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Optimal Role of Renewable and Zero-carbon Gaseous Fuels in the Future Energy Economy – Transforming the Gas Grid

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Abstract— The work to be presented is a comparative analysis of deep decarbonization strategies for the natural gas grid. The analysis is based on California supply and demand scenarios and unit costs, but results are broadly applicable to other markets seeking deep decarbonization. To achieve deep reductions in economy-wide GHG emissions, the fuel delivered over the natural gas system must be replaced by zero or near-zero-carbon substitutes. Electrification of many end uses will reduce the need for gaseous fuel over time. However, the least-cost approach to economy-wide decarbonization will likely include continued use of decarbonized forms of methane and expansion of the use of hydrogen for a range of applications. Low-carbon gaseous fuels are well suited for current uses of natural gas, those of conventional hydrogen (predominantly refining and ammonia production) and applications served by liquid fuels. Hydrogen and methane can be decarbonized through production pathways that use renewable energy sources and feedstocks, or through carbon capture and sequestration in geological formations or solid products. The presentation will compare the long-term costs of alternative strategies for decarbonizing the gas grid, including cost of potential transition from natural gas to pure hydrogen. Preliminary results show that decarbonized hydrogen is the most cost effective energy vector to serve zero-carbon gaseous fuel demand in the deeply decarbonized future economy.

Keywords: natural gas, decarbonization, hydrogen, renewable hydrogen, pipelines, hydrogen pipelines, renewable natural gas, carbon capture

I. INTRODUCTION

Economies around the globe are exploring pathways to achieve deep decarbonization. Conversion of many existing uses of liquid and gaseous fuel to technologies powered by renewable electricity is a dominant theme in decarbonization strategies. However, certain applications lack feasible and cost-effective all-electric solutions. In general, these are applications that require the storage and or transport of large amounts of energy or the ability to transfer energy at a high rate such as vehicle fueling. So-called hard to electrify applications include high-payload transportation such as freight, marine, rail and aviation applications, high-temperature process heat and firming of variable renewable energy sources. These applications must be decarbonized in other ways such as the use of low and zero-carbon liquid and gaseous fuels. The present analysis considers the potential role of renewable and zero-carbon (R&ZC) gaseous fuels in strategies to reach cross-sectoral zero carbon emissions. Specifically, the analysis assesses the relative economics of renewable and zero-carbon hydrogen and methane to serve various applications with consideration of infrastructure modifications necessary for the wide-scale adoption of hydrogen as a fuel. Electrofuels are an important class of R&ZC fuels and can be considered an indirect form of electrification.

II. RENEWABLE AND ZERO-CARBON GASEOUS FUEL PATHWAYS

A variety of pathways can be used to produce renewable and zero-carbon fuel. Broadly, there are three categories that are commercial or on the near-term horizon: thermochemical biomass conversion; anaerobic digestion of organic material, water electrolysis, and natural gas with carbon capture. Splitting of water using direct photochemical energy is another pathway on the longer-term horizon. These pathways are depicted in Fig. 1. A key determinant of the optimal role of these pathways in the future, deeply-decarbonized, energy and transportation sectors is the relative cost of producing fuels via these pathways. This depends on the cost of primary inputs (such as organic material or electricity), the capital cost of conversion facilities, conversion efficiency and new infrastructure or end-use devices needed to transport and use these fuels.

III. RENEWABLE ZERO-CARBON FUELS PRODUCTION COST EVOLUTION

In prior analysis, future cost of renewable hydrogen production via thermochemical conversion, anaerobic digestion with steam methane reforming, and water electrolysis were assessed [1]. The forecasts were developed using a variety of methods applied directly or adopted from published literature. Methods included expert consultation, learning curve analysis and bottom-up estimation based on

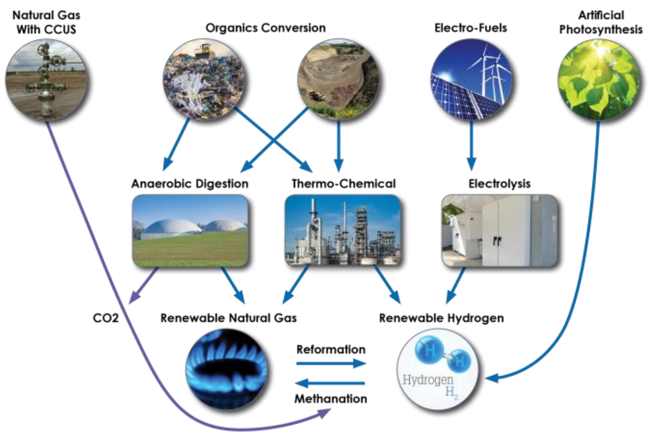

Fig 1. Renewable and zero-carbon gaseous fuel pathways

current and future designs. That analysis has been extended in the present work to include methane as an end product and adds carbon capture and sequestration to the analysis. The resultant cost forecast is shown in Fig. 2.

Although the future cost bands for renewable electrolytic methane and hydrogen overlap, the cost of renewable electrolytic methane will always be higher than that of renewable electrolytic hydrogen and the two will follow that same trajectory. The reason for this is that renewable electrolytic hydrogen is the primary feedstock for renewable electrolytic methane. The cost adders are shown in Fig. 3 for two illustrative cases. First, additional capital cost will be incurred for the methanation step. Second, the methanation reaction is exothermic, so there is less energy in the final product fuel. Finally, the methanation reaction requires CO_2 is an additional feedstock and, in generally, providing this reactant to the process will add equipment costs and the CO_2 may carry a commodity cost based on competing uses of zero-carbon CO_2 and carbon credit prices. Because of these additional costs, electrolytic methane is only a viable fuel choice in cases where its value as a drop-in substitute for natural gas are lower than the costs to adapt infrastructure and end uses to use hydrogen. This is assessed in the next section.

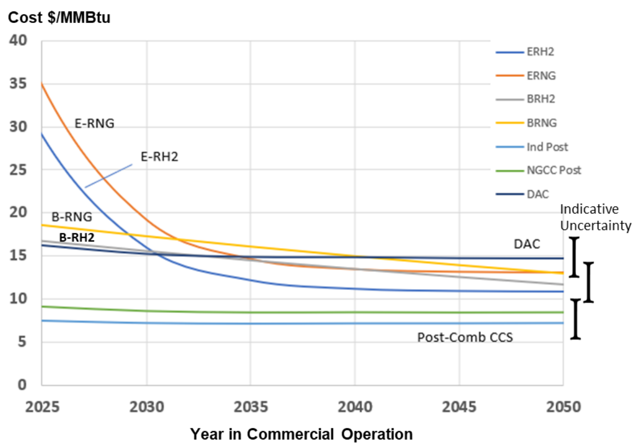

Fig. 2. Cost evolution for renewable and zero-carbon gaseous fuels

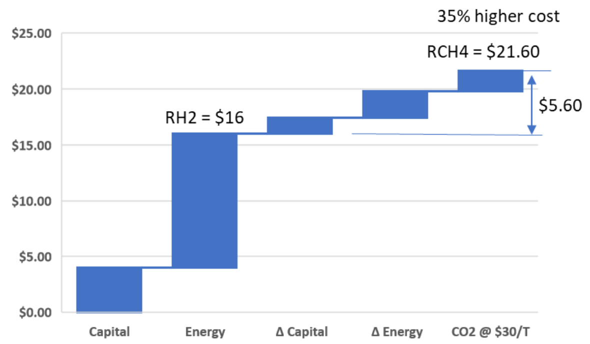

Fig. 3. Illustration of cost increments to produce methane from hydrogen

IV. Hyddrogen Infrastructure Costs

Unlike methane pathways, wide-scale adoption of hydrogen will require new or adapted transport and storage infrastructure and new or adapted conversion devices such as prime movers and combustion systems. Prior analysis assessed the infrastructure costs for transportation applications and concluded that the plant-gate-through-dispensing cost of hydrogen vehicle fuel would reach $2/kg by 2050 [1]. The present work adds projection of the cost of adapting or replacing the natural gas system to deliver hydrogen to both transportation markets and the applications currently served by natural gas. The cost projections draw on work in the United Kingdom, the European Union, and hydrogen infrastructure cost estimates contained in the U.S. Department of Energy HDSAM 3.0 hydrogen infrastructure cost model [2][3][4].

The analysis is based on the natural gas system in Southern California. The basic system parameters are shown in Table I.

The H21 study found that the low pressure distribution system requires minimal modification to accommodate hydrogen. Pressure regulation devices require replacement and a few areas on the system analyzed required capacity enhancement due to the lower volumetric energy density of hydrogen in comparison to natural gas (methane). However, plastic and protected steel pipe were found to be tolerant of hydrogen and required no modification or replacement [2]. To optimize the interface with the high-pressure system, the

TABLE I. Southern California Natural Gas System

System Element	Value		
Annual Throughput (PJ)	900		
Storage Capacity (PJ)	160		
Transmission Pipe Miles	12,600		
Distribution Pipe Miles	120,000 (approx.)		
	Residential	Commercial / Industrial	Generation
Customer Meters (x1000)	5,600	12 / 107	NA
Consumption %	30%	38%	32%

Sources: American Gas Association, EIA, company reports.

H21 study added about 350 miles of distribution main (a small fraction of the main in place). The above modifications and additions, scaled to Southern California led to a cost estimate of $930 million for distribution system modifications.

The high pressure transmission backbone and laterals require replacement or retrofit to accommodate pure hydrogen (or methane/hydrogen blends at high hydrogen fraction). The Southern California region was used to assess the cost of constructing a hydrogen transmission backbone. Fig. 4 illustrates such a hydrogen backbone routed to serve existing thermal power plants. The system would also supply other uses for which hydrogen is adopted potentially including industrial users, buildings, and transportation.

The hydrogen backbone will require an estimated 800 miles of high pressure, large diameter pipe and laterals. Using construction unit cost estimates from the North of England study converted to US dollars and escalated to 2021, the cost of the new high-pressure hydrogen system is $4B. The European backbone study estimated that natural gas transmission lines can be repurposed for hydrogen at roughly 20% of the cost of new lines. For the present analysis, we assume that 25% of the system can use repurposed natural gas lines reducing the transmission backbone cost estimate to $3.2B.

Natural gas storage facilities will require modification of compression and other surface facilities and new cushion gas. These costs were estimated using cost metrics developed by Lord et al. escalated to 2021$ [5] which equates to just under $8 per kilogram of storage capacity. Cushion hydrogen is assumed to cost $2/kg and the ratio of cushion to working gas is estimated to be 30%. Converting 50 Bcf of natural gas storage to hydrogen is estimated to cost $3.1 B.

For building applications, costs will be incurred when hydrogen is adopted in the form of appliance replacement costs and other work at the premise level. For commercial and industrial facilities, these costs were estimated based on the H21 North of England project [2] with costs converted from 2018 British pounds to U.S. dollars and escalated to 2021. The incremental cost of converting residences depends on the type and number of appliances, conversion or replacement costs and normal stock turnover for different types of appliances. Analysis of these factors applicable to the U.S. market is ongoing. The present analysis assumes one day of technician time at $100 per hour and replacement of cooking range, water heater and furnace for $3,000 based on current mid-range appliance costs discounted by 30% to account for mid-life replacement of existing appliances.

Fig. 4. Notional hydrogen backbone system for Southern California

TABLE II. SOUTHERN CALIFORNIA NATURAL GAS SYSTEM HYDROGEN CONVERSION COST ESTIMATES

System Element	Costs $ (rounded)	
	Region	*Per Meter*
Transmission	3.2 billion	535
Storage	3.1 billion	515
Distribution	0.93 billon	155
Customer Side of Meter	13.8 billion	2,900
Total	21 billion	4,100

V. RENEWABLE AND ZERO-CARBON FUELS DEMAND

The future demand for gaseous R&ZC fuels depends on relative economics and technical feasibility. In prior work, renewable hydrogen demand scenarios were developed for California based on various technology assumptions and decarbonization trajectories. The present work considers additional R&ZC pathways. In addition, the recently announced U.S. Department of Energy Hydrogen Energy Earthshot[1] established a target cost for clean hydrogen of $1 per kilogram by 2030 improving the demand outlook on the high end.

R&ZC gaseous fuels can serve all sources of demand currently served by natural gas and petroleum fuels. Due to the drive-train efficiency advantage of hydrogen fuel cells relative to methane pathways employing internal combustion engines, hydrogen is the assumed fuel serving the transportation sector. Other applications can be served by either methane or hydrogen.

R&ZC pathways will compete with direct electrification and low-carbon liquid fuels for some applications. Fig. 5 shows modeling results for the adoption of renewable or zero carbon gas in the least-cost dispatch serving the California grid. The results were developed with the California Public Utilities Commission RESOLVE resource planning model [6].

California is embracing electrification as a primary strategy for space and water heating using electric heat pumps. However, if pipeline-delivered R&ZC gaseous fuels achieve cost levels on the low end of the forecast range, continued use of gas in buildings directly in existing appliances and equipment or employing thermal heat pumps will be cost-optimal for most users. Fig. 6 shows an energy cost comparison between a high-performance electric heat pump and thermal heat pumps.

[1] https://www.energy.gov/eere/fuelcells/hydrogen-shot

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Industrial process heat is also a large source of potential demand for R&ZC gaseous fuels. About 55% of industrial process heat requires heat input at temperatures above 250 C [7]. For these applications, electrification is infeasible or cost prohibitive. For lower temperature process heat, the degree of electrification will depend on relative economics.

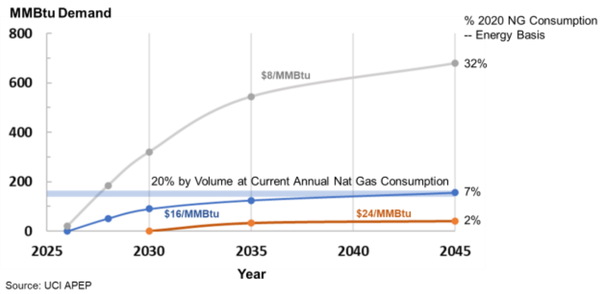

Fig. 5. RESOLVE model renewable gas adoption as a function of commodity cost

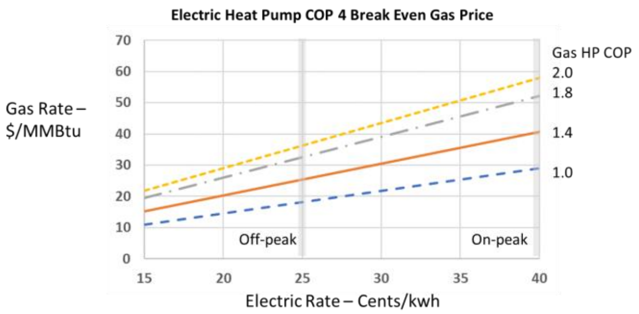

Fig 6. Energy cost comparison for an electric heat pump with a COP of 4 relative to thermal heat pumps over a range of COPs

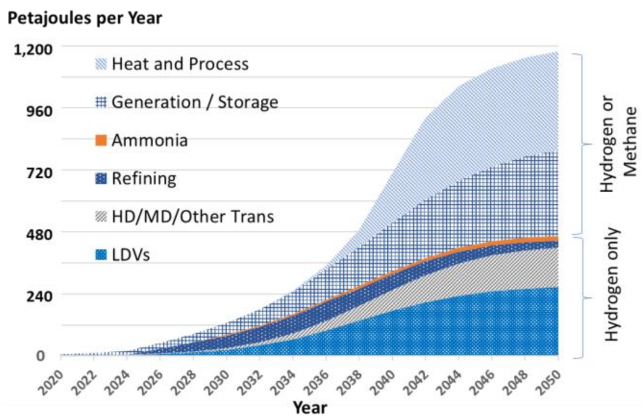

Fig. 7. Potential California Renewable Gas Demand Growth

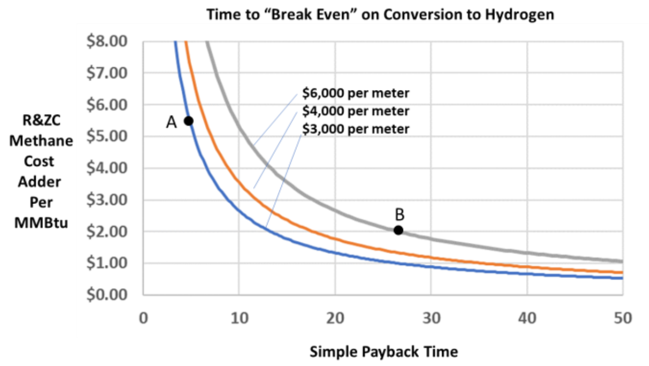

Fig. 8. Time required to achieve simple payback for conversion of natural gas system to hydrogen using demand projection in Fig. 7.

VI. Conclusions

If the aggressive cost targets that have been established for renewable and zero carbon hydrogen and methane can be achieved, these fuels will see significant adoption as replacements for natural gas and conventional hydrogen, and will achieve substantial penetration in transportation markets currently served by petroleum fuels. Pipeline delivery is a cost effective delivery option if pipeline utilization is sufficient.

Among R&ZC options, electrolytic hydrogen, and zero-carbon hydrogen from the use of steam methane reforming with carbon capture are likely to be the least-cost zero-carbon gaseous fuel options. This can be seen in Fig. 2. However, the pure hydrogen pathways require adapted or new infrastructure and equipment as discussed above. The trade-off question is whether the cost "savings" from using hydrogen provide net savings when conversion costs are considered.

Fig. 8 illustrates this trade-off. The vertical access represents the additional cost to produce methane from hydrogen. The horizontal axis is the simple payback time to recover the cost of new infrastructure and equipment. The per meter costs roughly span a range of 25% lower than the base case estimate of $4,100 per meter to about 50% higher. Fig. 2 provided an indicate cost uplift to go from hydrogen to methane of $5.60 per MMBtu. The minimum cost uplift between hydrogen and methane could be as low as $2 per MMBtu if CO2 could be provided to the process for $25 per ton (notional capture, compression, and transport cost). The cost uplift for thermochemical and post-combustion carbon capture would fall within the range.

The point labeled "A" represents a low-conversion-cost case with a high hydrogen-to-methane cost uplift. In this case, the payback for converting the gas system to hydrogen is rapid. In case "B", with higher conversion costs and a lower cost difference between hydrogen and methane, the payback is substantially longer.

Although analysis is still ongoing, it appears that the cost difference between decarbonized forms of hydrogen and decarbonized forms of methane will be sufficient to justify the cost of converting the natural as pipeline system from methane to hydrogen. Payback time can potentially be under ten years. A more complete analysis will include timephasing of the transition and discounting of cash flows, but the simple payback analysis suggests the conversion to hydrogen will be a least cost solution.

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