Technological Characterisation of Hydrogen Production Technologies

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Table of contents

1 Introduction ... 3

2 Steam Methane Reforming ... 4
2.1 Overview ... 4
2.2 Discussion of Data ... 4
2.2.1 Economies of scale ... 8
2.2.2 Effect of CO_2 capture ... 8
2.2.3 Sensitivity to natural gas price ... 8
2.3 Future Trends ... 10
2.3.1 Cost savings & learning effects ... 10
2.3.2 New technologies ... 10
2.4 Uncertainties ... 11

3 Coal Gasification ... 12
3.1 Overview ... 12
3.2 Discussion of data ... 13
3.2.1 Economies of scale ... 15
3.2.2 Effect of CO_2 capture ... 15
3.2.3 Co-production of power ... 15
3.2.4 Effect of coal price ... 15
3.3 Future trends ... 15
3.3.1 New technologies ... 15
3.4 Uncertainties ... 16

4 Biomass Gasification and Pyrolysis ... 17
4.1 Overview ... 17
4.2 Discussion of data ... 17
4.2.1 Economies of scale ... 21
4.2.2 Effect of technology ... 21
4.2.3 Effect of feedstock cost ... 22
4.2.4 Effect of co-production ... 22
4.2.5 Effect of CO_2 capture ... 22
4.2.6 Economic assumptions ... 22
4.3 Future trends ... 23
4.3.1 Cost savings, learning effects ... 23
4.3.2 New technologies ... 23

5 Electrolysis ... 24
5.1 Overview ... 24
5.2 Discussion of data ... 25
5.2.1 Effect of electricity price ... 27
5.2.2 Economies of scale ... 27
5.2.3 Effect of renewable energy sources and interaction with the grid ... 27
5.2.4 Nuclear power and large-scale electrolysis ... 28
5.3 Future trends ... 28
5.3.1 Improvements, cost savings, learning effects ... 28
5.3.2 New technologies ... 28

6 Environmental aspects of Hydrogen production ... 30

7 Summary and Conclusions ... 34

8 References: ... 35

1 Introduction

Hydrogen has been hailed by some as a solution to the problems of energy security, climate change and air pollution (Rifkin 2002). However, if hydrogen is seen as a significant energy vector for the future, the fundamental and immediate question is "how will it be produced". This question contains within it many others such as what is the primary energy source? What technologies are needed? How expensive is it likely to be?

This paper provide a review of four major production pathways: Steam Methane Reforming (SMR), coal gasification, biomass gasification or pyrolysis, and electrolysis, focusing on the technologies used and the hydrogen production costs.

To accommodate the various and competing visions of a 'hydrogen economy', a set of six 'hydrogen visions' have been developed by PSI for the UK Sustainable Hydrogen Energy Consortium, to serve as a framework for discussion and analysis. It is expected that the cost and technology data presented here will inform quantitative assessments of the various costs and benefits of these different visions.

Many studies have looked at hydrogen production costs. However assumptions vary between studies, and there are no agreed standards for analysis or reporting results which makes comparison across studies difficult. The H2A model (H2A 2005), being developed by the US Department of Energy, is seeking to establish common standards for analysis and reporting, which should make future comparisons easier, and results more robust.

Here costs are presented in US dollars, adjusted to a base year of 2000. Quantity of hydrogen is given in GJ, and production rate is given in MW. The 'size' or 'scale' of a hydrogen production plant refers to the production rate. Conversion factors are given in Table 1.1, which also includes comparisons with natural gas.

		Hydrogen (HHV)			Natural gas (HHV)		
		kg	MJ	Nm^3	kg	MJ	Nm^3
1	kg	1	142	11.1	1	28.1	1.41
1	GJ	7.04	1000	78.4	35.6	1000	25.3
		kg/h	Nm3/h		kg/h	Nm3/h	
1	MW	25.4	282		128	181	

1GJ = 0.95 MMBtu = 277.8 kwH

Table 1.1:Conversion factors for hydrogen and natural gas

Where the costs of CO_2 capture have been reported, it usually refers only to the separation of CO_2 at the plant, and does not include the cost of CO_2 transport and sequestration. CO_2 sequestration specifically for emissions reduction has not been demonstrated on any sizeable scale, and its costs and long term viability remain speculative. The cost and viability of CO_2 transport, which would require additional infrastructure, is also very uncertain and is likely to be very site-specific, depending on factors such as distance and terrain to a suitable sequestration site.

The four production pathways reviewed here do not cover all the possible routes to hydrogen. In particular, biological production through bacterial breakdown of biomass, and thermo-chemical cycles utilising nuclear or concentrated solar heat are not analysed. However, the routes presented here are commonly thought to be important, especially for the early stages, or transitions to, a 'hydrogen economy', and are the pathways with the most data available.

2 Steam Methane Reforming

2.1 Overview

Steam Methane Reforming (SMR) is widely used in the chemical and refining industries, and is currently thought to be the cheapest way of producing hydrogen. The basic process is shown in Figure 2.1, although there are many variations. Reforming involves the reaction of desulferised natural gas with high-temperature steam over a nickel-based catalyst. This produces syngas – mainly a mixture of hydrogen and carbon monoxide. Carbon monoxide is then converted to hydrogen and CO_2 via a water-gas shift reaction, then high purity (up to 99.999%) hydrogen is separated using Pressure Swing Adsorption (PSA) with the remaining gas recycled or used as a fuel for the reforming process. Adding CO_2 capture depends on the design, but generally requires an additional CO_2 removal stage before the PSA unit, based on physical or chemical absorption. For a good overview, see Rostrup-Nielson (2002).

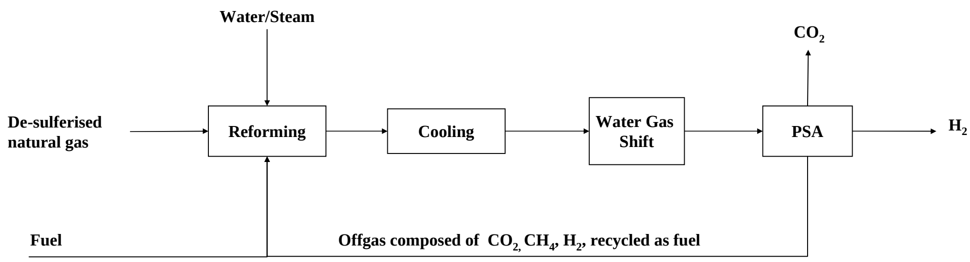


Figure 2.1: Simplified schematic for steam methane reforming

2.2 Discussion of Data

Most studies distinguish between 'large' or 'central' SMR plants, similar to the ones in operation today, and 'small', 'distributed' or 'forecourt' reformers, which might be built in hydrogen fuelling stations in the future. Four studies provided data for large plants (NRC 2004), (Parsons Technology Group 2002), (Bayse and Swaminathan 1997) (Blok et al. 1997). Three studies provided data for small plants: (Ogden et al. 1996), (NRC 2004) and (Myers et al. 2002).

Figure 2.2 shows hydrogen cost estimates from large SMR plants, and Table 2.1 outlines some of the factors behind the differences. Plant sizes range from 39MW – 3170MW, although it is not clear whether the largest (Blok, Williams et al. 1997) is based on an actual physical design, or whether this size has just been chosen for convenient analysis (3170MW = 100PJ/yr).

For plants larger than 100MW, without CO_2 capture, hydrogen production costs range from \$5.25 to \$7.26 /GJ. This is reasonably consistent with other studies reviewed by Bayse and Swaminathan (1997), who found productions costs across four large plants (360 - 1000 MW) ranging from \$5.23/GJ to \$6.48/GJ, with an average of \$5.73/GJ. However, in the data studied here, cost breakdowns varied significantly between studies e.g. feedstock contributed between 42% (Bayse and Swaminathan 1997) and 73% (NRC 2004) to overall production cost.

Figure 2.3 shows the cost of hydrogen from small, or forecourt, SMR plants. Hydrogen production costs range from \$11.5/GJ to \$40.4/GJ, with an average of \$21.6/ GJ. Table 2.2 summarises some of the factors contributing to the variation, much of which is accounted for by the range of plant sizes:

0.19 – 4 MW. The highest estimate ($40.4/GJ) comes from Ogden et al (1996), for a 0.42MW plant. The main contributor is the high capital cost of the reformer, which accounts for 42% of the production cost, compared to 21% for a plant ten times the size. However, this estimate is based on a scaled-down, custom-built, industrial SMR plant, whereas in reality distributed SMR plants will be redesigned specifically for mass production and better operation at this small scale. Myers et al (2002) estimate lower production costs (23.8$/GJ) for even smaller plants (0.19MW) so the figure of $40.4 seems unrealistically high. Recently ChevronTexaco have claimed to have built a small (0.1MW), compact, self contained SMR unit which produces hydrogen at a cost of $13/GJ, below the US DOE targets (Nguyen et al. 2005)

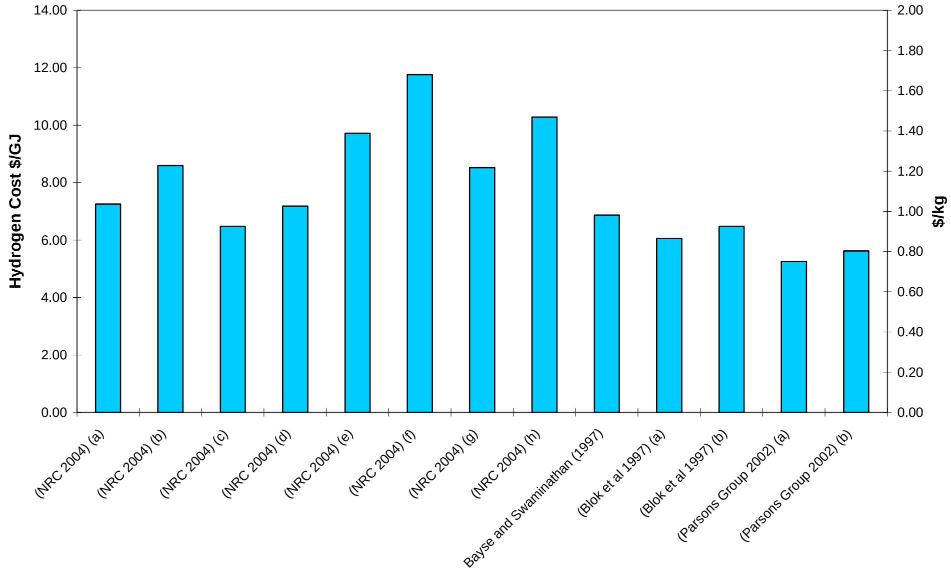


Figure 2.2: Hydrogen cost for large 'centralised' SMR plants

Source	Case	Size (MW)	Capital cost $10^6	Capital intensity $/W H2	Feedstock contribution $/GJ H2	Feedstock price $/GJ	Hydrogen cost $/GJ	Notes
NRC (2004)	a	1971	453.39	0.23	5.28	4.27	7.26	Large-scale SMR with conventional technology
NRC (2004)	b	1971	623.75	0.32	5.56	4.27	8.59	As (a) but with CO_2 capture. Does not include cost of CO_2 storage and transport
NRC (2004)	c	1971	326.85	0.17	5.00	4.27	6.48	Large-scale SMR with 'future' technology., 10% reduction in capital costs from improved catalysts; increased reaction pressure to reduce final compression of hydrogen . Efficiency improved by 5%. Timescale not specified
NRC (2004)	d	1971	425.54	0.22	5.14	4.27	7.18	As (c) but with CO_2 capture. Does not include cost of CO_2 storage and transport
NRC (2004)	e	39.44	21.52	0.55	5.56	4.27	9.72	Intermediate scale SMR. As (a) but at smaller scale
NRC (2004)	f	39.44	29.26	0.74	5.78	4.27	11.76	As (e) but with CO_2 capture
NRC (2004)	g	39.44	17.12	0.43	5.21	4.27	8.52	As (c) but smaller scale. Effect of capital reductions are more significant at this scale
NRC (2004)	h	39.44	23.06	0.58	5.56	4.27	10.28	As (g) but CO_2 capture
Bayse and Swaminathan (1997)		376.4	136.27	0.36	2.90	2.27	6.87	Large scale SMR with conventional technology. Updates the model of Simbeck and Chang (1989) to calculate costs
Blok et al (1997)	a	3171	1281.99	0.40	3.95	3.55	6.05	Very large scale SMR, although the scale of the process may have been chosen for convenience (100PJ/yr), as no actual plant design is presented
Blok et al (1997)	b	3171	1317.54	0.42	3.95	3.55	6.48	As (a) but with CO2 capture and storage. Estimate includes cost of sequestration in depleted gas reservoir. Seems optimistic, may be due to the extra capital cost being spread over such a large output.
Parsons Group (2002)	a	622.5	143.00	0.23	4.03	2.99	5.25	Large-scale SMR with conventional technology
Parsons group (2002)	b	622.5	155.35	0.25	3.37	2.99	5.62	As (a) with CO_2 capture

Table 2.1: Explanation of data for large SMR plants

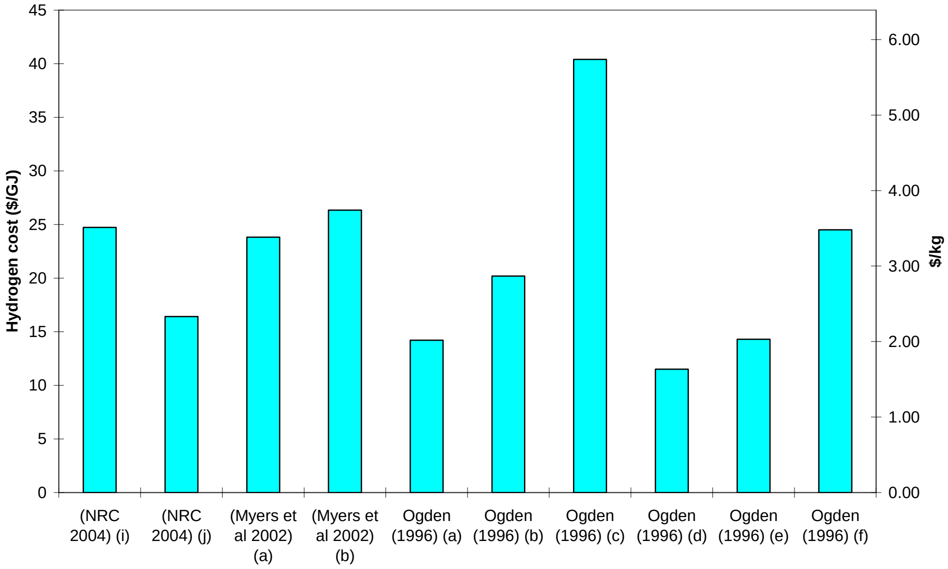


Figure 2.3: Hydrogen cost from small 'forecourt' SMR plants

Source	Case	Size (MW)	Capital cost $10^6	Capital intensity $/W H_2	Feedstock $/GJ H_2	Feedstock price $/GJ	O&M $/GJ	Hydrogen price $/GJ	Notes
NRC(2004)	i	0.79	1.85	2.35	1.85	6.16	2.47	24.72	Small-scale SMR. Current technology. Uses higher domestic gas price.
NRC(2004)	j	0.79	0.96	1.22	0.96	6.16	1.27	16.41	Small-scale SMR with 'future optimism'. Cost savings from standardisation of design and mass production, reduced capital costs.
Myers et al (2002)	a	0.19	0.25	1.34	0.25	5.06	2.32	23.81	Small-scale forecourt reformer with conventional technology
Myers et al (2002)	b	0.19	0.27	1.45	0.27	5.06	2.32	26.34	Small-scale forecourt reformer with hydrogen separation via gas-permeable metal (palladium) membrane. Current technology, though not widely commercialised. Costs are based on current estimates.
Ogden (1996)	a	4.18	5.38	1.29	5.38	3.79	2.78	14.20	Small-scale forecourt reformer. Costs are based on a custom built industrial reformer, scaled down using cost factors.
Ogden (1996)	b	1.53	3.05	2.00	3.05	3.79	5.35	20.20	As (a) but smaller scale
Ogden (1996)	c	0.42	1.77	4.23	1.77	3.79	15.13	40.40	As (b) but smaller scale
Ogden (1996)	d	4.18	3.38	0.81	3.38	3.79	2.50	11.50	Small-scale forecourt reformer. Purity of the hydrogen is relaxed (higher methane content permitted). Allows lower temperature and pressure reactor and hence cheaper materials. Also benefits from standardised design and mass production. Current technology, though based on future cost reductions
Ogden (1996)	e	1.53	1.37	0.89	1.37	3.79	4.26	14.30	As (d) but smaller scale
Ogden (1996)	f	0.42	0.63	1.50	0.63	3.79	11.67	24.50	As (e) but smaller scale.

Table 2.2: Explanation of data for small SMR plants

2.2.1 Economies of scale

Economies of scale are most obvious by the differences between Figure 2.2 and Figure 2.3 which show production costs of small forecourt reformers are roughly double those from large SMR plants.

Within the large category, there appears to be some economies of scale, although over a certain threshold (~100MW) there is no clear relation between size and production cost. However, comparison across studies is difficult as other factors (e.g. economic and technical assumptions) also change. Within a study, economies of scale are more clearly visible, for example between (NRC 2004) case (a) and case (e), where reducing the scale of the process by a factor of 50 increases hydrogen price by 33%.

Within the small category, where capital costs dominate, economies of scale are very pronounced - as can be seen in Figure 2.3. In addition to lower hydrogen output, it is often assumed that smaller plants cannot benefit from revenues from exported steam, due to their scattered locations away from industrial centres. Also, at a smaller scale heat recycling is harder to achieve, making the overall process less efficient.

2.2.2 Effect of CO_2 capture

Adding CO_2 capture to large plants increased hydrogen cost between 7% (Blok, Williams et al. 1997; Parsons Technology Group 2002) and 18% (NRC 2004). This is a large disparity since the smaller value *includes* the cost of carbon transport and sequestration, whereas the larger includes only CO_2 capture. Blok et al's estimate also seems low when compared with a study by Guadernack & Lynum (1994) which found CO_2 capture, transport, and storage in a deep offshore aquifer, increased total production costs by 27% for a large (425MW) hydrogen plant. One reason for the low estimate may be that the very large output of the plant makes increases in capital costs less significant.

For distributed SMR, the cost of CO_2 sequestration appears prohibitive, possibly adding $31/GJ for forecourt sequestration (NRC 2004 Appendix G). CO_2 capture from distributed SMR plants may become economical with new membrane technology, but the costs of constructing a CO_2 transport infrastructure would still remain a barrier, and no studies directly estimated the cost of CO_2 capture for distributed plants.

2.2.3 Sensitivity to natural gas price

Natural gas feedstock contributes between 40% and 70% of overall costs, and hence the price of natural gas is an important factor. Figure 2.4 shows the sensitivity of the NRC's (2004) estimate to natural gas price at various production scales.

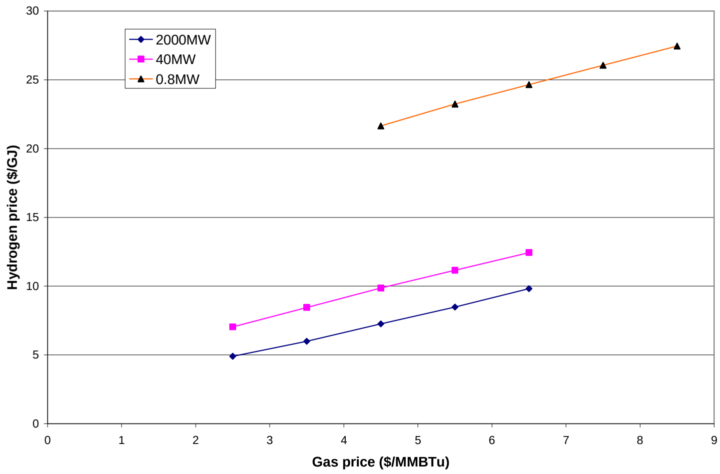


Figure 2.4: Sensitivity to natural gas price. Source (NRC 2004). 1 MMBTU = 10 therms = 1.055GJ

At larger scales, a rise in natural gas price of $1/MMBtu increases hydrogen cost by about $1.25/GJ, or about 10-20%. Blok et al (1997) found that raising natural gas price from $3 to $5/GJ increased hydrogen costs by 43%, from 5.11 $/GJ to 7.33 $/GJ. Figure 2.4 also shows the slightly increased sensitivity to natural gas prices for smaller scale plants (0.8MW). This comes from lower overall efficiencies, meaning more natural gas is used per unit of hydrogen output.

Most studies use a natural gas price around $4/MMBtu, although the NRC use $6.5/MMBtu for the distributed SMR plants. Gas prices have been above $6/MMBtu in the US for over a year (EIA 2005), and current day ahead UK price is around 30 – 40 p/therm, or about $5 - $7 /MMBTu (Figure 2.5). This is now seen to be at least partly a result of increasingly tight global markets and could be expected to increase. However, it may be a temporary trend until new infrastructure for gas imports into the UK become fully operational. Whatever the reasons, most existing studies use a natural gas price which currently looks 40 - 50% too low.

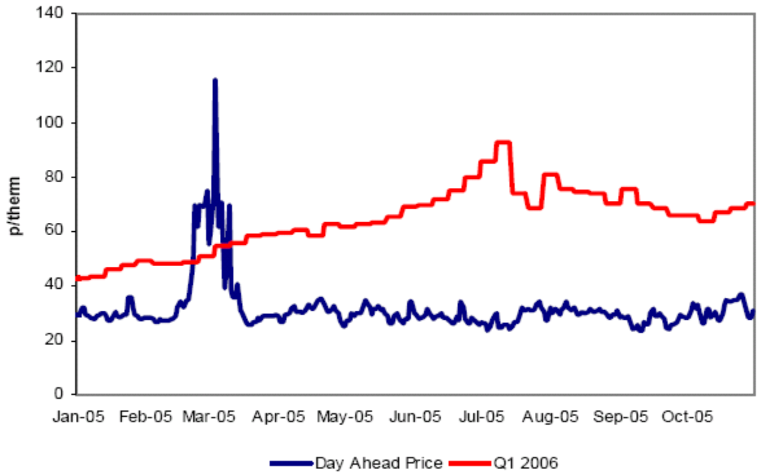


Figure 2.5: UK wholesale natural gas prices between January-October 2005 for day ahead and first quarter 2006 delivery. Source National Grid Ten Year statement 2005.

2.3 Future Trends

2.3.1 Cost savings & learning effects

Large-scale SMR plants are big, capital-intensive plants with relatively long lifetimes based on a mature technology. As such, there appears to be limited scope for cost-savings through mass production or standardisation. Nonetheless, some industry sources suggest that recent improvements in plant design have reduced hydrogen production cost by 26% (Boyce et al. 2004).

Standardisation of design and mass production will significantly reduce the costs of small-scale reformers. Several companies are redesigning small, compact reformers suitable for mass production, expected to be introduced during 2005, and some claim tens of thousands will be manufactured by 2010 (Altman et al. 2004). Aaron et al (2003) produced designs for 0.1 and 0.2MW plants with estimated hydrogen costs of $23/GJ and $18/GJ respectively, when production was at 100 units per year, falling to $20/GJ and $16/GJ respectively when production was 1000 units per year. NRC (2004) estimate hydrogen cost from a small (0.8MW) SMR plant could be reduced from $24.7/GJ to $16/GJ through standardisation and mass-production (p95), and recently ChevronTexaco have designed and built an small integrated SMR reformer, which they estimate produces hydrogen for $13/GJ (with natural gas price $4/MMBtu)

As well the savings through standardisation and mass production already described, Ogden et al (1996) claim that cost savings could occur if the required purity of the hydrogen is relaxed. Conventional reformers for industrial customers produce very pure (99.999%) hydrogen by operating at high pressure (so that downstream PSA works well) and temperature (so that methane conversion is high). Ogden et al (1996) claim this can be relaxed for fuel-cell hydrogen, where impurities (apart from CO) can be tolerated. This would allow the use of cheaper steels, remove the need for PSA, and would significantly reduce the capital cost of small-scale SMR. Preferential oxidation could be used to remove CO. However, impurities (such as methane) that do not poison the fuel cell, still reduce its performance, and there is no general agreement on what will be an ‘acceptable’ purity of hydrogen.

2.3.2 New technologies

In common with coal gasification, SMR may benefit from the development of new oxygen, hydrogen or CO_2 permeable membranes. Oxygen permeable membranes would make small-scale SMR based on partial oxidation or auto-thermal reforming a possibility, simplifying reactor designs and further reducing costs.

Hydrogen permeable membranes would allow either cheaper hydrogen purification than PSA, or more promisingly, a reaction chamber from which hydrogen is continuously removed, allowing it to operate at lower temperatures and pressures, and eliminating the need for a CO shift reactor and a PSA unit. The savings depend on the cost of this membrane (NRC 2004), as current palladium-based membranes are more expensive than conventional techniques (Myers, Ariff et al. 2002). A preliminary evaluation put hydrogen from membrane reforming between $10.4 – $13.3 $/GJ (based on a natural gas price of $3/MMBTU), and found large (50-60%) reductions in capital costs would be needed to make it economically competitive with conventional reforming combined with PSA (Shah et al. 2001). It is unlikely palladium based membranes will become economical, since the palladium market is fairly tight. Thus such advances appear to depend on the development of alternatives such as ceramic membranes which are at an early stage of development.

2.4 Uncertainties

Comparison within a study is often complicated by a number of factors which change simultaneously between cases (such as gas price and production scale). Comparison between studies is even more difficult due to different economic assumptions such as discount rate, plant lifetime and internal rate of return, different technical designs (trade-offs between hydrogen purity and plant cost); assumptions about future technologies (whether new membranes will become economical); and assumptions about economies of production (how much a plant will decrease in cost when mass produced). This adds uncertainty to any conclusions drawn from a review of the literature.

The uncertainties in hydrogen cost estimates are greater for small-scale plants as these have not been widely deployed, have higher capital costs, but have more potential for reducing these capital costs.

Although adding CO_2 capture is technically relatively straightforward, the costs are still uncertain, as it has not been demonstrated at a large scale. If the overall cost of CO_2 transport and sequestration were to be included, this would introduce further uncertainties e.g. capital costs of CO_2 pipelines, revenues from enhanced gas recovery, choice of disposal options etc.

Perhaps the largest uncertainty is the future price of natural gas. Given that, realistically, the widespread introduction of fuel cell vehicles is at least a decade away, natural gas prices could change substantially in that time. If natural gas were to become – through hydrogen – a major source of fuel for vehicles, the increased demand may also affect natural gas prices.

3 Coal Gasification

3.1 Overview

Coal gasification (CG) is an established, commercial technology used in the chemical and refining industries, and increasingly for power generation. It involves the production of syngas (CO and H_2) from coal. This syngas can be used directly for electrical power generation, as a chemical feedstock for the production of synthetic chemicals and fuels (Fischer-Tropsch liquids), or for hydrogen production.

Figure 3.1 shows a simplified schematic for the co-production of hydrogen and electricity from coal, although there are many different configurations. Pulverised or slurried coal is exposed to steam and carefully controlled amounts of oxygen or air at high temperature (1100-1300 ^oC) and high pressure (~6 MPa). The use of pure oxygen over air ensures a concentrated syngas stream, making subsequent gas cleaning and separation much easier. The syngas is then chemically cleaned of hydrogen sulphide, coal ash and other impurities, before being fed to a water gas shift reactor, where carbon monoxide reacts with water to produce hydrogen and CO_2. CO_2 is removed either by an amine-based absorbent (such as Selexol) or by Pressure Swing Adsorption (PSA). CO_2 is usually vented to the atmosphere, although it could be or compressed for later sequestration.

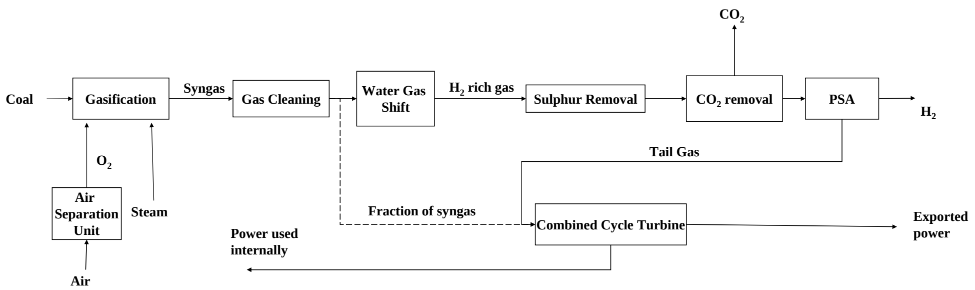


Figure 3.1: Simplified schematic of a coal gasification process produ ing hydrogen and electrical power.

Hydrogen produced by CG has generally been more expensive than SMR, although CG is economical where gas is relatively expensive and coal relatively cheap. Since significant coal reserves exist in many areas of the world, and gas prices are increasing, it could become important for hydrogen production (Padro and Putsche 1999), especially if it were successfully combined with large-scale carbon capture and storage.

There are currently around 180 coal gasifiers in operation at 22 locations worldwide, with a further 22 planned. Capacities range from 120 000 to 39 600 000 Nm^3 syngas/day (NETL 2004), mainly for the production of chemicals, liquid fuels, and increasingly for power generation. Most commercial-size gasifiers have been engineered by a handful of companies including Lurgi, Shell, Texaco, and Dow. Of the three main types of gasifier: fixed bed, entrained flow, and fluidised flow, entrained flow gasifiers are the most common, and include the Texaco process (now owned by General Electric) which has about 75% of market share (NETL 2004).

3.2 Discussion of data

Data came from seven studies: (Gray and Tomlinson 2002), (NRC 2004), (Parsons Technology Group 2002), (Williams 2001), , (Steinberg and Cheng 1989), (Bayse and Swaminathan 1997)

Figure 3.2 shows the range of estimates found in the literature for hydrogen from coal gasification, which represent a range of technologies and assumptions. Table 3.1 summarises some of the factors leading to this range.

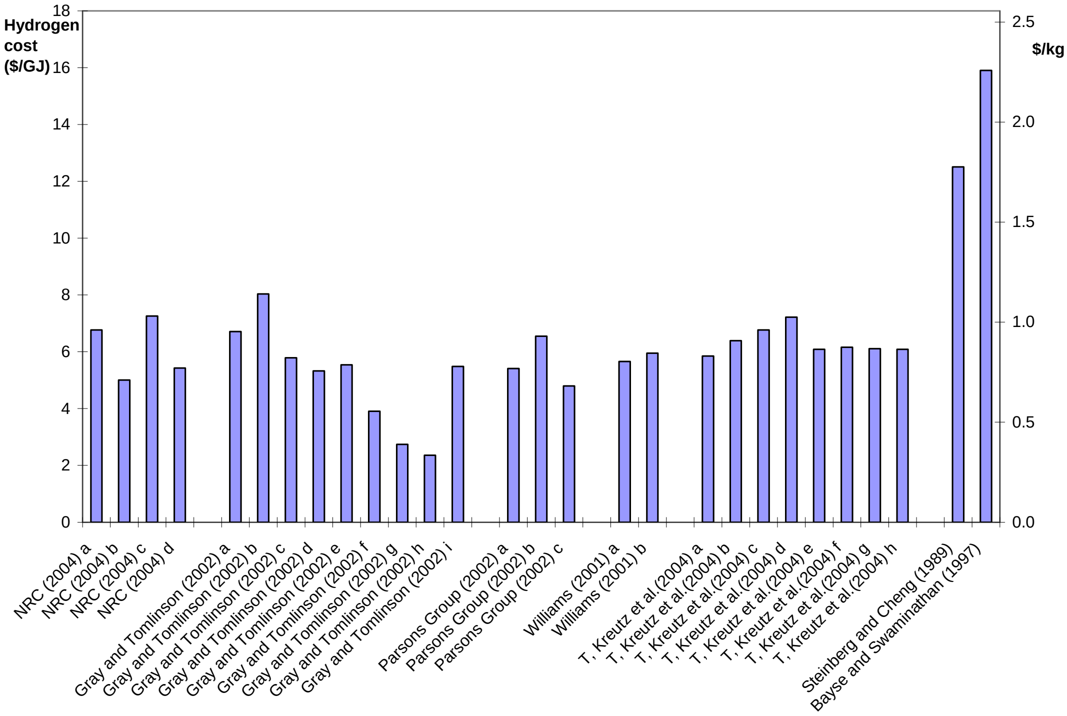


Figure 3.2: Hydrogen cost from coal gasification

The cost of hydrogen from current technology without CO_2 capture is reasonably consistent, being between $5.4/GJ to $6.8/GJ, apart from two studies which produced much higher hydrogen costs $12.51/GJ (Steinberg and Cheng 1989) and $15.9/GJ (Bayse and Swaminathan 1997). Both of these studies use the same economic model, but it is not clear what factor leads to the higher price. Steinberg and Cheng use a high coal price, and Bayse and Swaminathan have high O&M costs. Whatever the reason, these estimates seem very high in comparison with others.

If the two high estimates are excluded, the cost of hydrogen production from CG, is very similar to the range of estimates found for centralised SMR with current technology.

Source		Size (MW)	Capital cost $10^6	Capital intensity $/W	Feedstock contribution $GJ H2	Feedstock price $/GJ	O&M $/GJ H_2	Hydrogen cost $/GJ H_2	Notes
NRC (2004)	a	1971	1152	0.58	1.48	1.16	1.27	6.77	Current technology, conventional gasification
	b	1971	868	0.44	1.34	1.16	0.92	5.00	Future technology, modest savings from learning effect and improved gas cleaning.
	c	1971	1177	0.60	1.48	1.16	1.27	7.26	As (a) with CO_2 capture
	d	1971	890	0.45	1.34	1.16	0.92	5.43	As (b) with CO_2 capture.
Gray and Tomlinson (2002)	a	509	380	0.75	1.76	1.23	1.69	6.71	Current technology: conventional gasification with quench cooling
	b	462	432	0.94	1.94	1.23	2.01	8.03	As (a) with CO_2 capture
	c	613	440	0.72	1.48	1.23	1.39	5.79	Future technology, membrane gasification and CO_2 capture. Assumes membrane system obtained at the same cost as conventional technology, although technology in R&D phase
	d	578	943	1.63	3.14	1.23	3.06	5.32	Current/Mid term technology. Advanced gasification and electricity co-production
	e	594	984	1.66	3.06	1.23	2.98	5.54	As (d) with CO2 capture
	f	594	984	1.66	3.06	1.23	2.98	3.91	Future technology. Advanced gasification with electricity co-production and membrane gas separation. 417 MW_e sold at current market rates ($0.05/kWh)
	g	578	1075	1.86	3.14	1.23	3.48	2.74	Current/Mid term technology. Advanced gasification and electricity co-production via SOFC. Low hydrogen price only valid if electricity sold at current market rates. If electricity is sold at production cost, hydrogen price is $5.82/GJ
	h	582	1056	1.81	3.12	1.23	3.41	2.36	Future technology. Advanced gasification, electricity co-production via SOFC, and ceramic membrane gas separation. Assumes electricity sold at current market rates ($0.05/kWh)
	i	582	1056	1.81	3.12	1.23	3.41	5.48	As (h) but electricity sold at production cost from a SOFC plant i.e. without cross subsidy
Parsons Group (2002)	a	466	354	0.76	1.32	0.95	0.78	5.41	Current technology, conventional gasification
	b	466	412	0.88	1.32	0.95	2.18	6.55	As (a) with CO2 capture
	c	642	395	0.62	0.95	0.95	1.62	4.80	Future technology, advanced membrane separation and CO_2 capture
Williams (2001)	a	1019	793	0.78	1.89	1.12	1.06	5.66	Current technology, conventional gasification with electricity co-production
	b	1016	794	0.78	1.90	1.12	1.06	5.95	As (a) with CO2 capture
T, Kreutz et al.(2004)	a	1263	824	0.65	1.82	1.17	0.92	5.85	Current technology, conventional gasification
	b	1263	869	0.69	1.82	1.17	0.97	6.39	As (a) with CO2 capture
	c	1218	1008	0.83	1.82	1.17	1.17	6.77	As (a), but with convective and radiative gas cooling. Increased capital cost for modest efficiency gains
	d	1218	1052	0.86	1.82	1.17	1.22	7.22	As (c) but with CO2 capture
	e	1279	827	0.65	1.80	1.17	0.91	6.08	Fuel grade hydrogen suitable for use in boilers and combustion engines, but not PEM fuel cells.
	f	1241	843	0.68	1.83	1.17	0.96	6.16	Advanced gasification at high pressure, 120 bar
	g	1263	810			1.17		6.11	Conventional gasification with quench cooling. Savings made from co-capturing CO_2 and H_2S
	h	1279	827	0.65	1.80	1.17	0.91	6.08	As (g) but producing fuel grade hydrogen not suitable for PEM fuel cells.
Steinberg and Cheng (1989)		388	388	1.00	3.07	3.34	2.10	12.51	Old data, gives very high cost estimate. Uses very high coal price
Bayse and Swaminathan (1997)		376	483	1.28	2.69	1.29	4.06	15.9	Updates Steinberg and Cheng, very high O&M. Overall cost is three times similar studies

Table 3.1: Hydrogen from coal gasification

3.2.1 Economies of scale

Since coal gasification is capitally intensive, it is generally assumed to be only suitable for large, central plants. Plant sizes studied here range from 353MW (Parsons Technology Group 2002) to 1177MW (NRC 2004), and among the studies there is no clear relation between plant size and hydrogen price.

3.2.2 Effect of CO_2 capture

Adding CO_2 capture increases hydrogen prices by between 7% (NRC 2004) and 20% (Gray and Tomlinson 2002). However, Gray and Tomlinson (2002) also include the cost of carbon sequestration at \$10/tC. If this estimate is excluded, then adding CO_2 capture increases hydrogen production cost price by an average of 11%. CO_2 capture is relatively easy to add to CG plants, as often CO_2 removal used to ensure the gas leaving the PSA unit is combustible and can be used for energy.

3.2.3 Co-production of power

Co-producing electrical power and hydrogen can significantly change the economics of a plant, depending on the electricity selling price. The lowest hydrogen production costs, as low as \$2-\$3 /GJ (Gray and Tomlinson 2002, f,g,h) co-produce power and sell it at current market rates (\$0.05/kWh). However, this is cross-subsidising hydrogen production through electricity sales. If the electricity is sold at the cost of production (Gray and Tomlinson 2002, i), the hydrogen cost rises to \$5.48/GJ. Most other studies which include co-production assume electricity could be sold at current market rates at the time of the study.

Co-production of FT liquids also changes plant economics (Williams 2001) but this is sensitive to assumptions about the market for liquid fuels and was not analysed in detail here.

3.2.4 Effect of coal price

Sensitivity to coal price was not explored in detail in any of the surveys. Coal price is a lot more stable than oil and natural gas prices, though coal prices have been rising in recent years. Also, coal is cheaper in the US than in Britain, with wholesale prices in Britain about 115 – 125p/GJ, or \$2 -\$2.5/GJ /GJ.

3.3 Future trends

3.3.1 New technologies

Many future options explored in the literature are based on the development and deployment of new hydrogen, oxygen, or CO_2 permeable membranes. These could allow either (a) cheaper oxygen separation than cryogenic units, (b) cheaper hydrogen and CO_2 separation than PSA, or (c) an integrated gasification reaction chamber from which hydrogen is constantly removed, eliminating the need for a water-shift reactor and subsequent PSA purification. For (b) and (c), current palladium-based membranes are too expensive, with little potential for future cost reductions (Rostrup-Nielsen and Rostrup-Nielsen 2002; Kreutz et al. 2003). Ceramic membranes may eventually be suitable for (b) and (c) and could then offer significant cost savings. When Gray and Tomlinson (2002) assumed these membranes could be deployed at the same cost as a conventional system, hydrogen price was reduced from \$8.03/GJ to \$5.79/GJ, almost a 30% reduction. However, these technologies are at an early stage of research.

Solid oxide fuel cells (SOFCs) will improve the efficiency and economics of electricity co-production, and are well suited to high temperature operation on pure hydrogen or syngas. Small units (few MW at most) are at an early stage of commercialisation, are thought to have large potential for economies of scale savings. No large scale (100+ MW) SOFC stacks have yet been demonstrated.

Improving plant design has some limited potential for improvements. Convective and radiative cooling of syngas has the potential to increase overall efficiency by 2%, but currently adds 30% to the capital cost of a hydrogen plant, making it uneconomical (Kreutz et al. 2005). Co-capturing H_2S together with CO_2 could lower the cost of hydrogen by around 4% as it eliminates the need for separate sulphur recovery equipment (Kreutz, Williams et al. 2005).

The use of calcium oxide as a sorbent (the HyPr-RING process) may give good overall efficiencies (75% or more) and remove the need to use pure oxygen, thereby reducing hydrogen costs. This method appears to be at an early stage of development (Lin et al. 2005).

3.4 Uncertainties

Some of the differences in the figures quoted in the literature arise from different economic assumptions, such as rates-of-return or tax rates. These discrepancies will be avoided in the future as standards are developed for reporting data on hydrogen costs.

If CO_2 sequestration were included in the estimates, it would introduce another element uncertainty as the costs of transporting and storing CO_2 are not known. As well as the uncertainties associated with new technology, there are other factors to consider such as the plant location, the available options for sequestration, whether a CO_2 transport infrastructure already exists, the level of any carbon tax, and potential revenues from enhanced oil and gas recovery.

4 Biomass Gasification and Pyrolysis

4.1 Overview

Gasification and pyrolysis provide two ways to produce hydrogen from biomass. The processes can be adapted to a range of feedstocks including dedicated fuel crops such as willow and switch grass, and biomass residues such as peanut shells and sugar cane waste. Different feedstocks may require different amounts of pre-treatment – drying, pelletising, milling etc. If the feedstock crops are regrown, then, once the energy inputs of fertiliser, harvesting and transport have been accounted for, the rest of the cycle is carbon neutral.

Gasification and pyrolysis are both followed by a reforming stage very similar to that used in steam methane reforming (SMR). Simplified schematics for the two processes are shown in Figure 4.1.

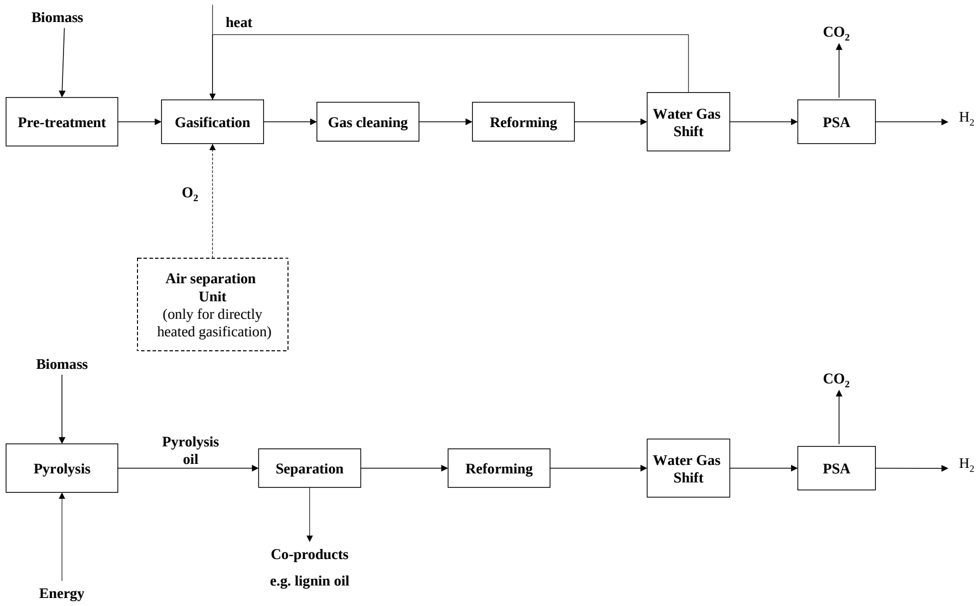


Figure 4.1: Simplified schematics for biomass gasification and pyrolysis

There are two major classifications of gasifier: indirectly heated and directly heated. The first, such as the Batelle Columbus Laboratory (BCL) gasifier, heat biomass in the absence of oxygen by circulating hot sand into the gasification chamber. The second, such as the Institute of Gas Technology (IGT) gasifier, provide the heat for gasification by allowing the partial oxidation of the biomass feed in pure oxygen inside the gasification chamber.

With pyrolysis, biomass is rapidly heated in the absence of oxygen; the vapours are then condensed to form pyrolysis oil (also called bio-oil). This pyrolysis oil can later be used as a feedstock for hydrogen production, and is more easily stored and transported than raw biomass (it contains about 5 times the volumetric energy density of wood chips). Pyrolysis also generates non-condensable gases and char (carbon), which can be combusted to provide part of the energy for the process.

4.2 Discussion of data

Six studies provided the data for gasification: (NRC 2004), (Mann 1995), (Hamelinck and Faaij 2001), (Spath et al. 2003) (Bowen et al. 2001) and (Simbeck and Chang 2002). Less data exists on pyrolysis compared with gasification, and only two studies were looked at: (Mann 1995), and (Spath, Mann et al. 2003).

Figure 4.2 shows the range of hydrogen costs found for gasification. These range from $7.54/GJ to $34/GJ. Table 4.1 summarises some of the factors leading to this range.

NRC (2004) produce the highest hydrogen cost estimate: $32/GJ (without carbon capture). This is $10-$15/GJ higher than other estimates from plants of a similar size. This appears to be due to a combination of relatively high capital costs, coupled with the relatively small scale of the process and a high feedstock cost. Whether these are reasonable assumptions will depend on the situation.

The lowest estimates $7.43 – $8.78/GJ come from Bowen et al (2001), for hydrogen from three different biomass feedstocks. These estimates arise from low capital costs. In all three processes, the biomass source is homogenous, and gasification is tailored to that particular feedstock, and can be performed with little pre-treatment, at high pressure, and using a process very similar to coal gasification. A sensitivity analysis, where capital costs were increased by 30%, put hydrogen between $8.75 – $10.44/GJ, still quite low.

Figure 4.3 shows data from two studies of pyrolysis. Hydrogen prices range from $6.19/GJ to $16.83/GJ. Table 4.2 summarises the cases. Studies of pyrolysis include the option of the co-production chemicals, since fractions of pyrolysis oil can replace petroleum based oils in the manufacture of several chemicals.

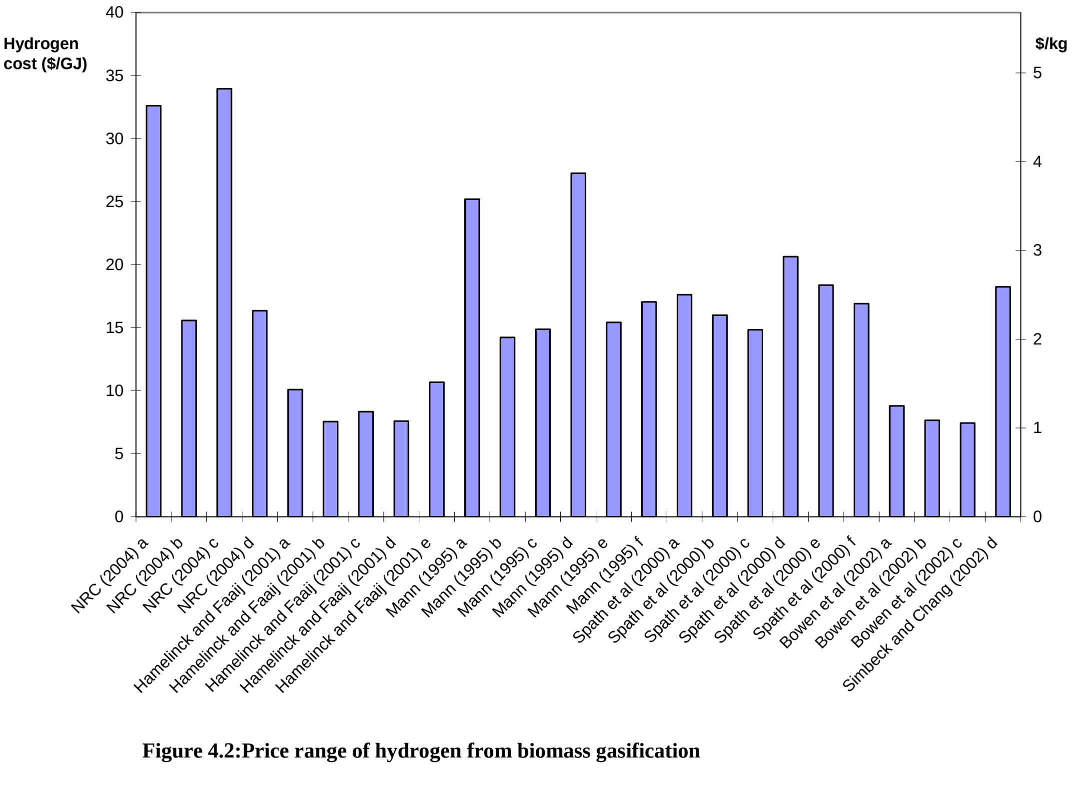


Figure 4.2:Price range of hydrogen from biomass gasification

Source	Case	Size (MW)	Capital cost $10^6	Capital intensity $/W H_2	Feedstock contribution $/GJ H_2	Feedstock price $/GJ	Hydrogen price $/GJ	Notes
NRC (2004)	a	39	121.04	3.07	6.55	2.85	32.61	Current technology: directly heated gasification. High capital costs compared with coal gasification due to smaller scale. Overall efficiency 50%
	b	39	59.04	1.50	2.81	1.91	15.57	Future: reductions in biomass cost from improved breeding. Reduced capital cost of gasification and increased overall efficiency (70%).
	c	39	123.91	3.14	6.55	2.85	33.95	As (a) but with carbon sequestration
	d	39	60.53	1.53	2.81	1.91	16.34	As (b) but with carbon sequestration
Hamelinck and Faaij (2001)	a	176	249.68	1.42	4.97	2.00	10.08	Pressurised, oxygen blown gasification. Mostly current technology, though not all elements of hot gas cleaning have been proven. Large scale leads to low hydrogen price.
	b	259	182.38	0.70	4.97	2.00	7.54	Future technology: based on successful development of ceramic membrane reforming. Assumes membrane reformer is substantially cheaper than steam reformer, shift reactor and PSA combination.
	c	177	217.25	1.23	4.97	2.00	8.33	Future technology. Similar to (b) but increased capital cost from additional combined cycle turbine, giving modest efficiency gains
	d	303	210.12	0.69	4.97	2.00	7.59	Atmospheric, indirectly heated gasification. Conventional technology, low capital cost but reliant on imported electricity.
	e	149	242.84	1.63	4.97	2.00	10.67	As (d) but no SMR stage, higher capital cost and improved efficiency due to combined cycle turbine, less reliant on imported electricity.
Mann (1995)	a	3	6.60	2.07	1.62	0.91	25.19	Current technology, though some elements of hot gas cleaning not proven. Small scale leads to high cost
	b	32	37.46	1.17	1.60	0.91	14.22	As (a) but larger scale
	c	106	98.15	0.92	4.47	2.55	14.88	As (b) but larger scale and higher biomass costs as dedicated biomass producer required
	d	2	5.48	2.20	2.07	0.91	27.25	As (a) but without water-shift reactor - trades lower capital cost for less hydrogen production
	e	25	31.81	1.28	2.05	0.91	15.42	As (d) but larger scale
	f	83	86.86	1.05	5.72	2.55	17.05	As (e) but larger scale and higher biomass cost.
Spath et al (2000)	a	37	53.80	1.44		0.84	17.62	Update of (Mann 1995). Current technology. Atmospheric, indirectly fired with SMR.
	b	125	128.80	1.03		2.34	15.99	As (a) but larger scale
	c	187	172.30	0.92		2.34	14.84	As (b) but larger scale
	d	37	72.00	1.93		0.84	20.64	Current technology: pressurised, oxygen fired with SMR
	e	125	169.40	1.36		2.34	18.38	As (c) but larger scale
	f	187	227.20	1.22		2.34	16.90	As (d) but larger scale
Bowen et al (2002)	a	52	35.59	0.69	2.30	1.44	8.78	Current technology: pressurised, oxygen fired with hot gas cleaning. Bagasse (sugar cane waste) feedstock requires drying before processing. Relatively low estimates of capital cost.
	b	61	35.11	0.57	2.24	1.44	7.65	As (a) using switch grass feedstock, no pre-drying
	c	64	34.92	0.55	2.27	1.44	7.43	As (a) using nutshell feedstock, no pre-drying
Simbeck and Chang (2002)	d	246	347.96	1.41	4.11	2.94	18.24	Current technology: directly heated, oxygen fired. No reforming stage.

Table 4.1: Hydrogen costs from biomass gasification

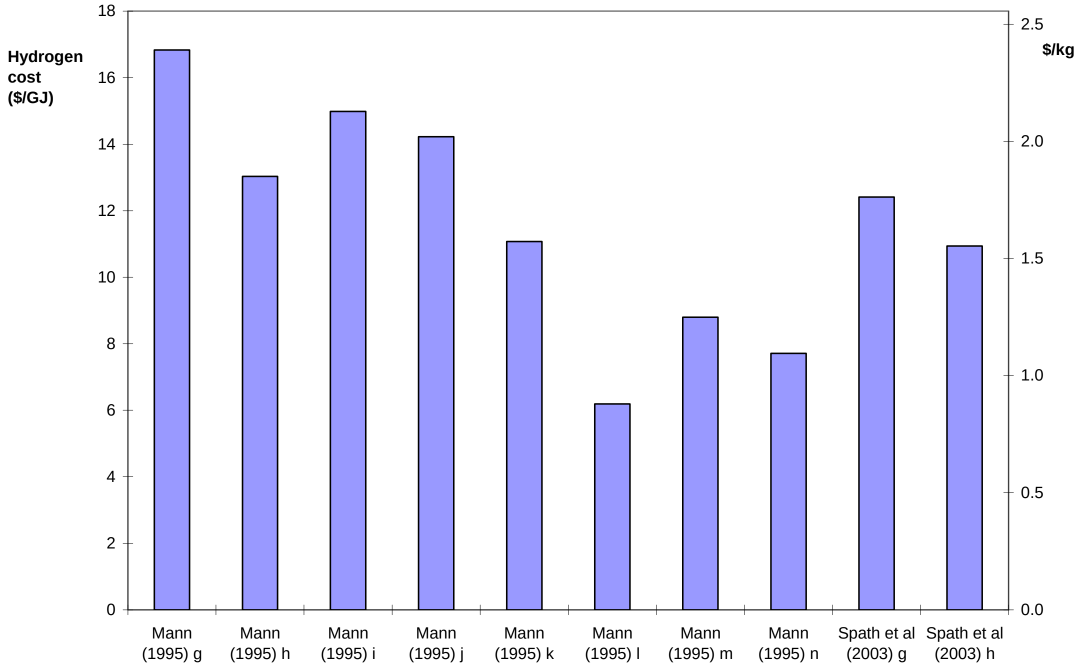


Figure 4.3: Hydrogen from pyrolysis.

Source	Case	Size MW	Capital cost $10^6	Capital intensity $/W H_2	Feedstock contribution $/GJ H_2	Feedstock price $/GJ	Hydrogen price $/GJ	Notes
Mann (1995)	g	4	3.33	0.742	7	0.91	16.83	Reforming of pyrolysis oil bought from supplier. Current technology.
Mann (1995)	h	45	21.93	0.488	7	0.91	13.03	As (g) but larger scale
Mann (1995)	i	45	21.93	0.488	7	2.55	14.98	As (h) but higher biomass cost
Mann (1995)	l	150	63.74	0.425	8	2.55	14.22	As (i) but larger scale
Mann (1995)	k	4	3.14	0.873	8	0.91	11.07	Reforming of pyrolysis oil bought from supplier. Separation of lignin component and sold as phenol substitute. Current technology
Mann (1995)	l	36	19.76	0.549	8	0.91	6.19	As (k) but larger scale
Mann (1995)	m	36	19.76	0.549	8	2.55	8.79	As (l) but higher biomass cost
Mann (1995)	n	120	57.11	0.476	10	2.55	7.71	As (m) but larger scale
Spath et al (2003)	g	37	18.80	0.50		7.06	12.41	Reforming of pyrolysis oil. Lignin component sold as phenol substitute
Spath et al (2003)	h	125	59.40	0.48		7.06	10.94	As (g), but larger scale

Table 4.2: Hydrogen from pyrolysis

4.2.1 Economies of scale

Figure 4.4 shows the effect of production size on hydrogen cost from biomass gasification. Only data for current technologies is plotted.

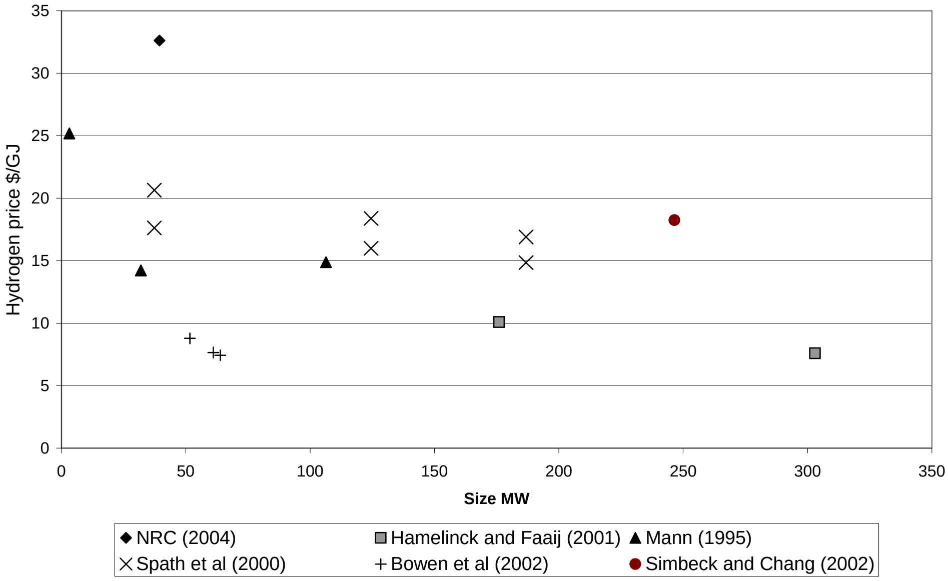


Figure 4.4: Effect of size on production economics for hydrogen gasification with current technology

The general trend shows that larger plants benefit from economies of scale, with reduced capital costs per unit of output.

However, the size of a biomass plant may be limited by the availability of biomass input. Biomass production competes with other land uses, biomass resources tend to be dispersed, and biomass has high transportation costs. Smaller biomass plants may be able to benefit from lower transportation costs and availability of local biomass residues, whereas larger plants may have to buy from a dedicated biomass producer. In some cases, e.g. sugar cane processing, large amounts of biomass waste may be available.

Economies of scale are also visible in pyrolysis plants. However, it was often assumed that plants above a certain size would have to pay more for pyrolysis oil to reflect a higher cost of biomass at this scale.

4.2.2 Effect of technology

For gasification, indirectly heated gasification appears a cheaper option at smaller scales as it avoids the need for an air separation unit. However, directly heated, pressurised gasification may be cheaper (Bowen, Lau et al. 2001) where large amounts of homogenous feedstock is available (e.g. nutshells, bagasse).

It is difficult to assess whether pyrolysis is significantly more or less expensive than gasification, as there is too little data, and the costs are sensitive to assumptions about feedstock costs and co-product selling price.

4.2.3 Effect of feedstock cost

Determining the effect of feedstock cost within studies is difficult, as feedstock cost is often only varied with plant size (e.g. by assuming smaller plants obtain cheaper biomass). Isolating the effect of feedstock cost across studies is also difficult due to the number of other factors which also change between studies.

However, there is expected to be a wide range of sensitivities to biomass cost across studied due to the wide variation in the contribution biomass cost makes to overall hydrogen cost: between 6% (Mann 1995) and 66% (Hamelinck and Faaij 2001). How the biomass market might develop depends on future demand, economic incentives for energy crop production, and the price of other energy alternatives including the price of fossil fuel energy.

4.2.4 Effect of co-production

Selling of co-products from pyrolysis plants improves the economics of plants significantly. All of the cheapest pyrolysis cases come from co-production, where the lignin-based fraction of pyrolysis oil is separated and sold as a phenol substitute. The market for this co-product is reasonably large: 0.57bn kg of phenol is used in the US each year, about half of which is estimated could be substituted by lignin oil (Spath, Mann et al. 2003). Facilities producing this much lignin oil would produce enough hydrogen for 20 million fuel cell vehicles. Spath et al (2003) used a selling price for lignin oil of \$0.44/kg, about two thirds of the market value for phenol.

4.2.5 Effect of CO_2 capture

Adding CO_2 capture was only considered in one study (NRC 2004) case (c) and (d), as biomass is often considered carbon neutral (most studies omit energy inputs such as fertiliser). However, adding carbon capture to biomass plants could provide a net carbon sink, which might prove attractive for reducing emissions, and possibly economically attractive with high carbon taxes. It also may be an attractive option to co-fire biomass residues in coal gasification plants with CCS, which may have attractive economics, and reduce carbon emissions.

4.2.6 Economic assumptions

Both gasification and pyrolysis are sensitive to economic and technical assumptions used in their evaluation. A sensitivity analysis by Spath et al (2003) found, for biomass gasification, the two variables affecting hydrogen price most were the hydrogen production factor (how well a plant performs compared with its theoretical design), and the operating capacity factor (the fraction of time a plant is operational). Combined, they determine how much hydrogen is produced, and accounted for 51-76% of the variance in hydrogen production cost. The same analysis for pyrolysis found the most important variables were the bio-oil feedstock cost, co-product selling price, and the yield of the carbohydrate fraction separated from the bio-oil.

Spath et al (2003) and Bowen et al (2001) also found demonstrated how internal rate of return has a large influence on hydrogen price, shown by the example in Table 4.3.

(Spath, Mann et al. 2003)		**(Bowen, Lau et al. 2001)**	
Internal rate of return	Hydrogen price (\$/GJ)	Internal rate of return	Hydrogen price (\$/GJ)
0%	8.81	5%	5.85
10%	13.39	10%	6.90
15%	15.39	15%	7.95
20%	17.65		

Table 4.3: Effect of rate of return on hydrogen price.

4.3 Future trends

4.3.1 Cost savings, learning effects

The equipment for reforming and shifting biomass gas or pyrolysis oil is similar to that used in steam-methane reforming (SMR). In common with SMR, the largest cost savings are likely to come from smaller-scale plants, where capital costs dominate and where there is the largest potential to realise savings through standardisation and mass production. At the larger scale, where capital costs are not as important, these savings will be less. Hamelinck and Faaij (2001) estimate that capital costs for building a third gasification plant built are '15% lower' (presumably than the first plant) due to lower specific component costs and overall learning, making the product hydrogen 8 – 15 % cheaper. It is not clear how much costs could be predicted to decrease with further production. NRC (2004) predict capital costs for biomass gasification decreasing from \$17/GJ H_2 to \$8.5/GJ H_2 in the future scenario due to learning effects.

Perhaps the most important area where savings can be made is the cost of biomass. Energy crops are at a fairly early stage of development, and higher yields are predicted through improvements in breeding and management. NRC (2004) predict biomass yields increasing by 50% in the future case. In the UK some estimate yields of short-rotation willow might increase by up to 300% (Andersen et al. 2005). If a biomass market emerges, then other sources such as domestic and agricultural waste may become important and might help to lower the costs.

4.3.2 New technologies

Also see the SMR section, as future developments in small-scale SMR are relevant such as hydrogen permeable ceramic membranes, which allow the reforming and shift reaction to take place in one vessel.

The development of new air separation units based would significantly reduce the cost of oxygen production, especially at smaller scales. This would reduce the cost of directly heated gasification and may allow autothermal reforming. Some projects are at the demonstration phase (Hamelinck and Faaij 2001 Annex B).

Currently, biomass gas is cooled before it is cleaned (wet gas cleaning) which introduces an energy penalty. Hot gas cleaning could become commercial in the near future (Hamelinck and Faaij 2001 Annex D) which will make the process more efficient. NRC (2004) estimate overall efficiency improving from 26% to 40% [1]

[1] This figure seems to takes into account the energy inputs from fertiliser which are often neglected in other studies

5 Electrolysis

5.1 Overview

Hydrogen can be produced by the electrolysis of water producing hydrogen produced at the cathode, and oxygen at the anode. The electrodes are separated by an ionic transfer membrane, which allows a current to flow while ensuring the gases accumulate in separate physical streams. Electrolysis is a process, not an energy source - energy must be provided from primary sources such as natural gas, coal, nuclear or renewables. A simplified schematic is shown in Figure 5.1.

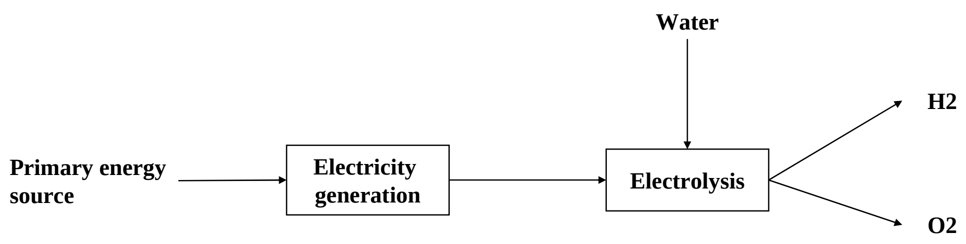


Figure 5.1: Schematic of electrolysis

There are two main types of electrolyser: conventional alkaline and Proton Exchange Membrane (PEM), also known as Solid Polymer Electrolyte (SPE). Alkaline units usually use a solution of potassium hydroxide (KOH) as the electrolyte due to its high conductivity. PEM electrolysers use a solid polymer electrolyte such as Nafion™, and are essentially a PEM fuel cell operating in reverse.

Alkaline electrolysers are a more mature technology than PEM electrolysers. They have lower capital costs, operate well (~80% efficiency) across a broader range of current densities (and hence hydrogen outputs), and currently dominate the industrial market. PEM technology is less well developed, although it has been successful in some niche markets. It is more expensive and has lower efficiency at high current densities. However, it has other advantages: PEM units are smaller, have very high efficiency (>90%) at low current densities, require less maintenance, do not require subsequent hydrogen drying, and are better suited to high-pressure electrolysis, which reduces substantially the energy needed for subsequent hydrogen compression. They also have more room for future improvement, and will benefit from the large amount of R&D going into PEM fuel cells. They are therefore generally seen as a promising future option for electrolysis and are the focus of much research. Major manufacturers of alkaline electrolysers include Norsk Hydro (Norway) and Stuart Energy (USA), while Proton Energy manufacture PEM units.

The economics of hydrogen produced by electrolysis, and other characteristics such as well-to-tank efficiency, GHG emissions and long-term sustainability, depend very much on how the electricity is generated. Here, stated efficiencies refer to the electrolysis process only, not the whole system. If auxiliary units such as hydrogen compression were included, efficiency would be reduced by about 10%. If the efficiency of electricity generation from primary energy sources were included, overall efficiencies might be lower than 30%, depending on the generation technology.

5.2 Discussion of data

Six studies provided data for analysis: (Ivy 2004), (NRC 2004), (Bayse and Swaminathan 1997), (British Energy 2002), (Audus et al. 1996). and (Mann et al. 1998), Figure 5.2 shows the range of hydrogen prices in the literature, and Table 5.1 summarises some of the factors leading to those costs.

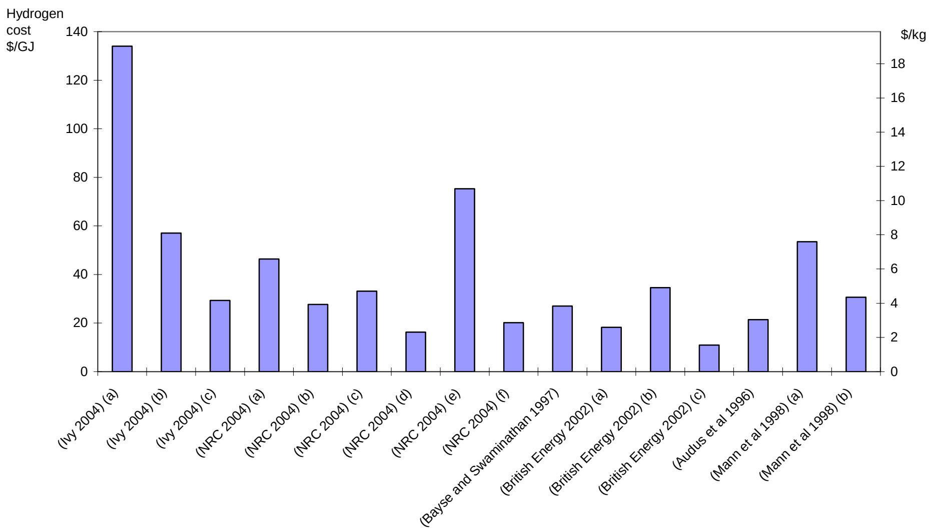


Figure 5.2: Hydrogen price range for electrolysis

Costs from electrolysis are much higher than other routes such as steam methane reforming or coal gasification. Costs vary significantly depending on the assumptions made but are generally above $20/GJ.

Source	Case	H_2 ouptut (MW)	Capital \$/W H_2	Electricity price (\$/GJ)	H_2 price (\$/GJ)	Notes
(Ivy 2004)	a	0.03	423	13	133	'neighbourhood' scale: high capital costs and low hydrogen output leading to very high hydrogen price
	b	0.16	27.0	13	57	'small forecourt' scale: benefits from cheaper electrolyser units and capital costs spread across larger output
	c	0.64	0.80	13	29	'forecourt' scale: further benefits from cheaper electrolyser and larger scale of production
(NRC 2004)	a	0.79	3.22	19	46	'distributed electrolysis, current technology': small scale alkaline electrolysis, comparatively high capital costs, including high cost for H_2 compressors. Domestic electricity rate
	b	0.79	0.72	19	28	'distributed electrolysis with future optimism' : drastic reduction in capital costs of electrolyser and compressors, plus efficiency improvements. Based on successful development and commercialisation of high-pressure PEM electrolysers.
	c	39	2.15	13	33	'mid-size, current technology': relatively large scale alkaline electrolysis, reasonably high capital costs, including H_2 compressors
	d	39	0.25	13	16	'mid-size with future optimism' : as (c) but reductions in capital costs, plus efficiency improvements.
	e	2.63	2.61	17	75	'current wind': electrolysis from current wind-based electricity with no grid backup. Low capacity factor (30%) leads to high cost
	f	1.97	0.45	11	20	'future wind' : as (c), but benefits from reduced turbine cost, larger turbines and increased capacity factor from wind, as well as lower cost and more efficient PEM electrolyser
(Bayse and Swaminathan 1997)		376	0.89	18	27	current technology, alkaline electrolyser
(British Energy 2002)	a	88	0.45		18	current technology, using combined cycle gas turbine electrolyser 70% efficient. Hydrogen price seems very low. .
	b	88	0.45		35	as (a) but using onshore wind
	c	113	0.70		11	combined cycle gas turbine with advanced electrolysis, electrolyser 95% efficient (utilising waste heat)
(Audus, Kaarstad et al. 1996)		986	0.88	10	21	current technology, conventional electrolysis
(Mann, Spath et al. 1998)	a	2.87	5.67		54	electrolysis from wind energy with current technology, no grid backup. Cost breakdown and system design is less-detailed than other sources, some extrapolation was used.
	b	3.48	3.06		31	as (a), circa 2010: reductions in capital cost for electrolyser and wind turbines due to mass production, increased capacity factor (40%) from wind, reduced O&M costs.

Table 5.1: Summary of costs from literature

5.2.1 Effect of electricity price

For electrolysers over 1MW, electricity costs dominate, typically accounting for 60-80% of hydrogen price. Since 1 GJ = 278 kWh, hydrogen cost can be expressed as:

hydrogen ($/GJ) = capital components + O&M + (278 x electricity price / electrolyser efficiency)
Where electricity price is given in $/kWh.

For example, at an electricity price of $0.05/kWh, and system efficiencies between 60-70%, then, ignoring all capital and O&M costs, hydrogen will cost at least $20-23/GJ to produce. Actual prices will be higher once capital costs are taken into consideration. A sensitivity analysis by Prince-Richard et al (2005) found that electricity cost had by far the largest effect on hydrogen price, when compared with other variables such as capital cost and capacity factor.

5.2.2 Economies of scale

Although variable costs dominate, capital costs are still significant, especially at smaller scales. Capital costs for electrolysers are usually provided per kW_e of electrolyser input capacity. Data for current commercial systems is surprisingly hard to find, and estimates vary from e.g. \$300/kW_e (Fairlie and Scott 1999), \$300-600/kW_e , to more than \$680/kW_e (E4tech 2004), \$1000/kW_e (NRC 2004), and up to $1700/kWe (E4tech 2004) for smaller units.

Economies of scale are most evident at smaller scales, e.g. Ivy (2004), as shown in Table 5.2. At scales larger than this, variable costs dominate, and economies of scale are not as apparent.

	Size (MW)	Capital	Electricity	Hydrogen cost ($/GJ)
Forecourt	0.64	32%	58%	29
Small forecourt	0.16	55%	35%	57
Household	0.03	73%	17%	133

Table 5.2: Effect of size on economics for smaller-scale electrolysers. Source Ivy (2004)

5.2.3 Effect of renewable energy sources and interaction with the grid

Some studies looked specifically at renewable energy for hydrogen production (Mann, Spath et al. 1998; British Energy 2002; NRC 2004) , although only wind was considered here. Renewable energy sources were modelled either through an associated electricity price (NRC 2004), or by explicitly including their capital costs (Mann, Spath et al. 1998) and their associated capacity factor. Capacity factor is important as it determines the hydrogen output, and low capacity factors leads to under utilisation of capital.

In general, hydrogen produced by wind was more expensive than grid electricity, Table 5.1, (NRC 2004 e), (Mann et al 1998 a), (British Energy 2002 b) due to higher electricity price and low capacity factor.

Using grid back-up to produce hydrogen when the wind is not blowing improves the economics significantly, since it increases the utilisation of the electrolyser. With grid backup, NRC (2004) found hydrogen to be 63% cheaper

($47/GJ compared to $75/GJ), and Mann et al (1998) found hydrogen to be 57% cheaper ($31/GJ compared to $54/GJ). Mann also found the best scenario for wind-based hydrogen was only to use grid back-up during off-peak hours. However, these analyses are based on assumptions which may not be valid in their envisioned futures. For example if there is a sizeable market for hydrogen, then increasing demand for off-peak electricity may increase prices, perhaps to the point where there is no 'off-peak'. Also, if wind is used to generate a significant fraction of electricity, then the cost of electricity on calm days may be significantly higher than normal. It has been estimated that if the cost of back-up generation is factored into the cost of wind generation, its cost increases by 46% - from 3.7p/kWh to 5.4pkWh for onshore wind (RAE 2004).

5.2.4 Nuclear power and large-scale electrolysis

Nuclear power can be used for electrolysis, and proponents point to their large, constant, electrical output and low overall CO_2 emissions as making them ideal for hydrogen production, which could utilise their off-peak capacity. Whether nuclear power is desirable or sustainable is highly contested, and there is not space here to debate this here. Thermo-chemical cycles may offer cheaper and more efficient nuclear routes to hydrogen, however distributed electrolysis offer a more flexible approach and can eliminate the need for hydrogen transport. The cost of hydrogen from nuclear power depends on the total cost of nuclear electricity.

5.3 Future trends

5.3.1 Improvements, cost savings, learning effects

On-site hydrogen production is becoming competitive with merchant delivered hydrogen, especially at smaller scales, and increasing industrial demand for electrolysers is driving improvements in design. Alkaline electrolysers have made significant progress over last few years, many units operate at 1 – 3Mpa avoiding the first stage of compression (Altman, Schmidt et al. 2004). Size of individual units is increasing, and gradually 1 – 3.5 MW units are on the way. However, this still means larger electrolysis plants have to have multiple units increasing their capital costs - scaling up alkaline electrolysers further could significantly decrease marginal capital costs.

PEM electrolysers are benefiting from the large amount of R&D going into PEM fuel cells. They are currently restricted to niche markets, and have large potential for cost reductions: Maloney and Wolff (2002) believe immediate reductions of 50% can be achieved through improved design and component selection; they also estimate each doubling of production will reduce costs by 25%. NRC (2004) believes an 8-fold reduction in capital costs, from $1000/kW to $125/kW can be achieved (by an unspecified date) mainly through improved design, cheaper membranes, and mass-production.

The US DOE target is $300/kW by 2010, which it believes is achievable mainly through increasing production rates.

5.3.2 New technologies

Cheaper and more durable membrane to replace Nafion ® would reduce the cost of PEM electrolysis, and fluorinated polyethylene membranes are promising options

High-pressure electrolysis can also offer cost reductions, since it can eliminating costly and energy intensive hydrogen compressors. H3-energy, a spin-off Mitsubishi, have recently developed a PEM electrolyser operating above 35MPa without a hydrogen compressor.

High-temperature steam electrolysis utilising waste heat from power plants, or concentrated solar energy, is also a promising future option, reducing electricity requirements by 35%, and possibly increasing electrical-to-hydrogen efficiency to 95%. Utilising nuclear heat would appear to require high temperature reactors operating above 900^{o}C which have not yet been that widely developed, although test reactors are operational. Solid-oxide electrolysers could be suitable for high temperature electrolysis due to their high operating temperatures, robustness and relatively low cost. A preliminary assessment put hydrogen price from high temperature steam electrolysis at around $15/GJ (Werkoff and Marechal 2003).

6 Environmental aspects of Hydrogen production

Power generation from pure H_2 is in general more expensive than direct production from primary resources (E4 Tech *et al*, 2004). Depending on the process, it can also result in higher CO_2 emissions from the complete energy chain. The additional conversion step required for production of H_2 and then electricity reduces the overall efficiency of the energy chain, resulting in higher CO_2 emissions when using non-renewable resources. Even when renewable resources are used, the lower efficiency of the energy chain means that a greater quantity of renewable resource is required per kWh generated than for direct renewable electricity use. As renewable energy resources are at a premium in most countries that are trying to mitigate climate change, this is likely to lead to higher overall CO_2 emissions.

The CO_2 emissions relating to the use of H_2 are entirely dependent on the method of production and distribution. H_2 can be produced from a wide variety of energy sources, at a range of scales and distributed in different ways, and one cannot attribute a single emissions factor to it, or even a narrow range.

Much of the work on CO_2 emissions from H_2 energy chains has focused on its use in the transport sector. Such studies generally take a 'well-to-wheels' approach, comprising two parts: a 'well-to-tank' analysis to calculate the carbon-intensity of the H_2 used, and a 'tank-to-wheels' analysis that focuses on the efficiency with which the H_2 is used. The well-to-tank component of such analyses identifies the CO_2 emissions from each part of the energy chain, from extraction and distribution of the original feedstock, through H_2 production and compression/liquefaction. This 'well-to-tank' component therefore provides a good representation of the range of CO_2 emissions that are 'embodied' in a megajoule of H_2, though the 'tank-to-wheels' component of such analyses are not directly relevant for power generation from H_2.

The most comprehensive well-to-wheels study to date was undertaken in 2003 by CONCAWE, EUCAR and the Joint Research Centre of the EU Commission (JRC). This report evaluates "the Well-to-Wheels energy use and greenhouse gas (GHG) emissions for a wide range of potential future fuel and powertrain options" (CONCAWE *et al*, 2004). This includes a number of automotive fuels, including H_2; Figure 3 illustrates the chains for compressed H_2 considered in the study.

Figure 3 Representation of hydrogen energy chains (from Concawe et al, 2004)

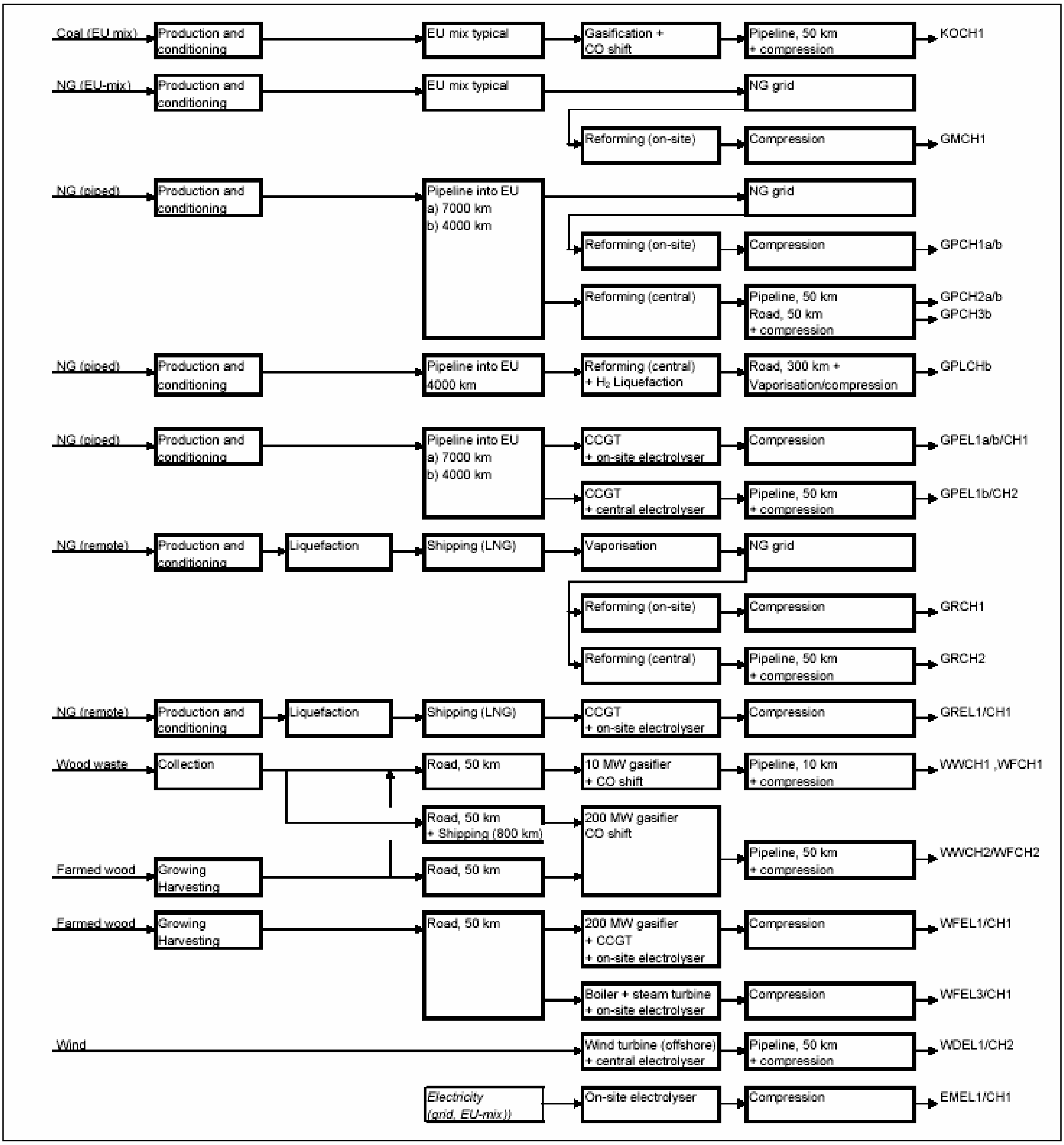


Figure 4 Well-to-tank CO_2 emissions for electricity to H_2 chains

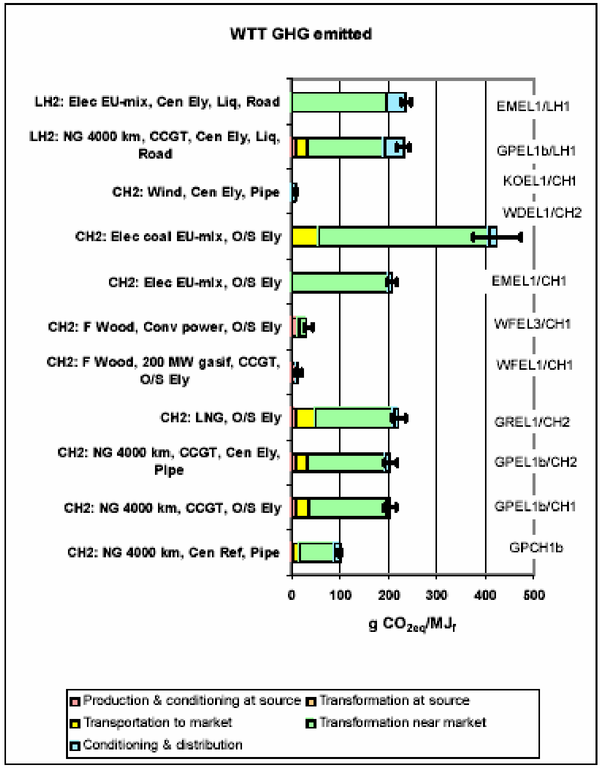


Figure 5 Well-to-tank CO_2 emissions for natural gas to H_2 chains

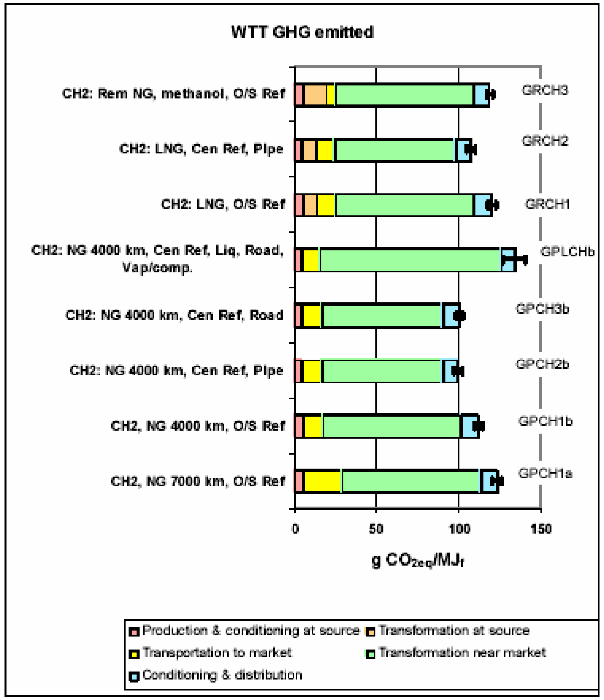
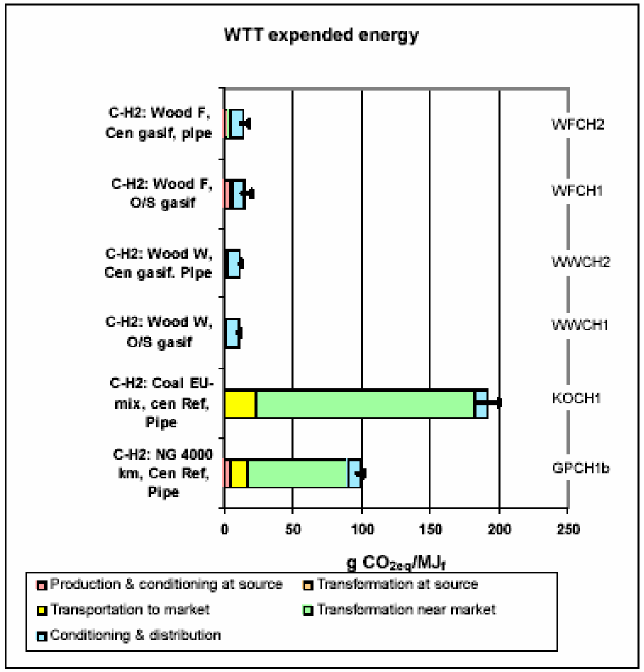


Figure 6 Well-to-tank CO_2 emissions for wood and coal to H_2 chains



All Figures above are taken from Concawe et al (2004)

The results of the well-to-tank component of this study are presented in Figures 2-4, showing the chains for H_2 from electricity, natural gas, wood and coal. The range of results for the carbon-intensity of the H_2 chains is very wide, especially for the electrolysis routes. The lowest well-to-tank emissions are less than 20g CO_2 equivalent per MJ, from a centralised wind-H_2 route using pipelines for H_2 distribution. The highest CO_2 is a factor of more than 20 greater at over 400g CO_2 equivalent per MJ, with the H_2 coming from electrolysis using electricity from existing coal-fired power stations.

The analysis presented above covers many of the ways in which H_2 might be produced and distributed primarily for use in the transport sector; if an infrastructure for the transport sector is developed, this is also likely to be the main source of H_2 for the power sector. However, H_2 is sometimes produced as a by-product of industrial processes. Studies that have considered this as a source of H_2 for the transport sector have tended to assume that the H_2 would otherwise be mixed with natural gas and used in thermal processes. They have therefore treated the CO_2 emissions for this H_2 as those that would otherwise result from combustion of the natural gas displaced in such processes (IPTS, 2004).

7 Summary and Conclusions

Four major hydrogen production pathways were reviewed: steam methane reforming, coal gasification, biomass gasification and pyrolysis, and electrolysis. Data on costs were presented, and the underlying drivers and uncertainties examined.

A difficulty with this type of review is dealing with the broad, and often unspecified, range of assumptions which appear in the literature. Data was presented in standard units, but economic assumptions and the scope of different studies often varied, making comparison across studies difficult.

Large scale fossil routes to hydrogen provide the cheapest option, with hydrogen from both SMR and coal gasification available for around $6/GJ. Small scale SMR currently appears more expensive, perhaps somewhere between $15-$25 /GJ, but with room for significant reductions if it becomes widespread. SMR costs are sensitive to the price of natural gas, and most studies use a natural gas price which is perhaps 40-50% too low. Therefore coal may provide the cheapest route to hydrogen.

Fossil fuel pathways contribute to CO_2 emissions, coal more than gas. Adding CO_2 capture to fossil plants may increase the cost of hydrogen by 10-20%, excluding the costs of CO_2 transport and sequestration. The cost of CO_2 transport and sequestration are difficult to predict, since the technologies are uncertain, costs are likely to be very site-specific, and depend on economic factors such as enhanced oil and gas recovery revenues.

Estimates for cost of hydrogen from biomass vary widely, with costs of production using current technologies ranging from about $15-30 /GJ, but some estimates putting the future cost as low as $8/GJ. A major uncertainty is the cost of biomass, and the size of the resource potential. Waste biomass may be available much cheaper than dedicated fuel crops, though not in as large or predictable volumes.

Electrolysis is the most expensive option, and estimates for current technology range from $20 - $60/GJ, to more than $100/GJ for very small scale electrolysis. The major component is electricity price, and at current market rates this would contribute $20-$23/GJ to hydrogen cost, before capital costs are considered. However, some studies suggest large advanced electrolysis utilising waste heat from power plants could bring electrolysis costs down to $10-15/GJ.

The production of cost of hydrogen is not the only factor which will determine whether hydrogen will or could be suitable as a widespread future energy vector. The implications, costs and constraints on the whole energy system need to be considered, including the overall demand for primary energy, overall CO_2 emissions, well-to-wheels efficiency, and well-to-wheels costs, including the costs of storing and transporting hydrogen. However, in a competitive energy market, the production cost of hydrogen is of key importance as to whether, or in what circumstances, it can compete with incumbents such as gasoline or natural gas.

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