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HYDROGEN PRODUCTION COSTS - A SURVEY

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1.0 INTRODUCTION

Hydrogen, produced using renewable resources, is an environmentally benign energy carrier that will play a vital role in sustainable energy systems. The US Department of Energy (DOE) supports the development of cost-effective technologies for hydrogen production, storage, and utilization to facilitate the introduction of hydrogen in the energy infrastructure.

International interest in hydrogen as an energy carrier is high. Research, development, and demonstration (RD&D) of hydrogen energy systems are in progress in many countries. Annex 11 of the International Energy Agency (IEA) facilitates member countries to collaborate on hydrogen RD&D projects. The United States is a member of Annex 11, and the U.S. representative is the Program Manager of the DOE Hydrogen R&D Program.

The Executive Committee of the Hydrogen Implementing Agreement in its June 1997 meeting decided to review the production costs of hydrogen via the currently commercially available processes. This report compiles that data.

2.0 CLASSIFICATION OF HYDROGEN PRODUCTION

Hydrogen can be produced from both fossil and renewable resources. Table 2.1 summarizes the various methods of hydrogen production.

Table 2.1: Hydrogen Production Processes

Feedstock	Production Process
Natural Gas	Steam Reforming (SMR) Partial Oxidation (POX)
Heavy Oil	Partial Oxidation (POX)
Coal	Gasification
Biomass	Gasification Pyrolysis
Electricity	Electrolysis
Solar insolation & water	Photoelectrochemical Photochemical
Solar insolation, biological organisms & water	Photobiological

The direct conversion of solar energy into hydrogen via photochemical and photobiological processes are in early stages of development. Similarly, considerable development and technology validation efforts will be required before the commercial feasibility of biomass pyrolysis processes can be definitively established. Thus, these processes are not considered in any depth in this report.

The electricity for electrolysis can be obtained from fossil fuels, hydro-power or renewable resources. At present, low cost electricity is obtained from hydro-electric projects or from off-peak operation of base load generation plants. Electricity together with water are the feedstocks of electrolytic hydrogen production.

The process descriptions and production economics of each of the commercially available processes are described in the following sections.

3.0 STEAM REFORMING

3.1 Process Description

Steam reforming of natural gas (SMR) is the most commonly used process for producing hydrogen in large quantities. Natural gas is reacted with steam at elevated temperatures in the presence of a nickel catalyst supported on alumina. The reaction product is *syngas*- a mixture of hydrogen and carbon monoxide. The syngas is often used as a raw material for the production of other organic chemicals. When hydrogen is the desired product the syngas from the reformer is cooled and fed to a water-gas shift reactor in which carbon monoxide reacts with steam over a catalyst to produce more hydrogen and carbon dioxide, finally to achieve ultra pure hydrogen the gas is sent to a pressure swing absorption unit (PSA). Though wet scrubbing processes using a variety of chemicals were used in the past , the PSA process has become very popular in the newer plants. The PSA process has a lower operating and maintenance cost which generally offsets the world wide higher capital cost. Key companies supplying steam reformer systems is given in Table 3.1. Schematics of a steam reforming operation is shown in Figure 3.1.

Table 3.1: Companies Supplying Steam Reformer Systems

Company
Foster Wheeler Constructors, Inc. (Clinton, NJ, USA)
Haldor Topsoe AS (Copenhagen, Denmark)
Howmar Inc. (Tyler, TX, USA)
Linde AG (Wiesbaden, Germany)
Lurgi AG (Frankfurt, Germany)
MW Kellogg Company (Houston, TX, USA)

Figure 3.1: Block Diagram of Steam Methane Reforming Production Process

3.2 *Production Economics*

Steam methane reforming (SMR) of natural gas to produce hydrogen is a mature technology. Large SMR plants are commonly found in petroleum refineries to produce the hydrogen required in the refinery.

Table 3.2 summarizes the recently published data on capital and operating and maintenance (O&M) costs of large (1.4 - 2.8 million Nm³/day) hydrogen production plants. By-product steam credits are significant for such plants amounting to as much as \$5 million annually. The operating and maintenance costs shown in Table 3.2 include steam byproduct credits. Table 3.3 normalizes the numbers given in Table 3.2 for easy comparison.

Table 3.2: Summary of Literature Data on Capital and Operating Cost - SMR Process

Source: Author, Year [Reference]	Plant Size	Capital Cost (million \$)	O&M Cost	Feedstock Cost	Production Costs
Chemical Engineering Handbook, 1994 [1]	17 billion SCF/year	77	\$0.13/kSCF	\$0.78/kSCF	\$1.51/kSCF
Steinberg & Cheng, 1989 [3]	100x10 ⁶ SCF/day	83.2	\$5.5 million/year	\$39 million/year	\$5.9/MMBtu
Gaudernack et. al., 1996 [4]	120,000 Nm ³ /hour	106.8	\$0.52/Nm ³	\$0.039/Nm ³	\$0.0671/Nm ³
Audus et. al., 1996 [5]	278,000 Nm ³ /hour	262	-	\$2.95/GJ	\$5.6/GJ
Thomas et. al., 1997 [15] - Praxair	267 tonnes/day	180.3	0.2\$/kg	\$1.9/GJ	\$1.0/kg
Thomas et. al., 1997 [15] - Airproducts	267 tonnes/day	73	0.23\$/kg	\$1.9/GJ	\$0.76/kg
IKARUS, 1994 [16]	100,000 Nm ³ /hour	85	-	-	\$5/GJ

Table 3.3: Normalized Literature Data on Capital and O&M Costs - SMR Process

Source: Author, Year [Reference]	Plant Size (Nm ³ /day)	Capital Costs 1997\$	Capital Costs 1997\$ (\$/Nm ³ /day)	O&M (cents/Nm ³)	Feedstock (cents/Nm ³)	Total Production Costs (centsNm ³) (\$/GJ)	
Chemical Engineering Handbook, 1994 [1]	1.4 million Nm ³ /day	83	60	0.45 /Nm ³	2.76 /Nm ³	5.3/Nm ³	4.14/GJ
Steinberg & Cheng, 1989 [3]	2.83 million Nm ³ /day	108	38	0.59 /Nm ³	4.20 /Nm ³	7.2/Nm ³	5.59/GJ
Gaudernack et. al., 1996 [4]	2.88 million Nm ³ /day	110	38	0.52 /Nm ³	3.93 /Nm ³	6.7/Nm ³	5.23/GJ
Audus et. al., 1996 [5]	6.67 million Nm ³ /day	269	40	-	3.78 /Nm ³	7.2/Nm ³	5.60/GJ
Thomas et. al., 1997 [15] - Praxair	2.96 million Nm ³ /day	180	61	1.8 /Nm ³	2.4 /Nm ³	9/Nm ³	7.03/GJ
Thomas et. al., 1997 [15] - Airproducts	3.62 million Nm ³ /day	73	20	2.1 /Nm ³	2.4 /Nm ³	6.8/Nm ³	5.31GJ
IKARUS, 1994 [16]	2.4 million Nm ³ /day	93	39	-	-	8.3/Nm ³	6.48/GJ

A first glance at Table 3.2 suggests that the reported normalized capital costs for SMR plants vary significantly. That is surprising for a mature technology. A more closer examination however, indicates that economies of scale continue to play an important role even in these large scale plants.

There are six estimates (References 3,4,5,15,16) for SMR plants in the size range 2.4 million Nm^3/day to 6.7 million Nm^3/day . The normalized capital costs for four of those plants (References 3,4,5,16) fall within a narrow band of \$35 to \$40 per Nm^3/day suggesting little impact of economies of scale in this size range. The estimates from reference 15, however, differ significantly. The Praxair estimate is at \$61 per Nm^3/day for a 2.96 million Nm^3/day plant is significantly higher. The cost estimate in this case actually represents the costs of three 1 million Nm^3/day plants aggregated to produce the 2.96 million Nm^3/day capacity. Thus, the cost of \$61 per Nm^3/day is more typical of a 1 million Nm^3/day SMR plant. This is also confirmed when we compare that to the SRI estimate (reference 1) of a similar sized plant of \$60 per Nm^3/day . The \$20 per Nm^3/day estimate for the Air Product plant is low compared to the other estimates. The reason for this discrepancy is not clear. Excluding the Air Products estimate, it appears that the normalized capital cost of a 1 million Nm^3/day plant is around \$61 per Nm^3/day , while plants larger than 2.5 million Nm^3/day cost around \$40 per Nm^3/day .

Table 3.3 indicates that at least for 3 cases (references 1, 3, 4) the normalized O&M costs fall in narrow range between 0.45cents/ Nm^3 and 0.59 cents/ Nm^3 . Feedstock costs are not included. The O&M cost estimates for Air Products and Praxair are significantly higher. These cost estimates, however, include O&M cost associated with liquefaction, storage and refueling. There was no easy way to separate there cost components from that of the production component based on the literature data.

The hydrogen production cost depends to a very large extent on the price of the natural gas feedstock. Approximately, 60% of the production cost is attributed to feedstocks, 30% to capital related charges and only 10% to O&M costs.

Capital and operating costs for smaller SMR plants do not decrease proportionately with plant size. The efficiency of the process is unchanged and therefore the raw material needs per unit of hydrogen produced remains the same, though the price of feedstock may be higher for smaller plants. Smaller plants often do not have adequate heat recovery and use systems. Thus, the steam credits commonly associated with large plants are not available. Table 3.3 summarizes the characteristics and available capital cost data associated with the small scale SMR process plant.

Table 3.4: Description of Small Steam Methane Reforming Process

Manufacturer	Production Capacity (MMSCF/day)	Reformer Temperature	Hydrogen Purity	Efficiency	Plant Size and Cost
Halder-Topsoe	0.07 to 3.3	1525°F	99.999% w/PSA	80%	\$500kW, 30' high, 8' wide
Howmar Industries	1 to 5	1550 - 1600°F	99.999% w/PSA	80%	\$3 million for 1 MMSCF/day
Hydro-chem	0.12 to 5	-	99.99% w/PSA	-	40' wide, 40X80' area, 1 million for 120,000 SCF/day
KTI/Air Products and Chemicals Inc.	0.1 to 3	-	99.99% w/PSA	80%	\$3 million for 1 MMSCF/day
International Fuel Cells ONSI	0.05 to 0.150	-	<75% pure hydrogen, Contains H ₂ , CO & CO ₂	84%	10' high, 4' wide, \$500 kWe reformer being developed as part of a PAFC cogen package
Ballard Power Systems	0.006 to 0.12	-	99.99% pure (for use with PEM fuel cell)	80%	being developed as part of a fuel cell package est. \$500/kWe
ONSI/PC-25 unit	0.033	750°F	with PSA, 99.9% pure	-	@0.29 tonnes/day the plant is rated at 477 kW (HHV) and a unit cost of \$500/kW

Installed capital cost of small SMR plants in the range of 28,300 Nm³/day (100,000 SCF/day) can be estimated by Ogden[6] and given by the formula in both terms of SCF and Nm³.

$$\text{INSTALLED COST} = \$3 \times 10^6 * (\text{PLANT CAPACITY IN MILLION SCF/DAY})^{0.3}$$

$$\text{INSTALLED COST} = \$1.03 \times 10^6 * (\text{PLANT CAPACITY IN MILLION Nm}^3/\text{DAY})^{0.3}$$

Figure 3.2: Illustration of Installed Capital Cost of Small SMR Plants as Estimated by Equation

A small SMR plant producing 0.01 million Nm³/day (0.366 million SCF/day) was considered by Ogden. From the equation above, the installed cost of a 0.01 million Nm³/day steam reformer plant could be estimated to be approximately \$2.2 million. This reformer cost will include the reformer, shift reactors, and the PSA unit. Efficiency of up to 85% was estimated to be achievable with these reformers. The operating costs estimates of this plant, given by Ogden is given in Table 3.4.

Table 3.5: Operating and Maintenance Cost of Small SMR Plants

O&M Cost	Cost Parameters	Total Costs (\$/year)	Unit Costs	
			(US cents/Nm ³)	(\$/GJ)
Catalyst	10.65/1000 SCF/H ₂	8683	0.23	0.18
Electricity	0.6 kWh/1000 SCF/H ₂	4809	0.13	0.10
Cooling Water	200 gallons/1000 SCF/H ₂	26,700	0.71	0.55
Boiler Feed Water	40 lbs/1000 SCF/H ₂	712	0.02	0.02
Other O&M Cost	3.5% of installed cost	77,700	2.06	1.61
Raw Material	0.40 MMBtu/1000 SCF/H ₂	213,744	5.65	4.42
Total O&M Cost	-	332,348	8.80	6.88

The ONSI division of IFC Corp. has developed a reformer to supply hydrogen for its 200 kW phosphoric acid fuel cell unit (PAFC). ONSI has shipped more that 100 units of this type plant and provides a realistic picture of the capital cost estimate of small reformers. IFC estimates its 477 kW (HHV) SMR unit will have a capital cost of ~\$240,000, of which ~\$200,000 will be for the reformer and \$41,000 for the PSA unit [15]. The larger plants given in Table 3.2 have a per unit cost in the range of \$250-350/kW, compared to the \$500/kW for the ONSI unit.

The total production cost of hydrogen from such plants was estimated to range from \$10/GJ to \$27/GJ as the plant size decreases from 0.028 million Nm³/day (1 million SCF/day) to 0.0028 Nm³/day (100,000 SCF/day). The fraction of the production cost that is associated with feedstocks becomes predominate in the larger plant. The estimation made in reference [15] estimates the production cost of the IFC/PC-25 unit to be \$13/GJ, with reformer capital cost recovery, feedstock, and O&M cost accounting for 50%, 44%, and 6% respectively.

4.0 ELECTROLYSIS

4.1 Process Description

Water is electrolyzed in an electrochemical cell to produce hydrogen and oxygen. Before the SMR process was introduced water electrolysis was one of the main means of hydrogen production. Water electrolysis is not currently used for large scale hydrogen production in the U.S. or Europe. In countries that do not have ready access to low cost natural gas, electrolyzers are still used to produce hydrogen. Electrolysis is still the primary production technology for the hydrogen supply to the semiconductor and food processing industries. Annual world-wide sales of water electrolyzers are quite limited, being less than 10-15 plants annually.

Alkaline water electrolyzers have been in use commercially for sometime. Both unipolar and bipolar designs are available. Recent advances in alkaline electrolyzers include inorganic membranes, higher current density of operation as well as an improvement in efficiency. Companies that supply alkaline water electrolyzers and their design are listed in Table 4.1.

Table 4.1: List of Companies Supplying Electrolyzer Systems

Company	Technology
Lurgin AG (Frankfurt, Germany)	Alkaline Cells, pressurized
Norsk Hydro AS (Oslo, Norway)	Alkaline Cells, atmospheric
Orauzi de Nora (Milan, Italy)	Alkaline and PEM Cells, atmospheric
Hamilton Standard (Connecticut, USA)	Alkaline and PEM Cells
Teledyne-Brown Engineering(Maryland, USA)	Alkaline Cells, atmospheric
The Electrolyzer Corporation, Ltd. (Ontario, Canada)	Alkaline Cells, atmospheric, bipolar

Figure 4.1 Block Diagram of Electrolysis Production Process

A block diagram of the production process is given in Figure 4.1. Water can be electrolyzed by passing direct current (DC) through it in the presence of a suitable electrolyte, causing positively charged hydrogen ions to migrate to the negatively charged cathode, where they reduce to form hydrogen. Similarly, oxygen is formed at the positively charged anode. Chemically inert conductors such as platinum are used as electrodes to avoid unwanted reactions and the production of impurities in the hydrogen gas.

Current research in to high efficiency electrolysis is being conducted in several areas. Raising the process temperature has the effect of lowering the voltage required to electrolyze the water. Proton exchange membranes in an electrolyzer cell (PEM) separate the electrodes and allows the hydrogen ions to pass through while preventing oxygen, thus splitting the element.

Proton Exchange Membrane (PEM) electrolyzers were first developed by General Electric (GE). Hamilton-Standard purchased the GE technology and has developed systems for defense applications. Packard Instruments uses the Hamilton-Standard PEM technology for very small systems to produce hydrogen for use with gas chromatography. Proton, a spin-off from Hamilton-Standard is developing the PEM electrolyzers technology for civilian applications.

Proton, however, is not alone. The recent increased interest in hydrogen has prompted other companies to focus on PEM electrolyzer development. Major European companies, such as ABB, Siemens, and Oreinzio de Nora have active development programs with some of them installing and operating prototype units in technology validation efforts. A key point that must be made is that world wide interest in PEM fuel cells, the reverse of a PEM electrolyzers, is extremely high. The technology base being established for PEM fuel cell will clearly accelerate PEM electrolyzer development. PEM electrolyzers exhibit higher efficiency while operating at significantly higher current densities when compared to the advanced alkaline electrolyzers. System costs are high and development efforts are focused at reducing costs through technology improvements and mass manufacturing.

High temperature pressurized electrolyzers have the potential for demonstrating performance that is substantially better than PEM systems. However, such systems are still laboratory curiosities and difficult technical hurdles must be overcome before this technology is commercially viable.

In discussing production economics, the focus is clearly on the commercially available alkaline electrolyzers, however, since much analysis of potential costs of PEM electrolyzers are present in the available literature, a brief analysis of those cost projections are included.

4.2 Production Economics

Table 4.2 lists the plant size, capital costs and the hydrogen production costs for alkaline water electrolyzers that are available in the literature.

Table 4.2: Electrolyzer Plant Description and Costs

Source: Author, Year [Reference]	Plant Size	Capital Costs	Unit Costs 1997 \$	Efficiency	Production Costs
Audus et. al., 1996 [5]	278,000Nm ³ /hour ~1,000 MW (HHV)	\$811 million	~834 \$/kW	64% LHV	\$20.1/GJ
Cloumman et. al., 1996 [9]	265 MW	NOK 1,100 million	617\$/kW	65% LHV	NOK 1.0/Nm ³ \$11.3/GJ
Flour Daniel, 1991 [10]	100MW _{in} , 60 MW _{out}	\$770/kW	\$712/kW	71.6% LHV	-
Electrolyzer Corp. [11]	100MW _{in} , 67 MW _{out}	\$590/kW	\$624/kW	80% HHV	-
Steinberg & Cheng, 1989 [3]	100 MMSCF/day ~410 MW (HHV)	\$132 million, \$186 million(97\$)	- 454/kW(97\$)	80% HHV	\$19.4GJ \$23.8/GJ (97\$)
Thomas, 1997 [15] - Electrolyzer, Corp.	51 ton/day, 83 MW (HHV)	\$52.9 million	630\$/kW	-	2.5\$/kg \$17.6/GJ

Reference [5] provides the actual cost data of a ~1,000 MW plant built and operated in Norway. We were cautioned that the capital cost incurred in constructing this plant will be on the higher side compared to the costs seen in the U.S. The capital cost estimates for a one-of-a-kind, 83 MW plant made by Electrolyzer Corp is ~\$630/kW, compared to the Norsk Hydro plant cost of ~\$811/kW. Other references listed in Table 4.2 also suggest the capital cost of the electrolyzer system seem to be in the range of ~\$600/kW, for the 100 MW scale plants.

Smaller electrolysis plants given in Table 4.3 have larger per unit capital cost. Due to the higher capital cost of these units, the smaller plants are typically designed for home use to power hydrogen cars. Due to the higher electricity prices in the residential sector the production cost of these smaller units can be as high as \$50/GJ.

Table 4.3: Small Eletrolyzer Plant Description and Costs

Source: Author, Year [Reference]	Plant Size	Capital Costs	Unit Costs 1997 \$	Effiency	Production Costs
Moore et. al., 1996 [5]	3kg/day ~5kW (HHV)	\$13,500 to \$23,000	3000 to 5000 \$/kW	65%	\$7 kg 49.1 \$/GJ
Berry, 1996 [17]	0.8kg/day ~1.3kW (HHV)	\$3500	\$2700 \$/kW	50%	--
Thomas et. al., 1997	2.72kg/day ~4.5kW (HHV)	--	4371 \$/kW (LHV) 3800 \$/kW (HHV)	65.7%	\$6 kg continuous operation \$4 kg Off-peak (12 hr) operation

The O&M costs, apart from feedstock (electricity), for electrolysis is small. Large electrolysis plants are generally well automated, requiring two operators per shift during normal operation of a 265 MW plant and a crew of four during regularly scheduled maintenance[3]. Electrode reactivation is normally carried out every five to seven years for alkaline electrolyzers. A certain number of electrolyzers are taken off-line each year for electrode reactivation. Compressors in the system also require periodic maintenance and small amounts of potassium hydroxide are also required for replenishment. Thus, the sum total of O&M costs, apart from the electricity costs is quite small. Estimates available in the literature are summarized in Table 4.3.

Table 4.4: Operating Costs of Alkaline Electrolyzer Plants

Source: Author, Year [Reference]	Plant Size	O&M Costs	Unit O&M Costs
Cloumman et. al., 1996 [9]	265 MW, ~396 million Nm ³ /year	43 millionNOK/year, \$6.23 million	1.57 cents/Nm ³ (11 cents/GJ)
Steinberg & Cheng, 1989 [3]	100x10 ⁶ SCF/day, ~928 million Nm ³ /year	\$5.68 million, \$8 million (97\$)	- 0.86 cents/Nm ³ (6 cents/GJ)
Thomas et. al., 1997 [15]	2.72 kg/day	-	Feedstock-\$27.5/GJ, capital recovery-\$8.8/GJ, O&M-\$1.7/GJ

Oxygen is the by-product of water electrolysis. Whether any credit can be taken for the oxygen produced depends very much on the demand for this by-product in close proximity to the plant. For the purposes of this report no by-product credit for the oxygen has been considered.

The cost of electricity determines, to a very large extent, the production cost of electrolytic hydrogen. Typically, electrolytic hydrogen, from advanced alkaline water electrolyzers with efficiencies in the range of 65 - 75%, cost around \$20 to \$30/GJ depending on the price of electricity. Approximately 70 to 80% of the cost is attributable to electricity cost, while capital related charges amount to as little as 15 - 20%. Costs associated with O&M amount to approximately 5% of the production cost.

PEM electrolyzers are not commercially available although some firms are supplying prototype systems for technology validation purposes. The capital cost data for PEM systems reported were based mainly on analytical studies and have not yet been demonstrated at actual plants. The available data is summarized in Table 4.4.

Table 4.5: Capital and Operating Costs of PEM Electrolyzer Plants

Source: Author, Year [Reference]	Plant Size/	Capital Costs	Efficiency
Stone & Webster, [11]	17.5MW _{in} , 100 MW _{out}	\$850/kW	67.5% LHV
FSEC, 1990 [12]	-	-	-
Los Alamos, [11]	530 MW _{in} , 360 MW _{out}	\$410/kW	80% HHV
Thomas, et. al., (1995) [11]	4 kW _{in} , 3 kW _{out}	\$300/kW	80% HHV
Hamilton Standard, [11]	12lbs/day, 7.55kW _{out}	\$330/kW	-

5.0 GASIFICATION AND PARTIAL OXIDATION

5.1 Process Description

Gasification and Partial Oxidation processes convert hydrocarbons via reaction with steam and oxygen into H_2 , CO , and CO_2 . Partial oxidation (POX) is the term used when gaseous (methane) or liquid (heavy oil) is the feedstock, while gasification is the term used when solid feedstocks, such as coal or biomass are required. Handling solid feedstocks, as well as, the residue ash that results, makes the gasification process more complex and adds significantly to the capital cost. Companies that supply partial oxidation systems are listed in Table 5.1.

Table 5.1: List of Companies Supplying Partial Oxidation Systems

Company	Technology
Shell Oil Company (Houston, TX, USA)	Partial Oxidation
Texaco Inc.	Partial Oxidation

The POX reaction occurs in the presence of a catalyst at approximately $600^{\circ}C$. Feedstocks ranging from methane to naphtha can be used. Currently it is more economical to use the SMR process for low molecular cost hydrocarbons such as natural gas, and the POX process for heavy oils. New technology development including ceramic membrane reactor systems are in progress that potentially could reduce POX process cost to the point where it would be very competitive with SMR even for low molecular weight hydrocarbons.

Figure 5.1 shows a flow diagram of a POX process. There are essentially three segments, namely: syngas preparation, water-gas shift reaction, and gas purification. The POX requires an oxygen plant (air separation), the shift reactor, and gas separation units larger than those required for a SMR process. Capital cost requirements are therefore higher than the comparable SMR plant. The yield of a POX plant is however, higher than that of SMR and a trade off of capital investment versus efficiency is an important issue when evaluating a POX plant.

Figure 5.1: Block Diagram of Partial Oxidation Production Process

Gasification, in contrast to POX, occurs at a much higher temperature (approximately 1,100 to 1,300°C) in the absence of any catalyst. Coal is the most commonly used fossil fuel in gasification, although biomass gasification is also becoming a commercial reality. Kopper-Totzek and Texaco gasification processes are commercially available. Figure 5.2 provides a simplified flow diagram for the two processes.

Figure 5.2: Block Diagram of Hydrogen Production from Coal Gasification

[A] Koppers Totzek [B] Texaco

Gasification in the Koppers-Totzek process occurs at atmospheric pressure, while the Texaco gasifier operates at approximately 800 psig. The syngas is then desulfurized, shifted and purified in subsequent steps. The need to handle a solid fuel (coal) and to deal with large amounts of ash makes coal gasification a very complex and capital intensive process.

Biomass gasification not only has to deal with the same issues but must include an additional step of drying the biomass to reduce the moisture content from as high as 70%. Considerable work on biomass gasification is also in progress. Both fixed and fluidized bed biomass gasifiers have been operated. Fixed bed updraft gasifiers of the Lurgi Mak IV type have been used for high bulk

density biomass. Fluidized bed gasifiers, on the other hand demonstrate greater fuel flexibility and higher through-put capabilities than fixed bed systems. Reiubraum-Uhde (Germany) and IGT-Rengas (USA) have operated bubbling bed gasifiers with biomass. Similarly, circulative bed gasifiers developed by Lurgi, Alslhom, and Battelle among others have operated successfully with biomass resources. Biomass, is either dried and introduced directly into the gasifier or can be pyrolyzed to convert it into oil, which is then fed to a gasifier. Simplified flow diagrams of the two approaches are shown in Figure 5.3.

Figure 5.3: Block Diagram of Hydrogen Production from Biomass Gasification

(A) Pyrolysis Followed by Partial Oxidation in the Texaco Gasification

(B) High Pressure Gasification followed by Steam Reformation

5.2 Production Economics

Capital costs for POX and gasification processes are higher than SMR or electrolysis, while the feedstock prices, heavy oil, and coal are lower. Consequently, capital costs begin to contribute more to the overall production costs. Biomass costs vary substantially depending on the type, nonetheless the trend observed with oil and coal is also valid for biomass.

If hydrogen is to play a role in transportation, distributed refueling stations will be required. Partial oxidation systems operating on natural gas resources may be an alternative. Thus cost

estimates of small POX plants have been considered in the analysis. In contrast small gasification plants are known to be highly non economically viable and are therefore not considered in the analysis.

Table 5.2 lists the Capital and O&M costs associated with different POX and gasification processes. POX of heavy oil and coal gasification are commercial processes. The cost estimates are based on considerable experiences. Biomass gasification to produce hydrogen on the other hand has not been operated commercially. The sub-systems of the overall process have been in commercial operation and thus cost estimates are considered to be reliable. Biomass pyrolysis, however, is still in the development stage and the confidence level in the cost estimates therefore are lower.

Table 5.2: Gasification and Partial Oxidation Plant Description and Costs

Source: Author, Year [Reference]	Plant Size	Raw Material	Cap. Cost (million \$)		O&M	Production Cost
			POX	Gasification		
Steinberg & Cheng, 1989 [3]	100x10 ⁶ SCF/day	Heavy Oil	204	-	~\$1.9/GJ	3.10/kSCF (\$9.13/GJ)
Steinberg & Cheng, 1989 [3]	100X10 ⁶ SCF/D	Coal		316	~3/GJ	\$4.19/kSCF (\$12.3/GJ)
Audus et. al., 1996 [5]	278,000 Nm ³ /hour	Coal		859	-	\$10.3/GJ
Chemical Engineering Handbook, 1994 [1]	50x10 ⁶ SCF/day	-	58	-	fuel -\$3.7/GJ O&M-\$3.7/GJ	-
Moore et. al., 1996 [7]	2.7 tons/day	Heavy Oil	12.5			\$3.96/kg (\$28/GJ)
Spath, 1997 [13] - IGT gasifier	1,500 tons/day	Biomass Pyrolysis	-	~235	-	\$22/GJ
Spath, 1997 [13] - Texaco gasifier	1500tons/day	Biomass	-	~200	-	\$21/GJ
Mann, 1995 [14]	27 tons/day	Biomass	-	6.8	-	\$23/GJ
Mann, 1995 [14]	907 tons/day	Biomass	-	90	-	\$13/GJ
IKARUS report, 1994 [16]	100,000 Nm ³ /hour	Heavy Oil	210	-	-	\$7.7/GJ
IKARUS report, 1994 [16]	100,000 Nm ³ /hour	Coal	-	460	-	\$11/GJ

Despite its lower feedstock cost, coal gasification process with its high capital cost is more expensive than the POX process of heavy fuels. The unit cost of POX equipment is almost half of that of the coal gasification equipment. For modeling purposes the capital cost of coal gasifiers and POX equipment was assumed to be \$400 million and \$248 million respectively for a 100 MMSCF/day plant. The per unit capital cost of a biomass gasifier (IGT gasifier) is almost similar to those of the coal gasifier, with no actual plants in existence for either of these technologies.

The total production cost of a POX process is of the order of \$8-11/GJ, while coal gasification process is projected to be \$10-13/GJ. Large biomass gasification process cost between \$13-23/GJ, with no actual plant built to date.

6.0 MODELING OF PRODUCTION COSTS

Steinberg and Cheng of Brookhaven National Laboratory in 1989 created a model¹ to compute the various cost components in different hydrogen production technologies, and to establish a realistic price for hydrogen manufactured by each technology.

This report will update those numbers to reflect today's conditions. The capital and operating cost parameters established through literature surveys and personal communication with experts. Five production processes will be modeled. The processes modeled, their production capacity, and their installed capital costs used in the model are listed in Table 6.1. The other assumptions of the model are given in Table 6.2.

Table 6.1: Description of Production Processes Modeled

Production Technology	Production Capacity	Installed Capital Cost
Steam Reformation -Natural Gas	2.83 million Nm ³ /day (100 million SCF/day)	\$110 million
Electrolysis	2.83 million Nm ³ /day (100 million SCF/day)	\$250 million
Partial Oxidation of Fuel Oil	2.83 million Nm ³ /day (100 million SCF/day)	\$248 million
Gasification of Coal	2.83 million Nm ³ /day (100 million SCF/day)	\$400 million
Gasification of Biomass	1.31 million Nm ³ /day (46 million SCF/day)	\$235 million

Incorporating the data in to the model provides interesting insights of the cost constituents of the five hydrogen production technologies. Detail model run outputs are provided in Annex 1. Figure 4.1 illustrates the total cost of hydrogen production under three categories; feedstock cost, operating and maintenance cost, and capital and investment returns.

Figure 6.1: Hydrogen Production Cost Constituents by Technology Type (in \$/GJ)

¹ Modern and prospective Technologies for Hydrogen Production from Fossil Fuels. M.Steinberg and H.Cheng. International Journal of Hydrogen Energy, Vol. 14, No.11. 1989

Table 6.2: Hydrogen Production Cost - Data Sheet and Assumptions

A. Steam Reformation - natural gas,	Conversion Efficiency =	78.5% based on HHV
B. Electrolysis - Alkaline electrolyzer,	Conversion Efficiency =	80.0% based on HHV
C. Texaco Gasifier - coal,	Conversion Efficiency =	48.0% based on HHV
D. Partial Oxidation - natural gas,	Conversion Efficiency =	89.0% based on HHV
E. Gasification - Biomass,	Conversion Efficiency =	57.8% based on HHV
Capacity:	2.83 million Nm3 per day - all plants except biomass gasifier (100 million SCF/ day) 1.31 million Nm3 per day for biomass gasifier (46 million SCF/day)	
Plant Operating Factor:	328 day per year	
Annual Production in GJ (HHV):	11,870,000 GJ (10.6x10 ⁶ MBtu, 928 million Nm3, 83.6 million kg) 5,486,000 GJ (4.9x10 ⁶ MBtu, 429 million Nm3, 38.6 million kg)	
Facility & Equipment Cost:*	110 For technology "A" in millions of dollars (1997\$) 250 For technology "B" in millions of dollars (1997\$) 400 For technology "C" in millions of dollars (1997\$) 248 For technology "D" in millions of dollars (1997\$) 235 For technology "E" in millions of dollars (1997\$)	
Life of plant in years:	20	
Depreciation of Plant:	5% per year straight line basis	
Capital Structure	100% equity	
Return on Investment:	20% return on investment before taxes	
Cost Assumptions		
Interest during construction	10% of Facility investment	
Start up Expenses	2% of Facility investment	
Working Capital	2 month's expenses on feedstock, utilities, and wages	
Total capital investment	Facility, IDC, start up expenses, and working capital	
Operating Labor cost	40,000 \$/man-year	
Supervisor cost	15% of labor cost	
Maintenance Labor cost	2% of Facility investment	
Material	2% of Facility investment	
Administrative Labor	20% of operating and maintenance labor	
Fringe & Benefits	20% of all labor	
Insurance	2% of Facility investment	
General Administrative Expenses	2% of Facility investment	
Cost of Inputs & Prices of By-products		
Feedstock Prices:	Coal	40 \$/ton 1.235 \$/GJ
	Natural Gas	2.28 \$/10 ⁶ Btu 2.167 \$/GJ
	Fuel Oil	2.97 \$/10 ⁶ Btu 2.823 \$/GJ
	Electricity	0.05 \$/kWh 13.9 \$/GJ
	Hydroelectricit	0.02 \$/kWh 5.6 \$/GJ
	Biomass	46 \$/dry tonne 2.38 \$/GJ
Process Water	0.5 \$/1000 gallons	
Cooling water	0.5 \$/1000 gallons	
Clean up of Coal gasification	1.26 \$/ton of coal burnt	
Clean up of POX process - fuel oil	3.94 cents/GJ	
Byproduct Credit:	Sulfur	100 \$/ton
	Steam	5 \$/1000 lbs
	Power	0.03 \$/kWh
	Oxygen	40 \$/ton
Conversion Factors		
HHV of Hydrogen	142 MJ/kg of hydrogen	1 MBtu = 1.052 GJ
	12.8 MJ/Nm3	1 Nm3 = 35.3 CF
	362 kJ/SCF	Heat content of biomass 19.3 GJ/ton
LHV of Hydrogen	121 MJ/kg of hydrogen	Heat content of coal (bitum:)
	10.9 MJ/Nm3	32.4 GJ/ton
	309 kJ/SCF	
Weight per unit volume (NTP)	393 CF/kg	

The plots assume a 5 cents/kWh electricity cost, which is the typical electricity prices paid by large industrial customers in the U.S. This cost of electricity has the largest impact in the electrolysis process, accounting for close to 68% of the cost of production. A 3 cents/kWh electricity price drops the production cost from 25.7 \$/GJ to 18.6 \$/GJ, with feedstock portion of the cost dropping to 56% of the cost.

Table 6.3 lists the capital cost and production cost for each of the technologies for the base case considered, with the assumptions in Table 6.2.

Table 6.3: List of Capital Cost and Production Cost for each of the Technologies - Base Case

Production Technology	Installed Capital Cost	Production Cost
Steam Reformation -Natural Gas	\$110 million	\$ 6.6/GJ
Electrolysis	\$250 million	\$25.8/GJ
Partial Oxidation of Fuel Oil	\$248 million	\$11.3/GJ
Gasification of Coal	\$400 million	\$15.9/GJ
Gasification of Biomass	\$235 million	\$21.7/GJ

Table 6.4: Cost Constituents of the Five Production Processes

Production Process	Percentage of Total Cost			Total Cost (\$/GJ)
	Feedstock	Capital Recovery & ROI	O & M	
Steam Reforming - natural gas	42%	41%	17%	6.56
Electrolysis - electricity	68%	25%	8%	25.8
Partial Oxidation - fuel oil	28%	52%	10%	11.3
Gasification - coal	16%	59%	25%	15.9
Gasification - biomass	19%	56%	25%	21.68

In order to analyze the sensitivity of the production cost to the variation of constituent costs various sensitivity analysis were performed. The variation of the base costs listed in Table 6.3 to the variation in the capital cost, feed stock prices, and return on investment were analyzed. A 10% favorable and adverse variation of these 3 parameters were analyzed.

The base case production cost illustrates that SMR process for hydrogen production is the most economical, with a production cost of \$6.6/GJ for large central plants. The most expensive mode of production is electrolysis. The POX, coal and biomass gasification processes economics lies in between, with almost equal spread between the five production costs.

When the three cost drivers of the production processes were varied $\pm 20\%$ on parameter at a time, the variation in production costs were not significant enough to displace the economic ranking order of the 5 production processes.

As illustrated in Figure 6.1 and Table 6.4, the electrolysis process is most sensitive to feedstock prices. A 10% increase in feedstock prices (an electricity price increase from 5 cents/kWh) in the electrolysis process increases the hydrogen production cost by 6.6%, compared to a 1.5% increase in coal gasification production costs.

With a 20% post-tax return on investment assumed in the base case, recovery of capital cost and return on investment is the predominant cost component for high capital cost processes such as coal and biomass gasification.

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APPENDIX: STEINBERG AND CHENG MODEL RUNS

Hydrogen Production Cost using Steam Reformation of Natural Gas

Annual Hydrogen Production Capacity 11,870,000 GJ (HHV)

CAPITAL COST (in millions of dollars, 1997\$)

Equipment & Facility (includes reformer, desulfurization, heat recovery, shift converter, PSA and other related equipment, building and facility)		110.0
Interest During Construction:	10% of facility investment	11
Start up Expenses	2% of facility investment	2.2
Working Capital	2 months of expenses	7.69
Total Capital Required (in millions of 1997\$)		<u>130.9</u>

Annual Operating Cost (in millions of dollars, 1997\$)

Feedstock Consumption		32.8	42.1%
(@ 78.5% efficiency (HHV)	15,121,019 GJ of natural gas)		
15,121,019 GJ @ a natural gas price of	2.167 \$/GJ)		
Utilities			
Power:	32.4 GWh @	0.05 \$/kWh	1.62 2.1%
Process Water	310 million gallons@	0.5 \$/1000 gallons	0.16 0.2%
Cooling water	440 million gallons@	0.5 \$/1000 gallons	0.22 0.3%
Operation			
Operators:	17 operators @	40,000 \$/per man year	0.68 0.9%
Supervisors:	15% of operator labor cost		0.10 0.1%
Maintenance:			
Labor	2% of facility investment	2.20	2.8%
Supervisors:	15% of maintenance labor cost	0.33	0.4%
Material:	2% of facility investment	2.20	2.8%
Administrative & Support Labor	20% of all labor	0.66	0.9%
Fringe Benefits	20% of all labour	0.79	1.0%
Insurance	2% of facility investment	2.20	2.8%
General and Administration	2% of facility investment	2.20	2.8%
Annual Operating Cost (in millions of dollars, 1997\$)		<u>46.1</u>	59.3%

Return on Investment

Depreciation: facility depreciated at	5% per year	5.5	7.1%
Return on Investment:	20% on capital invested	26.18	33.6%

TOTAL REVENUE REQUIREMENT PER YEAR (in millions of dollars) 77.8 100.0%

ANNUAL HYDROGEN PRODUCTION (in GJ) 11,870,000
(in millions of kg) 83.6

COST PER UNIT HYDROGEN	(in \$/GJ)	6.56
	(in \$/kg)	0.93

Comparison: Electricity @ 5 cents/kWh is equivalent to 13.9 \$/GJ in energy terms

APPENDIX: STEINBERG AND CHENG MODEL RUNS

Hydrogen Production Cost with Alkaline Electrolysis

Annual Hydrogen Production Capacity 11,870,000 GJ (HHV)

CAPITAL COST (in millions of dollars, 1997\$)

Equipment & Facility (includes reformer, desulfurization, heat recovery, shift converter, PSA and other related equipment, building and facility)	250.0
Interest During Construction: 10% of facility investment	25
Start up Expenses 2% of facility investment	5
Working Capital 2 months of expenses	38.35
Total Capital Required (in millions of 1997\$)	<u>318.4</u>

Annual Operating Cost (in millions of dollars, 1997\$)

Feedstock Consumption	206.1	67.3%
(@ 80.0% efficiency (HHV) 14,837,500 GJ of electricity equiv)		
14,837,500 GJ @ a electricity price of 13.9 \$/GJ)		
Utilities		
Power: 0 GWh @ 0.05 \$/kWh	0.00	0.0%
Process Water 200 million gallons @ 0.5 \$/1000 gallons	0.10	0.0%
Cooling water 0 million gallons @ 0.5 \$/1000 gallons	0	0.0%
Operation		
Operators: 10 operators @ 40,000 \$/per man year	0.4	0.1%
Supervisors: 15% of operator labor cost	0.06	0.0%
Maintenance:		
Labor 2% of facility investment	5.00	1.6%
Supervisors: 15% of maintenance labor cost	0.75	0.2%
Material: 2% of facility investment	5.00	1.6%
Administrative & Support Labor 20% of all labor	1.24	0.4%
Fringe Benefits 20% of all labour	1.49	0.5%
Insurance 2% of facility investment	5.00	1.6%
General and Administration 2% of facility investment	5.00	1.6%
Annual Operating Cost (in millions of dollars, 1997\$)	<u>230.1</u>	75.1%
<u>Return on Investment</u>		
Depreciation: facility depreciated at 5% per year	12.5	4.1%
Return on Investment: 20% on capital invested	63.67	20.8%
TOTAL REVENUE REQUIREMENT PER YEAR (in millions of dollars)	306.3	100.0%
ANNUAL HYDROGEN PRODUCTION (in GJ)	11,870,000	
(in millions of kg)	89.2	
COST PER UNIT HYDROGEN (in \$/GJ)	25.80	
(in \$/kg)	3.43	

Comparison: Electricity @ 5 cents/kWh is equivalent to 13.9 \$/GJ in energy terms

APPENDIX: STEINBERG AND CHENG MODEL RUNS

Hydrogen Production Cost using the Texaco Gasifier using Coal

Annual Hydrogen Production Capacity 11,870,000 GJ (HHV)

CAPITAL COST (in millions of dollars, 1997\$)

Equipment & Facility		400.0
Interest During Construction:	10% of facility investment	40
Start up Expenses	2% of facility investment	8
Working Capital	2 months of expenses	12.75
Total Capital Required (in millions of 1997\$)		<u>460.8</u>

Annual Operating Cost (in millions of dollars, 1997\$)

Feedstock Consumption		30.5	16.2%
(@ 48.0% efficiency (HHV)	24,729,167 GJ of coal)		
24,729,167 GJ @ a bituminous coal price of	1.235 \$/GJ)		
Utilities			
Power:	0 GWh @	0.05 \$/kWh	0.00 0.0%
Process Water	0 million gallons@	0.5 \$/1000 gallons	0.00 0.0%
Cooling water	11,600 million gallons@	0.5 \$/1000 gallons	5.8 3.1%
Clean up	0.763 M tons of coal@	1.26 \$/ton of coal burnt	0.96 0.5%
Operation			
Operators:	30 operators @	40,000 \$/per man year	1.2 0.6%
Supervisors:	15% of operator labor cost		0.18 0.1%
Maintenance:			
Labor	2% of facility investment	8.00	4.2%
Supervisors:	15% of maintenance labor cost	1.20	0.6%
Material:	2% of facility investment	8.00	4.2%
Administrative & Support Labor	20% of all labor	2.12	1.1%
Fringe Benefits	20% of all labour	2.54	1.3%
Insurance	2% of facility investment	8.00	4.2%
General and Administration	2% of facility investment	8.00	4.2%
Annual Operating Cost (in millions of dollars, 1997\$)		<u>76.5</u>	40.6%
Return on Investment			
Depreciation: facility depreciated at	5% per year	20	10.6%
Return on Investment:	20% on capital invested	92.15	48.8%
TOTAL REVENUE REQUIREMENT PER YEAR (in millions of dollars)		188.7	100.0%
ANNUAL HYDROGEN PRODUCTION	(in GJ)	11,870,000	
	(in millions of kg)	83.6	

COST PER UNIT HYDROGEN	(in \$/GJ)	15.90
	(in \$/kg)	2.26

Comparison: Electricity @ 5 cents/kWh is equivalent to 13.9 \$/GJ in energy terms

APPENDIX: STEINBERG AND CHENG MODEL RUNS

Hydrogen Production Cost by Partial Oxidation of Fuel Oil

Annual Hydrogen Production Capacity 11,870,000 GJ (HHV)

CAPITAL COST (in millions of dollars, 1997\$)

Equipment & Facility		248.0
Interest During Construction:	10% of facility investment	24.8
Start up Expenses	2% of facility investment	4.96
Working Capital	2 months of expenses	10.67
Total Capital Required (in millions of 1997\$)		<u>288.4</u>

Annual Operating Cost (in millions of dollars, 1997\$)

Feedstock Consumption		37.7	28.1%
(@ 89.0% efficiency (HHV)	13,337,079 GJ of fuel oil)		
13,337,079 GJ @ a fuel oil price of	2.823 \$/GJ)		
Utilities			
Power:	11 GWh @ 0.05 \$/kWh	0.55	0.4%
Process Water	964 million gallons@ 0.5 \$/1000 gallons	0.48	0.4%
Cooling water	- million gallons@ 0.5 \$/1000 gallons	0	0.0%
Clean up	13,337,079 GJ of fuel oil 3.94 cents/GJ of fuel oil	0.53	0.4%
Operation			
Operators:	26 operators @ 40,000 \$/per man year	1.04	0.8%
Supervisors:	15% of operator labor cost	0.16	0.1%
Maintenance:			
Labor	2% of facility investment	4.96	3.7%
Supervisors:	15% of maintenance labor cost	0.74	0.6%
Material:	2% of facility investment	4.96	3.7%
Administrative & Support Labor	20% of all labor	1.38	1.0%
Fringe Benefits	20% of all labour	1.66	1.2%
Insurance	2% of facility investment	4.96	3.7%
General and Administration	2% of facility investment	4.96	3.7%
Annual Operating Cost (in millions of dollars, 1997\$)		<u>64.0</u>	47.7%
Return on Investment			
Depreciation: facility depreciated at	5% per year	12.4	9.2%
Return on Investment:	20% on capital invested	57.69	43.0%

TOTAL REVENUE REQUIREMENT PER YEAR (in millions of dollars) 134.1 100.0%

ANNUAL HYDROGEN PRODUCTION (in GJ) 11,870,000
(in millions of kg) 83.6

COST PER UNIT HYDROGEN	(in \$/GJ)	11.30
	(in \$/kg)	1.60

Comparison: Electricity @ 5 cents/kWh is equivalent to 13.9 \$/GJ in energy terms

APPENDIX: STEINBERG AND CHENG MODEL RUNS

Hydrogen Production Cost by Biomass Gasification

Annual Hydrogen Production Capacity 5,486,000 GJ (HHV)

CAPITAL COST (in millions of dollars, 1997\$)

Equipment & Facility	235.0
Interest During Construction:	10% of facility investment 23.5
Start up Expenses	2% of facility investment 4.7
Working Capital	2 months of expenses 8.80
Total Capital Required (in millions of 1997\$)	<u>272.0</u>

Annual Operating Cost (in millions of dollars, 1997\$)

Feedstock Consumption		22.6	19.0%
(@ 57.8% efficiency (HHV)	9,491,349 GJ of biomass)		
9,491,349 GJ @ a biomass price of	2.383 \$/GJ)		
Utilities			
Power:	150 GWh @	0.05 \$/kWh	7.50 6.3%
Process Water	0.156 million gallons@	0.5 \$/1000 gallons	0.00008 0.0%
Cooling water	- million gallons@	0.5 \$/1000 gallons	0 0.0%
Clean up	- GJ of fuel oil	3.94 cents/GJ of fuel oil	0.00 0.0%
Operation			
Operators:	12 operators @	40,000 \$/per man year	0.48 0.4%
Supervisors:	15% of operator labor cost		0.07 0.1%
Maintenance:			
Labor	2% of facility investment		4.70 4.0%
Supervisors:	15% of maintenance labor cost		0.71 0.6%
Material:	2% of facility investment		4.70 4.0%
Administrative & Support Labor	20% of all labor	1.19	1.0%
Fringe Benefits	20% of all labour	1.43	1.2%
Insurance	2% of facility investment	4.70	4.0%
General and Administration	2% of facility investment	4.70	4.0%
Annual Operating Cost (in millions of dollars, 1997\$)		<u>52.8</u>	44.4%

Return on Investment

Depreciation: facility depreciated at	5% per year	11.75	9.9%
Return on Investment:	20% on capital invested	54.40	45.7%

TOTAL REVENUE REQUIREMENT PER YEAR (in millions of dollars) 119.0 100.0%

ANNUAL HYDROGEN PRODUCTION (in GJ) 5,486,000
(in millions of kg) 38.6

COST PER UNIT HYDROGEN	(in \$/GJ)	21.68
	(in \$/kg)	3.08

Comparison: Electricity @ 5 cents/kWh is equivalent to 13.9 \$/GJ in energy terms