An Assessment of Renewable-Hydrogen Costs, Infrastructure, and Resource Constraints

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ABSTRACT

A hydrogen production and infrastructure model was developed to investigate the resource constraints and fuel costs of a future renewable-based hydrogen infrastructure in the U.S. automotive sector. The model uses Geographic Information Systems (GIS) data to estimate resource characteristics and supply-chain models to scale resource, production, and delivery costs. Linear optimization was used to determine the most economic combinations of renewable resources and hydrogen infrastructure. The results indicate that there is a widely distributed wind and biomass resource that could produce cost-competitive hydrogen in the U.S. via large-scale water electrolysis and biomass gasification. No renewable-hydrogen options are projected to be as cheap as natural gas-based steam-methane reforming on a national basis, but some favorable locations could be supplied with very cost-competitive renewable-hydrogen, even without incentives.

Keywords: hydrogen, infrastructure, wind, biomass, renewables

1 INTRODUCTION

The use of hydrogen as a fuel for automotive applications has been identified by the U.S. government as a future path to achieve energy independence and improve the environment through the reduction of fossil fuel-related emissions. Even when conventional fossil resources are used to produce hydrogen (e.g., natural gas reforming), automotive PEM fuel cell technology shows the potential to achieve overall energy savings and environmental benefits. It is widely recognized, however, that these benefits would be greatly enhanced if hydrogen were produced from non-CO_2 emitting pathways, such as renewable energy resources, nuclear power, or conventional fossil generation with carbon sequestration.

This study, conducted by TIAX and the National Renewable Energy Laboratory (NREL) for the Department of Energy (DOE), investigates the resource constraints, fuel cost, and infrastructure deployment of renewable-based hydrogen production ("renewable-hydrogen") in the U.S. automotive sector.

While several domestic renewable resources – notably wind and solar – have the technical potential to produce quantities of hydrogen far in excess of projected demand from the U.S. automotive sector, this potential does not take into account the economic viability of the different resources, including feedstock, production, and delivery costs. Notably, much of the renewable resource potential in the U.S. is found in relatively remote locations, which can severely limit its use for hydrogen production due to the high cost of delivering hydrogen over long distances.

To assess the complex trade-off between minimizing fuel transport and production costs, a location-sensitive hydrogen production and infrastructure ("Hydrogen Logistics") model was developed. The model is used to determine the most economically attractive combination of renewable resources and hydrogen infrastructure to supply hydrogen to demand centers across the continental U.S.

2 MODEL OVERVIEW, DATA SOURCES, & ASSUMPTIONS

2.1 Overview

The TIAX Hydrogen Logistics model minimizes the projected average price for renewable-hydrogen at individual demand centers across the U.S. To account for the geographical variation in renewable energy supply and projected hydrogen demand, the model deconstructs the U.S. into a grid of discrete nodes, each with an associated renewable resource supply and hydrogen demand. For this implementation of the model, land-use and population data were gathered at a resolution of 0.25° latitude by 0.25° longitude (approximately 230 sq. mi) using NREL GIS Data [1] to ascertain resource availability and NASA Modis data to determine land cover characteristics [2].

Based on scale-, location-, and resource-specific cost data [3,4,5,6,7,10] and projections for hydrogen demand at localized population centers, a linear optimization routine based on the Simplex method [12] calculates the combination of resources and infrastructure that globally minimizes the average hydrogen selling price[1]. The optimization is constrained by a fixed hydrogen demand, which must be met; and the renewable-hydrogen supply, which may not be exceeded. The optimization process entails trading between the economies of scale associated with a larger plant size and the cost savings associated with minimizing transportation distance. A final post-processing step investigates the optimal deployment of a hydrogen pipeline delivery infrastructure.

The results of the model estimate, for each demand node that participates in the optimization, (1) the hydrogen selling price; (2) a breakdown of resources used to supply the demand node; and (3) the pipeline delivery infrastructure that supplies the node.

2.2 Resource Selection and Quality

For this study, we focused on large-scale renewable resources that are likely to be cost competitive with conventional technology and widely available in the next twenty years.

Based on these criteria, we focused our analysis on utility-scale wind resources, concentrating solar power (CSP), centralized photovoltaics (PV), and biomass (energy crops and agricultural, forest and urban wood residues). We did not consider the impact of distributed renewables (e.g., residential or commercial PV) or of energy storage. The wind and solar resources are assumed to produce hydrogen from electricity that powers water electrolysis plants. The biomass resource is assumed to be used as a feedstock in biomass gasification-based hydrogen plants.

Using GIS data [1], the energy available from each resource type ("resource quality") within each node was estimated. In a given node, the resource quality depends on a number of location-specific resource characteristics, such as land type, solar insolation, or average wind speed. The potential for a resource's development in a given node was screened first on a logistic, not economic, basis. For example, urban areas and crop land were considered unsuitable for centralized solar installations.

2.3 Hydrogen Resource, Production, and Distribution Assumptions

Hydrogen selling price is separately modeled in terms of resource, hydrogen production, and delivery costs. The hydrogen "resource cost" refers to either the cost of the electricity used to power an electrolysis plant (wind and solar) or the feedstock cost including delivery to the hydrogen production plant (biomass). The "production cost" refers to the amortized costs of operating a hydrogen production plant, less this resource cost. The "delivery cost" refers to the cost to transmit hydrogen via pipeline from plant locations to demand centers, plus the cost to deliver and dispense hydrogen within the demand center.

Simulations were evaluated for both base case and favorable scenarios using previously established estimates of these costs and their associated scaling functions. **Error! Reference source not found.** summarizes these assumptions and data sources.

Table 1: Representative Cost Assumptions and Sources

Parameter	Case	Biomass Gasification	Wind and Solar Electrolysis
Resource Cost[2]	Base	\$100-\$120 [5,6]	Varies[3]
	Fav.	~\$40 [7]	Varies[4]
H_2 Plant Capacity Factor	Base	0.9 [8]	Varies[5]
	Fav.	0.95 [8]	Varies[6]
H_2 Plant Capital Cost[7]	Base	\$96M [8]	\$360/kW [8]
	Fav.	\$77M [8]	\$250/kW [8]
H_2 Conversion Efficiency (LHV)	Base	55% [8]	74% [8]
	Fav.	60% [8]	79 %[8]
Fixed Delivery Cost	Base	\$1.72/kg (derived from [8])	
	Fav.	\$0.92/kg (derived from [9])	
Variable Delivery Cost	Base	\$0.0011/kg/mi (derived from [8])	
	Fav.	\$0.0006/kg/mi (derived from [9])	

For each resource, hydrogen production costs are derived based on functions for the size (i.e., throughput) and capacity factor of the hydrogen production plant. Note that capacity factors for wind- and solar-based plants are assumed to be equivalent to the resource capacity factors, i.e., we assume no energy storage or electricity use other than for hydrogen production. To optimize the economics of biomass-based production, individual resource supply nodes were consolidated into larger regional biomass-to-hydrogen conversion plants. These economics involved a trade off between improved production economies of scale (i.e., larger plants with lower production cost) and increased biomass transportation costs (i.e., smaller plants with lower resource cost). For the other resources, hydrogen production plants are assumed to be co-located with the resource.

[1] "Hydrogen selling price" and most of the "costs" described in this paper include appropriate rates of return for investors. Taxes are not included.

[2] Biomass cost in \$/dry ton biomass, which varies based on feedstock type and distance to processing plant; Wind/Solar in \$/kWh elec.

[3] For example, favorable locations (e.g., Class 6 wind) are: Wind = \$0.03 [3]; PV = \$0.076 [3]; CSP = \$0.064 [4]

[4] For example, favorable locations are: Wind = \$0.03 [3]; PV = \$0.050 [10]; CSP = \$0.041 [4]

[5] For example, favorable locations are: Wind = 0.479 [3]; PV = 0.295 [3]; CSP = 0.729 [4]

[6] For example, favorable locations are: Wind = 0.491 [3]; PV = 0.295 [3]; CSP = 0.760 [4]

[7] Biomass plant cost based on a 175 TPD H_2 plant; other plant sizes are scaled using a 0.85 power rule

Hydrogen delivery cost estimates are derived from the H2A Hydrogen Delivery Scenario Delivery Model (HDSAM version 1.0) [8] for various compressed hydrogen pipeline throughputs. Costs include central plant to “city gate” transmission pipeline, compressor and storage systems; as well as intra-city distribution and dispensing (i.e., fueling station) costs. Of these, the transmission pipeline scales with distance and throughput, while the other components scale with throughput only.

The Logistics Model optimization assumes a point-to-point delivery infrastructure (i.e., hydrogen travels directly from the production plant to the “city gate”). To approximate a more realistic, mature delivery infrastructure, we also performed a separate analysis that takes advantage of a potentially lower-cost networked pipeline delivery infrastructure.

2.4 Demand Assumptions

Demand assumptions (summarized in Table 2) are based on U.S. census data [11] for a 2040 time frame in which fleet penetration of hydrogen vehicles in the selected markets is 50%. To reflect the likely diffusion of fuel-cell technology from urban to rural areas, it is assumed that hydrogen demand is concentrated within urban centers. As such, the logistics model simulations were fixed to only supply hydrogen to demand nodes with populations greater than 300,000 people. This restriction captures roughly one-half of the projected US population (46%), and includes 240 different demand centers.

Table 2: Demand Assumptions for the U.S.

Analysis Year	2040
Fraction of U.S. Population in selected nodes	46%
LDV Population in selected nodes	169M
Renewable H_2 Penetration (Renewable/Total)	50%
Renewable H_2 Demand, TPD	49,100

3 RESULTS

Figure 1 shows the locations and types (wind = yellow diamond, biomass = green star, red = solar; demand centers = white circles) of plants that result from the base case optimization, as well as the consolidated pipeline infrastructure to deliver from supply nodes to demand centers. As shown, biomass (especially in the East and Midwest) and wind (especially in the West) dominate the renewable-hydrogen supply. The model projects that no utility-scale solar resources (CSP or PV) are utilized.

The model projects a mean price of renewable-hydrogen of \$4.35/kg in the base case. Figure 2 shows the location-dependent distribution of hydrogen price seen at demand centers across the U.S. broken out by resource type. The bimodality of the wind-based hydrogen price is an artifact of the discrete distinction between Class 6 and Class 5 wind resource cost assumptions. For reference, H2A model results project that the natural gas-based hydrogen selling price[8] will be about \$3.50/kg H_2. As shown, the vast majority of renewable-hydrogen is considerably more expensive.

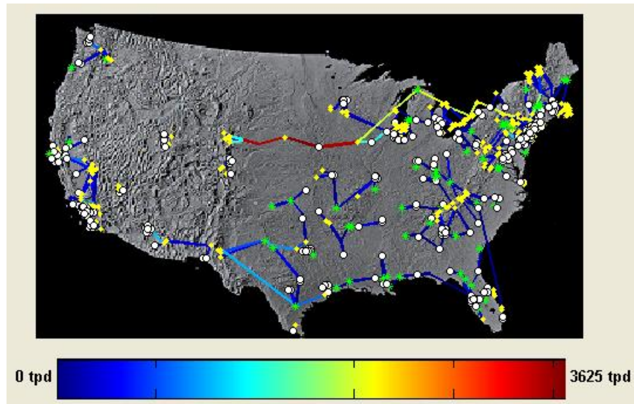

Figure 1: Location of Economically Utilized Resources and H_2 Pipeline Network

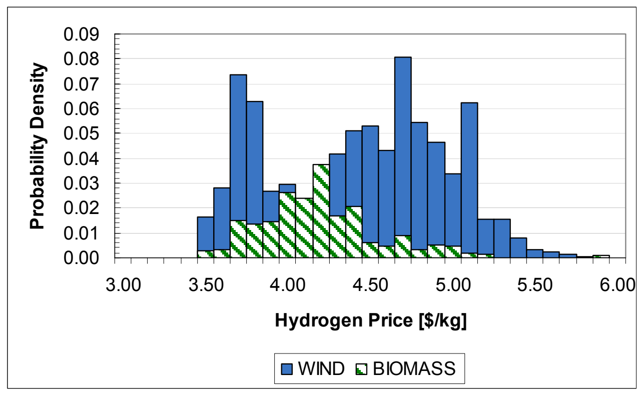

Figure 2: Hydrogen Price Variation

Although some biomass is projected to be utilized for hydrogen production in regions with very dense biomass availability, four times more wind-based than biomass-based production is projected to meet a hydrogen demand of 49,100 TPD, or about 25% of projected U.S. light-duty vehicle demand in 2040. However, the total biomass utilization taps a much larger fraction of the assumed overall resource than does the wind utilization (17% vs 2%). Hence, as demand grows beyond the assumed levels, the economically available biomass resource quickly diminishes. This implies that higher demand would lead to an increasing fraction of wind utilization.

The contribution of resource, production, and delivery costs to the overall hydrogen price are shown in Figure 3 (the uncertainty bar approximates the impact of favorable

[8] Central natural gas steam reformer plant (2030 technology) assuming 180 miles of pipeline delivery.

delivery). The resource cost and hydrogen production cost each account for about 25% of the total. Hydrogen delivery costs, including pipeline, compression, storage and dispensing (i.e., fueling station) costs, account for the other half. Note that this delivery cost is higher than typical H2A values due to the longer delivery distances than that assumed by H2A. The average delivery distance in the base case is 180 miles compared to 62 miles typically for H2A.

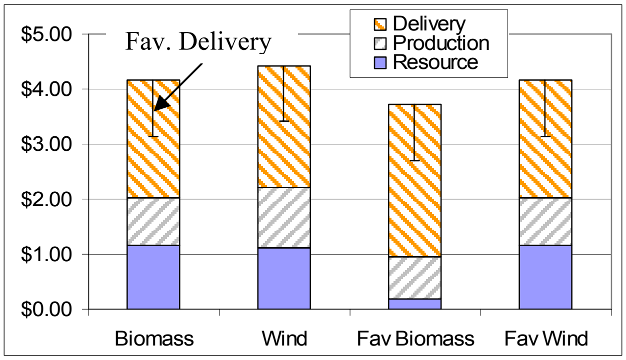

Figure 3: Average Hydrogen Selling price Contribution

The favorable biomass case offers significant cost reductions (14%) due to lower resource costs. The favorable wind assumptions – which lowers production, but not resource, costs – have only a marginal impact on price (3.2% decrease). Even using optimistic assumptions, the model projects that no solar resources (CSP or PV) are utilized. Because delivery costs account for such a large fraction of the overall hydrogen selling price, reducing these costs offers a 23% cost reduction on average.

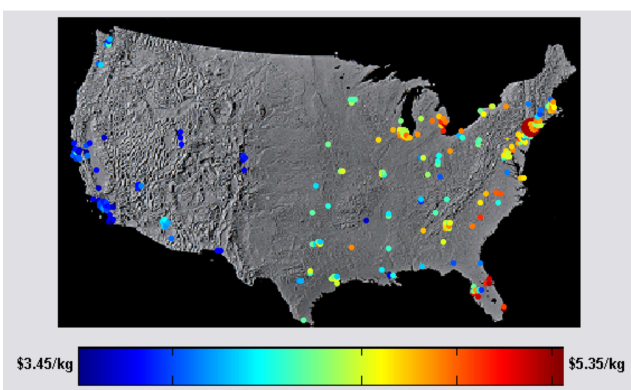

Figure 4: Price Distribution in the Base Case

Figure 4 shows two very distinct trends (note that the size of the marker is a representation of hydrogen quantity). The first trend is that the hydrogen selling price increases from West to East. The second trend is that the Northeast coastal region and Florida are concentrated regions of >$5.00/kg H_2. The case of the Northeast's high hydrogen price can be explained by its dense population and accompanying lack of (or depletion of) cheaper resources. Florida, while not as densely populated as the Northeast, faces resource restrictions since, as a long peninsula, it can only accept resources from the north and at the cost of high transmission costs.

4 CONCLUSION

The results indicate that there is a widely distributed wind and biomass resource that could produce cost-competitive hydrogen in the U.S. via large-scale water electrolysis and biomass gasification. Due to the higher cost of utility-based solar power relative to wind-power, the model projects that no solar resources are used in the base case. Distributed solar-based production may be more attractive, but distributed options were not evaluated here. No renewable-hydrogen options are projected to be as cheap as natural gas-based production on a national basis, but some favorable locations could be supplied with very cost-competitive renewable-hydrogen, even without incentives. The results further indicate that hydrogen price is heavily influenced by delivery costs; this suggests that resource utilization depends very much on its proximity to demand centers. Further study will seek to integrate conventional (fossil and nuclear) resources in the model, and characterize the impact of carbon monetization.

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