Sustainable and Economic Hydrogen Co-generation from Nuclear Energy in Competitive Power Markets

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Abstract

Hydrogen is becoming the reference fuel for future transportation. However, hydrogen production either directly or indirectly needs to satisfy three criteria: no associated emissions, including CO_2; wide availability; and affordability. Water electrolysis is the only available technology today able to meet the first and second criteria. The third criterion includes costs of electrolysis and electricity. The primary requirements for affordable electrolysis are low capital cost and high utilization. Consequently, the electricity supply must enable high utilization as well as being itself low-cost and emissions-free. The only proven, large-scale source of electricity is evolved nuclear technologies, producing electricity at rates competitive with today's CO_2-emitting, fossil-fuelled technologies. As an example, we show sustainable deployment using co-generation in a typical competitive power market.

KEYWORDS: Hydrogen, transportation, electrolysis, nuclear power

1 The Broader Context of Hydrogen Production

1.1 Introduction

In AECL-12142[1], we have argued the importance of moving the global economy away from CO_2-emitting energy sources. In that wide-ranging paper, we argued that migration to non-CO_2-emitting sources should be instigated with urgency and that a program of substitution should and could be in effect by 2040. This must occur in the context of a rapid expansion of energy consumption in the world's emerging economies. In this paper, we focus on how hydrogen can be produced to effect the migration of transportation away from oil, whose price volatility; finite supply, GHG emissions, and security concerns make it a prime candidate for substitution.

The recent US Hydrogen Roadmap[2] echoes this theme, and recognises the need for rapid hydrogen deployment as an energy currency. The focus is on extensive use in the transportation and energy sectors by 2015 or so. We first put transportation in context and then look at the electricity market for its suitability to produce hydrogen by water electrolysis. In the main part of the paper, we look at different approaches to electrolysis and compare these with alternatives for hydrogen production. We use technical and economic analyses based on current cost data.

2 Transportation's Emissions, Energy Demand and Power Generation

All developed countries have a high dependency on gasoline use in transportation, and developing countries are heading in the same direction. In Canada, if one examines CO_2 emissions by broad sectors (Fig. 1), four sectors cover over 75% of the total. In 2000, transportation had 26%, industrial 18%, power generation 16%, and fossil-fuel industries 15%. Since a large proportion of "fossil-fuel industries" actually supplies transportation and power generation, one can conclude that these two sectors actually account for around half the total.

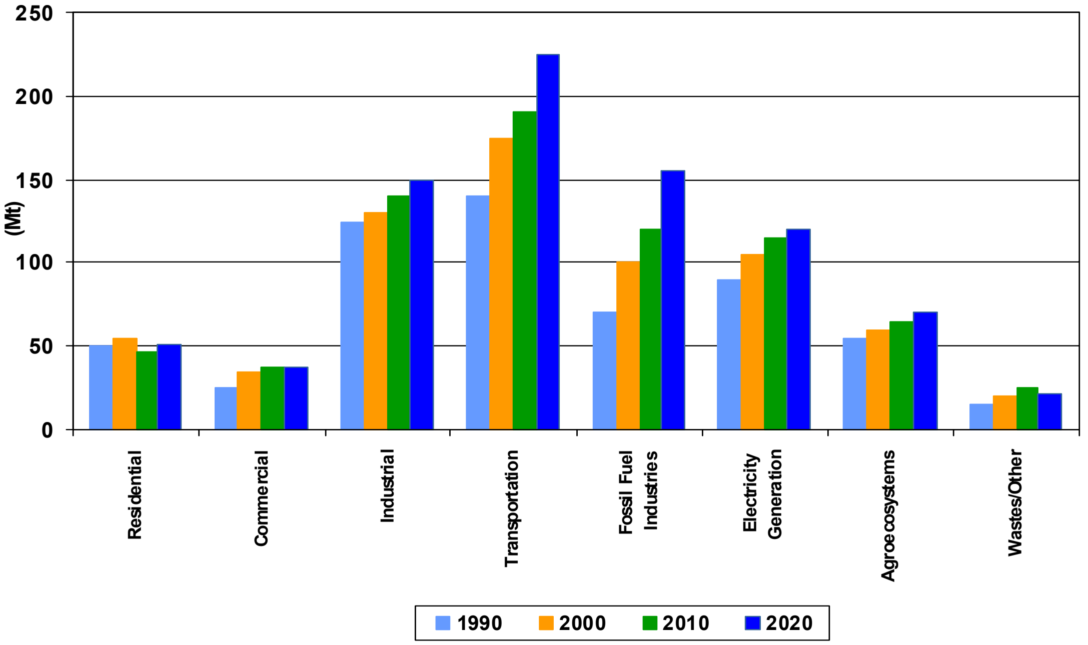

Figure 1: Canadian Energy Consumption, Past and Projected, by Sector

Canadian transportation is very typical of developed economies, responsible for direct consumption of 25 to 30% of all energy used. The proportion is projected to rise: for example, the report of the United Kingdom Government's Inter-departmental Analysts Group[3] projects that the British transportation sector's CO_2 emissions will rise from 25% of the total in 2000 to 29% in 2010 and to 41% in 2050. The USA's Energy Information Administration projects[4] an increase in transportation's energy consumption from 27% of the total in 2000 to 31% in 2025. Natural Resources Canada has published "Canada's Emissions Outlook, an Update"[5] and this projects transportation's share of CO_2 emissions rising from 25.6% in 2000 to 27.0% in 2020. The percentages vary between countries but the pattern of rising importance for transportation is similar. As an example, China is a developing economy, where transportation oil use is expected to grow by a factor of four over the next 20 years (source: DOE International Energy Outlook, 2002)[6].

2.1 Synergy between Electricity Generation and Hydrogen Production

Taking transportation and electricity generation largely off carbon would be a major step to reducing CO_2 emissions; conversely, any strategy that fails to address these two sectors will be severely constrained by their exclusion. Furthermore, apart from their importance, these two conversions can actually be advantageously entwined through the proposed use of hydrogen as a transportation fuel from water electrolysis.

The particular attraction of this synergy between the two energy conversions – off-coal for electricity and onto hydrogen for transportation – lies in the one major complication in replacing coal-fired electricity generation: coal-fired electricity generation is well adapted to meeting variation in electricity demand while the replacement sources are not. This is caused by the different cost structures of electricity produced from carbon (i.e. coal or natural gas) and of electricity produced by other means. The cost of electricity generation based on carbon is dominated by fuel cost and so coal-fired and natural-gas-fired generators are predominantly used to provide the variable part of electricity demand. Non-carbon sources of electricity are generally capital-intensive and suited to base-loaded demand (nuclear) or have intrinsically low capacity factors (typically ~ 30%), at the caprice of weather (wind, solar, tidal) thus requiring backup, storage and/or a reliable alternate grid connection. So widespread replacement of coal-fired generating stations has the potential to produce electricity at little or no incremental cost when there is no market. Routing otherwise unmarketable electricity to supply the fuel demands of the transportation sector in the form of hydrogen produced by water electrolysis can, in principle, provide a mechanism for smoothing out the traditional peaks and valleys of electricity demand. Selling power to the grid when the electricity price is high and using it for electrolysis at other times leads to relatively cheap hydrogen.

To fix the order of magnitude, we estimate that some 600 000 vehicles could be fuelled by the hydrogen produced by the power from one medium-sized (700-MW) reactor (see Section 4.5). The energy requirement for electrolysis production of hydrogen is ~ 56 kW·h per kg H_2.

2.2 The Existing Inefficiency of Transportation

There is one more reason for focusing on taking transportation off carbon: much of it is strikingly inefficient. The transportation sector in developed economies is considerably diverse but nearly 60% of its energy use is for personal vehicles (cars and light trucks). While the industrial, fossil-fuel and residential sectors achieve energy conversion efficiencies of 70% and up, North American cars are about 15% efficient and even the European Union's 2008 undertaking of 140 gCO_2/km for new cars amounts to only 25%-efficient conversion. Fuel cells burning hydrogen, although still in their infancy, already achieve over 50% efficiency. The high efficiency of fuel cells can more than offset the losses in converting electricity to hydrogen and substantially less electrical energy is needed than the energy content of the oil-based fuel that it replaces.

So replacing carbon-based fuels in this sector requires less hydrogen than would be needed to displace most industrial, commercial and residential demands for energy.

2.3 Batteries as an Alternative to Electrolytic Hydrogen

In theory, electric storage batteries could take the place of hydrogen in vehicle propulsion but extensive efforts around the world over the last 30 to 40 years have failed to devise an electric storage battery with the required *combination* of cost, efficiency of conversion, and – above all – weight. So it is almost by default that hydrogen is being touted as the transportation fuel of choice for the 21st Century. It is an opportunity for hydrogen-based technology and it is also a major challenge since, to make an effective contribution to the reduction of CO_2 emissions, the scale of hydrogen deployment will be prodigious. This paper largely focuses on how hydrogen could be generated in the required quantities.

2.4 Alternatives to Electrolysis for Making Hydrogen

We adopt a condition and assumption that, in addition to being competitive, the production must be sustainable.

The main alternative to electrolytic hydrogen is to produce it by steam-methane reforming (SMR). This is currently the dominant source of hydrogen in large quantities. But, as we shall discuss in more detail below, the competitive advantage of SMRs is quickly lost as they are scaled down and operation of world-scale SMRs to supply the transportation market would require large distribution networks and costs. As well, SMRs produce CO_2. Sequestering CO_2 will add considerable cost and about 28% is in the form of dilute flue gas, which probably cannot practically be sequestered.

The other SMR alternative, that of using micro-SMRs for on-board conversion of a carbon-based fuel to hydrogen cannot achieve sequestration and would, at best, produce only modest CO_2 reduction and, at worst, could actually increase total CO_2 emissions, e.g. if using methanol that had been produced without CO_2 sequestration.

In practice, we shall show that the cost premium for electrolytic hydrogen can be small enough that SMRs are unlikely ever to have a major role in producing hydrogen for transportation. After perhaps 2030, new possibilities may appear in the form of "high" or "very high" temperature reactors, concepts currently being studied. These could use nuclear heat to provide the reaction heat for SMRs or provide the energy for indirect thermochemical cycles to produce hydrogen (see e.g. Forsberg *et al*[7]). However, these are many years away from demonstrating economic feasibility and are, of course, central stations, and so not suited for distributed hydrogen generation.

3 Patterns of Electricity Cost Variation

We now show how hydrogen and electricity co-generation can work and compete in an "open" power market, where time of day demand and price varies.

3.1 Free-Market Electricity Prices

In the free-market economies of the USA and in Canada, the anomaly of regulated prices within parts of the energy market appears to be ending. Although prices for electricity are still the most widely regulated within the energy sector, even there a trend toward price deregulation is becoming evident despite well-publicized failures in some jurisdictions – failures that are largely attributable to distortions of a political nature. Where the market has been allowed to ride through an initial period of price turbulence, prices seem to settle into a workable pattern, with price fluctuation providing appropriate guidance to both the supply and demand sides of the market. In Canada, Alberta is the major jurisdiction to have passed successfully through this initial period. The year of deregulation launch, 2001, produced extreme price spikes but the market had settled down in 2002. The published price data[8] provide useful information on the variation in price that can be expected with a market in which price is controlled by demand, and not by edict or by legislated caps or limits.

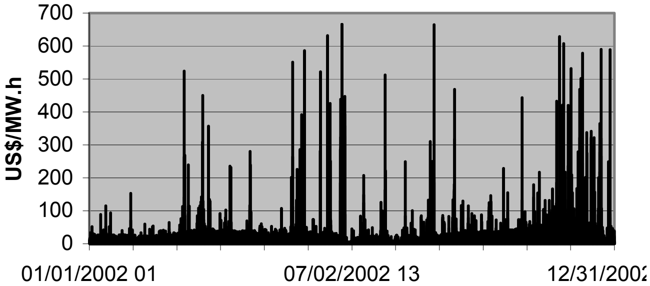

Figure 2: Hourly Power Rates in Alberta for 2002

The Alberta Power Pool sets hourly prices (see Figure 2) one week in advance of actual power delivery through an auction system. Figure 2 shows the actual values in 2002, converted to US dollars at 1.5 C$ = 1 US$. Figure 2 does not show all of the fine detail in Alberta prices but it does reveal that the price pattern is not the assumed classic structure of weekday peaks at times of daily maximum demand, an approach that has been used in the past to structure regulated rates. The average price (just under 30$/MW.h) is clearly NOT a good indicator of the economic market conditions, or of the potential generating load factors for the two streams (electricity and hydrogen). Rather, electricity should not be used to produce hydrogen when the price is higher than a certain threshold. The threshold will be optimized by the balance between the costs of (1) cheaper electricity; (2) additional electrolysis capacity; and (3) storage of hydrogen.

Note that, in proposing new nuclear generation for this role, we are departing from the normal “baseload power” application of nuclear.

The annual value of the electricity will be the same but it will be divided at a threshold rate, T, between a fraction (F) of more expensive power with an average cost P_E and the balance with an average cost P_H.

The concept of producing hydrogen electrolytically using electricity off-peak can be examined in light of real data using the 2002 Alberta Pool experience and dividing the time into low- and high-price periods on either side of a variable price threshold (Table 1).

Table 1: Proportion of Alberta Pool Prices above (P_E) and below (P_H) a Price Threshold (T)

Threshold Price T, ($/MW.h)	P_H Av. Under Threshold ($/MW.h)	F % Above Threshold	P_E Av. Above Threshold, ($/MW.h)	Total Peak Rev. Above T (M$)	Total Rev. Below T (M$)
20	10.36	54.46%	45.11	215.21	41.33
25	12.50	44.54%	50.19	195.83	60.73
30	14.57	35.49%	56.04	174.22	82.34
35	16.65	27.08%	63.32	150.21	106.36
40	19.19	17.07%	78.34	117.14	139.41
42	20.05	13.68%	87.61	104.99	151.61
44	20.93	10.25%	102.49	92.03	164.55
46	21.43	8.31%	115.96	84.41	172.13
48	21.71	7.28%	125.70	80.16	176.33
50	21.87	6.74%	131.94	77.90	178.67
55	22.22	5.65%	147.29	72.90	183.65
60	22.44	5.06%	157.83	69.96	186.63
65	22.63	4.60%	167.31	67.42	189.12
70	22.79	4.26%	175.35	65.44	191.14
75	23.06	3.73%	189.77	62.01	194.47
80	23.27	3.38%	201.45	59.65	196.96
90	23.49	3.03%	215.04	57.08	199.54
100	23.71	2.73%	228.22	54.58	202.03
110	23.99	2.39%	246.01	51.51	205.13
120	24.21	2.15%	260.69	49.10	207.52

4 Different Approaches to Producing Hydrogen: Distributed and Centralized

Producing hydrogen as fuel for transportation could take one of three forms:

1. Bulk, centralized production;
2. Distributed production; and
3. Home production by individual users.

Today, hydrogen production belongs overwhelmingly to the first category with centralized SMRs of typically 3 million m^3/d (100 million ft^3/d or 250 tonne/d) capacity. Smaller SMRs range down to around one-fiftieth of that size. Falling into the second and third categoies, still smaller amounts are usually produced electrolytically.

4.1 Distributed Hydrogen Production

We argue that it is the novel, second category of *distributed hydrogen production* that is likely to launch hydrogen fuelling for the transportation sector, and particularly for its dominant road-transport component.

It is widely appreciated that establishing a new fuel for road transportation is a daunting and expensive task. Sequencing is a particular difficult problem: except for special circumstances where they are totally limited to a small geographical range, vehicles are useless without widely available fuelling stations and fuelling stations are expensive white elephants until there are lots of vehicles using that fuel. Electrolytic hydrogen solves this paradox with relative ease since the *existing* electricity grid can handle the energy distribution task – especially if electrolysis occurs only with off-peak power when the grid will have spare transmission capacity. While transmission costs are typically 30% of the final power cost, adding distribution load at off-peak times should be much cheaper.

For distributed electrolytic production at neighbourhood filling stations, there will be the three main cost components already identified: (1) electrical energy; (2) amortization of the production equipment (electrolytic cells, compressors, and dispensing equipment); and (3) amortization of storage. Since service stations will wish to avoid running out of fuel and supplementary bulk delivery of hydrogen will be expensive – though probably a necessary, occasional back-up – storage is a key issue.

4.2 A Fuel-demand Scenario

To make hydrogen an affordable fuel, the development of cost-competitive, fuel-cell-powered vehicles is highly desirable. That is topic beyond this paper but is assumed to occur in the timeframe of the next ten years, a position supported by the current optimism of companies such as General Motors. (Hydrogen-fuelled internal combustion engines (ICEs) are an available alternative but with at least a 50% premium on fuel use.) It is assumed that fuel-cell powered cars will have similar range to gasoline- and diesel-fuelled vehicles. Since existing ICEs achieve about 15% efficiency compared to fuel-cells' efficiencies exceeding 50% and the energy content of hydrogen is rather more than three times greater than gasoline on a weight basis, a typical fill-up for a gasoline-fuelled car of 40 litres (30 kg) will become 3 kg of hydrogen – stored as a gas on-board in 700-atmosphere aluminum, carbon-fibre re-inforced cylinders, which are already available. (The volume of the compressed gas is about 80 L.)

4.3 Capital Costs for Electrolytic Hydrogen

As well as the power cost, costs for the cells and for storage must be included. Stuart Energy Systems (SES)[9] estimate that 300 $/kW is a reasonable estimate for this size of installation[i]. The cost includes compression and associated delivery equipment. Because this is a cell design optimized for low capital cost, it uses a slightly inefficient 1.8 volts and an estimated total energy use (including compression) equivalent to 2.1 volts. Storage cost turns out to be particularly significant. This cost is also difficult to estimate since this is a new type of activity and likely to be hedged around with regulation. Using 800 000 $/tonne[ii] of storage is judged to be a reasonable estimate – probably in the form of tube storage and so subject to fairly linear scaling with the size of the installation.

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[i] For much larger scale centralized installations, costs as low as 170 $/kW are projected by Stuart.

[ii] Tube trailers with 4000 standard m^3 capacity cost $285 000. These are mobile and so could be somewhat more expensive than a fixed installation.

4.4 Cost Optimization

Detailed examination of the Alberta data shows how the three cost elements can be optimized for minimum cost of hydrogen. Operating only when electricity is very cheap raises the cost contribution of the cells, since they are disproportionately idle and a larger installation is needed to meet the total demand. Storage has to be larger to carry the station through longer periods when power costs are high.

Table 2 calculates the storage requirement for a range of conditions as hours of demand. Obviously, interruption of production requires additional cell capacity. Offsetting this, the larger the electrolysis excess, the less storage will be needed. Table 2 covers the most interesting part of the information from the Alberta Power Pool, diverting power to electrolysis when the pool price drops below a threshold between 40 and 65 $/MW·h . Looking back at Table 1, this is somewhat surprising since power is available at around half that cost for almost half the time but the capital costs turn out to be important. However, the average cost is far below the threshold cost.

Table 2: Hydrogen Storage Requirements in Hours as a Function of Threshold Pool Price and Electrolytic Capacity as a Function of the Continuous Rate

Electrolysis Installation (% Continuous)	Threshold Pool Price, T ($/MW·h)								
	40	42	44	46	48	50	55	60	65
	Required Hours of Storage Capacity								
110	N/P	N/P	N/P	190	119	92	65	51	45
115	N/P	N/P	234	123	67	52	30	21	19
120	N/P	409	187	82	37	29	17	16	16
125	536	363	148	51	32	26	16	14	14
130	496	320	120	29	28	24	16	13	13
135	460	278	94	27	25	23	15	12	12
140	423	255	67	25	24	21	14	12	12
145	387	234	57	23	22	20	14	11	11
150	351	214	51	21	20	18	13	11	11
160	291	175	37	18	17	15	12	9	9
170	257	155	32	15	14	12	11	9	9
180	240	135	26	12	12	11	11	9	9

Note: N/P means "not possible": the excess is smaller than the fraction of time for which power is available at that price.

Table 3 converts the data of Table 2 into estimated hydrogen costs, including the three elements of electricity, cell capital, and storage. Capital recovery over 10 years at 15%/a return on investment has been used.

Table 3: Cost of Hydrogen ($/tonne)

Electrolysis Installation (% Continuous)	Threshold Pool Price, T ($/MW·h)								
	40	42	44	46	48	50	55	60	65
	Cost of Hydrogen ($/tonne)								
110	N/P	N/P	N/P	5086	3810	3328	2856	2614	2516
115	N/P	N/P	N/P	3886	2883	2619	2239	2087	2062
120	N/P	9127	5044	3160	2357	2220	2021	2016	2026
125	11413	8313	4335	2615	2285	2185	2022	1998	2009
130	10708	7554	3825	2234	2231	2167	2042	1999	2010
135	10076	6813	3352	2216	2196	2168	2043	2000	2011
140	9426	6417	2861	2199	2197	2151	2044	2020	2030
145	8794	6059	2679	2182	2180	2152	2063	2021	2031
150	8162	5718	2570	2165	2162	2135	2064	2040	2050
160	7117	5054	2315	2149	2146	2119	2084	2042	2053
170	6544	4737	2224	2133	2130	2103	2104	2080	2091
180	6281	4419	2115	2116	2132	2123	2143	2119	2129

Table 3 (plotted in Figure 3) shows a broad, flat minimum cost between 55 and 65 $/MW·h with storage around 12 hours. The calculated optimum of approximately a half-day's storage is quite convenient since the pattern of actual demand for hydrogen will vary over a daily cycle.

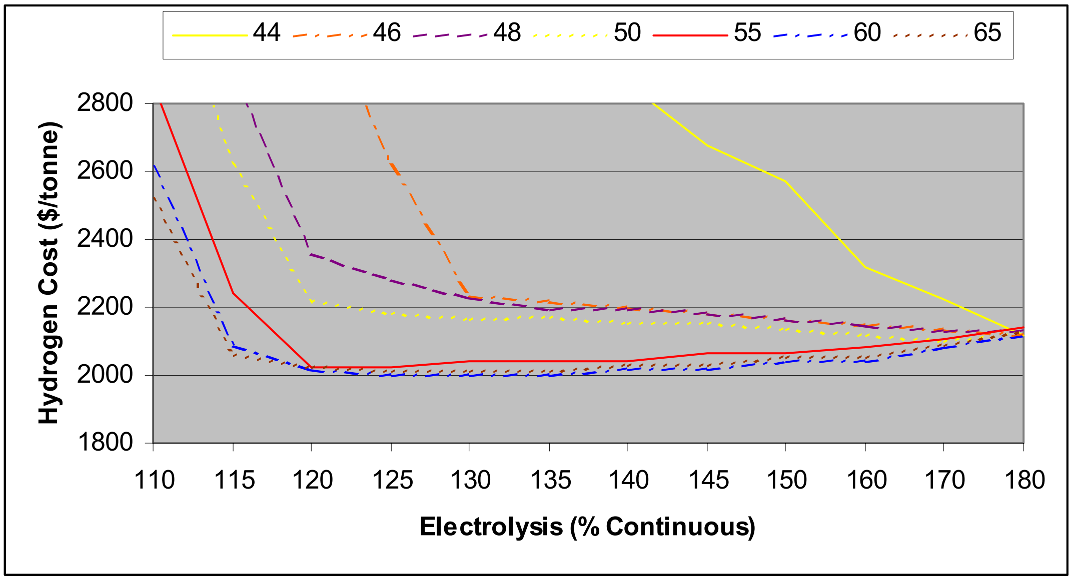

Figure 3: Cost of Hydrogen for Various Levels of the Cost of Electricity (40 to 60 $/MW.h) above which Hydrogen is not produced as a Function of Electrolytic Capacity above that required for Continuous Production

The pattern of Table 3 is largely controlled by the cost of storage. The cost of additional electrolysis is a weaker effect and only appears when the requirement for storage is very low. However, moving the threshold down to achieve lower electricity rates is unattractive even when the storage requirement is the same (compare the 46 $/MW·h , 180% electrolysis case with the 65 $/MW·h , 135% case).

The calculations in Tables 2 and 3 are relatively rigid. Since the price of electricity in the Alberta Pool is known well in advance, a decision to produce hydrogen could be made even when the cost exceeds the threshold whenever storage is expected to become dangerously low.

So, for example, if an upper threshold were set of 325 $/MW·h to permit production on the rare occasions when hydrogen in storage had dropped below one hour's supply, for a normal threshold of 60 $/MW·h and for 12 hours of storage, the cost of hydrogen drops to 1965 $/tonne. The saving in this instance is only 1.7% but it does indicate that flexibility in varying the threshold is beneficial. More sophisticated schemes to avoid local high points of electricity price while still meeting hydrogen demand would likely be of greater benefit.

4.5 Home Production

For reasons of perceived safety (affecting insurance as well as personal inclination), home production of hydrogen must be an uncertain prospect but it is worth examining as a possibility at least for locations remote from service-station supply.

First, we need to establish the size for a typical one-vehicle system.

The average Canadian car covers 21 000 km in a year with a fuel efficiency of 11.3 L/100 km (20.8 mile/gal (US)) from its ICE. On the basis that the currently typical ICE's efficiency is 15%, 3185 kW·h is actually expended annually as propulsive energy delivered through the vehicles wheels. So a fuel cell with 50% efficiency will require 6370 kW·h of hydrogen fuel or 161 kg of hydrogen per year. As one example of distributed generation, SES has developed a simple electrolysis design, again emphasising low capital cost and based on existing commercial systems used to compress natural gas. Combining an electrolysis cell with a small compressor, SES has packaged this technology into a prototype for a small "home hydrogen refueller". Since it is based on the same electrolytic cell technology as proposed for the service station, the power requirement (expressed as an effective cell voltage of 2.1 volts) is the same. So the 6370 kW·h/a of hydrogen – the actual energy content, which can be thought of as equivalent to the thermoneutral electrolysis voltage of 1.47 V – requires 9100 kW·h/a of input power to the system. Assuming an average retail off-peak power cost of 17 $/MW·h (in 2002, this would have been available in Alberta for 75% of the time) and add a typical 20 $/MW·h mark-up for distribution to small residential customers, the annual operating cost would be 337 $. SES estimates the cost of the refueller in mass production of 1500 to 2000 $/unit. Using the higher figure and 6%/a financing (typical of a consumer's borrowing cost) and ten-year amortization, this adds a further 272 $/a for a total annual cost of 610 $.

Note that the SES system's low capital cost can easily justify the moderately high voltage. In general, given the limited scope for lowering the voltage required to electrolyse water, high-cost, low-voltage designs are unlikely to be competitive for highly distributed hydrogen production.

At a rating of 1.75 kW (15 amps at 117 V), the time to produce the hydrogen required for a 58 km average daily range is 14.2 hours, an implied capacity factor for the refueller of 59%. Within the constraints of using off-peak power and plugging into standard North American 117-volt power outlets, home fuelling could supply most of the hydrogen needs for the average Canadian vehicle. Those driving consistently greater distances could easily install multiple fuelling systems without constraint from the typical household's 200-amp capacity with the same fuel economics.

One interesting possible offset to the higher cost is re-conversion of hydrogen back to electricity using the automobile's fuel cell. While this is inefficient, with true time-of-day-pricing, the Alberta price figures show that it could be usefully profitable.

4.6 Cost Comparison with Gasoline for Electrolytic Hydrogen

At 45 ¢/L for gasoline, the fuel cost for a conventional car (11.3 L/100 km) is 836 $/a. Of course, the hydrogen cost is without the taxation associated with gasoline but the point is that the operating cost of the electrolytic hydrogen vehicle is within the range currently experienced by Canadian drivers.

So even the home-refueller option appears to be economically feasible and not excessively expensive, though the cost is over 4000 $/tonne H_2. However, the estimated cost of hydrogen produced in greater volume at a service station is less than half that of the home refueller. *If one adds a 25% profit mark-up – which is a good deal larger than enjoyed by gasoline, the typical annual fuelling cost for hydrogen produced electrolytically at a service station would be 0.161 x 1826 x 1.25 = 368 $/a.*

4.7 SMR Production of Hydrogen

In the minds of those involved in the petrochemical industry, where the demand for hydrogen is very large, steam-methane reforming is the technology of choice. At scales of several million cubic metres per day, it is a highly efficient, cost-effective technology. Even if encumbered with a high price for natural gas (5 $/GJ) and a large CO_2 sequestering charge of 37 $/tonne[i] (based on a UK Department of Trade and Industry study of the cost of sequestration[10]), SMR hydrogen costs only slightly over 1200 $/tonne. The fuel cost makes up 61% (744 $/tonne), the SMR capital contributes 16% (200 $/tonne) and the remaining 23% (275 $/tonne) is the sequestration charge.

However, this production cost is without the almost incalculable distribution costs from a large centralized SMR to individual service stations. In the absence of any basis on which to judge the area that a large SMR would service, distribution costs are essentially unknowable.

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[i] The position paper UK Government's DTI uses £84/tonne C (37 $/tonne CO_2) for the typical cost for CO_2 sequestration, in a deep geological aquifer 300 km from the source. This cost ignores the difficult problem of how to sequester the 28% of the CO_2 produced by an SMR as dilute flue gas.

We note though that sourcing of hydrogen for small customers from large SMRs does not appear to occur in practice. What is clear from the current market for hydrogen is that the size of SMRs shrinks as far as is economically practicable and electrolysis then takes over. So we suggest that the distribution cost – quite apart from the difficulty of financing it before a vehicle hydrogen market has evolved – would more than outweigh the modest premium on electrolytic hydrogen produced at a service station.

If distribution from large SMRs is indeed unaffordable, the comparison for electrolytic hydrogen ought to be against small, localized SMRs. A price for hydrogen produced by smallish SMRs and then distributed in quantities around one tonne per day (which is three times larger than we envisage for a typical service station) is currently around 3400 \$/tonne[i], which implies distribution costs of over 2000 \$/tonne. For the envisaged service station, a scale of 300 kg/d – 3400 m^3/d – is one-thousandth the scale of the size typical of the chemical industry. Very small SMRs are possible and have already been developed for reforming of fuel to hydrogen on board fuel-cell-powered vehicles. However, size-reduction comes at a price. The chemical industry usually expresses the effect of size changes as a power law:

$$\text{Cost} \propto (\text{size})^n$$

The exponent, n, is a fraction typically between about 0.6 and 1. For processes – like electrolysis – where scale-up simply means adding units, n will be close to 1. Unpublished cost data indicate an exponent of 0.66 for SMRs. So a reduction in size by a factor of 1000 would reduce the capital cost by about 100 – which would explain why SMRs below 50 000 m^3/d are generally considered uneconomic. Assuming that the scaling does hold, the SMR capital charge is now 2000 \$/tonne. So indeed the existing pattern of hydrogen production is confirmed and indicates that *small-scale SMRs do not compete with distributed electrolysis and the costs of natural gas and for* CO_2 *sequestration are of secondary importance*.

4.8 Cost Summary

The cost of hydrogen produced locally by the various methods is summarized in Table 4. These do not include any profit, taxes or other mark-up.

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[i] This is a price for liquid H_2, which is the preferred form simply because compressed gas is more expensive.

Table 4: Summary of Hydrogen Costs in $/tonne

	Costs per Tonne of Hydrogen				
Large SMR (250 tonne/d; 5 $/GJ nat. gas)	Methane	Capital	CO_2 Sequestration	Distribution	Total
	744	200	275	>2000	>3200
Small SMR (0.3 tonne/d; 5 $/GJ nat. gas)	Methane	Capital	CO_2 Sequestration		Total
	744	2000	275		3019
Service Station Electrolytic H_2 (0.3 tonne/d)	Electricity	Production Equipment	Storage		Total
	1231	556	39		1826
Home Electrolytic H_2 (0.4 kg/d)	Electricity	Production Equipment	Storage		Total
	2308	1689	0		3997

Looking at Table 4, one can observe that “>2200” for a large SMR must really be considerably greater since smallish SMRs are actually built, down at least to two to three tonnes/day capacity but small-scale H_2 demand is usually met with merchant, liquid H_2.

4.9 Source of Electricity for Hydrogen Production

Interestingly, the average price for the Alberta Power Pool in 2002 was 29.29 US$/MW·h, which is just below the projected target cost of electricity of 30 $/MW·h from a new Advanced CANDU® Reactor[i]. Because the variation in price is largely seasonal, ACR-produced power would be profitable in this market through appropriate scheduling of outages to periods of low-value electricity *provided there is a market for additional power at periods of off-peak demand*. It is precisely by providing a new, off-peak demand for electricity that electrolytic hydrogen production offers a natural synergy.

So, if nuclear energy can supply electricity to a grid at periods of peak demand at the actual prices prevailing in Alberta in 2002 – and Alberta is a province of relatively low fuel costs – ACR-produced electricity can deliver hydrogen at the costs derived in this paper.

5 Conclusion

We have examined sustainable hydrogen production using nuclear energy. Based on the Alberta Power Pool figures, we have demonstrated that fuel-cell-powered vehicles can be

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[i] The Advanced CANDU® Reactor (ACR®) is a Generation III+ reactor being developed by Atomic Energy of Canada Limited (AECL). It is developed from the CANDU-6 reactor with pressure tubes and heavy water moderation and its economics are firmly based in AECL’s experience in building CANDU 6s around the World. The expected 30% reduction in capital and operating costs comes in substantial part from use of around 2% uranium enrichment, which allows higher operating temperature and pressure, a smaller reactor lattice pitch, and use of light water as coolant plus the effects of ongoing experience in reactor building.

CANDU = CANadian Deuterium Uranium and ACR = Advanced CANDU reactor are registered trademarks of Atomic Energy of Canada Limited.

affordably fuelled with hydrogen produced by electrolysis. The overall economics can be secured in a cogeneration mode by interrupting hydrogen production at times of peak electricity prices and selling the electricity to the grid. Neglecting the potential for a new power source to influence peak prices, power produced by an Advanced CANDU® Reactor would have been economic in Alberta in that cogeneration mode in 2002.

6 References

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