Hydrogen Delivery Technology Roadmap

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FINAL

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1 Introduction

Hydrogen holds the long-term potential to solve two critical problems related to the energy infrastructure: U.S. dependence on foreign oil and U.S. emissions of greenhouse gases and pollutants. The U.S. transportation sector is almost completely reliant on petroleum, over half of which is currently imported, and tailpipe emissions remain one of the country's key air quality concerns. Fuel cell vehicles operating on hydrogen produced from domestically available resources – including renewable resources, coal with carbon sequestration, or nuclear energy – would dramatically decrease greenhouse gases and other emissions, and would reduce dependence on oil from politically volatile regions of the world. Clean, domestically-produced hydrogen could also be used to generate electricity in stationary fuel cells at power plants, further extending national energy and environmental benefits.

In the 2003 State of the Union address, President Bush announced a $1.2 billion Hydrogen Fuel Initiative to support the development of commercially viable, hydrogen-powered fuel cells. The Initiative recognizes hydrogen's potential to play a major role in America's future energy system and calls for increased federal funding for research and development (R&D). The goal is to enable industry to reach a commercialization decision by 2015 so that Americans will have the opportunity to purchase hydrogen-powered fuel cell vehicles in auto showrooms by 2020. The Initiative features parallel R&D tracks to develop (1) reliable, cost-effective, fuel cell vehicle and stationary power technologies and (2) the supporting *hydrogen production and delivery infrastructure*.

The FreedomCAR and Fuel Partnership is a key organization in this national R&D effort. The partnership is a collaborative effort among the U.S. Department of Energy (DOE), major energy companies (BP America, Chevron Corporation, ConocoPhillips, Exxon Mobil Corporation, and Shell Hydrogen LLC), and automobile manufacturers in the United States Council for Automotive Research or USCAR (DaimlerChrysler Corporation, Ford Motor Company, and General Motors Corporation). The Partnership is an effort to examine and advance the pre-competitive, high-risk research needed to develop the component and infrastructure technologies necessary to enable a full range of affordable cars and light trucks, and the fueling infrastructure for them that will reduce the dependence of the nation's personal transportation system on imported oil and minimize harmful vehicle emissions, without sacrificing freedom of mobility and freedom of vehicle choice. The Partnership strives to provide an historic opportunity to support the development of technologies that could potentially transform the U.S. personal transportation system to one that uses sustainable energy resources and produces minimal criteria or net carbon emissions on a life cycle or well-to-wheel basis. Fuel cell vehicles fueled by hydrogen, especially hydrogen derived from renewables, will make an important contribution toward achieving this vision.

The partners jointly conduct technology roadmapping, determine technical requirements, suggest research and development (R&D) priorities, and monitor the R&D activities necessary to achieve the Partnership's Research Goals. The Research Goals are used as the criteria against which the Partnership will assess specific research directions and the overall progress of its efforts. DOE, or DOE and USCAR, are responsible for determining the methodology and other assumptions that will be input into the methodology from which the Partnership's Research Goals will be derived. The projected prices of energy feedstock, energy products and other alternative energy sources, used to assess pathways for production of energy carriers such as hydrogen, are not provided by the Partnership but come from DOE and DOE identified third party sources. Furthermore, the original members of the FreedomCAR Partnership determined the following basic assumptions in 2002, prior to the inclusion of energy providers in the expanded FreedomCAR and Fuel Partnership:

1. All new vehicle and fuels options, including hydrogen, have to be cost-competitive with current vehicle and fuels options, including gasoline and diesel.
2. The performance goals determined from the above assumptions have to be pathway independent.

The FreedomCAR and Fuel Partnership has established Technical teams—consisting of scientists and engineers with technology-specific expertise from the USCAR member companies, energy partner companies, national laboratories, and DOE technology development managers as well as other Federal agencies if approved by the appropriate Operating Group/Groups. Technical teams have non-proprietary discussions and are responsible for developing R&D plans and roadmaps, reviewing research results, and evaluating the technical progress toward meeting the Partnership's Research Goals. The technical teams:

- Identify comprehensive technical goals related to improving the energy efficiency and cost of vehicles and/or to establishing a national hydrogen infrastructure;
- Assess overall appropriateness of technical goals on a systems and benchmarking basis;
- Identify data gaps and R&D needs;
- Identify technical expertise to undertake the technical effort;
- Establish technical milestones and timing;
- Monitor progress in the R&D programs; and
- Report progress toward goals at regular intervals to the FreedomCAR and Fuel Operations Groups and to external reviewers.

Successful commercialization of hydrogen fuel cell vehicles will depend upon the presence of a hydrogen delivery infrastructure that provides the same level of safety, convenience, and functionality as the existing gasoline delivery infrastructure. In addition, the hydrogen delivery infrastructure will need to support hydrogen's various production options. 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. Due to the higher capital investment required for centralized production, distributed production is expected to play a particularly important role during the transitional phase while hydrogen is gaining public acceptance. Hydrogen delivery systems must include not only transport and delivery from central production operations, but also the storage, compression, and dispensing operations, which are essential no matter where production takes place.

Hydrogen delivery pathways include gaseous hydrogen, cryogenic liquid hydrogen, and a spectrum of possible solid or liquid hydrogen carriers. Mixed pathways are also an option. These pathways contain numerous components such as compressors, pipelines, liquefiers, gaseous tube trailers, cryogenic liquid trucks, storage vessels, terminals, and dispensers.

The FreedomCAR and Fuel Partnership has organized a Hydrogen Delivery Technical (Tech) Team which developed this Hydrogen Delivery Roadmap. This roadmap identifies the technical goals and milestones for hydrogen delivery systems; surveys technologies that could help meet these goals; identifies the barriers to achieving the goals; and suggests research priorities and a strategy for conducting R&D in hydrogen delivery, including critical needs for the near term (*transition period*) versus the longer term (*fully-developed hydrogen economy*).

In order to meet the identified cost, efficiency, and reliability technical goals and milestones, the hydrogen delivery infrastructure will require a variety of improved and new technologies. While some of these advancements represent developmental improvements to existing technology, others will require radical new concepts and major breakthroughs to deliver the required performance and costs. The Delivery Tech Team recognizes that federal funding should be directed and focused on high-risk, breakthrough research efforts while the private sector needs to take on the tasks of developmental technology improvements. This research approach is delineated in the suggested Research Strategy, Section 8.

2 Goal and Objectives

Goal:

Hydrogen delivery technologies that enable the introduction and long-term viability of hydrogen as an energy carrier for transportation and stationary power.

Objectives:[1]

By **2007**, Criteria for a cost-effective and energy-efficient hydrogen delivery infrastructure for the introduction and long-term use of hydrogen for transportation and stationary power.

By **2010**, Cost of compression, storage, and dispensing at refueling stations and stationary power sites less than ***<$0.80 per kg*** of hydrogen.

By **2012**, Cost of hydrogen delivery from central and semi-central production facilities to the gate of refueling stations and other end users ***<$0.90 per kg*** of hydrogen.[2]

By **2015,** Cost of compression, storage, and dispensing at refueling stations and stationary power sites less than ***<$0.40 per kg*** of hydrogen.[2]

By **2017**, Cost of hydrogen delivery from the point of production to the point of use in vehicles or stationary power units ***<$1.00 per kg*** of hydrogen in total.[2]

[1] These objectives are derived from the FreedomCAR and Fuel Partnership overall premise that hydrogen fuel cell vehicles have 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 the the ultimate objective for hydrogen delivery to cost <$1.00 per kg of hydrogen. The intermediate timeframe objectives are milestones along the path to this ultimate objective to track progress. The dates of these objectives are for laboratory data verifying technology capable of achieving the goal when projected to a well-established hydrogen market for transportation.

[2] These cost targets assume a well-established hydrogen market demand for transportation, where greater than 50% of light-duty vehicles on the road are hydrogen-fueled. These costs are derived for typical cities of 200,000 to a million or more people.

3 Scope

Delivery is an essential component of any future hydrogen energy infrastructure. As shown in Figure 3-1, the 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 central or moderate sized semi-central production facilities as well as from small-scale, distributed production facilities located at vehicle refueling stations and often referred to as "forecourt" production facilities. The scope of the delivery infrastructure does *not* include technologies for hydrogen production or for hydrogen storage *on board* a fuel cell vehicle.

Central hydrogen production facilities are likely to use the full complement of delivery infrastructure functions, including transport. Distributed production facilities will need only the 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 3-2: Gaseous Delivery Pathway)
- liquid hydrogen delivery (Figure 3-3: Liquid Hydrogen Delivery Pathway)
- novel solid or liquid hydrogen carriers (Figure 3-4: Hydrogen Carrier Delivery Pathway)

The liquid and gas paths transport pure hydrogen in its molecular form (H_2) via truck, pipeline, rail, or barge. Liquid or gaseous truck and gas pipelines are the primary methods for delivering industrial hydrogen today. The carrier pathway uses materials that transport hydrogen in a form other than free H_2 molecules, such as liquid hydrocarbons, absorbents, metal hydrides, chemical hydrides, or other hydrogen-rich compounds. Ideal carrier materials would have simple, inexpensive treatment processes at a fueling station, or on-board a vehicle, to release H_2 for use in fuel cells. For organizational purposes, materials that require more elaborate processing or are commonly used as hydrogen feedstocks today (natural gas, ethanol, methanol, etc.) are not considered "carriers," and fall outside the purview of this roadmap.

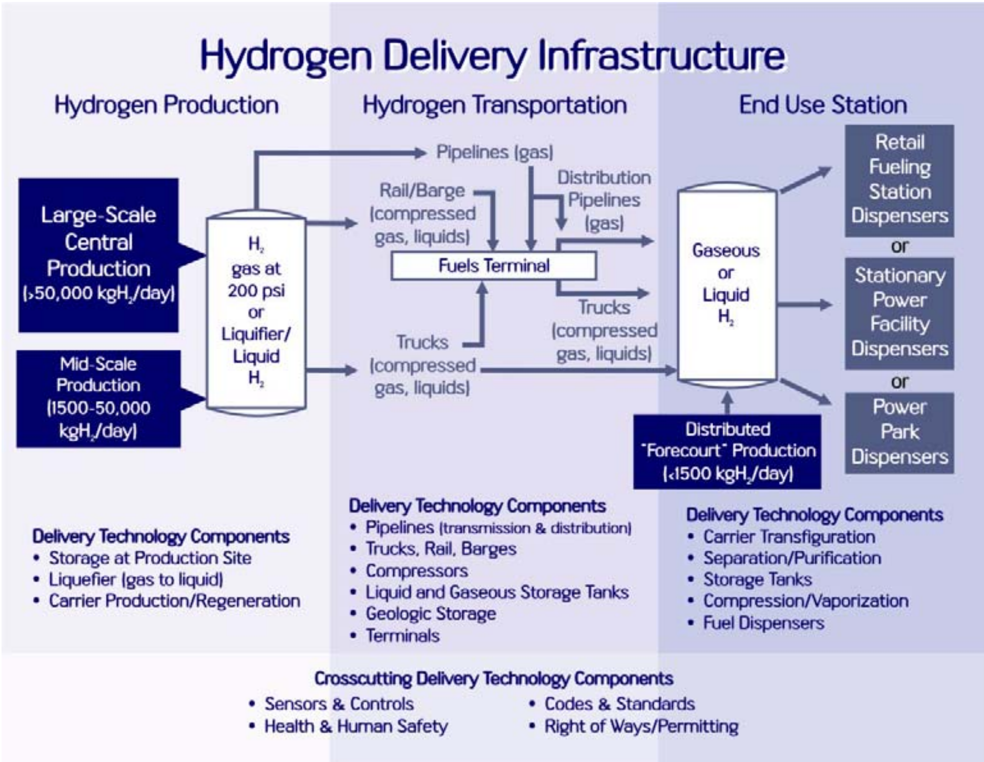


Figure 3-1: Hydrogen Delivery Scope

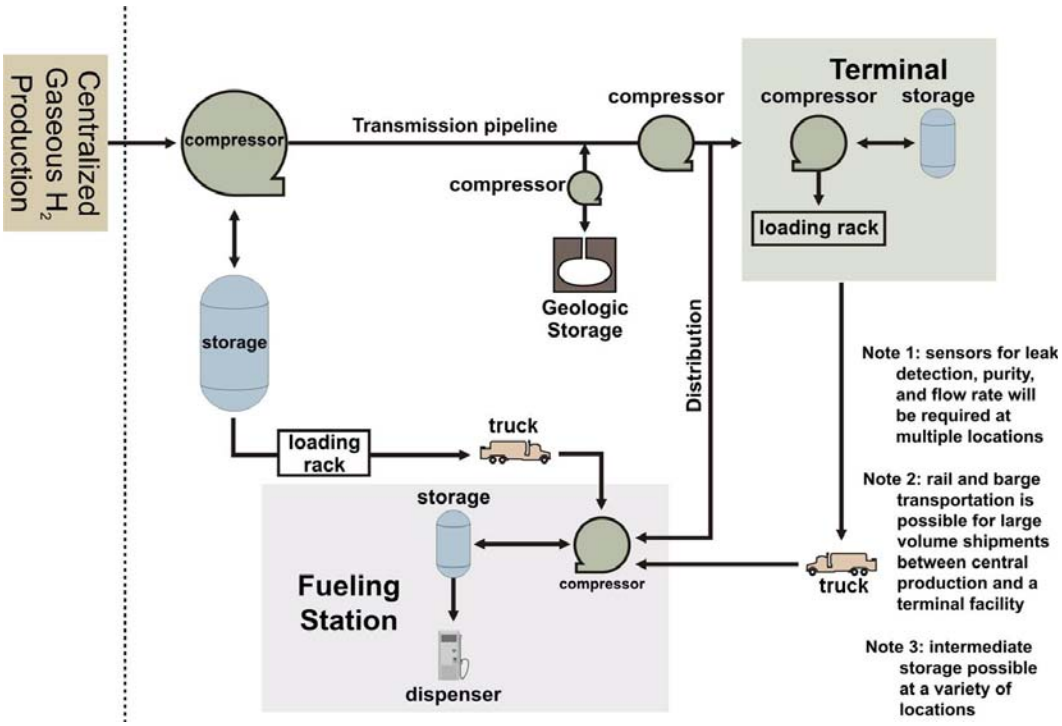


Figure 3-2: Gaseous Delivery Pathway

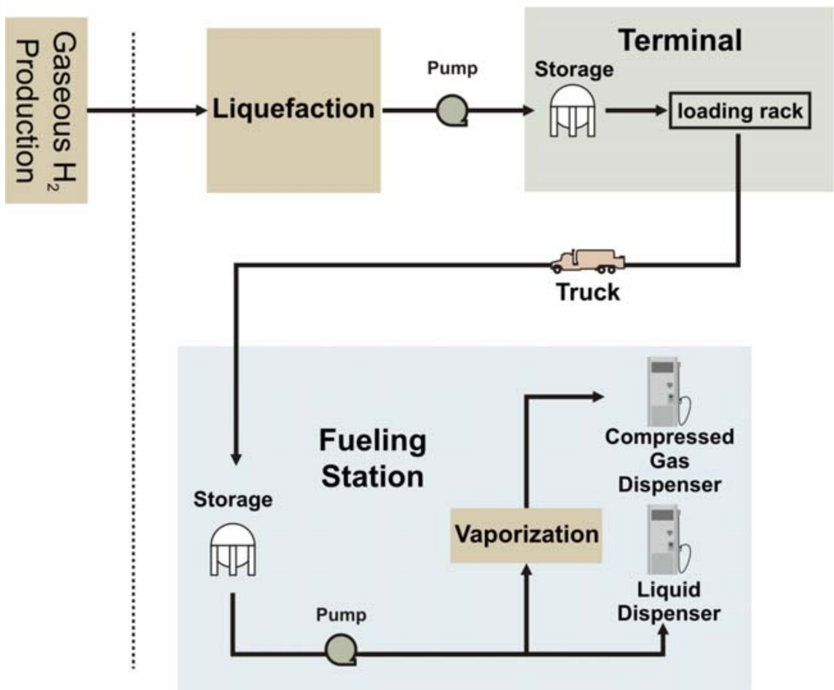


Figure 3-3: Liquid Hydrogen Delivery Pathway

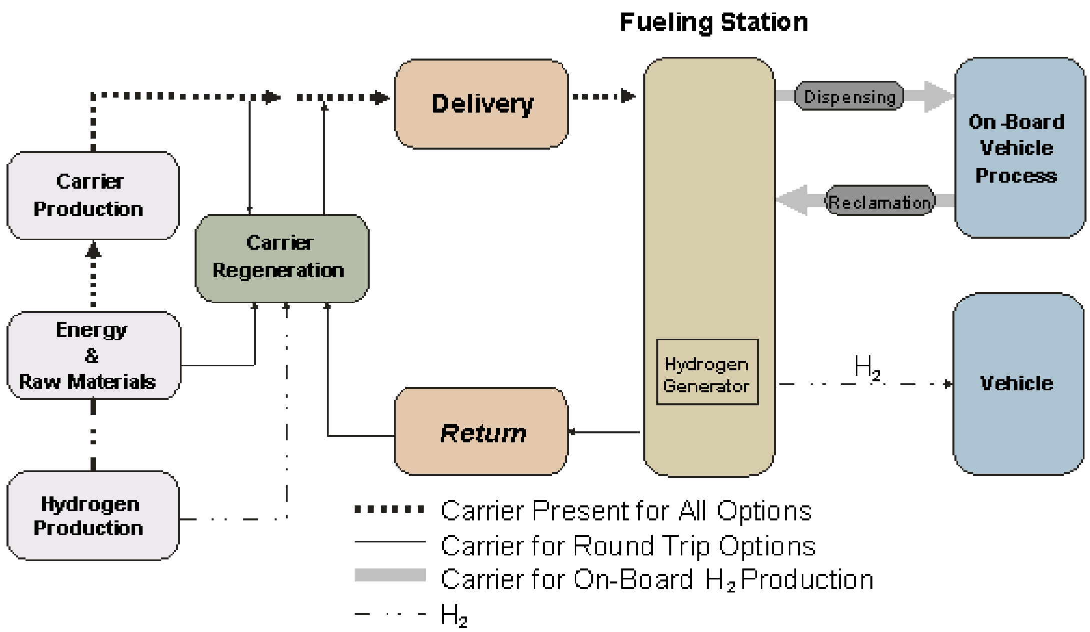


Figure 3-4: Hydrogen Carrier Delivery Pathway

Within the three primary delivery pathways, this roadmap addresses the specific technology components listed in Table 3-1.

Table 3-1: Hydrogen Delivery Infrastructure Components

• Pipelines	• Geologic Storage
• Compression	• Separation/Purification
• Liquefaction	• Dispensers
• Tube Trailers, Cryogenic Liquid Trucks, Rail Transport, Barges, and Ships	• Other Forecourt Operations
• Liquid and Gaseous Tanks	• Carriers and Carrier Charging and Discharging

The roadmap also addresses the need for delivery system analysis. 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. Such detailed analyses will help to evaluate tradeoffs among hydrogen delivery methods and build understanding of how advanced technologies could alter requirements for transitional and long-term systems. Results of these analyses will focus R&D on areas that show the greatest promise for contributing to a commercially viable hydrogen delivery infrastructure.

Transitioning from a gasoline-based to a hydrogen-based transportation fuel economy 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 as delivery technologies develop and improve. This roadmap identifies the R&D needed to support hydrogen delivery during the transition period *and* after the hydrogen economy has become fully developed. Support for both of these time periods will be critical to achieving a successful transition and then ensuring that advanced, lower-cost technologies will be available for the future. While the precise makeup of the infrastructure for each time frame remains unclear, various combinations or permutations of all three paths (gaseous, liquid, and novel solid or liquid hydrogen carriers) are likely to play a role. The mix 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, although the density of refueling stations may decrease somewhat from current levels. Alternatives that could change delivery technology needs, such as home refueling, are not addressed at this time.

4 Technology Status

4.1 Status of Alternative Delivery Pathways

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, liquid, and carrier-based. The technologies required to support these delivery pathways are at various stages of development, but must ultimately meet or exceed the level of safety, convenience, reliability, and energy efficiency provided by the existing gasoline delivery infrastructure.

Gaseous Hydrogen Pathway

As shown earlier, in Figure 3-2, the gaseous hydrogen delivery path 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, only about 1,000 km (630 miles) of dedicated hydrogen transmission pipelines serve the United States. In contrast, the natural gas and petroleum pipeline system is quite extensive in the continental United States, as shown in Table 4-1.

Table 4-1: Natural Gas and Petroleum Pipelines

Type	Approximate Distance	Typical Material Used	Diameter	Pressure
Natural Gas Transmission	580,000 km (360,000 miles)	steel	0.1-0.8 m (3.9-31.5 in)	40-70 bar (580-1,000 psi)
Natural Gas Distribution	1,600,000 km (1,000,000 miles)	steel/cast iron/ polyethylene	0.05-0.2 m (2.0-8.0 in)	0.03-10 bar (0.5-150 psi)
Crude Oil & Finished Petroleum Products	257,440 km (160,000 miles)	steel	up to 1.07 m (up to 42 in)	96.53 bar (1,400 psi)

More than nine million metric tons of gaseous hydrogen is produced in the United States annually, mostly for use as an industrial feedstock. The majority of this hydrogen is produced at or near petroleum refineries and ammonia plants—the main users of industrial hydrogen. The 630 miles of existing hydrogen pipelines serve regions with high concentrations of these industrial hydrogen users (primarily along the Gulf coast). The relatively small market for other uses of merchant hydrogen is served by gaseous hydrogen tube trailers or cryogenic liquid hydrogen trucks.

Gaseous hydrogen transmission by pipeline is currently the lowest-cost delivery option for large volumes of hydrogen. The high initial capital cost for this option, however, constitutes a major barrier to the construction of new hydrogen pipelines. These initial costs include materials, labor, right-of-way, and other expenses. Major technical barriers also restrict more widespread use of hydrogen pipelines. The chief concern is the potential for hydrogen to embrittle steels and welds. Other potential obstacles include the need for improved seal technology and techniques to control permeation and leakage in general. In addition, the need for lower cost, more reliable, and more durable hydrogen compression technology is vital.

Right-of-way (ROW) costs vary greatly by location. In some cases, it may be possible to use an existing ROW; in other cases, ROW costs may be prohibitive, or the ROW may be unattainable. Existing codes and standards for hydrogen pipelines are insufficient and must be further developed to ensure adequate safety and to simplify the process of obtaining permits. Improved leak detection or sensor technology will be essential to ensure safe operation and conformance to standards.

Use of existing natural gas pipelines for the delivery of pure hydrogen or mixtures of up to 20% hydrogen is a possibility, particularly in the transitive stages of a hydrogen economy. The existing natural gas pipeline infrastructure is heavily utilized, however, and natural gas consumption continues to grow. Some excess pipeline capacity exists during parts of the calendar year, but the capacity is fully utilized during peak summer and winter periods. Nonetheless, this option warrants further exploration for the transition period. Some studies suggest that <20% hydrogen mixed with natural gas may pose less of an embrittlement problem than pure hydrogen, but this remains to be verified. If mixtures of hydrogen and natural gas are to be considered for hydrogen delivery, a low-cost technology for hydrogen separation and purification will be needed.

The conversion of existing natural gas or petroleum pipelines to hydrogen use if and when they became available is also a possibility. Research into the suitability of these pipelines for hydrogen use relative to hydrogen embrittlement would need to be examined carefully. It might also be possible to develop coatings and in-situ coating technology to overcome hydrogen embrittlement issues to permit utilization of these pipelines.

Relatively small amounts of gaseous hydrogen can be transported short distances by high-pressure (182 bar or 2,640 psi) tube trailer. A modern high-pressure tube trailer is capable of transporting approximately 300-400 kg of hydrogen (in contrast to gasoline tank trucks, which can transport nearly 20 times the equivalent energy). Unfortunately, this method of hydrogen delivery is expensive for distributing hydrogen as a transportation fuel. There is the potential to develop higher pressure tube trailers (up to about 690 bar or 10,000 psi) that would be considerably more economical for hydrogen delivery. (See Section 4.2 for more information on tube trailers).

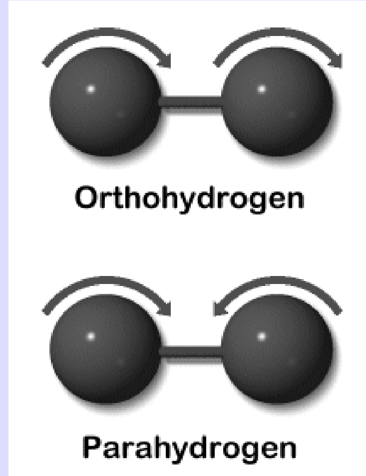
Liquid Hydrogen Pathway

The liquid delivery path for hydrogen includes a number of well-known and currently practiced elements. As shown in Figure 3-3: Liquid Hydrogen Delivery Pathway, the first step is liquefaction, which is a well-understood yet costly operation because of the large energy requirement and relatively low energy efficiencies. 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 cryogenic liquid hydrogen is then stored at the liquefaction plant in large, insulated tanks; dispensed to liquid delivery trucks; and transported over long distances to local distribution sites. At those sites, the liquid is stored and then vaporized to a high-pressure gaseous product for dispensing.

Today, the liquid hydrogen pathway is used almost exclusively by merchant vendors to lower the cost of delivering hydrogen to industrial sites located far from hydrogen pipelines. Over these longer distances, liquid trucking becomes more economical than gaseous trucking, because a liquid tanker truck can transport a tenfold larger mass of hydrogen than a gaseous tube trailer. The ten existing liquefaction plants in North America vary in size from 5,400 to 32,000 kg of hydrogen per day.

The energy cost for converting gaseous hydrogen to liquid is extremely high because it requires low temperatures and the need to change the *ortho* spin of hydrogen to *para* (see inset). The theoretical thermodynamic energy needed for hydrogen liquefaction represents 10% of the energy in the hydrogen (lower heating value or LHV). In addition, the current technology is not energy efficient, and the liquefaction step itself consumes one-third or more of the energy in the hydrogen.

Improved economies of scale could help lower the cost of the liquid pathway. Today's liquefaction units are relatively small, in keeping with the minimal demand for liquid hydrogen. Larger markets could justify the construction of larger-scale liquefaction units with better heat integration. New, large-scale liquefaction plants placed adjacent to hydrogen production facilities or power plants could expand opportunities for heat and energy integration between plants, which would further improve system economics. Breakthrough liquefaction technology such as magnetic or acoustic liquefaction might also be developed.



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

Hydrogen Carrier Pathway

Simply stated, carriers are a means of transporting, delivering, or storing hydrogen in any chemical state *other than* free hydrogen molecules. Potential carriers include liquid hydrocarbons, metal hydrides, sorbents, and ammonia.

Carriers would avoid many of the problems associated with transporting pure molecular hydrogen. If carriers could be delivered via existing and/or low-cost infrastructures, they could significantly lower hydrogen delivery costs. Reliance on this type of infrastructure suggests that the following characteristics would be desirable in potential carriers:

- Maintain liquid, solid, or slurry phase under favorable temperature and pressure conditions

- Provide high hydrogen capacity with respect to both volumetric and mass energy densities
- Offer simple, low-cost, highly energy-efficient transformation process for discharging hydrogen
- Support simple and low-energy process for recharging with hydrogen (in the case of two-way carriers)
- Are safe and environmentally benign

Materials such as methane and ethanol are not considered carriers because the chemistry required to process them is quite complex and expensive. These types of materials are classified as hydrogen *feedstocks* and are being investigated as potential sources of hydrogen, as discussed in the *Hydrogen Production Roadmap*.

Most potential carriers are two-way (round-trip) carriers. In a round-trip system, the hydrogen-rich carrier material is transported to the fueling station, dehydrogenated on location (or on a vehicle), and then returned to a central facility for recharging with hydrogen. A one-way carrier is a hydrogen-rich material that is transported to the refueling station and decomposed to yield hydrogen and an environmentally benign, disposable by-product (e.g., nitrogen, in the case of ammonia). One-way carriers offer a distinct advantage in that they do not have to be returned to a central facility for reprocessing. The by-product(s) of a one-way carrier, however, must pose no environmental issues and possess virtually no value.

Sample Hydrogen Carriers

A variety of potential carriers are under consideration for hydrogen delivery. Candidates currently include ammonia, liquid hydrocarbons, hydrates or clathrates, metal hydrides, nanostructures, and bricks or flowable powders.

Ammonia: Ammonia is a common chemical commodity produced from natural gas today. It is a potential one-way carrier that can be easily transported and simply transformed by cracking to nitrogen and hydrogen:

$$NH_3 \rightarrow N_2 + 3H_2$$

Hydrogenation/Dehydrogenation of Liquid Hydrocarbons: A liquid hydrocarbon carrier could be catalytically dehydrogenated at a refueling station or on a vehicle. The “dehydrided” liquid would then be returned to a central plant or terminal for rehydriding:

$$C_nH_{2n} \leftrightarrow C_nH_n + n/2\ H_2$$

Hydrates/Clathrates: A clathrate is a stable structure of water molecules formed around a light molecule (see Figure 4-1). The most common clathrates are methane hydrates, which hold large amounts of natural gas. Clathrates were recently discovered to form around hydrogen molecules, but these materials currently suffer from stability problems. Stable hydrogen clathrates would offer high hydrogen capacities and be easily decomposed into hydrogen and the clathrate components—typically, light hydrocarbons and/or water:

$$(H_2O)_n(CH_4)_m(H_2)_p \rightarrow nH_2O + mCH_4 + pH_2$$

Clathrates would likely be handled as slurries or solids to deliver hydrogen.

Figure 4-1: Clathrate Molecule

Metal Hydrides: Metal hydrides are well-known hydrogen carriers. They adsorb hydrogen at low pressures and can hold up to 6-7% hydrogen by weight. Generally, hydrides that hold the most hydrogen have high heats of adsorption, so they give off a great deal of heat when "charged" with hydrogen, and they require high temperatures to release the hydrogen.

As hydrogen carriers, metal hydrides work best in situations in which both the delivering and receiving systems are based on the same hydride. In this way, the heat generated by the receiver can be used to release hydrogen from the delivery system.

Nanostructures: Nanostructures, particularly single-walled carbon nanotubes (SWNTs), have attracted considerable attention as candidates for the on-board storage of hydrogen. Although mounting evidence indicates that they lack the adsorption capacity to serve in that role, they may still be useful in the hydrogen delivery infrastructure. They appear to have the ability to adsorb hydrogen and increase the storage capacity of vessels under moderate pressures or low temperatures.

Bricks or Flowable Powders: Although most of the discussion on carriers has focused on liquids, several of the materials mentioned above are solids. Stable, solid carriers might be delivered in many different ways. Slurries have been mentioned, but novel systems such as flowable powders or solid "bricks" might also be considered as potential delivery mechanisms. Such systems could flow one way or involve the exchange of spent material for fresh, "charged" carrier material.

Status

Although hydrogen carriers have not been thoroughly investigated for use in hydrogen delivery, much of the relevant science and technology has been studied in connection with other applications. Hydrogenation and dehydrogenation of hydrocarbons are fairly common industrial operations, but those operations generally require high amounts of energy and high temperatures to release the hydrogen. New materials must be developed to provide greater hydrogen capacity and optimized energetics. Metal hydrides are under intense study for use in storing hydrogen on-board vehicles. They may also be useful as carriers for hydrogen delivery, which imposes substantially different, and perhaps less challenging, performance requirements.

Carrier use will require the development of simple conversion technology and equipment. Dehydriding of the carrier must be straightforward and produce high-purity hydrogen. Although generic methods exist for many potential carriers, innovative technologies may be needed for new carriers, and standard technologies may need to be modified for use at retail sites. Similarly, chemistry and technologies for rehydriding must be adapted for commercial use.

Round-trip carriers will entail some additional complexity and costs, including the addition of storage at refueling stations or terminals. Reprocessing of a two-way carrier is an additional operating step, whether it is accomplished at terminals or more central locations. This approach would significantly increase the complexity of terminal operations compared to today's typical gasoline terminals.

Logistics for liquid or gaseous carrier delivery are generally assumed to be similar to those associated with today's liquid and gaseous fuel delivery systems, yet fuel delivery mechanisms may differ radically from those used today. Carriers might be solid slurries, flowable powders, or even solid materials ("bricks"). Unconventional carriers could radically alter the current retail model. For example, easily loadable solid carriers could be marketed on an exchange basis from almost any retail site, much like small propane cylinders are distributed today.

Another possible use within the delivery infrastructure of some of the novel carriers being researched would be for hydrogen storage alone. Solid carriers such as metal hydrides or nanostructures that could adsorb large amounts of hydrogen could be placed in storage vessels and potentially reduce the pressure needed to contain the same amount of hydrogen in their absence. Such a storage system might be less costly than the alternative higher pressure system depending on the cost and durability of the carrier.

4.2 Status of Technology Components

Gaseous Pipelines

Today, in the U.S there is a very extensive pipeline transmission and distribution infrastructure for natural gas as shown in Table 4-1. A complete hydrogen pipeline infrastructure would include both transmission and distribution to minimize overall hydrogen transport costs. Hydrogen for the key target light duty fuel cell vehicle market would ideally be delivered at high pressures to refueling sites. High pressures would be desirable to minimize compression needs for possible high pressure gas storage at refueling sites. It is also likely that vehicle refueling pressures will require high pressures. Current fuel cell vehicle prototypes are utilizing predominantly 350 bar (5,000 psi) hydrogen fuel tanks and beginning to experiment with 700 bar (10,000 psi) hydrogen fuel tanks. The long term fuel cell vehicle goal is to utilize novel solid or liquid hydrogen carriers to permit low pressure hydrogen fuel storage on the vehicle but even in this case, pressures on the order of 35 -150 bar (500- 2,000 psi) may be needed.

When one considers the costs for pipelines, including as a function of pressure, the costs of compression, the typical distance hydrogen will need to be transported from its point of production to its point of use, the demand volume, the pressure needs and costs of compression at refueling sites, and safety considerations, it is clear that there will be some semi-optimized hydrogen pipeline infrastructure operating pressure range. Safety considerations as well as national and local codes and standards will be an important factor. The natural gas pipeline infrastructure operating pressures have evolved based on similar considerations. The major difference is that the desirable use pressure of natural gas is typically relatively low (less than 1 bar) compared with hydrogen for fuel cell vehicle applications.

More analysis is needed to better understand the cost and other trade-offs for a hydrogen pipeline infrastructure before a semi-optimzed pressure range can be identified. Initial analysis efforts based on the H2A Delivery Components and Scenario Models[3] suggest that line sizes nominally similar to natural gas transmission and distribution line sizes with line pressures on the order of 35-150 bar (500-2,200 psi) may be advantageous relative to minimizing cost. Safety considerations, codes, standards and regulations might reduce the pressures allowed in urban distribution lines. Current urban regulations restrict natural gas distribution line pressures to 8.5 bar (125 psi) for non-industrial users. It currently appears desirable to develop sufficient information and technology to permit higher distribution line pressures for hydrogen.

Other considerations may also impact urban area hydrogen distribution pipeline infrastructure. Right of way availability or cost in urban areas may prove to be a limiting factor. Current natural gas regulations require the use of an odorant for leak detection for lines servicing non-industrial customers. Odorant technology might need to be developed for hydrogen. The odorant would need to be completely miscible with hydrogen and be easily removed or non-harmful to vehicle fuel cells. Sensor based leak detection methods might overcome this problem if proven acceptable to regulators. For these or other reasons, hydrogen transmission by pipeline to terminals coupled with hydrogen distribution by gaseous tube trailer or other trucking approach may be utilized. This would be analogous to how gasoline is delivered today where pipelines are used for transmission and trucks are used for distribution.

The United States currently has about 1,000 km (630 miles) of dedicated steel hydrogen transmission pipeline operating at constant line pressures covering the range of about 30-80 bar (500-1,200 psi). However, significant technical questions must be addressed prior to establishing a very large hydrogen pipeline infrastructure. The chief technical concern is hydrogen embrittlement of metallic pipelines and welds. In the simplest sense, hydrogen embrittlement describes the decrease in ductility or toughness of materials as a result of interaction with atomic hydrogen. Pipeline materials can be exposed to atomic hydrogen in several ways, on both sides of the pipeline. On the outside, atomic hydrogen may form as a result of natural corrosion processes or from electrochemical systems employed to protect against corrosion (cathodic protection). Although this can be an issue, it is currently addressed adequately by prudent cathodic protection management, coating selection and inspection.

On the inside of the pipeline, some molecular hydrogen under high pressure may dissociate. In the absence of significant stresses, hydrogen embrittlement may lead to blistering or internal cracking. When exposed to aggressive stress states associated with fabrication (e.g., welding) or service (e.g., high pressure and/or cyclic loading), hydrogen-embrittled materials may be susceptible to unstable crack growth leading to sudden, low-ductility failure (i.e., pipeline ruptures). While details of embrittlement depend on specific combinations of material and environment, a key factor in susceptibility is the microstructure of the material, including such properties as composition, crystal structure of the phase(s) present, and strength level. Welds are particularly susceptible to embrittlement due to the microstructure changes that can occur during the welding process. Special welding techniques enable the reduction of residual stress and thus reduce the risk of embrittlement. Such practices are in use for deepwater and sour gas pipelines. Hydrogen embrittlement could also be a concern if one wanted to try to use the existing natural gas infrastructure to transport a mixture of hydrogen and natural gas.

The hydrogen pipelines in the U.S. are constructed essentially exclusively of X42 or X52 steel grades. Theses grades of steel are of moderate strength compared to some newer higher strength

[3] www.hydrogen.energy.gov

steels now being used for new natural gas pipelines. The moderate strength requires the use of somewhat thicker walls for the current typical operating pressures of 35-70 bar (500-1,000 psi) but these steels have proven to not be prone to hydrogen embrittlement under current service conditions. The current service conditions include operating at constant line pressure. A large hydrogen pipeline infrastructure servicing hydrogen use as a major energy carrier is likely to be operated with significant pressure changes as is the current natural gas infrastructure. This is mostly due to the use of the infrastructure as storage by running the line pressures up in times of less demand and down in times of greater demand. There is laboratory data that suggests hydrogen embrittlement issues can be exacerbated by this type cyclic fatigue.

Important avenues for improving hydrogen pipeline performance and technology include; developing a more comprehensive understanding of hydrogen embrittlement to allow the design of improved and lower cost steel pipelines, investigating the use of coatings to prevent hydrogen embrittlement, improved welding technology, and the investigation of fiber reinforcement or other approach to plastic composite pipelines to replace the use of steel.

No commercial pipelines for liquid hydrogen currently exist. Without breakthrough technologies, liquid hydrogen delivery in pipelines is considered impractical and cost prohibitive. In addition to the high cost and low energy inefficiency of current liquefaction technologies, the engineering requirements for constructing of a pipeline with appropriate materials and codes are problematic. This option will not be addressed by this Delivery Roadmap.

Liquefaction

Liquefaction is an energy-intensive, multi-stage process that uses a series of refrigerants and compression/expansion loops to produce the extreme cold necessary to convert hydrogen from the gaseous to the liquid phase. Hydrogen has the lowest boiling point of any element except helium, and shifts from gas to liquid at -253°C (-423°F). Liquid hydrogen is odorless, transparent, and only one-fourteenth as dense as water. Figure 4-2: Hydrogen Liquefaction Plant 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.

As noted earlier, a hydrogen molecule can exist in two electron orbital spin states: *ortho* and *para*. Hydrogen in the liquid state must be close to 100% parahydrogen since orthohydrogen at low temperatures will naturally convert to parahydrogen, 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.

Liquefaction technology is currently employed only in small plants by merchant hydrogen vendors. The liquefaction process alone costs more than $1.00/kg and is only about 65% energy efficient. The primary barriers to using liquid hydrogen for delivery are the high cost and high energy use of liquefaction. Potential areas of improvement include:

- increasing the scale of the operation

- improving the heat and energy integration, (e.g., co-locating the liquefaction with hydrogen production or power production and integrating energy and heat across the operations)
- lowering the cost of heat exchange materials
- developing novel approaches to liquefaction such as magnetic or acoustic liquefaction

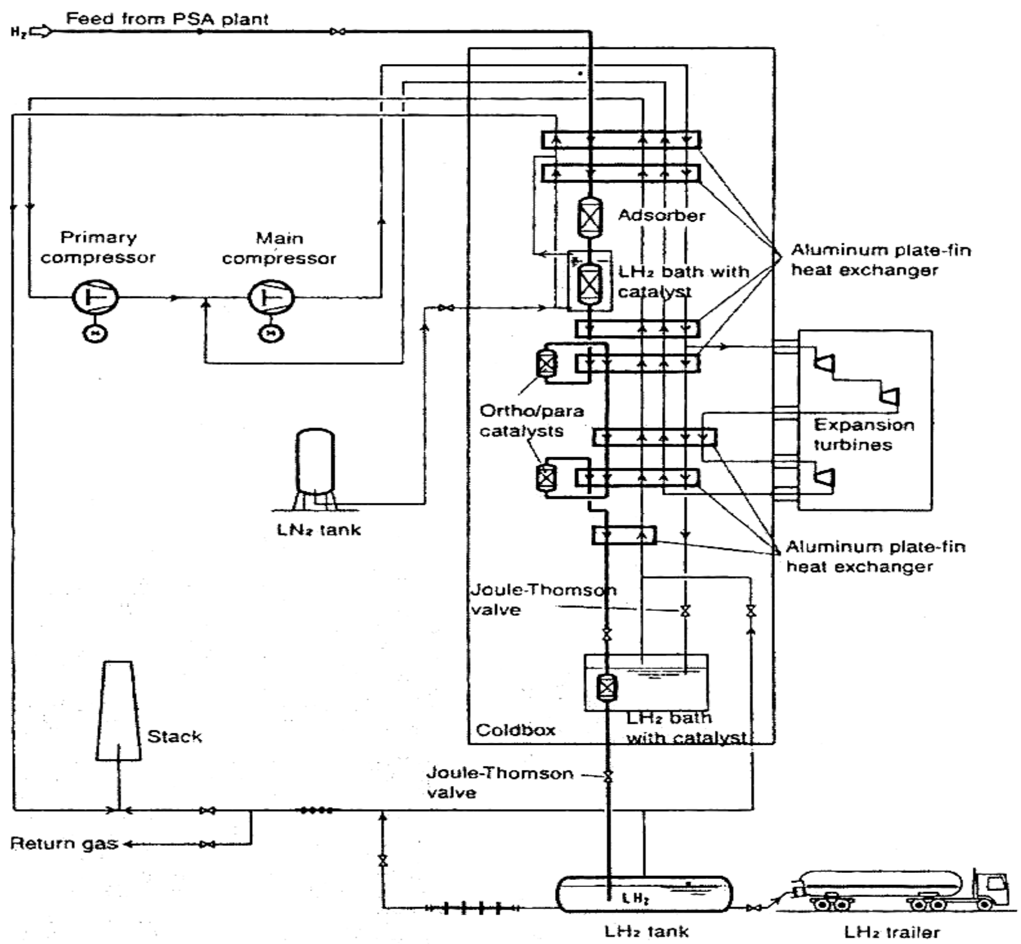


Figure 4-2: Hydrogen Liquefaction Plant

Compression and Cryogenic Liquid Hydrogen Pumps

Compression Status

As seen in Figures 3-1 through 3-4, compression is an integral aspect of hydrogen delivery. A compressor is a device that will accept a gas at a certain pressure and add force or energy such that the gas exits the device at a higher pressure. Figure 4-3 plots types of compressors typically used for natural gas service as a function of throughput and pressure. Displacement compressors used to compress hydrogen today are similar to those used for natural gas, but they incorporate different materials and some design changes.

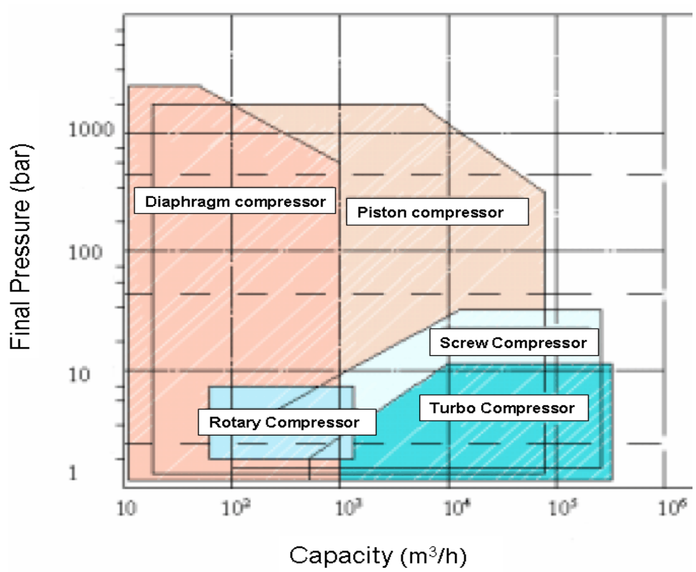


Figure 4-3: Operating Characteristics of Various Compressors

Most displacement compressors fall into two major categories: reciprocating and rotary. A reciprocating compressor uses pistons with a back-and-forth motion to compress the gas, and contains inlet and outlet check valves. The most common reciprocating compressors are piston-type and diaphragm compressors operating at high rpm. Problems with reciprocating compressors for hydrogen include poor reliability (due to many moving parts and other issues), contamination from lubricants, high noise levels, and high capital costs (arising from the need to install spares to improve reliability). Intensifiers, which are piston-type compressors of a different design that operate at low rpm, potentially address some of these problems associated with reciprocating compressors in hydrogen service.

Rotary compressors are displacement compressors that have rotating pumping elements such as gears, lobes, screws, vanes, or rollers, but do not contain check valves. Examples of this type include screws, rotary vanes, scrolls, and trochoidal ''Wankel'' compressors. Rotary compressors have not been used with hydrogen due to the extremely tight tolerances required to compress hydrogen, which is an extremely small molecule.

Centrifugal compressors are routinely used in natural gas service for pipeline transmission and to meet other needs involving high throughput and modest compression ratios. Unfortunately, centrifugal compressors do not currently work for hydrogen. Hydrogen's low molecular weight causes seal design problems including contamination, vibration, and rotor dynamics issues. To achieve high pressures, these compressors would require many stages operating at high rotational speeds, as well as special seals and tolerance standards. Improved materials and designs are needed.

The energy required to compress a gas is a logarithmic function of the pressure ratio. The incremental energy input becomes smaller as higher pressures are reached. Multi-stage compression and intercooling are used to achieve high pressures.

The state-of-the-art in gaseous hydrogen compression involves the use of reciprocating pistons for high-volume applications and pistons or diaphragms for small-volume applications. Advances have centered on the optimization of subsystems rather than the development of new approaches. Required compression ratios vary at different points in the delivery system. Transmission pipeline compression is a high-throughput application (50,000-2,000,000 kg/day) with a modest compression ratio, typically requiring raising the pressure from about 5 to about 70 bar (100 to 1,000 psi). Refueling stations have lower flow rates (50-3,000 kg/day) but much higher compression ratios. If high-pressure hydrogen tanks are used for on-board vehicle storage, the delivered hydrogen pressure requirements may be 350 to 700 bar (5,000-10,000 psi). If low-pressure on-board hydrogen carrier and storage technology is successfully developed, the delivery pressure may be only 7-100 bar (100-1,500 psi). Other throughput and compression ratios will be needed at other points in the delivery infrastructure (e.g., at terminals, for geologic storage, etc.).

Cryogenic Liquid Hydrogen Pumps

Liquid hydrogen is pressurized with cryogenic pumps in the liquid delivery pathway (see Figure 3-3: Liquid Hydrogen Delivery Pathway). Cryogenic pumps can achieve high pumping speeds and operate at relatively high discharge pressures. These pumps must operate under extremely 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. Capital investment on cryogenic pumps can be high owing to the materials and other specialized hardware it employs. The need to periodically recharge the pump and purge any frozen or trapped gases results in expensive process downtime.

Liquid and Gaseous Storage Tanks

High Pressure Vessels

Gaseous pressure vessels (tanks) are currently the most common means of storing hydrogen. Storage pressures may range from 135 bar (~2,000 psi) up to 1,000 bar (~15,000 psi). The practice of storing hydrogen under pressure has been in use for many years, and the procedure is similar to that for storing natural gas.

High pressure on-board vehicular tanks represent the state-of-the-art in gaseous hydrogen storage vessels. For on-board applications, high-pressure tanks rated at 700 bar (10,000 psi) have been demonstrated using carbon-fiber composites to ensure strength and durability, and work continues on reducing cost and optimizing material properties. Even at these high pressures, the energy density is low compared to an equivalent volume of gasoline; the hydrogen vessel contains 4.4 MJ/L at a pressure of 700 bar (10,000 psi), which is only 14% of the 31.6 MJ/L contained in gasoline. High pressure tanks can be characterized by their structural element (wall, shell) and their permeation barrier (liner). According to the European Integrated Hydrogen Project (EIHP), compressed hydrogen storage vessels are classified according to the categories shown in Table 4-2.

Table 4-2: Classification of Hydrogen Storage Vessels

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

The most common off-board stationary gaseous storage pressure vessels are Type I cylinders and tubes. Typical industrial hydrogen cylinders hold approximately 0.61 kg (1.35 lbs) of hydrogen at a pressure of 156 bar (2,265 psi) at 21°C (70°F), and have a volume of 54 L (1.9 ft^3). Cylinders may be used individually or can be joined by a manifold to extend storage volumes.

Stationary tube modules can be used to store larger quantities of hydrogen. The amount of hydrogen contained in each tube depends on its diameter, length, and pressure rating. Modules typically used are available in configurations of 3 to 18 tubes holding up to approximately 700 kg of hydrogen (150,000 scf) at 165 bar (2,400 psi). Higher pressure Type I or Type II stationary vessels are also available. The higher pressure allows more hydrogen to be stored per unit volume. However the cost of the vessel goes up due to the thicker walls required. For any particular application there will be an optimum balance of storage pressure, tank volume and footprint and capital cost. Stationary tubes have individual valves and safety devices, but are joined by a manifold so that hydrogen can be withdrawn from a single tube or from several tubes simultaneously.

Refueling site hydrogen storage is emerging as one of the major costs in hydrogen delivery infrastructure. Storage in other parts of the delivery infrastructure can also be costly. Based on the development of Type III and IV high pressure hydrogen tanks for on-board vehicles, research and development is underway to utilize this technology for higher pressure stationary hydrogen storage. With further development, it is believed that Type III or Type IV hydrogen vessels may be more cost effective than Type I or Type II vessels by storing hydrogen at higher pressures. This will depend on the cost reduction achievable for both carbon or alternative fibers, and the manufacturing process used to make these tanks. Some other composite tank technology might also be effective in this area in the future.

There is also a need to better understand the effects of high pressure charge/discharge cycles—as well as environmental effects (heat, moisture, etc.) on tank integrity. These factors could have a significant effect on useful tank lifetime and economics.

Cryo-Compressed Tanks

Researchers are also exploring use of high-pressure, cryogenic gaseous tanks to increase the amount of hydrogen that can be stored per unit volume and avoid the energy penalties associated with hydrogen liquefaction at 20 K (-253°C or -423°F). Compressed hydrogen gas at cryogenic temperatures is much denser than in regular compressed tanks at ambient temperatures. These new tanks would have the potential to store hydrogen at temperatures as low as 80 K (-193ºC or -315°F). This approach avoids the energy needed for the ortho-para conversion if the hydrogen is liquefied. This approach does require energy to cool the gas, however, and also requires proper vessel insulation to keep the gas cool. These high-pressure cryogenic tanks are currently capable of maintaining pressure at 200-400 bar (2,900-5,800 psi) and could be filled with either compressed hydrogen gas (ambient to cryogenic temperatures) or even liquid hydrogen. Alternatively one could consider using cold hydrogen gas tanks that would require less cooling. There may be some optimum combination of pressure and temperature over the range of 80-200°K (-193°C to -73°C).

Use of Solid Carriers for Hydrogen Tank Storage

Another concept that might reduce the cost and increase the volumetric efficiency of hydrogen storage is the use of solid carriers within the storage tank. This is identical to some of the approaches being researched for on-board vehicle hydrogen storage. For example a metal hydride or novel nanostructured absorbent such as carbon nanotubes, might be put inside the vessel to allow for higher density storage of hydrogen at lower pressures. Stationary off-board storage does not have the same weight and volume restrictions of on-board vehicle storage. Systems that might not meet the goals for on-board storage might be effective for stationary off-board storage vessels.

Finally one can imagine using some combination high pressure, cold gas, and a solid carrier that might result in a cost and volumetric efficient hydrogen stationary gas storage system.

Liquid Hydrogen Tanks

Cryogenic liquid hydrogen tanks are currently the most common way to store larger quantities of hydrogen because they provide a higher volumetric density than gas storage. Most current demonstration projects use liquid hydrogen, which is then converted to pressurized gaseous hydrogen for on-board storage.

Super-insulated pressure vessels are needed to store liquid hydrogen since temperatures close to 20 K (-253° C or -423° F) are required to maintain hydrogen as a liquid at typical vessel pressures (<5 bar or 73 psig). No matter how well-insulated, some hydrogen boil-off will occur, a phenomenon that is especially pronounced in small tanks which have relatively large surface-to-volume ratios. Typical evaporation values are presented in Table 4-3.

Table 4-3: 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	5,000,000	<0.06%

Liquid hydrogen tanks can be spherical or cylindrical. Larger tanks are usually spherical to reduce the surface area and thus decrease evaporative losses. Capacities range from 5,700 L to 95,000 L (1,500-25,000 gallons or 400-6,650 kg) of hydrogen.

Large vessels originally developed for the space program represent the state-of-the-art in liquid hydrogen tanks. NASA has been using and storing liquid hydrogen for over 30 years. At Cape Canaveral, NASA has a spherical tank with an outer diameter of 20 m (66 ft) and a storage volume of about 3,800 m^3 (1 million gallons) with a storage period of several years (evaporation rate is under 0.03% per day).

While underground liquid hydrogen storage would likely cost more than a traditional above-ground pressurized hydrogen system, the underground approach offers several advantages. Underground liquid storage reduces the above-ground footprint and also provides greater storage capacity per unit volume compared with gas storage. In addition, if the underground tank can maintain both high pressures and cryogenic temperatures, it provides the flexibility to store hydrogen in any of three different forms: liquid hydrogen, cryo-compressed hydrogen, and compressed hydrogen. A refueling station that uses an underground storage tank is also inherently safer. In addition—as is common at today's gasoline stations—portions of the area above the underground tanks could be used for business. This space-saving feature is particularly advantageous at urban refueling stations, where space is at a premium.

Development of a successful cryogenic storage tank design involves a multi-disciplinary approach. It will involve materials engineering (high strength metallic and composite materials) to achieve pressure containment and material integrity at low temperatures, thermal engineering (design and deployment of novel insulation materials), and small foot-print compression technology (to handle boil-off gas).

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

The majority (66%) of today's transportation fuels are transported to local terminals over a network of pipelines and then distributed locally to the points of use over the road in tanker trucks. The remainder of the long-distance fuel transportation is handled by trucking (4%), barges (28%), with the rest (2%) carried by rail. Distribution from terminals to filling stations is predominantly by fuel trucks.

Today, gaseous tube trailers and cryogenic liquid tank trucks are used to deliver hydrogen to end users not served by the limited hydrogen pipeline system that has been established for some industrial users. Rail, barge, and ship are also potential transport modes, but are not typically used today.

High-pressure cylinders and tube trailers at 182 bar (2,640 psi) are used for gaseous hydrogen distribution over distances of up to 320 km (200 miles). For greater distances, hydrogen is usually transported as a liquid in super-insulated, cryogenic, over-the-road trucks, and then vaporized for use at the customer site. High-pressure gaseous tube trailers can hold 300-400 kg of hydrogen, whereas cryogenic liquid trucks have a capacity of 3,000-4,000 kg of hydrogen.

Success in making hydrogen the "transportation fuel of the future" 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 pipeline network similar to that used for natural gas, other modes of transport may be needed in outlying areas or for hydrogen distribution in urban areas. Trucks, rail, and barge may also be more viable options for some remote areas of the country. Rail and barge offer higher load-carrying capacities and higher weight limits than over-the-road trailers. Trucks, rail, and barge may also play a key role during the transition phase, when hydrogen demand is low and economic incentives for building hydrogen pipelines are not yet in place.

Hydrogen is currently shipped overseas using tube skids or high-efficiency liquid storage skids in limited volumes. In the future, large-volume liquid hydrogen tankers (similar to LNG tankers) may be used to ship large volumes of hydrogen overseas.

Gaseous Hydrogen Tube Trailers

Current hydrogen tube trailers utilize Type I storage cylinders (see Liquid and Gaseous Storage Tanks directly above). Tube trailers are available in capacities of up to 300-400 kg of hydrogen utilizing nine tubes, each with a volume of 2.6 cubic meters (93 ft^3) at pressures of 182 bar (2,640 psi). Tube trailers are currently limited by Department of Transportations (DOT) regulations to pressures less than 200 bar. Further development and testing of Type II, III, or IV higher pressure vessels for hydrogen, along with the development of appropriate codes and standards, might allow their use for higher pressure hydrogen tube trailers. The other approaches being researched for more cost effective stationary gaseous hydrogen storage could also be utilized for gaseous tube trailers. This includes the use of cryo or cold gas, and even possibly the use of solid carriers in the tube vessels. With sufficient technology development to minimize capital cost, this could dramatically decrease the cost of hydrogen transport by tube trailer by significantly increasing the carrying capacity of the tube trailer.

Higher pressure, higher capacity tube trailers will have to overcome significant technical challenges. To maintain a high strength-to-weight ratio of the trailer, and ensure high toughness, the tubes will have to be manufactured from novel materials (high toughness alloys, non-metallic composite materials, etc.). The materials of construction should also address hydrogen outgassing resulting from hydrogen permeation at these higher pressures. Outgassing is generally a concern with non-metallic composites and less with metallic alloys.

Enhanced risk management methods must be employed to increase the system integrity. This might encompass novel leak detection and monitoring methods, newer methods to ascertain the structural integrity, pressure vessel design philosophies, and containment philosophies.

Hydrogen leak detection, in the absence of odorizers, is a challenge-currently, commercially available leak detection equipment are hand held. Ideally, an on line leak detector (direct or indirect measurement) 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, in addition to existing assessment methods would be in-situ strain monitoring, acoustic emission monitoring, etc. Codes and standards will need to address integrity management for the operating envelope.

Protective and control devices on the trailer must offer very high levels of reliability. In addition, as with current high pressure pipelines, a robust community awareness program will greatly complement the risk management strategies.

Liquid Hydrogen Tank Trucks

Cryogenic liquid hydrogen tank trucks can carry up to 4,000 kg of hydrogen. The cryogenic tank operates at atmospheric pressure. Some hydrogen boil-off can occur during transport despite the super-insulated design of these tankers. This could be on the order of 0.5%/day. Hydrogen boil-off also occurs when unloading the liquid hydrogen on delivery. This can be on the order of 5%.

A system could be installed to compress and recover the hydrogen boil-off during unloading if warranted. Currently, liquid hydrogen trucks are deliberately limited to at most three and preferably only one drop off delivery to minimize boil-off losses.

At least one industrial gas company is developing a liquid hydrogen truck equipped with its own cryogenic liquid pump and evaporator in order to discharge and deliver high pressure gaseous hydrogen. This system may be effective for smaller users of hydrogen such as small refueling stations during the early phases of the transition to the use of hydrogen fuel cell vehicles.

Geologic Storage

Depending on the geology of the area in question, geologic storage could develop into a relatively inexpensive method for the large-scale storage of hydrogen. Geologic storage is routinely used to provide seasonal and surge capacity for natural gas, and hydrogen will eventually require similar bulk storage space.

Town gas, which contains 20-60% hydrogen, has been successfully stored in caverns in France and Germany for many years. In Teeside, England, Imperial Chemical Industries (ICI) has stored hydrogen in a brine salt cavern for years. These facilities have operated without any known hydrogen leakage problems.

Many geological sites have the potential to store hydrogen, including salt caverns, mined caverns, natural caves, and aquifer structures. Salt caverns are hollow cavities inside a large underground salt layer. Most commonly, they are formed by drilling a hole into the salt structure and gradually dissolving the salt with fresh water or seawater, thus creating a geological void. Salt caverns provide secure containment for materials that do not dissolve salt (such as hydrogen).

ChevronPhillips operates a hydrogen storage cavern in cooperation with the ConocoPhillips' Sweeny, Texas refinery. The 580,000 m^3 cavern was solution mined in a mile-thick "salt pillow." The cavern is a cylinder roughly 50m across and 300m tall. The cavern roof is 850m (2,800 ft) below ground. Hydrogen is stored at approximately 135 atmospheres (2,000 psi). Hydrogen capacity is over 5,000 tonnes. The cavern pressure is normally maintained above 1000 psi to prevent cavern shrinkage due to creep closure. This gives an effective hydrogen storage capacity of around 2,500 tonnes. Hydrogen stored in the cavern is used by refinery hydrotreaters without purification. The cavern is connected to the refinery by a 15 mile 8" pipeline operated at a maximum pressure of 2,200 psi.

The suitability of mined and natural caverns for hydrogen storage will depend on their location and geological characteristics. Aquifers are porous geological formations, and many have a water-saturated top layer that creates a caprock. For underground storage, a good caprock serves to seal the structure and make it impermeable to the surroundings.

Most geological sites can handle pressures of 80 to 160 bar (1,200-2,300 psi). As with any large storage vessel, the cushion gas that remains in a geologic storage site represents a major issue in discharging hydrogen. 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.

Currently no public data exists describing contaminants introduced by geologic storage. ConocoPhillips uses cavern-stored hydrogen for petroleum hydrotreating without any purification. Fuel cell applications demand higher purity hydrogen, so cavern-related contamination needs to be quantified and purification strategies developed if needed.

Specially engineered rock caverns, referred to as lined rock caverns (LRC), present another storage option. The concept relies on the rock mass (primarily crystalline rock) as the structural element. Creating this artificial geological pressure vessel involves excavating a vertically cylindrical cavity 20-50 m (60-160 ft) in diameter and 50-115 m (160-380 ft) in length, building a 1 m (3 ft) thick reinforced concrete outer shell, and lining the cavity with 12 to 15 mm (0.5-0.6 in) of carbon steel. These latter two engineering elements serve two purposes: the first is to distribute the forces (stresses) from the engineered shell structure to the rock mass surrounding it, and the second is to provide an impermeable barrier to the gas being held. This geological pressure vessel, while containing natural gas, can sustain pressures in the range of 150-250 bar (2,200-3,600 psi). Technical studies and field tests of the technology, which has been under development in Sweden since 1987, indicate that the idea is technically sound and economically practical. In the United States, LRC technology has focused on two projects for storing natural gas: one near Atlanta, Georgia, with 148 million cubic meters (5.2 billion cubic feet (bcf)) of working gas capacity, and another near Boston, Massachusetts, with a capacity of 74 million m^3 (2.6 bcf).

One way to lower the construction and mining costs of an LRC is to refrigerate the geological pressure vessel. Refrigerated storage reduces the physical space required to store a given quantity and provides multiple, high-capacity peaking cycles per year (as compared to liquefied natural gas). Work is ongoing to evaluate the technical specifications and economics of a 140 million-cubic-meter (5 bcf) refrigerated natural gas mined cavern in the Baltimore/Washington metropolitan area. The design calls for a mined cavern of approximately 1 million cubic meters (0.037 bcf) at a depth of 900 meters (3,000 ft) with a temperature of -29° C (-20° F) and a maximum pressure of 86 bar (1,250 psig). The facility is estimated to cost about $173 million, or approximately $34.5 per million standard cubic feet of gas stored.

Hydrogen Purification and Quality

Hydrogen Quality

Hydrogen purity requirements are determined by the application needs. For example, much hydrogen today is made in refineries to supply hydrogen-consuming refining processes such as hydrotreating for sulfur removal. In this case, hydrogen purity can be lax with purities of 80-90% not uncommon. On the other hand, compressed gas companies today provide hydrogen to the electronics and chip manufacturing industries with “six nines” purity 99.9999%. Standard “pipeline grade” hydrogen purity is 99.95%. As purity demands increase, so does the cost of the hydrogen and also the cost of storage and transport to maintain that purity.

Current Fuel Cell Hydrogen Guidelines and Specification Efforts

For fuel cell vehicles, the information currently available indicates that very high purity hydrogen will be required. The final purity specifications will be dependent on future fuel cell technology development. There is a plethora of activity underway to develop interim guidelines and specifications for fuel cell grade hydrogen by several groups. As of December 2005, there is a FreedomCAR and Fuel Partnership task group formed to examine hydrogen purity needs, costs, and testing methodology. There is a fuel cell hydrogen purity guideline developed by the California Fuel Cell Partnership (CaFCP). SAE and ISO are finalizing specification guidelines for hydrogen purity for fuel cell vehicles. The Japanese standards organization JARI is active in this area. Finally, ASTM has also begun an effort to develop hydrogen for fuel cell standards under the ASTM D03 Gaseous Fuels Committee. ASTM is the fuel standards most in use for current fuels in the U.S.

Before hydrogen final specifications are developed, open literature data on the effects of various levels of contaminants on fuel cells should be reviewed by an all-inclusive group of stakeholders. Likewise cost data on the costs of purifying hydrogen must be reviewed. Until final or near-final designs for vehicle fuel cells are ready, it is premature to develop hydrogen fuel cell specifications, but interim guidelines may be more useful. (See Appendix A for the current and proposed hydrogen purity guidelines.)

Purification of Hydrogen

Hydrogen purification is normally part of the production process, yet the need for purification may also arise during the hydrogen delivery process. With the potentially very stringent hydrogen quality requirements for fuel cell vehicles, either great care must be taken that no contamination occurs in the delivery infrastructure or there may be a need for final purification just prior to dispensing at the refueling station and/or on the vehicle.

Current commercial technologies for high purity hydrogen gas include cryogenic liquefaction and sorption—typically pressure swing adsorption (PSA). If the hydrogen is liquefied, the hydrogen gas from that liquid hydrogen is absolutely pure. PSA is the most commonly deployed commercial technology and 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.

Further information on these separation and purification technologies can be found in the Hydrogen Production Roadmap. This document explores only the particular purification needs relevant to hydrogen delivery:

- Removal of small amounts of impurities introduced between the production site and retail site ("polishing"). The main concerns in this area are lubricants, if lubricated compressors are used, contamination from geologic storage, and particulates.
- Separation of hydrogen from natural gas in a hydrogen-natural gas mixture used for hydrogen delivery
- Separation of impurities produced upon production of hydrogen from a carrier

Polishing entails the removal of small amounts of impurities or fuel cell poisons from hydrogen prior to final delivery. In this application, PSA may offer advantages over membrane and cryogenic technologies in terms of speed, cost, and efficiency. Use of polymer and ceramic membranes, for example, causes some level of pressure drop, and the purified hydrogen may need to be recompressed at additional cost. Similarly, cryogenic liquefaction of all the hydrogen to remove trace impurities would be extremely costly. Although a sorption-based scheme appears most cost-effective at present, membrane technologies are constantly improving. In an effective sorption-based scheme, the sorbent should 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. Polishing particulate filters may also be needed. In any event, polishing purification would add to the hydrogen cost.

Separation of hydrogen-natural gas mixtures poses a different problem: large volumes of gas must be treated at very low cost. Hydrogen is likely to be present in concentrations of < 20% with methane accounting for the majority of the balance. PSA units, membrane separators, or other novel approaches could all potentially be useful in this separation process. The cost of this operation will likely dictate if this delivery option can be cost effective.

Requirements for purifying hydrogen after delivery via carrier will depend on which carrier system is used. For a carrier like ammonia, hydrogen would have to be separated from nitrogen and the unreacted ammonia removed. In the case of a hydrocarbon carrier, hydrocarbon vapors and secondary reaction products would need to be removed. In view of this high dependence on the carrier, research on post-carrier separations will be pursued only after the most promising carriers have been identified.

Analytical Methodology and Sampling

There is a strong need to develop more sensitive testing for hydrogen purity and contaminants. Work is needed on better GC, mass spectrometer, and other methods more sensitive than today's available techniques. ASTM Committee D03 is investigating these methods. As well as testing capability, there is also a need for a better sampling methodology for hydrogen purity determination. Sampling and purity conformance should be demonstrated at the point of hydrogen manufacture. Testing for hydrogen purity at the point of use at refueling sites could be cost prohibitive unless very fast, simple, and low cost sampling and test methodology is developed. Particulate sampling is especially challenging. Ideally retail site testing for hydrogen would be performed for a quality survey on an infrequent basis, since the hydrogen production plant is the primary site for delivering hydrogen purity to meet specifications.

Sensors

Hydrogen Sensors

A robust hydrogen delivery infrastructure will likely require a means to detect hydrogen leaks. This will be important from both a safety and economic perspective. Odorants are required by regulation in today's urban natural gas distribution pipelines. Odorants may be problematic for hydrogen since they would most likely need to be removed due to the stringent quality requirements for fuel cells unless one could be found that did not interfere with fuel cell performance. Hydrogen pipeline infrastructure, stationary storage, refueling sites, and in 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.

Mechanical Integrity Sensors

A 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 sensors have been developed which can monitor time-dependent defects including internal corrosion, external corrosion, stress corrosion cracking, pipe movement, pipe stress, and buckling strains due to pipeline slope instability, ground settling, and currents acting on exposed pipeline river and stream crossings. This technology is particularly well adapted to composite structures but can also be applied to steel pipelines or vessels. Such technology might prove very valuable for the hydrogen delivery infrastructure and could compliment leak detection. It might prove valuable as an early detection approach that could avoid mechanical failures and significant hydrogen leakage.

Generally, the biggest problem for natural gas pipelines over the years has been third party damage where contractors digging up the pipeline right of way to lay new pipeline or for other purposes, inadvertently damage the existing pipeline. This can result in very serious consequences. Mechanical integrity sensors could immediately detect the occurrence of such damage.

Hydrogen Dispensers

Dispensing both gaseous and liquid hydrogen to vehicles is in the early stages of development, and demonstration projects are under way. Europe and other parts of the world are examining the use of liquid hydrogen on board the vehicle, while the United States is focusing on gaseous hydrogen delivery. This roadmap deals primarily with gaseous dispensing. The issues that need to be addressed include costs, safety, nozzles, pressures, expansion, materials of construction, metering, units of sale, and carrier exchange.

The pressure of the delivered hydrogen will be dictated by the available on-board storage system and the desired mileage of the vehicle between fill-ups. Currently, gaseous hydrogen is being dispensed to vehicles with a final fill pressure at ambient temperature of 350 bar (5,000 psi). Development of 700 bar fills is underway. Research is being carried out to develop new on-board vehicle storage technology that would have a very high hydrogen storage density at lower pressures (<20 bar).

Few vendors currently offer the sophisticated technology for compressed hydrogen dispensers, and costs are high compared to gasoline dispensers. Expanded demonstration and pilot programs sponsored by the DOE in partnership with industry should spur efficiency improvements in the technology and help lower costs associated with hydrogen gas/liquid delivery via dispensers. The long-term target is for self-refueling, which will require a high level of safety and incorporate engineering controls and education of the public.

A single hydrogen nozzle currently costs about $4,000. In contrast, a gasoline dispensing nozzle costs $40 to $110. A complete gasoline dispenser unit currently costs less than $15,000, while a hydrogen dispenser costs many times more. 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. As the technology matures and more manufacturers enter the market, however, these costs are likely to decrease.

Hydrogen, particularly high-pressure hydrogen, presents safety concerns that differ from those of gasoline and must be addressed by engineering controls to assure safe delivery. These controls involve fail-safe, leak-proof connectors between the dispenser nozzle and vehicle fill port. The ease with which hydrogen can ignite mandates zero leakage from the equipment.

The few sites that now deliver compressed hydrogen have experienced persistent problems with nozzle leakage. Analysis of the problem points to corrosion of components from moisture and abrasion of the high-pressure seals by external dirt particulates. Leakage of hydrogen involves significant safety issues, particularly for untrained refuelers at the forecourt. An engineering solution is also needed to prevent inadvertent discharge of the nozzle when it is not coupled to the vehicle. Inadvertent discharge has resulted in a high-pressure hydrogen release or "pop" that could startle a customer.

Development of dispenser technology will also require stakeholders to reach a consensus on the style of vehicle and dispenser connectors. To avoid over- or under-filling the vehicle hydrogen tank, it must somehow "communicate" with the dispenser. While a vehicle is being refueled with compressed hydrogen, a heating effect occurs that raises the temperature in the vehicle hydrogen storage tank. The higher the filling pressure, the more severe this problem becomes. This is discussed in more detail in the Other Forecourt Issues section.

Equipment for handling both liquid and high-pressure hydrogen involves expensive, robust materials of construction. Development of low-cost, reliable materials of construction for hydrogen dispensing equipment is a key challenge.

Reliable and accurate metering of the dispensed hydrogen is another important technology needed for retail vehicle refueling with hydrogen. Metering of cryogenic liquid hydrogen involves electronic or mechanical mechanisms that work under conditions of extreme cold. Likewise, metering of high-pressure hydrogen will require mechanisms that perform under extreme pressure conditions and very high gas flow rates.

Finally, the hydrogen refueling industry and federal and state governments need to decide upon the unit of sale for refueling vehicles with hydrogen. Options include using the energy equivalent to gasoline, or absolute units such as dollars per liter, per pound, or per kilo.

As mentioned, one alternative to compressed hydrogen is a novel hydrogen "carrier." Carriers might enable novel refueling paradigms, such as a hydrogen-containing "brick" or granular solid absorbent that can be exchanged at the refueling site. Technology would then be needed to support the quick, convenient exchange of "spent" bricks/absorbent for "full" bricks/absorbent. Design of this exchange equipment at the refueling site depends heavily on the characteristics of the chosen carrier.

Mobile Fuelers

Mobile fuelers are an option being explored for hydrogen delivery during the very early part of the transition. Mobile fuelers combine hydrogen storage with a dispenser in a portable unit that can fuel vehicles directly. A mobile fueler has less capacity than tube trailers, but typically provides a higher delivery pressure. While tube trailers are capable of hauling 300-400 kg of hydrogen at 182 bar (2,460 psi), current mobile fuelers have a typical capacity of 110 kg at 350 bar (5,000 psi). Just as tubes are carried on a trailer, the mobile fueler is transported using a separate vehicle. A smaller size can also be towed using a pickup truck instead of a tractor trailer. This smaller unit can supply 60 kg (130 lb) at 350 bar (5,000 psi). No utility requirements pertain to a mobile fueling site, but the site is required to meet the NFPA 50A Standard for Gaseous Hydrogen Systems at Consumer Sites and local codes.

Terminals

Petroleum

The United States has approximately 132 operating refineries and 1,300 petroleum product terminals. These facilities supply petroleum products to more than 167,000 retail service stations, truck stops, and marinas. Not counted in these statistics are the distributor bulk storage and non-retail fleet locations, such as rental companies and schools. As shown in Figure 4-4 on the next page, the number of retail stations has dropped by 19% in the last 12 years, and the number of refineries and terminals has also declined significantly. In addition, ownership of retail stations and terminals has shifted significantly from major oil companies toward third parties.

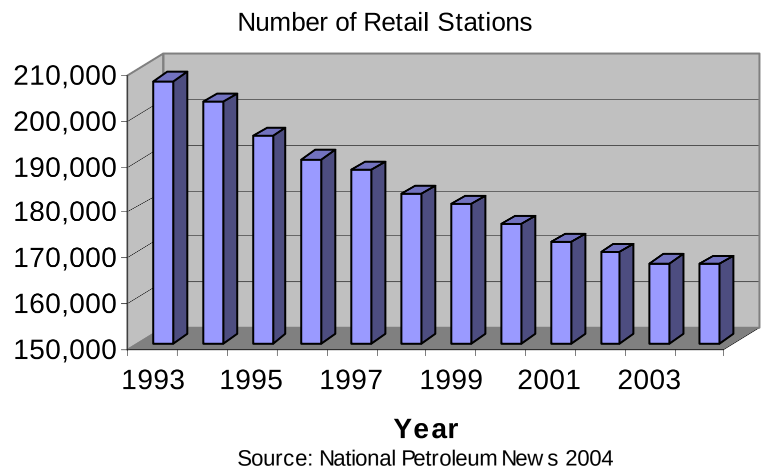


Figure 4-4: Number of Retail Stations Over Time

Terminaling costs can range from 10-25% of the transportation cost of gasoline, about 0.1 to 0.3 cents per liter (0.4-1.2 cents/gal) from the refinery to the retail station. Since 68% of domestic petroleum shipments are delivered via pipeline and 27% by water, the majority of the terminals are connected to pipelines and many have docks or both. As shown in Table 4-4, terminals range widely in size, depending on the retail network they serve.

Table 4-4: Terminal Statistics

Number of Tanks	2-25
Tank Sizes	<1,000 - 150,000 bbls (barrels) <160 - 24,000 m^3
Typical Tank Sizes	20,000 - 60,000 bbls 3,200 - 10,000 m^3
Number of Products	1-12
Number of Personnel	2-20

Logistical hubs serve as gateways for regional supply and play an important role in balancing supply and demand. A logistical hub is characterized by interconnections of many pipelines to each other, and often to other modes of transport such as tankers, barges, and rail. These interconnections allow supply to move from system to system across counties, states, and regions in a hub-to-hub progression. These hubs, such as Pasadena, Texas, and New York Harbor, are also characterized by their substantial storage capacity. The storage and transportation options enhance supply opportunities and increase supply flexibility, both of which are essential for an efficient and cost-competitive market. Storage and transportation options at hubs also allow market participants to adjust their supply and demand between hubs to restore balance.

Natural Gas

Post-production natural gas is most commonly stored in one of three types of pressurized geologic underground facilities: 1) depleted reservoirs in oil and/or gas fields, 2) aquifers, or 3) salt caverns. Abandoned mines have also been used in the past, and hard-rock caverns are undergoing evaluation for commercial storage. As of 2003, approximately 407 storage facilities were located in the lower 48 states. The approximately 38 aquifers were primarily in the Illinois/Indiana/Iowa area, while the 29 salt cavern facilities were along the Gulf Coast. The 340 depleted reservoirs were spread across several states, but were concentrated in the western Pennsylvania/Ohio/West Virginia/New York areas. Many areas, such as New England, the south Atlantic, the Dakotas, and Arizona/Nevada, have no storage at all. The suitability of a location is dependent on its physical characteristics (porosity, permeability) and economics (site costs, deliverability rate, cycling capability). Capacities are shown in Table 4-5 (from the EIA).

Table 4-5: Current Natural Gas Storage Sites

Type of Storage	Number	Total Capacity	Average Capacity
Salt Caverns	29	6.4×10^9 m^3 (226 bcf)	0.22×10^9 m^3 (7.8 bcf)
Aquifers	38	35×10^9 m^3 (1,234 bcf)	0.92×10^9 m^3 (32.5 bcf)
Depleted Fields	340	219×10^9 m^3 (7,747 bcf)	0.56×10^9 m^3 (19.8 bcf)
Total	407	260×10^9 m^3 (9,207 bcf)	0.57×10^9 m^3 (20.2 bcf)

Hydrogen

The United States currently has 40 gaseous hydrogen distribution terminals, and there are nine liquid hydrogen production facilities in North America. The United States also has 118 captive hydrogen producers. In addition to serving the industrial sector, all of these facilities could (and some do) distribute gaseous hydrogen.

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 since they incorporate additional steps for vaporization and compression and must address issues of higher-pressure and lower-temperature storage. Future gaseous hydrogen distribution terminals may also be supplied by a pipeline or on-site generation systems. If hydrogen carriers were to be used for hydrogen distribution, terminals may perform carrier regeneration/recharging and handling of spent carriers. Quality control, which is getting more stringent at petroleum terminals, will be extremely important in monitoring and maintaining the high-purity specification required for hydrogen.

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 be similar, along with the back-office business of custody transfers, truck tickets, and other paperwork.

Other Forecourt Issues

Cooling Equipment

The pressure of the delivered hydrogen at the dispenser will be dictated by the available on-board storage system and the desired mileage of the vehicle between fill-ups. Currently, gaseous hydrogen is being dispensed to vehicles with a final fill pressure at ambient temperature of 350 bar (5,000 psi). Development of 700 bar fills is underway. Research is being carried out to develop new on-board vehicle storage technology that would have a very high hydrogen storage density at lower pressures (<20 bar). This technology might not be ready for the transition to hydrogen but is targeted to be commercialized for full penetration of hydrogen fuel cell vehicles in the transportation market. Thus equipment development and other issues for refueling stations need to cover this entire range of dispensing pressures.

As discussed in the Dispenser section, while a vehicle is being refueled with compressed hydrogen, a heating effect occurs that raises the temperature in the vehicle hydrogen storage tank. The higher the filling pressure, the more severe this problem becomes. For 350 bar fills, vehicle tanks are being filled to somewhat higher pressures so that when the hydrogen in the vehicle tank cools down, the final pressure will be 350 bar. The 700 bar filling technology is still under development. In this case it appears that the hydrogen being delivered may need to be chilled to be able to fill the vehicle quickly (<5 min.) without exceeding the temperature limitation of the composite tanks being used on the vehicles. This may require equipment at the refueling station to chill the hydrogen and possibly to store the chilled hydrogen. The temperature required is not yet determined but might be as low as -30^{o}C or somewhat lower. This will add cost to hydrogen delivery and cost effective technology needs to be developed for this.

Cooled hydrogen or some other cooling system may also be required for two other on-board vehicle hydrogen storage systems being researched, cryo-compressed gas storage and the use of metal hydrides. Cryo-compressed on-board storage is looking at temperatures as low as 70^{o}K but a range of temperatures up to -100^{o}C is being considered. Storing cold compressed hydrogen gas on the vehicle increases its density and thus the vehicle range. Metal hydride on-board storage technology releases a great deal of heat as the hydrogen is absorbed onto the metal hydride. This heat would need to be removed to maintain the temperature of the tank and other materials used in the on-board storage system within their safe operating temperature limits. The exact refueling site cooling equipment required for these technologies can not be determined until these technologies are better defined.

Two-Way Carrier Systems

Another on-board vehicle storage approach being researched is liquid chemical systems where hydrogen is released as needed on the vehicle and the spent liquid is returned to a central or terminal operation to be regenerated. This would require space and cost at the refueling site for storage and pumping of the spent liquid. An example of this approach is liquid hydrocarbons discussed in Section 4.1 under the Carrier Pathway. Other two-way chemical storage technologies are also being researched.

Final Hydrogen Purification/Polishing

The earlier **Hydrogen Purification and Quality section** of this Roadmap mentioned the possibility of needing final purification at the retail site. If needed, such purification would have to be engineered to give long term reliable and cost-effective operation. If such purification/filtration processes are needed, research into low-cost reliable systems is needed.

Safety

Safety is paramount for public acceptance of hydrogen, and forecourt engineering must employ the safest design that is cost-effective. For compressed hydrogen, liquefied hydrogen, or a hydrogen carrier, key safety issues remain to be addressed. Hydrogen has a wide range of flammability in air and a low ignition energy threshold; therefore, forecourt hydrogen handling equipment must be leak-proof. The U.S. DOE Hydrogen Technical Team on Codes and Standards and Safety is exploring design, construction, and storage issues. The forecourt must incorporate engineering controls that meet these final codes and standards. Such items as hydrogen leak sensors, ultra-violet/infrared fire/flame detectors, remote monitoring, dispenser break-away shutdown valves, and fail-safe designs may be considered to meet the eventual standards. Safety preparedness is necessary to deliver safe refueling to the public. Therefore, hazard reviews (HAZOPS), failure mode and effective analysis review (FMEA), emergency response plan, catastrophic release plan, and training for retail site and bulk delivery staff are all components to be considered.

As the level and sophistication of safety controls increases, so does the cost for hydrogen refueling sites. Safety controls are essential, but they must be cost-effective. Since this equipment will be in frequent use as more hydrogen-powered vehicles get on the road, the equipment will also require regular maintenance to prevent failures and protect the public and retail site employees. As the pressure of refueling vehicle storage tanks increases, so should the maintenance and inspection schedule. Inspection and maintenance of dispenser nozzles during delivery of 700 bar (10,000 psi) hydrogen would be critical.

Storage of intermediate and high-pressure hydrogen at the retail site poses other challenges. Some designs provide for intermediate storage at 160-500 bar (2,000-7,000 psi), with compression and storage in a smaller, high-pressure delivery tank at 350-700 bar (5,000-10,000 psi). Other design options are also possible. Locations under consideration for these tanks include placement in the forecourt behind protective barriers, underground, or even above ground in a supported canopy. Each design offers advantages and drawbacks. Codes and Standards will guide the choices.

Bulk hydrogen off-loading at the retail site will require delivery trucks to be on-site. With cryogenic liquid hydrogen, the hydrogen will be off-loaded to storage at the refueling site. Truck delivery of gaseous storage may include off-loading if high capacity tube trailers are developed or the tube trailers could be left at the site and utilized as the site storage. This unloading of hydrogen gas or liquid involves hazards that must be addressed, and the refueling trucks must be kept out of the way of retail traffic. Tankers also must have adequate room for maneuvering. Depending upon tanker size and retail site footprint, refueling truck access could pose special challenges for site design.

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 assure that the process is performed safely without overfilling storage capacity. These technologies are relatively well-known in the compressed gas and liquefied gas industry, but new to the fuels 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 engineering controls must be considered in forecourt equipment including the dispenser and nozzle.

To meet the goal of letting customers refuel their own vehicles, consumer education and community awareness are essential. Demonstrations on how to use this new technology can be delivered via on-site attendants, pamphlets, brochures, and even advertising. Education to raise awareness and instill confidence in consumers is critical to widespread acceptance of this new fuel and vehicle technology.

High Volume Manufacturing

Experience shows that the cost to produce equipment typically goes down as more and more units are produced. This is due to the improved manufacturing methods that are learned and employed and a certain "economy" of producing more units per year. Thus costs decrease as the volume of manufacturing increases. This is especially true when very large volumes of a particular piece of equipment are produced per year such in the automotive industry where the number of units produced can be > 500,000/yr.

When one considers the hydrogen delivery infrastructure, high volume manufacturing may play a role in significantly reducing the cost of some equipment. As discussed earlier, there are over 160,000 refueling stations in the U.S. today. The industry typically completely rebuilds on the order of 600 or more of these stations every year. As the hydrogen delivery infrastructure gets built up over time and is appropriately refurbished, there is the opportunity for some level of volume manufacturing for the equipment at these refueling sites, in particular, compressors, hydrogen storage vessels, and dispensers. Similar or identical storage vessels would be used at terminals and possibly on tube trailers, further increasing the number needed. If pipeline delivery is employed, a significant number of larger compressors for this service would also be needed that could also be used at terminals and at geologic storage sites.

High volume manufacturing costs can be projected using Design For Manufacturing and Assembly (DFMA). This methodology was presented in a report to DOE entitled *Cost and Performance Comparison of Stationary Hydrogen Fueling Appliances* Task 2 Report, April 2002 by DTI. DFMA is based on work done by Boothroyd and Dewhurst, described in *Product Design for Manufacture and Assembly, 2nd edition*. This method projects costs for "constructed" equipment based on the material cost, manufacturing cost and assembly cost for each component. In addition, overhead for general and administrative costs are added as a "Mark-up Rate." A mark up rate of 15% was reported for compressors and storage. The projected cost is developed based on a selected production volume. Higher production volumes result in lower unit manufacturing costs. The 2002 DTI study selected a yearly production of 250 units.

Production volume cost reduction adjustments can be done using the learning curve method described in Perry's Chemical Engineers Handbook VII, 9-20:

$$Y = KX^N$$

where, Y = cumulative-average cost, production time, etc., per unit
X = cumulative production, units
K = effective value of first unit produced
N = slope of straight-line plot of Y versus X on log-log paper

The particular learning curve is usually characterized by the percentage reduction in the cumulative average value Y when the number of units X is doubled. From this definition it follows that:

$$N = \log(\text{characteristic}/100)/\log 2$$

The "characteristic" is often called the "progress ratio." It was reported that mature industries would have a progress ratio of around 95%. Less mature technology can have values in the 80-95% range. The lower the progress ratio value, the more the cost decreases as the volume of manufacturing increases. This method was used to calculate equipment costs in *Economy Topic Team Report California 2010 Hydrogen Highway Network,* January 2005. They reported that compressors have a characteristic "progress ratio" of 0.90 and storage has a value of 0.95 for steel storage vessels. Composite tank storage vessels would be expected to have a lower characteristic progress ratio.

A specific example for refueling station compressors can provide insight into the impact of volume manufacturing. The current capital cost for a compressor for a 1,500 kg/day refueling station is on the order of $300k. This is based on relatively few compressors of this nature having been built. Let us assume that number is 200. By the time 10,000 of these compressors are built, the capital cost would be expected to decrease to $225k with a progress ratio of 95%.

5 Key Technical Barriers

Analysis

Lack of Comprehensive Delivery Infrastructure Analyses. The options and trade-offs involved in various approaches to hydrogen delivery are not completely understood. Additional in-depth comparative analyses are required to examine the most promising options for delivering and distributing hydrogen from large central production (>50,000 kg/day), semi-central/city-gate production (5,000-50,000 kg/day), and distributed production at refueling sites for both the transition and longer term. Such analyses would provide critical information for defining a cost-effective, energy-efficient, and safe hydrogen delivery infrastructure to support both the introductory phase and the long-term use of hydrogen for transportation and stationary power.

Pipelines

Installed Capital Cost. The cost of new pipeline construction is high. Labor comprises approximately 50% and materials comprise approximately 20% of new pipeline construction costs. Technology is needed to fabricate pipelines that eliminates or requires a minimum of sophisticated joining and inspections and other labor intensive aspects of pipeline construction.

Lack of Understanding of Material Science Issues. There is incomplete understanding of hydrogen embrittlement, fracture toughness, crack propagation, and permeation issues for steel pipeline materials under aggressive hydrogen service conditions. For example, materials need to be investigated under higher pressures than previously studied and under pressure cycling, or for performance with mixtures of hydrogen and natural gas. Research should encompass the compatibility of hydrogen with improved metallic and non-metallic materials of construction. If older infrastructures are converted to handling hydrogen, the compatibility issues must be well understood as well.

Innovative, Low-Cost Materials and Construction Techniques. Current steel pipeline materials are costly, expensive to weld and join, and potentially susceptible to hydrogen embrittlement, permeation, and leakage. New metallic materials, alternative materials such as plastics or composites, or surface treatments (coatings) need to be explored. Non-metallics might require much simpler (and thus lower-cost) joining technologies and could potentially be fabricated in significantly longer sections than the metallic materials currently used for pipelines. There is a need to evaluate novel materials (i.e., composite materials, alternate metal alloys) and newer and automatic joining techniques with the objective of reducing the pipeline construction unit cost.

Seals, Valves, and Related Equipment. Improved seals, valves, and other components for pipelines will be required to enable safe, efficient, and leak-free transport of hydrogen gas in pipelines.

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.

Acceptability, Cost, and High Pressure Operation of Hydrogen Distribution Pipelines in Urban Areas. Since the preferred use and storage pressure for hydrogen as an energy carrier is relatively high (100-800 bar), it is desirable for hydrogen distribution lines to be operated at relatively high pressures 20-100 bar). This is significantly higher than the typical pressures of the current natural gas distribution pipeline infrastructure. Non-industrial natural gas distribution in urban areas also includes use of an odorant for leak detection. A suitable odorant may need to be developed for hydrogen which could either be easily removed or non-harmful to vehicle fuel cells. Sensor based leak detection methods might overcome this problem if proven acceptable to regulators. Safety precautions including pipeline design and other measures will be needed for regulators to permit extensive hydrogen distribution pipeline infrastructure in urban areas. The cost and availability of ROW in urban areas can also be problematic.

Liquefaction

High Capital Cost. Current liquefaction technology adds more than $1.00 per kg to the cost of hydrogen. The plants are capital-intensive, and this problem is exacerbated by the lack of low-cost materials that can withstand the 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 hydrogen that is liquefied. Roughly 10% of the energy in the hydrogen is thermodynamically required to cool the hydrogen and to achieve the ortho/para transition. Better technology could offer opportunities to improve energy efficiency, including aluminum heat exchangers, heat exchanger technology and engineering, improved gas compressors, and turbo expanders used in the process. 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. Achieving breakthroughs in liquefaction costs and energy efficiency will require substantial research to increase the scale of operations, improve heat/energy integration (perhaps by co-locating the liquefaction with hydrogen production or power production and integrating energy and heat across the operations), lower the costs of heat exchange materials, and improve the catalysts for the ortho/para transition. Development of a novel, next-generation technology, such as acoustic or magnetic liquefaction, could potentially provide a breakthrough and a more effective process.

Carriers

Insufficient Knowledge/Experience. Research has been limited on the use of carriers for hydrogen delivery. As yet, no materials have been identified with the right combination of high hydrogen capacity and optimal energetics. Considerable uncertainty exists regarding how a carrier-based delivery infrastructure might look and operate. In addition, carrier development suffers from a lack of standardized computational methods and protocols for calculating the thermodynamics and kinetics for the hydrogenation and dehydrogenation of potential carrier materials. Lack of these tools creates large scientific and economic uncertainties around carrier-based delivery.

Energy Efficiency. Many potential carriers with high hydrogen capacities require too much energy for dehydriding or rehydriding. This problem adversely affects their overall suitability as carriers.
Inadequate Transformation Processes. Simple dehydriding processes that produce clean hydrogen ready for compression are essential for any potential carrier. Many current processes are complex, inefficient, or produce hydrogen with impurities.

Round-Trip Issues. Round-trip carriers, which require a return trip for re-hydriding, increase transportation costs, require station storage space, and introduce additional complexity at terminals, which are traditionally "low-tech" operations.

Compression

Low Reliability. Reciprocating compressors exhibit low reliability, requiring redundant systems to assure acceptable availability. Current centrifugal compression technology is not suitable for hydrogen. New centrifugal compression technology could overcome these issues.

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/contamination 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 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 forecourts could significantly reduce the capital cost of these compressors.

Low Energy Efficiency. The low efficiency of the electrical drives and the mechanical losses present in compressors result in some level of energy inefficiency. Higher energy efficiency designs are needed.

Cryogenic Liquid Pumps

Cost. Cryogenic liquid pumps have high capital cost per-unit pumping capacity.

High Maintenance, Poor Reliability, and Excessive Downtime. Cryogenic pumps work under extremely cold temperatures. The hydrogen entering the pump must be in the liquid state at all times as any vaporization will cause cavitation that will damage the pump. In addition, periodic recharging of the pump is required to purge any frozen or trapped gases. This requirement results in expensive downtime for the pumping process.

Tube Trailers

High Capital and Labor Cost. The low hydrogen-carrying capacity of current gaseous trucks results in high delivery costs. Research needs include the investigation of higher-pressure, steel and/or composite tubes, the use of cold hydrogen, and the possible use of solid carriers to increase the carrying capacity of tube trailers. The existing body of knowledge in composites for various pipeline and pressure vessel applications can be leveraged to arrive at improved solutions.

Leak Detection & Inspection. Research and development efforts should also address improved leak detection, monitoring and inspection methods. Codes and standards must be developed to cover design, inspection, and subsequent integrity management.

Risk Management. Improved Risk Management Methods must be developed to address the higher pressure transportation of gaseous hydrogen. Higher pressure tube trailers would require new regulations through the Department of Transportation (DOT).

Rail, Barge, and Ship Carriers

Poor Availability and Delivery Schedule. Hydrogen rail delivery is currently economically feasible only for cryogenic liquid hydrogen. At present, however, almost no hydrogen is transported by rail. Reasons include the lack of timely scheduling and transport to avoid excessive hydrogen boil-off and the lack of rail cars capable of handling cryogenic liquid hydrogen. Needed improvements include scheduling to eliminate delays or storage methods that would allow for delays in delivery without excessive hydrogen boil-off. Hydrogen transport by barge faces similar issues in that few vessels are designed to handle the transport of hydrogen over inland waterways. Storage methods and terminal technologies must also be developed to support the economical transport of hydrogen over rail or water.

Lack of Terminal Infrastructure. Due to the lack of hydrogen distribution by barge and rail systems, no terminal infrastructure currently exists for these delivery options.

Gaseous and Liquid Tanks

Cost. Gaseous and liquid storage tanks add significantly to the cost of hydrogen delivery—especially at refueling and stationary power sites where the hydrogen throughput is low compared to the required capital investment. Technology for lower-cost systems is needed. This technology could include new, higher strength and/or lower-cost materials and designs, design for high-throughput manufacturing of identical units, and higher hydrogen capacity per unit volume through the use of higher-pressure gaseous storage, cold hydrogen gas storage, or carriers. Relative costs of steel and composite tanks as a function of size and pressure are needed to choose optimal stationary storage systems designs.

Footprint. Real estate at refueling stations is costly. The footprint of hydrogen storage needs to be minimized.

Hydrogen Losses. Liquid storage tanks lose hydrogen by boil-off. The boil-off of liquid hydrogen requires venting and results in a cost and energy penalty.

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 high-pressure cycling environments and/or cryogenic temperatures. Use of novel materials of construction, both metallic and non-metallic, must be considered.

Underground Liquid Storage Issues. Concerns unique to underground liquid storage present major research challenges. For instance, the effects of soil pressure on the tank, and tank leakage on the surroundings, are unknown. Ground freezing must be avoided, and corrosion issues must be resolved. In addition, seismic (earthquake) effects on the underground tank need to be determined.

Geologic Storage

Cost. Potential cost barriers to geologic storage include the high costs of storage field development, compression, and hydrogen losses (due to leakage).

Identification of and Sufficient Suitable Locations. Candidate sites for geologic storage must have promising permeability characteristics and good caprock formation. Currently, researchers lack adequate tools for modeling potential sites for hydrogen containment and for collecting site-specific geophysical information.

Inadequate Understanding of Hydrogen Behavior in Rock Formations. Potential barriers include the risk that hydrogen gas will escape through unknown conduits in the geologic formation or if there are unexpected variations in storage geometry and material composition. The chemistry between hydrogen and minerals in underground formations is unknown, and unexpected reactions may compromise the integrity of the storage unit or consume large amounts of hydrogen on initial use. Little is known about the nature and extent of contamination introduced to hydrogen in geologic storage. Contamination issues need to be resolved for all potential geologic storage media. Finally, the rock mass used may not be a continuous medium, and pressure cycling may cause unexpected behavior.

Hydrogen Losses/Leakage During Operation. As with all storage mechanisms, geologic storage may suffer from hydrogen leakage. The amount likely to be lost to the surroundings is currently not known and will depend greatly on the particular geologic formation. 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.

Hydrogen Purification and Quality

Hydrogen Quality Requirements. Hydrogen fuel cells require very high quality hydrogen. The final specifications for fuel cell vehicles will depend on future fuel cell development efforts. Some cost will likely be incurred within the delivery infrastructure to maintain the high purity required and/or to re-purify as a result of potential contamination from compressors, geologic storage, particulates, or carriers depending on the development of these technologies.

Refueling Site "Polishing Purification". The nature and amount of the contaminants to be removed will depend on the final fuel cell vehicle hydrogen quality specifications and the amount of contamination that occurs in the delivery infrastructure. As a result, the requirements for the polishing purification step will unfold over time as these technologies are developed. The cost and energy use of any polishing step must be minimized, and hydrogen losses must be negligible. Pressure drops will need to be low to avoid additional compression costs.

Hydrogen-Natural Gas Mixture Separation. The cost and energy use for this process must be reduced. Options to be explored include membranes and PSA technologies.

Analytical Methodology and Sampling. Improved methodologies and sampling approaches need to be developed to achieve the low level of detection of some of the particular contaminants being considered and to minimize the cost of appropriate testing to ensure the hydrogen quality dispensed meets the requirements.

Sensors

Hydrogen Leak Detection Technology. The potential for hydrogen leakage exists at every step of the delivery system, and leak detection is crucial to maintaining safe handling. Odorizing hydrogen gas (as is done with natural gas) is particularly challenging since the extremely small and light hydrogen molecule diffuses faster than any known odorant. Odorants may also interfere with the use of hydrogen in fuel cells. Suitable odorant technology might need to be developed. Alternativly, cost-effective sensors for leak detection will likely be needed.

Mechanical Integrity Sensors. Development and utilization of mechanical integrity sensor technology for hydrogen pipelines, vessels, and other elements within the hydrogen delivery infrastructure would be very beneficial to maintain a high level of system safety and integrity.

Dispensers

High Cost. The high cost of components and the low number of manufacturers are the major factors behind the current expense of hydrogen dispensers.

Materials Requirements. Special materials are required to withstand the high pressures of compressed hydrogen, the low temperatures of cryogenic hydrogen, and corrosion issues.

Accurate Metering. Current technology makes it difficult to accurately meter hydrogen, whether compressed or cryogenic, and to dispense it at a rate that ensures an acceptable fill-time duration.

Other Forecourt Issues

Fueling Station Design Requirements. Design of the fueling station must solve a variety of forecourt issues. The location of hydrogen storage tanks at the retail site must be optimized for safety and convenience, and the location for bulk off-loading of hydrogen from tanker trucks must allow safe and efficient replenishment of on-site hydrogen while avoiding interference with retail traffic. There might be additional space requirements such as for storage of spent two-way carriers or cooling equipment. Due to the high cost of real estate, the footprint for storage and other operations must be minimized. Conversion of existing gasoline refueling station to hydrogen stations may present severe space limitations.

Cooling Requirements. Fast filling of hydrogen at high pressures will likely require pre-cooling of the hydrogen. Hydrogen cooling may also be required if particular metal hydrides or cryo-compressed gas are used for on-board vehicle storage systems. Low cost, energy efficient and compact hydrogen cooling technology will need to be developed if this technology is utilized.

Safety, Codes and Standards

Lack of a Comprehensive System of Codes and Standards. Codes and standards governing safety and equipment design, construction, and compatibility must be established for every aspect of the hydrogen delivery infrastructure—including truck, rail, and pipeline transport; tank and geologic storage; handling at the terminal; and handling and dispensing in the forecourt. Some components of the delivery system are so new that the appropriate governing codes and standards simply do not exist. For codes and standards that do exist, the key barrier is communication and education—making the appropriate officials aware of and confident in administering the codes and standards.

Cost-Effective, Reliable, Safety Technology. A variety of safety challenges arise as a result of hydrogen's diffusivity and volatility, the pressures and temperatures at which it must be stored, and the goal of refueling by the public. Monitoring and control technologies (e.g., hydrogen leak sensors, infrared fire/flame detectors, remote monitoring, and fail-safe designs) are needed to meet codes and standards in a cost-effective manner. The need includes methods for low-cost maintenance of hydrogen delivery equipment, especially in the forecourt.

Permitting. The lack of sufficient codes and standards for some technologies makes securing permits especially challenging. The "Not In My Back Yard" (NIMBY) syndrome also acts as a major barrier to permitting needed facilities, including storage sites, pipelines, terminals, and fueling stations.

Education. Education and training programs will be needed to achieve public acceptance and ensure safe handling of hydrogen. Fueling station operators and truck drivers must be trained to handle hydrogen safely. Also, the consumer must be instructed on how to use the refueling equipment safely.

6 Pros and Cons of Hydrogen Delivery Pathways

The three hydrogen delivery pathways have advantages and disadvantages, as described below and summarized in Table 6-1.

Gaseous Pathway. Although gaseous pipelines are the lowest cost-known delivery option at high market penetration, the large fixed capital investments for pipelines make it unacceptably expensive at low penetrations. Safety concerns as well as ROW costs and availability may make pipeline distribution of hydrogen in urban areas problematic. Truck delivery of gas is very inefficient. Today's 36,000 kg (80,000 lb) gaseous hydrogen truck/trailer combination delivers 300-400 kg of useable hydrogen – enough hydrogen to fuel only 30-80 vehicles. Advances in materials and structure configurations could solve some of these problems by enabling the cost-effective transition from steel to composite structures. Composite pipelines could be much lower in capital cost. They could be constructed in much longer segments and spooled and thus significantly reduce the labor needed for joining and trenching. Composite storage vessels could be more cost effectively used for higher pressure stationary storage as well as for higher pressure tube trailers. Use of cold hydrogen and/or carriers could further increase the hydrogen carrying capacity of vessels for stationary storage and tube trailers.

Liquid Pathway. Although liquefaction consumes a significant portion of the hydrogen's energy content, it appears to be the best currently known option for delivery of centrally-produced hydrogen for long distances at low market penetration. Liquid trucks can deliver around 7 times more hydrogen than today's gaseous tube trailer. This increased delivery capacity makes up for the high cost of liquefaction when compared with gaseous hydrogen delivery for distances more than 100-200 miles. Although it is cheaper than gaseous delivery, liquid delivery is still costly and very energy-intensive. Breakthroughs in liquefaction or economies of scale could reduce the cost and increase the energy efficiency, making liquid delivery more attractive.

Carriers. Carriers are the "wild card" in the delivery portfolio. A carrier with high energy density and simple transformation (both hydriding and dehydriding) could deliver hydrogen using trucks and be a key enabler for a hydrogen economy. Novel carriers—solids, liquids, powders, or other novel forms—have the potential to radically alter the distribution system. Carriers are, however, not well understood, and extensive engineering and economic analysis is needed with experimental development of promising materials.

Mixed Pathways. Although the above pathways are distinct, it is highly likely that no single pathway will serve as the exclusive mode of hydrogen delivery. It is likely that a mixture of pathways will be needed during the transition to a hydrogen economy. Even when the transition is complete, economics will dictate the preferred delivery pathway for a given locality so that all of the pathways are expected to play a role in hydrogen delivery for the foreseeable future. For example, gaseous distribution pipelines in urban areas are likely to be more difficult and costly to construct than transmission pipelines located in more rural areas. This may create a feasible delivery scenario involving pipeline transmission from a central/semi-central production facility to a terminal where the gas is distributed by tube trailer or liquefied and distributed via tanker trucks, or incorporated into a carrier that is delivered by truck to refueling stations. Mixed pathways might also be used to supplement onsite production.

Table 6-1: Pros and Cons of Pathways

Pathway	Pros	Cons
Gaseous	• Pipelines are currently the most cost-effective option for high volumes of hydrogen • No thermodynamic limitations to low costs • Pipeline delivery is highly energy efficient • Minimizes over-the-road transportation (environment and safety benefits) • Tube trailer delivery feasible for small amounts of hydrogen in the transition	• High capital investment • Low cost when full, very costly when marginally used • Permitting difficult and costly • ROW may be costly and difficult to obtain, especially in urban areas • Likely to require geologic or other low-cost bulk storage • Tube trailer delivery is very costly
Liquid	• High energy density • Small volumetric footprint • Liquid tankers are relatively cheap and efficient • Potential option for the transition • Minimizes need for compression in the forecourt	• Thermodynamics limit energy efficiency • High energy consumption and high costs • Not a likely low-cost long-term solution • Complexity of handling cryogenic liquids
Carriers	• Potential to change the economic paradigm (could be the lowest cost option) • Might use existing infrastructure (or at least known infrastructure technology) • Could provide modest (<2,000psi) pressure, modest temperature (+/- 200°C from room temperature) delivery system • Could reduce off-board storage costs	• Little is known; much fundamental R&D is required • Requirements for production, transformation and rehydriding will impact energy efficiency and add costs • May introduce contaminants that could poison the fuel cell • Transformations to release hydrogen will increase forecourt complexity • Two-way carriers will require two-way transport • Unknown safety and environmental issues

7 Transition Issues

As suggested elsewhere in this roadmap, transition to a hydrogen-based transportation system will take time and will face economic challenges. The market will supply hydrogen when customers will demand it. Customers will demand it when hydrogen fuel cell vehicles are competitive in terms of cost and benefits. Thus the market will evolve over time.

Until demand for hydrogen grows, hydrogen delivery, storage, and dispensing costs may be quite high—especially relative to costs for conventional liquid fuels delivery, storage, and dispensing. As hydrogen markets increase, however, newer technologies and methods for delivering, dispensing, and storing hydrogen are likely to offer economic advantages, putting the early technology adopters at risk of stranding their assets. Those who invest in liquefaction and truck transport of hydrogen during the initial stages, for example, may find their equipment obsolete with the subsequent introduction of more efficient and economic pipelines. Without those early investors, however, demand may never grow enough to support the more economic delivery pathways.

A number of technical or business approaches may help to ease this transition process. One possibility is to initially deliver and dispense hydrogen from larger, more centralized refueling stations instead of from a relatively large number of conveniently-located small refueling stations. This business model might reduce the early economic burden on individual retail sites, giving each a larger market area; the drawback is decreased convenience for end users. Other business strategies could include home refueling or refueling at the workplace.

As a strategy to initiate the transition, it may be more economically attractive to launch hydrogen on a local or regional scale. This approach would reduce initial infrastructure costs—but may cause problems for automakers, whose economic models may depend on the largest potential number of buyers. Since the cost of the infrastructure per unit of hydrogen consumed is likely to be higher in rural areas than in urban areas, these markets may develop at different rates, with urban areas leading the growth in demand.

All of the above-mentioned alternatives need to be studied during the next several years. Technical and business analyses are required to determine which models offer the lowest business risk. Clearly, incentives by automakers or local or national government may be necessary to make any of the early business propositions viable.

8 Research Strategy

Hydrogen can become a major energy carrier only after research has solved many issues that currently hinder development of a full hydrogen-delivery infrastructure. Many infrastructure components face economic and technical barriers, and the R&D needs range from incremental improvements to major breakthroughs in technology. Some of the infrastructure research needs must be met in the near term for use during the transition period, while others do not need to be solved until later, when a full delivery infrastructure is needed to handle the hydrogen demand.

Federal support is appropriate for the higher-risk, breakthrough research that can achieve the major cost reductions and efficiency improvements needed to meet delivery targets. The private sector can support the lower-risk development work needed as the hydrogen economy begins to develop.

A critical early R&D need is for additional **analysis** of all the options and trade-offs involved in the various delivery pathways and configurations. Such an analysis will help to identify the more efficient and cost-effective approaches for delivery during the transition period and for the long term. This improved understanding is needed to focus research on the most critical areas with the highest impact. At a minimum, this analysis should focus on the following:

- The trade-offs among various configurations and options for storage and compression at refueling sites, and how those options may affect capacity utilization of distributed production at a site
- The trade-offs involved in moving sooner rather than later toward use of transmission pipelines for long-distance hydrogen transport instead of relying on liquefaction and liquid transport
- A better understanding of the role that hydrogen carriers could play in transport and storage
- The trade-offs among options for where and how to purify hydrogen to meet stringent PEM fuel cell specifications and avoid any contamination of the hydrogen downstream of the final purification step

Getting through the **transition** period is vital. Prices per unit of hydrogen will be high due to the relatively low demand level. First priority should be placed on the research needed to reduce delivery costs during this early period. Based on current knowledge, the federal government should emphasize research in the following areas:

- **Forecourt Storage and Compression Technology:** Development of reliable, low-cost compression and low-cost, smaller-footprint storage
- **Lower-Cost, Higher-Pressure Tanks for Storage and Tube Trailers:** This research could be applied to reduce the costs of forecourt storage and tube trailer transport
- **Low-Cost Carrier Technology:** This research could improve forecourt storage and/or result in a cost breakthrough for hydrogen transport from current hydrogen production sites or new, semi-central, central, or terminal sites

- **Liquefaction:** Breakthrough liquefaction technology that could dramatically reduce costs, increase energy efficiency, and minimize the cost of hydrogen transport from current hydrogen production sites or new, semi-central, central, or terminal sites

Since distributed production at the forecourt is likely to play a major role during the transition period, the most immediate need is for lower-cost forecourt compression and storage. A breakthrough in gaseous tube trailer carrying capacity, hydrogen liquefaction, or carriers, could substantially reduce the costs and energy use involved in transporting hydrogen from existing or new, semi-central or central production sites. Carrier technology or lower-cost, high-pressure tank technology could also reduce forecourt storage and/or hydrogen transport costs.

Pipeline delivery currently represents the lowest-cost known option for hydrogen delivery when demand is high enough to substantially utilize the pipeline capacity. This cost advantage is particularly strong for long-distance transmission. Research is needed to resolve the hydrogen embrittlement and fatigue issues of steels and/or to develop alternative pipeline materials and joining techniques. If the associated capital costs could be substantially reduced, hydrogen pipeline transmission could be used sooner rather than later. Research should also explore the use of the existing natural gas and gasoline pipeline infrastructure for hydrogen, or natural gas and hydrogen mixtures. If some capacity is available and the technical issues can be resolved, this method of hydrogen delivery could be used during the transition. Pipeline research requires a concerted and focused effort, including fundamental materials science. It will require strong government support.

Compression technology for pipeline transmission and research on hydrogen **geologic storage** are needed to support pipeline delivery. Geologic storage is heavily relied on for the natural gas pipeline delivery infrastructure and will likely be important for a hydrogen pipeline infrastructure. New, more reliable compression technology is necessary for pipeline transmission applications and to meet geologic storage requirements.

Hydrogen **carrier technology** could result in a paradigm shift for hydrogen delivery. This approach could not only reduce costs but might substantially reduce the amount of capital investment required for the hydrogen delivery infrastructure. It could also change the nature and cost of hydrogen storage. The federal government's current investment in the development of carrier materials for on-board vehicle hydrogen storage should be leveraged and expanded as warranted for hydrogen delivery applications.

Finally, **codes and standards, permitting issues, and sensors** for hydrogen leak detection are all vital to the development of a hydrogen delivery infrastructure. This area has its own FreedomCAR and Fuel Partnership Tech Team. The Delivery Tech Team will collaborate with the Codes & Standards Tech Team in these areas.

All of the other delivery infrastructure components and pathways, barriers, and needs discussed in this roadmap can be adequately addressed by the private sector through their own efforts and by applying the technology funded and developed through government-supported efforts. For example, a gaseous hydrogen terminal would use the advances achieved in high-pressure or carrier storage technology and compression technology.

9 Component Technical Targets

These technical targets are derived from the FreedomCAR and Fuel Partnership overall premise that hydrogen fuel cell vehicles have 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 the overall objective for hydrogen delivery to cost <$1.00 per kg of hydrogen by 2017. (See Section 2.)

The individual component technical targets were derived from publicly available information and models for hydrogen delivery systems as necessary to achieve the overall delivery cost target of <$1.00 per kg. The intermediate timeframe technical targets are milestones along the path to track progress.

The H2A Delivery Components and Scenario Models[4] are the foundation for the status and targets in the table. The 2005 status column is based on analysis of available public information that has been incorporated into the H2A Delivery Models. Based on these models the targets listed are necessary but not necessarily sufficient to meet the overall delivery cost target of <$1.00/kg. Additional analysis and infrastructure architecture and options are being studied that will provide more insight into delivery infrastructure and all the pertinent cost factors. (See Section 10 for more information.)

Table 9-1: Hydrogen Delivery Targets[a]

Category	2005 Status	FY2010	FY2012	FY2015	FY2017
Pipelines: Transmission					
Total Capital Investment ($k/mile for a 16" pipeline)[b]	$700		$600		$490
Pipelines: Distribution					
Total Capital Investment ($k/mile for a 2" pipeline)[b]	$320		$270		$190
Pipelines: Transmission and Distribution					
Reliability/Integrity (including 3rd party damage issues)[c]	Acceptable for current service				Acceptable for H_2 as a major energy carrier
H_2 Leakage[d]	Undefined		Will be determined		<0.5%
Large Compressors: Transmission, Terminals, Geological Storage					
Reliability[e]	Low		Improved		High
Energy Efficiency[f]	98%		98%		≥98%
Total Capital Investment ($M) (based on 200,000 kg of H_2/day)[g]	$15		$12		$9
Maintenance (% of Total Capital Investment)	10%		7%		3%

[4] H2A Delivery Components Model V1.1, H2A Delivery Scenario Model V1.0: www.hydrogen.energy.gov

Category	2005 Status	FY2010	FY2012	FY2015	FY2017
Contamination[h]	Varies by design				None
Forecourt Compressors: Forecourt					
Reliability[i]	Low	Improved		High	
Energy Efficiency[j]	94%	94%		95%	
Installed Capital Cost [k$/(kg/hr)] (based on servicing at 1,500 kg/day station)[k]	$4.6	$4.0		$3.0	
Maintenance (% of Total Capital Investment)	3%	2%		2%	
H_2 Fill Pressure (Fill/Peak psi)[l]	5,000/6,250	5,000/ 6,250		10,000/12,000	
Contamination[m]	Varies by Design			None	
Tube Trailers[n]					
Delivery Capacity (kg of H_2)	280		700		1,100
Operating Pressure (psi)	2,640		<10,000		<10,000
Purchased Capital Cost ($)	$165,000		<$300,000		<$300,000
Geologic Caverns					
Installed Capital Cost[o]	Assumed equal to natural gas caverns				Equal to natural gas caverns
H_2 Capacity Availability[p]	Unknown		Defined		Sufficient to meet the need
Liquid Hydrogen Delivery					
Small-Scale Liquefaction (30,000 kg H_2/day)					
Installed Capital Cost ($)[q]	$50M		$40M		$30M
Energy Efficiency (%)[r]	70%		75%		85%
Large-Scale Liquefaction (300,000 kg H_2/day)					
Installed Capital Cost ($)[q]	$170M		$130		$100M
Energy Efficiency (%)[r]	80%		>80%		87%
Delivery Hydrogen Carriers					
Carrier H_2 Content (% by weight)[s]	6.2%		6.6%		13.2%
Carrier H_2 Content (kg H_2/liter)[s]	0.054		>0.013		>0.027
Carrier System Energy Efficiency (from the point of H_2 production through dispensing at the forecourt) (%)	Undefined		70%		85%
Total System Cost Contribution (from the point of H_2 Production through dispensing at the forecourt) ($/kg of H_2)	Undefined		$1.70		<$1.00

Category	2005 Status	FY2010	FY2012	FY2015	FY2017
Off-Board Gaseous Hydrogen Storage Tanks (for forecourts, terminals, or other off-board storage needs)					
Storage Tank Purchased Capital Cost ($/kg of H_2 stored)[t]	$820	$500		$300	
Volumetric Capacity (kg H_2 /liter of storage volume)[u]	0.023	0.030		>0.035	
Delivered Hydrogen Quality					
Hydrogen Quality[v]	Suitable for PEM Vehicle Fuel Cells				Suitable for PEM Vehicle Fuel Cells

Footnotes:

a. All costs in Table 9-1 are in 2005 dollars.

b. Pipeline Capital Costs: These costs are derived from the H2A Components Model V1.1. The model uses historical costs published by the *Oil & Gas Journal* for natural gas pipelines as a function of pipeline diameter. The costs are broken down into materials, labor, miscellaneous costs, and right of way. It is assumed that current (2005) hydrogen pipelines costs are 10% higher than for natural gas pipelines based on informal discussions with industrial gas companies who build, and operate the current hydrogen pipelines in the U.S. (For more details on the H2A Delivery Model see www.hydrogen.energy.gov) The 2017 target cost is set at 70% of current natural gas pipeline costs for Transmission and 60% of current natural pipeline costs for Distribution in order to achieve the overall delivery cost objectives.

   Note that material and labor costs have risen significantly in the past few years and this may not be fully taken into account in the *Oil & Gas Journal* historical data.

c. Pipeline reliability refers to maintaining integrity of the pipeline relative to potential hydrogen embrittlement, third party damage, or other issues causing cracks or failures. The 2017 target is intended to be at least equivalent to that of today's natural gas pipeline infrastructure.

d. Hydrogen leakage is hydrogen that permeates or leaks from fittings, etc. from the pipeline as a percent of the amount of hydrogen put through the pipeline. The 2017 target is based on being equivalent to today's natural gas pipeline infrastructure based on the article: David A. Kirchgessner, et al, "Estimate of Methane Emissions from the U.S. Natural Gas Industry," Chemososphere, Vol.35, No 6, pp1365-1390, 1997.

e. Transmission Compressor Reliability: Currently the only hydrogen compressor technology available for pipeline transmission service and similar high throughput, modest pressure boost service (e.g., a compression ratio of 1.5 to 4) is reciprocating compression. Due to the large number of moving parts and other challenges with hydrogen, this technology has low reliability. This translates to installing multiple compressors to ensure high availability. The current status (2005) of "Low" is modeled in the H2A Delivery Scenario model V1.0 as installing 3 compressors, each rated at 50% of the system peak flow. The 2017 target of "High" reliability assumes 2 compressors each rated at 50% of the peak flow. It is unlikely that a reciprocating compressor will achieve this level of reliability. It is likely that new centrifugal technology suitable for hydrogen or some other compression technology will need to be developed.

f. Transmission Compression Efficiency: Hydrogen energy efficiency is defined as the hydrogen energy (LHV) out divided by the sum of the hydrogen energy in (LHV) plus all other energy needed for the operation of the process. The current status (2005) of 98% represents 80% isentropic energy efficiency for the compressor itself which is typical for large reciprocating compressors used for hydrogen and a conservative estimate of 0.5% hydrogen losses in the compression step. The 2017 target is set to at least maintain this efficiency.

g. Transmission Compression Capital Cost: These costs are based on the H2A Components Model V1.1. The model uses costs published in the "Special Report: Pipeline Economics,*" Oil and Gas Journal*, Sept. 4, 2000, p 78. The compressor capital cost data was plotted vs. the power required for the compressor using the natural gas transmission compressor data provided. The power required was calculated assuming 200,000 kg/day of hydrogen flow with an inlet pressure of 700 psi and an outlet pressure of 1,000 psi. It is assumed that current (2005) hydrogen compressor costs are 30% higher than for natural gas compressors to satisfy particular needs for hydrogen. (For more details on the H2A Delivery Model see www.hydrogen.energy.gov) The 2017 target cost is set at 80% of current natural gas compressor costs in order to achieve the overall delivery cost objectives.

h. Some gas compressor designs require oil lubrication that results in some oil contamination of the gas compressed. Due to the stringent hydrogen quality specifications for PEM fuel cells, the 2017 target is to ensure no possibility of lubricant contamination of the hydrogen from compression. As an alternative, it may be possible to remove such contamination at refueling sites just prior to charging the hydrogen to vehicles if this is not cost prohibitive.

i. Forecourt Compressor Reliability: Currently several compressor technologies are being demonstrated for forecourt service. These include reciprocating, diaphragm, and intensifiers. There are concerns about reliability for this service. This translates to potentially installing multiple compressors to ensure high availability. The current status (2005) of "Low" is modeled in the H2A Delivery Scenario model V1.0 as installing 2 compressors each rated at 50% of the system peak hourly flow as a very conservative perspective. The 2015 target of "High" reliability is modeled as just one compressor with very high reliability. This is deemed necessary to achieve the overall hydrogen delivery cost targets.

j. Forecourt Compression Efficiency: Hydrogen energy efficiency is defined as the hydrogen energy (LHV) out divided by the sum of the hydrogen energy in (LHV) plus all other energy needed for the operation of the process. The current status (2005) of 94% represents 65% isentropic energy efficiency for the compressor itself which is typical for the size of hydrogen forecourt compressors and a conservative estimate of 0.5% hydrogen losses in the compression step. The 2015 target represents new technology to increase the compressor isentropic energy efficiency to 80%.

k. Forecourt Compressor Installed Capital Cost: These costs are based on the H2A Components Model V1.1. The model uses a cost of $4,600 per kg/hr of hydrogen flow for a 1500 kg/day Forecourt compressor based on quotes from vendors for compression from 300 psi to 6250 psi for 5000 psi vehicle fills. (For more details on the H2A Delivery Model see www.hydrogen.energy.gov) The 2015 target cost is set in order to achieve the overall delivery cost objectives.

l. Forecourt Hydrogen Fill Pressure: Most current prototype hydrogen fuel cell vehicles are equipped with hydrogen gas storage tanks rated for 5,000 psi fills with estimated peak filling pressures during filling of 6,250 psi. Technology is being developed and tested for vehicle gas storage tanks rated for 10,000 psi fills with estimated peak filling pressures during filling of 12,000 psi. The long term goal of the DOE is to develop solid or liquid carrier systems for vehicle storage tanks that will allow for at least 300 miles between refueling with low pressure storage (<2,000 psi). The DOE has set targets that include 5,000 psi fills in 2005 and 10,000 psi fills in 2015 to allow for the introduction of hydrogen fuel cell vehicles with high pressure vehicle gas storage technology prior to achieving commercialization of the ultimate goal of low pressure vehicle storage technology utilizing carriers.

m. Forecourt Compressor Contamination: Some gas compressor designs require oil lubrication that results in some oil contamination of the gas compressed. Due to the stringent hydrogen quality specifications for PEM fuel cells, the 2015 target is to ensure no possibility of lubricant contamination of the hydrogen from compression.

n. Tube Trailers: The current (2005) tube trailer characteristics and costs are based on the H2A Components Model V1.1 which uses available information on tube trailers. (For more details on the H2A Delivery Model see www.hydrogen.energy.gov) The 2015 targets are set to achieve the overall delivery cost objectives. There are several possible technology approaches to achieve these 2015 targets. It may be possible to develop composite structures to increase the working pressure of gaseous tube trailers. Another approach would be to utilize solid carrier technology and or to employ low temperature hydrogen gas. It may also be possible to utilize some combination of these approaches.

o. Geologic Cavern Capital Costs: Based on information from the one U.S. hydrogen geologic storage site (see Section 4.2), it is assumed that hydrogen geologic caverns have the same capital cost as natural gas caverns. However, this is very limited information and is for a salt dome cavern only. This capital cost target is simply stating that hydrogen geologic storage capital costs need to be about the same as current natural gas geologic storage to make geologic storage of hydrogen cost effective to help enable achieving the overall delivery cost objectives.

p. Geologic Cavern Capacity Availability: Transportation vehicle fuel demand is significantly higher in the summer than in the winter. In order to handle this demand surge in the summer without building prohibitively expensive excess production capacity, there will need to be hydrogen storage capacity within the hydrogen delivery system. Geologic storage is a very cost effective storage method for these types of demand swings and is used very effectively for similar demand swings for natural gas. There are only two currently operating geologic storage sites for hydrogen in the world (see Section 4.2). Greater knowledge needs to be developed on the availability and suitability of hydrogen geologic storage sites. Technology development may also be required to ensure suitability for hydrogen. More information and modeling is required to quantify the amount of hydrogen geologic storage that will be needed.

q. Liquefaction Installed Capital: The current (2005) costs are based on the H2A Components Model V1.1. The 2017 target cost is set in order to achieve the overall delivery cost objectives.

r. Liquefaction Energy Efficiency: The current (2005) energy efficiencies are based on the H2A Components Model V1.1. The 2017 efficiency target is set in order to achieve the overall delivery cost objectives.

s. The 2005 status values are based on a liquid hydrocarbon carrier currently under development by Air Products. The 2010 hydrogen content targets are based on transporting 1500 kg of hydrogen in a truck. Although regulations vary to some degree by state, a typical truck is limited to carrying 25,000 kg of load (36,400 kg total loaded weight including the trailer) and/or 113,000 liters of volume. The minimum hydrogen content (% by weight and kg H_2/liter) to achieve 1500 kg of hydrogen on the truck is determined by these maximum loads allowable. Trucking costs with this hydrogen payload are such that this transport option would seem attractive relative to the delivery cost objectives. A typical refueling station of 1500 kg/day of hydrogen servicing hydrogen fuel cell vehicles would service the same number of vehicles as typical gasoline stations serve today. This delivery option would require one truck delivery per day which is also typical of today's gasoline stations. The 2017 targets are calculated in the same way but assuming 3000 kg per truck load so that the one truck could service two refueling stations. The total cost and attractiveness of this delivery option would depend on the cost of the total carrier delivery system including the cost of discharging the hydrogen at the refueling station and any carrier regeneration costs. (Note that although the current status for hydrogen content on a volume basis exceeds the 2017 targets, all of the carrier targets must be met simultaneously for a carrier system to be a cost effective and energy efficient delivery pathway.)

t. Storage Tank Capital Cost: These costs are based on the H2A Components Model V1.1. The model uses a current cost of $820 per kg of hydrogen stored for a 1,500 kg/day Forecourt station. This is based on quotes from vendors for steel tanks capable of 6,250 psi working pressure. The 2015 target cost is set in order to achieve the overall delivery cost objectives.

u. Forecourt Storage Volumetric Capacity: The 2005 value is based on the specific volume of hydrogen at room temperature and 6,250 psi. The 2015 target is based on the specific volume of hydrogen at room temperature and approximately 12,000 psi. Off-board storage tank technology could use carriers as opposed to or in addition to compressed hydrogen as a means to store hydrogen. The most important target is system capital cost. However, the footprint for the storage must also be taken into consideration where space is limited such as at forecourts. For this reason, it is assumed that the hydrogen volumetric content of the storage volume should be at least as high as for 10,000 psi hydrogen gas.

v. The specifications for hydrogen quality required for fuel cell vehicles have not been finalized as discussed in Section 4.2 Hydrogen Purification and Quality. The specifications under consideration are shown in Appendix A.

10 Component Targets and Objectives

As mentioned in Section 9, the delivery Components Targets have been set in order to achieve the overall Delivery Objectives as set out in Section 2. The DOE has funded the development of the H2A Delivery Components and Scenario Models[5] to develop an understanding of the overall cost and energy use of hydrogen delivery infrastructure options and the contributions of the delivery components to these costs. These models were used to help establish the Component Technical Targets in Section 9.

Figures 10-1 and 10-2 show representative results from the H2A Delivery Scenario Model for hydrogen delivery to urban markets of two different sizes: 250,000 and 1,000,000 people. The basis is for a central plant located 100 km (62 miles) from the edge of the city. Since urban markets will require sufficient hydrogen to justify large production plants, it is likely these will be located within a few 100 km from the city. These Figures are based on the current (2005) costs for delivery technology and show delivery by pipeline, gaseous tube trailer and for liquefaction with cryogenic liquid truck delivery. (There is not yet sufficient information available to model carrier pathway systems.) These figures show several important aspects of hydrogen delivery costs.

- At less than 10% market penetration, delivery costs from a central plant located some distance from the urban area are very high. During this period, local distributed production will likely play an important role. Another alternative would be to utilize gaseous tube trailer delivery from existing nearby central hydrogen production facilities if such facilities exist near or in that urban area. This could be cost effective if the ultimate tube trailer carrying capacity target of 1,100 kg could be achieved.
- The cost of delivery drops rapidly as market penetration increases and tends to flatten out above 25%. The difference in delivery cost for a city of 1,000,000 people vs. 250,000 people is not large. Although not shown, the costs for delivery for cities less than 250,000 people do start to increase significantly.
- Current costs for hydrogen delivery to urban markets are >\$2.00/kg of hydrogen even at high market penetrations. This compares with a target of <\$1.00/kg.
- Pipelines are the low cost delivery pathway with current technology when market penetration is greater than about 10%.

[5] H2A Delivery Components Model V1.1, H2A Delivery Scenario Model V1.0: www.hydrogen.energy.gov

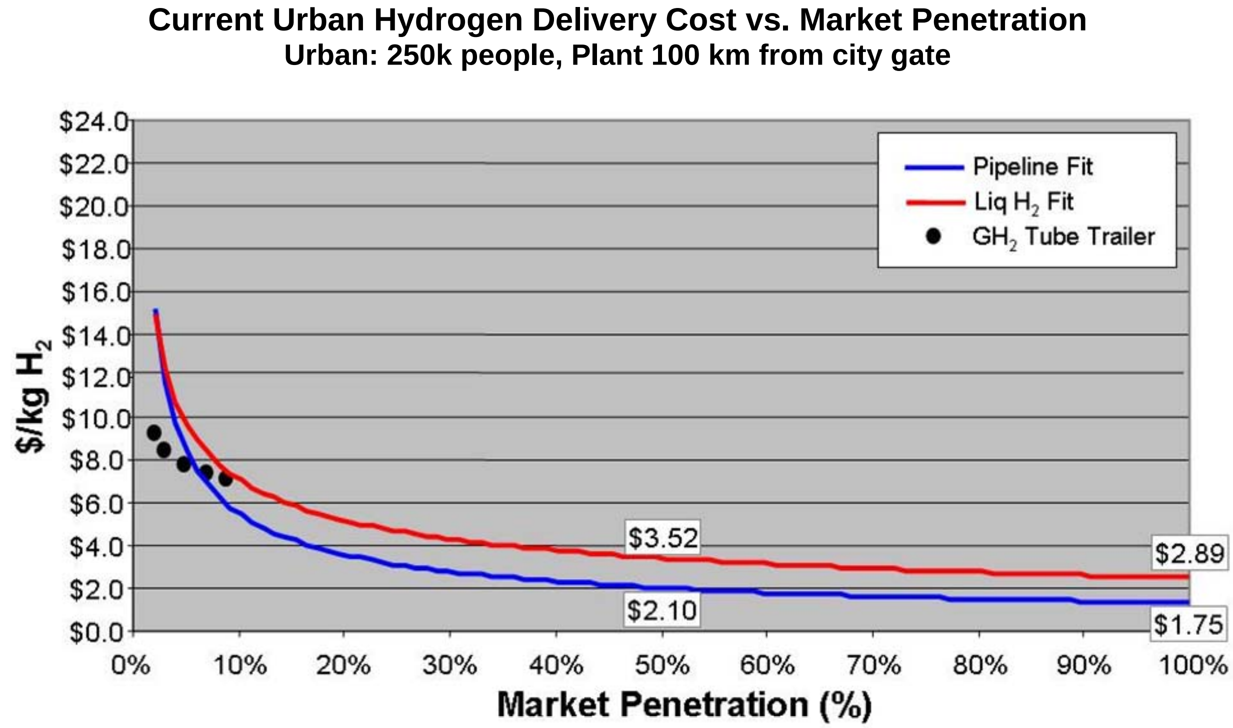


Figure 10-1: H2A Delivery Scenario Model for H_2 Delivery to Urban Market (250k people)

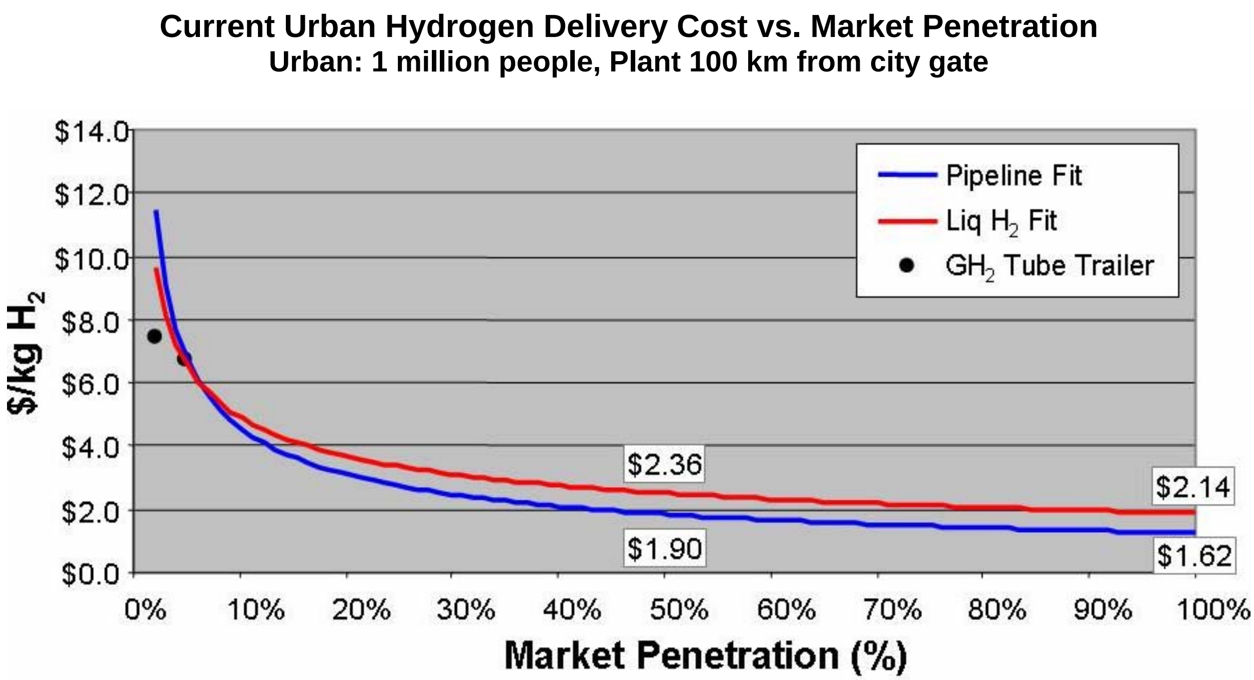


Figure 10-2: H2A Delivery Scenario Model for H_2 Delivery to Urban Market (1 million people)

Figure 10-3 on the next page shows representative results from the H2A Delivery Scenario Model for a rural/interstate case. This models delivery to interstate refueling stations.[6] These stations might also service the surrounding rural area. Costs for this scenario are somewhat higher than for urban markets and cryogenic liquid hydrogen appears to be the more favorable delivery mode based on cost alone. The energy efficiency of this liquid hydrogen pathway is quite low however.

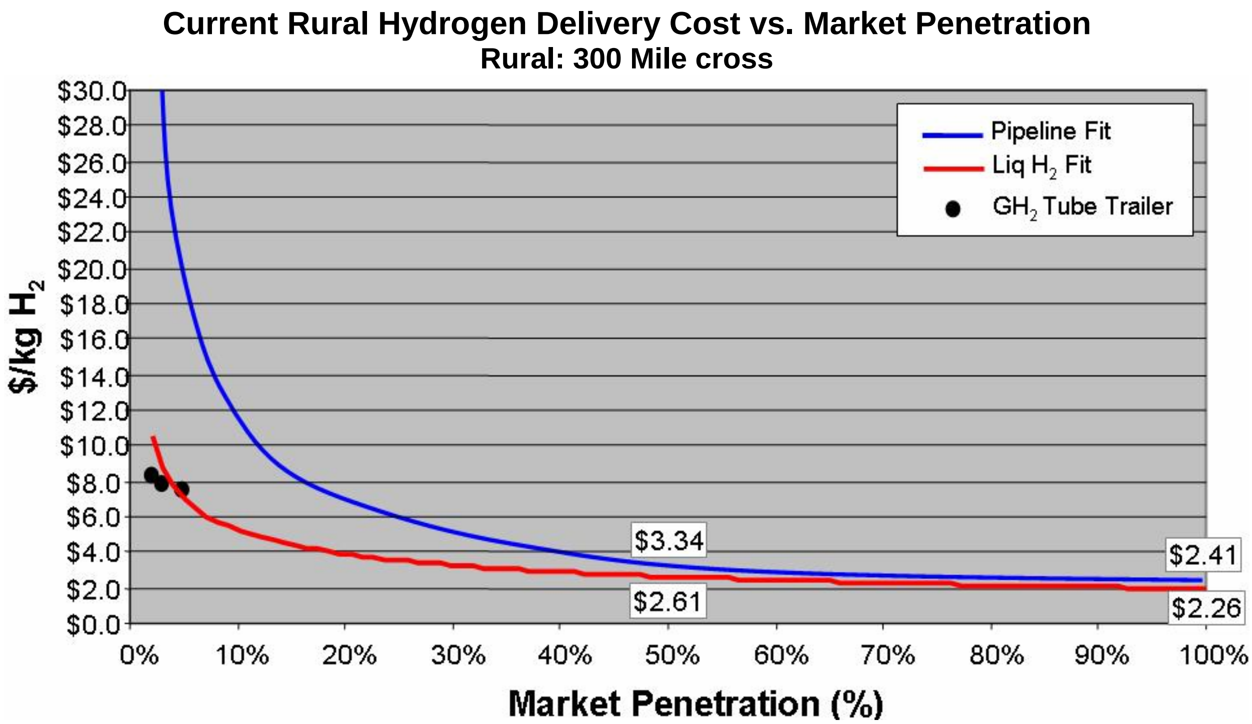


Figure 10-3: H2A Delivery Scenario Model for Rural/Interstate Case

Figures 10-4 and 10-5 show a breakdown of the current delivery costs for pipelines and cryogenic liquid truck delivery for an urban market of 250,000 people. For the pipeline pathway it is clear that the forecourt/refueling site cost represents a large fraction of the total delivery cost (40%). This is predominantly the cost of compression and storage at the refueling site and highlights the importance of these areas for cost reduction. The remainder of the cost is split relatively evenly over the cost of the other parts of the pipeline infrastructure. This means that some cost reduction is needed in all of these other areas.

For the cryogenic liquid hydrogen pathway shown in Figure 10-5, it is clear that the liquefaction step is the key cost driver. This is due to the relatively high capital cost and large amount of energy needed. These must be reduced for liquid hydrogen delivery to be an attractive option.

[6] H2A Delivery Components Model V1.1, H2A Delivery Scenario Model V1.0: www.hydrogen.energy.gov

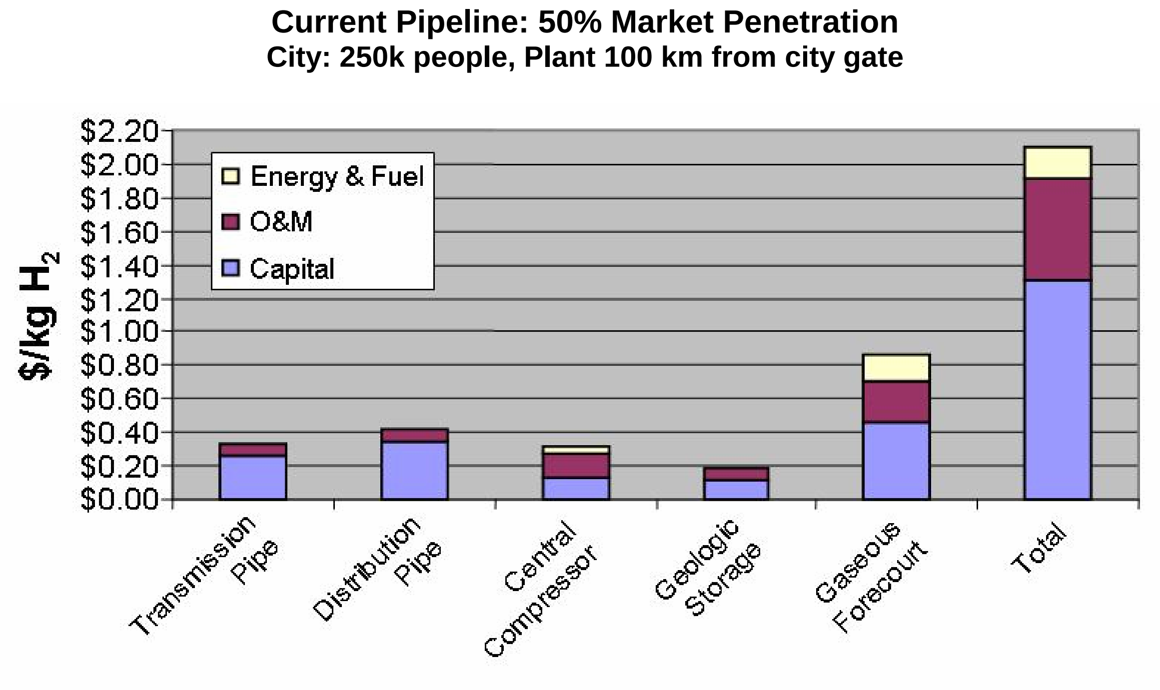


Figure 10-4: Current Delivery Costs for Pipeline Pathway

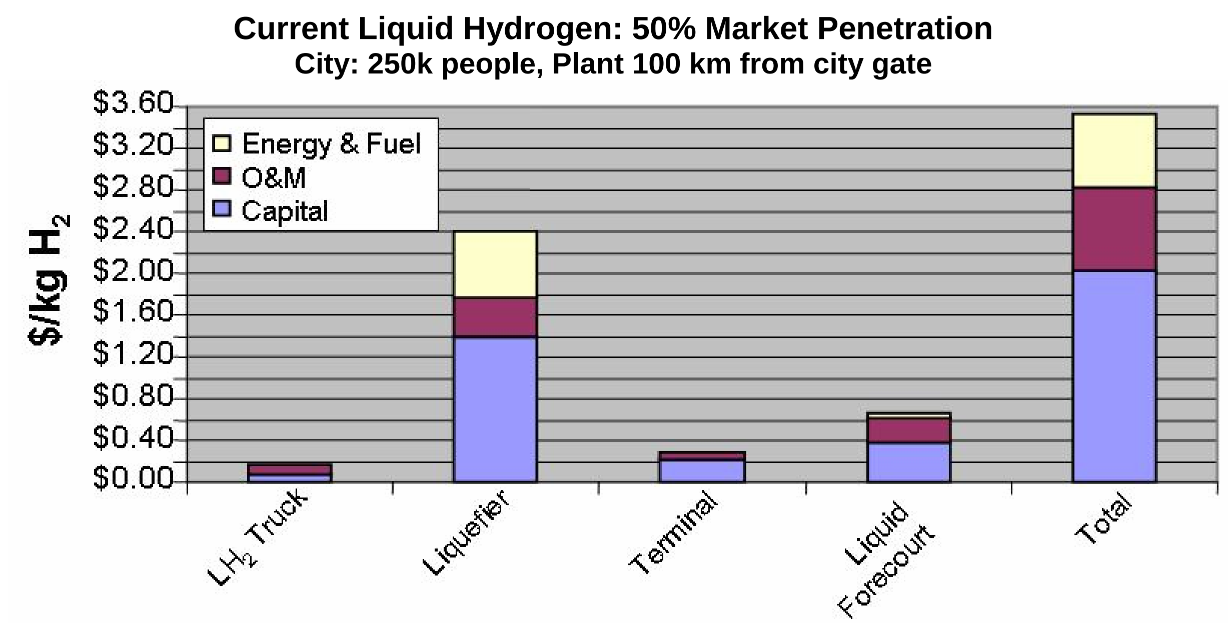


Figure 10-5: Current Delivery Costs for Cryogenic Liquid H_2 Pathway

Figures 10-6 and 10-7 show the results of the H2A Delivery Scenario Model when the ultimate Targets in Table 9-1 are inserted into the model. The cases shown are for urban markets of 250,000 and 1,000,000 people.

- As expected, the costs of all the pathways are reduced significantly compared with the current costs shown in Figures 10-1 and 10-2.
- The costs at high market penetrations for pipelines and high capacity tube trailers approach the overall cost target of <$1.00/kg especially for the larger urban area.
- The costs for the high capacity tube trailer pathway (1,100 kg capacity) are nearly equivalent to the pipeline pathway even at large market penetrations and are lower than pipelines at lower market penetrations. If technology for a high capacity tube trailer could be developed it would be a very attractive delivery option especially for hydrogen distribution within an urban area. This would avoid the potentially problematic option of extensive pipeline distribution infrastructure in urban areas.

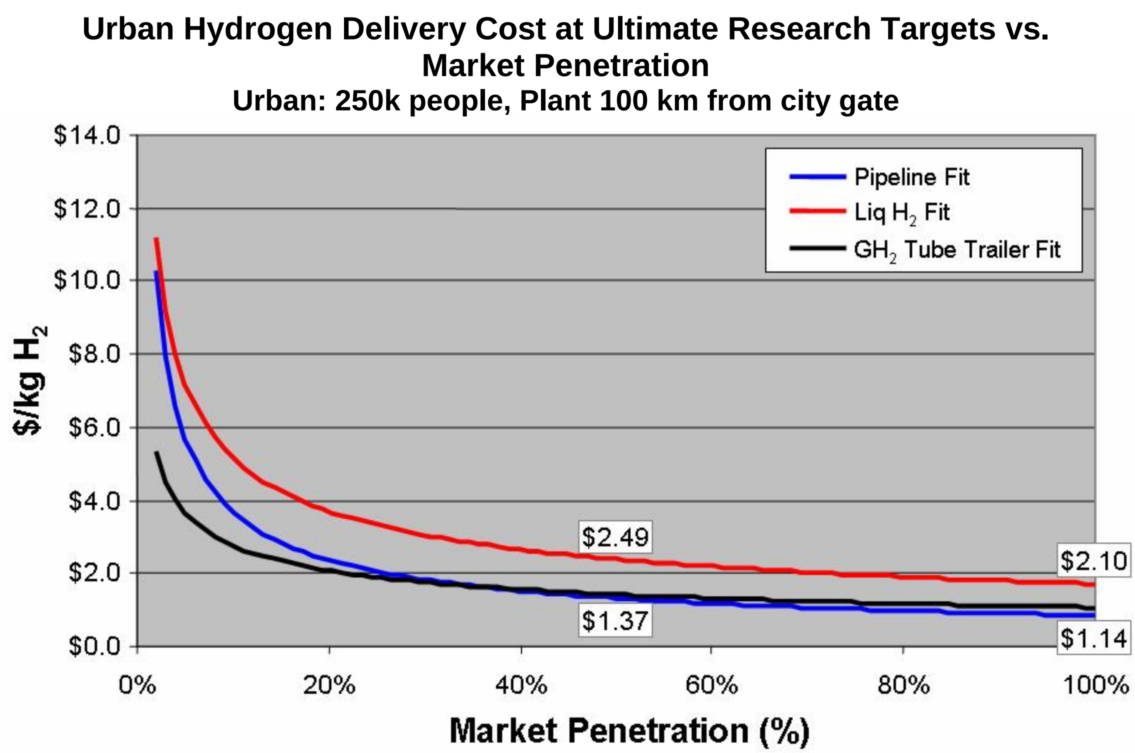


Figure 10-6: H2A Delivery Scenario Model for Urban H_2 Delivery Cost at Ultimate Research Targets vs. Market Penetration (250k People)

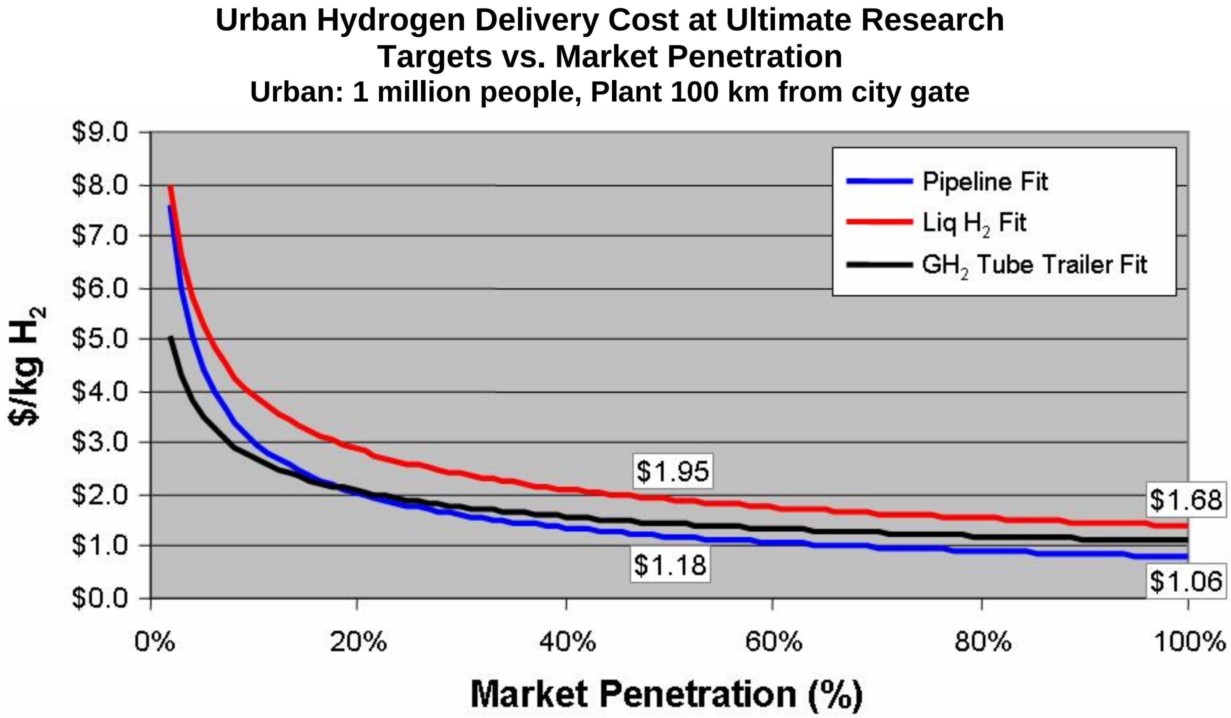


Figure 10-7: H2A Delivery Scenario Model for Urban H_2 Delivery Cost at Ultimate Research Targets vs. Market Penetration (1 million people)

The H2A Delivery Scenario Model results are very instructive. They show that the targets that have been set for delivery infrastructure components will significantly decrease overall delivery costs and at least approach the overall delivery objectives stated in Section 2. However, there is still more to be learned about delivery infrastructure options and costs. The H2A Delivery Models are continuing to be further developed and refined.

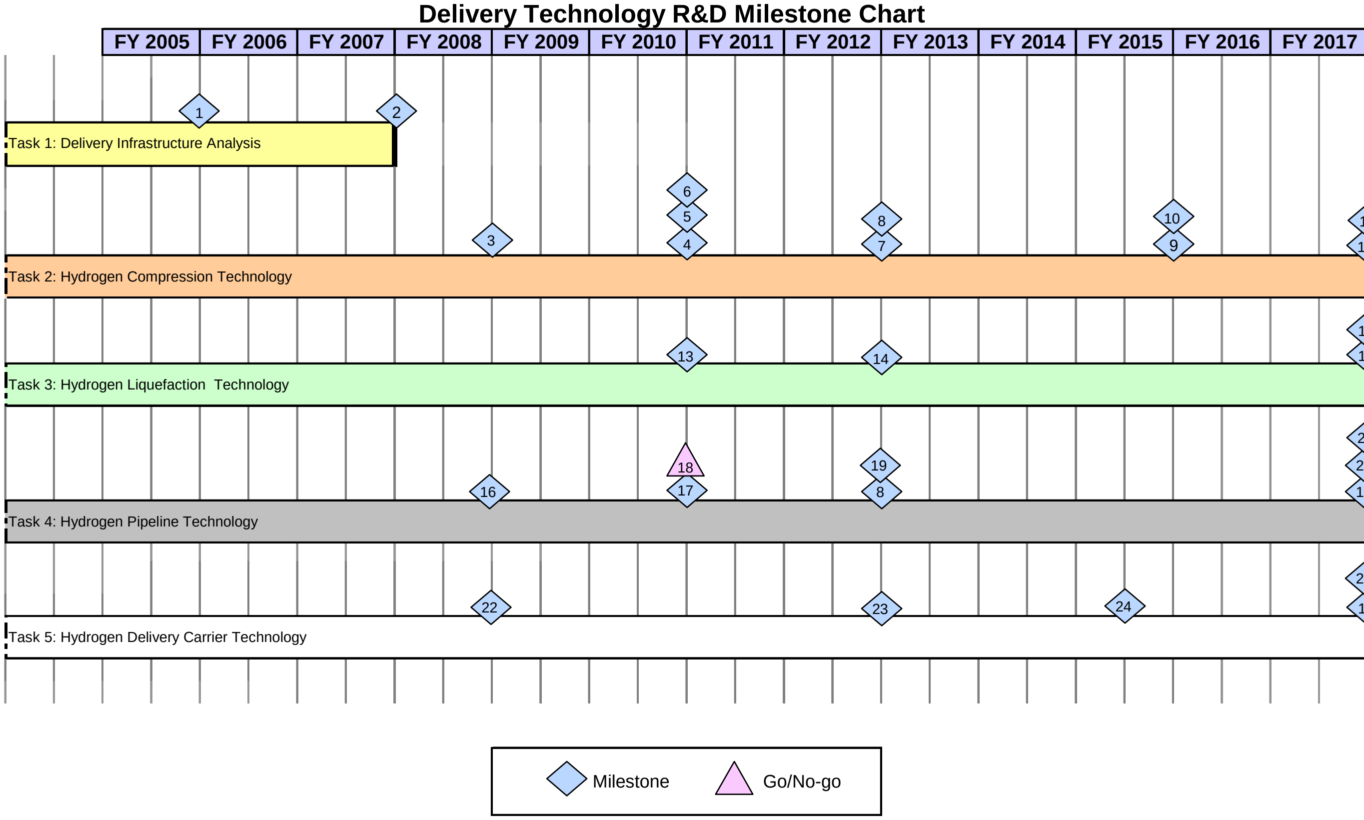
- The models allow for only two sizes of refueling stations. At less than about 10% market penetration, 100 kg/day stations are used. At higher market penetrations, all stations are 1,500 kg/day. Larger stations (>1,500 kg/day) offer an important economy of scale and thus cost reduction. It is also likely that there will be a distribution of station sizes.
- It is possible that clusters of smaller cities will be serviced by one or more nearby central hydrogen production plants and this can reduce the cost of hydrogen delivery to these markets. This aspect is not yet being modeled.
- The needs for hydrogen storage within the delivery infrastructure are not fully understood. Storage adds considerable cost. This will be explored more fully in the near future.
- The current delivery models do not include options for mixed pathways (e.g., pipeline transmission with tube trailer distribution) or carrier pathways.
- The current models need further development to get a better understanding of options and costs for interstate and rural hydrogen delivery.

These further developments in hydrogen delivery modeling will help future refinements of delivery Component Targets.

11 Task Timelines and Milestones

The DOE Hydrogen, Fuel Cells and Infrastructure Technologies Program has determined that the following timeline and milestones for hydrogen delivery are appropriate in order to meet the Program's overall objectives and timing.

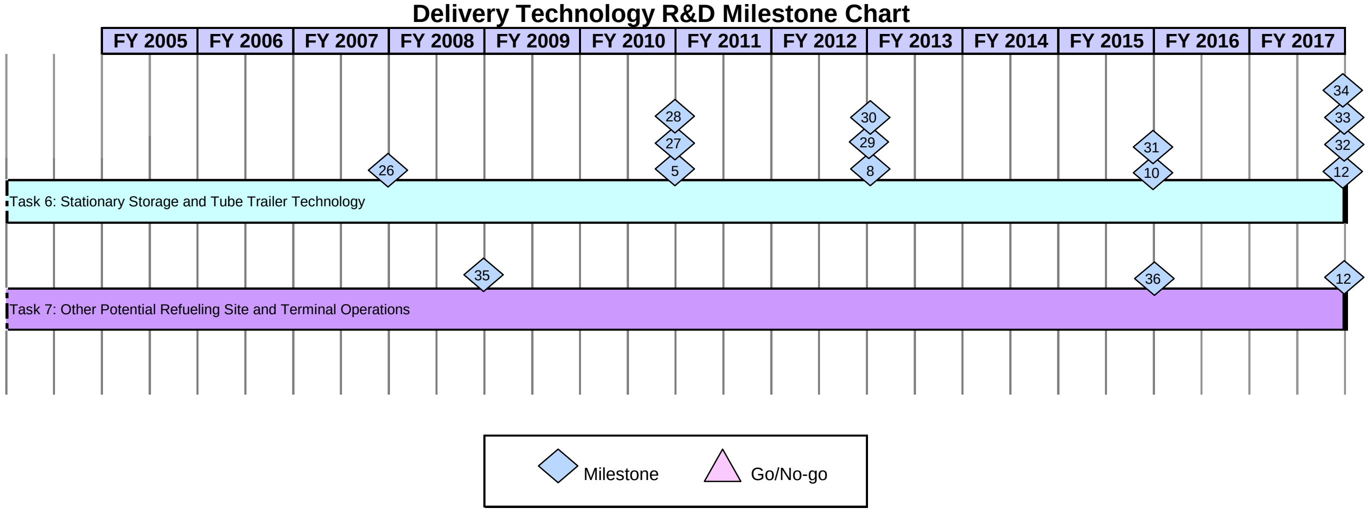
Delivery Technology R&D Milestone Chart



Milestones

Task 1: Delivery Infrastructure Analysis	
1	**Characterize the current cost and energy efficiency of the components and complete pathways for gaseous and liquid hydrogen delivery and the cost boundaries of potential novel solid and liquid carrier systems. (4Q 2005)**
2	**Identify cost-effective options for hydrogen delivery infrastructure to support the introduction and long-term use of hydrogen for transportation and stationary power. (4Q 2007)**
Task 2: Hydrogen Compression Technology	
3	**Down select to 2-3 most promising compression technologies for hydrogen refueling sites. (4Q 2008)**
4	**Verify 2010 targeted costs and performance for hydrogen refueling site compression. (4Q 2010)**
5	**By 2010, reduce the cost of compression, storage and dispensing at refueling sites to <$.80/gge. (4Q 2010)**
6	**Down select to 2-3 most promising compression technologies for hydrogen pipeline transmission, and similar high throughput compression needs in the hydrogen delivery infrastructure. (4Q 2010)**
7	**Verify 2012 targeted costs and performance for hydrogen pipeline compression. (4Q 2012)**
8	**By 2012, reduce the cost of hydrogen transport from central and semi-central production facilities to the gate of refueling sites to <$.90/gge of hydrogen. (4Q 2012)**
9	**Verify 2015 targeted costs and performance for hydrogen refueling site compression. (4Q 2015)**
10	**By 2015, reduce the cost of compression, storage and dispensing at refueling sites to <$.40/gge. (4Q 2015)**
11	**Verify 2017 targeted costs and performance for hydrogen pipeline compression. (4Q 2017)**
12	**By 2017, reduce the cost of hydrogen delivery from the point of production to the point of use at refueling sites to <$1.00/gge. (4Q 2017)**
Task 3: Hydrogen Liquefaction Technology	
13	**Down select to most promising 1-2 liquefaction technologies. (4Q 2010)**
14	**Verify 2012 targeted costs and performance for hydrogen liquefaction. (4Q 2012)**
15	**Verify 2017 targeted costs and performance for hydrogen liquefaction. (4Q 2017)**
12	**By 2017, reduce the cost of hydrogen delivery from the point of production to the point of use at refueling sites to <$1.00/gge. (4Q 2017)**
Task 4: Hydrogen Pipeline Technology	
16	**Research identifies fundamental mechanism of hydrogen embrittlement and permeation in steel pipelines and identifies promising cost effective measures to mitigate these issues. (4Q 2008)**
17	**Down select on materials and/or coatings for hydrogen pipelines, including the potential use of natural gas pipelines for mixtures of natural gas and hydrogen, or hydrogen alone. (4Q 2010)**
18	**Go/No-Go on the use of hydrogen and natural gas mixtures in the existing natural gas pipeline infrastructure as an effective means of hydrogen delivery. (4Q 2010)**
19	**Verify 2012 targeted cost and performance for hydrogen pipelines. (4Q 2012)**
8	**By 2012, reduce the cost of hydrogen transport from central and semi-central production facilities to the gate of refueling sites to <$.90/gge of hydrogen. (4Q 2012)**
20	**Suitable technology for system mechanical integrity monitoring and leak detection is developed. (4Q 2017)**
21	**Verify 2017 targeted cost and performance for hydrogen pipelines. (4Q 2017)**
12	**By 2017, reduce the cost of hydrogen delivery from the point of production to the point of use at refueling sites to <$1.00/gge. (4Q 2017)**
Task 5: Hydrogen Delivery Carrier Technology	
22	**Initial down-select for potential solid or liquid carrier systems for hydrogen delivery and bulk storage based on cost boundary analysis and initial research efforts. (4Q 2008)**
23	**Verify the feasibility of a hydrogen delivery carrier system to meet the 2012 carrier targets. (4Q 2012)**
24	**Down select on hydrogen delivery carrier system technologies to achieve the 2017 cost and performance targets. (2Q 2015)**
25	**Verify the feasibility of a hydrogen delivery carrier system to meet the 2017 carrier targets. (4Q 2017)**
12	**By 2017, reduce the cost of hydrogen delivery from the point of production to the point of use at refueling sites to <$1.00/gge. (4Q 2017)**

Delivery Technology R&D Milestone Chart



Milestones

Task 6: Stationary Storage and Tube Trailer Technology	
26	**Complete baseline analyses of stationary storage options at refueling stations and throughout the delivery infrastructure. (4Q 2007)**
27	**Down select to the most promising 1-3 technologies for stationary storage and gaseous tube trailers. (4Q 2010)**
28	**Verify the feasibility of achieving the 2010 refueling station storage cost targets. (4Q 2010)**
5	**By 2010, reduce the cost of compression, storage and dispensing at refueling sites to <$.80/gge. (4Q 2010)**
29	**Complete the research to establish the feasibility and define the cost for geologic hydrogen storage. (4Q 2012)**
30	**Verify the feasibility of achieving the 2012 tube trailer cost and performance targets. (4Q 2012)**
8	**By 2012, reduce the cost of hydrogen transport from central and semi-central production facilities to the gate of refueling sites to <$.90/gge of hydrogen. (4Q 2012)**
31	**Verify the feasibility of achieving the 2015 refueling station storage cost targets. (4Q 2015)**
10	**By 2015, reduce the cost of compression, storage and dispensing at refueling sites to <$.40/gge. (4Q 2015)**
32	**Verify the feasibility of achieving the 2017 tube trailer cost and performance targets. (4Q 2017)**
33	**Verify the feasibility of achieving the 2017 geologic storage cost and performance targets. (4Q 2017)**
12	**By 2017, reduce the cost of hydrogen delivery from the point of production to the point of use at refueling sites to <$1.00/gge. (4Q 2017)**
34	**By 2017, reduce the cost of hydrogen transport from central or semi-central production facilities to the gate of refueling sites utilizing gaseous truck delivery to <$.70/gge in support of early market penetration. (4Q 2017)**
Task 7: Other Potential Refueling Site and Terminal Operations	
35	**Define the targets and research needs for the other potential operational needs for refueling sites and terminals. (4Q 2008)**
36	**Verify achieving the 2017 targets for the other defined operational needs for refueling sites and terminals. (4Q 2015)**
12	**By 2017, reduce the cost of hydrogen delivery from the point of production to the point of use at refueling sites to <$1.00/gge. (4Q 2017)**

12 Appendices

A. Comparison of Fuel Hydrogen Specifications

B. Conversion Factors

Appendix A: Comparison of Fuel Hydrogen Guidelines

Purity/Contaminant		GM, Oct. 2004	Ballard SPC5100203 July 2004	Jari, Sept. 2004	UTC 5/01/2005	CH2FSS350 Ver. 1.0 7/25/2005 GM, Ford, DCX	CaFCP, Ver. 1.0	SAE J2719, Nov 2005	ISO TC 197N,WG 12 Type 1, 03/24/2006	Test method	Detectability Level
H_2 Purity		99.9		99.99				100	99.99(a)		
Total Gases									100		
Water	ppmv or umole/mole	1000	2.5		5	5	5	5	5	D6348, D5454,	0.5
O_2	ppmv or umole/mole	1000	5	5	5	5	5	5	5	D1946, D5466	1
N_2	ppmv or umole/mole	1000	200	10000	200	200	200			D1946, D5466	60
He	ppmv or umole/mole									D1946, D5466	60
Ar	ppmv or umole/mole	1000								D1946, D5466	60
He + N_2 + Ar	ppmv or umole/mole							100	100		
CO_2	ppmv or umole/mole	1000	1	2	1	1	1	1	2	D1946, D5466	0.1
CO	ppmv or umole/mole	0.1	1	0.2	0.2	1	0.2	0.2	0.2	D1946, D5466	0.2
Sulfur	ppmv or umole/mole		0.01			0.01	0.01	.004	0.004	D1946, D5466	0.004
H_2S	ppmv or umole/mole	0.05		0.1						D1946, D5466	
SO_2	ppmv or umole/mole			0.1						D1946, D5466	
Mercaptans	ppmv or umole/mole	0.05								D1946, D5466	
Total HC	ppmv or umole/mole	10	1		1	1	1	2	2	D6348, D6968	0.1
Methane	ppmv or umole/mole	1000		10000						D6348, D6968	
Acetylene	ppmv or umole/mole	2								D6348, D6968	
Ethylene	ppmv or umole/mole	5		100						D6348, D6968	
Ethane	ppmv or umole/mole	1000		100						D6348, D6968	
Propylene	ppmv or umole/mole	5								D6348, D6968	
Benzene	ppmv or umole/mole	2		100	1.5					D6348, D6968	1
Formaldehyde	ppmv or umole/mole			10	0.01		0.01	0.01	0.01	D1946, D5466	0.01
Formic Acid	ppmv or umole/mole			100	0.2		0.2	0.2	0.2	D1946, D5466	0.2
Acetone	ppmv or umole/mole			100	0.8					D1946, D5466	0.01
Methanol	ppmv or umole/mole			500	5						?
Ammonia	ppmv or umole/mole		6		1	1	2	0.1	0.1	D1946, D5466	0.1
Halogens	ppmv or umole/mole				0.05			0.05	0.05	EPA 2007	0.01
Max. PM	ug/mole		10		10	20		1 ug/L	1 ug/L	EPA 625	
Max PM size	um		10			10	10	10	10	SCAQMD 301-91	1
Sodium	ppmv or umole/mole		0.05		0.05	0.05	0.05	0.05			
Potassium	ppmv or umole/mole		0.05		0.05	0.05	0.08	0.05			

Appendix B: Conversion Factors

Hydrogen/Gasoline
1 kg of hydrogen = 113,571 Btu (LHV) ~ 1 gallon of gasoline

Energy
1 Joule = 0.0009478 Btu
1 Btu = 1055 J

Weight
1 kilogram = 2.2 pounds
1 lb = 0.45 kg
1 metric ton = 1.1023 short tons
1 short ton = 0.9072 metric tons

Volume
1 Liter = 0.035 cubic feet
1 ft^3= 28.32 L = 0.0283 m^3
1 cubic meter = 6.29 barrels
1 bbl = 0.159 m^3

Pressure
1 bar = 14.5 pounds per square inch
1 psi = 0.069 bar

Distance
1 km = 0.62 miles
1 mile = 1.61 km