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Economic analysis of a high-pressure urban pipeline concept (HyLine) for delivering hydrogen to retail fueling stations

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A B S T R A C T

Reducing the cost of delivering hydrogen to fueling stations and dispensing it into fuel cell electric vehicles (FCEVs) is one critical element of efforts to increase the cost-competitiveness of FCEVs. Today, hydrogen is primarily delivered to stations by trucks. Pipeline delivery is much rarer: one urban U.S. station has been supplied with 800-psi hydrogen from an industrial hydrogen pipeline since 2011, and a German station on the edge of an industrial park has been supplied with 13,000-psi hydrogen from a pipeline since 2006. This article compares the economics of existing U.S. hydrogen delivery methods with the economics of a high-pressure, scalable, intra-city pipeline system referred to here as the "HyLine" system. In the HyLine system, hydrogen would be produced at urban industrial or commercial sites, compressed to 15,000 psi, stored at centralized facilities, delivered via high-pressure pipeline to retail stations, and dispensed directly into FCEVs. Our analysis of retail fueling station economics in Los Angeles suggests that, as FCEV demand for hydrogen in an area becomes sufficiently dense, pipeline hydrogen delivery gains an economic advantage over truck delivery. The HyLine approach would also enable cheaper dispensed hydrogen compared with lower-pressure pipeline delivery owing to economies of scale associated with integrated compression and storage. In the largest-scale fueling scenario analyzed (a network of 24 stations with capacities of 1500 kg/d each, and hydrogen produced via steam methane reforming), HyLine could potentially achieve a profited hydrogen cost of $5.3/kg, which is approximately equivalent to a gasoline cost of $2.7/gal (assuming FCEVs offer twice the fuel economy of internal combustion engine vehicles and vehicle cost is competitive). It is important to note that significant effort would be required to develop technical knowledge, codes, and standards that would enable a HyLine system to be viable. However, our preliminary analysis suggests that the HyLine approach merits further consideration based on its potential economic advantages. These advantages could also include the value of minimizing retail space used by hydrogen compression and storage sited at fueling stations, which is not reflected in our analysis.

1. Introduction

One of the largest challenges to widespread consumer adoption of fuel cell electric vehicles (FCEVs) is the lack of an extensive network of hydrogen refueling stations. One recent study suggests a U.S. network of approximately 1500–3300 hydrogen stations would be required to serve 1.8–4.5 million FCEVs (Melaina et al., 2017). This refueling network would require 1.3–3.4 million kg/d of hydrogen for the scenario studied. However, only about 40 retail hydrogen stations are operating in the United States today, most of which are concentrated in California (AFDC, 2018).

To be competitive, hydrogen must be produced, delivered to stations, and dispensed at a cost comparable to competing fuels (after adjusting for the efficiency differences between FCEVs and other vehicle types)—while offering the reliability and convenience of gasoline fueling. However, owing to small scale and limited competition, dispensed hydrogen fuel prices currently are higher, averaging about $16.30/kg in California in the third quarter of 2018 (CEC and CARB, 2018). About half of the levelized cost of retail station hydrogen can be attributed to hydrogen delivery, compression, and dispensing costs (CEC and CARB, 2017). The U.S. Department of Energy (DOE) estimates that a dispensed cost of about $7/kg must be achieved to make FCEVs competitive with gasoline

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internal combustion engine vehicles in early FCEV markets (DOE, 2015d).

Today, hydrogen is primarily delivered to stations in gaseous form by trucks, with smaller numbers of stations served by truck delivery of liquid hydrogen, onsite electrolysis of water, or onsite steam methane reforming (SMR) (CaFCP, 2018). Pipeline delivery of hydrogen is another option, which may provide cost synergies where large industrial hydrogen demands—such as petroleum refining and ammonia production—already exist. Compared with other delivery options, pipelines generally have low operating expenses, high reliability, long service life, and low public visibility. Pipeline networks can be integrated with several different hydrogen production facilities (as is the case for today's industrial hydrogen pipelines on the Gulf Coast[1]), which can mitigate shortages in supply if one facility goes offline or there is a spike in demand.

In 2011, a hydrogen station supplied by a low-pressure hydrogen pipeline opened in Torrance, a dense urban area in the Los Angeles, California, region. The pipeline is a spur connected to a larger pipeline—fed by two large SMR plants delivering 800-psi industrial hydrogen—that runs underneath the street adjacent to the station. The hydrogen is purified, compressed, stored, and dispensed (at 5000 and 10000 psi) onsite at the station. The station remains operational and is the only U.S. hydrogen station supplied via pipeline (Air Products et al., 2013; Brindle, 2016).

This article compares the economics of various existing hydrogen-delivery methods with the economics of a novel variation on pipeline delivery: a high-pressure, scalable, intra-city pipeline system referred to here as the "HyLine" system. In the HyLine system, hydrogen would be produced at industrial or commercial sites near and within urban areas, compressed to 15,000 psi, stored at centralized facilities as necessary, delivered via high-pressure pipeline to retail stations, and dispensed directly into FCEVs.

The primary potential advantages of the HyLine system relate to its minimization of hydrogen storage and compression equipment sited at retail refueling stations. Centralization of compression could reduce costs via economies of scale, because compressor costs do not scale linearly with size: one large compressor is significantly cheaper than two smaller compressors of the same total capacity. In addition, compressor efficiency increases with size, because a lower percentage of hydrogen leaks between high- and low-pressure stages (DOE, 2015c). HyLine connection might also minimize operating costs at fueling stations, by reducing maintenance needs and costs associated with accepting regular hydrogen deliveries from trucks. Finally, eliminating compression and storage at fueling stations could also reduce land-area requirements, which would lower station capital cost and make stations easier to site.

However, development of high-pressure hydrogen pipelines within urban areas, per the HyLine concept, also presents various challenges, which are described in Section 2 along with a real-world example of a hydrogen station supplied via high-pressure pipeline. Sections 3 and 4 present our methods and results for comparing the delivered cost of hydrogen from HyLine versus other delivery methods, and Section 5 discusses the results. This preliminary analysis is meant to help determine whether HyLine has potential economic benefits that might justify the significant research, development, and demonstration that would be required to realize its implementation.

2. Challenges and real-world experience related to high-pressure hydrogen pipelines

This section discusses challenges related to implementing high-pressure hydrogen pipelines in urban areas, and it describes real-world implementation of a high-pressure hydrogen pipeline within an industrial park in Germany.

2.1. Challenges related to implementing high-pressure hydrogen pipelines in urban areas

Because the HyLine system represents a novel application of energy distribution within urban areas, enabling such a system would require development of technical knowledge, codes, and standards that account for its unique attributes. This article focuses on the potential delivered costs of hydrogen using HyLine rather than these requirements. Thus, this section highlights key technical issues only briefly. If HyLine is deemed worthy of further exploration based on its potential economic and logistical benefits, then these issues would need to be examined in greater depth.

The HyLine system operates at pressures significantly higher than those typically used for pipeline transport of gases. Transmission pipelines within the vast U.S. natural gas system typically operate at pressures of 200–1500 psi, which are 10–75 times lower than the maximum HyLine operating pressure. Typically, pressures are stepped down further, to 0.25–200 psi, in natural gas distribution pipelines (American Gas Association, 2019). Today's hydrogen pipelines, which are associated with industrial facilities such as oil refineries and chemical plants, operate at pressures around 500–1200 psi (U.S. Drive, 2013). Use of pipelines at HyLine pressures would need to be preceded by sufficient engineering knowledge, operating experience, and time to enable widespread acceptance.

Beyond its general characteristics as a high-pressure gas, high-pressure hydrogen presents unique challenges related to its impact on metallic materials. These effects—often captured under the term "hydrogen embrittlement"—include effects on fracture toughness, ductility, and fatigue resistance. Although the phenomenon has been studied since the beginning of the 20th century, its mechanisms and impacts are still debated among researchers. In general, hydrogen atoms dissolve into metals and change their properties in a way that reduces strength and crack resistance, which manifests when the metals are subjected to mechanical stress

[1] An extensive hydrogen pipeline network serves the high concentration of refineries and hydrogen producers along the U.S. Gulf Coast (Air Products, 2018). Additional outside-the-plant-gate pipelines are operational in California and Indiana (Praxair, 2018). More than 1600 miles of U.S. hydrogen pipelines are in service today, typically at pressures of no more than 1000 psi (U.S. Drive, 2017, PHMSA, 2019).

(e.g., pressure in the case of pipelines). Hydrogen may penetrate metals concurrently with mechanical stress/deformation, which often localizes the interaction to a stress-concentration site such as a crack (Furtado and Barbier, 2014). In any case, science and engineering efforts have addressed embrittlement issues sufficiently to enable the safe handling of pressurized hydrogen in various applications, as evidenced by hydrogen's industrial uses, FCEV onboard fueling systems, hydrogen fueling stations, hydrogen piping and pipelines, and so forth as well as the development of codes and standards such as American Society of Mechanical Engineers (ASME) B31.12 (discussed below).

A significant volume of fracture-mechanics data has been reported from testing of metals in gaseous hydrogen at pressures less than about 3000 psi (e.g., Ronevich et al., 2016; San Marchi et al., 2010, 2011; Slifka et al., 2014). Conversely, the published fatigue and fracture data evaluated in gaseous hydrogen at pressures greater than about 3600 psi are extremely limited owing to two primary factors: (1) fracture-mechanics experiments conducted in gaseous hydrogen are challenging and can be performed by only a small number of laboratories at high pressure (Somerday et al., 2017), and (2) pipelines are typically not operated at pressures greater than 1500 psi. In contrast, the fatigue and fracture properties of pressure-vessel steels have been studied in gaseous hydrogen at pressures around 15,000 psi (San Marchi et al., 2019), and these steels are used to store hydrogen at such high pressures. Additional evaluation is needed on the performance of pipeline steels at pressures and loading conditions relevant to the HyLine system (e.g., fatigue and fracture tests in gaseous hydrogen at a pressure of 15,000 psi) to assess the system's technical feasibility.

Following assessments of technical feasibility, construction of pipelines at the pressures of interest in a HyLine system would require revisions to the ASME B31.12 code. Code revisions are rigorous and time-consuming, and they rely on robust experimental data. Sandia National Laboratories and the National Institute of Standards and Technology are among the organizations that have provided data to inform the code's treatment of hydrogen embrittlement in the past. The ASME B31.12 code currently considers pressures up to 15,000 psi for many piping materials, "provided the material suitability is demonstrated by tests in hydrogen," although the code's maximum allowable hydrogen pipeline pressure is currently only 3000 psi (ASME, 2015, p. 15).

The current ASME B31.12 code relates a pipeline's operating pressure to its design requirements. The relationship includes a design factor based on the types of areas through which the pipeline will travel. Area types range from Location Class 1 (sparsely populated) to Location Class 4 (densely populated). Location Class 4 includes areas "where multistory buildings are prevalent, where traffic is heavy or dense, and where there may be numerous other utilities underground" (ASME, 2015, p. 132). The design factor decreases as the location class increases. As a result—for a given steel pipeline design pressure, material, and outer diameter—pipelines in densely populated areas must be thicker (and therefore more expensive) than those in sparsely populated areas. The current design specifications account for hydrogen embrittlement based on the characteristics of the pipeline materials (ASME, 2015, p. 135). A code revision that enables HyLine systems would need to account for the effects that higher pressures have on those materials. The current ASME code also mandates a full risk assessment when buildings intended for human occupancy are within a proposed hydrogen pipeline's potential impact area, with reference to a Compressed Gas Association procedure for risk assessment (ASME, 2015, p. 132). To accommodate HyLine pressures, the risk-assessment requirements would need to be revisited as well.

High-pressure pipelines in urban areas must also undergo the most stringent risk-management procedures. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) requires gaseous pipeline operators to implement special protections for "high consequence areas" (HCAs). An HCA is defined as "a geographic territory in which, by virtue of its population density and proximity to a pipeline, a pipeline failure would pose a higher risk to people." Operators must evaluate whether any HCAs fall within impact circles calculated based on the location of pipelines, maximum allowable operating pressure (MAOP), pipeline diameter, and a factor varying by properties of the transported gas. Higher MAOPs result in larger impact circles. If an HCA lies within an impact circle, the operator must implement an integrity-management program that includes "threat assessments, both baseline and periodic internal inspection, pressure testing, or direct assessment (DA), and additional measures designed to prevent and mitigate pipeline failures and their consequences" (PHMSA, 2008, 2011, 2016; RSPA, 2003). A HyLine system implemented within an urban area would likely require a stringent integrity-management program.

HyLine systems would present other implementation challenges as well. Construction projects in urban areas are subject to numerous requirements and processes overseen by various authorities, such as fire marshals, zoning departments, and public works departments. Projects crossing jurisdictional boundaries, as HyLine pipelines might do, would require additional coordination across all the affected jurisdictions. Because they involve pipelines, HyLine projects would also fall under the regulations and oversight of PHMSA, which might require regulatory revisions.

Clearly the challenges to implementing a HyLine system are significant, and the concept's novelty could result in additional, unforeseen challenges. However, previous experience with pipeline distribution of hydrogen to refueling stations could facilitate the required steps. The next subsection describes a high-pressure hydrogen pipeline that has been operating for more than 12 years in Frankfurt, Germany.

2.2. German experience with a hydrogen fueling station supplied via high-pressure pipeline

As part of the Zero Regio project funded by the European Commission, a hydrogen refueling station opened in November 2006 on the edge of the Industrial Park Höchst in Frankfurt, Germany's Höchst district. It was formally evaluated for 3 years, during which time 850 kg of hydrogen were consumed by fuel cell vehicles. Hydrogen was initially supplied to the station via two sources: (1) truck deliveries of liquid hydrogen, and (2) a 1.7-km (1.1-mi) high-pressure pipeline delivering byproduct hydrogen from a chemical plant through the industrial park to the station. The initial permitting process for the station was completed in two stages. Approval for the station building was obtained in 10 weeks, and approval for the three dispensers (two supplied by the pipeline and one supplied by

Table 1
Initial Specifications of the Zero Regio (Höchst, Frankfurt, Germany) High-Pressure Hydrogen Pipeline Refueling System (evaluated 2006–2009).

Storage	
After initial compression	25 m^3 at 3260 psi
Final Compression	
Type	Linde ionic compressor
Maximum capacity	80 kg/h
Inlet pressure	3260 psi
Maximum outlet pressure	13,000 psi
Pipeline	
Length	1.1 mi
Installation	~Half aboveground (hanging pipe)~Half underground (polyethylene sleeve in sand bed)
Inner diameter	0.71 in
Outer diameter	1.3 in
Wall thickness	0.31 in
Steel material (DIN no.)	1.4462
Yield strength	65,300 psi
Welding type	Gas tungsten arc welding (GTAW)[a]
Minimum operating pressure	4350 psi
Maximum operating pressure	14,500 psi
Station	
Number of dispensers (pipeline supply)[b]	2
Dispensing pressures	5000 psi; 10,000 psi (cold fill)

Sources: Lienkamp and Rastogi (2007); Zero Regio (2010); personal communication with Heinrich Lienkamp, Zero Regio infrastructure project coordinator (April 2019).

[a] Also known as tungsten inert gas (TIG) welding or, in Germany, Wolfram-Inertgas-Schweißen (WIG-Schweißen).

[b] The station also had a third dispenser dispensing liquid hydrogen (which was delivered to the station via truck) using a standard Linde system.

liquid hydrogen) was obtained in 4.5 months (Lienkamp, 2007; Lienkamp and Rastogi, 2010; Zero Regio, 2010).[2] Table 1 shows the initial configuration of the station components related to high-pressure pipeline delivery.

Hydrogen gas generated as a byproduct of electrolytic chlorine production was initially stored in a large tank at near-atmospheric pressure. Hydrogen bound for the refueling station would be extracted from the large tank, dried, cleaned, compressed, and stored at 3260 psi near the production plant. No gaseous hydrogen was stored onsite at the refueling station; all storage was upstream of the high-pressure pipeline (Zero Regio, 2010).

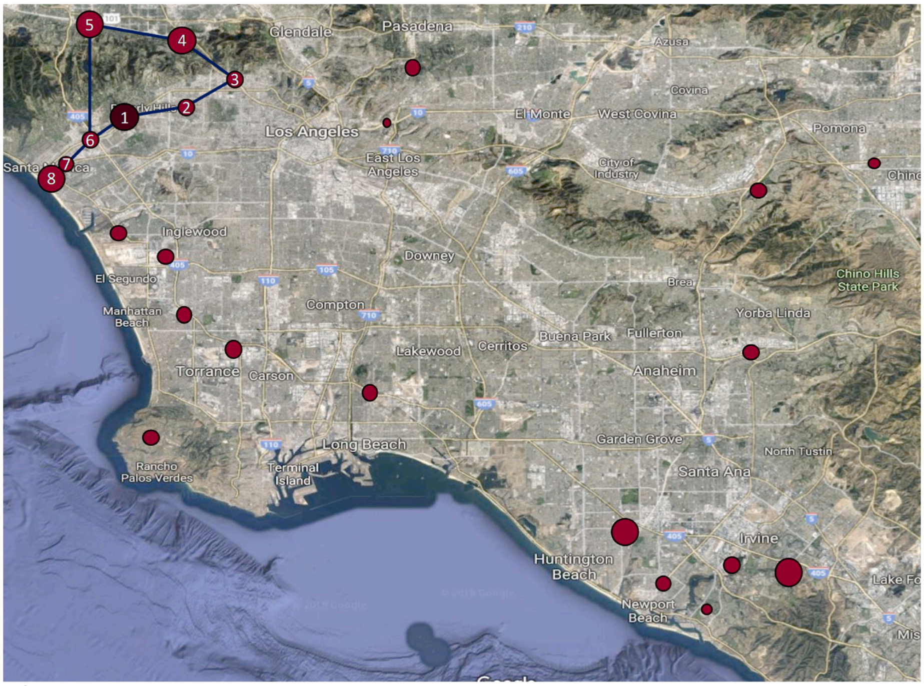
The stored hydrogen was compressed from 3260 psi to 13,000 psi by a Linde ionic compressor with a capacity of 80 kg/h and buffer storage at 4350 psi. This compression technology uses ionic fluids with zero vapor pressure as liquid pistons with the goal of providing near-isothermal compression and low maintenance requirements. However, the compressor required unexpected maintenance during the 3-year project evaluation and ended the period with an availability of 86%. The Zero Regio project represented the first application of this prototype technology for compressing hydrogen to such high pressure (Lienkamp and Rastogi, 2007, 2012; Zero Regio, 2010).

Following compression, the hydrogen was transported across the industrial park to the refueling station through a 1.1-mile pipeline with a design pressure of 14,500 psi. The pipeline material—a fully welded duplex stainless steel, material DIN no. 1.4462—was chosen based on its mechanical strength, resistance to hydrogen embrittlement and external corrosion, workability, availability, and price. Although this was the world's first hydrogen pipeline operating at such high pressures, it achieved an availability of 96% during the project-evaluation period. The only incident occurred during the startup phase, when insufficient purging of the pipeline with hydrogen resulted in too much nitrogen entering vehicle tanks (the fuel cells were not damaged). The Zero Regio final report concluded, "Transport of hydrogen with high pressure pipelines is technically feasible" (Lienkamp and Rastogi, 2007, 2012; Zero Regio, 2010).

The pipeline hydrogen was delivered to a refueling station on the edge of the Industrial Park Höchst, where it directly supplied a 5000-psi dispenser and a 10,000-psi dispenser (i.e., without any storage sited at the station). The 5000-psi hydrogen was not precooled. The 10,000-psi was precooled to −40 °C to enable fast filling (3–5 min to fill with 4 kg of hydrogen). During the project-evaluation period, the 5000-psi dispenser achieved an availability of 95%. The 10,000-psi dispenser's availability was only 64% because of damage from an accident; a station customer negligently reversed a conventional car into the dispenser, but no hydrogen leakage occurred. A new dispenser replaced the damaged unit (Lienkamp and Rastogi, 2012, 2016; Zero Regio, 2010).

The high-pressure hydrogen pipeline and refueling station have remained operational up to the present, now fueling hydrogen cars and buses. After the project-evaluation period, the ionic compressor was replaced by a Hofer piston compressor, which has worked well since. The pipeline has continued to supply the refueling station reliably and without incident (personal communication with Heinrich Lienkamp, Zero Regio infrastructure project coordinator, April 2019). Although this German high-pressure hydrogen pipeline has operated within an industrial park rather than a dense urban area, the experience indicates the feasibility of the HyLine concept.

[2] Because permitting processes are very different in Germany and the United States, the time required to permit such a project in the United States may be very different.



Map from Google

Fig. 1. Actual station locations in Los Angeles (all circles) and hypothetical smallest modeled HyLine station network (numbered circles connected by lines at upper left) (CARB, 2018).

3. Economic analysis methods and inputs

We use the National Renewable Energy Laboratory's Hydrogen Financial Analysis Scenario Tool (H2FAST) to model the economics of a hypothetical HyLine system connecting hydrogen stations in the Los Angeles metro area (NREL, 2018). The smallest modeled system connects eight existing stations, shown in the northwest corner of Fig. 1. We assume a total pipeline length of 38 miles (4.8 miles per station) based on the 27 miles of straight-line distance between the stations and a detour index (ratio of pipeline miles to straight-line miles) of 1.4.[3] The current real-world capacity of the eight stations is 2720 kg/day, or 340 kg/d per station on average (CEC and CARB, 2018). In our analysis, we assume each station has a capacity of exactly 400 kg/d in our smallest-delivery scenario (3200 kg/d total), to account for near-term capacity growth. We also model two expanded scenarios with larger numbers of higher-capacity stations along the same pipeline route: 16 stations at 950 kg/d each (15,200 kg/d total), and 24 stations at 1500 kg/d each (36,000 kg/d total). In all scenarios, we assume 65% utilization, which represents a midpoint between today's approximate utilization of 50% and an estimate of 80% for more established markets.

In each scenario, we model hydrogen production via SMR or electrolysis at a single station—station #1 in Fig. 1—and that station also hosts hydrogen compression and storage adequate to satisfy the needs of all stations. The other stations are equipped only with cooling units, flow regulation, and dispensers. Most of the stations are connected in a loop. Thus, if a pipeline disruption occurred along the network, an alternative route could deliver hydrogen from station #1 to all or most other stations, depending on the location of the disruption. Although we locate all production, compression, and storage at one site for all scenarios to simplify this exploratory analysis, in practice a substantial HyLine network likely would be supplied by multiple sites, which would strengthen the network's reliability but might increase costs owing to somewhat diminished economies of scale. Supply-side cost data are from DOE's Hydrogen Analysis (H2A) production models and the Hydrogen Delivery Scenario Analysis Model (HDSAM) (DOE, 2015a, 2015b, 2015c).

We also use this station configuration to analyze pressure-drop considerations using ASPEN Engineering software. For this simplified analysis, we assume an average hydrogen capacity of 2500 kg/d per station across the eight stations in our smallest HyLine network. This is a much higher per-station capacity than in our cost-modeling scenarios, and it assumes a well-developed FCEV market following historical demand patterns observed with gasoline stations.[4] The pipeline would need to be designed to satisfy the

[3] The detour index of 1.4 is based on estimated on-road driving distance, which may be a plausible approximate for pipeline installation (Boscoe et al., 2012).

[4] 2016 California sales = 15.5 billion gallons (FHWA, 2017), California stations = 8456 stations (CEC, 2018), ratio of FCEV to internal combustion engine vehicle fuel economy ≈ 2 (DOE, 2015d). Average hydrogen station size: 15.5 billion gal/yr ÷ 365 d/yr ÷ 8456 stations ÷ 2 Gal/kg H_2 ≈ 2500 kg H_2/d per station.

Table 2
ASPEN Modeling of 1.6-in. (inner diameter) HyLine Pipeline Pressure Drop Across an Eight-Station Network with an Average Station Capacity of 104 kg/h and Peak Flow of 208 kg/h.

Station#	1 & prod.	2	3	4	5	6	7	8
Peak dispensing rate (kg/h)	208	208	208	208	208	208	208	208
Delivery pipe segment		1–2	2–3	3–4	4–5	5–6	6–7	7–8
Delivery pipe segment length (miles)		4.68	4.32	5.19	6.98	10.04	2.72	1.67
Pipe segment peak flow (kg/h)	1664	1456	1248	1040	832	624	416	208
Station delivery pressure (psig)	15,000	14,700	14,493	14,318	14,164	14,038	14,023	14,020
Segment pressure drop (psi)		300	207	176	153	126	15	2
Station delivery pressure (bar)	1035	1015	1000	988	978	969	968	968

Table 3
Specifications and costs of materials potentially applicable to low- and high-pressure hydrogen pipelines.

Working pressure (psig)	Bar	MPa	Material	Allowable pipe stress (MPa)	Conditioning	Inner diameter (in)	Wall thickness (in)	Outer diameter (in)	Weight (metric ton/mile)	Material cost $/mile
600	41	4	316L	115	Annealed	4.00	0.07	4.15	7.71	54,000
600	41	4	XM-11	230	Annealed	4.00	0.04	4.07	3.78	26,000
600	41	4	XM-19	230	Annealed	4.00	0.04	4.07	3.78	26,000
600	41	4	316L	345	Strain-hardened	4.00	0.02	4.05	2.50	26,000
600	41	4	XM-19	575	Strain-hardened	4.00	0.01	4.03	1.49	16,000
15,000	1,034	103	316L	115	Annealed	1.61	1.57	4.75	128.76	901,000
15,000	1,034	103	XM-11	230	Annealed	1.61	0.50	2.60	26.86	188,000
15,000	1,034	103	XM-19	230	Annealed	1.61	0.50	2.60	26.86	188,000
15,000	1,034	103	316L	345	Strain-hardened	1.61	0.29	2.20	14.42	151,000
15,000	1,034	103	XM-19	575	Strain-hardened	1.61	0.16	1.93	7.40	78,000

The options for low- and high-pressure pipelines are based on personal communication with Chris San Marchi and Joe Ronevich, Sandia National Laboratories (2019). Pipeline sizing is based on ASME B31.3 and B31.12 (ASME, 2015, 2017). The cost analysis assumes a steel pipe cost of $7,000/metric ton, approximated based on web searching. The relative factor cost for strain hardening is 1.5.

peak fueling demand of stations as well as capacity expansion over time. The peak hydrogen flow can be assessed by considering the fueling behavior seen in California's emerging hydrogen market, where the peak flow is about twice as high as the average flow (CEC and CARB, 2017). Thus, a station with average flow of 2,500 kg/d (104 kg/h) would have a peak flow of 208 kg/h. Table 2 shows the pressure drop of hydrogen in a 1.6-in. (internal diameter) pipeline across the eight-station network. At the end of each segment, 208 kg/h of peak hydrogen flow are extracted, and the remaining flow goes to downstream stations. The 15,000-psi initial pipeline pressure enables a delivery pressure of at least 14,000 psi at all the stations. Therefore, the stations have an adequate pressure differential for efficiently fueling light-duty FCEVs, which have onboard tank pressures of 10,000 psi, without the need for onsite compression or high-pressure storage.

The 1.6-in. inner diameter is much smaller than would be expected for a pipeline operating at typical lower pressures of 200–1500 psi, because the higher pressure makes the hydrogen behave more like a liquid. The liquid-like behavior enables a small-diameter pipeline to meet the pressure-drop requirements. Table 3 shows estimated specifications and costs per mile for 1.6-in. pipeline designs that might be suitable for 15,000-psi operation (along with parameters for low-pressure pipeline options). The costs range from about $80,000/mile (for strain-hardened XM-19 steel) to $900,000/mile (for annealed 316L steel); because of the much higher cost of annealed 316L steel, one of the other options likely would be used. Those options have outer diameters of about 2–3 in.

We use historical data on pipeline costs to estimate the installed cost of high-pressure pipelines with outer diameters of 2–3 in. Fig. 2 shows historical pipeline cost estimates by outer diameter based on Oil and Gas Journal (O&GJ) data for pipeline projects during 1991–2012, and it plots DOE's HDSAM urban and rural pipeline-cost equations derived from the O&GJ data (O&GJ, 2018; DOE, 2015c).[5] Urban pipelines are substantially more expensive than comparable-diameter rural pipelines owing to higher construction costs in urban settings, which accounts for much of the large spread of costs observed in the figure. These data suggest installed urban pipeline costs of well under $2 million/mile for pipelines 2–3 in. in diameter.

Key considerations for urban pipelines include specific street rights of way, existing underground infrastructure, time of day specified for construction, and cost of managing traffic. Small-diameter pipelines may enable use of cost-reducing technologies such as directional drilling and routing of sleeves inside existing retired pipelines (personal communication with Sempra Energy and Southern California Gas, 2018).

Based on this analysis, we assume an installed pipeline cost of $2 million/mile in our central scenarios. We believe this estimate leaves a margin for additional unexpected costs such as those related to high-pressure pipeline operation, a higher detour index

[5] The O&GJ data are from 1467 reported projects with pipeline lengths of 0.01–8400 miles per project.

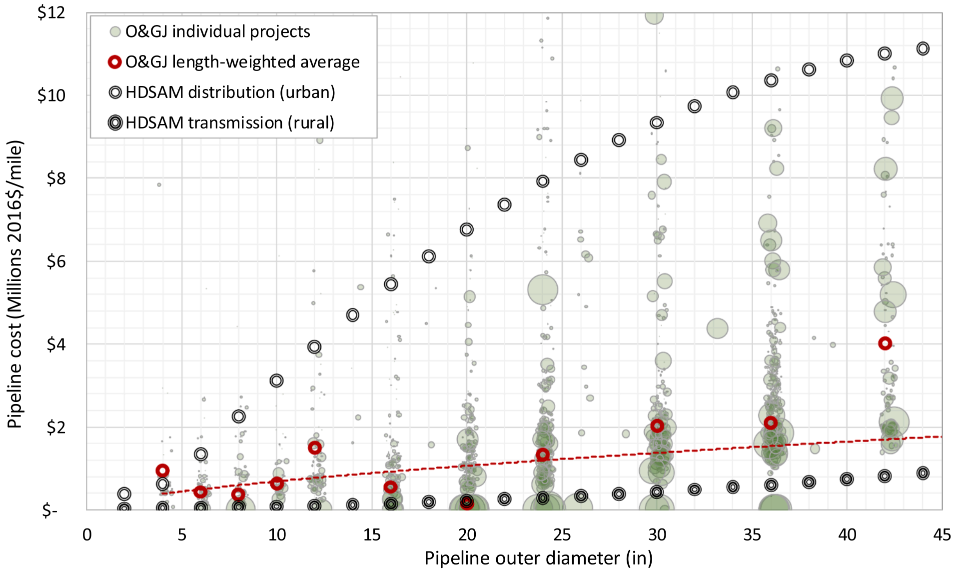


Fig. 2. Pipeline costs based on O&GJ data between 1991 and 2012 as a function of pipeline diameter. For data points, bubble area is proportional to pipeline length and is capped at 500 miles. Cost by pipeline diameter is weighted by pipeline length. Note: The dashed red line is a fit to the average values represented by the red circles. Some random spread in pipeline diameter is plotted into the O&GJ data to reduce overlap of data points. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

needed to avoid existing underground infrastructure, and allowance for marginally higher-diameter and higher-capacity pipelines. Excluding the high-cost annealed 316L material, estimated material costs would represent 4%–9% of total pipeline costs, suggesting that the material cost of thicker walls required for high-pressure pipelines will not have a substantial impact on overall pipeline cost. However, because pipeline of this diameter is substantially denser than typical pipelines with outer diameters of 2–3 in. owing to its unusually thick walls, we expect installation to require cranes and incur somewhat higher installation expense. Our sensitivity analysis considers pipeline costs of $1–$3 million/mile. It is important to note that the cost of right-of-way varies widely throughout the United States, and it is expected to be higher in dense urban areas (such as Los Angeles).

In addition to the three HyLine scenarios, we develop comparable scenarios for station networks supplied via three other pathways: gaseous hydrogen truck delivery, liquid hydrogen truck delivery, and low-pressure hydrogen pipeline delivery. Table 4 summarizes key inputs for each pathway and scenario based primarily on values from DOE's HDSAM and H2A models, assuming low-volume component manufacturing (DOE, 2015a, 2015b, 2015c). The leveraged, after-tax, nominal internal rate of return is 10%, and no incentives are assumed; see the H2FAST website and user manual for all financial assumptions used in the calculations (NREL, 2018).

The gaseous and liquid truck pathways assume large-scale, centralized hydrogen production, with much of the hydrogen used for applications other than vehicle refueling stations. The trucks fill up with hydrogen at the production plants (after hydrogen liquefaction in the case of liquid trucks) and deliver it to the refueling stations, where it is stored, compressed, and dispensed. Because gaseous delivery trucks carry much less hydrogen than liquid delivery trucks do, gaseous truck delivery would be impractical in our most mature scenario (24 stations with capacities of 1500 kg/d), so we exclude it from this scenario. The low-pressure pipeline and HyLine scenarios are largely identical: hydrogen is produced at a single site on the network and delivered to refueling stations in pipelines with capital costs of $2 million/mile; we assume the same capital costs because the low-pressure pipeline would have a larger diameter, whereas the HyLine pipeline would have higher material costs per mile, and the resulting net cost differential is likely within the uncertainty level of the pipeline-cost estimation. In the low-pressure pipeline pathway, hydrogen is compressed to only 600 psi at the production site, compared with 15,000 psi in the HyLine pathway. Thus, the low-pressure pipeline pathway requires storage and compression at all refueling stations, whereas the HyLine pathway does not.

4. Results

Fig. 3 shows delivered hydrogen cost results for SMR-produced hydrogen using the various delivery pathways and refueling station scenarios. With the smallest fueling network (eight stations with capacities of 400 kg/d), hydrogen from the HyLine pathway costs more than hydrogen from the gaseous and liquid truck pathways, and it costs less than hydrogen from the low-pressure pipeline pathway. The truck pathways realize economies of scale from centralized hydrogen production, saving almost $5/kg in this scenario compared with the two pipeline scenarios, which both use smaller production units. The truck pathways also save around $7/kg in delivery costs, although this is more than offset for liquid trucks by $8/kg of liquefaction costs. The resulting trucked-hydrogen costs are in line with hydrogen prices recently observed in California (CEC and CARB, 2018). HyLine realizes its largest advantage through retail costs (mostly storage and compression costs) that are $5–$8/kg lower than the retail costs from the other pathways.

Table 4
Key Cost-Analysis Inputs for Each Hydrogen-Delivery Pathway and Scenario (see Fig. 3 and Fig. 4 for the cost results).[a]

Stations scenario	400 kg/d stations × 8 (values are totals for all stations)				950 kg/d stations × 16 (values are totals for all stations)				1500 kg/d stations × 24 (values are totals for all stations)		
Delivery	GH2 truck	LH2 truck	40 bar pipe	HyLine (1000 bar)	GH2 truck	LH2 truck	40 bar pipe	HyLine (1000 bar)	LH2 truck	40 bar pipe	HyLine (1000 bar)
Production SMR[b]											
Capacity (kg/d)	379,387	379,387	3,200	3,200	379,387	379,387	15,200	15,200	379,387	36,000	36,000
Cap cost (2016$)	248,498,022	248,498,022	14,156,747	14,156,747	248,498,022	248,498,022	36,056,172	36,056,172	248,498,022	60,486,014	60,486,014
Life (years)	40	40	40	40	40	40	40	40	40	40	40
NG use (mmBTU/kg)	0.156	0.156	0.156	0.156	0.156	0.156	0.156	0.156	0.156	0.156	0.156
Elec. use (kWh/kg)	0.569	0.569	0.569	0.569	0.569	0.569	0.569	0.569	0.569	0.569	0.569
Max utilization (%)	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Demand ramp-up (years)	1	1	1	1	1	1	1	1	1	1	1
Fixed operating costs ($/year)	8,901,358	8,901,358	1,216,410	1,216,410	8,901,358	8,901,358	2,162,896	2,162,896	8,901,358	3,064,827	3,064,827
Depreciation period (years)	20	20	20	20	20	20	20	20	20	20	20
Replacement capital ($/year)	1,239,738	1,239,738	70,627	70,627	1,239,738	1,239,738	179,882	179,882	1,239,738	301,760	301,760
Variable operating costs	63,193,500	63,193,500	3,507,900	3,507,900	63,193,500	63,193,500	5,411,900	5,411,900	63,193,500	8,712,000	8,712,000
Production Electrolyzer[b]											
Capacity (kg/d)	50,000	50,000	3,200	3,200	50,000	50,000	15,200	15,200	50,000	36,000	36,000
Cap cost (2016$)	165,837,229	165,837,229	31,870,584	31,870,584	165,837,229	165,837,229	81,171,988	81,171,988	165,837,229	136,170,029	136,170,029
Life (years)	40	40	40	40	40	40	40	40	40	40	40
Elec. use (kWh/kg)	54.3	54.3	54.3	54.3	54.3	54.3	54.3	54.3	54.3	54.3	54.3
Max utilization (%)	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Demand ramp-up (years)	1	1	1	1	1	1	1	1	1	1	1
Fixed operating costs ($/year)	8,186,103	8,186,103	1,433,171	1,433,171	8,186,103	8,186,103	3,454,745	3,454,745	8,186,103	6,332,755	6,332,755
Depreciation period (years)	20	20	20	20	20	20	20	20	20	20	20
Replacement capital ($/year)	2,988,380	2,988,380	574,307	574,307	2,988,380	2,988,380	1,462,716	1,462,716	2,988,380	2,453,778	2,453,778
Variable operating costs	66,214,400	66,214,400	4,425,000	4,425,000	66,214,400	66,214,400	20,268,500	20,268,500	66,214,400	47,730,400	47,730,400
Liquefaction											
Capacity (kg/d)	–	27,216	–	–	–	27,216	–	–	27,216[c]	–	–
Cap cost (2016$)	–	1,132,565,781	–	–	–	1,132,565,781	–	–	1,132,565,781	–	–
Life (years)	–	40	–	–	–	40	–	–	40	–	–
Elec. use (kWh/kg)	–	10.512	–	–	–	10.512	–	–	10.512	–	–
Max utilization (%)	–	97%	–	–	–	97%	–	–	97%	–	–
Demand ramp-up (years)	–	1	–	–	–	1	–	–	1	–	–
Fixed operating costs ($/year)	–	3,431,958	–	–	–	3,431,958	–	–	3,431,958	–	–
Depreciation period (years)	–	15	–	–	–	15	–	–	15	–	–

(continued on next page)

Table 4 (*continued*)

Stations scenario	400 kg/d stations × 8 (values are totals for all stations)				950 kg/d stations × 16 (values are totals for all stations)				1500 kg/d stations × 24 (values are totals for all stations)		
Delivery	GH2 truck	LH2 truck	40 bar pipe	HyLine (1000 bar)	GH2 truck	LH2 truck	40 bar pipe	HyLine (1000 bar)	LH2 truck	40 bar pipe	HyLine (1000 bar)
Terminal or piping compressor											
Capacity (kg/d)	27,216	27,216	3,200	3,200	27,216	27,216	15,200	15,200	27,216[c]	36,000	36,000
Cap cost (2016$)	56,309,095	23,899,578	3,877,662	14,005,276[d]	56,309,095	23,899,578	16,940,240	66,525,060[d]	23,899,578	38,663,759	157,559,354[d]
Life (years)	30	30	30	30	30	30	30	30	30	30	30
Elec. use (kWh/kg)	1.792	0.001	0.399	4.352	1.792	0.001	0.348	4.349	0.001	0.338	4.346
Max utilization (%)	91%	91%	97%	97%	91%	91%	97%	97%	91%	97%	97%
Demand ramp-up (years)	1	1	1	1	1	1	1	1	1	1	1
Fixed operating costs ($/year)	4,016,274	1,213,045	22,665	81,860	4,016,274	1,213,045	59,887	235,178	1,213,045	110,453	450,111
Depreciation period (years)	15	15	10	10	15	15	10	10	15	10	10
Replacement capital ($/year)	939,791	3,310	8,584	31,005	939,791	3,310	29,643	116,408	3,310	59,340	241,817
Truck or pipeline delivery											
Piping cost (2016$M/mile)	–	–	2	2	–	–	2	2	–	2	2
Capacity (kg/d)	27,216	27,216	3,200	3,200	27,216	27,216	15,200	15,200	27,216[c]	36,000	36,000
Cap cost (2016$)	38,993,413	8,520,000	77,596,899	77,596,899	38,993,413	8,520,000	77,596,899	77,596,899	8,520,000	77,596,899	77,596,899
Life (years)	30	30	30	30	30	30	30	30	30	30	30
Max utilization (%)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Demand ramp-up (years)	0	0	3	3	0	0	3	3	0	3	3
Fixed operating costs ($/year)	2,905,575	1,205,308	3,342,587	3,342,587	2,905,575	1,205,308	3,342,587	3,342,587	1,205,308	3,342,587	3,342,587
Depreciation period (years)	5	5	15	15	5	5	15	15	5	15	15
Replacement capital ($/year)	1,995,377	521,140	–	–	1,995,377	521,140	–	–	521,140	–	–
Diesel use (gal/kg)	0.031	0.011	–	–	0.031	0.011	–	–	0.011	–	–
Retail station											
Ramp-up years	3	3	3	3	3	3	3	3	3	3	3
Capacity (kg/d)	3,200	3,200	3,200	3,200	15,200	15,200	15,200	15,200	36,000	36,000	36,000
Cap cost (2016$)	32,103,624	17,691,440	22,856,272	5,862,136	88,601,520	45,293,936	88,327,360	21,211,488	92,116,896	191,143,656	45,922,440
Life (years)	10	10	10	10	10	10	10	10	10	10	10
Elec. use (kWh/kg)	1.969	0.562	5.165	0.325	1.897	0.548	5.084	0.325	0.542	5.049	0.325
Max utilization (%)	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Demand ramp-up (years)	3	3	3	3	3	3	3	3	3	3	3
Fixed operating costs ($/year)	1,840,616	1,747,064	1,319,328	338,376	5,203,984	4,323,888	4,843,920	1,163,248	8,102,736	10,525,152	2,716,656
Credit card fees (%)	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Sales taxes (%)	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225
Depreciation period (years)	5	5	5	5	5	5	5	5	5	5	5

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Table 4 (*continued*)

Stations scenario	400 kg/d stations × 8 (values are totals for all stations)				950 kg/d stations × 16 (values are totals for all stations)				1500 kg/d stations × 24 (values are totals for all stations)		
Delivery	GH2 truck	LH2 truck	40 bar pipe	HyLine (1000 bar)	GH2 truck	LH2 truck	40 bar pipe	HyLine (1000 bar)	LH2 truck	40 bar pipe	HyLine (1000 bar)
Energy prices											
Natural gas cost ($/mmBTU)	3.510	3.510	3.510	3.510	3.510	3.510	3.510	3.510	3.510	3.510	3.510
Production elec. cost ($/kWh)	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068

[a] Technical and economic inputs are based on data in DOE's H2A and HDSAM models.

[b] The large disparities in production capacity associated with the truck, tanker, 40-bar pipeline, and HyLine pathways stem from our assumption that a 1000-bar pipeline (as in the HyLine system) would not serve as many other industries as gaseous trucks and tankers, because hydrogen pressures this high are not commonly required in industry. As a result, the associated production capacity would likely primarily be monetized by hydrogen fueling stations. Alternatively, production capacity associated with trucks and tankers can be monetized in diverse sectors in the region (e.g., glassmaking, electronics fabrication, steelmaking). As a result, SMR units of much higher capacity would likely be built around terminals for trucks and tankers. The production capacity associated with trucks and tankers was chosen to match that in the H2A Centralized Steam Methane Reforming case study, such that the corresponding cost data could be utilized; SMRs of this capacity are common in industry today. The production capacity associated with the 40-bar pipe and HyLine scenarios reflects supply required for (8) 400-kg/day fueling stations. The 40-bar pipe scenario was modeled to highlight the impact that an increase in pressure from conventional values to 1000 bar (as in the HyLine system) has on cost.

[c] The liquid truck pathway's liquefaction, terminal, and truck costs are based on a nominal capacity of 27,216 kg/d, which is lower than the 36,000 kg/d total station capacity in the highest-capacity scenario (24 stations at 1,500 kg/d each). The corresponding costs assume that multiple sets of equipment and trucks at this capacity would be used to address hydrogen demand throughout the region, yielding the same cost per kilogram of hydrogen.

[d] Compressors with the compression ratio and throughput required for HyLine are not commercially available today. These HDSAM-derived values estimate potential future costs of such technology.

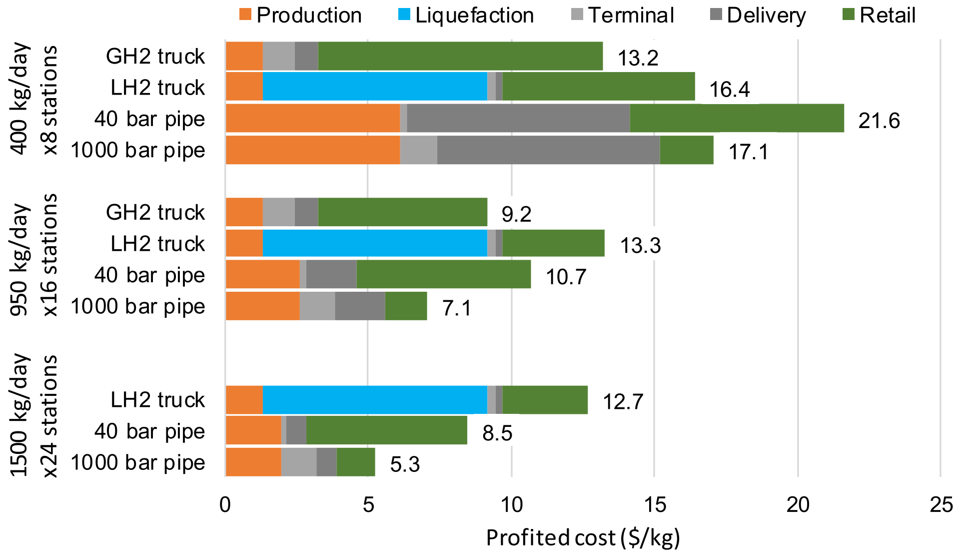

Fig. 3. Delivered hydrogen costs based on SMR hydrogen production, four delivery pathways, and three refueling station scenarios. For delivery trucks, "terminal" entails compression, storage, and filling of trucks. For pipelines, it entails compression and storage at the production site.

As the refueling station networks and capacities grow, HyLine becomes the lowest-cost option. In the middle scenario (16 stations with capacities of 950 kg/d), HyLine hydrogen costs 20% less than the next-closest option (gaseous truck delivery). At this scale, the truck pathways' production and delivery cost advantages narrow substantially as the pipeline pathways realize production and delivery economies of scale. At the same time, HyLine maintains a $2–$5/kg advantage in retail costs. In the final scenario (24 stations with capacities of 1500 kg/d), HyLine's advantages are amplified. It achieves a cost of $5.3/kg, which is 60% lower than the liquid truck cost and 40% lower than the low-pressure pipeline cost.[6]

Many of the same trends are visible when hydrogen is produced via electrolysis, although the total costs are higher across all scenarios and pathways (Fig. 4). Because economies of scale due to centralized production have less impact, even in the smallest refueling scenario HyLine's hydrogen costs are nearly equal to the lowest-cost option (gaseous truck delivery). In the largest refueling scenario, the HyLine costs reach $12.3/kg, which is 40% lower than the liquid truck cost and 20% lower than the low-pressure pipeline cost.

Fig. 5 and Fig. 6 show the sensitivity of the results to changes in key HyLine parameters, based on the middle scenario (16 stations with capacities of 950 kg/d). For SMR production, pipeline cost has the largest impact, with costs ranging from $6.6/kg at a pipeline cost of $1 million/mile, to $7.6/kg at $2 million/mile (Fig. 5). Natural gas cost, compressor cost, and retail equipment life are the next most influential parameters. For electrolysis production, electricity cost is the dominant parameter (Fig. 6). The hydrogen cost falls to $12.7/kg at an electricity cost of $0.047/kWh and rises to $15.1/kg at an electricity cost of $0.088/kWh. For both production pathways, varying no single parameter results in a hydrogen cost higher than the costs from the other pathways shown in Fig. 3 and Fig. 4.

5. Discussion

Because local delivery and dispensing constitute a large portion of total hydrogen fuel costs for FCEVs, reducing local delivery and dispensing costs is critical to making hydrogen fueling competitive. As FCEV demand for hydrogen in an area becomes sufficiently dense, truck delivery of hydrogen to retail fueling stations becomes less attractive and pipeline delivery becomes more attractive for economic and logistical reasons. Pipeline delivery of hydrogen can also facilitate the growth of renewable electricity generation by providing a bridge between the electricity, transportation, and natural gas sectors, thus improving the stability and economics of electric grids with high variable generation penetrations.

We evaluate the HyLine pipeline approach to local hydrogen delivery and dispensing, which offers additional benefits beyond conventional pipeline approaches. Its high pressure (15,000 psi) results in lower dispensed hydrogen costs compared with conventional (600 psi) pipelines owing to economies of scale associated with integrated compression and storage. It not only requires significantly smaller pipe diameters for pressure-drop considerations, but also reduces the need for hydrogen compression and storage sited at all retail stations, which provides further economic and logistical benefits. At the same time, siting the hydrogen production, compression, and storage at one or more sites within the fueling network provides scalability, reducing the need for retail stations to make large upfront investments while increasing system reliability and manageability.

Our preliminary economic analysis suggests that HyLine could provide hydrogen at costs that approach the target of $4/gasoline-

[6] Gaseous truck delivery is excluded from this scenario; see Section 3.

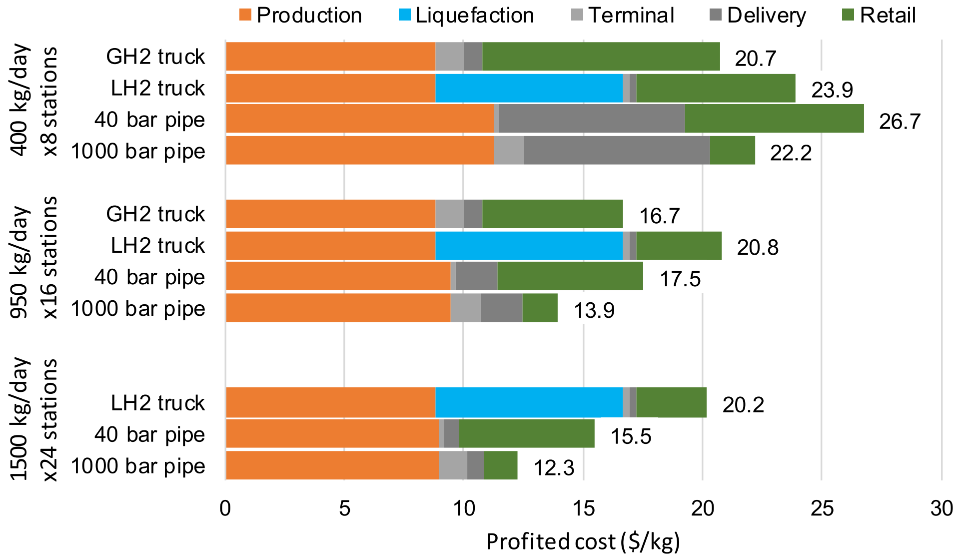

Fig. 4. Delivered hydrogen costs based on electrolytic hydrogen production, four delivery pathways, and three refueling station scenarios. For delivery trucks, "terminal" entails compression, storage, and filling of trucks. For pipelines, it entails compression and storage at the production site.

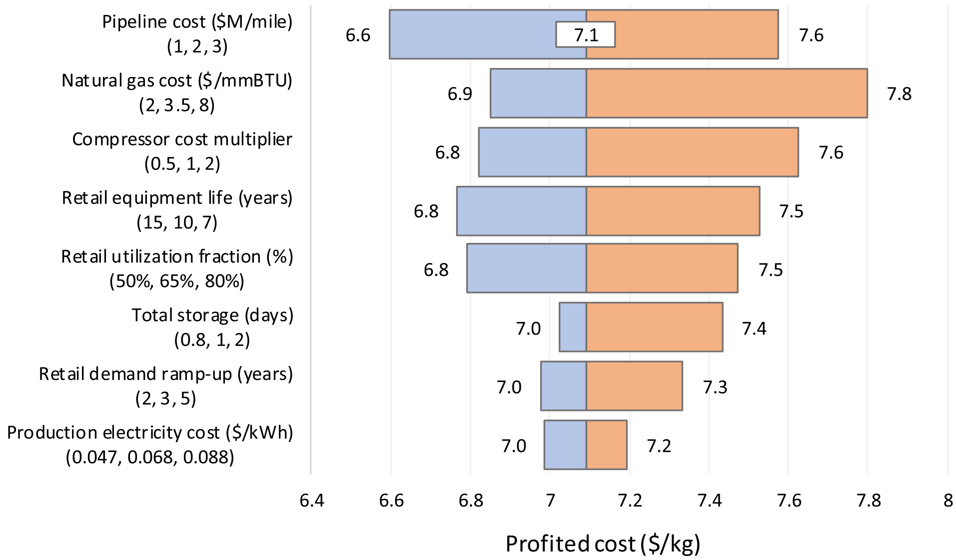

Fig. 5. Sensitivity of hydrogen cost to key input parameters for the SMR HyLine system (based on 16 stations with capacities of 950 kg/d). Note: The input values for all parameters are meant to approximate reasonable lowest, most likely, and highest values. The distribution of cost sensitivity results depends largely on the input assumptions, which are not always symmetrical. For example, the storage results have a larger differential between high cost and baseline cost than between low cost and baseline cost, because the baseline storage assumption (1 day of storage) is a full day lower than the high assumption (2 days) but only 0.2 days higher than the low assumption (0.8 days).

gallon equivalent, set by DOE's Office of Energy Efficiency and Renewable Energy Fuel Cell Technologies Office, for competitiveness with gasoline engine vehicles in high-volume markets. The relatively low costs associated with delivery and dispensing in a HyLine system could also facilitate use of a broader range of hydrogen production technologies, while ensuring affordable hydrogen fuel.

The cost results may not apply to hydrogen markets with different characteristics than those in our study. The viability of capital-intensive infrastructure will depend on proximity and certainty of demand, both of which vary across the United States. More detailed analysis of the costs and characteristics of HyLine networks in diverse geographic areas—using a range of values for key inputs—would help clarify when and where the approach might become attractive as well as which variables are most impactful. In addition, the use of a HyLine approach for applications beyond light-duty vehicles, particularly for industrial and heavy-duty applications in rural areas where high-pressure pipelines may be easier to site, should be evaluated.

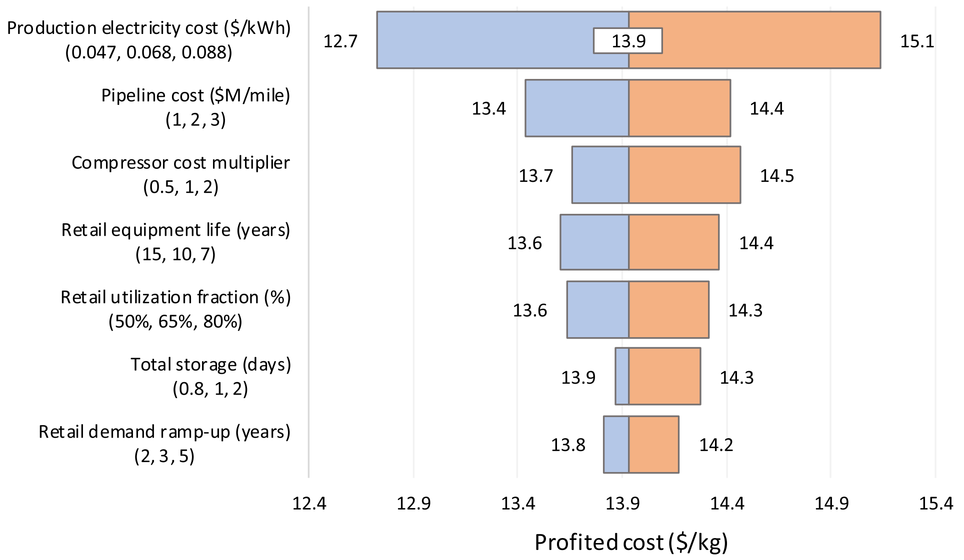

Fig. 6. Sensitivity of hydrogen cost to key input parameters for the electrolysis HyLine system (based on 16 stations with capacities of 950 kg/d). Note: The input values for all parameters are meant to approximate reasonable lowest, most likely, and highest values. The distribution of cost sensitivity results depends largely on the input assumptions, which are not always symmetrical. For example, the storage results have a larger differential between high cost and baseline cost than between low cost and baseline cost, because the baseline storage assumption (1 day of storage) is a full day lower than the high assumption (2 days) but only 0.2 days higher than the low assumption (0.8 days).

In any case, our preliminary analysis suggests that, because of its multiple inherent benefits, the HyLine approach merits further research and development. A key first step is materials research and development as well as development of codes and standards that address the unique aspects of high-pressure hydrogen pipelines. Because codes and standards development requires significant time, initiating it in the near term would help enable construction of this architecture as FCEV densities begin to reach required levels in certain areas. The historical experience with natural gas pipelines—for which engineering designs led to safety best practices and then codes and standards—offers a relevant precedent for the development of HyLine codes and standards. In addition, detailed analysis of the retail space reduction and corresponding value of minimizing hydrogen compression and storage sited at refueling stations would provide a fuller picture of HyLine's potential benefits.

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Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.trd.2019.10.005.

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