A Realistic Look at Hydrogen Price Projections

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Introduction. For the past half century, most cities of population over 100,000 in industrialized nations have had dozens of industrial and research users regularly purchasing pressurized hydrogen gas in heavy steel cylinders containing about 0.6 kg H_2 per cylinder. The price of this hydrogen has been reasonably stable at about $100/kg plus cylinder rental. One of the basic assumptions underlying the putative "hydrogen economy" is that this cost can be reduced to a few dollars per kilogram even while hydrogen production costs rapidly increase over the next 30 years. There appear to be serious problems with this assumption.

Clearly, the question of the cost of hydrogen fuel to the consumer 15 to 50 years from now is of critical importance in any discussion of the possibility of a "hydrogen economy". A number of studies have been carried out over the past seven years on the cost of hydrogen, but there are major problems with most of these studies that are not widely appreciated. The four biggest problems with many hydrogen cost projections are:

1. The rate of introduction of hydrogen-fueled vehicles is currently nearly two orders of magnitude lower than was generally expected 4 to 8 years ago [*1*], and it seems likely to remain at such a depressed rate for at least several more decades [*2*]. This is largely because the costs of proton exchange membrane fuel cell (PEMFC) engines are still over $3,000/kW [*3*], which is two orders of magnitude higher than was officially expected in the late '90's [*4*]. Also, their lifetime under road conditions is still 20% that of the diesel engine, and they achieve under 35% efficiency [*3*].
2. North America is facing natural gas (NG) shortages that will steadily worsen over the coming decades [*5*]. The price of NG has increased by a factor of 10 in the past 30 years and a factor of three in the last six years [*6*]. Its cost is likely to increase by more than another factor of two (in constant dollars) within 15 years.
3. Small hydrogen-dispensing stations [*7*] are costing about $600K each, which is ten times more than was initially expected for stations an order of magnitude larger [*8*] and is thus another error in assumptions of two orders of magnitude.
4. Hydrogen storage costs by all methods (at least for quantities below tens of thousands of kilograms) are two orders of magnitude greater than for liquid hydrocarbon fuels [*9*]. This is clearly not appreciated in many published studies which have often referenced erroneous earlier works [*4, 8*].

There are also a number of other significant issues which were not well appreciated in earlier studies, such as (1) the increase in pipeline costs to avoid hydrogen embrittlement failures [*10*], (2) the significance of flash losses associated with dispensing moderate quantities (100-500 kg) from trailer-truck tankers of liquid hydrogen, and (3) failure to consider the implications of taxes, including the imposition of a fossil-carbon tax or similar disincentive to the use of fuels such as fossil hydrogen which have huge life-cycle green-house-gas emissions.

Most hydrogen studies over the past several years contain a mixture of facts and advocacy. As noted, there have been at least four common errors of at least an order of magnitude in many published hydrogen-economy studies over the past decade – FC costs, rate of introduction of hydrogen vehicles, hydrogen storage costs, and fuel dispensing costs. All of these errors have been in the direction to make hydrogen seem more attractive as a fuel. However, it is important to point out that several thorough and generally accurate infrastructure studies have been carried out [*9, 11*]. But even the rather scholarly works are often misused by hydrogen advocates who fail to carefully note their assumptions. For example:

1. NG costs were usually assumed to be $3.5/GJ – compare to today's $6/GJ at the well head, $7/GJ at the city gate, and probably $15/GJ at the city gate in 2020.
2. Dispensing stations were often assumed to be filling 300 vehicles each per day – about two orders of magnitude more than seems likely for at least 15 years.
3. Often 300,000 hydrogen vehicles were assumed within 100 km of the central station with a total demand of 150 tons/day – three orders of magnitude more vehicles than seems likely for several decades.

The above FC prices for PEMFCs will surprise most readers because the hydrogen lobby (and the DOE) have been saying for three years that PEMFCs cost as little as $1200/kW, but that is simply not true. A 2 kW, 50 kg, PEMFC system (stacks, compressor, regulators, controller, no storage), that apparently gets ~32% efficiency, can be purchased today for $14,000 [*12*]. Moderate-weight PEMFCs with 30-35% HHV electrical efficiency may now be commercially available in the range of $2500-5500/kW for combined heat and power (CHP) applications [*3*], but these FCs have inadequate environmental and vibrational tolerance for small vehicles, in addition to being much too large and massive. Best estimates from available financial data from Ballard Power (who has made over 80% of the FCs for vehicles over the past decade) are that road-qualified PEMFC engines still cost over $6,000/kW to produce, even though they sometimes sell the stacks alone for as little as $1300/kW [*13*]. (Over two-thirds of their revenue still comes from other sources).

Manufacturing scale-up from current FC operations (where four large firms have each been spending $100M/year) cannot be expected to achieve more than an order of magnitude reduction in costs. It has been suggested that the show-stopper issues of FC-stack cost and reliability can be avoided by using hydrogen-fueled internal combustion engines (ICEs). Indeed, such have been demonstrated, but it does not appear that they can achieve efficiencies above 28% [*14*] – 70% that of the gasoline engine [*15*]. Moreover, hydrogen ICEs still have all the fuel-cost, fuel-storage, and safety issues of hydrogen FC vehicles (FCVs) [*3*].

There are, of course, a number of possible sources of hydrogen other than NG – coal, nuclear breeder reactors, wind farms in ideal locations, biomass (pyrolysis and water shift), and solar electrolysis. Of these, only coal currently begins to compete economically with NG, but generating LH2 from coal produces at least 8 kg of carbon (29 kg of CO_2) per kilogram of H_2 [*3*]. When a realistic future (fossil) carbon tax of $0.1/kg of carbon is included, coal is likely to remain uncompetitive. Hence, the focus here will be on NG, even though most discussions of a hydrogen economy assume NG will not be an acceptable source of H_2 for long because of its increasing cost and CO_2 release. A few comments on some challenges presented by the other options will be included near the end.

Gas and Oil Price Projections. For the past five years, the DOE/EIA have demonstrated a callous disregard for objectivity when it comes to projections of both U.S. and world oil and gas reserves and likely pricing trends. Their projections for oil and gas prices (and, to a lesser extent, coal) have been proven wrong by huge amounts year after year, with five-year NG price projections from 4 to 7 years ago now proving too low by more than a factor of two. Most experts outside the U.S. have done a much better job.

Until quite recently, most analysts have predicted sufficient NG reserves worldwide for the next 30 to 50 years. However, the most recent, detailed analysis, published in the Oil and Gas Journal, now predicts global conventional gas production peaking in 2019 [*16*]. The shortages in North America are already becoming critical, as Canada is cutting back on exports (at the rate of at least 2%/year) to preserve their domestic resources – especially for use in recovery of oil from oil sands (or tarsands) [*17, 18*]. This is forcing the U.S. to frantically develop the infrastructure needed to import liquefied NG (LNG) from the Persian Gulf, East Caspian, Northern Africa, South Pacific, Western Siberia, Nigeria, and other places where NG is currently abundant and cheap [*18*]. It is worth noting that in the past year the DOE/EIA have nearly quadrupled their projections for 12-years-out of LNG imports while cutting their projections of NG imports from Canada in half [*19*].

Since then, El Paso Corp has revised its proved natural gas reserves downward by over 35% and the first major methane-hydrate project (Deadhorse, Alaska, one of the "North Slope" projects) has ended in complete failure.

Even though stranded NG is relatively abundant world wide (i.e., in locations where it cannot be economically piped to market), the assumption by the EIA that LNG will be able to be imported at very low prices is fundamentally flawed. The prices of LNG and fuel oil have stayed fairly close per unit energy for the past two decades (especially for the past seven years), and it is clear that LNG will not drop below fuel oil prices for prolonged periods. World-wide oil demand is beginning to exceed conventional oil production. The shortfall will steadily drive oil prices up, and world oil prices (the dominant market) will establish minimum international LNG prices. As carbon taxes begin to be imposed, LNG prices will exceed petroleum pre-tax prices.

The assessment of oil reserves by the Association for Peak Oil [*20*] is now internationally recognized (except within the U.S.) as the gold standard in this field. The data are undeniable that the gap between global oil production capacity and global demand has dropped from over 8% to under 1.5% in the past three years, while China continues to deal with chronic oil and gas shortages. Campbell, Simmons, and other oil experts contend there are good reasons to believe that the Middle East reserves are significantly overstated [*20*]. Moreover, it will be impossible for production of non-conventional oil (heavy oil, tarsands, etc.) to increase rapidly enough over the coming decade to significantly change Campbell's general depletion model, as shown in **Figure 1**. Clearly, the stage is set for continued increases in oil prices in the coming decade.

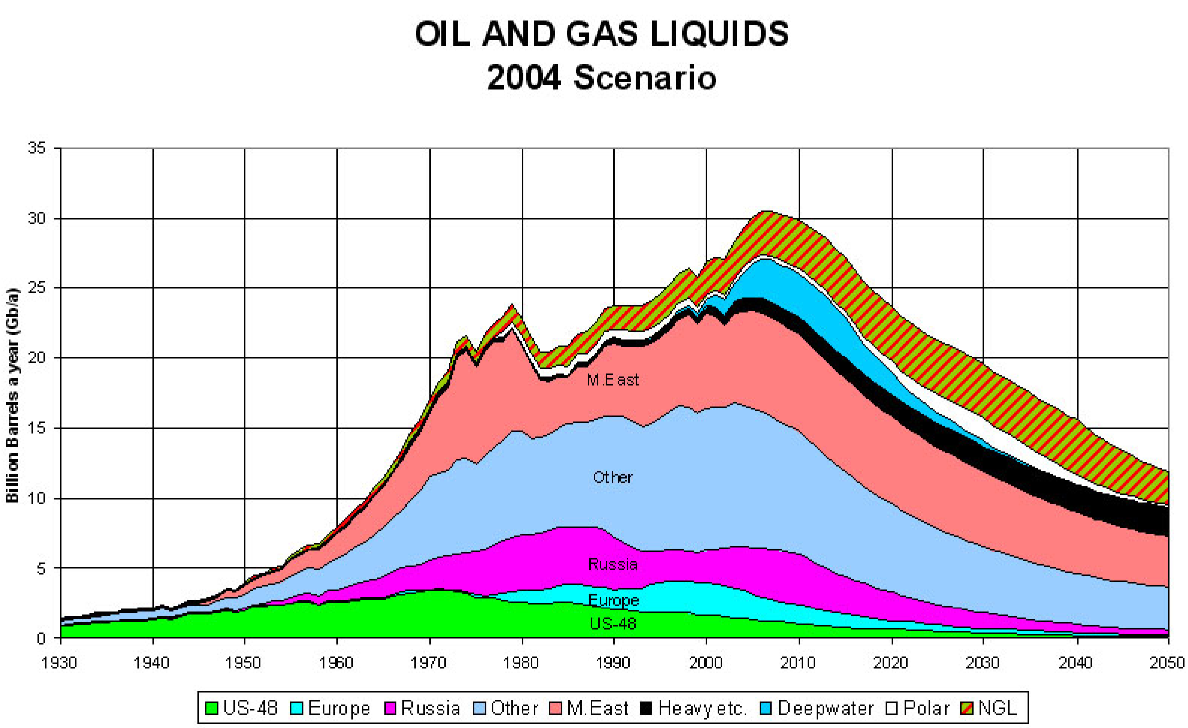

Figure 1. Campbell's general depletion model has changed relatively little in the past four years.

The price of oil will trend toward the price of the replacements, which seems likely ultimately to be at least $60/bbl for next-generation biofuels [*21*], though initially they will be considerably more expensive. A similar price can be expected for oil from coal when fossil carbon taxes (which seem likely to be widely imposed with 15 years) are included. The target price of $60/bbl has been publicly advocated over the near term (perhaps within three years) by some ministers and economists from oil-producing nations [*22*], and some extremists leaders have recently advocated $140/bbl.

The primary problems in the latest oil and gas price projections by the DOE/EIA [*23*] are:

1. They overestimate the ability of the U.S. to control oil prices [*22*]. Stated differently, they underestimate the resolve that is beginning to arise among oil exporters to save some of their limited resources for their great-grand-children; and they greatly overestimate the amount of oil we'll be able to pump out of Iraq – over the next 3 years, the next 15, and the next 50 [*24*].
2. They greatly underestimate the rate at which costs of developing new oil production capacity are increasing [*17*]. (Deep water, heavy, and polar oil and oil sands are an order of magnitude more expensive than were many conventional oil wells two decades ago. Oil shale and gas hydrates will be even more expensive [*17*].)
3. They greatly underestimate the political pressure the world will be able to place on the U.S. to limit fossil CO_2 release [*25, 26, 27*].
4. They underestimate the costs and difficulties of increasing our imports of LNG [*28*].
5. They underestimate growth of demand in the former Soviet Union, China, and India [*29*].
6. They overestimate the long-term value of the dollar relative to other major currencies [*30*].

There are also several flaws in EIA projections affecting oil prices in the other direction:

7. They underestimate the growth in use of renewables worldwide – especially in the U.S.
8. They underestimate the efficiency gains that are likely, especially in the U.S., over the next two decades.

Clearly, the first six points greatly outweigh the second two in their effect on oil and gas prices. The trend of oil prices over the last three years, as shown in **Figure 2**, could continue for six more years, taking the price temporarily above $100/bbl within this decade, before improved efficiencies and increased production of alternatives (and possibly a global economic slowdown) are able to bring the price back down, eventually to perhaps 30% below the long-term price of renewable biofuels. If oil is $60/bbl 16 years from now (in 2004 dollars), imported LNG will be at least $12/GJ (more likely $13/GJ, because of higher carbon taxes on oil). The DOE/EIA have a radically different opinion on the price of NG in 2020 ($4/GJ) [*23*], but most experts outside the U.S. differ regarding readily available oil and gas resource limitations.

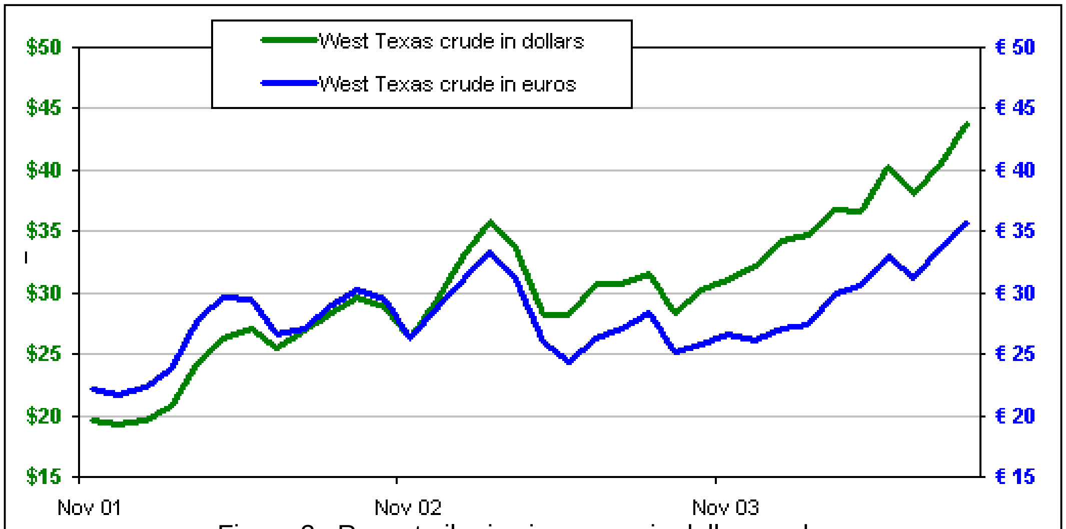

Figure 2. Recent oil price increases in dollars and euros.

Of course, there will be places in the world where natural gas will be available locally at a very low price (perhaps $1/GJ), and this will permit enormous profits for many LNG producers for several more decades until this resource too is exhausted. (When such conditions exist, it can also lead corrupt leaders to fabricate reasons for pre-emptive wars, and this could radically alter prices for a while.) The 20% losses associated with cleaning, liquefying, and shipping LNG, combined with its lower carbon burden, will eventually make LNG at least 25% more expensive than oil – probably within 25 years.

Projecting the price of electricity is slightly more risky because it depends more strongly on the magnitude of the fossil carbon tax. Assuming \$0.1/kg carbon tax by 2020, electricity will likely be about \$0.09/kWhr.

Hydrogen Storage. A fundamental advantage of liquid hydrocarbon fuels compared to hydrogen is in the cost of storage. A 10-gallon automobile fuel tank costs about \$150. Hydrogen storage by metal hydride in small quantities currently costs \$16,000/kg (of H_2 stored) [*12*] and is 20 times as massive as the common diesel tank. One reference indicates metal-hydride storage in large quantities (400 kg H_2) costs only \$2600/kg H_2 [*9*]. A common 120-gallon compressed-air tank, which can store 0.57 kg of hydrogen at 15 atm., costs \$730 [*31*]. At \$1300/kg, this is 85 times as expensive as the diesel tank per energy storage, and it is 40 times more massive and over 200 times larger. Fifty (very large) 3000 psi aluminum scuba tanks could provide 10 kg of H_2 storage for under \$14,000 and only 750 kg [*32*]. Pricing data from the high-volume production of these tanks suggest high-volume production of 5000-10,000 psi tanks for storage of 3-8 kg of H_2 might cost \$600/kg of H_2, which is about 30% less than suggested in an earlier study [*9*].

Light-weight tanks made of carbon-fiber composites are considerably more expensive (at least \$2000/kg), though some cost reduction (perhaps to \$1400/kg) could be expected in high-volume production of larger tanks. However, there are serious safety issues with light-weight tanks because of their low impact strength. For over half a century, the standard commercial limit for pressurized gases (in tanks of high impact strength) has been 2000 psi for safety reasons. The mechanical energy alone (ignoring the chemical energy) in a 5000 psi fuel tank may be five times that of a 50-caliber armor-piercing artillery shell. It is not at all clear that light-weight 5000 psi tanks could ever be acceptable in production vehicles from a safety perspective [*3*], even with extensive protective structures. The ultra-thin wall of these brittle tanks is not faithfully presented in the manufacturer's promotional pictures, as shown in **Figure 3**.

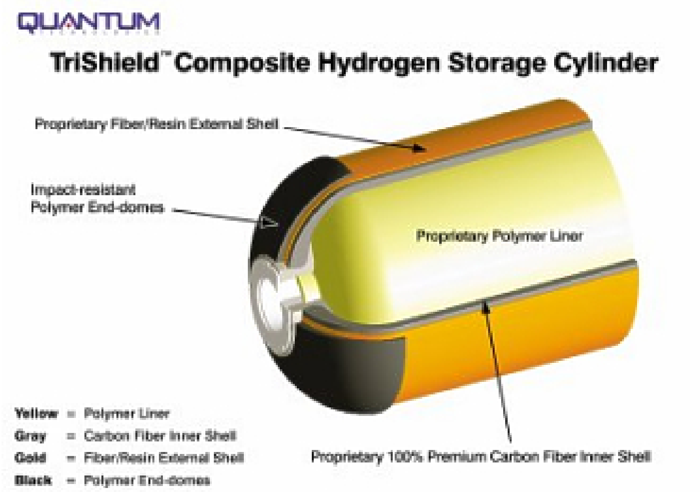

Figure 3. The ultra-thin-wall in a brittle, carbon-fiber-composite, storage tank is not apparent in promotional pictures.

A 180-liter liquid-nitrogen (LN2) dewar, which could store 12.8 kg of liquid hydrogen (LH2), costs only \$2040 [*33*], or \$160/kg. While these dewars have daily boiloff of only 1.5% for LN2, the daily boiloff with LH2 is about 15%, primarily because its heat of vaporization per liter is 10% that of LN2. Satisfactory LH2 dewars of similar size, which cut the daily loss to ~2% for LH2 and meet safety requirements, cost about \$600/kg [*9*]. Of course, production of LH2 wastes ~40% of the available energy in liquefaction. Moreover, losses on filling a dewar of this size are typically another 25% [*9*]. The unit cost of qualified LH2 storage does not drop very rapidly with increasing size, as 10,000 kg LH2 vessels (for rail tankers) are still ~\$60/kg [*9*].

Hydrogen from Natural Gas – Production Distribution, and Dispensing. Bulk, wholesale prices at the plant for hydrogen from NG depend mostly on NG price and plant size. The data below, in 2004 dollars, are for 99.99+% hydrogen in bulk at the plant, pre-tax [*34*].

Table 1. Bulk H_2 gas costs, 2004 USD			
NG price, $/GJ	Plant size, tons/day	Plant Cost, $	H_2 gas cost, $/kg
3.5	22	23M	1.8
7.0	22	23M	2.4
15.0	22	23M	4.1
3.5	80	44M	1.2
7.0	80	44M	1.9
15.0	80	44M	3.0
3.5	600	210M	0.7
7.0	600	210M	1.0
15.0	600	210M	2.7

There is steadily increasing awareness of the need to reduce CO_2 emissions to limit global warming [*25, 26*]. There is reason to expect that within 15 years we will see a fossil carbon tax (at least in some countries) of approximately $0.1/kg of carbon and probably more for low-efficiency power plants [*27*]. Production of H_2 from NG in very large plants releases approximately 2.6 kg of carbon (9.5 kg of CO_2) [*3*], and this increases to about 3.5 kg in small plants. (The chemical energy in the H_2 produced at very large plants is about 85% that in the NG feed stock, but efficiencies below 50% are obtained in small plants [*34*].) Hence, the above bulk H_2 costs would likely be increased by $0.26-0.35/kg by 2020 when a reasonable carbon tax is included.

Liquefaction of H_2 adds $1.3-3/kg to the above prices for H_2 gas, depending on plant size and energy costs [*9*]. Moreover, liquefaction using coal-fired power plants releases another 2.8 kg of carbon. Thus, bulk LH2 from NG at a very large plant with a 0.1/kg fossil carbon tax and cheap power ($0.06/kWhr) can be expected to cost $1.8/kg more than shown above for pre-tax bulk H_2 gas. LH2 from NG at a small (22 tons/day) plant with higher power costs ($0.08/kWhr) and the carbon tax would cost $3.6/kg more than indicated in the above table.

The data in the above Table from Padro and Putsche [*34*] is basically in agreement with that by Simbeck and Chang [*11*], though here it is sometimes a bit confusing. For example, Simbeck and Chang obtain detailed studies (from three sources) for a 27 t/day plant with distribution to 30 dispensing stations, each 1000 kg/day. They give the cost of this pipeline distributed (but not dispensed) hydrogen as $3.2/kg for NG at $3.5/GJ. For the case with liquid distribution and with commercial power for the liquefaction costing $0.045/kWhr, they give the distributed cost to the dispensing stations as $4/kg. (Again, the above prices are corrected for 2004 dollars.) Later, they begin assuming 150 ton/day plants. This less supported data for a fully developed hydrogen economy (300,000 vehicles per plant) apparently forms the basis of most of their summary and their Table 8, etc., but scale and market penetration seem to vary (somewhat ambiguously) with the various pathways throughout the study.

According to Padro and Putsche, one would expect hydrogen to cost $2.2/kg more at a 27 tons/day plant for NG costing $15/GJ than at $3.5/GJ. Hence, Simbeck and Chang should expect hydrogen from a 27 t/d plant, with NG at the city gate costing $15/GJ, to cost $5.7/kg (including fossil carbon tax, which may be $0.3/kg of H_2) delivered to dispensing stations by pipeline. For power costing $0.08/kWhr rather than $0.045/kWhr, the cost of LH2 increases by another $0.8/kg [*9*]. Hence, their LH2 could be expected to cost $7.3/kg (4 + 2.2 + 0.8 + 0.3) by tanker in 2020 from a 27 t/d plant.

Of course, these costs drop with larger scale assumptions, but it's hard enough to imagine a city with 50,000 hydrogen vehicles (averaging 50 miles/kg, 25 miles/day) in the next 30 years, so lets go back and correct some of the numbers that need adjusting to have real usefulness 5, 20 or

20 years from now. (We'll also ignore the pipeline estimates, and assume, as virtually everyone else has, that the method of distribution for at least the next 30 years will be LH2 by tanker truck.)

Major problems with the LH2 estimates by Simbeck and Chang arise from their assumption of 30 huge stations, each dispensing 1000 kg/day, servicing 50,000 vehicles in a large city. Many current (and planned) dispensing stations have storage capacities in the range of 100 to 1000 kg. Tanker LH2 distribution costs increase rapidly for deliveries below 500 kg (~1700 gallons). The tankers must be maintained slightly above atmospheric pressure to prevent the formation of devastating ice blockages. Depressurization for dispensing and cool-down of the transfer lines results in unavoidable waste of about 1% of the tanker's load every time liquid is dispensed. Both the liquid density and the heat of vaporization per liter of LH2 are about one-tenth those of LN2. From experience in the well established LN2 industry, one can estimate that tanker distribution costs of 1000 kg LH2 to a dispensing station would be about $250, or $0.25/kg, assuming there are three more stations in the region to take the rest of load from the 4300 kg tanker. (This estimate is quite close to that by Simbeck and Chang.) However, the distribution cost of 200 kg of LH2 to each of 20 dispensing stations in a large city would be about $200, or $1/kg. And when the total demand in any city drops below 4000 kg per week, the tanker delivery costs skyrocket. Basically, LH2 distribution analysis suggests it is impractical to start a hydrogen program below 4000 kg per week per city (~1000 vehicles per city) without substantial, continuing federal subsidies. Some believe gas pipelines might be less expensive in the distant future, but studies generally show this option to be more expensive at least up the level of several hundred thousand vehicles per city [*3, 11*].

Looking more closely at the hydrogen dispensing costs shows even greater problems here. Available dispensing stations, and those planned for the foreseeable future, have capacities of 25-60 kg/day for servicing 6 to 20 customers per day [*7, 34*] and will cost about $0.5-1M, at least for the next decade. A $600K station consuming 150 kWhr of energy per day (primarily for pressurization), with half the salary burden of a single attendant (24/7), needs a net daily margin of at least $500 to break even, assuming a 15 year loan at 5% interest and low equipment maintenance and land costs. Of course, if there are 20 dispensing stations in each of 200 cities in 2025, the costs of the dispensing stations will be lower. It may be reasonable to expect the cost of a 200 kg/day dispensing station to cost $200K at this level of mass production.

Other Sources of Hydrogen. Hydrogen production from coal necessitates a large central plant to adequately handle the problems of sulfur separation/disposal and CO_2 sequestration. The central-plant approach also generally argues for liquefaction for distribution [*11*]. Current hydrogen production costs from coal in large plants are about 20% higher than from natural gas, and such plants do not include sequestration [*11*]. The amount of carbon released is typically a little over 5 kg per kg of FC-grade gaseous H_2. With liquefaction, the C/H ratio increases to about 8. Carbon sequestration costs have been estimated over a very wide range, from $0.05 to $0.8/kg, but perhaps $0.1/kg is reasonable for a very large plant 20 years from now, which would add $0.8/kg to the cost of hydrogen from coal and thus may keep this source of hydrogen more expensive than NG for some time.

Hydrogen from biomass (pyrolysis and water shift) using waste biomass (from logging, paper mills, farming, and clearing) is about 10% more expensive than hydrogen from coal without sequestration [*11*], but this is not likely to be a major possibility, as waste biomass is limited and is likely to be more valuable in the production of methanol, biodiesel, and ethanol [*21, 37*]. Hydrogen from biomass crops (switch grass, poplars, hemp, eucalyptus, pines) is likely to be about 30% more expensive than hydrogen from waste biomass, and again this is not a real option, as this biomass is likely to be much more valuable for methanol or ethanol [*38, 39*].

Electrolysis from wind farms, nuclear power plants, and solar is also a possibility. Simple calculations show that for electricity at $0.05/kWh (the current mean U.S. industrial rate), with 80% electrolysis efficiency and 90% compression efficiency (both are optimistic figures), the power bill alone for compressed hydrogen gas by this method is $2.7/kg. Simbeck and Chang estimate the bulk cost of gaseous H_2 by electrolysis, for power at $0.045/kWhr, to be $5.4/kg at a very large plant when capital equipment costs are properly included. For LH2, the cost becomes $6.4/kg [*11*]. There is reason to believe that the electrolysis equipment maintenance costs may be significantly reduced in the future [*3*], which might reduce the cost of H_2 by electrolysis (either gaseous or LH2) by up to $1/kg.

Nuclear energy could be used to generate hydrogen by either of several processes, including hydrolysis and thermo-chemical reactions [*3*]. Both have serious cost and societal acceptance issues in addition to the fact that economical sources of sufficient uranium to power several hundred more nuclear reactors for a sufficiently long time to justify their construction (at least 40 years) cannot be assured without the use of breeder reactors. The global uranium high-grade ore (greater than 0.15% U) available to be mined is sufficient only to supply the world's total electrical power needs for three years, and the low-grade (but still viable) reserves may be only twice as large [*40*]. Recent studies have concluded that hard ores of lower grade than 0.02% may have negative energy balance and result in more CO_2 emissions (during the ore refining and processing, etc.) than would be produced by gas-fired power plants [*40*]. For half a century, it has been assumed that breeder reactors would eventually be used and thus increase the potential for nuclear energy more than 100-fold. But no successful breeder reactor has yet been demonstrated, and all breeder demonstration programs have been terminated [*40*]. (Indeed, liquid-metal-cooled fast-neutron reactors have operated, but that is only one step toward a successful breeder demonstration.) Moreover, the rapid progress in robotics over the past decade and the expected continued advances in this field seem to significantly increase the proliferation concerns with plutonium production in breeder reactors by greatly reducing the personnel risk associated with clandestine bomb-making operations from spent fuel from breeder reactors. Hence, it will likely become even more difficult to muster the political will to develop breeder reactors.

Many fusion physicists now believe it could be technically possible to have the first commercial, 500 MW nuclear fusion power plant (a tokamak) ready to come on-line in 2050 [*41*]. What they always fail to mention is that the envisioned power plant would have an operating lifetime of only a few years and would cost at least 50 times as much as a 500 MW biomass power plant. Moreover, these costs are inherent to the design (requiring 20,000 tons of Nb_3Sn superconducting magnet windings, for example) and there are no known ways for significantly reducing these costs. Alternatively, perhaps the plant could have a lifetime of 20 years, by using isotopically depleted construction materials, at a cost of perhaps 10,000 times that of the reference biomass power plant. On the other hand, there seems a reasonable possibility that inertial confinement concepts could prove more viable from an economic perspective, but here there are still a number of basic, technical feasibility issues [*42*].

Wind energy is now a viable power option in specific localities. If used for hydrogen production without a hydrogen gas line to the wind farm, the hydrogen would need to be liquefied for transport. To generate and liquefy 10 tons/day (one rail-tanker per day on average) would require at least 100 MW installed rated capacity for 30 MW average capacity, which requires 200 wind turbines of 39 m span in a Class 5 site [*43*]. This assumes 80% electrolysis efficiency, even though 65% is currently more common, as there is good reason to expect 80-85% will eventually be practical in large facilities when energy is more valuable. Liquefaction efficiency is assumed to be 60%, though lower efficiencies are currently achieved in plants of this size. The capital cost of the wind turbines (installed) would be about $60M-90M, and the effective power cost (20 year payback) is expected to be about $0.06/kWhr [*44*]. This could make the wholesale cost of LH2 at a very large wind farm (at a choice location) as low as $6.9/kg within 10 years, assuming substantial progress in cost reduction of electrolysis equipment (which seems probable, [*3*]) and some further progress in wind turbine technology (especially, for non-synchronous power applications, as for hydrogen or ammonia production).

Quite a number of excellent locations can be found for wind farms in the Dakotas, Kansas, Wyoming, and several other states, and the trend of decreasing costs of wind turbines will probably continue for at least another decade. However, until such time as we are no longer using coal to power the grid within at least 1000 km of wind farms, it seems that the best use of this wind energy would be to put it into the grid, as this would not require wasting 50% right off the top for electrolysis and liquefaction [*45*]. When surplus wind energy becomes available is select regions, perhaps the best use of it would be to produce ammonia for renewable fertilizers, as ammonia is much more easily trucked than hydrogen and ammonia production currently accounts for about two-thirds of our total hydrogen usage. Electrolysis hydrogen from wind farms in Class 5 sites could compete with natural gas for chemical fertilizer production, hydrocracking of heavy oils, and hydroforming of fuels when natural gas prices exceed $11/GJ. (Imported LNG seems headed for this price within 10 years.) Nearly 400 GW of installed wind power (30 times the current world-wide installed base, and 4 times the current stated U.S. goal for 2020) would be required to produce all the hydrogen needed for these industries in the U.S. Such a massive scale-up in wind energy could eliminate U.S. dependence on imported LNG for many decades and dramatically reduce U.S. green house gas emissions.

Photovoltaic (PV) production has risen sharply in the past few years, thanks primarily to Japan's commitment. The cost of PV cells has dropped by a factor of three in the past decade and is now about $6/W, which works out to about $0.18/kWhr for energy in favorable locations [*46*]. Though Japan's strong support for solar will soon end, GE appears ready to take over, and another factor of two drop in cost is expected in the next decade [*46, 47*].

Assuming at least a 20 year lifetime, low maintenance and other costs, and 4% interest (for present-value calculations), the cost of PV power might be down to $0.10/kWhr in generally sunny locations by 2015. The cost of PV-generated bulk H_2 gas at a large plant then might be $8/kg in 2015, but of course it would still need to be liquefied, adding about $2.5/kg, for distribution. For the private home-owner, PV-generated H_2 gas would likely be twice as expensive because of the relatively high costs of small electrolyzers, purification equipment, compressors, and storage tanks.

Finally, a few influential space scientists are still suggesting (even before congressional committees) it will be possible to build PV factories on the moon, set up huge PV arrays there, and beam the power back to earth for less cost than we could build the solar arrays here. This energy could then be used to electrolyze water. Most scientists and engineers rate the chances of this proving viable similar to those for cold fusion.

Summary: Because of the enormous complications of moderate-scale hydrogen storage, distribution, and dispensing compared to liquid hydrocarbon fuels, there is very little correlation between bulk hydrogen costs at a large plant and what the consumer can expect to pay at the dispensing station.

Although it has now been ten years since the first FCV was delivered, there are fewer than 200 FCVs on the road today (partially because few last more than two years). The very recent (and highly commendable) report by the National Academy of Engineering points out the serious challenges facing fuel cells and notes that it is unlikely they will have a significant effect on oil imports or CO_2 emissions during the next 25 years [*3*]. Ballard Power and Plug Power seem likely to be bankrupt (or effectively so) within a few years. Very few experts today are expecting more than 800 FCVs on the road six years from now. Honda and GM have each indicated within the past six months they expect to sell one million FCVs by 2020, but they are already backing away from those estimates. Those projections, like many other "hydrogen economy" projections over the past decade, may prove too high by two orders of magnitude. Personally, I think it unlikely to expect more than a few thousand hydrogen FCVs on the road 16 years from now, but perhaps there will be unforeseen breakthroughs. It is worth noting that there are about 100 cities with populations over one-half million in the wealthy, industrialized countries throughout the world where one could expect to sell some hydrogen vehicles if a significant number are sold. So it seems highly unlikely to find many cities with more than 1000 FCVs by 2030.

Five scenarios, spanning a range of 10 to 20,000 hydrogen vehicles per city, are presented in **Figure 4** based on realistic distribution costs, dispensing costs, and imported LNG delivered to the city gate ($5/GJ in 2002, $10/GJ in 2008, $14/GJ in 2015, $17/GJ in 2025, and $20/GJ in 2040). The scenarios assume there is sufficient additional industrial demand in the city for the hydrogen produced by the 22 t/day central plant to keep it operating near full capacity, otherwise the

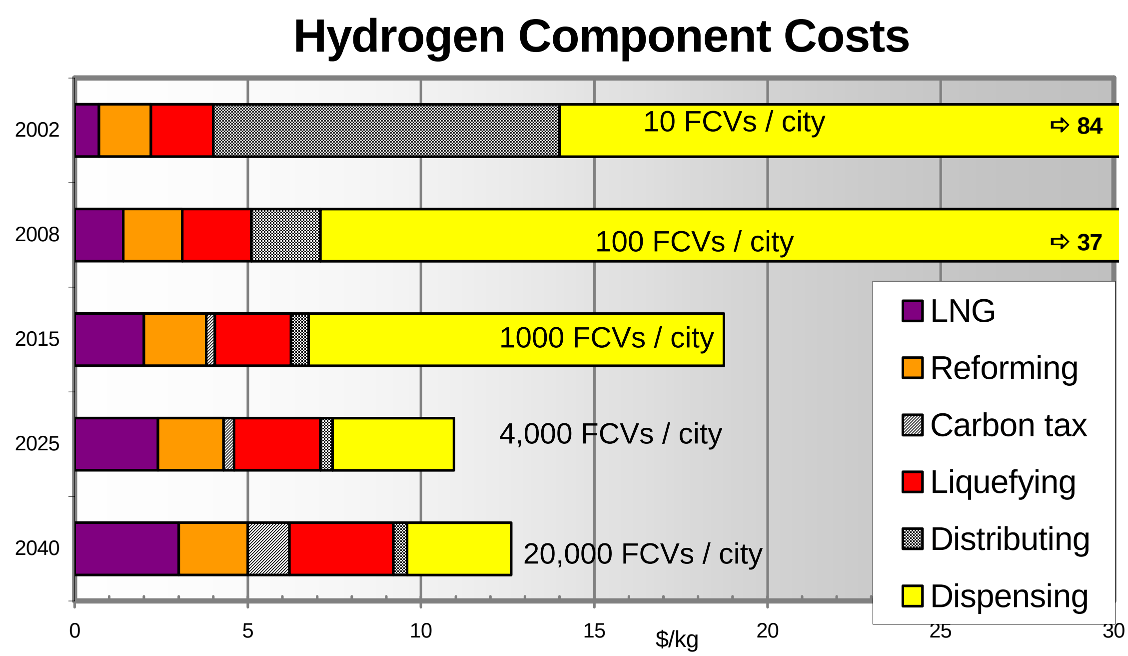

Figure 4. Unsubsidized hydrogen cost breakdown for several years and numbers of FCVs per city. Assumptions, notes: All costs in 2004 USD/kg of H_2. "LNG" is cost of imported liquefied natural gas, distributed to city, with energy equivalent to 1 kg H_2. "Reforming" includes additional LNG and equipment costs. Additional local demand present to utilize all LH2 from a plant producing 22 tons/day. Power costs inflating 1.5%/ year. Tanker truck distribution. 5000 psi dispensing station.

hydrogen prices will be higher by up to $3/kg. Even the largest case considered here is smaller (by an order of magnitude) than that in the NAS/NAE report, where they assumed NG would cost $4.5/GJ [*3*] compared to my projection of $20/GJ in the year 2040. I assume electrical power to be $0.06/kWhr in 2004 and inflating at 1.5%/yr. In view of the very recent highly pessimistic long-range LNG and oil supply forecasts [*16, 20*], both these LNG and power price estimates could actually be too low. However, the greatest uncertainties in these scenarios lie in the hydrogen market penetration assumptions and dispensing costs. I assume fifteen $600K fueling stations dispensing up to 50 kg H_2 per day in each city in case 3, but only four of these stations per city in cases 1 and 2. For case 4, I assume twenty $250K fueling stations dispensing up to 200 kg H_2 per day in each city; and in the last case, their cost drops to $150K each. I assume an attendant will be required to operate the dispenser, and the dispensing station makes a small profit.

At the risk of being extremely repetitious, we emphasize that we are well aware of the sharp discrepancies between our projections and those of others. It is only necessary to attempt to purchase pressurized hydrogen from any unsubsidized supplier to confirm that its current retail price is about $100/kg plus cylinder rental, not $6/kg, as most other "experts" imply. And no one should attempt to make any energy-related projections without reading Chapter 3 of Vaclav Smil's "Energy at the Cross-roads", in which he discusses hundreds of failed energy projections over the past thirty years [*48*]. A key lesson there is to appreciate historical data.

Of course, one can imagine that the hydrogen price could be reduced if there were a large fertilizer, gasoline, or chemical plant in the city to justify the construction of a large hydrogen plant.

Hence, LH2 could possibly be delivered to fueling stations for as little as $4/kg in 2015 in large cities near gas wells that have large LH2 plants for other industrial markets (note this price is very close to that predicted by most other studies). However, this does nothing to address the more significant dispensing cost, and liquefaction cost is also not likely reduced.

For comparison, the current U.S. pre-tax cost of diesel for the individual consumer at the local station is about $0.5/kg. Of course, one needs 3 kg to equal the energy of one kg of H_2, but that still leaves more than an order of magnitude cost advantage for diesel per unit energy for the next 15 years. Moreover, it appears diesel engines (some of which will be over 60% efficiency by 2020) will continue to get higher efficiency than road-qualified, production-quality PEMFCs. Estimates suggest the pre-tax price of bio-diesel from either bio-methanol or high-oil algae could ultimately be below $0.6/kg, and either route promises ample capacity [*21*].

Personally, I doubt we'll ever see anything beyond the first two of the above hydrogen scenarios. By then at the very latest, it will be abundantly clear that next-generation liquid biofuels offer a far cheaper, safer, cleaner, and more convenient option.

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