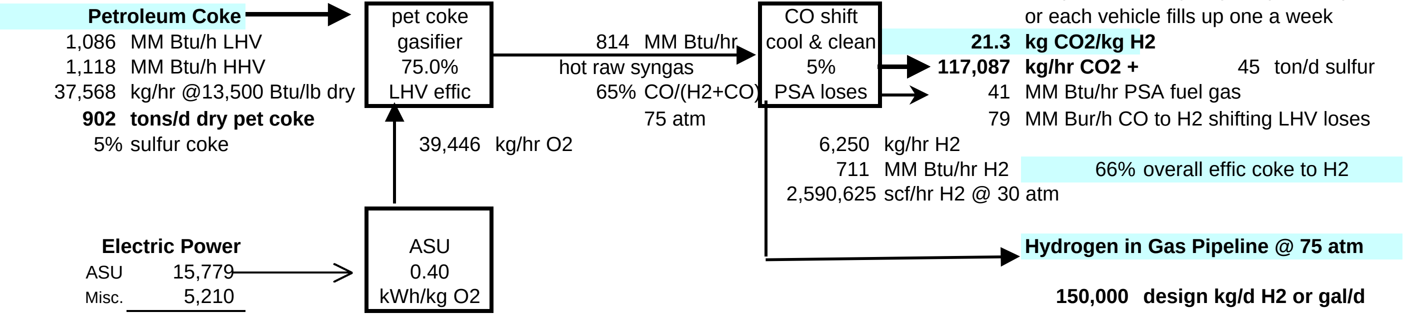
Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr
requires 218 kg/yr H2/vehicle or gal/yr gaso equiv
Assuming 90% **annual load factor at**
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv
or 4,106,250 kg/month H2 or gal/mo. gaso equiv
thereby **225,844** **vehicles can be serviced at**
32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up
or each vehicle fills up one a week

1 Central Plant Design		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28



Petroleum Coke
1,086 MM Btu/h LHV
1,118 MM Btu/h HHV
37,568 kg/hr @13,500 Btu/lb dry
902 **tons/d dry pet coke**
5% sulfur coke

pet coke gasifier
75.0%
LHV effic

814 MM Btu/hr
hot raw syngas
65% CO/(H2+CO)
75 atm

39,446 kg/hr O2

CO shift cool & clean
5%
PSA loses

21.3 **kg CO2/kg H2**
117,087 **kg/hr CO2 +** 45 ton/d sulfur
41 MM Btu/hr PSA fuel gas
79 MM Bur/h CO to H2 shifting LHV loses

6,250 kg/hr H2
711 MM Btu/hr H2
2,590,625 scf/hr H2 @ 30 atm

66% overall effic coke to H2

Hydrogen in Gas Pipeline @ 75 atm

Electric Power
ASU 15,779
Misc. 5,210
Total **20,989** **kW**

ASU
0.40
kWh/kg O2

947 metric tons/d O2
1.05 tons O2/ton dry feed

150,000 **design kg/d H2 or gal/d**
gasoline equivalent
135,000 **actual kg/d annual ave.**

at 0.75 kg CO2/kWh current U.S. average for all electricity = **15,742** **kg/hr CO2 equivalent at power plants**

Capital Costs	**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**	**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**	**Notes**	
Coke handling & prep	$ 20	/kg/d coke	75%	$ 18	/kg/d coke	16.3		
Texaco coke gasifers	$ 25	/kg/d coke	85%	$ 24	/kg/d coke	42.4	100% spare unit	HP quench
Air separation unit (ASU)	$ 28	/kg/d oxygen	75%	$ 25	/kg/d oxygen	24.0	$ 1,518 /kW ASU power	
CO shift, cool & cleanup	$ 20	/kg/d CO2	75%	$ 18	/kg/d CO2	50.8	$ 0.8 /scf/d H2	MDEA & PSA
Sulfur recovery	$ 330	/kg/d sulfur	80%	$ 304	/kg/d sulfur	13.7	lower unit cost that coal due to high S	
				Total process units		133.5		
General Facilities	30%	of process units				40.0	20-40% typical, SMR +	10%
Engineering Permitting & Startup	15%	of process units				20.0	10-20% typical	
Contingencies	10%	of process units				13.3	10-20% typical, low after the first few	
Working Capital, Land & Misc.	7%	of process units				9.3	5-10% typical	
				U.S. Gulf Coast Capital Costs		216.2		
Site specific factor	110%	of US Gulf Coast costs		**Total Capital Costs**		**237.8**		
Unit Capital Costs	**3.82**	**/scf/d H2 or**	1,585	/kg/d H2 or	1,585	/gal/d gaso equiv		

Hydrogen Costs at	90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0%	/yr of capital	2.4	0.42	0.12	0.05	0.5-1.5% typical
Pet Coke	$ 0.20	/MM Btu HHV	1.8	0.31	0.09	0.04	$0.00-0.50/MM Btu typical at refinery
Electricity	$ 0.045	/kWh	7.4	1.33	0.36	0.15	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost			**11.6**	**2.07**	**0.57**	**0.24**	
Fixed Operating Cost	5.0%	/yr of capital	**11.9**	**2.12**	**0.58**	**0.24**	4-7% typical for refining
Capital Charges	18%	/yr of capital	**42.8**	**7.63**	**2.10**	**0.87**	20-25% typical for refining
Total Gaseous Hydrogen Costs from Pet Coke			**66.3**	**11.82**	**3.25**	**1.35**	including return of investment

into pipeline still requires distribution

note $ **5.95** /tonne pet coke price from above $/MM Btu input at 13,500 Btu/lb HHV

Source SFA Pacific, Inc

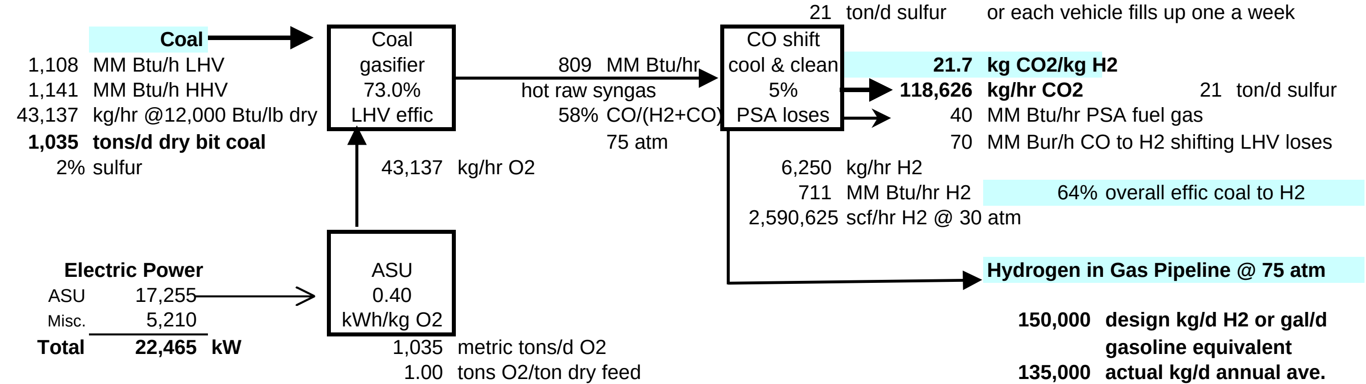
Path C8
Central Hydrogen via Coal Gasification, Shipped by Pipeline

Final Version June 2002 **IHIG Confidential**

Color codes variables via summary inputs key outputs

1 Central Plant Design		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent
Assuming 55 mpg and 12,000 mile/yr
requires 218 kg/yr H2/vehicle or gal/yr gaso equiv
Assuming **90%** **annual load factor at**
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv
or 4,106,250 kg/month H2 or gal/mo. gaso equiv
thereby **225,844** **vehicles can be serviced at**
32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up
or each vehicle fills up one a week



at 0.75 kg CO2/kWh current U.S. average for all electricity = **16,849 kg/hr CO2 equivalent at power plants**

Capital Costs		**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**		**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**		**Notes**	
Coal handling & prep	$	20	/kg/d coal	75%	$	18	/kg/d coal	18.7		solids & slurry prep	
Texaco coal gasifers	$	25	/kg/d coal	85%	$	24	/kg/d coal	48.7	100%	spare unit	HP quench
Air separation unit (ASU)	$	28	/kg/d oxygen	75%	$	25	/kg/d oxygen	26.2	$ 1,518	/kW ASU power	
CO shift, cool & cleanup	$	20	/kg/d CO2	75%	$	18	/kg/d CO2	51.5	$ 0.8	/scf/d H2	MDEA & PSA
Sulfur recovery	$	400	/kg/d sulfur	80%	$	369	/kg/d sulfur	7.6		O2 Claus & tailgas treat	
							Total process units	145.1			
General Facilities		30%	of process units					43.5	20-40% typical,	SMR +	10%
Engineering Permitting & Startup		15%	of process units					21.8	10-20% typical		
Contingencies		10%	of process units					14.5	10-20% typical, low after the first few		
Working Capital, Land & Misc.		7%	of process units					10.2	5-10% typical		
							U.S. Gulf Coast Capital Costs	235.0			
Site specific factor		110%	of US Gulf Coast costs				**Total Capital Costs**	**258.5**			
Unit Capital Costs		**4.16**	**/scf/d H2 or**	1,723	/kg/d H2 or		1,723	/gal/d gaso equiv			

Hydrogen Costs at		90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M		1.0%	/yr of capital	2.6	0.46	0.13	0.05	0.5-1.5% typical
Coal	$	1.10	/MM Btu HHV	9.9	1.76	0.48	0.20	$0.75-1.25/MM Btu typical
Electricity	$	0.045	/kWh	8.0	1.42	0.39	0.16	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost				**20.5**	**3.65**	**1.00**	**0.42**	
Fixed Operating Cost		5.0%	/yr of capital	**12.9**	**2.30**	**0.63**	**0.26**	4-7% typical for refining
Capital Charges		18%	/yr of capital	**46.5**	**8.30**	**2.28**	**0.94**	20-25% typical for refining
Total Gaseous Hydrogen Costs from Coal				**79.9**	**14.25**	**3.91**	**1.62**	including return of investment

into pipeline still requires distribution

note **$ 29.11** /tonne coal price from above $/MM Btu input at 12,000 Btu/lb HHV

Source SFA Pacific, Inc

Path C9

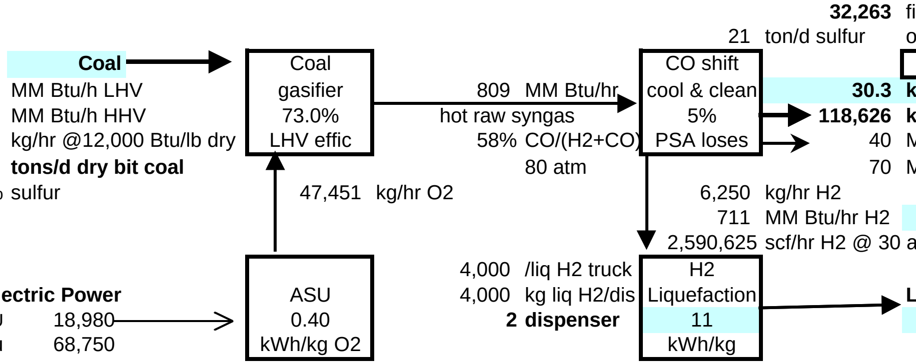
Central Hydrogen via Coal Gasification, Shipped by Cryogenic Tanker Truck

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

	gasoline equivalent	
Assuming	55	mpg and 12,000 mile/yr
requires	218	kg/yr H2/vehicle or gal/yr gaso equiv
Assuming	**90%**	**annual load factor at**
actual H2	49,275,000	kg/y H2 /station or gal/y gaso equiv
or	4,106,250	kg/month H2 or gal/mo. gaso equiv
thereby	**225,844**	**vehicles can be serviced at**
	32,263	fill-ups/d @ 4.2 kg or gal equiv/fill-up
		or each vehicle fills up one a week



21 ton/d sulfur

Coal

1,108 MM Btu/h LHV

1,141 MM Btu/h HHV

43,137 kg/hr @12,000 Btu/lb dry

1,035 tons/d dry bit coal

2% sulfur

809 MM Btu/hr hot raw syngas

58% CO/(H2+CO)

80 atm

47,451 kg/hr O2

12 hr liq H2 storage

30.3 kg CO2/kg H

75,000 kg liq H2 stor

118,626 kg/hr CO2

279,975 gal phy liq H2

40 MM Btu/hr PSA fuel gas

70 MM Bur/h CO to H2 shifting LHV loses

6,250 kg/hr H2

711 MM Btu/hr H2

64% overall effic coal to H2

2,590,625 scf/hr H2 @ 30 atm

4,000 /liq H2 truck

4,000 kg liq H2/dis

2 dispenser

Electric Power		
ASU	18,980	
H2 Liqu	68,750	
Misc.	6,253	
Total	**93,983**	**kW**

1,139 metric tons/d O2

1.10 tons O2/ton dry feed

Liquid Hydrogen in Tanker Trucks

38 Cryo tanker fill-ups/d at

150,000 design kg/d H2 or gal/d

gasoline equivalent

135,000 actual kg/d annual ave.

at 0.75 kg CO2/kWh current U.S. average for all electricity = **70,487 kg/hr CO2 equivalent at power plants**

Capital Costs	**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**	**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**		**Notes**	
Coal handling & prep	$ 20	/kg/d coal	75%	$ 18	/kg/d coal	18.7		solids & slurry prep	
Texaco coal gasifers	$ 25	/kg/d coal	85%	$ 24	/kg/d coal	48.7	100%	spare unit	HP quench
Air separation unit (ASU)	$ 28	/kg/d oxygen	75%	$ 25	/kg/d oxygen	28.8	$ 1,518	/kW ASU power	
CO shift, cool & cleanup	$ 20	/kg/d CO2	75%	$ 18	/kg/d CO2	51.5	$ 0.8	/scf/d H2	MDEA & PSA
Sulfur recovery	$ 400	/kg/d sulfur	80%	$ 369	/kg/d sulfur	7.6		O2 Claus & tailgas treat	
H2 Cryo Liquefaction	$ 700	/kg/d H2	75%	$ 633	/kg/d H2	94.9	$ 1,380	/kW power	
Liquid H2 storage	$ 5	/gal phy vol	70%	$ 4	/gal phy vol	1.2	$ 4	kg of H2 liquid storage	
Liquid H2 dispenser	$ 100,000	/dispenser	100%	$ 100,000	/dispenser	0.2	$ 1	/kg/d dispenser design	
					Total process units	251.6			
General Facilities		of process units				75.5	20-40% typical,	SMR +	10%
Engineering Permitting & Startup	15%	of process units				37.7	10-20% typical		
Contingencies	10%	of process units				25.2	10-20% typical, low after the first few		
Working Capital, Land & Misc.	7%	of process units				17.6	5-10% typical		
					U.S. Gulf Coast Capital Costs	407.7			
Site specific factor	110%	of US Gulf Coast costs			**Total Capital Costs**	**448.4**			
Unit Capital Costs	**7.21**	**/scf/d H2 or**		2,989	/kg/d H2 or	2,989	/gal/d gaso equiv		

Hydrogen Costs at	90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M		1.0% /yr of capital	4.5	0.80	0.22	0.09	0.5-1.5% typical
Coal	$	1.10 /MM Btu HHV	9.9	1.76	0.48	0.20	$0.75-1.25/MM Btu typical
Electricity	$	0.045 /kWh	33.3	5.95	1.63	0.68	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost			**47.7**	**8.51**	**2.34**	**0.97**	
Fixed Operating Cost		5.0% /yr of capital	**22.4**	**4.00**	**1.10**	**0.46**	4-7% typical for refining
Capital Charges		18% /yr of capital	**80.7**	**14.39**	**3.95**	**1.64**	20-25% typical for refining
Total Liquid Hydrogen Costs from Coal			**150.9**	**26.90**	**7.39**	**3.06**	including return of investment
plant gate		still requires distribution					

note **$ 29.11** /tonne coal price from above $/MM Btu input at 12,000 Btu/lb HHV

Source SFA Pacific, Inc

Path C10

Central Hydrogen via Biomass Gasification, Shipped by High Pressure Gas Tube Trailers

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design	**Design LHV energy equivalent**				
	Hydrogen	**gasoline**	**million**		
Size range	**kg/d H2**	**gal/d**	**Btu/hr**	**scf/d H2**	**MW t**
Maximum	200,000	200,000	948	82,900,000	278
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming **90%** **annual load factor at**

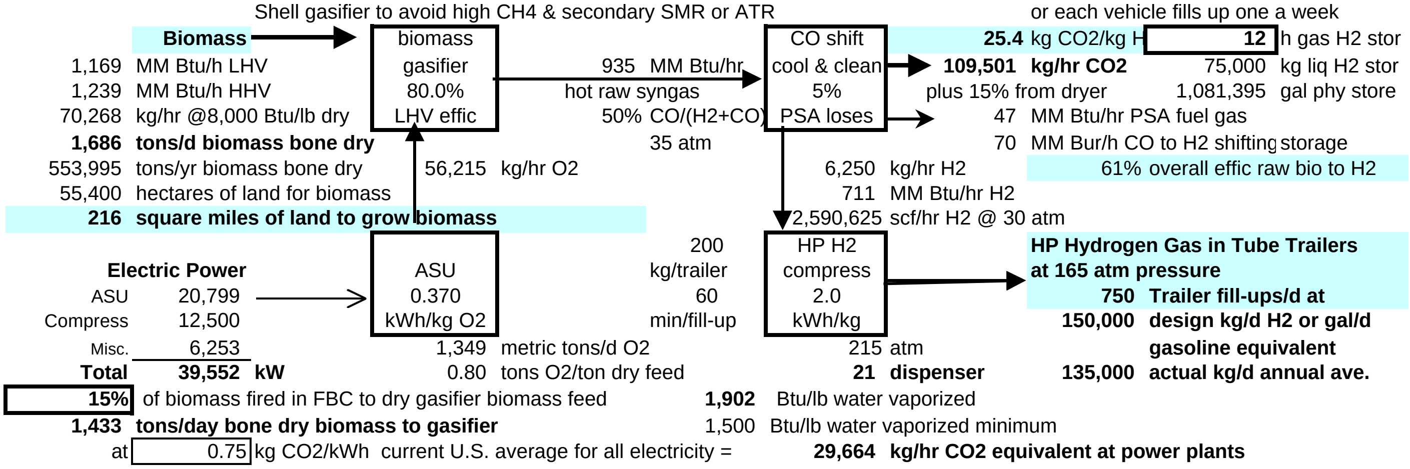
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv

or 4,106,250 kg/month H2 or gal/mo. gaso equiv

thereby **225,844** **vehicles can be serviced at**

32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week



Shell gasifier to avoid high CH4 & secondary SMR or ATR

Biomass

1,169 MM Btu/h LHV

1,239 MM Btu/h HHV

70,268 kg/hr @8,000 Btu/lb dry

1,686 **tons/d biomass bone dry**

553,995 tons/yr biomass bone dry

55,400 hectares of land for biomass

216 **square miles of land to grow biomass**

biomass gasifier 80.0% LHV effic

935 MM Btu/hr hot raw syngas

50% CO/(H2+CO)

35 atm

56,215 kg/hr O2

CO shift cool & clean 5% PSA loses

25.4 kg CO2/kg H

109,501 **kg/hr CO2**

plus 15% from dryer

47 MM Btu/hr PSA fuel gas

70 MM Bur/h CO to H2 shifting

12 h gas H2 stor

75,000 kg liq H2 stor

1,081,395 gal phy store

storage

61% overall effic raw bio to H2

6,250 kg/hr H2

711 MM Btu/hr H2

2,590,625 scf/hr H2 @ 30 atm

Electric Power

ASU	20,799
Compress	12,500
Misc.	6,253
Total	**39,552 kW**

ASU 0.370 kWh/kg O2

1,349 metric tons/d O2

0.80 tons O2/ton dry feed

200 kg/trailer

60 min/fill-up

HP H2 compress 2.0 kWh/kg

215 atm

21 **dispenser**

HP Hydrogen Gas in Tube Trailers
at 165 atm pressure

750 **Trailer fill-ups/d at**

150,000 **design kg/d H2 or gal/d**

gasoline equivalent

135,000 **actual kg/d annual ave.**

15% of biomass fired in FBC to dry gasifier biomass feed **1,902** Btu/lb water vaporized

1,433 **tons/day bone dry biomass to gasifier** 1,500 Btu/lb water vaporized minimum

at 0.75 kg CO2/kWh current U.S. average for all electricity = **29,664** **kg/hr CO2 equivalent at power plants**

		Unit cost basis at		**cost/size**		**Unit cost at**		**millions of $**			
Capital Costs		**100,000**	**kg/d H2**	**factors**		**150,000**	**kg/d H2**	**for 1 plant**		**Notes**	
Biomass handling & drying	$	25	/kg/d dry bio	75%	$	23	/kg/d dry bio	38.1		11	/kg/d green (wet) biomass
Shell gasifier	$	20	/kg/d dry bio	85%	$	19	/kg/d dry bio	54.0		100%	spare unit H2O quench
Air separation unit (ASU)	$	27	/kg/d oxygen	75%	$	24	/kg/d oxygen	32.9	$	1,583	/kW power
CO shift, cool & cleanup	$	15	/kg/d CO2	75%	$	14	/kg/d CO2	35.6	$	0.6	/scf/d H2 MDEA & PSA
H2 Compressor	$	2,000	/kWh	75%	$	1,807	/kWh	22.6	$	151	//kg/d H2
HP H2 gas storage	$	20	/gal phy vol	70%	$	18	/gal phy vol	19.2	$	255	/kg of HP H2 gas storage
HP H2 gas dispenser	$	30,000	/dispenser	100%	$	30,000	/dispenser	0.6	$	3	/kg/d dispenser design
						Total process units		203.0			
General Facilities			of process units					60.9		20-40% typical, SMR +	10%
Engineering Permitting & Startup		15%	of process units					30.4		10-20% typical	
Contingencies		10%	of process units					20.3		10-20% typical, low after the first few	
Working Capital, Land & Misc.		7%	of process units					14.2		5-10% typical	
						U.S. Gulf Coast Capital Costs		328.8			
Site specific factor		110%	of US Gulf Coast costs			**Total Capital Costs**		**361.7**			
Unit Capital Costs		**5.82**	**/scf/d H2 or**	2,411	/kg/d H2 or	2,411	/gal/d gaso equiv				

			million $/yr	**$/million**	**$/1,000**	**$/kg H2 or**	
Hydrogen Costs at	90%	ann load factor	**of 1 plant**	**Btu LHV**	**scf H2**	**$/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0%	/yr of capital	3.6	0.64	0.18	0.07	0.5-1.5% typical
Delivered biomass	$ 3.22	/MM Btu HHV	31.5	5.61	1.54	0.64	based on costs below
Electricity	$ 0.045	/kWh	14.0	2.50	0.69	0.28	0.04-0.05/kWh typical **industrial** rates
Variable Operating Cost			**49.1**	**8.76**	**2.41**	**1.00**	
Fixed Operating Cost	5.0%	/yr of capital	**18.1**	**3.22**	**0.89**	**0.37**	4-7% typical for refining
Capital Charges	18%	/yr of capital	**65.1**	**11.61**	**3.19**	**1.32**	20-25% typical for refining
Total HP Gas Hydrogen Costs from Biomass			**132.3**	**23.59**	**6.48**	**2.69**	including return of investment
plant gate	still requires distribution						

Delivered biomass @ $ 56.82 /bone dry ton (BDT) or $ 3.22 /million Btu LHV based on below:

$ 500 /hectare per yr gross total revenues or $ 200 /acre per yr gross total revenues

10 ton biomass/yr per ha - bone dry basic or 4.0 tons biomass/yr per acre - bone dry

8,000 Btu/lb HHV bone dry and 50% moisture of green biomass

$ 2.08 /mile round trip for typical 25 ton truck hauling green biomass

41 miles round trip haul = $ 3.41 /ton green or $ **6.82** **/ton bone dry equivalent transportation**

If waste bio or coproduct lower gross revenue needs but much lower yield/ha

Source SFA Pacific, Inc

Path C11

Central Hydrogen via Steam Reformer of Natural Gas, Shipped by High Pressure Gas Tube Trailers

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

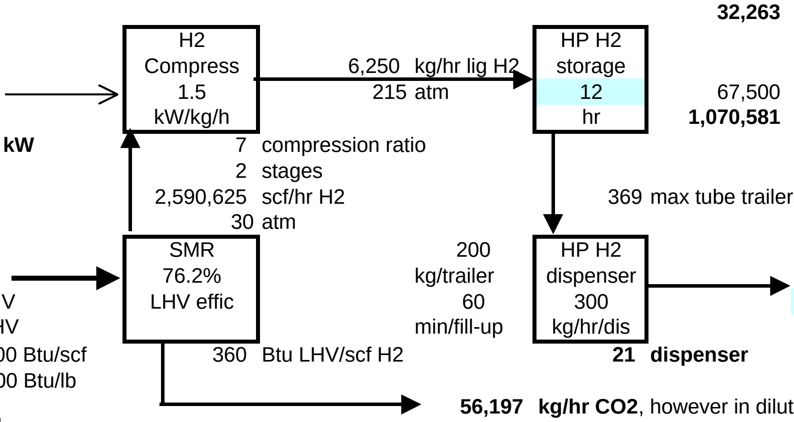
1 Central Plant Design — **Design LHV energy equivalent**

Size range	Hydrogen kg/d H2	gasoline gal/d	million Btu/hr	scf/d H2	MW t
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent
Assuming 55 mpg and 12,000 mile/yr
requires 218 kg/yr H2/vehicle or gal/yr gaso equiv
Assuming **90%** **annual load factor at**
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv
or 4,106,250 kg/month H2 or gal/mo. gaso equiv
thereby **225,844** **vehicles can be serviced at**
32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up
or each vehicle fills up one a week

Electric Power

Compress	9,572	
SMR & misc.	1,295	
Total	**10,868**	**kW**



67,500 kg H2 max storage or
1,070,581 gal phy vol at **215** atm

369 max tube trailers/hr at this production & storage

Natural Gas
934 MM Btu/h LHV
1,036 MM Btu/h HHV
1,036,186 scf/hr @ 1,000 Btu/scf
20,435 kg/hr @23,000 Btu/lb

HP Hydrogen Gas in Tube Trailers
at 165 atm pressure
750 **Trailer fill-ups/d at**
150,000 **design kg/d H2 or gal/d**
gasoline equivalent
135,000 **actual kg/d annual ave.**

56,197 **kg/hr CO2**, however in dilute N2 rich SMR flue gas
at 0.75 kg CO2/kWh current U.S. average = **8,151** **kg/hr CO2** equivalent at power plants
10.3 **kg CO2/kg H2**

Capital Costs		**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**		**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**		**Notes**	
SMR	$	0.75	/scf/d H2	70%	$	0.66	/scf/d H2	41.3	$	275	/kg/d H2
H2 Compressor	$	2,000	/kWh	90%	$	1,921	/kWh	18.4	$	123	/kg/d H2
HP H2 gas storage	$	20	/gal phy vol	70%	$	18	/gal phy vol	19.0	$	281	/kg of HP H2 gas storage
HP H2 gas dispenser	$	30,000	/dispenser	100%	$	30,000	/dispenser	0.6	$	4	/kg/d dispenser design
							Total process units	79.3			
General Facilities			of process units					15.9	20-40% typical		
Engineering Permitting & Startup			of process units					11.9	10-20% typical		
Contingencies			of process units					7.9	10-20% typical, low after the first few		
Working Capital, Land & Misc.			of process units					5.5	5-10% typical		
							U.S. Gulf Coast Capital Costs	120.5			
Site specific factor		110%	of US Gulf Coast costs				**Total Capital Costs**	**132.5**			
Unit Capital Costs		**2.13**	**/scf/d H2 or**			884	/kg/d H2 or	884	/gal/d gaso equiv		

Hydrogen Costs at	90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0%	/yr of capital	1.3	0.24	0.06	0.03	0.5-1.5% typical
Natural Gas	$ 3.50	/MM Btu HHV	28.6	5.10	1.40	0.58	$2.50-4.50/MM Btu **industrial** rate
Electricity	$ 0.045	/kWh	3.9	0.69	0.19	0.08	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost			**33.8**	**6.02**	**1.65**	**0.69**	
Fixed Operating Cost	5.0%	/yr of capital	**6.6**	**1.18**	**0.32**	**0.13**	4-7% typical for refining
Capital Charges	18%	/yr of capital	**23.9**	**4.25**	**1.17**	**0.48**	20-25% typical for refining
Total HP Hydrogen Costs from Natural Gas			**64.3**	**11.46**	**3.15**	**1.30**	including return of investment

plant gate still requires distribution

note:

Source SFA Pacific, Inc

Path C12

Central Hydrogen via Electrolysis of Water, Shipped by High Pressure Gas Tube Trailers

Final Version June 2002 **IHIG Confidential**

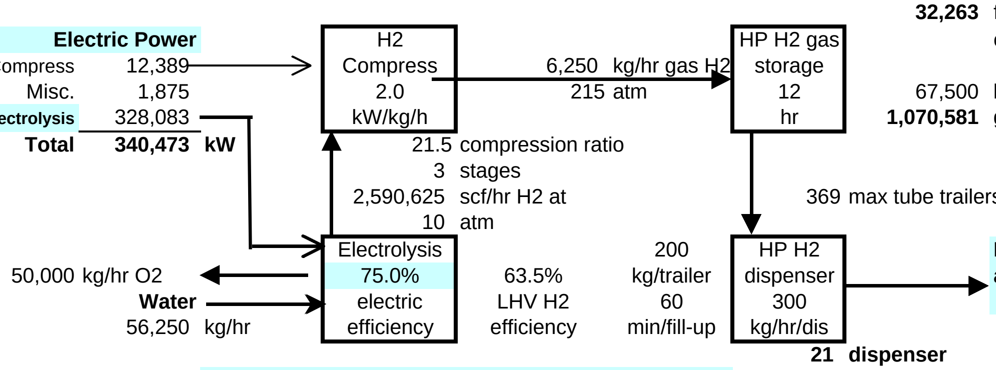
Color codes **variables** via summary inputs key outputs

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr
requires 218 kg/yr H2/vehicle or gal/yr gaso equiv
Assuming actual H2 **90%** **annual load factor at**
49,275,000 kg/y H2 /station or gal/y gaso equiv
or 4,106,250 kg/month H2 or gal/mo. gaso equiv
thereby **225,844** **vehicles can be serviced at**
32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up
or each vehicle fills up one a week

1 Central Plant Design		**Design LHV energy equivalent**			
	Hydrogen	**gasoline**	**million**		
Size range	**kg/d H2**	**gal/d**	**Btu/hr**	**scf/d H2**	**MW t**
Maximum	200,000	200,000	948	82,900,000	278
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

Electric Power		
Compress	12,389	
Misc.	1,875	
Electrolysis	328,083	
Total	**340,473**	**kW**



67,500 kg H2 max storage or
1,070,581 gal phy vol at **215** atm

369 max tube trailers/hr at this production & storage

HP Hydrogen Gas in Tube Trailers
at 165 atm pressure
750 **Trailer fill-ups/d at**
150,000 **design kg/d H2 or gal/d**
gasoline equivalent
135,000 **actual kg/d annual ave.**

theoretical power 39.37 kWh/kg H2 at 100% electric efficiency
actual power 52.49 kWh/kg or 4.73 kWh/Nm3 H2
at 0.75 kg CO2/kWh current U.S. average for all electricity = **255,355** **kg/hr CO2 equivalent at power plants**
40.9 **kgCO2/kg H2**

		Unit cost basis at		**cost/size**		**Unit cost at**		**millions of $**			
Capital Costs		**100,000**	**kg/d H2**	**factors**		**150,000**	**kg/d H2**	**for 1 plant**			**Notes**
Electrolyser	$	1,000	/kW	90%	$	960	/kW	315.0	$	5.1	/scf/d H2
H2 Compressor	$	2,200	/kW	80%	$	2,029	/kW	25.1	$	168	/kg/d H2
HP H2 gas storage	$	20	/gal phy vol	70%	$	18	/gal phy vol	19.0	$	281	/kg of HP H2 gas storage
HP H2 gas dispenser	$	30,000	/dispenser	100%	$	30,000	/dispenser	0.6	$	4	/kg/d dispenser design
						Total process units		359.8			
General Facilities				of process units				72.0	20-40% typical		
Engineering Permitting & Startup			**15%**	of process units				54.0	10-20% typical		
Contingencies			**10%**	of process units				36.0	10-20% typical, low after the first few		
Working Capital, Land & Misc.			**7%**	of process units				25.2	5-10% typical		
						U.S. Gulf Coast Capital Costs		546.9			
Site specific factor			**110%**	of US Gulf Coast costs		**Total Capital Costs**	**$**	**601.5**			
Unit Capital Costs of			**9.67**	**/scf/d H2 or**		4,010	/kg/d H2 or	4,010	/gal/d gaso equiv		

			million $/yr	**$/million**	**$/1,000**	**$/kg H2 or**	
Hydrogen Costs	**at**	90% ann load factor	**of 1 plant**	**Btu LHV**	**scf H2**	**$/gal gaso equiv**	**Notes**
Non-fuel Variable O&M		**1.0%** /yr of capital	6.015	1.07	0.29	0.12	0.5-1.5% typical
Oxygen byproduct	$	**(10)** /ton O2	(3.942)	(0.70)	(0.19)	(0.08)	large amount could create min. value
Electricity	$	**0.045** /kWh	120.793	21.54	5.91	2.45	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost			**122.866**	**21.91**	**6.02**	**2.49**	
Fixed Operating Cost		**5.0%** /yr of capital	**30.077**	**5.36**	**1.47**	**0.61**	4-7% typical for refining
Capital Charges		**18%** /yr of capital	**108.276**	**19.31**	**5.30**	**2.20**	20-25% typical for refining
Total HP Gas Hydrogen Costs from Electrolysis			**261.219**	**46.58**	**12.79**	**5.30**	including return on investment
	plant gate	still requires distribution					

Note: if 12 hr/d at only $ 0.020 /kWh lower off-peak rate and
12 hr/d at $ 0.060 /kWh higher peak rate daily average rate is $ 0.040 /kWh

Assume Hydrogn Systems Electrolysis at 150 psig pressure, Norsk Hydro & Stuard systems are low pressure

Source SFA Pacific, Inc

Path C13

Central Hydrogen via Petroleum Residue Gasification, Shipped by Pipeline

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design		**Design LHV energy equivalent**			
	Hydrogen	**gasoline**	**million**		
Size range	**kg/d H2**	**gal/d**	**Btu/hr**	**scf/d H2**	**MW t**
Maximum	900,000	900,000	4,268	373,050,000	1,251
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

gasoline equivalent

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming 90% annual load factor at

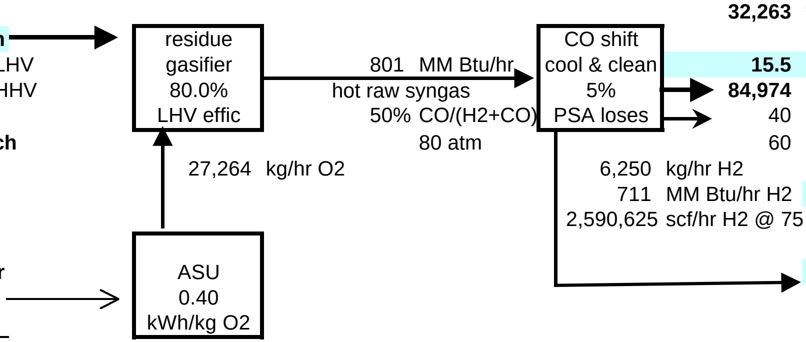
actual H2 49,275,000 kg/y H2 /station or gal/y gaso equiv

or 4,106,250 kg/month H2 or gal/mo. gaso equiv

thereby **225,844 vehicles can be serviced at**

32,263 fill-ups/d @ 4.2 kg or gal equiv/fill-up

or each vehicle fills up one a week



Pet Residue Pitch

1,002 MM Btu/h LHV

1,052 MM Btu/h HHV

27,264 kg/hr

654 tons/d pitch

5% sulfur

801 MM Btu/hr

hot raw syngas

50% CO/(H2+CO)

80 atm

27,264 kg/hr O2

15.5 kg CO2/kg H2

84,974 kg/hr CO2 · 33 ton/d sulfur

40 MM Btu/hr PSA fuel gas

60 MM Bur/h CO to H2 shifting LHV loses

6,250 kg/hr H2

711 MM Btu/hr H2 71% overall effic residue to H2

2,590,625 scf/hr H2 @ 75 atm

Hydrogen in Gas Pipeline @ 75 atm

Electric Power

ASU	10,906	
Misc.	5,210	
Total	**16,116**	**kW**

654 metric tons/d O2

1.00 tons O2/ton dry feed

150,000 design kg/d H2 or gal/d gasoline equivalent

135,000 actual kg/d annual ave.

at 0.75 kg CO2/kWh current U.S. average for all electricity = **12,087 kg/hr CO2 equivalent at power plants**

Capital Costs	**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**	**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**	**Notes**
Residue handling & prep	$ 12	/kg/d residue	75%	$ 11	/kg/d residue	7.1	
Texaco residue gasifiers	$ 32	/kg/d residue	85%	$ 30	/kg/d residue	39.4	100% spare unit soot recycle
Air separation unit (ASU)	$ 28	/kg/d oxygen	75%	$ 25	/kg/d oxygen	16.6	$ 1,518 /kW ASU power
CO shift, cool & cleanup	$ 22	/kg/d CO2	75%	$ 20	/kg/d CO2	40.5	$ 0.7 /scf/d H2 MDEA & PSA
Sulfur recovery	$ 330	/kg/d sulfur	80%	$ 304	/kg/d sulfur	10.0	lower unit cost that coal due to high S
				Total process units		103.6	
General Facilities		of process units				31.1	20-40% typical, SMR + 10%
Engineering Permitting & Startup	15%	of process units				15.5	10-20% typical
Contingencies	10%	of process units				10.4	10-20% typical, low after the first few
Working Capital, Land & Misc.	7%	of process units				7.3	5-10% typical
				U.S. Gulf Coast Capital Costs		167.8	
Site specific factor	110%	of US Gulf Coast costs		**Total Capital Costs**		**184.6**	
Unit Capital Costs	**2.97**	**/scfd H2 or**	1,231	/kg/d H2 or	1,231	/gal/d gaso equiv	

Hydrogen Costs at	90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0%	/yr of capital	1.8	0.33	0.09	0.04	0.5-1.5% typical
Pitch	$ 1.50	/MM Btu HHV	12.4	2.22	0.61	0.25	$1.00-2.00/MM Btu typical at refinery
Electricity	$ 0.045	/kWh	5.7	1.02	0.28	0.12	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost			**20.0**	**3.57**	**0.98**	**0.41**	
Fixed Operating Cost	5.0%	/yr of capital	**9.2**	**1.65**	**0.45**	**0.19**	4-7% typical for refining
Capital Charges	18%	/yr of capital	**33.2**	**5.93**	**1.63**	**0.67**	20-25% typical for refining
Total Gaseous Hydrogen Costs from Residue			**62.5**	**11.14**	**3.06**	**1.27**	including return of investment

into pipeline still requires distribution

note **$ 57.88** /tonne pitch price from above $/MM Btu input at 17,500 Btu/lb HHV

$ 9.65 /barrel at 6.0 bbl/tonne

Source SFA Pacific, Inc

Path C15

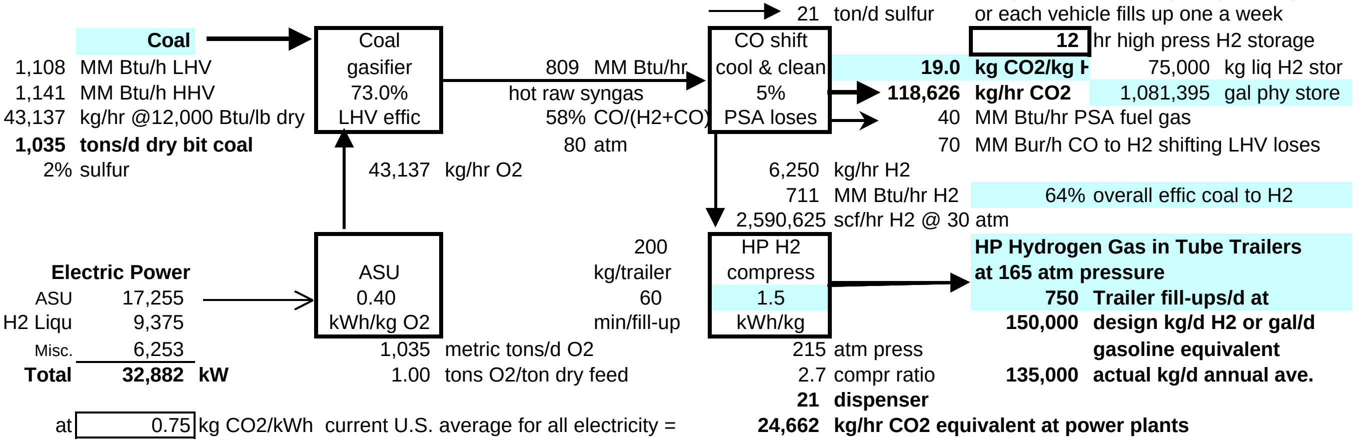
Central Hydrogen via Coal Gasification, Shipped by High Pressure Gas Tube Trailers

Final Version June 2002 **IHIG Confidential**

Color codes **variables** via summary inputs key outputs

1 Central Plant Design		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**
Minimum	20,000	20,000	95	8,290,000	28

	gasoline equivalent		
Assuming	55	mpg and	12,000 mile/yr
requires	218	kg/yr H2/vehicle or gal/yr gaso equiv	
Assuming	**90%**	**annual load factor at**	
actual H2	49,275,000	kg/y H2 /station or gal/y gaso equiv	
or	4,106,250	kg/month H2 or gal/mo. gaso equiv	
thereby	**225,844**	**vehicles can be serviced at**	
	32,263	fill-ups/d @ 4.2 kg or gal equiv/fill-up	
		or each vehicle fills up one a week	



21 ton/d sulfur

Coal
1,108 MM Btu/h LHV
1,141 MM Btu/h HHV
43,137 kg/hr @12,000 Btu/lb dry
1,035 tons/d dry bit coal
2% sulfur

Coal gasifier
73.0%
LHV effic

809 MM Btu/hr
hot raw syngas
58% CO/(H2+CO)
80 atm

43,137 kg/hr O2

CO shift
cool & clean
5%
PSA loses

12 hr high press H2 storage
19.0 kg CO2/kg H 75,000 kg liq H2 stor
118,626 kg/hr CO2 1,081,395 gal phy store
40 MM Btu/hr PSA fuel gas
70 MM Bur/h CO to H2 shifting LHV loses

6,250 kg/hr H2
711 MM Btu/hr H2 64% overall effic coal to H2
2,590,625 scf/hr H2 @ 30 atm

Electric Power
ASU 17,255
H2 Liqu 9,375
Misc. 6,253
Total 32,882 kW

ASU
0.40
kWh/kg O2

1,035 metric tons/d O2
1.00 tons O2/ton dry feed

200
kg/trailer
60
min/fill-up

HP H2
compress
1.5
kWh/kg

215 atm press
2.7 compr ratio
21 dispenser

HP Hydrogen Gas in Tube Trailers
at 165 atm pressure
750 Trailer fill-ups/d at
150,000 design kg/d H2 or gal/d
gasoline equivalent
135,000 actual kg/d annual ave.

at 0.75 kg CO2/kWh current U.S. average for all electricity = **24,662 kg/hr CO2 equivalent at power plants**

Capital Costs		**Unit cost basis at 100,000**	**kg/d H2**	**cost/size factors**		**Unit cost at 150,000**	**kg/d H2**	**millions of $ for 1 plant**			**Notes**	
Coal handling & prep	$	20	/kg/d coal	75%	$	18	/kg/d coal	18.7			solids & slurry prep	
Texaco coal gasifers	$	25	/kg/d coal	85%	$	24	/kg/d coal	48.7		100%	spare unit	direct quench
Air separation unit (ASU)	$	28	/kg/d oxygen	75%	$	25	/kg/d oxygen	26.2	$	1,518	/kW ASU power	
CO shift, cool & cleanup	$	20	/kg/d CO2	75%	$	18	/kg/d CO2	51.5	$	0.8	/scf/d H2	MDEA & PSA
Sulfur recovery	$	400	/kg/d sulfur	80%	$	369	/kg/d sulfur	7.6			O2 Claus & tailgas treat	
H2 Compressor	$	2,000	/kWh	90%	$	1,921	/kWh	18.0	$	120	//kg/d H2	
HP H2 gas storage	$	20	/gal phy vol	70%	$	18	/gal phy vol	19.2	$	255	/kg of HP H2 gas storage	
HP H2 gas dispenser	$	30,000	/dispenser	100%	$	30,000	/dispenser	0.6	$	3	/kg/d dispenser design	
						Total process units		190.5				

General Facilities		of process units	57.1	20-40% typical, SMR + 10%
Engineering Permitting & Startup	15%	of process units	28.6	10-20% typical
Contingencies	10%	of process units	19.0	10-20% typical, low after the first few
Working Capital, Land & Misc.	7%	of process units	13.3	5-10% typical
		U.S. Gulf Coast Capital Costs	308.6	
Site specific factor	110%	of US Gulf Coast costs **Total Capital Costs**	**339.4**	

Unit Capital Costs 5.46 /scf/d H2 or 2,263 /kg/d H2 or 2,263 /gal/d gaso equiv

Hydrogen Costs at	90%	ann load factor	**million $/yr of 1 plant**	**$/million Btu LHV**	**$/1,000 scf H2**	**$/kg H2 or $/gal gaso equiv**	**Notes**
Variable Non-fuel O&M	1.0%	/yr of capital	3.4	0.61	0.17	0.07	0.5-1.5% typical
Coal	$ 1.10	/MM Btu HHV	9.9	1.76	0.48	0.20	$0.75-1.25/MM Btu typical
Electricity	$ 0.045	/kWh	11.7	2.08	0.57	0.24	$0.04-0.05/kWh **industrial** rate
Variable Operating Cost			**25.0**	**4.45**	**1.22**	**0.51**	
Fixed Operating Cost	5.0%	/yr of capital	**17.0**	**3.03**	**0.83**	**0.34**	4-7% typical for refining
Capital Charges	18%	/yr of capital	**61.1**	**10.90**	**2.99**	**1.24**	20-25% typical for refining
Total HP Gas Hydrogen Costs from Coal			**103.0**	**18.37**	**5.04**	**2.09**	including return of investment
	plant gate	still requires distribution					

note **$ 29.11** /tonne coal price from above $/MM Btu input at 12,000 Btu/lb HHV

Source SFA Pacific, Inc

Summary for Hydrogen Delivery Pathways

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Inputs **Boxed in yellow** are the key input variables **you** must choose, **current inputs are just an example**

Hydrogen Production Inputs

Design hydrogen production	150,000	kg/d H2			
Annual average load factor	90%	/yr of design			
Average distance to forecourt	150	km, key assumption for tube trailer & especially pipeline			
Truck utilization	80%				
Tube load	300	kg	key imput for tube trailer		
Tube pressure full	160	Atmosphere			
Tube pressure (min)	30	Atmosphere			
Pipeline	621,504	$/km			
Gasoline sales/month/station	10,000	kg/month	thereby supplying	411	stations
Fuel cost	1	$/gal			

Capital Cost Buildup Inputs from process unit costs

General Facilities	20%		20-40% typical	assume low for pipeline
Engineering, Permits & Startup	10%		10-20% typical	assume low for pipeline
Contingencies	10%		10-20% typical, should be low after the first few	
Working Capital, Land & Misc.	7%		5-10% typical	
Site specific factor	110%	of US Gulf Coast	90-130% typical; sales tax, labor rates & weather issues	

Product Cost Buildup Inputs

Electricity cost	0.045	$/kwh	$0.04-0.05/kWh typical **industrial** rate, see www.eia.doe.gov
Non-fuel Variable O&M	1.0%	/yr of capital	0.5-1.5% typical but could be lower for pipeline
Fixed O&M Costs	5.0%	/yr of capital	4-7% typical for refiners: labor, overhead, insurance, taxes, G&A
Capital Charges	18.0%	/yr of capital	20-25%/yr CC typical for refiners & 14-20%/yr CC typical for utilities

Outputs 135,000 kg/d H2 that supports 226,032 FC vehicles 10,000 kg/month per station supports **411 stations**

actual annual average 32,290 fill-ups/d if 1 fill-up/week @ 4.2 kg/fill-up with **329 kg/d H2**

				Operating Cost		**Product Costs**
		Capital Costs		**Fixed**	**Variable**	**including return on capital**
	Absolute	Unit cost	Unit cost	Unit cost	Unit cost	**Unit cost**
Delivery Method	$ millions	$/scf/d H2	/kg/d H2 or	$/kg H2	$/kg H2	**$/kg H2**
Liquid H2 via Tank Trucks	13.2	0.6	88.0	0.02	0.10	**0.18**
Gaseous H2 via Pipeline	603.0	29.5	4,019.9	0.61	0.61	**2.94**
Gaseous H2 via Tube Trailers	140.7	6.9	938.0	0.14	0.14	**2.09**

Click on specific Excel worksheet tabs below for details of cost buildups for each case

Source: SFA Pacific, Inc.

Liquid Hydrogen Distributed via Trucks

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1 Central Plant Design		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742.186	414,500,000	1,389.448
This run	**150,000**	**150,000**	**711.328**	**62,175,000**	**208.417**
Minimum	20,000	20,000	94.844	8,290,000	27.789

Assuming	55	mpg and 12,000 mile/yr
requires	218	kg/yr H2/vehicle or gal/yr gaso equiv
Assuming	**90%**	Annual average load factor
actual H2	10,000	kg/month H2 or gal/mo. gaso equiv
or	**550**	**FC vehicles can be supported at**
thereby	**78**	fill-ups/d @ 4.2 kg or gal equiv/fill-up
	411	station supported by this central faciltiy

Average delivery distance	**150** km		
Delivery distance	210 km	40%	increase to represent physical distance
Truck utilization	**80%**		

Capital costs	**Million $**		**Notes**
Tank & undercarrage	11.2	$ 75	/kg/d H2
Cabe	2.0	$ 13	/kg/d H2
Total tube trailer cost	**13.2**		

Variable Operating Cost		**Million $/yr**	**$/million Btu LHV**	**$/k scf H2**	**$/kg H2 or $/gal gaso equiv**	
Labor		4.43	0.79	0.22	0.09	
Fuel		0.54	0.10	0.03	0.01	
Variable non-fuel O&M	**1%** /yr of capital	0.13	0.03	0.01	0.00	6,000 $/yr/truck
Total variable operating costs		**5.10**	**0.91**	**0.25**	**0.10**	
Fixed Operating Cost	**5%** /yr of capital	**0.66**	**0.12**	**0.03**	**0.02**	
Capital Charges	**18%** /yr of capital	**2.38**	**0.42**	**0.12**	**0.06**	
Total operating costs		**8.14**	**1.45**	**0.40**	**0.18**	

Assumptions

Truck costs					
Tank unit	450,000	$/module	113	$/kg H2 stroage	
Undercarrage	60,000	$/trailer			
Cabe	90,000	$/cab			
Truck boil-off rate	0.30	%/day			
Truck capacity	4000	kg/truck			
Fuel economy	6	mpg			
Average speed	50	km/hr			
Load/unload time	4	hr/trip could be lowered with a liquid H2 pump			
Truck availability	24	hr/day			
Hour/driver	12	hr/driver			
Driver wage & benefits	28.75	$/hr			
Fuel price	1	$/gal			
Truck requirement calculations					
Trips per year	12,319		34	trips per day	
Total Distance	5,173,875	km/yr	235,176	km/yr per truck	little high
Time for each trip	8.4	hr/trip			
Trip length	12.4	hr/trip			
Delivered product	48,658,030	kg/yr			
Total delivery time	152,753	hr/yr			
Total driving time	103,478	hr/yr			
Total load/unload time	49,275	hr/yr			
Truck availability	7008	hr/yr			
Truck requirement	22	trucks			
Driver time	3504	hr/yr			
Drivers required	44	persons			
Fuel usage	535,000	gal/yr			

Source: SFA Pacific, Inc.

Gaseous Hydrogen Distributed via Pipeline

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							gasoline equivalent			
							55	mpg and	12,000	mile/yr
1 Central Plant Design		**Design LHV energy equivalent**				Assuming	218	kg/yr H2/vehicle or gal/yr gaso equiv		
	Hydrogen	**gasoline**	**million**			requires	90%	**annual load factor at**		
Size range	**kg/d H2**	**gal/d**	**Btu/hr**	**scf/d H2**	**MW t**	**Assuming**	120,000	kg/y H2 /station or gal/y gaso equiv		
Maximum	1,000,000	1,000,000	4,742	414,500,000	1,389	**actual H2**	10,000	kg/month H2 or gal/mo. gaso equiv		
This run	**150,000**	**150,000**	**711**	**62,175,000**	**208**	or	**550**	**vehicles can be serviced at**		
Minimum	20,000	20,000	95	8,290,000	28	thereby	**78**	fill-ups/d @ 4.2 kg or gal equiv/fill-up		
							411	station supported by this central faciltiy		

Delivery distance	**150**	km	key input			
Number of arms	**4**	key input	Radiate four directions or	600	km of total pipeline	key issue
Delivery pressure	**440**	psia				
Pipeline cost	**621,504**	$/km	includes right of way costs which is the key cost issue in urban areas			
Electricity cost	**0.045**	$/kwh	if a booster compressor is required for long pipeline			

Capital costs				
Pipeline			372.9	
Capital cost			372.9	
General Facilities & permitting		of unit cost	74.6	could be lower for pipelines
Eng. startup & contingencies		of unit cost	37.3	
Contingencies		of unit cost	37.3	
Working Capital, Land & Misc.		of unit cost	26.1	could be lower for pipelines
			548.2	
Location factor	**110%**	of US Gulf Coast	**603.0**	

			Million $/yr	**$/million Btu LHV**	**$/k scf H2**	**$/kg H2 or $/gal gaso equiv**	
Variable Operating Cost							
Variable non-fuel O&M	**1%**	/yr of capital	6.03	1.08	0.30	0.12	could be lower for pipelines
Total variable operating costs			**6.03**	**1.08**	**0.30**	**0.12**	
Fixed Operating Cost	**5%**	/yr of capital	**30.15**	**5.38**	**1.48**	**0.61**	could be lower for pipelines
Capital Charges	**18%**	/yr of capital	**108.54**	**19.35**	**5.31**	**2.20**	
Total operating costs			**144.72**	**25.80**	**7.09**	**2.94**	

Source: SFA Pacific, Inc.

Gaseous Hydrogen Distributed via Tube Trailers

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Design per station		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
Maximum	1,000,000	1,000,000	4,742.186	414,500,000	1,389.448
This run	**150,000**	**150,000**	**711.328**	**62,175,000**	**208.417**
Minimum	20,000	20,000	94.844	8,290,000	27.789

Assuming	55	mpg and 12,000 mile/yr
requires	218	kg/yr H2/vehicle or gal/yr gaso equiv
Assuming	**90%**	Annual average load factor
actual H2	10,000	kg/month H2 or gal/mo. gaso equiv
or	**550**	**FC vehicles can be supported at**
thereby	**78**	fill-ups/d @ 4.2 kg or gal equiv/fill-up
	411	station supported by this central faciltiy

Average delivery distance	**150**	km	
Delivery distance	210	km	40% increase to represent physical distance
Truck utilization	**80%**		

Capital costs	**Million $**	**Notes**		
Tubes & undercarrage	113.7	$ 758 /kg/d H2, high due to the	411	units left at stations
Cabe	27.0	$ 180 /kg/d H2		
Total tube trailer cost	**140.7**			

Variable Operating Cost			**Million $/yr**	**$/million Btu LHV**	**$/k scf H2**	**$/gal gaso equiv**		
Operating costs								
Labor			60.44	10.78	2.96	1.23		
Fuel			8.79	1.57	0.43	0.18		
Variable non-fuel O&M	**1%**	/yr of capital	1.41	0.25	0.07	0.03	4,690	$/yr/truck
Total variable operating costs			**70.64**	**12.59**	**3.46**	**1.43**		
Fixed Operating Cost	**5%**	/yr of capital	**7.04**	1.25	0.34	0.14		
Capital Charges	**18%**	/yr of capital	**25.33**	4.52	1.24	0.51		
Total operating costs			**103.00**	**18.36**	**5.04**	**2.09**		

Assumptions

Truck costs			
Tube unit	100,000	$/module	333 $/kg H2 design stoage @ 160 atm
Undercarrage	60,000	$/trailer	
Cabe	90,000	$/cab	
Truck capacity	300	kg/truck key issue	
Pressure (max)	160	atmosphere	
Pressure (min)	30	atmosphere	
Net delivery	244	kg/truck key issue	
Fuel economy	6	mpg	
Average speed	50	km/hr	
Hour/driver	12	hr/driver	
Load/unload time	2	hr/trip	this could be lower as just change tube trailers at stations
Truck availability	24	hr/day	
Driver wage & benefits	28.75	$/hr	
Fuel price	1	$/gal	

Tube trailer requirement calculations

Trips per year	202,100	trips/yr or	554 trips per day
Total distance	84,882,000	km/yr	282,940 km/yr per truck little high
Time for each trip	8.4	hr/trip	
Total delivery time	2,101,840	hr/yr	
Total driving time	1,697,640	hr/yr	
Total load/unload time	404,200	hr/yr	
Truck availability	7008	hr/yr	
nt	300	trucks but	**711 tube trailers due to 1 left at each station**
Driver time, hr/yr	3504	hr/yr	
Drivers required	600	persons	
Fuel usage	8,790,000	gal/yr	

Source: SFA Pacific, Inc.

Summary for Hydrogen Fueling Pathways

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Inputs **Boxed in yellow** are the key input variables **you** must choose, **current inputs are** **just an example**

Hydrogen Production Inputs			Notes
Design hydrogen production		kg/d H2 from central facility	
Annual average load factor		/yr of design	
Gasoline sales/month/station	**10,000**	kg/month thereyb supplying	s
Forecourt loading factor	**70%**	/yr of design	"plug & play" 24 hr replacements for reasonable availability
High pressure gas storage buffer	**3**	hours at peak surge rate	

Capital Cost Buildup Inputs from process unit costs			
General Facilities	**25%**		
Engineering, Permitting & Startup	**10%**		Engineering costs spread over multiple stations
Contingencies	**10%**		
Working Capital, Land & Misc.	**7%**		
Product Cost Buildup Inputs			
Road tax or (subsidy)	**$ -**	/gal gasoline equivalent	may need subsidy like EtOH to get it going
Gas Station mark-up	**$ -**	/gal gasoline equivalent	may be needed if H2 sales drops total station revenues
Electricity cost	**0.07**	$/kwh	$0.06-.0.09/kWh typical **commercial** rate, see www.eia.doe.gov
Non-fuel Variable O&M	**0.5%**	/yr of capital	0.5-1.5% is typical, assumed low here for "plug & play"
Fixed O&M Costs	**3.0%**	/yr of capital	4-7% typicalfor insurance, taxes, G&A (may be low here)
Capital Charges	**18.0%**	/yr of capital	20-25%/yr CC typical for refiners & 14-20%/yr CC for utilities
			s about 12% IRR DCF on 100% equity where as
			s about 12% IRR DCF on 50% equity & debt at 7%

Outputs 135,000 kg/d H2 that supports 226,032 FC vehicles 10,000 kg/month per station supports **411 stations**

actual annual average 32,290 fill-ups/d if 1 fill-up/week @ 4.2 kg/fill-up each with 329 kg/d H2

				Operating Cost		**Product Costs**
		Capital Costs		**Fixed**	**Variable**	**including return on capital**
	Absolute	Unit cost	Unit cost	Unit cost	Unit cost	**Unit cost**
Delivery Method	$ millions	$/scf/d H2	/kg/d H2 or	$/kg H2	$/kg H2	**$/kg H2**
Liquid H2 Gaseous Fueling System	279	13.64	1,857	0.17	0.08	1.27
Gaseous H2 via Pipeline	212	10.39	1,415	0.13	0.16	1.07
Gaseous H2 via Tube Trailer	212	10.39	1,415	0.13	0.09	1.00

Click on specific Excel worksheet tabs below for details of cost buildups for each case

Source: SFA Pacific, Inc.

Liquid Hydrogen Based Fueling Stations

Final Version June 2002 **IHIG Confidential**

Central hydrogen production 150,000 kg/d
Annual average load factor 90% /yr of design

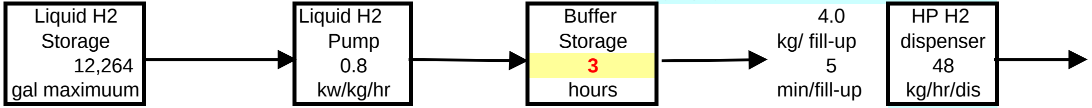
Design per station		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d/station H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
This run	470	**470**	**2.227**	**194,699**	**0.653**

Assuming 55 mpg and 12,000 mile/yr
requires 218 kg/yr H2/vehicle or gal/yr gaso equiv
Assuming 70% Forecourt loading factor
actual H2 10,000 kg/month H2 or gal/mo. gaso equiv
or **550 FC vehicles can be supported at**
thereby **78** fill-ups/d @ 4.2 kg or gal equiv/fill-up
329 kg/d H2 average consumption

one of 411 stations
at 4,000 **kg/load require one tanker every 12 days**

Electric Power
22 kw

123 kg
986 gal physical vol at 400 atm



3,288.04 kg H2 max liqiid H2 sotrage
7 Days of liquid H2 storage at design rate

at surge rate

20 kg/hr daily average design at 24 hr/d
3 times averge at peak surge rate
2 Dispensers
411 Fueling stations served
17 hour operation

	Unit cost basis at		cost/size	Unit cost at				
Capital Costs	**1,000**	**kg/d H2**	**factors**	**470**	**kg/d H2**	**millions of $**	**Notes**	
Liquid H2 pump/vaporizer	$ 250	/kg/d H2	70%	$ 314	/kg/d H2	0.15	$ 314	/kg/d H2
Liquid H2 storage	$ 10	/gal phy vol	70%	$ 13	/gal phy vol	0.15	$ 47	/kg/d H2
H2 buffer storage	$ 100	/gal phy vol	80%	$ 116	/gal phy vol	0.11	$ 931	/kg/d H2
Liquid H2 dispenser	$ 15,000	/dispenser	100%	$ 15,000	/dispenser	0.03	$ 64	/kg/d dispenser design
					Unit cost	0.45		
General Facilities & permitting	25%	of unit cost				0.11		
Eng. startup & contingencies	10%	of unit cost				0.04		
Contingencies	10%	of unit cost				0.04		
Working Capital, Land & Misc.	7%	of unit cost				0.03		
					Capital Costs	**0.68**	**for 1 of** 411	stations
					Total Capital Costs	**279**	**for all** 411	stations

Hydrogen Costs at	70%	ann load factor	**$/yr of 1 station**	**$/million Btu LHV**	**$/k scf H2**	**$/kg H2 or $/gal gaso equiv**	
Road tax or (subsidy)	$ -	/gal gaso equiv.	-	-	-	-	can be subsidy like EtOH
Gas Station mark-up	$ -	/gal gaso equiv.	-	-	-	-	if H2 drops total station revenues
Variable Non-fuel O&M	0.5%	/yr of capital	3,389	0.25	0.07	0.03	0.5-1.5 typical many be low here
Electricity	$ 0.070	/kWh	6,721	0.49	0.14	0.06	0.06-0.09 typical commercial rates
Variable Operating Cost			**10,110**	**0.74**	**0.20**	**0.08**	
Fixed Operating Cost	3.0%	/yr of capital	**20,333**	**1.49**	**0.41**	**0.17**	3-5% typical, may be lower here
Capital Charges	18.0%	/yr of capital	**121,996**	**8.93**	**2.45**	**1.02**	20-25% typical for refiners
Fueling Station Cost			**152,438**	**11.16**	**3.06**	**1.27**	

including return of investment

Hydrogen Fueling Station Costs	
Delivery to	**411 Stations**
	Million $/yr
Variable Operating Cost	**4.16**
Fixed Operating Cost	**8.36**
Capital Charges	**50.14**
Total Fueling Station Cost	**62.65**

Source: SFA Pacific, Inc.

Gaseous Hydrogen Based Fueling Stations - Pipeline Delivery

Final Version June 2002 **IHIG Confidential**

Central hydrogen production	150,000	kg/d
Annual average load factor	90%	/yr of design

Design per station		**Design LHV energy equivalent**			
	Hydrogen	**gasoline**	**million**		
Size range	**kg/d/station H2**	**gal/d**	**Btu/hr**	**scf/d H2**	**MW t**
This run	**470**	**470**	**2.227**	**194,677**	**0.653**
one of	**411**	**stations**			

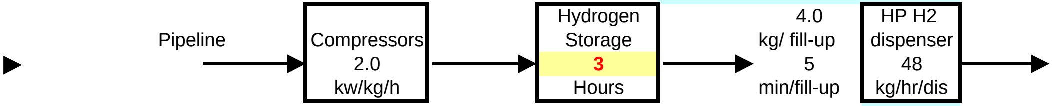
Assuming	55	mpg and	12,000	mile/yr	
requires	218	kg/yr H2/vehicle or gal/yr gaso equiv			
Assuming	70%	Forecourt loading factor			
or	10,000	kg/month H2 or gal/mo. gaso equiv			
	550	**FC vehicles can be supported at**			
	78	fill-ups/d @ 4.2 kg or gal equiv/fill-up			

Electric Power

Commpress 56 kw

123 kg

986 gal physical vol at 400 atm



30 Atm

400 Atm

of daily ave rate

Smaller stations use cascade system

Larger stations use booster system

20	kg/hr daily average design at 24 hr/d
3	times averge at peak surge rate
2	Dispensers
411	Fueling stations served
17	hour operation

		Unit cost basis at		**cost/size**		**Unit cost at**		**millions of $**			
Capital Costs		**1,000**	**kg/d H2**	**factors**		**470**	**kg/d H2**	**for 1 fueling station**			
H2 Compressors	$	3,000	/kwh	80%	$	3,490	/kg/d H2	0.20	$	415	/kg/d H2
H2 buffer storage	$	100	/gal phy vol	80%	$	116	/gal phy vol	0.11	$	931	/kg of HP H2 gas storage
Gaseous H2 dispenser	$	15,000	/dispenser	100%	$	15,000	/dispenser	0.03	$	64	/kg/d dispenser design
							Unit cost	0.34			
General Facilities & permitting		25%						0.08			
Eng. startup & contingencies		10%						0.03			
Contingencies		10%						0.03			
Working Capital, Land & Misc.		7%						0.02			
							Capital Costs	**0.52**	**for 1 of**	411	stations
							Total Capital Costs	**212**	**for all**	411	stations

			$/yr	**$/million**		**$/kg H2 or**	
Hydrogen Costs at	70%	ann load factor	**of 1 station**	**Btu LHV**	**$/k scf H2**	**$/gal gaso equiv**	
Road tax or (subsidy)	$ -	/gal gaso equiv.	-	-	-	-	can be subsidy like EtOH
Gas Station mark-up	$ -	/gal gaso equiv.	-	-	-	-	if H2 drops total station revenues
Variable Non-fuel O&M	0.5%	/yr of capital	2,583	0.19	0.05	0.02	0.5-1.5 typical many be low here
Electricity	$ 0.070	/kWh	16,800	1.23	0.34	0.14	0.06-0.09 typical commercial rates
Variable Operating Cost			**19,383**	**1.42**	**0.39**	**0.16**	
Fixed Operating Cost	3.0%	/yr of capital	**15,496**	**1.13**	**0.31**	**0.13**	3-5% typical, may be lower here
Capital Charges	18.0%	/yr of capital	**92,978**	**6.81**	**1.87**	**0.77**	20-25% typical for refiners
Fueling Station Cost			**127,857**	**9.36**	**2.57**	**1.07**	

including return of investment

Hydrogen Fueling Station Costs

Delivery to	**411 Stations**
	Million $/yr
Variable Operating Cost	7.97
Fixed Operating Cost	6.37
Capital Charges	38.21
Total Fueling Station Cost	**52.55**

Source: SFA Pacific, Inc.

Gaseous Hydrogen Based Fueling Stations - Tube Trailer Delivery

Final Version June 2002 **IHIG Confidential**

Central hydrogen production	150,000	kg/d
Annual average load factor	90%	/yr of design

Design per station		**Design LHV energy equivalent**			
Size range	**Hydrogen kg/d/station H2**	**gasoline gal/d**	**million Btu/hr**	**scf/d H2**	**MW t**
This run	470	470	2.227	194,677	0.653

Assuming 55 mpg and 12,000 mile/yr

requires 218 kg/yr H2/vehicle or gal/yr gaso equiv

Assuming 70% Forecourt loading factor

or 10,000 kg/month H2 or gal/mo. gaso equiv

550 FC vehicles can be supported at

78 fill-ups/d @ 4.2 kg or gal equiv/fill-up

329 kg/d H2 average consumption

one of 411 stations

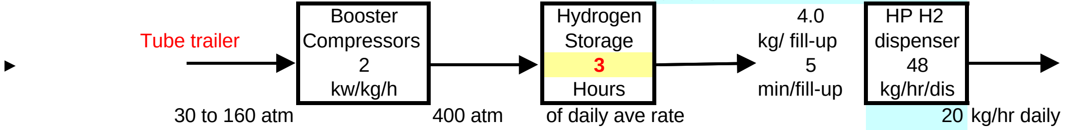
at 244 **kg/load require one tanker every 0.74 days or 18 hours**

Electric Power

Commpress 56 kw

123 kg

986 gal physical vol at 400 atm



20 kg/hr daily average design at 24 hr/d

3 times averge at peak surge rate

2 Dispensers

411 Fueling stations dispensers

17 hour operation

Capital Costs		**Unit cost basis at 1,000**	**kg/d H2**	**cost/size factors**		**Unit cost at 470**	**kg/d H2**	**millions of $**	**Notes**		
Compressors	$	3,000	/kwh	80%	$	3,490	/kwh	0.20	$	415	/kg/d H2
H2 buffer storage	$	100	/gal phy vol	80%	$	116	/gal phy vol	0.11	$	931	/kg of HP H2 gas storage
Gaseous H2 dispenser	$	15,000	/dispenser	100%	$	15,000	/dispenser	0.03	$	64	/kg/d dispenser design
								0.34			
General Facilities & permitting			of equipment cost					0.08			
Eng. startup & contingencies		10%	of equipment cost					0.03			
Contingencies		10%	of equipment cost					0.03			
Working Capital, Land & Misc.		7%	of equipment cost					0.02			
							Capital Costs	**0.52**	**for 1 of**	411	stations
							Total Capital Costs	**212**	**for all**	411	stations

Hydrogen Costs at		70%	ann load facto	**$/yr of 1 station**	**$/million Btu LHV**	**$/k scf H2**	**$/kg H2 or $/gal gaso**	**equiv**
Road tax or (subsidy)	$	-	/gal gaso equiv.	-	-	-	-	can be subsidy like EtOH
Gas Station mark-up	$	-	/gal gaso equiv.	-	-	-	-	if H2 drops total station revenues
Variable Non-fuel O&M		0.5%	/yr of capital	2,583	0.19	0.05	0.02	0.5-1.5 typical many be low here
Electricity	$	0.070	/kWh	8,400	0.62	0.17	0.07	assume 50% of design power due to tube pressrue
Variable Operating Cost				**10,983**	**0.80**	**0.22**	**0.09**	
Fixed Operating Cost		3.0%	/yr of capital	**15,496**	**1.13**	**0.31**	**0.13**	3-5% typical, may be lower here
Capital Charges		18.0%	/yr of capital	**92,978**	**6.81**	**1.87**	**0.77**	20-25% typical for refiners
Fueling Station Cost				**119,457**	**8.75**	**2.40**	**1.00**	

including return of investment

Hydrogen Fueling Station Costs	
Delivery to	**411 Stations**
	Million $/yr
Variable Operating Cost	4.51
Fixed Operating Cost	6.37
Capital Charges	38.21
Total Fueling Station Cost	**49.10**

Source: SFA Pacific, Inc.

Hydrogen Conversions

boxed yellow are key input variables

	Basis					Change below for any size
kg H2	**1.000**	**10**	**100**	**1,000**	**10,000**	**2,413**
Btu HHV	**134,690**	**1,346,900**	**13,469,004**	**134,690,037**	**1,346,900,370**	**324,972,145**
Btu LHV	**113,812**	**1,138,125**	**11,381,248**	**113,812,475**	**1,138,124,750**	**274,600,000**
H2 gas LHV/HHV	**84.5%**	**84.5%**	**84.5%**	**84.5%**	**84.5%**	**84.5%**
standard cubic feet (scf) @ 60°F & 1 atm	**414.5**	**4,145**	**41,447**	**414,466**	**4,144,664**	**1,000,000**
normal cubic meters (Nm3) @ 0°C & 1 atm	**11.1**	**111**	**1,110**	**11,104**	**111,040**	**26,791**
gallons @ standard conditions of 60°F & 1 atm	**3,100**	**31,004**	**310,042**	**3,100,424**	**31,004,242**	**7,480,520**
gallons gaseous H2 @ 400 atm & 60° F	**8.53**	**85**	**853**	**8,526**	**85,262**	**20,571**
gallons liquid H2 phy vol @ 2 atm & -430°F	**3.73**	**37**	**373**	**3,733**	**37,330**	**9,007**
kWh thermal equivalent LHV	**33.3**	**333**	**3,335**	**33,347**	**333,468**	**80,457**
Assumed gasoline Btu/gal HHV	**121,335**	**121,335**	**121,335**	**121,335**	**121,335**	**121,335**
Assumed gasoline LHV/HHV	**93.8%**	**93.8%**	**93.8%**	**93.8%**	**93.8%**	**93.8%**
Assumed gasoline Btu/gal LHV	**113,812**	**113,812**	**113,812**	**113,812**	**113,812**	**113,812**
gallons gasoline energy equiv LHV	**1.000**	**10**	**100**	**1,000**	**10,000**	**2,413**

Note: Essential to use LHV gasoline equivalent due to the 2.5 times larger water vapor energy losses of H2 vs gasoline

Source: SFA Pacific, Inc

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