Levelized Cost of Dispensed Hydrogen for Heavy-Duty Vehicles

Justin Bracci, Mariya Koleva, and Mark Chung

National Renewable Energy Laboratory

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List of Acronyms

BoP	balance of plant
CAPEX	capital expenses
FCEV	fuel cell electric vehicle
GH_2	gaseous hydrogen
H_2	hydrogen
HDSAM	Hydrogen Delivery Scenario Analysis Model
HRS	hydrogen (re)fueling station
LCOH	levelized cost of hydrogen
LH_2	liquid hydrogen
MTPD	metric tons per day
SMR	steam methane reforming

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1 Introduction

In this short technical report, we explore the range of levelized costs of dispensed hydrogen (H_2) from hydrogen refueling (or fueling) stations (HRS) for H_2 heavy-duty fuel cell electric vehicles (FCEVs) that are feasible in the 2030 timeframe. We explore different scenarios by varying hydrogen delivery distances, HRS sizes, HRS utilization rates, and economies of scale in the Hydrogen Delivery Scenario Analysis Model (HDSAM). Thus, we observe how the contribution to the levelized cost of each supply chain component changes.

2 Methodology Overview

This analysis accounts for (a) the levelized cost of hydrogen fueling stations, (b) the cost of hydrogen delivery to fueling stations, and (c) simplifying assumptions around the cost of hydrogen production. The analysis relies on the use of HDSAM V.4.5. Three key simplifications have been made across scenarios: (1) hydrogen is dispensed in pressurized gaseous form at 700 bar, (2) hydrogen is delivered to fueling stations via liquid tanker trucks or produced on-site, and (3) the cost of hydrogen production is \$1.50/kg H_2, as explained in Section 5. The second main source used for this analysis is the *Pathways to Commercial Liftoff: Clean Hydrogen* report.[1]

This report evaluates the levelized cost of hydrogen (LCOH) across several scenarios, representing the breakeven cost[2] for building and operating all equipment in the supply chain from production to dispensing. LCOH can also be described as the total annualized capital costs[3] plus annual feedstock, variable, and fixed operating costs, divided by the annual hydrogen dispensed. In this report, the LCOH is categorized into supply chain components to assess how their cost contribution varies with different dispensing volumes and HRS utilization rates. All infrastructure costs reported in this document are in 2022\$ unless otherwise stated.

3 Heavy-Duty Vehicle Fueling Station Size and Supply Type

In all scenarios, we assume that hydrogen is dispensed at 700 bar. While other methods of dispensing (e.g., 350-bar dispensing, liquid hydrogen dispensing) are currently under consideration within industry and may result in lower cost of hydrogen, dispensing was modeled at 700 bar because this approach can facilitate long ranges (up to 750 miles) and is at a higher level of commercial readiness than liquid fills.

The hydrogen delivery methods we consider are (1) liquid hydrogen supplied via liquid tanker truck and (2) gaseous hydrogen supplied via on-site production facility (i.e., production facility in close proximity to stations) with 0.1 km (0.062 miles or 330 feet) of piping[4] connecting the production facility to the HRS. Both delivery methods assume the same hydrogen production

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[1] U.S. Department of Energy. 2023. *Pathways to Commercial Liftoff: Clean Hydrogen*. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.
[2] Assumes 10% discount rate for all stations' components.
[3] Capital and fixed operating costs of individual technology components are annualized based on the weighted average cost of capital, which considers the lifetime of the technology component.
[4] In this report, piping refers to a 0.1-km transmission pipeline connecting production to the fueling station.

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capacity of 100 metric tons per day (MTPD). The general configuration for the liquid hydrogen supplied station type that we modeled can be seen in Figure 3.1. Key equipment at this station includes a liquid hydrogen storage tank, cryogenic pump, evaporator, and dispensers. The general configuration for the on-site gaseous supplied station is shown in Figure 3.2, using the production supply source at 20 bar. For this report, we will assess four different station throughput capacities—at 2, 4, 8, and 18 MTPD. These station capacities are selected based on the size of operating and planned medium- and heavy-duty FCEV HRS facilities reported by the California Energy Commission in its Senate Bill 643 Staff Report.[5]

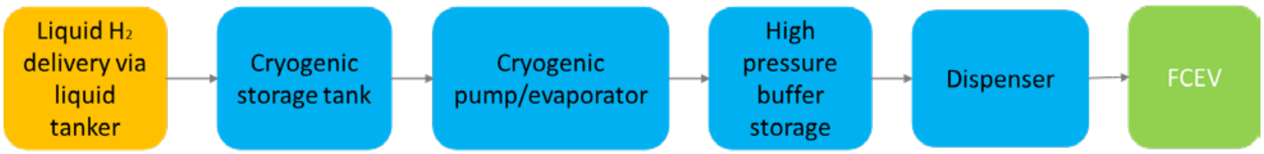

Figure 3.1. Generalized simplified liquid hydrogen supplied station configuration.[6] Yellow corresponds to the hydrogen transportation; light blue to the hydrogen fueling station components; and green to the fueling vehicles.

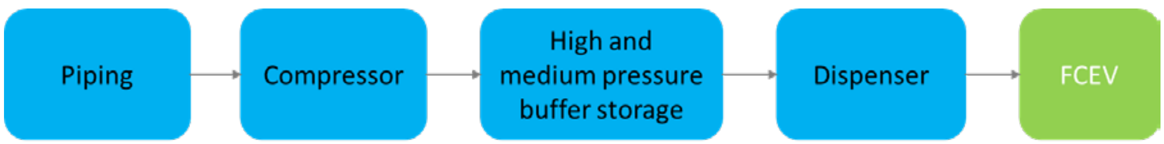

Figure 3.2. Generalized simplified gaseous supplied station configuration.[6] Light blue corresponds to the hydrogen fueling station components; and green to the fueling vehicles.

Total capital and operating costs of fueling station types examined in this report are available in Table 3.1 and are derived from HDSAM. We show results for 2, 4, 8, and 18 MTPD station sizes at various HRS lifetime utilization rates.

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[5] California Energy Commission. 2024. *Senate Bill 643: Clean Hydrogen Fuel Production and Refueling Infrastructure to Support Medium- and Heavy-Duty Fuel Cell Electric Vehicles and Off-Road Applications*. https://www.energy.ca.gov/publications/2023/senate-bill-643-clean-hydrogen-fuel-production-and-refueling-infrastructure.

[6] Argonne National Laboratory. 2023. "Hydrogen Delivery Scenario Analysis Model (HDSAM)." https://hdsam.es.anl.gov/index.php?content=hdsam.

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Table 3.1. HRS Modeled Cost Summary at Various HRS Capacities

Both direct and indirect capital costs are included, which are incentive-free.[7]

Total Estimated Costs [nameplate dispensing capacity]	On-Site GH_2 Station (700 bar dispensing) [2022$]	LH_2 Station (700 bar dispensing) [2022$]
Capital Cost ($2022) [2 MTPD]	$11.0 million ($5,500/kg-day)	$5.92 million ($2,960/kg-day)
Operating Cost ($2022) [2 MTPD]	$619,000 per year [30% utilization] $723,000 per year [50% utilization] $876,000 per year [80% utilization] (with feedstock costs)	$501,000 per year [30% utilization] $542,000 per year [50% utilization] $602,000 per year [80% utilization] (with feedstock costs)
Capital Cost ($2022) [4 MTPD]	$20.7 million ($5,170/kg-day)	$10.9 million ($2,730/kg-day)
Operating Cost ($2022) [4 MTPD]	$1.17 million per year [30% utilization] $1.38 million per year [50% utilization] $1.68 million per year [80% utilization] (with feedstock costs)	$850,000 per year [30% utilization] $929,000 per year [50% utilization] $1.04 million per year [80% utilization] (with feedstock costs)
Capital Cost ($2022) [8 MTPD]	$30.3 million ($3,790/kg-day)	$14.5 million ($1,810/kg-day)
Operating Cost ($2022) [8 MTPD]	$1.81 million per year [30% utilization] $2.17 million per year [50% utilization] $2.70 million per year [80% utilization] (with feedstock costs)	$1.13 million per year [30% utilization] $1.28 million per year [50% utilization] $1.50 million per year [80% utilization] (with feedstock costs)
Capital Cost ($2022) [18 MTPD]	$45.4 million ($2,520/kg-day)	$24.0 million ($1,330/kg-day)
Operating Cost ($2022) [18 MTPD]	$2.96 million per year [30% utilization] $3.64 million per year [50% utilization] $4.65 million per year [80% utilization] (with feedstock costs)	$1.88 million per year [30% utilization] $2.21 million per year [50% utilization] $2.71 million per year [80% utilization] (with feedstock costs)

Tables 3.2 and 3.3 break down the 4 MTPD and 18 MTPD fueling station costs, respectively, into various technology components and include the sizing and energy use of each technology component. We assume that each FCEV at the HRS takes 10 minutes to refuel a 60-kg tank that

[7] Direct capital costs include equipment and equipment installation costs. Indirect capital costs include site preparation, engineering and design, project contingency, licensing fees, and permitting costs.

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is 83% empty (50 kg for each fill).[8,9] Storage requirements at each HRS are dependent on daily station throughput and hourly operation profile.

As shown in Tables 3.1 through 3.3, a liquid hydrogen HRS is lower cost than an on-site gaseous HRS of the same capacity. This is primarily due to the energy density of the hydrogen when it reaches the HRS. For the on-site HRS case, hydrogen is supplied to the fueling station at 20 bar and requires additional storage and compression equipment to reach a dispensing pressure above 700 bar (Figure 3.2). Conversely, hydrogen delivered as a liquid is already more energy dense than gaseous hydrogen at 700 bar and only requires pumping through an evaporator to reach dispensing pressures (Figure 3.1). The capital costs presented in the tables are comparable to the announced 18 MTPD liquid hydrogen stations in California for heavy-duty truck fueling, which are estimated at ~$11.9 million.[10]

Table 3.2. HRS Cost Breakdown by Technology Component at 4 MTPD Capacity

All costs are in 2022$.[11]

Components	On-Site GH_2 Station [4 MTPD] (700 bar dispensing)	LH_2 Station [4 MTPD] (700 bar dispensing)
Compressors and Pumps	8 total compressors Energy: 5.5 kWh/kg CAPEX: $6.96 million	4 LH_2 pumps Energy: 0.54 kWh/kg CAPEX: $5.18 million
Storage	401 kg cascade storage 3,100 kg low-pressure storage CAPEX: $8.36 million	10,720 kg cryogenic tank 241 kg cascade storage CAPEX: $1.91 million
Dispenser	2 dispensers CAPEX: $0.37 million	2 dispensers CAPEX: $0.37 million
Refrigeration and Heat Exchanger	2 condensing/heat exchange units 16-ton capacity each Energy: 0.09 kWh/kg CAPEX: $0.57 million	2 heat exchangers 1 evaporator CAPEX: $1.14 million
Electrical, Controls, and Other	BoP[a] and electrical equipment CAPEX: $0.56 million	BoP and electrical equipment CAPEX: $0.27 million
Indirect Capital Costs	CAPEX: $3.87 million	CAPEX: $2.04 million

[a] BoP: balance of plant

[8] National Renewable Energy Laboratory. 2022. "Fast Flow Future for Heavy-Duty Hydrogen Trucks." https://www.nrel.gov/news/program/2022/fast-flow-future-heavy-duty-hydrogen-trucks.html.
[9] Matt Castrucci Nissan. 2020. "When's the Best Time to Refuel Your Vehicle?" https://www.mattcastruccinissan.com/blog/what-fuel-tank-level-should-drivers-refuel-at/.
[10] California Energy Commission. 2024. *Senate Bill 643: Clean Hydrogen Fuel Production and Fueling Infrastructure to Support Medium- and Heavy-Duty Fuel Cell Electric Vehicles and Off-Road Applications*. https://www.energy.ca.gov/publications/2023/senate-bill-643-clean-hydrogen-fuel-production-and-refueling-infrastructure.
[11] Argonne National Laboratory. 2023. "Hydrogen Delivery Scenario Analysis Model (HDSAM)." https://hdsam.es.anl.gov/index.php?content=hdsam.

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Table 3.3. HRS Cost Breakdown by Technology Component at 18 MTPD Capacity

All costs are in 2022$.[12]

Components	On-Site GH_2 Station [18 MTPD] (700 bar dispensing)	LH_2 Station [18 MTPD] (700 bar dispensing)
Compressors and Pumps	20 total compressors Energy: 4.1 kWh/kg CAPEX: $17.4 million	9 LH_2 pumps Energy: 0.54 kWh/kg CAPEX: $11.7 million
Storage	963 kg cascade storage 5,950 kg low-pressure storage CAPEX: $16.7 million	10,720 kg cryogenic tank 803 kg cascade storage CAPEX: $3.75 million
Dispenser	5 dispensers CAPEX: $0.92 million	5 dispensers CAPEX: $0.92 million
Refrigeration and Heat Exchanger	5 condensing/heat exchange units 16-ton capacity each Energy: 0.09 kWh/kg CAPEX: $1.32 million	5 heat exchangers 1 evaporator CAPEX: $2.59 million
Electrical, Controls, and Other	BoP[a] and electrical equipment CAPEX: $0.58 million	BoP and electrical equipment CAPEX: $0.56 million
Indirect Capital Costs	CAPEX: $8.49 million	CAPEX: $4.48 million

[a] BoP: balance of plant

4 Hydrogen Distribution Infrastructure and Liquefaction

The hydrogen distribution pathways examined in the report are based on the fueling station configurations detailed in Section 3. The scenarios assuming on-site production account for a short distance of piping to connect the production to the fueling station. The scenarios assuming central hydrogen production account for hydrogen delivery in liquid form. A summary of these two scenarios is provided in Table 4.1. Hydrogen delivery via gaseous tube trailers was not modeled because liquid trucking is expected to be more cost effective at the scales analyzed.[12,13]

[12] Argonne National Laboratory. 2023. "Hydrogen Delivery Scenario Analysis Model (HDSAM)." https://hdsam.es.anl.gov/index.php?content=hdsam.

[13] U.S. Department of Energy. 2023. *Pathways to Commercial Liftoff: Clean Hydrogen*. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

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Table 4.1. Pathway Definitions

Pathway Stage	On-Site GH_2 Pathway	LH_2 Delivery Pathway
1	On-Site Production	Central Production
2	Short-Distance GH_2 Piping	Liquefaction
3	Fueling Station	Liquid H_2 Truck Terminal
4		Liquid Trucking
5		Fueling Station

For liquid hydrogen truck delivery, levelized cost is dependent on both delivery distance as well as upstream facility sizing. As shown in Figure 4.1, liquid hydrogen transport via tanker trucks becomes more expensive with delivery distance, increasing from \$0.12/kg-H_2 with 10 km (6.2 miles) round-trip delivery to \$0.20/kg-H_2 with 200 km (120 miles) round-trip delivery. This \$0.08/kg-H_2 difference is small in comparison to typical LCOH dispensed values and illustrates the economic value of using liquid hydrogen carrying tanker trucks for longer distance deliveries. As an additional note on delivery, at real-world stations, the amount of time to fully unload liquid hydrogen from a tanker truck once it reaches an HRS as well as space constraints at the HRS must be considered by station operators if multiple liquid hydrogen deliveries are needed at the HRS each day.

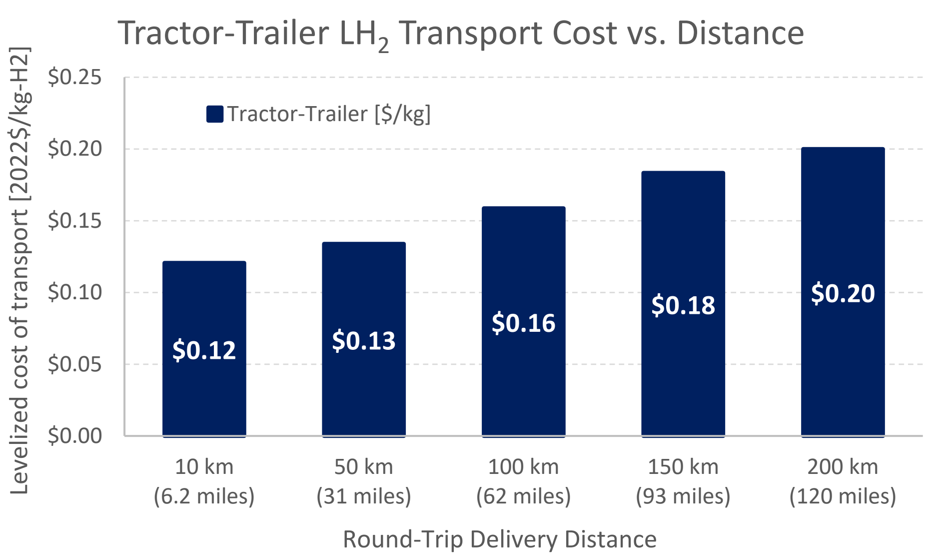

Figure 4.1. Tractor trailer delivery cost in \$2022 versus delivery distance. Assumes centralized, commercial-scale production.

Due to the economies of scale benefit of both hydrogen liquefaction facilities and liquid hydrogen terminals, delivering liquid hydrogen to fueling stations is lower cost if the hydrogen originates from larger liquefaction and terminal facilities. As shown in Figure 4.2, liquefaction

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plus terminal facility costs are reduced by over 50% on a levelized basis if the market size[14] is 1,000 MTPD instead of 5 MTPD. For context, current operating liquefaction plants have capacities in the range ~5–30 MTPD[15,16] while the largest liquefaction project announced in 2023 is designed for ~90 MTPD of liquid hydrogen.[17]

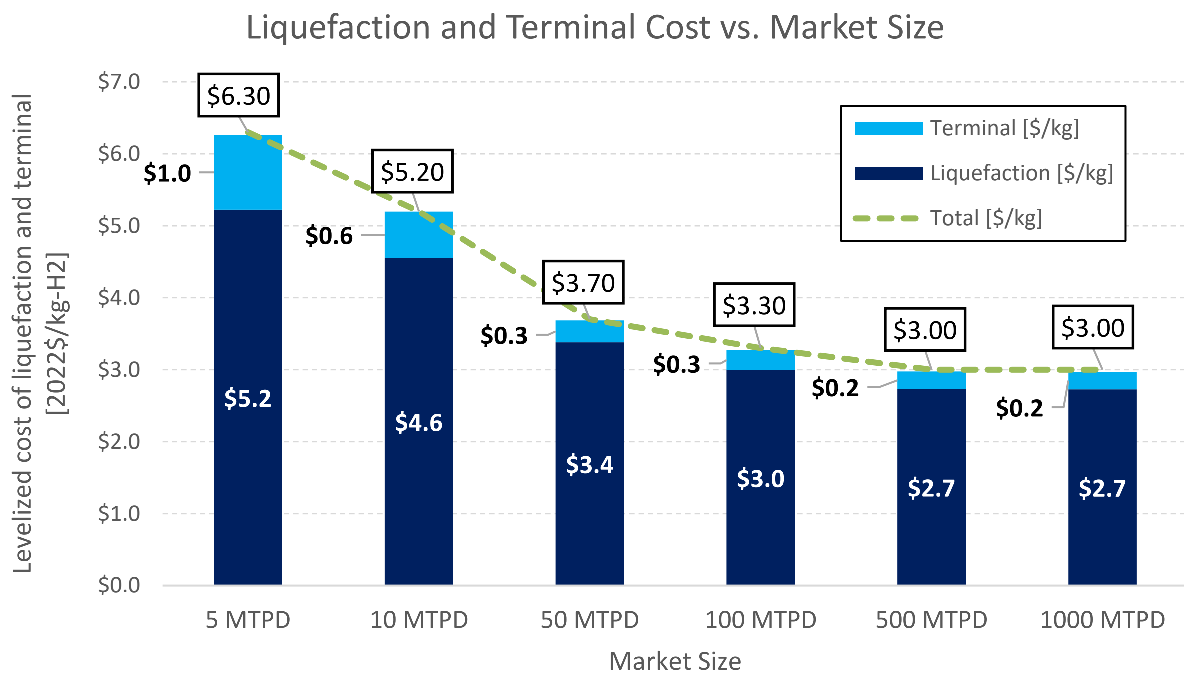

Figure 4.2. Liquefaction and transport terminal cost in 2022$ versus facility throughput. Values assume U.S. average Annual Energy Outlook electricity prices and standard liquefaction efficiencies of ~9–13 kWh/kg-H_2[18] at 99.5% mass efficiency.

[14] Market size for fueling stations is defined as the capacity of the upstream liquefaction and distribution terminal from which hydrogen delivered to the HRS is sourced from.

[15] S. Krasae-in, J. Stang, and P. Neksa. 2010. "Development of large-scale hydrogen liquefaction processes from 1898 to 2009." *International Journal of Hydrogen Energy*. https://doi.org/10.1016/j.ijhydene.2010.02.109.

[16] Chart Industries. 2024. "Hydrogen Liquefiers." https://www.chartindustries.com/Products/Hydrogen-Liquefiers.

[17] Air Liquide. 2023. "Hydrogen Liquefaction." https://engineering.airliquide.com/technologies/hydrogen-liquefaction.

[18] Monterey Gardiner. 2009. "Energy requirements for hydrogen gas compression and liquefaction as related to vehicle storage needs." https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/9013_energy_requirements_for_hydrogen_gas_compression.pdf.

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5 Hydrogen Production Costs

Hydrogen production pathways are diverse and include a number of technologies such as but not limited to fossil pathways with and without carbon capture and sequestration; electrolysis; and earlier stage pathways, such as thermochemical, photoelectrochemical, and biological processes. The cost of hydrogen production in 2030 will depend on the rate of economies of scale being achieved, the impacts of policy incentives (e.g., the 45V tax credit), and the success of research, development, and demonstration. The primary method of hydrogen production in the United States today is natural gas steam methane reforming (SMR), which is estimated to cost ~$1–$2/kg-H_2 with expected little change in the future due to its maturity. The SMR production cost, however, is significantly influenced by natural gas prices.[19] For other pathways to be predominantly deployed and competitive with natural gas reforming, they should achieve cost parity with the incumbent process. Therefore, the current analysis assumes that the cost of producing hydrogen that is later delivered to the modeled 2030 fueling stations is $1.50/kg-$H_2$ (i.e., the median of the aforementioned cost range), which roughly corresponds to a production scale of 100 MTPD anywhere in the United States. It must be noted that the assumed production cost in this analysis is technology agnostic and meant to serve as a placeholder for the levelized cost of produced hydrogen; it could easily be replaced with any other levelized cost of produced hydrogen by the reader. Real-world costs and emissions will vary depending on the method of hydrogen production supplying a given fueling station.

6 Levelized Cost of Hydrogen Dispensed

Figures 6.1 and 6.2 show the total LCOH (in 2022$) dispensed at a 2, 4, 8, and 18 MTPD HRS at various HRS lifetime utilization rates[20] from 30% to 80% covering from pessimistic to optimistic scenarios. Figure 6.1 results are for an HRS that is supplied with liquid hydrogen from a tanker truck and Figure 6.2 results are for an HRS with on-site production. Figure 6.1 assumes a market size sufficient to accommodate centralized commercial-scale production of ~100 MTPD and a round-trip delivery distance of 100 km (62 miles). It is important to note that, while Figure 6.1 assumes 100 km of liquid hydrogen delivery, real-world liquid delivery distances vary widely. As shown in Figure 4.1, the distance of liquid delivery does not significantly impact the dispensed cost of fuel. Figure 6.2 assumes 0.1 km (0.062 miles) of piping connecting on-site hydrogen production to the HRS.

For the liquid hydrogen supplied fueling stations in 2030 (Figure 6.1), total LCOH results range from $6.50/kg-$H_2$ to $11.20/kg-$H_2$ dispensed. For the fueling stations with co-located production (Figure 6.2), total LCOH results vary more with utilization rate and range from $3.80/kg-$H_2$ to $12.60/kg-$H_2$ dispensed. The LCOH range is greater in the on-site production scenario because it is dominated by equipment at the fueling station (as opposed to upstream equipment such as liquefaction and distribution terminals), which is sensitive to station utilization rate. While not shown in Figure 6.1, the LCOH, specifically the liquefaction component, for the HRS supplied with liquid hydrogen is also sensitive to changes in market size and would extend the range of

[19] U.S. Department of Energy. 2023. *Pathways to Commercial Liftoff: Clean Hydrogen*. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.

[20] Lifetime utilization rates are defined as the average amount of dispensed hydrogen over the lifetime of the station relative to the station capacity.

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the LCOH values shown in Figure 6.1 according to Figure 4.2. With the range of HRS capacities shown in Figures 6.1 and 6.2, we observe that there are economies of scale as HRS capacity increases. In particular, the HRS with liquid hydrogen delivery has a more than 15% (16%–30%) reduction in total LCOH at an 18 MTPD station size as opposed to a 2 MTPD station size. The HRS with on-site production has an even more pronounced economies of scale benefit, with a 38%–47% reduction in total LCOH dispensed if assuming an 18 MTPD station instead of a 2 MTPD station.

It must also be noted that the costs reported in Figures 6.1 and 6.2 are the lowest price at which the dispensed hydrogen could be sold but do not necessarily translate into retail prices, as the hydrogen retailer can choose to include an additional markup to make a profit on hydrogen sold at a fueling station. The LCOH values reported also do not consider any tax incentives or other state or federal incentive policies, which may impact the retail price of hydrogen consumers see at a fueling station relative to the estimated LCOH range. Fuel taxes are also excluded from the presented levelized costs of dispensed hydrogen.

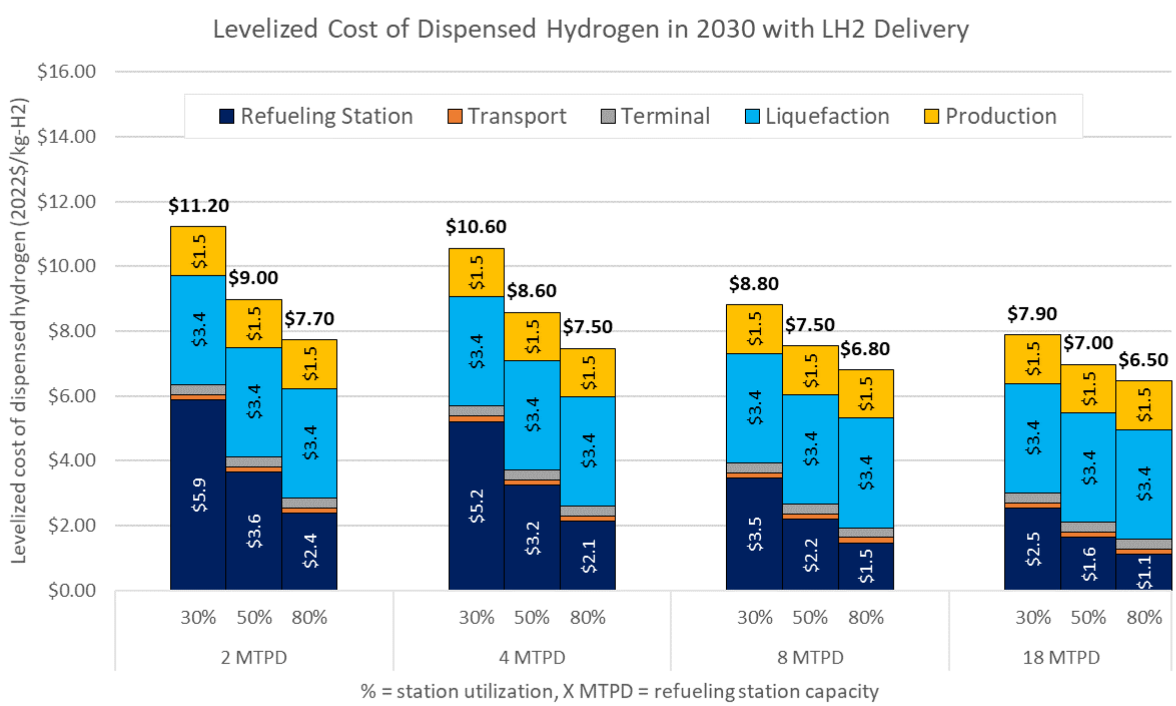

Figure 6.1. Potential total LCOH dispensed at 2, 4, 8, and 18 MTPD fueling stations with various fueling station lifetime utilization rates. Assumes a central, commercial-scale hydrogen production facility with a 100 km (62 miles) round-trip liquid hydrogen delivery.

Note: the dispensed LCOH values do not include additional markup that could affect the price of hydrogen fuel to the customer.

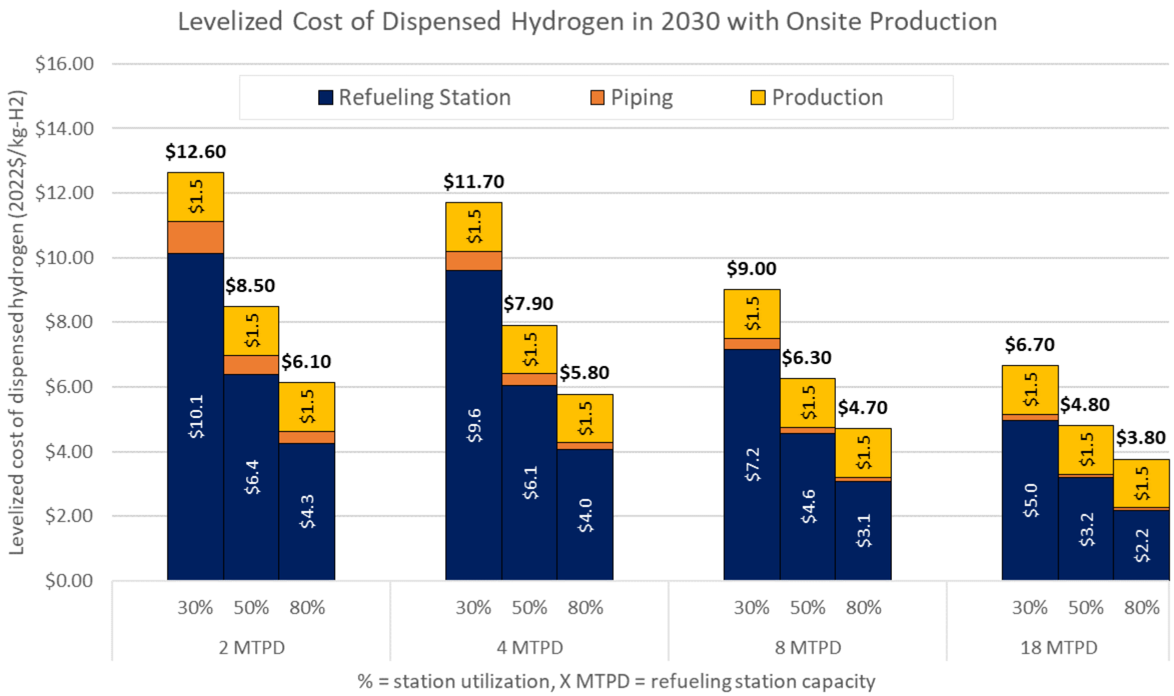

Figure 6.2. Potential total LCOH dispensed at 2, 4, 8, and 18 MTPD fueling stations with various fueling station lifetime utilization rates. Assumes an on-site production facility with 0.1 km (0.062 miles) of piping connecting production and fueling station.

Note: the dispensed LCOH values do not include additional markup that could affect the price of hydrogen fuel to the customer.

7 Conclusions

In this technical report, an analytical approach was applied for estimating the levelized cost of dispensed hydrogen at two types of fueling stations: (1) a liquid hydrogen station supplied via tanker truck and (2) a station supplied by gaseous hydrogen that is produced on-site. Given the methodology and assumptions described in Sections 2 through 5, the potential system levelized cost of hydrogen for 2–18 MTPD sized stations in 2030 could range widely from **~$3.80/kg-$H_2$ to ~$12.60/kg-$H_2$**, depending on the size of stations and method of hydrogen supply. This cost range does not necessarily translate into a retail price as seen by the customer. As observed in Section 6, consumer prices could be affected by retail markups at the fueling station and other market forces (e.g., fluctuations in supply and demand, inflation, supply chain disruptions). It is important to note that several federal incentives could also reduce the cost of hydrogen fuel at fueling stations in 2030 and were not accounted for in this analysis. Relevant incentives include, but are not limited to:

- Alternative Fuel Vehicle Refueling Property Credit (30C) for qualified alternative fuel vehicle fueling property
- Credit for Production of Clean Hydrogen (45V)
- Qualified Advanced Energy Project Credit (48C)
- Credit for qualified commercial clean vehicles (45W).

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In addition to these incentives, funding enacted by the Bipartisan Infrastructure Law, such as for the Regional Clean Hydrogen Hubs, and other research, development, and demonstration programs funded by the U.S. Department of Energy may also enable reductions in the cost of hydrogen fueling technologies by 2030.

In this report, many assumptions were made, and a limited number of scenarios were presented. While not exhaustive, the technology and cost uncertainties explored across the suite of scenarios provide useful insights of potential heavy-duty hydrogen fueling station economics. As shown in Section 6, the cost of hydrogen fuel can vary significantly depending on the size of the fueling station and its rate of utilization. Also as shown, while the cost of liquefying hydrogen is a significant share of the dispensed cost and subject to some uncertainty and fluctuation, the cost of liquid hydrogen delivery is relatively small and therefore not expected to materially influence the cost of dispensed hydrogen regardless of the delivery distance.

Additional work could provide greater fidelity to potential future costs of hydrogen. Such analysis could include, but is not limited to:

- Accounting for impacts of the Regional Clean Hydrogen Hubs on the rate and size at which stations are deployed in the United States and the demand at fueling stations
- Varying electricity, natural gas pricing, and emissions scenarios
- Optimizing on-site storage needs and hydrogen deliveries to meet operational and redundancy requirements of fueling stations
- Accounting for the impact of varying vehicle deployment rates on utilization at fueling stations and considering different applications (e.g., depot fueling vs. corridor fueling)
- Accounting for regional variability in methods of hydrogen production (e.g., using the Scenario Evaluation and Regional Analysis model)
- Conducting this analysis over a longer time horizon of numerous decades.

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