Hydrogen Distribution Infrastructure

Marianne Mintz*, John Molburg, Stephen Folga, Jerry Gillette

Argonne National Laboratory, Center for Transportation Research and Decision and Information Sciences Division, Argonne, IL 60439, USA*

Abstract. Whether produced from fossil or non-fossil sources, the widespread use of hydrogen will require a new and extensive infrastructure to produce, distribute, store and dispense it as a vehicular fuel or for electric generation. Depending on the source from which hydrogen is produced and the form in which it is delivered, many alternative infrastructures can be envisioned. Tradeoffs in scale economies between process and distribution technologies, and such issues as operating cost, safety, materials, etc. can also favor alternative forms of infrastructure. This paper discusses several infrastructure alternatives and the associated "well-to-pump" or "fuel cycle" cost of delivered hydrogen.

BACKGROUND

In virtually all advanced economies, there is considerable interest and enthusiasm over the concept of a "hydrogen economy" and the prospect of hydrogen-fueled vehicles. Not since the mid 1970s, when the term "hydrogen economy" was first coined, have we seen anything like the current level of research activity and discussion in the popular press. Since US transportation is 97% dependent on petroleum, much of it imported from politically unstable and strategically vulnerable parts of the world, a strategy of shifting to domestically-produced hydrogen fuel is appealing. That is why the National Energy Plan highlighted the important contributions that can be made by next-generation technologies such as hydrogen fuel cells, and the US government has become increasingly involved in efforts like the FreedomCAR initiative to advance fuel cell technologies. A comparable level of effort under the auspices of the Department of Energy's Energy Efficiency and Renewable Energy office (as well as several other initiatives under DOE's nuclear and fossil energy offices) is directed toward hydrogen production technology. This two-pronged effort, directed to advancing both fuel and end-use technology, is critical to addressing the "chicken and egg" problem[1] which is particularly acute for the transport sector, arguably, one of the last bastions of petroleum dependence in the US economy.

In related efforts, vehicle manufacturers and energy providers are grappling with the "chicken and egg" problem. Both individually and collectively, they are attempting to identify strategies to mitigate the risks associated with large up-front investments in fuel infrastructure in advance of an assured market for that fuel.

[1] The problem may be summarized thus: manufacturers are unwilling to produce vehicles without an in-place fueling infrastructure and fuel producers are unwilling to build that infrastructure without some certainty that vehicles requiring those fuels will be in operation.

These uncertainties are compounded by the lack of clearly superior methods for producing hydrogen, storing it either onboard or off-board the vehicle, and transporting it in pure liquid or gaseous form or via a hydrogen "carrier". Given these many uncertainties, one might argue that it is premature to analyze alternative forms of infrastructure. However, if one accepts the premise of a coming hydrogen transition and the need to begin making the necessary investments now, strategic planning cannot wait for resolution of these many issues. Rather, energy, economic and environmental analyses must be undertaken in concert with research on improved production, storage, and distribution technologies.

COMPONENTS OF A HYDROGEN INFRASTRUCTURE

Hydrogen infrastructure can be defined broadly to include the facilities and equipment needed to manufacture and operate hydrogen-fueled vehicles. This could include road construction and road maintenance, garages, equipment maintenance and repair facilities, aftermarket parts and services, etc., as well as fuel production and distribution. In fuel-cycle nomenclature, we can conceive of a hydrogen vehicle cycle and a hydrogen fuel cycle, analogous to the gasoline vehicle and fuel cycles shown in Fig. 1. For a complete "well-to-tank" or total lifecycle analysis of hydrogen-fueled vehicles, a broad definition of hydrogen infrastructure is desirable. In actual practice, however, it is difficult to quantify many of the costs associated with vehicle operation that are unique to hydrogen-fueled vehicles (e.g., modifying garages, changing maintenance and repair procedures and modifying facilities, enacting new codes and standards, etc.). However, since the vehicle cycle and fuel cycle are, for the most part, independent, we can limit the analysis to one or the other. On the vehicle side, original equipment manufacturers (OEMs) and manufacturers of fuel cells and other components are working hard to meet cost and performance targets, and a considerable body of knowledge is being developed. Much less effort has been devoted to the fuel side, especially to the cost of alternative delivery infrastructure.

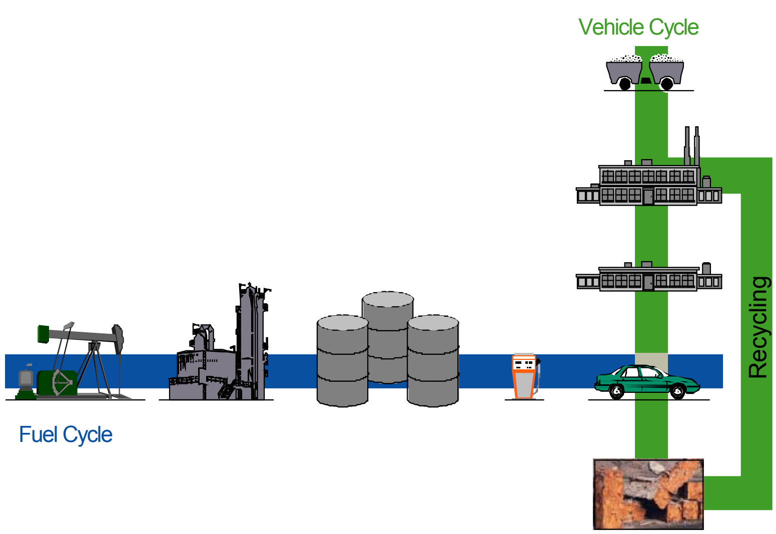

FIGURE 1. Key Stages in Gasoline Vehicle and Fuel Cycles (Source: Argonne National Laboratory)

For the present analysis, we restrict the scope of a hydrogen fuel infrastructure to major facilities and equipment required for delivery of hydrogen to a dispersed vehicle population. We assume that these vehicles will be powered by fuel cells, since fuel cell vehicles are projected to be approximately 2.5 times more efficient than comparable conventional vehicles. Infrastructure components can be enumerated by the following stages in a "well-to-pump" pathway. The first infrastructure element is feedstock transport rather than extraction and processing. We assume that feedstock infrastructure costs are reflected in feedstock prices.

- Feedstock transport and storage. This includes facilities for the bulk shipment of natural gas, coal or other hydrogen sources, above- or below-ground storage of feedstock, and compression equipment to prepare gaseous feedstock for transport systems.
- Processing. Analogous to refining on a gasoline pathway, hydrogen can be produced from a number of conventional and alternative processes. We have incorporated steam methane reforming (SMR), coal gasification, and thermochemical water-splitting using advanced nuclear reactors.
- Hydrogen distribution. Since the only fuel considered here is gaseous hydrogen, this infrastructure element includes transmission and distribution pipelines, compressors, pressure-regulating equipment, and above- and below-ground storage facilities near fuel markets.
- Hydrogen dispensing. Analogous to conventional refueling stations, this infrastructure element includes storage tanks, compression and monitoring equipment, and fuel dispensers.

MODELING APPROACH

Figure 2 presents a conceptual summary of our modeling approach. That approach addresses four sequential tasks, which are represented by the rectangles. Detailed models that serve those tasks are defined within the ovals. Assumptions, e.g., equipment lifetimes, efficiency, number of vehicles, and vehicle-miles of travel, are shown as model inputs and intermediate outputs. The demand model can be linked to the infrastructure cost model, CHAIN (Cost of Hydrogen under Alternative INfrastructures). Alternatively, demand can be provided to CHAIN exogenously. Thus, for example, an external forecast can be represented without actually running the vehicle stock model, or the cost implications of a policy target can be evaluated. Annual fuel demand is the key starting point for the CHAIN model. Working backward from this quantity and assumed efficiencies of each stage in the "well-to-pump" pathway, the model computes the quantity of feedstock needed and the throughput of each stage in the pathway. Facilities are sized to efficiently handle this throughput.

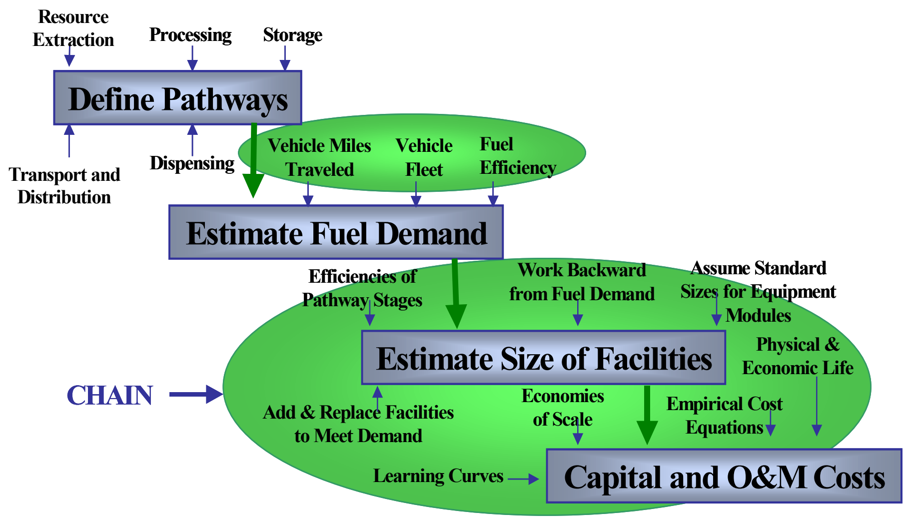

FIGURE 2. Vehicle Stock and Cost Estimation Models Are Used to Calculate the Cost of Hydrogen Fuel Infrastructure (Source: Argonne National Laboratory)

Each component of a hydrogen distribution infrastructure has a unique expected useful life, anticipated maintenance and repair cost, and labor cost for normal operation and maintenance. Capital cost, service life, maintenance and repair, and energy costs all can differ under the same operating conditions depending on design decisions. Infrastructure components are assumed to be replaced when they have achieved their design operating lifetimes.

The CHAIN model applies an annualization method to calculate total yearly cost, which includes operations and maintenance costs plus annualized capital and replacement costs. Annualizing evenly distributes the present-value of investments over a specified future period. Present value places a stream of project investments at a single point in time. Sometimes this is called the overnight construction cost. Present value is converted to the uniform stream of annual costs by the capital recovery factor (CRF), which accounts for the time-value of money in its conversion of up-front capital cost (installed equipment cost) to annualized cost. The CRF is defined as:

$$CRF = i\,(1 + i)^n / \{(1 + i)^n - 1\} \qquad (1)$$

Where:
i = discount rate (an input to CHAIN with an assumed base case value of 10%)
n = economic lifetime (from 5 to 30 years, depending on infrastructure component).

Typically, CRF will range from 10% to 20%, depending on the cost of capital, referred to as the discount or interest rate. A real (inflation-free) interest rate is used to annualize capital and replacement costs, which are specified at a 2000 price level.[2] For a given year, total annualized costs are the sum of annualized capital costs of those

[2] If nominal (with-inflation) interest rates were used to amortize capital, periodic (operation and maintenance) costs would have to be inflated to future levels, in accordance with the inflation expectations incorporated into the nominal interest rate.

infrastructure components that have been installed and have not yet reached the end of their economic lifetime, annual operating and maintenance (O&M) costs of all infrastructure components in operation that year, and annualized replacement costs for those infrastructure components that have reached the end of their physical lives and are replaced by new components.

"WELL-TO-PUMP" PATHWAYS

Figure 3 depicts the hydrogen "well-to-pump" pathways reported here. Two pathways begin with natural gas extraction. One begins with uranium.[3] (A fourth pathway based on coal gasification is shown in the figure but is not discussed in this paper). The four vertical lines, drawn at approximately equal intervals on the figure, show pathway stages corresponding to feedstock acquisition and transport, and H_2 production, transport and dispensing.

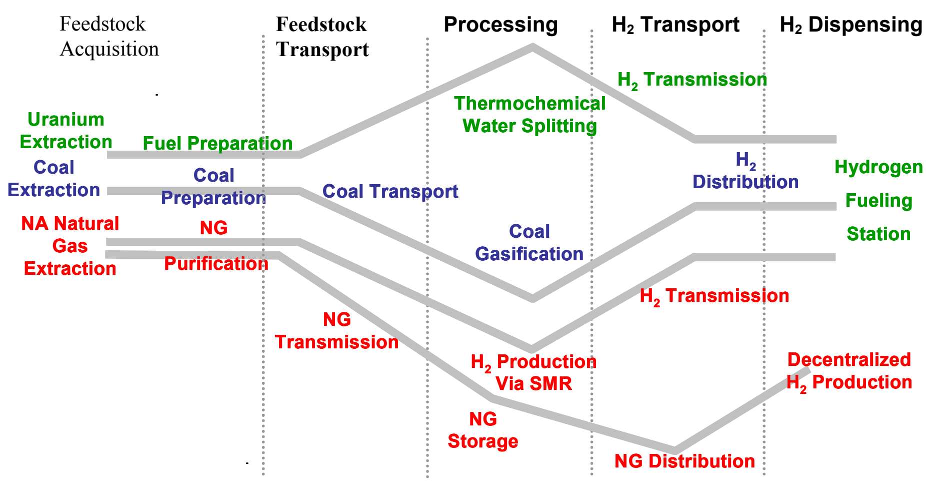

FIGURE 3. Hydrogen "Well-to-Pump" Pathways Evaluated (Source: Argonne National Laboratory)

COMPONENT COST ANALYSES

If natural gas demand were to increase to the level required to produce hydrogen as a significant transportation fuel, natural gas infrastructure would have to be expanded. New transmission and distribution pipelines would have to be built, additional underground storage would have to be provided, and capacity would have to be increased for existing pipelines.

[3] There is no particular significance to the shape of the pathway. The change in direction of the path simply emphasizes the sequential steps.

Feedstock Acquisition

We have assumed natural gas feedstock costs of $3.00/mmBtu[4] in 2010 rising to $3.50 by 2040. Fuel rods for advanced nuclear reactors were not examined as a separate cost item. Rather, they were included in the operating and maintenance costs of the high temperature reactors that are the assumed heat source for thermochemical water splitting (Schultz 2002).

Feedstock Transportation and Storage

Regression analysis of industrial data was used to determine a capital cost function for new natural gas transmission pipelines. Using reported project cost, as published annually in the Oil and Gas Journal, our analysis indicates that capital cost is proportional to pipe diameter, with a proportionality constant of approximately $53,000 per mile per inch diameter (see Figure 4). The unit capital cost is not strongly influenced by length of the pipeline segment. Rather, it is influenced by local, site-specific factors, such as geology, topography, land use, and right-of-way acquisition. In this analysis, we assumed an average diameter of 30 inches, which corresponds to $1.5 million per mile.

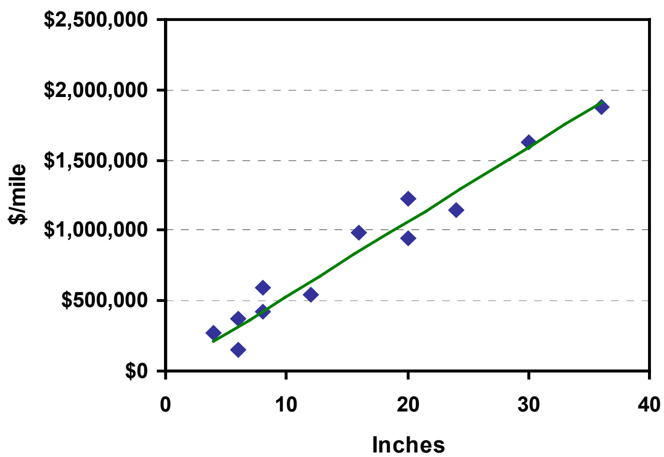

FIGURE 4. Capital Cost of Natural Gas Pipelines as a Function of Diameter

Processing

Steam methane reforming (SMR) is currently the most economical process for producing hydrogen from natural gas. The SMR process produces an initial syngas by steam-methane reforming. The hydrogen content of the syngas is then increased via the water-gas shift reaction. These are represented by equations 2 and 3, respectively.

$$CH_4 + H_2O \rightarrow CO + 3\ H_2 \qquad (2)$$

---

4 Million Btu is commonly abbreviated as mmBtu.

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (3)$$

Typical (SMR) production costs are approximately \$5.80/10^6 Btu (\$5.60/GJ), assuming byproduct credits. Raw materials, primarily natural gas feedstock, account for about 50% of production cost (SRI 2001). Reported costs of commercial SMR plants are plotted in Figure 5 as a function of plant capacity (tons per day of H_2 production). The regression-based trend line in Figure 5 shows that SMR exhibits significant economies of scale. Figure 6 contains a simple schematic diagram of the SMR process with purification of the product hydrogen achieved via the pressure swing adsorption (PSA) process. Consistent with the data shown in Figure 5, we have assumed that an SMR plant producing 200 tons per day of hydrogen will require an investment of \$100 million. The estimated capital cost for a comparably-sized facility producing hydrogen by thermochemical water splitting is \$1 billion (Schultz 2002).

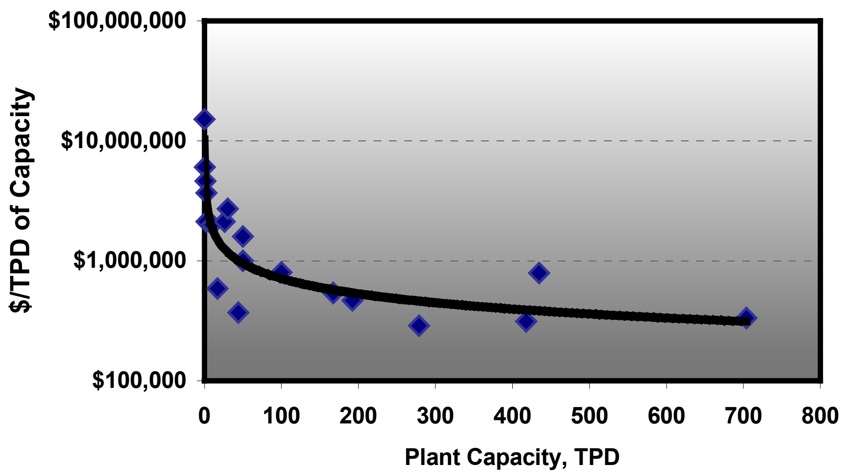

FIGURE 5. Capital Cost of Steam Methane Reforming (SMR) as a Function of Capacity

Hydrogen Distribution

Figure 6 illustrates the hydrogen production/distribution system assumed for the centralized SMR pathway. The distribution portion of the figure applies to the nuclear pathway as well. Note that hydrogen was assumed to exit the production facility at approximately 400 psi, to be compressed to 1,000 psi for transmission in dedicated hydrogen pipelines, and to enter the circular hydrogen distribution main pipeline at approximately 500 psi (due to friction losses). Hydrogen transmission and distribution main pipelines were assumed to be 12" diameter pipe costing approximately \$1 million per mile. Service pipelines were assumed to be 3" diameter pipe costing \$400,000 per mile.5 All costs exclude land acquisition.

[5] Hydrogen pipelines were assumed to have a cost penalty of 80% vis a vis comparable diameter natural gas pipe (Veziroglu, 1998)

For decentralized production via SMR (station reforming), costs for additional natural gas transmission, distribution and service pipelines, compressors, and underground storage facilities are estimated assuming standard module sizes.

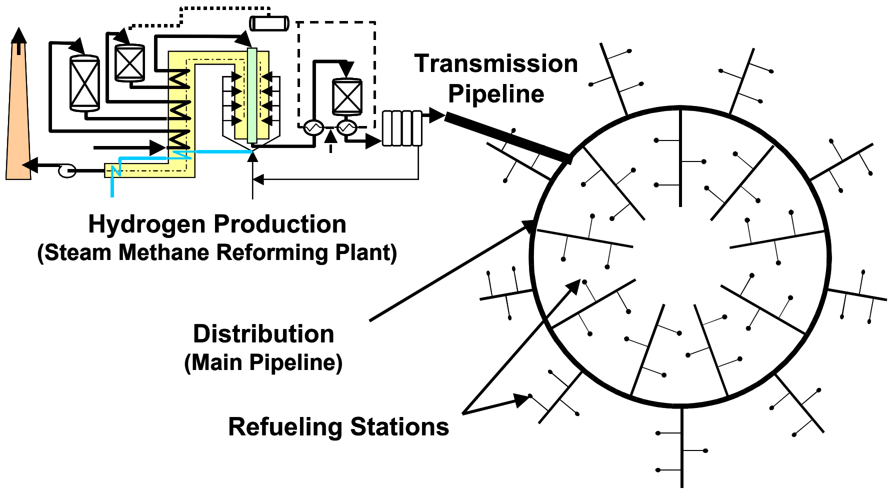

FIGURE 6. Conceptual Illustration of Centralized H_2 Production Via SMR with Pipeline Distribution (Source: Argonne National Laboratory)

Hydrogen Dispensing

In the two centralized production pathways, hydrogen is assumed to be delivered to refueling stations via 200 psi service pipelines. To satisfy peak demand, one quarter of daily hydrogen supply is assumed to be stored on-site at 6000 psi. The cost of hydrogen refueling stations is the sum of the individual component costs required for dispensing approximately 50,000 kg (or gasoline gallon equivalents) per month. Assuming an average fill quantity of 4 kg per vehicle, the resulting refueling facility serves about the same number of vehicles as a typical gasoline station. For centralized hydrogen production, the refueling station is assumed to cost approximately $700,000 including pumps, storage, compression equipment, sensors, etc. For decentralized production, each station costs roughly $2.5 million due, largely, to the investment required for on-site hydrogen production via SMR. Station costs were estimated as the sum of component costs, including site preparation, concrete foundations, piping, electrical, process equipment, and miscellaneous equipment. Because of the small scale of the SMR units built for these distributed (decentralized) facilities, we expect that mass production economies will be available for these units. Rather than apply the large plant cost data of Figure 5, we rely on published estimates reported by Ogden and provided by Howe-Baker Engineering (Ogden 1994). We have reduced these costs by 20% in accordance with more recent estimates of the benefits of mass production economies for such stations (Ref. 7). Other investigators (e.g., Thomas 1997) anticipate even more substantial cost reductions based on projections with the learning or experience curve, which has found application to many manufactured products. Our belief is that aggressive learning assumptions should be used with caution.

"WELL-TO-PUMP" COSTS

As part of their long-range planning activities, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and Natural Resources Canada have undertaken a joint study to examine the long-term supply and demand for energy in the North American transport sector.[6] The hydrogen cost estimates presented here are based on models and assumptions developed for that study, particularly on the annual demand forecasts in that study's Go Your Own Way scenario. Note that the following costs are in 2000 US dollars and are undiscounted.

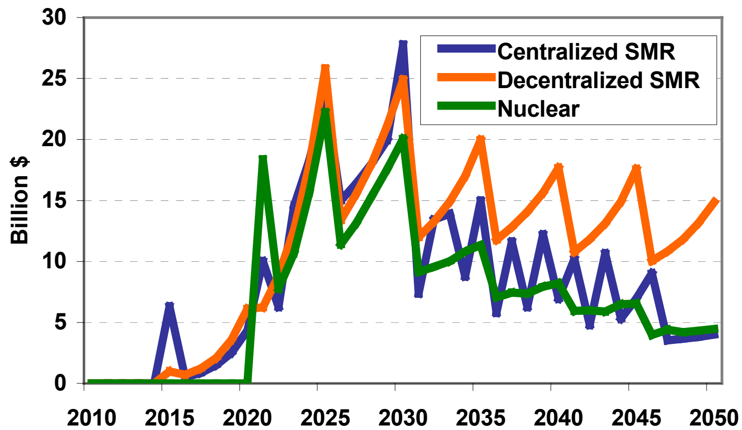

FIGURE 7. Capital Costs of Natural Gas and Nuclear "Well-to-Pump" Pathways, 2015-2050

As shown in Figure 7, capital costs of nuclear and natural gas pathways fluctuate as incremental capacity comes on line. Over time, annual expenditures for all three paths increase for the first 15-20 years, then decline. This is especially true for the two centralized pathways which achieve greater economies of scale. Note that annual capital investment peaks at approximately $25 billion, approximately five times the recent annual rate for investment in natural gas transmission pipelines (EIA 2001).

In Figure 8, unit costs are presented on an annualized basis,[7] which tends to smooth fluctuations in actual investment. Here, it is apparent that unit costs drop over time as hydrogen infrastructure is "built out" and amortized. The high cost in early years reflects the limited demand. In 2015, when hydrogen fuel production via SMR is assumed to start, the unit cost of delivered fuel is more than $16/kg for centralized production versus less than $3.00 for station reforming. Centralized costs quickly drop to ~$2.25/kg but station reforming costs decline only slightly (to ~$2.75 by 2030). This is due to an inability to achieve economies of scale in decentralized production (as compared with huge scale economies in centralized production), SMR plants' relatively short economic but long physical lifetimes (i.e., plants continue to produce

[6] For additional information and results of the 2050 Study see http://www.ott.doe.gov/2050/2050phase2.shtml. Note that although we assume the same hydrogen demand as in the 2050 study, we assume different pathways. In particular, 2050 does not incorporate a decentralized pathway and assumes that hydrogen production will be split between SMR and nuclear pathways.

[7] Although the axis label is $/gasoline gallon equivalent, it could also read $/kg since the energy content of a gasoline gallon is equal to that of a kg of hydrogen.

long after capital costs have been written off), and the long economic lifetimes of pipelines (i.e., capital costs are spread over many years).

Hydrogen production from chemical water splitting using nuclear heat sources is assumed to start in 2021. All cost data pertain to the sulfur-iodine cycle under development by General Atomics. Each plant was assumed to cost over $1 billion and have an economic lifetime of 30 years. (Schultz 2002) This is similar to existing nuclear power plants.

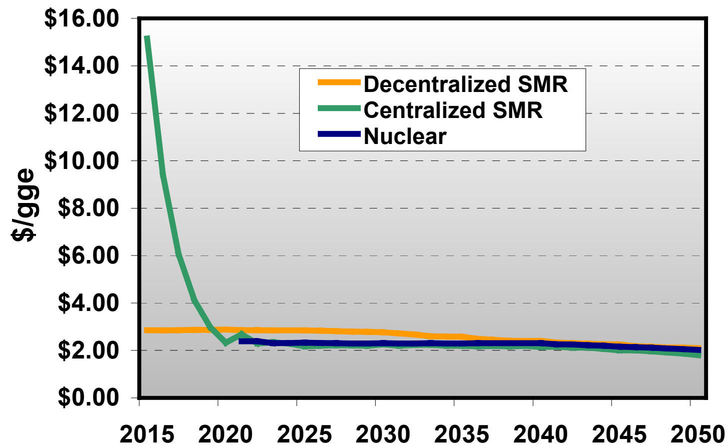

FIGURE 8. Annualized Cost of Hydrogen per Gasoline Gallon Equivalent (gge)

Figure 9 presents a "snapshot" of the data points for the year 2030 from Figure 8 broken down by pathway stage, and contrasted with comparable data for gasoline produced from $28/bbl crude oil.[8] Clearly, gasoline and hydrogen have very different cost distributions. Excluding taxes, the cost of gasoline is heavily dependent on feedstock, accounting for over 60% of delivered cost. By contrast, production accounts for as much as 75% of delivered hydrogen cost, as compared with only 21% for gasoline. Likewise, distribution accounts for only 10% of gasoline cost versus 25% of the cost for centrally produced hydrogen. Note that this cost comparison is based on equivalent energy, not on equivalent service. Higher efficiency fuel cell vehicles will offset some of the cost differential. Hydrogen is assumed to account for 16% of the fuel used by light-duty vehicles in 2030, 34% in 2050.

As indicated in Figure 9, infrastructure is a relatively small component of the cost to produce and deliver gasoline to consumers. Note that "delivered" gasoline cost includes the cost of crude oil to refiners, refinery processing, marketing and distribution, as well as retail station costs and taxes. The prices paid by consumers at the pump reflect these costs, as well as the profits (and sometimes losses) of refiners, marketers, distributors, and retail station owners.

[8] Gasoline costs include markups but exclude taxes; hydrogen costs exclude markups and taxes.

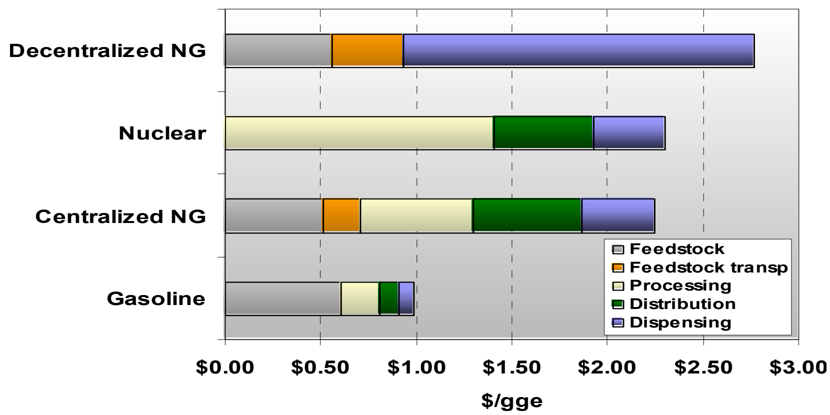

FIGURE 9. Annualized Hydrogen Unit Cost by Pathway Stage, 2030

CONCLUSIONS

1. "Well-to-pump" or lifecycle analysis of alternative fuel pathways is an appropriate method for comparing alternative hydrogen production/distribution options. Simpler comparisons fail to capture the trade-offs at each stage in the full pathway.
2. A new infrastructure for hydrogen production and transport can be expected to be costly, making a significant contribution to the delivered cost of hydrogen for vehicular use. With current technologies, the unit cost of hydrogen is likely to be 2-3 times that of gasoline, even after significant numbers of hydrogen-fueled vehicles are in operation. Thus, the fuel efficiency of these vehicles will have to exceed that of conventional gasoline-fueled vehicles by at least an equal margin for hydrogen to become a competitive vehicular fuel. Increases in gasoline prices will narrow this gap.
3. Transport and production are the largest components of all paths examined and, thus, are a prime focus for cost reduction. Our analysis assumed little cost reduction by virtue of producing and deploying large numbers of infrastructure components. Clearly, some reductions might be expected to occur from "learning" or "experience". However, reductions are unlikely to be large enough to change the relative costs of alternatives where mature technologies like SMR are involved.
4. In addition to technology development to reduce hydrogen production and transport cost, operational synergies like "bi-fuel" engines and distribution networks and production of co-products have the potential to reduce unit costs to a competitive level, especially in the transition. Their feasibility should be investigated further.

REFERENCES

1. *Oil and Gas Journal*, project summaries in various issues.
2. SRI, Inc. *Chemical Economics Handbook*, 2001.
3. Schultz, Ken, General Atomics, Inc. personal communication, 2002.
4. U.S. Department of Energy, Energy Information Administration, 2001. http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/primer_on_gasoline_prices/html/petbro.html.
5. Veziroglu, T., F. Barbir, "Hydrogen Energy Technologies," Emerging Technologies Series, prepared for the United Nations Industrial Development Organization, Vienna, 1998.
6. Ogden, Joan M., E. Dennis, M. Steinbugler, J. Strohbehn, "Hydrogen Energy Systems Studies", final report for NREL Contract No. XR-2-11265-1, Figure 10, "Howe-Baker Estimates for Hydrogen Plants (Installed)" based on private communication, 1994.
7. "Hydrogen 'Filling Station' May Pave the Way for Fuel Cells" http://www.us-tech.com/Jan97/news/news001.htm, accessed August 27, 2001.
8. Thomas, C.E., B. D. James, I. F. Kuhn, Jr., F.D. Lomax, G.N. Baum, Hydrogen Infrastructure Study, prepared for the Ford Motor Company under contract DE-AC02-94CE50389 to the US Department of Energy, Office of Transportation Technologies, July 1997.