USDRIVE

DRIVING RESEARCH AND INNOVATION FOR VEHICLE EFFICIENCY AND ENERGY SUSTAINABILITY

Hydrogen Delivery Technical Team Roadmap

July 2017

This roadmap is a document of the U.S. DRIVE Partnership. U.S. DRIVE (United States Driving Research and Innovation for Vehicle efficiency and Energy sustainability) is a voluntary, non-binding, and nonlegal partnership among the U.S. Department of Energy; United States Council for Automotive Research (USCAR), representing Chrysler Group LLC, Ford Motor Company, and General Motors; five energy companies — BPAmerica, Chevron Corporation, Phillips 66 Company, ExxonMobil Corporation, and Shell Oil Products US; two utilities — Southern California Edison and DTE Energy; and the Electric Power Research Institute (EPRI).

The Hydrogen Delivery Technical Team is one of 13 U.S. DRIVE technical teams ("tech teams") whose mission is to accelerate the development of pre-competitive and innovative technologies to enable a full range of efficient and clean advanced light-duty vehicles, as well as related energy infrastructure.

For more information about U.S. DRIVE, please see the U.S. DRIVE Partnership Plan, https://energy.gov/eere/vehicles/us-drive-partnership-plan-roadmaps-and-accomplishments or www.uscar.org.

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Mission

The mission of the Hydrogen Delivery Technical Team (HDTT) is to enable the development of hydrogen delivery technologies, primarily through early-stage research and development (R&D), that will enable competitiveness of fuel cell vehicles with gasoline and hybrid technologies. The HDTT goal for hydrogen cost is based on the FCTO target of $4 per gallon of gasoline equivalent of hydrogen (including the cost of hydrogen production, delivery to a fueling station, and dispensing into a fuel cell vehicle).[1]

The HDTT mission supports U.S. DRIVE Partnership (United States Driving Research and Innovation for Vehicle efficiency and Energy sustainability) Goal 2, which is to enable reliable fuel cell electric vehicles (FCEVs) with performance, safety, and costs comparable to or better than advanced conventional vehicle technologies, supported by viable hydrogen storage and the widespread availability of hydrogen fuel.

Scope

The scope of hydrogen delivery is broad. As shown in Figure 1, hydrogen delivery infrastructure starts immediately after hydrogen is produced and ends at the point at which it is introduced into the end-use device (e.g., light-duty vehicle). It includes delivery of hydrogen from large centralized and moderately sized semi-centralized production facilities, as well as compression storage and dispensing of hydrogen produced from small-scale, distributed facilities located at vehicle refueling stations. The scope of the delivery infrastructure does not include technologies for hydrogen production or for hydrogen storage onboard a fuel cell electric vehicle.

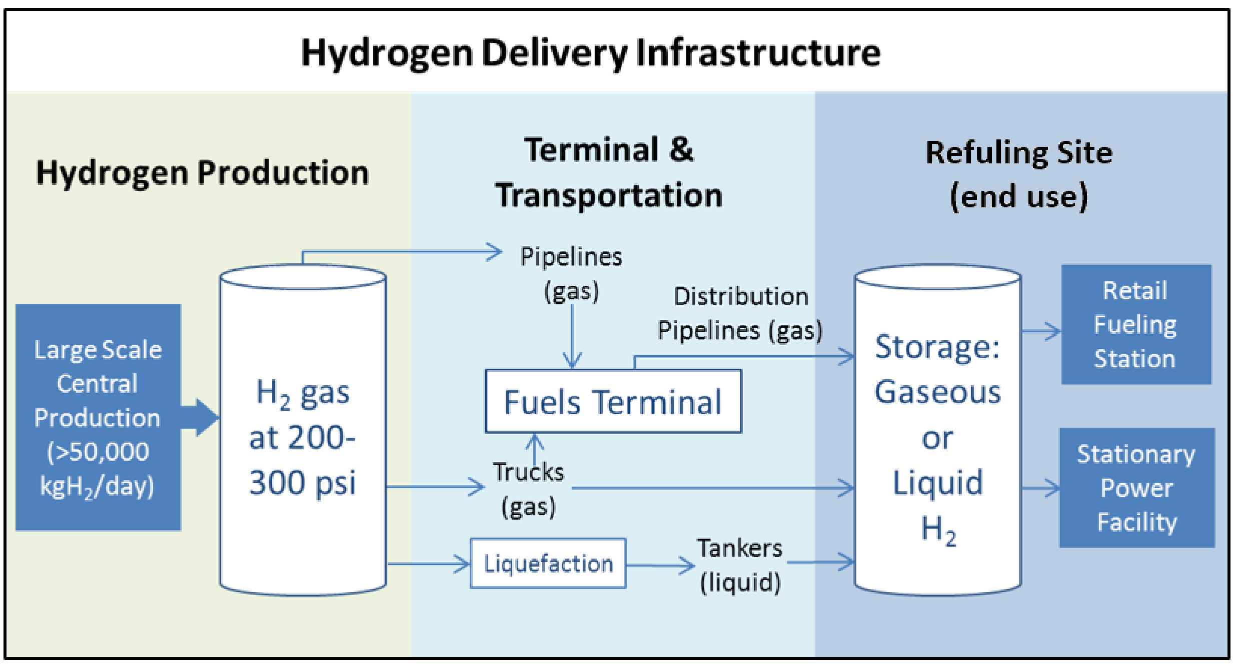

Figure 1. Hydrogen Delivery Scope

Centralized hydrogen production facilities are likely to use the full complement of delivery infrastructure functions, including transport. Distributed production facilities will need only the

[1] https://www.hydrogen.energy.gov/pdfs/11007_h2_threshold_costs.pdf

storage, compression, and dispensing operations. Delivery infrastructure needs at distributed facilities are a subset of the more comprehensive delivery infrastructure needs for centralized facilities.

This roadmap considers three potential delivery paths:

- Gaseous hydrogen delivery (Figure 2)
- Liquid hydrogen delivery (Figure 3)
- Novel solid or liquid hydrogen carriers (Figure 4)

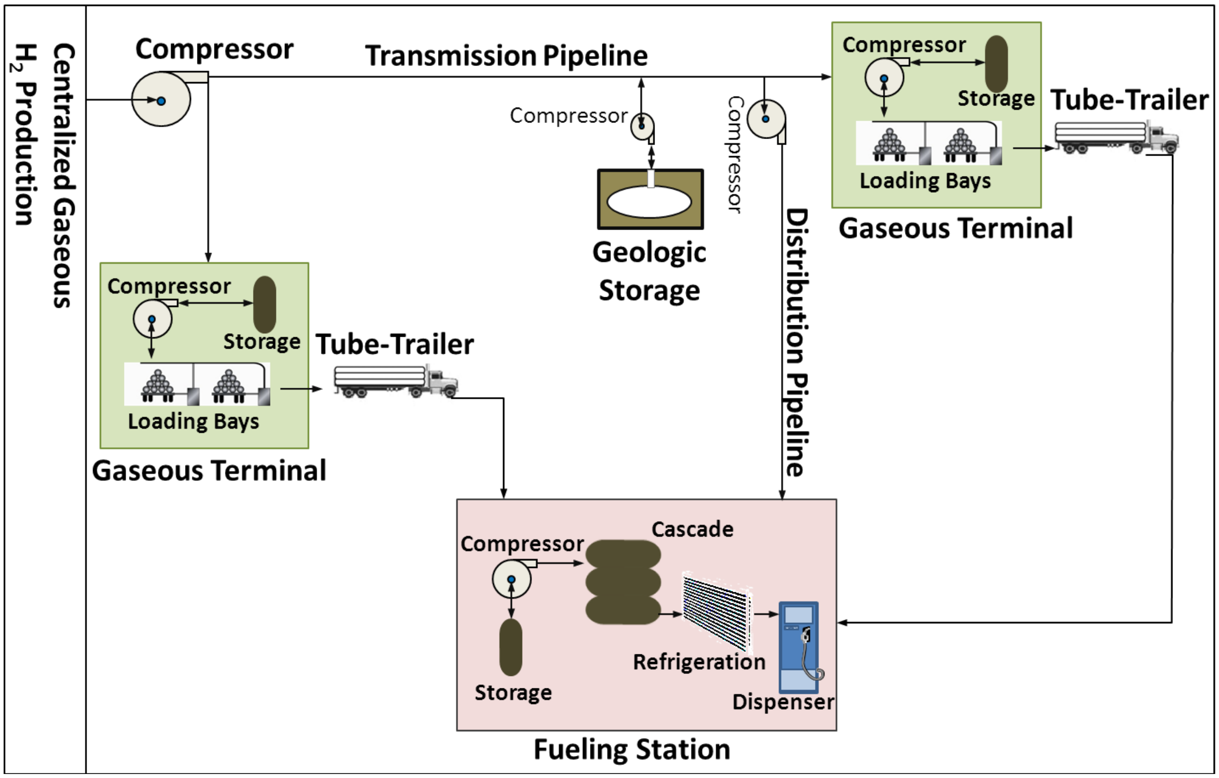

Figure 2. Example of Gaseous Delivery Pathway

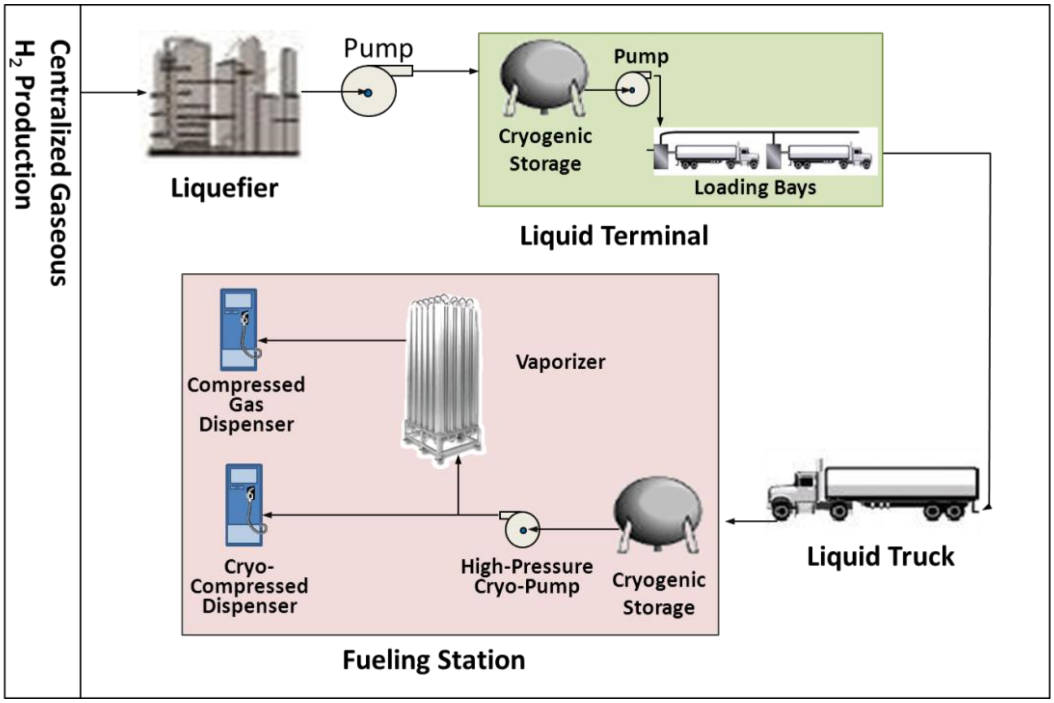

Figure 3. Example of Liquid Delivery Pathway

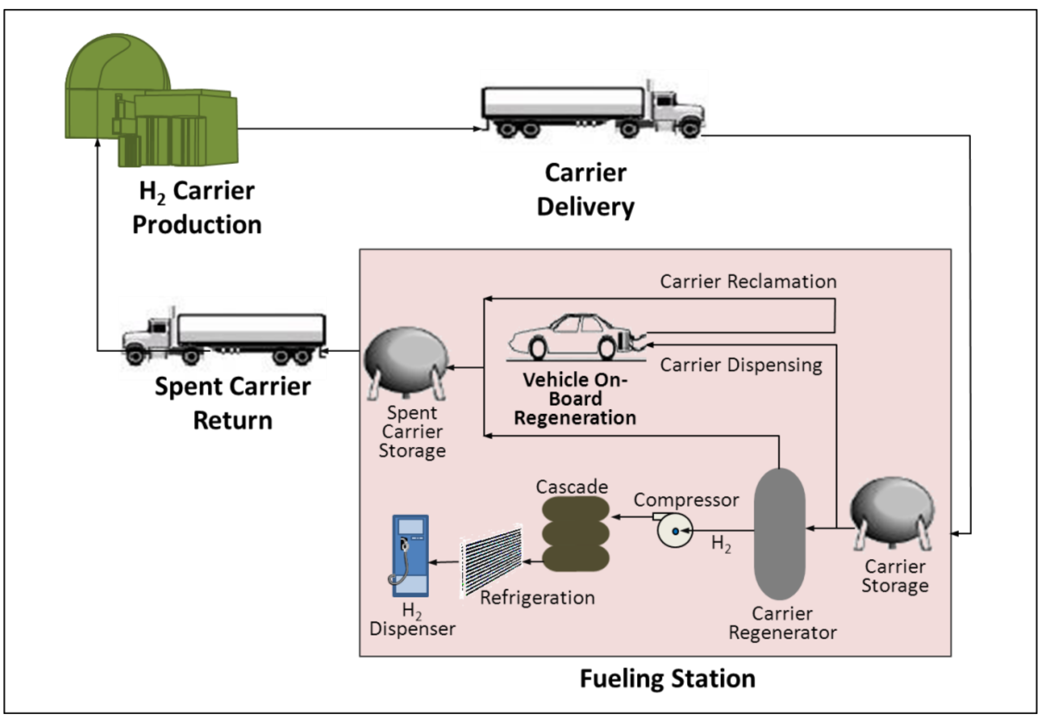

Figure 4. Example of Carrier Delivery Pathway

Roadmap Introduction

Hydrogen, as part of a portfolio of technologies, holds the long-term potential to reduce U.S. dependence on foreign oil and to reduce emissions, including criteria pollutants, associated with the transportation sector. The American transportation sector is almost completely reliant on petroleum, about 25% of which is currently imported[2], and tailpipe emissions remain one of the country's key air quality concerns; for example, over 95% of carbon monoxide emissions in U.S. cities are due to transportation[3]. Fuel cell electric vehicles operating on hydrogen produced from domestically available resources — including renewable or nuclear power and water, natural gas, and biomass— would dramatically decrease emissions as well as reduce dependence on oil. Clean, domestically produced hydrogen can also be used to generate electricity in stationary fuel cells used in backup power applications in large industries (e.g. telecommunications or data centers) nationwide.[4,5]

Successful commercialization of hydrogen fuel cell electric vehicles requires a hydrogen delivery infrastructure that provides the same level of safety and convenience as the existing gasoline delivery infrastructure. In addition, the hydrogen delivery infrastructure will need to support the various production pathways for hydrogen fuel. Because hydrogen can be produced from a variety of domestic resources, production can take place in large, centralized plants, or in a distributed manner — directly at refueling stations and stationary power sites. Hydrogen delivery systems include not only transport and delivery from centralized production operations, but also the storage, compression, and dispensing operations at a hydrogen fueling station.

Hydrogen delivery pathways are typically developed based on the various physical states in which hydrogen can be delivered. The three primary hydrogen delivery pathways are: gaseous hydrogen, liquid hydrogen, and a spectrum of possible solid or liquid hydrogen carriers. Pathways that combine these approaches are also possible. Delivery pathways contain numerous components such as compressors, pipelines, liquefiers, gaseous tube trailers, cryogenic liquid trucks, storage vessels, terminals, and dispensers. The HDTT of the U.S. DRIVE Partnership has developed this Hydrogen Delivery Roadmap to address the technical goals and milestones for hydrogen delivery systems, to assess technologies and early stage R&D that could help meet these goals, and to identify the barriers to achieving these goals. Research priorities and strategies are suggested for both the near term (transition period) and the longer term (fully developed hydrogen fuel cell technology and infrastructure).

While some of these advancements represent incremental improvements to existing technology, others will require novel concepts and major breakthroughs to achieve the required performance and costs. Close collaboration with other U.S. DRIVE technical teams is also critical to success. The HDTT coordinates closely with the Hydrogen Storage, Hydrogen Production, Codes and Standards, and Fuel Pathways Integration Technical Teams.

The liquid and gaseous pathways transport pure hydrogen in its molecular form (H_2) via truck, rail, or barge. Liquid or gaseous trucks and gas pipelines are the primary methods of delivering hydrogen today. The carrier pathway uses materials that transport hydrogen in a form other than molecules, such as liquid hydrocarbons, sorbents, metal hydrides, chemical hydrides, or other rich compounds. Ideal carrier materials would have simple, inexpensive treatment processes at a

[2] https://www.eia.gov/tools/faqs/faq.php?id=32&t=6

[3] https://www.afdc.energy.gov/vehicles/emissions_pollutants.html

[4] https://www.hydrogen.energy.gov/pdfs/16013_industry_deployed_fc_bup.pdf

[5] https://californiahydrogen.org/sites/default/files/ftco_early_mkts_fc_backup_power_fact_sheet.pdf

station, or onboard a vehicle, to release molecular hydrogen for use in fuel cells. Within the three delivery pathways, this roadmap addresses the specific technology components listed in

Table 1.

Table 1. Hydrogen Delivery Infrastructure Components

Delivery Technology Components		
Production	**Terminals & Transmission**	**Refueling Site**
Storage at Production Site	Pipelines, transmission & distribution	Carrier Processing and/or purification
Carrier Production/Regeneration	Trucks, rail, barges	Storage Tanks
	Compressors & Liquid Pumps	Compression
	Liquid and gaseous storage tanks	Heat exchanger/vaporizer
	Geological storage	Dispenser
	Terminals	
	Liquefiers	

Crosscutting	
Health & Human Safety	Codes & Standards
Sensors & Controls	Right-of-way/Permitting

This roadmap also addresses the need for delivery system analysis to inform further R&D. Current and emerging technologies, systems, and options for hydrogen delivery need to be comprehensively analyzed to ascertain the associated costs, performance, and advantages or disadvantages of each. Such detailed analyses help researchers evaluate trade-offs among hydrogen delivery methods and build an understanding of how advanced technologies could alter the requirements for transitional and long-term systems. Results of these analyses allow researchers to focus research and design on areas that show the greatest promise for contributing to a commercially viable hydrogen delivery infrastructure.

Full deployment of hydrogen-based transportation technologies and infrastructure will take time. Delivery infrastructure needs and resources will vary by region and type of market (i.e., urban, interstate, or rural), and infrastructure options will also evolve as demand grows and delivery technologies mature. This roadmap identifies the research, design, and demonstration needed to support hydrogen delivery during the transition period from laboratory to mature infrastructure technologies ready for large-scale deployment. Support for technology development through the transition period will be critical to achieving a successful transition. While the precise makeup of the infrastructure in the long term remains unclear, various combinations or permutations of all three pathways (i.e., gaseous, liquid, and carriers) are likely to play a role. The mix of technologies will vary by geographic location and over time as markets expand and new technologies are developed.

This roadmap was developed under the assumption that the current retail model for delivering fuel to customers will continue to be utilized. Alternatives that could change delivery technology needs, such as home refueling, are not addressed herein.

1. Gaseous Hydrogen Pathway

As shown in Figure 2, the gaseous hydrogen delivery pathway includes compression, storage, and transport by pipeline and/or tube trailer. Some operations, such as compression, occur at multiple points between the production facility and the end user.

Today, more than 2,575 kilometers (km) (1,600 miles) of dedicated hydrogen transmission pipelines serve the United States. In contrast, there are about 130,400 miles of onshore pipelines for petroleum and refined petroleum products, and nearly 300,000 miles of onshore natural gas pipelines.[6]

More than 10 million metric tons of gaseous hydrogen are produced in the United States annually, mostly for use as an industrial feedstock.[7] The majority of this hydrogen is produced at or near petroleum refineries and ammonia plants — the main users of industrial hydrogen. The existing hydrogen pipelines serve regions with high concentrations of these industrial hydrogen users, primarily along the Gulf coast. Due to their high capital cost, hydrogen pipelines are installed when demand is significant (i.e., hundreds of thousands of kilograms per day) and expected to remain stable for 15-30 years. Under such conditions, pipelines can be the most economic form of hydrogen delivery. When demand is smaller or less stable, it is typically satisfied via onsite hydrogen plants, gaseous hydrogen tube trailers, or liquid hydrogen trucks. Converting existing natural gas or petroleum pipelines to hydrogen use — if and when they became available — is also a possibility. This approach is currently challenged by the risks of hydrogen leakage form aging infrastructure, risks of hydrogen contamination in repurposed pipelines, and the technical challenges in assessing the risk of embrittlement in an existing pipeline with an unknown service history.

2. Liquid Hydrogen Pathway

The liquid delivery pathway for hydrogen includes a number of well-known and currently practiced elements. As shown in Figure 3, the first step is liquefaction, a well understood but costly process due to its capital intensity and low energy efficiency. The liquefaction process involves cooling gaseous hydrogen to below -253°C (-423°F) using liquid nitrogen and a series of compression and expansion steps. The energy consumed in liquefaction is equal to about 35% of the energy content of the hydrogen.

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[6] https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?Portalpages

[7] DOE Hydrogen and Fuel Cells Program Record, "Current U.S. Hydrogen Production", 2016. https://www.hydrogen.energy.gov/pdfs/16015_current_us_h2_production.pdf

Liquid hydrogen is stored at the liquefaction plant in large, insulated tanks, loaded into liquid delivery trucks, and transported to the "point of use." At distribution sites, the liquid is stored in vacuum-jacketed tanks until it is used, typically after vaporization into a gas. For fuel cell applications such as hydrogen vehicles and forklifts, the hydrogen pressure is increased, and it then vaporized before dispensing into storage vessel onboard the application. Converting liquid hydrogen to gas is performed by passing the liquid through an ambient air or warm water bath vaporizer (heat exchanger). Ambient vaporizers are sized to achieve the desired flow rates at the worst-case seasonal ambient conditions.

Today, the liquid hydrogen pathway is a well-developed and competitive method of providing hydrogen molecules for high-demand applications that are beyond the reach of hydrogen pipeline supplies. The liquid pathway is more economical than gaseous trucking for high market demands (i.e., greater than 500 kg/day[8]) because a liquid tanker truck with a capacity of approximately 5,000 kg can transport over 5 times the capacity of a typical steel gaseous tube trailer. The eight existing liquefaction plants in North America vary in production size from 5,000-70,000 kg of hydrogen per day. A large market penetration of fuel cell electric vehicles could justify the construction of additional large-scale liquefaction units. Breakthrough liquefaction technology such as magnetic or acoustic liquefaction may lower the costs of future liquefaction.

3. Hydrogen Carrier Pathway

Simply stated, hydrogen carriers are materials capable of transporting, delivering, or storing hydrogen in any chemical state other than free hydrogen molecules. Potential carriers include sorption materials, liquid hydrocarbons, chemical hydrides, and metal hydrides. Carriers are considered due to their potential to deliver hydrogen long distances at higher densities than gaseous tube trailers, and without the boil-off that liquid hydrogen tankers experience. Carriers are still at low levels of technology readiness. Technical challenges that must be overcome to enable their use are discussed in the section below.

4. Key Issues and Challenges

To support the diverse hydrogen production options, the future hydrogen delivery infrastructure may incorporate multiple delivery pathways capable of handling hydrogen in various forms, including gaseous delivery via pipelines and compressed gas tube trailers, liquid delivery via liquid trucks, and delivery via carriers. The technologies required to support these delivery pathways are at various stages of development, but they must ultimately meet or exceed the level of safety, convenience, reliability, and energy efficiency provided by the existing gasoline delivery infrastructure. The key issues and challenges with respect to the delivery pathways and refueling site delivery stations are outlined in **Error! Reference source not found.** and presented in more detail in the *Gaps and Technical Barriers* section.

[8] https://www.hydrogen.energy.gov/pdfs/review15/pd014_elgowainy_2015_o.pdf

Table 2. Key Issues and Challenges by Technology Area

Technology Area	Key Issues and Challenges
Refueling Site Compression, Storage, and Dispensing	▪ Compressor cost, reliability, and efficiency ▪ Storage cost and footprint ▪ Dispenser cost and reliability ▪ Cost of equipment for -40°C precooling ▪ Meter accuracy and cost
Pipelines	▪ Installed capital cost ▪ Management of pipeline integrity (e.g. potential for hydrogen embrittlement) ▪ Pipeline compressor cost and reliability
Compressed Gas Tube Trailers	▪ High capital cost of composite tube trailers ▪ DOT weight limit of 36.3 metric tons ▪ Cost and footprint of tube trailer terminals (comprising buffer storage and high-volume compressors)
Liquid Tankers	▪ Capital cost of liquefaction ▪ Energy intensity of liquefaction ▪ Boil-off losses
Carriers	▪ Capacity and cost of carriers ▪ Reversibility of carriers during repeated hydrogenation/dehydrogenation reactions ▪ Energy consumption of hydrogenation/dehydrogenation ▪ Development of catalysts and regenerators that can tolerate repeated hydrogenation/dehydrogenation cycles
All	▪ Hydrogen purity ▪ Leak detection ▪ Safety ▪ Education (including development of a skilled workforce as well as education of key stakeholders, such as local authorities having jurisdiction and potential station operators) ▪ Supply chain for key components

Current Status, Challenges, and Technical Barriers

1. Analysis

Current Status

Hydrogen delivery analysis is required to assist the U.S. DRIVE Partnership in understanding the trade-offs and impacts of various hydrogen transmission, distribution, and refueling technology options on the levelized cost of hydrogen at different market conditions. Market conditions include vehicle type (e.g., light-duty or heavy-duty vehicles), daily demand for hydrogen, refueling station capacity and utilization, hydrogen supply options (e.g., liquid or gaseous delivery, or onsite production), city size and population, vehicle ownership rate and annual vehicle miles travelled, market penetration of hydrogen vehicles, and refueling protocol implemented. In addition, analysis aims to identify key barriers to large-scale infrastructure deployment and the areas where R&D efforts are needed to address those barriers.

Once a delivery scenario for fuel cell electric vehicle (FCEV) markets is identified or defined, a delivery analysis begins by determining the size of refueling components necessary to satisfy the hourly demand of hydrogen at the defined market conditions. The next step is sizing the upstream infrastructure needed to supply the refueling station from the point of centralized production. The final step is calculating the delivery cost at the component and pathway levels. The delivery cost is reported in the forms of levelized cost (i.e., in \$/kg H_2), total capital costs, operation and maintenance costs, energy costs, and annual and cumulative cash flows. Other metrics important for the analysis include required terminal and refueling land area, life cycle energy use and emissions, and total fuel and electricity use.

To facilitate reliable analysis, accurate cost and performance data are needed for each component along the delivery pathway (see Table 1). This includes current cost of infrastructure components at today's market volume and components' capacity, as well as estimates of cost reductions possible in the future due to economies of scale.

Current analysis show that pipeline delivery provides the lowest cost option for large market demands (>150 metric tons per day) and large refueling station capacities (>1000 kg/day). Conventional (180 bar) gas tube-trailer delivery is suited for small end-use demand (~200 kg/day) and short distance deliveries due to their small payload (~300 kg). High-pressure (500 bar) tube-trailers can deliver payloads up to 1000 kg, and thus provide improved economics on hydrogen delivery, especially for large station demands of up to 1000 kg/day. Liquid delivery is suited for large end-use demand >500 kg/day, and long distances of delivery.[8]

The hydrogen delivery pathway for FCEVs terminates with hydrogen fueling stations. The contribution of refueling station capital investment constitutes approximately half of the total hydrogen delivery cost. The capital investment at the refueling station is dominated by the cost of compression or pumping, as well as the cost of storage. The investment risk and the underutilization of the refueling station capital investment during the early market deployment of fuel cell electric vehicles represent major market barriers to the full commercialization of fuel cell electric vehicles. Currently, ongoing analysis work for fueling stations includes optimization of station designs for medium- and heavy-duty vehicles.

Challenges and Technical Barriers

More comprehensive delivery infrastructure analyses need to be developed, and the options and trade-offs involved in various approaches to hydrogen delivery should be more fully understood. Longer term pathways, such as the distribution of hydrogen via carriers or as a cold gas, are still being assessed. Additionally, the costs of hydrogen delivery to support emerging applications, such as medium- and heavy-duty application, are continually being determined and re-evaluated.

A major barrier to reliable analysis is the availability of cost and performance data as a function of manufacturing volumes. Often such data are not available, because many of the delivery technologies have not been developed at commercial scale. In such cases, analysis relies on estimates based on surveys of manufacturers and experts in the field. Another barrier to reliable analysis is the consistency of cost estimates among alternative technologies that are at different maturity levels. While the cost of mature and reliable technology can be made with a high degree of certainty, cost estimates of emerging technologies in their proof of concept phase or at the demonstration scale are highly uncertain. Such uncertainties should be accounted for in the analysis of various delivery pathway options.

2. Gaseous Pipelines

Current Status

The United States has an extensive pipeline transmission and distribution infrastructure for natural gas, along with nearly 1,600 miles of hydrogen pipelines that are almost exclusively made of steel,[9] operate at maximum pressures of about 70 bar[10], and primarily supply the petrochemical industry. Due to high capital cost, pipelines are generally only installed in areas with end users whose demand is hundreds of thousands of kilograms per day[11,12] and is expected to be stable for at least 15-30 years.

Recent and ongoing R&D in the U.S. DOE's Fuel Cell Technologies Office (FCTO) on pipelines aims at lowering their capital cost through the codification of novel materials (e.g., fiber-reinforced polymer) and characterization of conventional materials (i.e., high-strength steels) in hydrogen service under the loading conditions that would be expected in a mature FCEV market. Under a mature FCEV market, pipelines are expected to experience cyclic fluctuations in pressure, or "fatigue" loading, that they do not experience today. This cyclic loading can cause pipeline damage that is not likely under constant pressure. FCTO-funded R&D studies the impact of varying hydrogen pressures and loading frequencies on the base metal and welds of steel pipelines. Over the past several years, research has shown that steels in the strength range of X52 – X80 have comparable resistance to hydrogen embrittlement.[10] Researchers are now evaluating the resistance to hydrogen embrittlement in welds in X100 steel, and in various microstructures in high-strength base metal. The experimentation will ultimately be used to guide the development of a novel high-strength steel (> X100) that exhibits acceptable resistance to hydrogen embrittlement.[13] "Acceptable resistance" is characterized by the crack growth rates that would be expected in a given steel under the hydrogen pressures and loading conditions a pipeline would experience when serving hydrogen fueling stations; these rates should be comparable to those experienced by steels currently accepted in the American Society of Mechanical Engineers (ASME) B31.12 code. In parallel with experimentation, research is also underway to develop physics-based predictive models of hydrogen embrittlement that can guide the development of integrity management practices for steel equipment in general, along with the development of novel steels.

Additionally, from around 2005-2015, FCTO funded R&D to evaluate the performance of fiber reinforced polymer (FRP) pipelines in hydrogen service. FRP pipelines are currently used in upstream oil and gas operations, and they are advantageous over steel because they can be delivered to job sites in spools of about0.5-mile or even manufactured onsite in lengths of 2-3 miles. Steel segments, in contrast,

[9] Pipeline and Hazardous Materials Safety Administration, Distribution, Transmission % Gathering, LNG, and Liquid Annual Data. http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print

[10] Fekete et al. "Economic impact of applying high strength steels in hydrogen gas pipelines", International Journal of Hydrogen Energy, 2015. http://www.sciencedirect.com/science/article/pii/S036031991501575X

[11] "Praxair Expands Hydrogen Supply with Gulf Coast Start-Up", 2013. http://www.praxair.com/news/2013/praxair-expands-hydrogen-supply

[12] Air Products' U.S. Gulf Coast hydrogen network: Enhanced reliability from the world's largest hydrogen pipeline. 2012. http://www.airproducts.com/microsite/h2-pipeline/pdf/air-products-US-gulf-coast-hydrogen-network-dataSheet.pdf

[13] Ronevich et al. "Fatigue Performance of High-Strength Pipelines Steels and their Welds in Hydrogen Gas Service." DOE FCTO FY 2016 Annual Progress Report, 2016. https://www.hydrogen.energy.gov/pdfs/progress16/iii_2_ronevich_2016.pdf

are deployed in segments of up to only 80 feet.[14] The long spool lengths significantly reduce the number of joints required for FRP installations in comparison to steel, thereby lowering the cost of pipeline installation. Research at ORNL and SRNL has evaluated the performance of FRP in high-pressure hydrogen service, including burst pressure, compatibility with hydrogen environments, flaw tolerance, leak rates, and resistance to fatigue.

In 2016, two significant modifications were made to the ASME B31.12 Hydrogen Piping and Pipelines Code, as a result of FCTO-funded R&D. First, the material performance factors ascribed to X70 steel were lifted. The reductions in pipeline wall thickness enabled by this change could lower pipeline installation costs by up to 30%.[15] Additionally, FRP was accepted into the ASME B31.12 code for service up to 170 bar. Installation of FRP is expected to cost over 25% less than installation of steel for a 1-inch diameter pipeline.[16]

In addition to dedicated hydrogen pipelines, injection of hydrogen into the existing natural gas infrastructure is another strategy that has been studied for cost and emissions reductions in recent years. Blends of hydrogen gas and methane used to be transported through the same pipeline infrastructure in both Europe and the U.S. from the 1800s to the mid-1900s, when gas was manufactured through gasification of coal. Manufactured gas could consist of up to 50% hydrogen, along with carbon monoxide, methane, and other trace gases. Manufactured gas was ultimately replaced when natural gas reserves were discovered that were more economical.[17,18] Blending of hydrogen into the existing natural gas infrastructure is now being studied to reduce the emissions associated with natural gas use.[19] In 2016, a collaborative project between the University of California- Irvine and SoCal Gas demonstrated the nation's first "power-to-gas" project, wherein hydrogen produced from an electrolyzer was blended into the school's natural gas pipeline system.

Challenges to the "power-to-gas" strategy include the following:

- The existing infrastructure is already in use at, or very near, capacity for much of the year; only limited seasonal volume could be made available for hydrogen.
- An unknown portion of the existing infrastructure has been compromised by corrosion or other physical damage, rendering it unfit for hydrogen service.
- The materials and fabrication techniques used in the construction of the pipelines were not designed for hydrogen compatibility, and post-fabrication inspection techniques used at the time of construction may not be sufficient for hydrogen use.

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[14] Gillette and Kolpa. "Overview of Interstate Hydrogen Pipeline Systems." Argonne National Laboratory Environmental Science Division, 2007. http://corridoreis.anl.gov/documents/docs/technical/APT_61012_EVS_TM_08_2.pdf

[15] Fekete et al. "Economic impact of applying high strength steels in hydrogen gas pipelines." International Journal of Hydrogen Energy, 2015. http://www.sciencedirect.com/science/article/pii/S036031991501575X?np=y&npKey=a240f0cf2da420c79034325ef9c897f460b05189e83fe7e0409fca1f3933506d

[16] U.S. DRIVE Highlights of Technical Accomplishments Report, 2015. https://www.energy.gov/sites/prod/files/2016/04/f30/2015%20U%20S%20%20DRIVE%20Accomplishments%20Report.pdf

[17] Junge and Cook. "The manufactured gas industry in Kansas." Kansas Department of Health and Environment, Bureau of Environmental Remediation/Remedial Section, 2008. http://www.kdheks.gov/remedial/articles/FMGP_History.pdf

[18] Leeds City Gate H21 Report, 2016. http://www.kiwa.co.uk/uploadedFiles/Our_Services/Energy_and_Carbon_Advice/H21%20Report%20Interactive%20PDF%20July%202016.pdf

[19] Melaina et al. "Blending Hydrogen into Natural Gas Pipeline Networks: a review of key issues." NREL Technical Report, 2013. http://www.nrel.gov/docs/fy13osti/51995.pdf

- End-use pressure requirements for hydrogen fuel cells significantly exceed the typical pressures in the natural gas distribution system, requiring additional compression.
- Contaminants associated with natural gas are potentially destructive to fuel cell operation and lifetime. Thus, hydrogen separation and substantial purification would be needed in order to implement a shared infrastructure scenario.
- The energy density of hydrogen per unit volume is approximately one-third that of natural gas. Thus mixing 12% of hydrogen in natural gas by volume translates to only 4% of hydrogen in the mixture by energy.
- The compatibility of hydrogen with end-use appliances designed for natural gas is not substantially understood. A "power-to-gas" concept will require separation of hydrogen from the natural gas unless appliances are developed or characterized that allow for the use of both gases.

A complete hydrogen pipeline infrastructure to supply fuel cell electric vehicles would include both transmission and distribution pipelines to minimize overall hydrogen delivery costs. Transmission pipelines would be necessary to deliver hydrogen across long distances (e.g. across states), and distribution pipelines would be necessary for regional delivery to end users. The capital cost of a hydrogen transmission pipeline is currently estimated at about $1,000,000/mile for an 8-inch line, including right-of-way;[20] however, the costs of right-of-way vary widely depending on the region of the country. The primary difference between the costs of hydrogen pipelines and natural gas pipelines is expected to be the cost of material, particularly at larger diameters (>12") wherein high-pressure hydrogen pipelines would be thicker than natural gas pipelines.

Challenges and Technical Barriers

Installed Capital Cost

The cost of new pipeline construction is high. Of these costs, labor comprises approximately 50% and materials comprise approximately 20%. A viable near-term approach to lowering the labor costs of steel pipelines is through the deployment of friction stir welding (FSW) technologies to installation sites. FSW involves the use of a rotating pin that fuses the parts to be joined via substantial frictional heating, rather than bulk melting like conventional approaches (e.g., arc welding). Advantages of FSW include its minimization of microstructural defects in the weld that often result from solidification after bulk melting, energy efficiency, and a reduction in the amount of time required to perform a weld. These latter two benefits can generate cost savings, particularly for large-diameter pipes. Field-deployable FSW units have only recently been developed.[21] Their deployment and verification at actual pipeline installation sites could lower the costs of hydrogen pipeline labor.

Another approach to lowering labor costs is through the use of fiber reinforced polymer (FRP) piping, as discussed on page 9. FRP labor costs can be about 25% lower than those of conventional steel. Increased deployment of FRP in industrial settings will also require performance verification in relevant environments.

[20] Estimate derived using the Hydrogen Delivery Scenario Analysis Model (HDSAM) V3.0, available here: https://www.hydrogen.energy.gov/h2a_delivery.html HDSAM's estimates are based on http://www.ogj.com/articles/print/volume-109/issue-1/transportation/national-lab-uses-ogj-data-to-develop-cost-equations.html

[21] Feng and Lim. "Final Technical Report: Flexible Friction Stir Joining Technology". Oak Ridge National Laboratory, 2015. http://info.ornl.gov/sites/publications/files/Pub56630.pdf

Lack of Understanding of Material Science Issues
While conventional steels have been accepted into the ASME B31.12 code for high-pressure hydrogen transmission, modern high-strength steels (i.e. X100) are not yet permitted due to concerns of hydrogen embrittlement. The resistance of modern must be assessed, and novel higher strength steels should be developed to lower the material costs of pipelines while retaining acceptable resistance to embrittlement.

An additional need in pipeline understanding is the development of strain-based models of hydrogen embrittlement. Conventional models used in the ASME B31.12 code for pipeline design are based on the expected operating conditions of a pipeline (i.e., stress-based models). These models are insufficient to predict performance if a pipeline's history is unknown, or if the pipeline experiences unexpected stress, like an overloading event or third party damage. The development of strain-based models could allow for the development of higher accuracy integrity management plans for pipelines, along with repurposing of current pipelines for hydrogen service.

Right Of Way Issues
Obtaining the Right of Way (ROW) to construct a pipeline through public or private property can be costly and administratively challenging. In some cases, ROW costs may be prohibitively high; in others, the ROW may simply be unattainable. Many ROW issues cannot be addressed directly with R&D activities. However, educating stakeholders will improve public acceptance and thus indirectly reduce some ROW issues, such as the "not-in-my-backyard" philosophy often prevalent in the face of new technologies.

Other
Current natural gas regulations require the use of an odorant for leak detection in lines servicing non-industrial customers. If odorant technology were to be developed for hydrogen pipelines, it would need to be easily removed or be compatible with vehicle fuel cells. Sensor-based leak detection methods could overcome this problem if proven acceptable to regulators.

3. Compression

Current Status
As seen in Figures 2-4, compression is an integral aspect of hydrogen delivery. However, compression needs differ along the delivery pathway and include the following:
- Pipelines: High throughput, medium pressure (100 bar or 1,450 psi), very high reliability
- Terminals: Medium throughput, high pressure (350-500 bar or 5,000-7,250 psi), high reliability
- Refueling Sites: Moderate throughput, high pressure (950 bar or 14,000 psi), high reliability

Mechanical compressors are classified as either positive displacement compressors or centrifugal compressors. Most positive displacement compressors used at stations are reciprocating technologies. A reciprocating compressor uses a linear drive to move pistons or a diaphragm in a back-and-forth motion to compress the gas, and it contains inlet and outlet check valves. The most common reciprocating compressors operate at high revolutions per minute (rpm) typically 750 to 1800 rpm. Problems with reciprocating compressors for hydrogen include poor reliability, potential for contamination from lubricants, high noise levels, and high capital costs. Intensifiers, which are piston-type compressors of a different design that operate at low rpm, may address some of these problems.

Centrifugal compressors are routinely used in natural gas service for pipeline transmission and to meet other needs involving high throughput and modest compression ratios of 1.1 to 2.0. If hydrogen is to be

transported via pipeline, compressors designed for hydrogen transmission will be needed. Due to hydrogen's low molecular weight, hydrogen compressors need tip speeds around three times higher than those used for natural gas. To achieve high hydrogen pressures, centrifugal compressors require multiple stages operating at high rotational speeds, as well as special seals and high mechanical tolerances. Centrifugal compressors designed to work with hydrogen are at the prototype stage of development. The cost of these advanced designs must be reduced, and reliability verified. Key research challenges include seal design, lubrication design, management of vibration, material selection, and rotor design.
State-of-the-art gaseous hydrogen compression involves the use of reciprocating pistons for high-volume applications and pistons or diaphragms for small-volume applications. Required compression ratios vary at different points in the delivery system. Transmission pipeline compression is a high-throughput application (50,000-2 million kg/day) with a modest compression ratio, typically requiring raising the pressure from about 20 bar to about 70 bar (70 psi to 1,000 psi). Refueling stations require lower compression throughput (up to 100 kg/h) but at a much higher compression ratios. Current refueling station compressors are capable of delivering up to 35 kg/h at a pressure ratio of 45 (20-950 bar). The energy required to compress a gas is a logarithmic function of the pressure ratio; thus, incremental energy input becomes smaller as higher pressures are reached. Multistage compression and intercooling are used to achieve high pressures. High-pressure, 700-bar hydrogen tanks are currently the leading technology for onboard vehicle storage. These tanks need to be filled at pressures as high as 950 bar (a tank filled at 950 bar at 85°C would equilibrate to 700 bar at room temperature).

Advances in compression have centered on the optimization of operations, improving specific components (e.g. new designs of diaphragms and coatings for seals), and developing innovative non-mechanical technologies. Non-mechanical technologies currently being researched include electrochemical and metal hydride compression. Electrochemical compressors pressurize hydrogen using electricity to split hydrogen molecules, along with proton conducting membranes to drive a pressure differential. Metal hydride materials achieve stasis at specific combinations of hydrogen concentration, hydrogen pressure, and temperature. Metal hydride compressors operate by absorbing hydrogen at low pressures and temperatures, and then releasing hydrogen at high pressures with the supply of heat. Both of these technologies are at early stages of research & development.

Challenges and Technical Barriers

Low Reliability
Refueling Site compressors exhibit low reliability, particularly under intermittent operation. Common causes of failure include mechanical stresses on valves and diaphragms, hydrogen ingress into polymeric seals, along with thermal stresses on polymeric seals.

Lubrication Contaminants
Lubricating oil in compression can contaminate the hydrogen being compressed. If this oil is not properly removed, it could have a detrimental effect on fuel cell performance. Non-lubricated designs or zero-lubrication leakage designs are needed.

High Capital and Maintenance Cost
Compressors require expensive materials to prevent hydrogen embrittlement and the associated risk of part failures during use. The large number of moving parts in reciprocating and diaphragm compressors also tends to increase maintenance issues and costs. Research needs include better materials and alternative compressor designs. High-volume manufacturing of one type of compressor for refueling sites could significantly reduce the capital cost of these compressors.

Other
Pipeline compressors are at insufficient capacities to meet the demands of larger diameter pipelines that may be needed in the mid to long term. Traditional centrifugal compression technology for natural gas

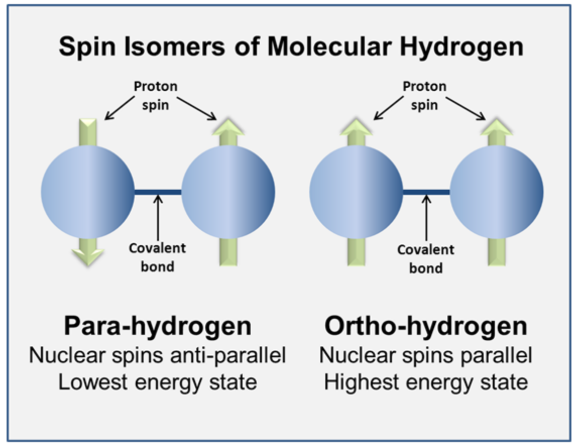
pipelines is not capable of the same flow rates for hydrogen due to the amount of horsepower required to compress hydrogen relative to natural gas. The significantly greater tip speeds of centrifugal compressors in hydrogen relative to natural gas imparts significant mechanical stress on compressor components (e.g. the impeller), compromising reliability. Managing hydrogen leak rates is another challenge for pipeline compressors, requiring tight tolerances and advanced seals.

4. Liquefaction

Current Status

Liquefaction is an energy-intensive, multistage process that uses a series of refrigerants and compression/expansion loops to convert hydrogen from the gaseous phase to the liquid phase. Hydrogen has the lowest boiling point of any element except helium, and it transitions from gas to liquid at -253°C (20 K) at atmospheric pressure. **Error! Reference source not found.** shows the typical liquefaction sequence of compression, isenthalpic expansion (through a Joule-Thomson valve), expansion cooling through a turbine, and cooling by liquid nitrogen via a brazed aluminum heat exchanger.

Most of the inefficiencies of current liquefaction plants come from cycle compressors and liquid nitrogen refrigeration.[22] A hydrogen molecule can exist in two electron orbital spin states: ortho and para. Hydrogen in the liquid state must be close to 100% para-hydrogen because ortho-hydrogen at low temperatures will naturally convert to para-hydrogen, releasing heat that causes the liquid hydrogen to vaporize. Ortho/para conversion catalyst beds are used to convert most of the hydrogen to the para form. A significant percentage of the energy required to liquefy hydrogen is consumed in making this ortho-to-para conversion.



Orthohydrogen and Parahydrogen
Each of the two hydrogen atoms in a hydrogen molecule contains one proton. These protons can be thought of as spinning in either the same or opposite directions. Molecules in which the protons spin in the same direction are orthohydrogen molecules; when they spin in opposite directions, the molecules are called parahydrogen molecules.

Why Convert Orthohydrogen to Parahydrogen?
At thermodynamic equilibrium, gaseous hydrogen is made up of a mixture of 75% *ortho* and 25% *para* hydrogen. Orthohydrogen is unstable at the low temperatures required for liquid hydrogen and will change to the more stable parahydrogen over time. This process releases heat that vaporizes a portion of the liquid. An ortho-para conversion catalyst is used during the liquefaction process to convert most of ortho to para hydrogen so that the resulting liquid can be stored without excessive vent loss.

*Source: C*CHEM, a division of Molecular Products Inc. www.cchem.com/opcat*

[22] Baker and Shander, A Study of the Efficiency of Hydrogen Liquefaction, International Journal of Hydrogen Energy, Vol. 3, pp. 321-334, 1978

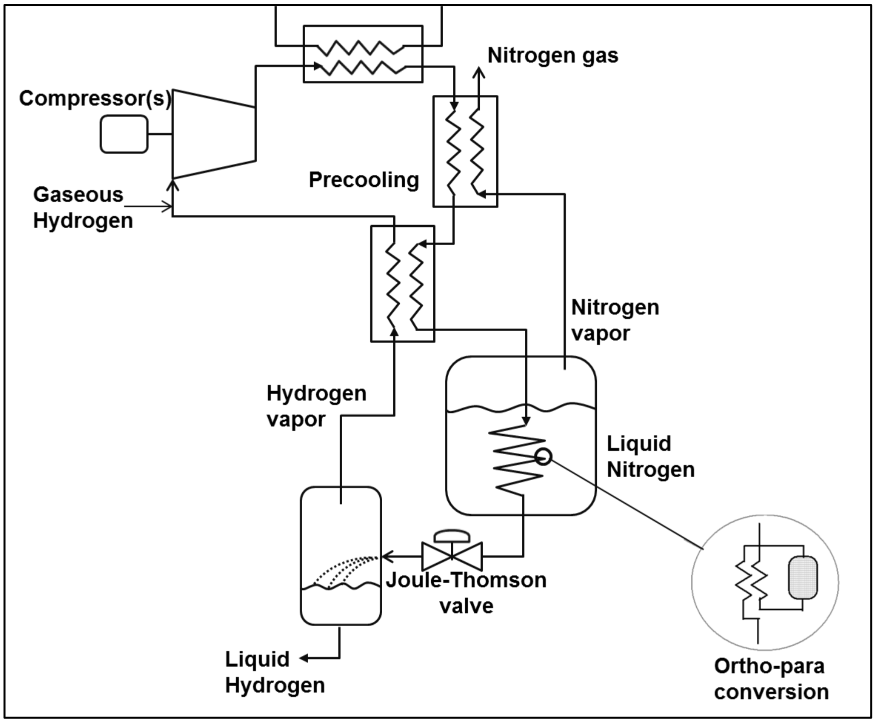


Figure 5. Hydrogen Liquefaction Plant

Challenges and Technical Barriers

High Capital Cost

Current liquefaction technology contributes more than $1.00 per kilogram to the cost of hydrogen. The plants are capital and footprint intensive, and this problem is exacerbated by the lack of low-cost materials that can withstand cryogenic conditions. As in the LNG industry, economies of scale can help reduce the cost of liquefaction by allowing for standard plant designs and improved thermal management.

Low Energy Efficiency and Losses

Liquefaction processes currently used by hydrogen vendors require high energy inputs equating to about 35% of the energy contained in the liquefied hydrogen (~33kWh/kg, lower heating value). Roughly 10% of the energy in the hydrogen is thermodynamically required to cool the hydrogen and to achieve the ortho/para transition. Opportunities to improve energy efficiency include: advanced heat exchanger technology and engineering (e.g. aluminum heat exchangers), along with gas compressors and/or turbo expanders that are compatible with mixtures of refrigerants.[23] Improvements must also be made in reducing the amount of hydrogen that is lost due to boil-off during storage and transportation.

Lack of Novel Technology and Approaches

Breakthrough cost reductions in liquefaction could potentially be achieved by novel next-generation technologies, such as acoustic liquefaction, magnetocaloric liquefaction, or development of novel catalysts to manage conversion of hydrogen from ortho to para form.

[23] Fuel Cells and Hydrogen Joint Undertaking. "Integrated Design for Demonstration of Efficient Liquefaction of Hydrogen (IDEALHY)". Assessment of Complete Plan, 2013. http://www.idealhy.eu/uploads/documents/IDEALHY_D5-23_Assessment_Complete_Plan_web.pdf

5. Cryogenic Liquid Hydrogen Pumps

Current Status
Liquid hydrogen can be directly pressurized at low temperatures using cryogenic pumps, as shown in the liquid delivery pathway (Figure 3). Cryogenic pumps can achieve high flow rates (up to 120 kg/hr has been demonstrated, although larger values could be theoretically achieved), can operate at high discharge pressures (up to 875 bar), and can minimize station footprint by eliminating the need for refrigeration and high-pressure storage. These pumps must operate under very cold temperatures to maintain the hydrogen in a liquid state at all times — any vaporization will cause damaging cavitation in the pump. The materials used in the pumps must be capable of withstanding these extreme temperatures without becoming brittle. Due to the materials and other specialized hardware employed, capital investment in cryogenic pumps can be high, but the pumps can satisfy high throughput at the station.

Cryogenic pumps can be used to fill a variety of onboard storage technologies, including room temperature compressed (using a vaporized downstream the pump), cryo/cold compressed, and cry-sorbent approaches.

Challenges and Technical Barriers
The main challenges of existing liquid hydrogen pump are their substantial capital costs, and the boil-off losses they experience when under-utilized. Research on novel structural and insulation materials could address these issues.

6. Hydrogen Storage

Current Status
High-Pressure Vessels
Gaseous pressure vessels, both for stationary and bulk transportation applications, are currently the most common means of storing hydrogen for meeting fuel demand at hydrogen stations. Storage pressures may range from 135 bar (~2,000 psi) to 930 bar (~13,500 psi). Current cost estimates for low (~160 bar), medium (430 bar), and high (860 bar) pressure are $600/kg, $1,100/kg, and $1,450/kg stored, respectively. Ongoing research at FCTO has the potential to reduce the costs of high-pressure storage dramatically through the use of wire-wrapped designs that minimize the use of steel.[24]

High-pressure tanks are designed in a cylindrical shape and can consist of a structural element (wall or shell) and a permeation barrier (liner). Compressed hydrogen storage vessels are classified according to the categories shown in Table 3.

Table 3. Classification of Hydrogen Storage Vessels

Type I	All-metal cylinder
Type II	Load-bearing metal liner, hoop-wrapped with resin-impregnated continuous filament

[24] Prakash and Saxena. "Low Cost Hydrogen Storage at 875 bar Using Steel Liner and Steel Wire Wrap". DOE FCTO FY 2016 Annual Progress Report, 2016. https://www.hydrogen.energy.gov/pdfs/progress16/iii_6_prakash_2016.pdf

Type III	Non-load-bearing metal liner, axial and hoop-wrapped with resin-impregnated continuous filament
Type IV	Non-load-bearing, non-metal liner, axial and hoop-wrapped with resin-impregnated continuous filament

Cylinders may be used individually or can be joined by a manifold to extend storage volumes. Stationary tubes have individual valves and safety devices, but they are joined by a manifold so that hydrogen can be withdrawn from a single tube or from several tubes simultaneously.

High-pressure refueling site stationary hydrogen storage is typically of Type II design, and it has been identified as one of the major cost contributors in hydrogen delivery infrastructure. Storage in other parts of the delivery infrastructure, such as at gaseous terminals, is also costly. There is a continued need to better understand the effects of high-pressure charge/discharge cycles and cycle depth, as well as environmental effects (heat, moisture, etc.) on tank integrity, because these factors are directly related to commercialization factors such as useful tank lifetime and cost.

Use of Solid Carriers for Hydrogen Tank Storage

Another concept that may have long term potential to reduce storage cost and increase the volumetric efficiency of hydrogen storage is the use of solid carriers for storing hydrogen within a low cost storage tank. For example, a metal hydride or a nanostructured absorbent such as carbon nanotubes could be put inside a vessel to allow for storage of hydrogen at higher densities and lower pressures than compressed gas tanks. Because stationary storage does not have the same weight and volume restrictions as onboard vehicle storage, systems that do not meet the goals for onboard storage might be effective for stationary storage vessels. However, such systems require cooling to adsorb hydrogen, and heating to regenerate the hydrogen for release; research is needed to optimize the thermodynamics of carrier systems.

Liquid Hydrogen Tanks

Liquid hydrogen tanks are currently used to store larger quantities of hydrogen at fueling stations because they provide a higher volumetric density than gas storage. Stations that use liquid hydrogen storage convert the liquid to high-pressure gas through a combination of pumping, vaporization, and compression steps prior to dispensing into FCEVs. The cryogenic liquid storage tanks at refueling stations are typically sized to satisfy station demand for 7-10 days or more in order to limit the frequency liquid tanker deliveries necessary.

Super-insulated steel pressure vessels are used to store liquid hydrogen because temperatures close to 20 K (-253°C or -423°F) are required to maintain hydrogen in liquid phase at typical vessel pressures (<5 bar or 73 psig). No matter how well a cryogenic liquid vessel is insulated, some hydrogen boil-off will occur, a phenomenon that is especially pronounced in small tanks that have relatively large surface area-to-volume ratios. Typical evaporation values are presented in Table 4.

Table 4. Evaporation Rates from Cryogenic Liquid Hydrogen Storage Tanks

Tank Volume (m^3)	Tank Volume (gal)	Evaporation Rate per Day
50	13,000	0.4%
100	26,000	0.2%
20,000	5 million	<0.03%

Liquid hydrogen tanks can be spherical or cylindrical. Very large tanks, such as developed for and used by NASA for over 30 years at launch pads for space exploration, are usually spherical to minimize surface area and thus decrease evaporative losses. Large tanks used at industrial manufacturing facilities and hydrogen stations are cylindrical. Large tank capacities range from 5,700-95,000 L (1,500-25,000 gallons or 400-6,700 kg) of hydrogen. All tanks consist of an outer shell of carbon steel, such as SA516 steel, and an inner shell of stainless steel, such as Type 304 steel. The inner sphere has a working pressure of 75–100 psi (5.2 – 6.9 bar). The annular space between the walls exists to function as an insulator and is a vacuum or filled with perlite insulator.

While underground liquid hydrogen storage would likely cost more than a traditional above-ground pressurized hydrogen system, an underground approach offers several advantages. For example, underground liquid storage reduces the above-ground footprint and also provides greater storage capacity per unit volume compared with underground gas storage. Underground storage vessels also have the potential to be permitted lower setback distances (per station design codes) than aboveground vessels.

Development of a new successful cryogenic storage tank design requires a multidisciplinary approach. It involves materials engineering (high-strength metallic or composite materials) to achieve pressure containment at low temperatures and during thermal cycling, and thermal engineering (design and deployment of novel insulation materials). The development of technologies and techniques to manage inevitable boil-off (e.g., the development of a small compressor that captures boil-off in a tank and stores it elsewhere onsite) would also be valuable.

Challenges and Technical Barriers

Cost

Gaseous and liquid storage tanks add significantly to the cost of hydrogen delivery — especially in early markets where hydrogen demand will be low compared to the required capital investment. Technological improvements that could lower the cost of storage include: 1) development of novel structural materials for tanks 2) standardization of tank sizes to enable manufacturing volumes, and 3) development of higher-accuracy non-destructive evaluation (NDE) technologies for use during vessel manufacturing. Improvements in the resolution of NDE technologies would allow for more accurate forecasts of vessel life, thereby preventing premature maintenance or over-conservative design.

Footprint

Real estate at refueling stations is costly. The footprint of hydrogen storage needs to be minimized, while also maintaining all public safety requirements. This may be accomplished through the development of underground storage technologies or carrier systems that achieve higher hydrogen densities than are possible with hydrogen in molecular form.

Hydrogen Losses
Liquid storage tanks lose hydrogen by boil-off, which can significantly deter the economics of refueling stations, especially in early markets where boil-off is significant.

Materials Requirements
The materials used to make both gaseous and liquid storage tanks must be resistant to hydrogen embrittlement and fatigue and maintain structural integrity under cryogenic temperatures. Use of novel materials of construction, both metallic and nonmetallic, must be considered.

Underground Storage Issues
Challenges that must be resolved to enable underground storage of hydrogen include: 1) assessment of the risks of corrosion of storage vessels and development of mitigation strategies, 2) determination of the effects of soil pressure on the tank, 3) assessment of the effects of tank leakage on the surroundings. In the case of underground liquid storage, ground freezing must also be avoided. In addition, seismic (earthquake) effects on underground tanks need to be determined.

7. Tube Trailers, Cryogenic Liquid Trucks, Rail, Barges, and Ships

Current Status
In addition to pipelines, fuels today are often transported via above-ground vessels and sea-faring barges.[25] Vessel shipments of hydrogen are currently limited to tube trailers and liquid tankers. Tube trailers with pressures of 250 bar (3,626 psi) and up to 800-kg capacity are commonly used to distribute gaseous hydrogen within 320 km (200 miles) of the source. Hydrogen can also be economically distributed within 600 miles of the source using liquid hydrogen tanker trucks that have capacities of 4,000-5,000 kg of hydrogen. However, their use is inhibited by the cost of liquid hydrogen, losses due to boil-off, and setback distances associated with liquid hydrogen storage at the point of use.

Successful widespread use of hydrogen will require a delivery infrastructure that accommodates diverse means of distribution. Although the most economical means of transporting hydrogen in the future may be by a larger pipeline network similar to that used for natural gas, other modes of transport may be more efficient for outlying areas or dense urban settings. Rail and barge transport may offer higher load-carrying capacities and higher weight limits than over-the-road trailers. They may also play a key role during the mid-term transition phase, when hydrogen demand is low and economic incentives for building hydrogen pipelines are not yet in place.

Tube Trailers and Liquid Tankers
Tube trailers are currently limited by U.S. Department of Transportation (DOT) regulations to pressures of less than 250 bar. Tube trailers with pressures up to 500 bar are, however, currently in use with Special Permits from the DOT. High-pressure tube trailers are advantageous for hydrogen fueling stations, because they reduce the energy required to compress hydrogen to the pressures necessary for hydrogen dispensing (875 bar). The dimensions of tube trailers are restricted by local and federal transport regulations.

Hydrogen leak detection, in the absence of odorizers, is a remaining challenge. Currently, commercially available leak detection equipment is handheld. An inline leak detector (direct or indirect measurement)

[25] DOE Quadrennial Energy Report: Energy Transmission, Storage, and Distribution Infrastructure. Appendix A: Liquid Fuels. 2015. https://energy.gov/sites/prod/files/2015/09/f26/QER_AppendixA_LiquidFuels_0.pdf

would be a desirable addition to a tube trailer. Improved monitoring and assessment of the structural integrity of tubes and appurtenances may be called for in the presence of higher containment pressures. Some examples of potentially novel methods include in-situ strain monitoring and acoustic emission monitoring.

Cryogenic liquid hydrogen trailers can carry up to 4,000 kg of hydrogen and operate at near atmospheric pressure. Some boil-off also occurs when unloading the liquid hydrogen on delivery. If cost effective, a system could be installed to compress and recover the hydrogen lost to boil-off during unloading. Given the economics of off-loading liquid hydrogen into a customer's tank, which includes factors such as distance from source, driver hours, and losses, most organizations plan deliveries to serve several customer sites with one tanker.

Challenges and Technical Barriers

Minimizing Boil-off: Liquid organic

Transport of liquid hydrogen via rail, barges, and ships is restricted by the boil-off losses incurred over long-distance delivery. The development of advanced insulation technologies, and high-capacity liquid organic hydrogen carriers (LOHCs) may enable long-distance delivery at high capacities. Technical challenges of LOHCs that must be addressed with research include: 1) high pressures required for hydrogenation, 2) high temperatures required for dehydrogenation, 3) quantity and cost of catalyst required for hydrogenation/dehydrogenation, 4) poisoning of catalysts during dehydrogenation, 5) formation of intermediate products during dehydrogenation, 6) the reversibility of hydrogenation and dehydrogenation, 7) hydrogen capacity, and 8) carrier cost.[26]

8. Geologic Storage

Current Status

Underground storage in natural and mined formations, known as geologic storage, is routinely used to provide seasonal and surge capacity for natural gas. Large-scale hydrogen infrastructure would require similar bulk storage space. There are currently five locations that use geologic storage for hydrogen — four salt caverns in Texas[27,28], one salt cavern in Teesside, England, and one hard rock cavern in Sweden.

Two types of geologic storage are currently viable for use with hydrogen: salt caverns and lined hard rock caverns. Most geologic gas storage sites can handle pressures of 80-160 bar (1,200-2,300 psi). Salt caverns are hollow cavities inside a large underground salt layer formed by drilling a hole into the salt structure and creating a geologic void by gradually dissolving the salt with freshwater or seawater. Salt caverns provide secure containment for materials that do not dissolve salt, such as hydrogen. All four hydrogen salt caverns currently in use have operated without any known hydrogen leakage problems. Hard rock caverns are an alternative where salt deposits are unavailable and are excavated in igneous or metamorphic rock, and then lined with concrete to prevent leakage. Both salt caverns and hard rock

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[26] Hu et al. "A novel liquid organic hydrogen carrier system based on catalytic peptide formation and hydrogenation". Nature Communications, 2015. https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4410633/

[27] Lord et al. "Geologic storage of hydrogen: Scaling up to meet city transportation demands". International Journal of Hydrogen Energy, 2014. http://www.sciencedirect.com/science/article/pii/S0360319914021223

[28] "Air Liquide operates the world's largest hydrogen storage facility". Press release, 2017. https://www.airliquide.com/media/usa-air-liquide-operates-world-largest-hydrogen-storage-facility

caverns can be cycled multiple times per year. Depleted oil or gas reservoirs and aquifers are widely used for storage of natural gas, but these bring risks of contamination and leakage if used to store hydrogen.[27]

Recent analysis at Sandia National Laboratories assessed the approximate levelized costs of each of these storage technologies, seen in Figure 7.

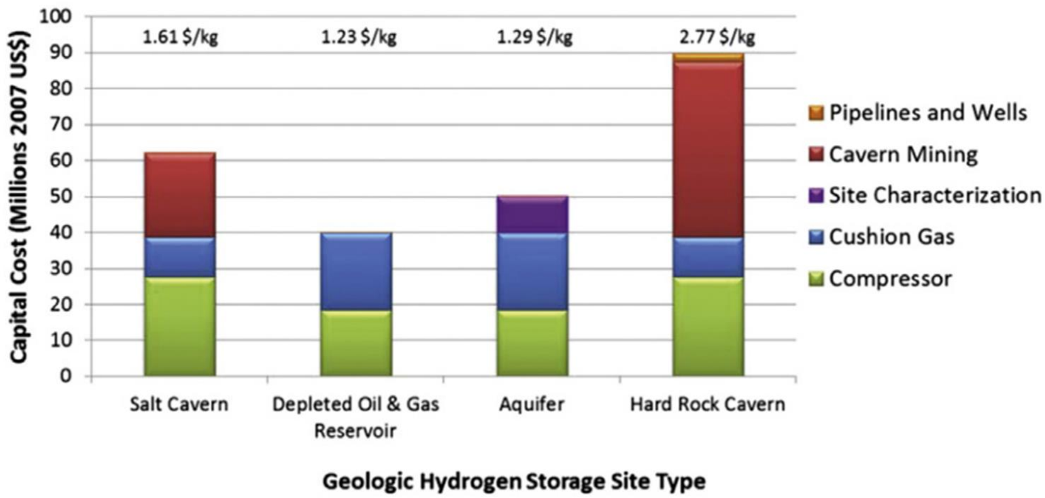

Figure 6. Cost Comparison of Geologic Storage Methods[27]

Challenges and Technical Barriers

Development Cost

The most significant barrier to the use of geologic storage for hydrogen is the high cost of field development and compression.

Cushion Gas Requirement

As with any large storage vessel, the cushion gas that remains in a geologic storage site represents a significant cost. Experience with natural gas suggests that cushion gas would amount to about 15% of the storage capacity. The amount needed is not well understood, however, and is highly dependent on characteristics of the specific structure.

Contamination Concerns

Little is known about the nature and extent of contamination introduced to hydrogen in geologic storage. It is not necessary to purify cavern-stored hydrogen today, as the hydrogen is used in industrial applications wherein high purities are not necessary. However, fuel cell applications demand hydrogen at a much higher purity; therefore, contamination needs to be quantified and purification strategies must be developed. Also, when a geologic storage site is first used, the area must be "flushed" of contaminants, and the volume of gas needed to accomplish this for hydrogen is unknown.

Leakage

Hydrogen losses and leakage during operation could also lead to significant cost. As with all storage mechanisms, geologic storage may suffer from hydrogen leakage through permeation. The amount likely to be lost to the surroundings is currently not known and will depend greatly on the particular geologic formation.

Effects of Pressure Cycling
There is an inadequate understanding of hydrogen storage in rock formations. The rock mass used may not be a continuous medium, and pressure cycling may cause unexpected behavior or cause hydrogen to react with specific materials in the cavern walls.

Geographical Limitations
Hydrogen geologic storage is further limited by geography, and the suitability of mined and natural caverns will depend on their size and proximity to hydrogen demand. **Error! Reference source not found.** shows potential geologic storage locations in the United States. While lined rock caverns (LRCs) can be constructed where other storage options are unavailable, cost of excavation in hard rock is a prohibitive factor.

Figure 7. Potential Geologic Storage Sites for Hydrogen in the United States[29]

9. Hydrogen Quality

Current Status

Hydrogen purity requirements are determined by the needs of the application. For example, refineries can utilize hydrogen at purities of 99.9%, while the electronics and chip manufacturing industries require "six nines" purity, i.e., 99.9999%. As purity demands increase, so does the cost of the hydrogen, given extra costs associated with the storage, transport, and testing necessary to maintain and monitor that grade of purity.

Current Fuel Cell Hydrogen Guidelines and Specification Efforts

After significant collaboration between industry, international standards agencies, the state of California, and research groups funded by the DOE, the Society of Automotive Engineers (SAE) published the standard "Fuel Quality Guideline for Fuel Cell Vehicles" (SAE J2719) as their specification for fuel-cell-grade hydrogen in 2011.[30] The state of California has adopted the SAE standard as its legal requirement for sale of hydrogen for FCEVs to consumers. The ASTM International Committee D03 on Gaseous Fuels has developed and published key sampling and testing methods for determination of contaminants in hydrogen for fuel cell electric vehicles. Hydrogen fueling stations in California today test their fuel against SAE J2719 requirements every few months.[31] There is, however, a need for in-line contaminant

[29] http://www.sciencedirect.com/science/article/pii/S0360319914021223

[30] https://energy.gov/sites/prod/files/2016/11/f34/fcto_h2_fuel_quality_specs_pem_fc_road_vehicles.pdf

[31] https://energy.gov/sites/prod/files/2015/04/f22/fcto_h2first_hydrogen_contaminant_detector_report_april2015.pdf

detection technologies that can be installed at stations to detect contaminants that are of greatest concern, either because of their likelihood or because of the damage they can cause to fuel cells. Such contaminants include water, carbon monoxide, sulfur, ammonia, and hydrocarbons.[31]

Purification of Hydrogen

The very stringent hydrogen quality requirements for FCEVs dictate that great care must be taken to mitigate contamination over the entire hydrogen supply chain. Contaminants can be introduced during hydrogen production, as well as at the fueling station; station equipment can emit particulates, especially during commissioning phases, as well as lubricating oil (e.g. in compressors).

Current commercial technologies for high-purity hydrogen include cryogenic liquefaction and sorption — typically pressure swing adsorption (PSA). If the hydrogen is supplied in liquid form, the hydrogen gas derived from that liquid hydrogen is absolutely pure, barring subsequent contamination. PSA is the most commonly deployed commercial technology for gas purification, and it is used for all large-scale commercial production. Refining and chemical operations commonly use metallic and nonmetallic membrane separation technologies to purify dilute hydrogen streams, and improved membrane separation is being investigated as a potentially lower-cost alternative to PSA.

Particular purification needs relevant to hydrogen delivery include:

- Removal of small amounts of impurities introduced between the production site and retail, known as polishing. The main concerns in this area are compressor lubricants (if lubricated compressors are used), contamination from geologic storage, and particulates. Ionic contaminants such as sodium or other cationic salts can arise from electrolytic production of hydrogen.
- There is currently some regional interest in the delivery of hydrogen and natural gas in the same pipeline followed by separation of hydrogen near the point of use. This concept is still at early stages of development, and it will require the development of cost-effective separation technologies for high concentrations of hydrogen.[32]
- There is interest worldwide in delivery of hydrogen via liquid carriers. Hydrogen that is recovered from carriers at station may have a greater risk of impurities. The separation technologies needed will depend on the specific carriers used.

Polishing entails removing small amounts of impurities or fuel cell poisons from hydrogen prior to final delivery. Polishing is accomplished via pressure swing adsorption (PSA) units today. Sorption-based purification requires the sorbent to be selective for the impurities so that hydrogen can flow through without any significant interactions. Any energy required to clean up the sorbent would be proportional to the concentration of impurities. Subsequent polishing particulate filters may also be needed.

Analytical Methodology and Sampling

Since 2003, researchers have made great progress in developing more sensitive sampling and testing methods for the determination of hydrogen purity and contaminants. Researchers have completed work and published standards on better gas chromatography, mass spectrometers, and other methods to detect trace levels of contaminants. Published standards include the Compressed Gas Association (CGA) G-5.3 Commodity Specification for Hydrogen and SAE J2719, Hydrogen Fuel Quality for Fuel Cell Vehicles. Currently, California regulations specify testing of dispensed hydrogen to SAE J2719 standards, but do does not specify any frequency. Research is currently underway to develop hydrogen contaminant detectors that can be installed at stations to sample for contaminants every time a vehicle is filled, and rapidly alert a station operators if fuel is at risk of being impure.

[32] http://www.nrel.gov/docs/fy13osti/51995.pdf

Challenges and Technical Barriers
In the near-term, it is unpractical to expect that an inline hydrogen contaminant detector will be able to sample all of the contaminants in the SAE J2719 standard per the specified accuracies. Detectors must be developed that can cost-effectively sample the contaminants of greatest concern, and rapidly alert station operators when impurities are present. The ability of currently available detector technologies to meet these performance requirements should also be established to support the early market while contaminant detectors with greater capabilities are being developed.[31]

10. Hydrogen Sensors

Current Status
A robust and safe hydrogen delivery infrastructure will likely require a means to detect hydrogen leaks. This will be important from both safety and economic perspectives. Odorants are required by regulation in today's urban natural gas distribution pipelines for commercial and residential use. However, odorants may be problematic for hydrogen because they would most likely need to be removed due to the stringent quality requirements for fuel cells, unless one could be developed that did not interfere with fuel cell performance. Hydrogen pipeline infrastructure, stationary storage, refueling sites, and any enclosed areas where hydrogen may be stored are all candidates for hydrogen detection sensors. Several different companies either have or are developing sensors for hydrogen detection.

Another relatively new area of technology development are sensors that monitor the mechanical integrity of structures such as pipelines and pressure vessels. Fiber optic sensors and other devices have been developed that can monitor time-dependent defects. Some of these defects include internal corrosion, external corrosion, stress corrosion cracking, pipe movement, pipe stress, and buckling strains due to pipeline slope instability, ground settling, currents acting on exposed pipelines in river and stream crossings, and third-party damage as a result of digging within the pipeline's right-of-way. This technology is particularly well adapted to composite structures, but it can also be applied to steel pipelines or vessels. Such technology might prove valuable for hydrogen delivery infrastructure and could complement leak detection. It might also prove valuable as an early detection approach that could avoid mechanical failures and significant hydrogen leakage.

11. Hydrogen Dispensers

Current Status
Retail hydrogen fueling stations dispense hydrogen into light duty fuel cell electric vehicles (FCEVs) at 875 bar, per the SAE J2601 protocol. Compliance with this protocol ensures that an empty FCEV tank can be safely and completely filled in 3-5 minutes. The J2601 protocol is programmed into dispensers, such that the dispensing pressure is determined by the ambient temperature and tank pressure. Fills can be performed both with and without communication with the FCEV tank (typically accomplished through fiber optics). When communication is achieved, the tank pressure is monitored throughout the fill, allowing for the pressure ramp rates (i.e., the rate of fueling) to be more dynamically controlled, and thereby enabling a more complete fill.[33]

The J2601 protocol can be programmed into hydrogen dispensers in two different ways: the lookup table method, and the MC method. Both methods have been derived based on thermodynamic studies of the impact that varying rates of dispensing at given pressures and temperatures have on the integrity of the

[33] *Reddi, K., et. al.*. "Impact of Hydrogen SAE J2601 Fueling Methods on Fueling Time of Light-Duty Fuel Cell Electric Vehicles". International Journal of Hydrogen Energy. In Press.

FCEV tank and completion of a hydrogen fill. The primary difference between the lookup table method and the MC method is that the MC method also monitors temperature at the outlet of the dispenser and adjusts the dispensing rate accordingly. This dynamic approach frequently enables a faster fill than is possible with the lookup table method, even when communication with the FCEV tank is achieved.[33]

Medium and heavy duty FCEVs are designed for dispensing at 350 bar, and they are currently filled at private stations. A standard for fueling of medium and heavy duty FCEVs (similar to SAE J2601), as well as test protocols to demonstrate compliance with this standard, must be developed for wider scale deployment of these vehicles.

The high capital costs associated with dispensing hydrogen to vehicles is a major barrier to widespread development of hydrogen refueling stations, particularly during the transition phase, when demand is low. A single 700-bar hydrogen nozzle currently costs about $7,000. In contrast, a gasoline dispensing nozzle costs $40-$110. A complete gasoline dispenser unit currently costs around $15,000, while a 700-bar hydrogen dispenser costs about $100,000. However, as the technology matures and more manufacturers enter the market, these costs are likely to decrease.

Dispensers today are also challenged by reliability and accuracy of their meters. Of the equipment at hydrogen fueling stations, dispensers account for the second highest share of maintenance hours;[34] many stations replace dispensing hoses once every few months[35]. Failures may include leaks of hydrogen at fittings, failures of valves, and failure of communication wire (fiber optics) due to rough handling of the dispenser by customers. Widespread commercialization of FCEVs will require meters for hydrogen dispensers to meet the acceptance tolerance outlined in the National Institute of Standards and Technology (NIST) Handbook 44: 1.5%; most U.S. states have accepted NIST Handbook 44 in whole or part for state motor vehicle fuel metrology requirements. Dispenser accuracy is challenged by the high pressures and low densities of hydrogen during fills, along with vibrations that other station equipment (e.g. compressors) often cause. The current industry standard, Coriolis mass flow meters, are only able to achieve accuracies of about 4% during hydrogen fills.[36]

To enable retail sales while higher accuracy meters are still being developed, the state of California has temporarily relaxed the metering accuracy requirement for retail stations until 2020. Thereafter, however, higher accuracy meters will be necessary for stations to continue selling hydrogen.

Challenges and Technical Barriers

High Cost

The high cost of components for 700 bar dispensing, in particular the nozzle and controls, and the low number of manufacturers are major factors behind the high current expense of hydrogen dispensers.

Materials and Design Requirements

Special materials and designs are required for dispensing hoses to withstand the high pressures and low temperatures of hydrogen dispensing.

Accurate Metering

Current technology does not allow metering of high-pressure (700 bar) hydrogen at the accuracy requirements specified in NIST Handbook 44 during hydrogen fills.

[34] http://www.nrel.gov/hydrogen/images/cdp-infr-21.jpg
[35] https://www.hydrogen.energy.gov/pdfs/review16/pd100_harrison_2016_o.pdf
[36] https://www.hydrogen.energy.gov/pdfs/review16/tv037_peters_2016_o.pdf

12. Mobile Fuelers

Current Status
Mobile fuelers have been used internationally for early market hydrogen delivery. They combine hydrogen storage with a dispenser in a portable unit that can fuel vehicles directly. Mobile fuelers have less capacity than tube trailers but typically provide a higher delivery pressure. While tube trailers are capable of hauling up to 800 kg of hydrogen at 250 bar (3,626 psi), current mobile fuelers have a typical capacity of about 100-110 kg at about 350 bar (5,000 psi) using steel tubes. Just as tubes are carried on a trailer, the mobile fueler is transported using a separate vehicle. The use of Type III or Type IV composite cylinders could increase the capacity of mobile fuelers. No utility requirements pertain to a mobile fueling site, but the site is required to meet the National Fire Protection Association (NFPA) 2: Hydrogen Technologies Code and local codes.

Challenges and Technical Barriers
Mobile fuelers are a short-term bridge technology and are not being investigated for further development by this technical team.

13. Terminals

Current Status
Hydrogen Terminals
The United States currently has eight liquid hydrogen production facilities and several gaseous hydrogen distribution terminals. Most of today's typical, bulk, gaseous hydrogen distribution terminals obtain their hydrogen supply through the vaporization of liquid hydrogen. Liquid-to-gas system terminals are more complex than their petroleum counterparts because they incorporate additional steps for vaporization and compression, and they must address issues of high-pressure and low-temperature storage. Future gaseous hydrogen distribution terminals may be supplied by liquid hydrogen delivery, pipelines, or on-site hydrogen generation systems. They may be required to load liquid hydrogen into cryogenic tankers or gaseous hydrogen into tube-trailers at pressures ranging from 250-500 bar (3,600-7,400 psi). If hydrogen carriers were to be used for hydrogen distribution, terminals would have to perform carrier regeneration/recharging and handling of spent carriers. Quality control will be extremely important in monitoring and maintaining the high purity specification required for hydrogen.

Terminals must have sufficient storage to be able to meet market demand with possible interruption of supply, both scheduled and unscheduled. Current liquid hydrogen terminals have 5-7 days of storage capacity in large cryogenic tanks. Gaseous hydrogen terminals are being built in California and on the East Coast to satisfy hydrogen demand in early FCEV markets via tube-trailer deliveries.

Tube trailer terminals use compressors to fill tube trailers from bulk storage. The cost of compressors is proportional to the pressure ratio of compression as well as the hydrogen throughput. Higher throughput compressors are costly, but they can load tube-trailers quickly. Terminals must optimize the trade-off between the cost of high throughput compressors and the cost associated with longer tube-trailer fill time. Currently, loading time of tube trailers is between 6-10 hours, depending on the compressor throughput, as well as the tube-trailer pressure and payload.

Despite these special considerations, hydrogen terminals will also bear many similarities to petroleum terminals. The terminals will have storage and loading racks (stanchions) and will be staffed with personnel that have the required skill sets to ensure safe and reliable operations. The terminal will be responsible for receipts, deliveries, and monitoring inventory to prevent stock-outs. The logistics of loading multiple trucks for multiple customers will also be similar.

Challenges and Technical Issues
Steel tank and sensor technologies required for terminals are reasonably mature. Remaining technical challenges include the development and verification of underground storage vessels to lower the footprint of tube trailer terminals, as well as economical high throughput compressors.

14. Other Refueling Site Issues

Footprint
Current hydrogen stations are mostly co-located with gasoline stations where space is usually at a premium. There are many factors that affect the station footprint. Bulk hydrogen off-loading at retail sites requires delivery trucks to maneuver and park on-site. With cryogenic liquid hydrogen, the hydrogen is off-loaded to storage at the refueling site. Truck delivery of gaseous storage may include off-loading of high-capacity tube trailers, or the tube trailers may be temporarily stationed at the site and utilized as the site storage until they are empty (this practice is known as "tube trailer swapping". The unloading of hydrogen gas or liquid involves hazards that must be addressed, and the refueling trucks must be kept separate from retail traffic. Tankers also must have adequate room for maneuvering. Depending on tanker size and retail site footprint, refueling truck access could pose special challenges for site design.

There are multiple designs for retail site storage. Some designs provide for banks of intermediate pressure storage at 160-500 bar (2,000-7,000 psi), as well as smaller, high-pressure tanks at 400-950 bar (6,000-14,000 psi). On-site storage tank placement includes locations in the refueling site behind protective barriers, underground, or even above-ground in a supported canopy. Each design offers advantages and drawbacks. Codes and standards vary by location and often require set-back distances or other protective barriers as specified by the National Fire Protection Association (NFPA) Guidelines.

Refueling Rate and Cooling Equipment
As discussed in the Dispenser section, while a vehicle is being refueled with compressed hydrogen, rapid buildup of energy raises the temperature in the vehicle hydrogen storage tank. The higher the filling pressure and the faster the fill, the more severe this problem becomes. For 350 bar fills (e.g., fuel cell buses), the vehicle tank is filled to pressures greater than 350 bar (due to hydrogen temperature increase during fill), so that when the hydrogen in the vehicle tank cools down to ambient temperature, the pressure in the tank settles at approximately 350 bar. In order to maintain the tank temperature below 85°C during a fast fill at 700 bar, refrigeration is required at the refueling station to chill the hydrogen and limit the rapid increase in temperature as the tank is filled. According to the SAE J2601 refueling protocol, precooling is required at -40°C for fast fills of light duty hydrogen vehicles (5 kg in 3 minutes); precooling to lower temperatures (e.g., -20°C and -30°C) requires much slower fills. At the required precooling temperature and desired fast fill rate, the required refrigeration cooling capacity at a fueling station is approximately 40 kW. One approach to reducing the chiller size required at a station is to also install a large thermal mass heat exchanger that can enable a smaller chiller to meet high instantaneous cooling demands.

The precooling equipment and associated heat exchanger add cost to the refueling site. Refrigeration capacity is driven by the required cooling temperature, as well as the time frame in which that temperature must be met. The SAE J2601 requires that the precooling temperature reach at least -33ºC within 30 seconds of the beginning of a fill (to ensure the fill is complete within 3-5 minutes). This constraint requires that the heat exchanger be kept at the desired precooling temperature all the time, such that it is always prepared to fill an FCEV. Continuous cooling of the heat exchanger (even when it is not in use) contributes to the station's energy consumption. Finally, the combination of high pressure and low temperature service conditions for fueling station equipment limits the materials that can be used, thereby adding the cost of hydrogen refueling.

An efficient and cost-effective chiller/heat exchanger system needs to be developed for 700 bar dispensing. Furthermore, the development of a less restrictive refueling protocol could reduce the cost of hydrogen fueling while still enabling fast vehicle fills.[37]

Safety

Safety is paramount for public acceptance of hydrogen, and refueling site engineering must comply with regional and national codes and standards. Hazard reviews, failure mode and effective analysis reviews, emergency response plans, catastrophic release plans, and training for retail site and bulk delivery staff are some of the safety practices that are being employed today.

Unlike bulk petroleum liquid off-loading, compressed gas or liquefied hydrogen bulk off-loading from a truck must incorporate gaseous or cryogenic liquid engineering controls to ensure that the process is performed safely without exceeding storage operational pressure and temperature limits. These technologies are relatively well known in the compressed gas and liquefied gas industry, but they are new to the refueling industry. Attention must also be given to the electrostatic properties of delivering hydrogen, a flammable but non-conducting gas. The prevention of electrostatic discharge by proper grounding and other engineering measures must be considered in refueling site equipment, including the dispenser and nozzle.

The Codes and Standards Technical Team (CSTT) of the U.S. DRIVE Partnership is working to close the remaining gaps in the codes and standards surrounding the various hydrogen infrastructure components. For more information, please see the CSTT Roadmap available through the U.S. DRIVE Partnership.[38] Research is ongoing to enhance the scientific basis for safety codes and standards that govern station design and operation. Another remaining key barrier is communication and education. Education is necessary for the general public to better understand fuel cell vehicle technology, code officials to be equipped to administer codes and standards at fueling stations, and first responders to be able to respond to safety incidents involving hydrogen.

Challenges and Technical Barriers

Emerging Market Challenges

One of the difficulties of encouraging market entry of hydrogen vehicles is the high cost of low-volume hydrogen production and refueling. The cost of delivered hydrogen in dollars per kilogram decreases as station capacity increases. Hydrogen fueling stations that have been deployed to date are approximately 100-300 kg/day in size, to meet near-term demand. As market penetration increases, the station size is expected to increase to 1,000 kg/day or greater in order to serve the same number of vehicles currently served by typical gasoline stations. Thus the stations that are entering the market first will have the disadvantage of producing hydrogen at a higher cost in the future due to their smaller size. This does not encourage potential early adopters to enter the market, because they will need to make costly upgrades to their stations in order to remain competitive as the market expands. A roll-out plan that addresses this investment risk for early adopters is needed.

[37] Reddi, K, et. al. "Impact of hydrogen SAE J2601 fueling methods on fueling time of light-duty fuel cell electric vehicles." International Journal of Hydrogen Energy. 2017, 42, 16675-16685.

[38] The *Codes and Standards Technical Team Roadmap* is available through the EERE Website: http://www.eere.energy.gov/vehiclesandfuels/about/partnerships/roadmaps-other_docs.html.

Component Technical Targets and Objectives

The U.S. DRIVE Partnership's overall premise is that hydrogen fuel cell electric vehicles need to be cost competitive with current vehicle and fuel options on a cost-per-mile-driven basis. Based on this premise, DOE analysis and methodology was used to arrive at an overall threshold cost goal for hydrogen delivery of <$2.00 per kilogram by 2020.[39]

FCTO is derived technical targets for individual components within the hydrogen delivery pathway to achieve the overall delivery cost target of <$2.00 per kilogram. These targets are documented in the Hydrogen Delivery Multi-year Research, Development, and Demonstration (MYRD&D) Plan, available here: https://energy.gov/sites/prod/files/2015/08/f25/fcto_myrdd_delivery.pdf

In the 2015 version of the Plan, targets were set such that the tube trailer pathway meets the $2.00/kg cost target by 2020, and all other pathways ultimately meet the $2.00/kg cost target in the future.

[39] K. Weil, S. Dillich, F. Joseck, and M. Ruth, "H_2 Production and Delivery Cost Apportionment," Program Record 12001 (Washington, DC: U.S. Department of Energy, December 14, 2012), http://www.hydrogen.energy.gov/pdfs/12001_h2_pd_cost_apportionment.pdf.

Appendix A: Acronyms and Abbreviations

CCS	carbon dioxide capture and sequestration
CSTT	Codes and Standards Technical Team
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EPRI	Electric Power Research Institute
FCEV	fuel cell electric vehicle
FRP	fiber reinforced polymer
ft	feet
FY	fiscal year
gal	gallon
GHG	greenhouse gas
h	hour
H_2	molecular hydrogen
H2I	Hawaii Hydrogen Initiative
HDSAM	Hydrogen Delivery Scenario Analysis Model
HDTT	Hydrogen Delivery Technical Team
ISO	International Organization for Standardization
kg	kilogram
km	kilometer
kW	kilowatt
kWh	kilowatt hour
L	liter
LNG	liquefied natural gas
LRC	lined rock cavern
m	meter
MJ	megajoule
MYRD&D	Fuel Cell Technologies Office Multi-Year Research, Development and Deployment Plan
NASA	National Aeronautics and Space Administration
NFPA	National Fire Protection Association
NH_3BH_3	ammonia borane
PEM	proton exchange membrane
PSA	pressure swing absorption
psi	pounds per square inch
psig	pounds per square inch gauge
R&D	research and development
ROW	right-of-way
rpm	revolutions per minute
TGC	Hawaii Gas Company
USCAR	United States Council for Automotive Research
U.S. DRIVE Partnership	United States Driving Research and Innovation for Vehicle efficiency and Energy sustainability
yr	year