III.7 Fuel Choice for Fuel Cell Vehicles: Hydrogen Infrastructure Costs

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Objectives

- Analyze transition scenarios that are associated with developing a hydrogen infrastructure for fuel cell vehicles (FCVs)
- Develop a model that can be used to determine investment risk and economic viability of natural gas to hydrogen pathways
- Determine investment risk and economic viability of pathways
- Identify key economic barriers to the development of a hydrogen infrastructure and possible development paths
- Assess impact on various stakeholders and how risks could be shared and minimized
- Evaluate scenarios that could bring down the initial costs of hydrogen (added scope)

Technical Barriers

This project addresses the following technical barriers from the Hydrogen, Fuel Cells and Infrastructure Technologies Program Multi-Year Research, Development and Demonstration Plan:

- Hydrogen Production: AD. Market and Delivery
- Hydrogen Delivery: A. Lack of Hydrogen/Carrier and Infrastructure Options Analysis
- Hydrogen Storage: V. Life Cycle and Efficiency Analysis

Introduction

In the previous phase of work, TIAX assessed the well-to-wheel energy use, greenhouse gas emissions and ownership costs of various fuel choices for FCVs at a future point in time assuming both high utilization (i.e., capacity factors) and high manufacturing production volumes for equipment (Lasher, et al. 2001). However, alternative fuels require significant up-front investment during a transition period, representing a risk to both vehicle manufacturer and fuel provider. The financial risks involved in each of the fuel options vary, and the risk may shift from one player in the value chain to another. Dealing with this risk represents a formidable barrier to the use of alternative fuels, especially hydrogen, for FCVs. In the current phase of work, DOE has commissioned TIAX to assess the relative risks of various hydrogen pathways for use in FCVs.

Approach

TIAX developed a net present value (NPV) analysis model to evaluate financial risks and the effect of various transition approaches for a hydrogen economy. The model first builds up a scenario for hydrogen infrastructure introduction over time based on a number of user-supplied inputs, including an assumed hydrogen vehicle market penetration curve. Other model inputs include infrastructure capital costs as a function of production volume, operating costs, fuel prices (e.g., gasoline), and vehicle fuel economies. The user also inputs an initial infrastructure mix and a target mix, which the model uses to estimate the number of fueling stations needed to meet coverage (availability of stations) and production capacity constraints (Figure 1). The model then determines expenditures and revenues from hydrogen sales for each type of hydrogen infrastructure. The NPV analysis takes into account the time value of money so that early investments are weighted more heavily than future investments (and profits). An example of the build-up of expenditures and revenue are shown in Figure 2.

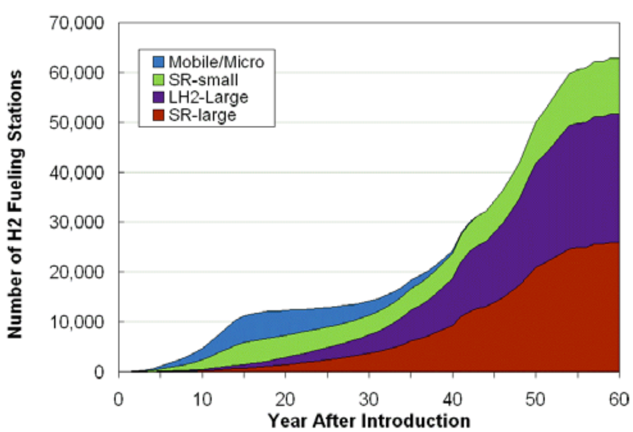

Figure 1. Fueling Station Mix Provides Sufficient Coverage and Production Capacity for the Vehicle Introduction Scenario

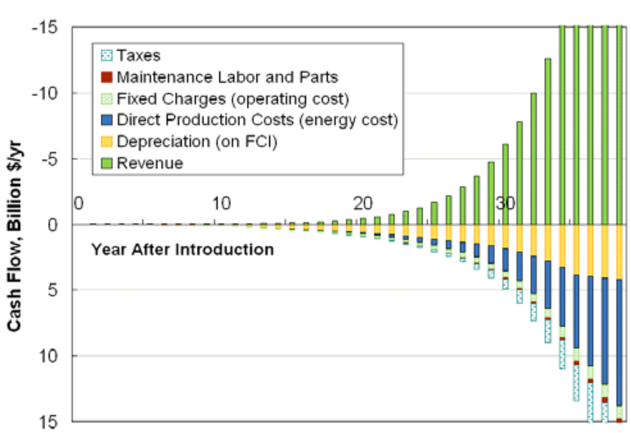

Figure 2. NPV is Determined Based On the Expenditures and Revenues for Each Type of Infrastructure

We have generated scenarios for the introduction of hydrogen infrastructure based on results from previous work, literature sources, stakeholder feedback, and additional analysis. We presented preliminary scenario assumptions and results to a limited number of stakeholders, including automotive and energy company representatives. Based on the feedback from these presentations, we are in the process of refining our analysis and ranking the hydrogen pathways and introduction scenarios in terms of overall financial risk and potential for reducing energy use and greenhouse gas (GHG) emissions.

Based on stakeholder input, we expanded our analysis this past year to include existing excess (in some cases "moth-balled") merchant, ammonia, refinery, and methanol plant hydrogen capacity. We analyzed how using this existing capacity could delay the investment in new hydrogen production capacity for different transition scenarios. The potential for utilizing the existing hydrogen infrastructure was evaluated using the following approach:

- Identify potential sources and locations of existing excess hydrogen capacity (e.g., refineries, ammonia and methanol plants);
- Determine amount of excess capacity (e.g., "moth-balled" plant capacity);
- Identify additional processing/delivery equipment (e.g., purification, storage, compression, liquefaction);
- Determine proximity to population centers using plant locations and Geographical Information Systems (GIS) population data;
- Calculate cost of delivering hydrogen based on distance and demand from population centers; and
- Determine fraction of hydrogen demand that is cost effective to serve with existing excess capacity.

TIAX developed a spatial demand model to calculate the cost of delivering excess hydrogen from the existing infrastructure to population centers across the US. The model determines the amount of excess hydrogen that could be utilized from existing plant capacity grouped by distance from the plant. For each location (i.e. GIS grid), the cost of truck delivery is calculated based on assumptions from the H2A model for liquid hydrogen delivery. This cost is then added to the additional cost of production, based on economics for the brownfield plant (e.g. feedstock and additional processing/delivery equipment capital costs). The cost results are grouped according to distance from the central plant and sorted by U.S. Petroleum Administration for Defense District (PADD) region.

Usable excess hydrogen results have been incorporated into the NPV model. For each PADD region, an input has been created to reflect the fraction of the hydrogen demand that can be supplied by the existing infrastructure. Investment in new central hydrogen plant capacity is delayed until the usable excess hydrogen capacity is consumed. Note that while investment in new production plants is delayed, investment for new liquefaction facilities, liquid (LH_2) tanker trucks, and LH_2 forecourt stations is included in the NPV analysis.

We also updated some economic, energy use, and GHG model inputs based on the latest H2A and GREET model assumptions and results. For example, we used H2A assumptions for high volume forecourt hydrogen production capital cost inputs and GREET emissions factors to calculate GHG results based on forecourt and central plant energy inputs.

Results

Existing U.S. Hydrogen Capacity

Ammonia and methanol plants are potentially the largest sources of existing excess hydrogen capacity with depreciated capital costs (see Table 1) in the U.S. Their excess production capacity corresponds to meeting the hydrogen demand from about 4% of U.S. light duty vehicles (LDVs) if those vehicles were operated on hydrogen. However, transportation (e.g. liquefaction and delivery) costs limit the potential for using these sources of excess hydrogen to demand centers that are in close proximity to the source.

Merchant liquid hydrogen and refinery capacity could provide broader coverage for an early introduction of hydrogen vehicles. However, most of the liquid hydrogen and refinery capacity is fully utilized. Nonetheless, a small fraction of this capacity could help delay investment in new hydrogen production facilities. The estimated existing excess merchant LH_2 capacity of 10 kT/y would support the demand from ~50,000 vehicles. This existing capacity could be important in the very early years of fuel cell vehicle introduction.

Table 1. Estimated Excess Hydrogen Capacity in the U.S.

Estimated U.S. H_2 Capacity	Total, kT/y	Excess, kT/y	Comments
Ammonia	2,880	1,800	U.S. plants are operating below capacity due to the high cost of natural gas
Refining	2,800	None	Sour crude and tighter fuel specs are further increasing refinery H_2 demand
Methanol	760	400	10 of 18 plants closed in last 5 years; but not widely dispersed (75% in Texas)
Captive Chemical (Chlor-alkali)	290	None	By-product hydrogen is used in-plant to make PVC and HCl
Merchant LH_2	80	10	17% difference between merchant H_2 capacity and demand in North America
Total	**6,810**	**2,210**	4% of U.S. LDVs assuming 2x fuel economy improvement for H_2 vehicles

Using the spatial demand model, we generated maps like the one in Figure 3, that graphically display which demand centers can be served by the existing excess capacity. The hydrogen demand is calculated from the distribution of U.S. population combined with annual fuel consumption. This analysis shows regions in the U.S. where hydrogen delivered from existing ammonia or methanol plants would be cost-effective compared to other options such as forecourt (i.e. distributed “on-site”) production. This analysis was performed for various hydrogen vehicle penetration rates. At low penetration rates (< 5%), the excess capacity from existing ammonia plants is greater than the vehicle demand within a 200 mile radius of the plants. Therefore, only a fraction of the excess capacity can

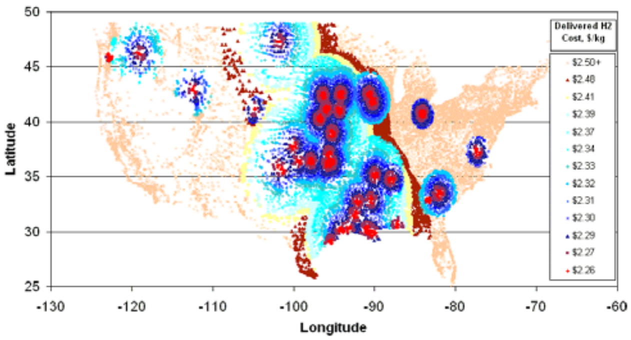

Figure 3. Demand Model Results for U.S. Ammonia Plants with LH_2 Delivery - 5% Penetration Scenario

be used to fuel vehicles. As hydrogen vehicle populations grow, more of the excess capacity can be delivered to meet the growing demand.

Table 2 shows the distribution of excess hydrogen capacity from U.S. ammonia plants by PADD region, again with the demand for the scenario based on the distribution of individuals living in the U.S. Most existing excess capacity comes from Texas (PADD 3) and Midwest fertilizer (PADD 2) industries. The table indicates the amount of excess hydrogen capacity that can be utilized within 50, 100, and 200 miles proximity to these plants for an initial U.S. vehicle hydrogen demand assuming 5% hydrogen vehicle penetration (2,700 kT/y total U.S.). Overall, only 11% of the existing excess capacity can be utilized if we assume a maximum delivery distance of 50 miles; 38% if we assume 200 miles maximum. The fraction of the initial vehicle hydrogen demand that can be met is also indicated by PADD.

Despite the relatively low overall potential to use existing excess capacity, a significant fraction of the initial vehicle hydrogen demand can be served in some regions. In the Gulf Coast, the existing excess hydrogen capacity can serve between 25 and 70 percent of the initial demand depending on the maximum delivery distance assumed.

The information in Table 2 will be used as an input to the NPV model to evaluate the impact on initial hydrogen infrastructure investment. In addition, the information in Table 2 can be used to assess the merits of early hydrogen infrastructure options in different regions of the U.S.

NPV Model Results

A base-case scenario has been developed that assumes a mix of hydrogen infrastructure options (e.g. forecourt and central plant production) with a range of hydrogen selling prices over time that are a function of the assumed conventional vehicle fuel economy, hydrogen vehicle fuel economy, gasoline price, and road tax. Figure 4 shows examples of results for the base-case scenario broken out by stakeholder. In this scenario, central plant and truck delivery stakeholders are assumed to achieve fixed

Table 2. Estimated Excess Hydrogen Capacity from U.S. Ammonia Plants and Proximity to Vehicle Demand

PADD Region	1 East Coast	2 Mid-west	3 Gulf Coast	4 Rocky Mt.	5 West Coast	U.S. Total
Total Excess Capacity, kT/y	85	633	968	29	39	1,755
Capacity Available for 5% Penetration Scenario, kT/y						
50 miles	20	76	86	4	10	196 (11%)
100 miles	51	201	163	17	12	445 (25%)
200 miles	86	293	225	29	23	661 (38%)
Percent of Demand by Region for 5% Penetration Scenario (2,700 kT/y Total U.S.)						
50 miles	2%	10%	26%	5%	2%	7%
100 miles	5%	26%	50%	22%	2%	17%
200 miles	9%	38%	69%	38%	5%	25%

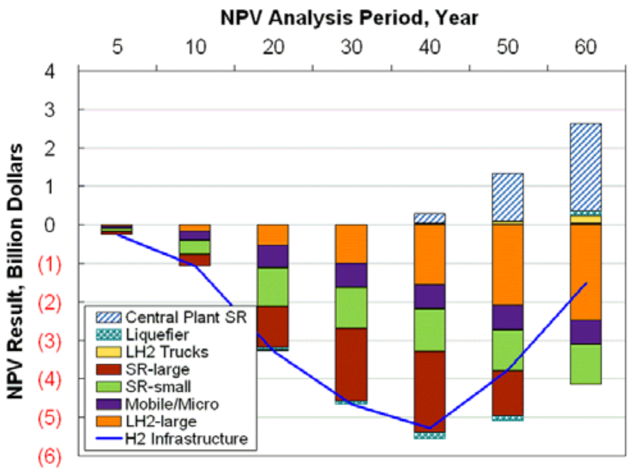

Figure 4. NPV Analysis of Hydrogen Infrastructure Broken out by Stakeholder - DOE OTT Case 1, No Excess Capacity Assumed

internal rates of return on their investment. Forecourt fueling station stakeholders (i.e., LH_2–large, Mobile/Micro, natural gas steam reforming [SR]-small, and SR-large) achieve rates of return based on end-user hydrogen selling prices that are assumed to be equivalent to fuel for conventional vehicles on a $/mile basis.

The NPV values are presented over different time horizons to show how the risk varies throughout the buildup of infrastructure. Negative values at each NPV time horizon indicate that the stakeholder would not achieve a positive return on its investment for the infrastructure mix, cost, and hydrogen price assumptions used in the scenario. The impact of utilizing existing excess hydrogen capacity discussed above has not been incorporated here, but will be included in the final report. Note that detailed model inputs and assumptions for various scenarios will also be presented in the final report.

Figure 5 shows examples of results for GHG emissions from gasoline and hydrogen fueled vehicles, a new feature for the NPV model. The GHG emissions are based on hydrogen production from natural gas. These emissions would be lower if the hydrogen were produced from renewable or zero-carbon resources such as wind, biomass, solar power, or others.

It should be noted that the results presented here are based on projections of the future cost and performance of high-efficiency hydrogen

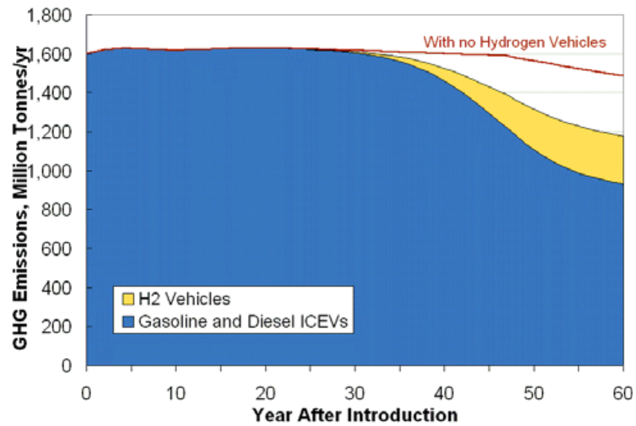

Figure 5. GHG Emissions from Hydrogen and Gasoline Fueled Passenger Cars - DOE OTT Case 1

infrastructure and vehicles. We did not use DOE targets, and there is on-going work at DOE and elsewhere to improve costs and performance beyond those projected here. In addition, these results were based on the DOE “Case I: 3% by 2030” fuel cell vehicle introduction scenario [1]. Faster vehicle introduction scenarios result in more positive economic outcomes and greater GHG reductions. These scenarios will be included in the final report.

Conclusions

Based on the results of a limited number of scenarios, a few general conclusions can be drawn:

- Hydrogen production costs could ultimately be low ($2-3/kg), but initial costs are high due primarily to low capacity factors in the early years.
- If hydrogen were priced to provide cost parity with conventional vehicles, most hydrogen infrastructure stakeholders could turn a profit in the long run, but break-even would not be achieved for many years.
- Unconventional approaches are needed to improve capacity factors and reduce the capital cost of the hydrogen infrastructure, especially in the early years of infrastructure development.
- Utilizing existing excess hydrogen capacity can result in significant capital investment reductions in the early years. These cost reductions need to be examined on a regional basis, for example, in the Midwest, 50 percent of the population is within 100 miles of an existing hydrogen plant.

- Hydrogen infrastructure development must be relatively swift and well coordinated with vehicle introductions. This requires that both vehicle and infrastructure technologies are ready and that there is buy-in from developers, regulators, and the public.
- Early hydrogen selling prices and/or infrastructure capital investments will likely require some form of subsidies to be competitive with conventional fuels. Scenarios will be presented in the final report.
- Ultimately, natural gas-based hydrogen could reduce vehicle GHG emissions by >50% if all vehicles are operated on hydrogen. However, even in a fast transition (not shown here), significant GHG reductions are not realized for 25+ years.

FY 2005 Publications/Presentations

1. Lasher, S. and S. Unnasch, "Hydrogen Infrastructure Costs," presented by E. Carlson at the First International Conference on Fuel Cell Development and Deployment, Storrs CT, March 10, 2004
2. TIAX LLC, "Technology and Market Assessments of Hydrogen as a Transportation Fuel," presented by B. Weber at the Council for Chemical Research 25th Annual Meeting, Tampa FL, April 17-20, 2004
3. Unnasch, S., B. Blackburn (CEC), and E. Ebeles (U.C. Davis), "Hydrogen Supply and Demand for Future Fuel Use," presented at the National Hydrogen Association Meeting, Los Angeles CA, April 26-29, 2004
4. Lasher, S., S. Unnasch, and M. Chan, "Hydrogen Infrastructure: Energy, Costs, and Transition," presented at the 2004 Fuel Cell Seminar, San Antonio TX, November 1-5, 2004
5. Lasher, S., "Fuel Choice for FCVs: Hydrogen Infrastructure Costs," presented at the 2005 Hydrogen Merit Review Meeting, Crystal City VA, May 25, 2005

References

1. Lasher, S., J. Thijssen, S. Unnasch, "Guidance for Transportation Technologies: Fuel Choice for Fuel Cell Vehicles", *2001 Annual Progress Report – Fuels for Advanced CIDI Engines and Fuel Cells,* EERE OTT, November 2001