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Natural gas as a bridge to hydrogen transportation fuel: Insights from the literature☆

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ABSTRACT

Natural gas has been proposed as a possible "bridge" fuel to eventual use of hydrogen in zero emission fuel cell vehicles. This literature review explores whether the natural gas system might help enable a transition to longer-term use of hydrogen in transportation. Two transition strategies are reviewed: adapting natural gas refueling infrastructure for future use with H2 and blending renewable hydrogen into the NG system.

Our review suggests it is not attractive to re-purpose or overbuild NG fueling station equipment for future hydrogen service. Transporting H2/NG blends in the NG pipeline grid appears technically possible at modest fractions of 5–15% hydrogen by volume, but requires careful case by case assessment and could be expensive. Blending does not enable major reductions in GHG emissions from transport, unless "green" hydrogen can be cost effectively separated from the blend and delivered to highly efficient fuel cell vehicles. Ultimately, blend limits could make it difficult to utilize the existing NG system to deliver hydrogen at the scale needed to achieve deep cuts in transportation related GHGs. A dedicated renewable hydrogen system would be needed, if zero emission fuel cell vehicles play a major role in a future low carbon world.

1. Introduction

Recent energy/economic modeling studies suggest that reaching a "2 degree" climate scenario will require significant electrification of the light duty vehicle sector over the next several few decades, with large roles emerging for both hydrogen fuel cell vehicles (FCVs) and plug-in battery electrics (PEVs) (IEA, 2012, 2015; NRC, 2013). Natural gas is often discussed as a possible "bridge" fuel to eventual use of hydrogen in zero emission fuel cell vehicles, technologies which might play an important long term role in achieving deep cuts in transportation-related carbon emissions.

Both fuels are currently under development for transportation applications. Natural gas is already widely used as a transportation fuel for fleet vehicles, medium duty trucks including class 4–6 urban last mile delivery trucks and class 7–8 short-haul drayage trucks. LNG is being developed for long-haul freight applications (Scheitrum et al., this issue; Fan et al., 2017).

Hydrogen fuel cell vehicles (FCVs) began commercialization in light duty markets, in 2014. About 5500 FCVs are on the road today (PR Newswire, 2017), concentrated in a few early adopter areas, and initial regional networks of hydrogen refueling stations are being built (E4Tech, 2016). Hydrogen fuel cells have also been proposed for zero emissions medium and heavy duty vehicles and a few dozen fuel cell buses and trucks are now being demonstrated (CAFCP, 2016; Ohnsman, 2017; Stewart, 2017; Hall-Geisler, 2017).

Fuel availability is a key barrier facing large scale introduction of hydrogen vehicles. Unlike natural gas or electricity, there is currently no widespread infrastructure bringing hydrogen to consumers, and building a new hydrogen supply system is seen as expensive and risky. This has generated interest in hydrogen transition strategies that might utilize existing energy systems, especially natural gas infrastructure.

It is logical to look for synergies between hydrogen and natural gas.

Abbreviations: bar, 1 atm of pressure = 14.7 psia (pressure unit); CAFCP, California Fuel Cell Partnership; CCS, carbon capture and sequestration; CH2, compressed hydrogen gas; CNG, compressed natural gas; FCV, fuel cell vehicle; FCB, fuel cell bus; gge, gallon gasoline equivalent energy (energy unit) = 121.7 MJ (lower heating value); GHG, greenhouse gas; GW, gigawatt (10^9 W); H2, hydrogen; HD, heavy duty; HHV, higher heating value; ICEV, internal combustion engine vehicle; kg, kilogram; LCFS, low carbon fuel standard; LDV, light duty vehicle; LH2, liquid hydrogen; LHV, lower heating value; LNG, liquefied natural gas; MD, medium duty; MJ, Megajoule (energy unit); NG, natural gas; NGV, natural gas vehicle; NRC, National Research Council; PEM, proton exchange membrane; PEV, plug-in electric vehicle; psia, pounds per square inch absolute (pressure unit); RNG, renewable natural gas; scf, standard cubic foot (volume unit); SMR, steam methane reformer; VRE, variable renewable electricity (e.g. solar, wind); ZEV, zero emission vehicle

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Most hydrogen today is produced from natural gas. Natural gas and hydrogen have physical similarities: both fuels can be stored as compressed gases or cryogenic liquids and many of the components in a natural gas infrastructure (such as compressors, storage tanks and pipelines) are analogous to those for hydrogen. Given ongoing expansion of both natural gas and hydrogen in transportation applications, planners and policymakers have asked whether some or all the existing natural gas infrastructure might be re-used or designed for compatibility with the emerging hydrogen infrastructure (Jaffe et al., 2017; Sandia National Laboratories, 2014).

Reducing greenhouse gas (GHG) emissions from transportation is a major motivation for adopting hydrogen FCVs. Thus, a critical long term issue is how to provide hydrogen transportation fuel at large scale from zero or near-zero carbon supply pathways. Today most hydrogen comes from fossil sources, usually natural gas, which emits greenhouse gases during hydrogen production (Nguyen et al., 2013). But ultimately, a switch to low carbon hydrogen pathways will be needed. A proposed strategy, currently being demonstrated, is "power-to-gas". Here hydrogen is produced electrolytically, for example, from low-cost curtailed solar or wind electricity in a renewable intensive electric grid. The produced hydrogen could be blended into natural gas pipelines and transported to users, without having to build a costly dedicated hydrogen infrastructure. This strategy offers multiple potential benefits: it could create a market for uneconomic excess renewable power, provide a way of storing and transporting renewable hydrogen, reduce carbon content of the NG/H2 gaseous blend fuel and ultimately help enable use of zero emission hydrogen in transportation, assuming the hydrogen could be cost effectively separated from the blend and dispensed to vehicles. Alternatively, electrolytic hydrogen could be combined with a renewable source of carbon via methanation (Goetz et al., 2016) to make renewable methane, which could be blended with natural gas. Or hydrogen might be delivered in a dedicated hydrogen infrastructure. A key question is under what conditions a hydrogen blending strategy that utilizes the natural gas system might help enable widespread use of zero emission hydrogen fuel cell vehicles, and whether a parallel dedicated hydrogen system will be preferred.

A number of recent technical articles have addressed particular aspects of how natural gas might relate to a hydrogen transition. These articles represent various perspectives: near term to mid-term planning for alternative transportation fuels; energy/economic analysis of potential roles for NG and H2 in low carbon, renewable-intensive energy futures; power to gas technology assessments; and fuel infrastructure technologies and transitions (Alliat et al., 2009; Brydol et al., 2017; Bünger et al., 2014, 2015; European Commission, 2015a, 2015b, 2015c; Fan et al., 2017; Goetz et al., 2016; IEA 2003, 2015; Jaffe et al., 2017; JRC, 2014; Judd and Pinchbeck, 2015; Melaina et al., 2013a; Sandia National Laboratories, 2014; Scheitrum et al., 2018; Schiebahn et al., 2015; Steen, 2015).

In this article, we undertake a comprehensive literature review, drawing on these diverse perspectives. Topics reviewed include natural gas vehicle markets and infrastructure options; hydrogen fuel cell vehicle introduction and infrastructure options; compatibility of natural gas and hydrogen infrastructures; technical aspects of using hydrogen blends in the natural gas system; power to gas for transport applications; scenarios for low carbon future transportation; and power to gas concepts for capturing renewable energy. Our overall goal is to distill insights from this broad literature review about how and when the natural gas system might facilitate adoption of hydrogen in transportation. We focus on several questions:

- What are the likely roles of natural gas and hydrogen in various transport applications?
- What infrastructure options could supply natural gas or hydrogen to vehicles? Could a future hydrogen refueling infrastructure grow "organically" from natural gas infrastructure? Could natural gas refueling equipment be re-purposed or designed for future hydrogen compatibility?
- How might the growth of natural gas and hydrogen transportation markets impact infrastructure development and synergies? How much might natural gas and hydrogen infrastructures "overlap" geographically and over time?
- Is it technically feasible to use hydrogen or hydrogen blends in the natural gas system?
- What is the role of renewable "power-to-gas" for low-carbon transportation? Is blending renewable hydrogen into natural gas pipelines an attractive path toward carbon-free hydrogen transportation or is a parallel hydrogen infrastructure needed?

Two transition approaches are reviewed where H2 transportation fuel infrastructure might grow out of the NG infrastructure 1) overbuilding or re-purposing natural gas refueling infrastructure for future use with H2; 2) blending renewable hydrogen into the NG pipeline system (e.g. electrolytic H2 is produced from curtailed variable renewable electricity). In many of the papers we reviewed, these are compared to a third option of building a dedicated hydrogen refueling infrastructure.

We first review which transportation applications are most promising for natural gas and hydrogen. Possible infrastructure supply chains for refueling natural gas and hydrogen vehicles are then described. We draw some general conclusions about the near to mid-term potential for overlap between natural gas and hydrogen infrastructures and assess whether components of the natural gas refueling supply system might be repurposed or built for forward-compatibility with hydrogen.

We review studies on the technical issues for using hydrogen or hydrogen blends in existing natural gas infrastructure. We discuss how blending renewable hydrogen into natural gas might reduce greenhouse gas emissions from transportation via "power to gas", as well as the technical limits to this approach.

We review a recent case study for how natural gas and hydrogen infrastructures in California might co-evolve over the next two decades (Jaffe et al., 2017). We also review studies from the European Union that take a longer term view, exploring the role of renewable "power to gas" in a transition to zero emission hydrogen, and its applicability in transportation markets (Alliat et al., 2009; Bünger et al., 2014, 2015; European Commission, 2015a, 2015b, 2015c; Rudd and Pinchbeck, 2015; Schiebahn et al., 2015).

Finally, we discuss the implications of our review and suggest areas for future research.

2. Literature review of vehicle and infrastructure options

2.1. Natural gas in transportation

The literature on natural gas vehicles has typically focused on light duty, transit and refuse vehicles applications, while only a few studies include long haul trucking applications. Rood-Werpy (2010) concludes that high costs, limited refueling infrastructure, and uncertain environmental performance constitute barriers to widespread adoption of natural gas as a transportation fuel in the United States but, in another substantial contribution to the literature, Krupnick (2011) finds that the move from a long-haul route structure to a "hub and spoke" structure could facilitate the development of natural gas refueling infrastructure in the highway system.

Kuby et al. (2009) found that early adopters of light duty natural gas vehicles may be willing to refuel more frequently and farther from home than gasoline drivers, but more so on work-based trips and less on home-anchored trips. In another study, Kelley and Kuby (2013) find CNG users favored refueling CNG along routes used frequently rather than closer to their homes. Both studies suggest CNG is more appealing for commercial applications including by captive fleets than for passenger vehicles. This matches with findings by the Boston Consulting

Group (BCG) that suggests that CNG vehicles will likely continue to replace high-mileage, low-fuel economy vehicles (Nath et al., 2014), and work by Knittel (2015) shows that CNG vehicles could offer long term cost advantages. Burnham et al. (2015) identify fueling infrastructure access and the incremental cost of vehicles as two key barriers to natural gas vehicle adoption. In some markets with high mileage, lower natural gas costs can help lower payback periods. They note that an important driver increasing vehicle sales is incetnives for both vehicles and infrastructure. Light duty CNG applications include taxis and government owned passenger vehicle fleets (ORNL, NGV Global http://www.iangv.org/natural-gas-vehicles/vehicle-types/).Schroeder (2016) discusses technical market barriers to natural gas vehicle commercialization. The report recommends research priorities to overcome barriers such as lack of fueling infrastructure, modest on-board fuel storage, and reduced engine performance. Fueling infrastructure can benefit from developing cost-effective home refueling technologies, developing modular fueling facilities, and increasing station operating efficiency. On-board fuel storage can be increased through development of high-density storage vessels and creating certification procedures for conformable storage tanks. A variety of new engine technologies, including direct injection, homogeneous charge compression, and reactivity controlled compression ignition, have the potential to increase fuel economy.

In terms of business models, the Boston Consulting Group finds that conventional petroleum fuel stations will only add CNG refueling when they find a fleet partner (Nath et al., 2014). BCG studies also note that manufacturers that offer both vehicle and refueling station technology are necessary to boost CNG adoption (Mosquet et al., 2011). Rosentiel et al. (2015) find that, in Germany, a monopoly of service stations at motorways, is one of the most prominent market failures inhibiting the development of a functioning market for NGVs.

Struben and Sterman (2008) research dynamics of alternative vehicles adoption, including CNG. They find that with word of mouth an important aspect of stimulating diffusion and that policies and subsidies are required in order to establish a is critical threshold for sustained adoption.

Dimitropoulos et al. (2013) find that, among light duty users, driving range and other attributes related to refueling activities, such as refueling duration and the coverage of refueling infrastructure, are important consideration in refueling behavior. They conclude that technological developments permitting longer driving ranges will, to some extent, facilitate alternative fuel vehicles market penetration.

Fan et al. (2017) find that use of liquefied natural gas (LNG) fuel can be most commercially attractive as a fuel for long haul class 8 trucks in high volume freight corridors where diesel prices are relatively high such as California and the Great Lakes region. California is particularly well-suited, the study finds, because of its concentration of trucking along a single north-to-south highway route connecting major port cities. California is currently home to 70% of LNG fueling facilities in the United States and 20% of total US CNG stations. There are approximately 25,000 registered natural gas vehicles in the state (California Energy Commission, 2015).

2.2. Natural gas infrastructure pathways

Natural gas fuel can be stored and transported as compressed natural gas (CNG) or as liquefied natural gas (LNG) (Fig. 1).

In the CNG pathway, natural gas is delivered by gas pipeline to the station, where it is compressed to 2400–3600 psia, stored in pressure cylinders, and dispensed to natural gas vehicles. Depending on the application, CNG stations can be "fast fill" or "timed fill".

Two LNG pathways are shown. In the first, natural gas is delivered by pipeline to a large centralized liquefaction plant. After the natural gas is liquefied at −160 degrees C, LNG is delivered by truck to a refueling station, stored in a cryogenic tank, and dispensed to LNG vehicles. In the second, natural gas is delivered directly to the refueling station via gas pipeline. At the refueling station, natural gas is converted to LNG onsite in a small modular liquefaction plant and dispensed to the vehicle (Fan et al., 2017).

Most natural gas for vehicles today comes from fossil sources, but renewable natural gas (RNG) could also be used (Jaffe et al., 2015; Scheitrum et al., in this issue).[1]

2.3. Hydrogen and fuel cells in transportation

Hydrogen has been proposed as a future transportation fuel for zero emission fuel cell vehicles, because of its potential to reduce greenhouse gas emissions in the transport sector as well as air pollutant emissions (Nguyen et al., 2013; Bünger et al., 2014). Recent studies of low carbon futures suggest that electric drive vehicles could play a major role in the future light duty vehicle fleet (IEA, 2012; NRC, 2013). For example, in the International Energy Agency's "2 degree scenarios", corresponding to 80% GHG emissions cuts by 2050, hydrogen fuel cell (FCVs) and plug-in electric vehicles (PEVs) account for nearly 75% of on-road passenger cars by 2050 (IEA, 2014). A recent study by the National Academies examined a variety of low carbon scenarios for the United States, where hydrogen fueled over half of on-road light duty vehicles by 2050 (NRC, 2013).

Hydrogen fuel cell passenger cars began commercial introduction in Japan, Europe and the United States (notably California), in 2014. Major automakers including Hyundai, Toyota and Honda have entered the market. Nissan, GM and Daimler have announced plans to commercialize FCVs within the next few years (E4Tech, 2016). Hydrogen is also being demonstrated in fleet vehicles such as transit buses (where there are currently a few dozen in operation with a few hundred planned over the next several years), trucks (CAFCP, 2016), and specialty vehicles, notably forklifts, where hydrogen fuel cells offer operational advantages over batteries (E4Tech, 2016). Fuel cell truck applications focus on medium duty delivery trucks and short haul drayage trucks. Long haul applications are seen as further in the future (CAFCP, 2016). However, recent announcements by Toyota and Nikola suggest industry interest in demonstrating hydrogen fuel cells for heavy duty long haul freight applications as well (Ohnsman, 2017; Stewart, 2017; Hall-Geisler, 2017).

Fuel cell vehicles are potentially attractive to buyers of zero emission passenger vehicles, because of their fast refueling time (3–5 min), long range (> 500 km), large size and good performance. Most automakers are developing both PEVs and FCVs, seeing future roles for both types of zero emission vehicles. While further development is needed for hydrogen technologies, to reduce the cost of proton exchange membrane (PEM) fuel cells and improve their durability, and to reduce the cost of hydrogen storage on vehicles, it is anticipated that hydrogen FCVs will meet these goals over the next few years (Satyapal, 2016).[2]

[1] RNG can be produced from manure, food waste, landfill gas, wastewater treatment sludge, forest and agricultural residues, and organic municipal solid waste. Biomass gasification offers another path to RNG production. Blending RNG with fossil natural gas provides a potential opportunity to build RNG usage and familiarity, while lowering costs through integration with existing infrastructure.
In the longer term, methane could be produced from power to gas pathways (methanation), e.g. combining renewable electrolytic hydrogen with renewable carbon.

[2] Today's automotive fuel cell vehicles use proton exchange membrane fuel cells (PEMFCs) and store hydrogen onboard. Several other configurations have been considered for fuel cells in transportation, including onboard production of hydrogen by reforming more readily stored fuels including natural gas, diesel, and jet fuel, and use of solid oxide fuel cells (SOFCs) which can use these fuels directly. This avoids the cost and complexity of building a hydrogen infrastructure. In the 1990s-early 2000s there was interest in PEM FCVs with onboard reformation of liquid fuels to make H2. However, the cost, efficiency losses and complexity of onboard reformer systems were found to outweigh the advantages of onboard liquid fuel storage, at least for light duty vehicles (Ogden et al., 1999) Even with the complexities of H2 storage and infrastructure all the major car makers have focused on direct H2 instead of onboard reformers.
High temperature SOFCs could use NG directly. However, SOFCs have some limitations for on-road transportation applications compared to the proton exchange membrane

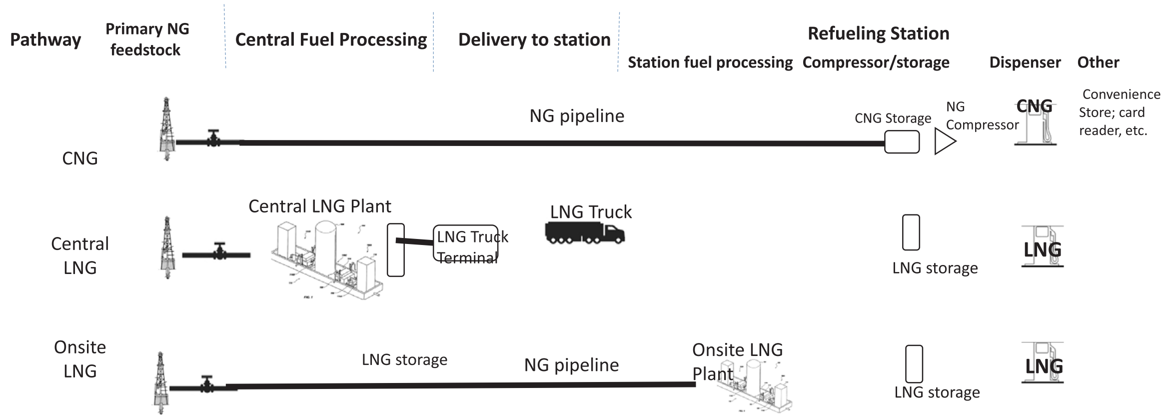

Fig. 1. Natural Gas fuel supply pathways.

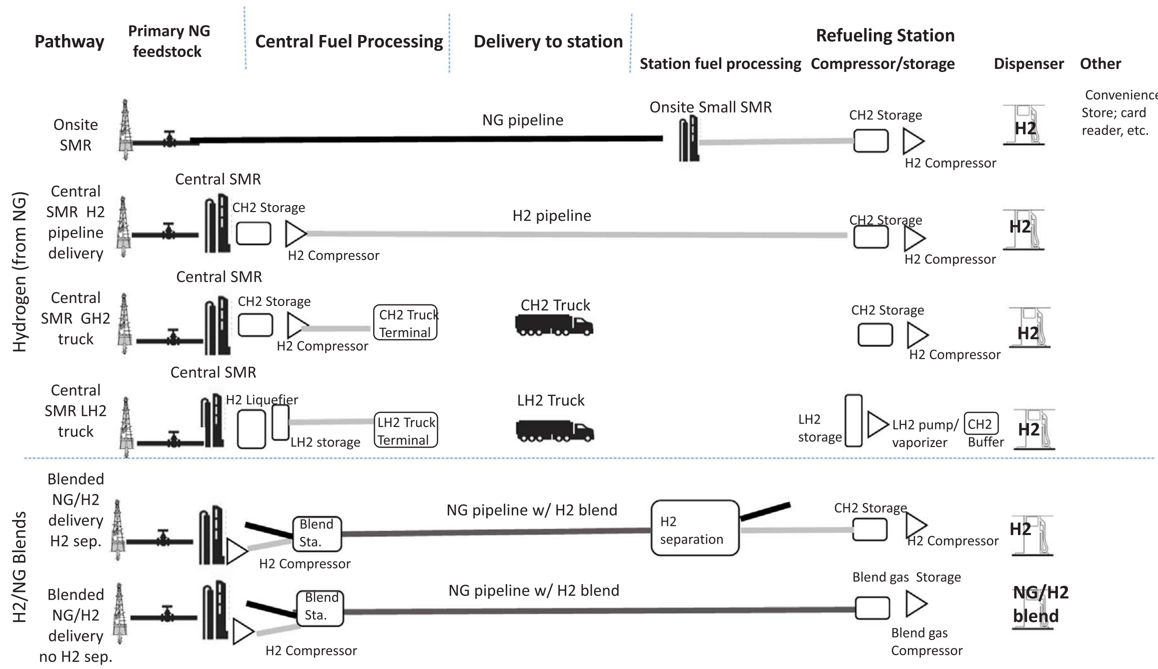

Fig. 2. Fuel supply pathways for H2 and H2/NG blends derived from natural gas.

Although current fuel cell passenger vehicles are costly, projections by the National Academies (NRC, 2008; NRC, 2013) suggest that mass produced FCV passenger cars could become competitive with incumbent internal combustion engine technologies over the next decade or so.

(*footnote continued*)
(PEM) fuel cells typically used today (Fergus, 2015).

1) NG fueled SOFCs have a higher operating temperature (700–1000 C) and longer start-up time than automotive PEM fuel cells (which operate at 100 C and can start up in a few seconds).
2) The power density of PEMFCs is higher than SOFCs, which makes PEMs more desirable for transportation applications, especially cars where space is at a premium.
3) Lifetime under variable conditions such as transportation is better for PEMFCs than SOFCs.

High temperature SOFCs are not suitable for light duty vehicles, which require fast start-up, have frequent stops and starts, and need a compact power plant. SOFCs may be better suited for locomotives (Martinez et al., 2012, LIdicker et al., 2012) or ships (Ezgi et al., 2013) where the vehicle would be operated continuously for a long period of time. SOFCs have also been proposed for use as Auxiliary Power Units in trucks and aircraft (USDOE, 2016).

2.4. Hydrogen infrastructure pathways

Hydrogen can be produced from a variety of primary resources, via thermochemical processing of hydrocarbons, such as natural gas, coal or biomass, or via water electrolysis using any source of electricity including renewables, such as wind or solar, or nuclear power. Today, most hydrogen is produced commercially from fossil fuels (primarily natural gas) as a feedstock for oil refining and other industrial uses, accounting for 1–2% of global primary energy use. The growth of low-cost shale gas has been an important factor boosting interest in hydrogen in the United States. In the future, to realize the maximum greenhouse gas reductions, hydrogen might be produced from a variety of low carbon sources, including fossil hydrogen with carbon capture and sequestration (CCS), and water electrolysis using renewable electricity and be used throughout the energy system. Further, hydrogen could serve as flexible energy storage for intermittent renewable electricity that might otherwise be curtailed, opening the possibility of "greening" both electricity and fuels via "power to gas" (Bünger et al., 2014, 2015; European Commission 2015a, 2015b, 2015c; Goetz et al., 2016; Schiebahn et al., 2015).

There are several pathways to supply hydrogen to vehicles. Hydrogen can be produced regionally in large central plants, stored as a compressed gas or cryogenic liquid (at −253 °C), and distributed by truck or gas pipeline to refueling stations (USDOE, 2016). Hydrogen production and delivery technologies are well established in the merchant hydrogen and chemical industries. Alternatively, hydrogen can be produced on-site at refueling sites from natural gas or electricity. No one hydrogen supply pathway is preferred in all situations, and, like electricity, it is likely that diverse primary sources will be used to make hydrogen in different regions (Melaina et al., 2013b).

Fig. 2 illustrates six possible pathways for producing hydrogen from natural gas and delivering it to vehicles. For the "onsite SMR" pathway, natural gas is delivered by pipeline to a refueling station, where hydrogen is produced onsite in a small steam methane reformer (SMR). (This avoids the need to transport final hydrogen fuel to the station in a truck or pipeline.) For "centralized production", hydrogen could be produced from natural gas in a large central SMR. Or, if low cost curtailed renewable electricity was available, hydrogen could be produced electrolytically at a central location, for example, near a wind or solar farm, and stored for use as a transport fuel (Büngeret al., 2015; Judd et al., 2015). Pure hydrogen can be delivered to refueling stations by truck as compressed gas (CH2) or cryogenic liquid (LH2) or via hydrogen gas pipeline. Centrally produced hydrogen can also be blended into existing natural gas pipelines. The NG/H2 blend gas can be delivered to refueling sites, where it can be combusted directly as a fuel gas, or pure H2 can be separated from the blend for use in a fuel cell vehicle.

Adoption of hydrogen vehicles will require a supporting hydrogen refueling infrastructure. Early hydrogen infrastructure must offer enough station locations to provide convenient fuel accessibility for the early adopter vehicles; enough capacity to meet hydrogen demand as the fuel cell vehicle (FCV) fleet grows; a positive cash flow for hydrogen suppliers and hydrogen priced competitively with gasoline, estimated to be \$10 per kilogram initially, and \$5–8 per kg for the longer-term.[3]

Hydrogen FCV commercialization roadmaps are being developed by public-private partnerships around the world (Baronas and Achtelik, 2016; McKinney et al., 2015; Ogden et al., 2014; Joint Research Centre (JRC) 2014).[4] Such plans must coordinate the deployment of FCVs and hydrogen infrastructure build-out, geographically and over time.

For passenger cars, some hydrogen planners adopt a "cluster strategy", co-locating the first several thousand vehicles and tens of stations in "lighthouse" communities identified as early adopter areas within a larger region (Ogden and Nicholas, 2011; Brown et al., 2013). The cluster strategy brings the required number of initial stations to a more manageable level (EMFAC, 2014; CARB, 2016).

3. Literature review of synergies between natural gas and hydrogen fueling infrastructures and insights from transition case studies

3.1. Comparing markets for hydrogen fuel cell and natural gas vehicles

Several recent studies have compared markets for natural gas and hydrogen vehicles (Sandia National Laboratories, 2014; Jaffe et al., 2017) (see Table 1).

Current natural gas transport fuel development in the United States is focused on heavy duty long haul trucks fueled with LNG, as well as medium and heavy duty fleet vehicles fueled with CNG including buses,

Table 1
Transportation Applications for Natural Gas and Hydrogen[a].

Application	NG		H2	
	CNG	*LNG*	*CH2*	*LH2*
Light duty vehicles	X		X	
Buses	X		X	
Med duty trucks	X		X	
Heavy duty trucks	X	X	X	X
Rail		X		X
Marine		X		X
Aviation		X		X

CNG = compressed natural gas; LNG = liquefied natural gas; CH2 = compressed hydrogen gas; LH2 = liquid hydrogen.
[a] Ogden, 2014.

delivery trucks, refuse trucks and drayage trucks.

A National Petroleum Council (2012) study of class 7 and 8 trucks shows substantial potential for natural gas vehicle market penetration. They note that natural gas spark ignition (SI) engines are lower cost but also have lower fuel economy than compression ignition (CI) engines. From a purely economic analysis they conclude that SI engines could reach roughly a 20–30% higher market share than CI engines. A Citi GPS (2013) analysis also shows significant potential for natural gas vehicles in the heavy-duty fleet with a small contribution in the long haul fleet. They note that Westport is focusing R&D on their HPDI CI engine platform expecting to achieve greater penetration of the long haul and heavy duty market.

Although CNG light duty passenger cars have not been widely adopted in the United States, they have been successful in countries such as China, Iran, Pakistan, India, Argentina and Brazil (NGV Global, 2017).

For hydrogen, much of the current focus is on light duty fuel cell passenger vehicles fueled with compressed hydrogen (CH2), although a few dozen hydrogen buses are in operation in the United States and Europe. There is growing interest in developing medium and heavy duty applications over the next 7–15 years, with a focus on Heavy-Duty Class 7–8 short haul/drayage trucks (ports) and Medium-Duty Class 4–6 last-mile package delivery trucks. Interest in demonstrating hydrogen fuel cells for long haul heavy duty trucks, is emerging, as evidenced by recent projects by Toyota and Nikola.

While there is some overlap in the types of transport applications served by natural gas and hydrogen, there is also a degree of market segmentation apparent in the United States, with hydrogen proposed for light duty passenger cars, natural gas proposed for long haul freight trucks, and both fuels serving buses, and medium and heavy duty short haul fleets (Sandia National Laboratories, 2014). In the longer term, a truck decision choice model developed at UC Davis suggests liquid hydrogen fueled trucks might serve long haul markets as well (Miller et al., 2017).

3.2. Comparison of infrastructure options for supplying H2 and NG to vehicles

Refueling infrastructure design depends on the types of vehicles served and the application. For passenger cars, the goal is providing a convenient, widespread and low-cost network of public stations to many geographically dispersed users, especially during the early stages of the transition. For medium and heavy duty fleet vehicles that return to a base each day, a smaller number of stations, some of which can be private (so-called "behind the fence") will suffice (CAFCP, 2016). Fueling stations serving long haul heavy duty trucks will be built along key interstate corridors, while most stations serving light duty vehicles and medium and heavy duty short haul would be concentrated in urban areas or near ports.

A recent case study by UC Davis researchers, conducted for the

[3] Hydrogen costs are typically given in \$ per kilogram (\$/kg). 1 kg of hydrogen has about the same energy content as 1 gallon of gasoline. Hydrogen FCVs are about 2–2.5 times as energy efficient as conventional gasoline internal combustion engine vehicles. So the fuel cost per mile for H2 at \$10/kg is equivalent to gasoline at \$4–5/gallon. For estimates for vehicle efficiencies see: (NRC, 2013).

[4] The California Air Resources Board (CARB) is actively analyzing policy options for hydrogen rollouts in the commercial sector for work vehicles like medium duty last mile trucks and fleets such as buses and work trucks. Further, the California Energy Commission is supporting the development of the first 100 hydrogen fueling stations on California over the next 5 years (Baronas and Achtelik, 2016).

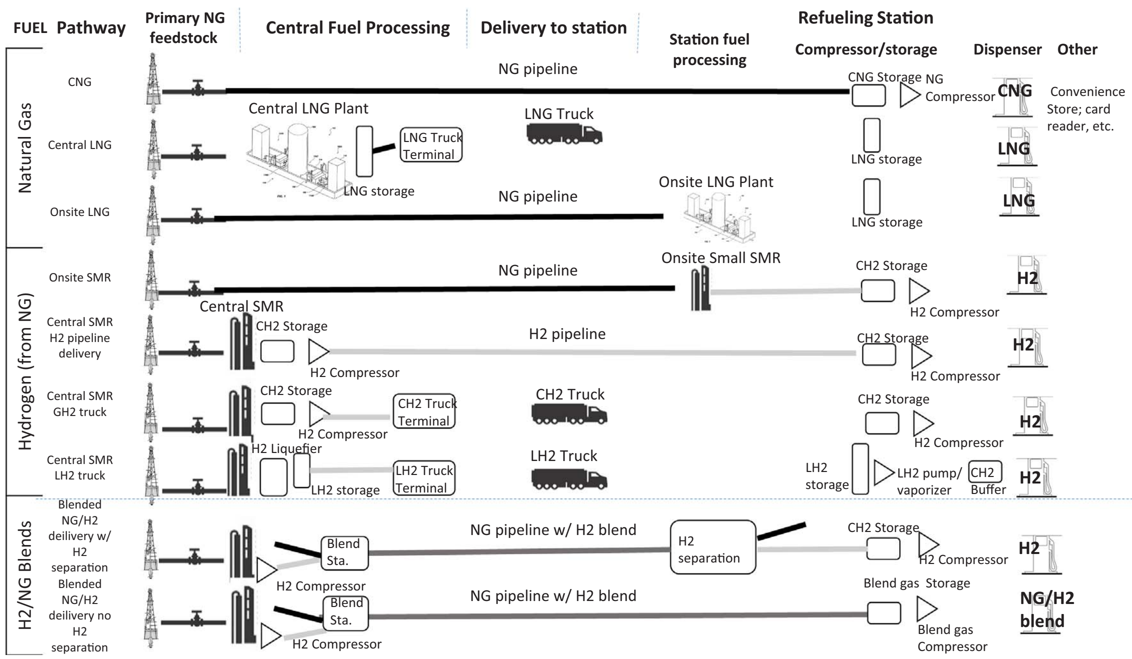

Fig. 3. Fuel supply chains for natural gas (top 3 pathways), pure hydrogen (middle 4 pathways) and hydrogen/natural gas blends (bottom 2 pathways).

California Air Resources Board, explored synergies between natural gas and hydrogen supply infrastructures (Jaffe et al., 2017). The motivation for this study was the interest by California policymakers in understanding whether natural gas infrastructure now being put in place could be reused for hydrogen.

Three natural gas pathways were considered: CNG, central LNG, and onsite LNG. These are compared with six H2 fuel pathways: on site H2 production via steam methane reforming (SMR), central H2 (Compressed Gas Truck Delivery), central H2 (Liquid Hydrogen Truck Delivery), central H2 (H2 Pipeline Delivery), central H2 (H2 blended into NG pipeline and separated at station), central H2 (H2 blended into NG pipeline but not separated) (See Fig. 3) (Jaffe et al., 2017).

The equipment for each pathway is shown in four sequential supply stages: primary feedstock, central fuel processing, fuel delivery, and the refueling station, which can include onsite production. Note that not all pathways have all stages.

Fig. 4, identifies areas of potential overlap between natural gas and hydrogen infrastructure pathways (Jaffe et al., 2017). Items which are common between a hydrogen pathway and a natural gas pathway are colored green; items which are unique to the H2 or NG system are colored red indicating that there is no possibility for shared infrastructure or adapted equipment; items in the NG pathway that potentially could be re-used or built to provide forward compatibility with H2 are colored yellow. Some CNG station equipment (natural gas compressors and storage cylinders) and natural gas pipelines were identified as potentially compatible with hydrogen.

3.2.1. Compatibility of CNG refueling station equipment with hydrogen

To further assess compatibility Jaffe et al. (2017) carried out a literature review to compare technical details and costs of CNG and hydrogen station compressors and storage drawing on a variety of studies (Alliat et al., 2009; Brydol et al., 2017; Judd and Pinchback, 2015;

FUEL	Pathway	Primary feedstock	Central Fuel Processing			Delivery to station		Refueling station: Station fuel processing		Refueling station: Compression/ Storage		Refueling station: Dispenser	Refueling station: Other
Natural Gas	CNG	NG via pipeline				NG pipeline		Dryer/filter		NG compressor;	CNG storage	CNG dispenser	Card reader, convenience store, etc.
Natural Gas	Central LNG	NG via pipeline	Dryer/filter;	NG Liquifier;	LNG Cryo storage	LNG truck terminal	LNG Truck			LNG storage		LNG dispenser	Card reader, convenience store, etc.
Natural Gas	Onsite LNG	NG via pipeline				NG pipeline		Dryer/filter;	Small NG Liquefier (LNG in a box)	LNG storage		LNG dispenser	Card reader, convenience store, etc.
Hydrogen (from NG)	Onsite SMR	NG via pipeline				NG pipeline		Dryer/filter;	Small SMR	CH2 compressor; CH2 storage		CH2 dispenser	Card reader, convenience store, etc.
Hydrogen (from NG)	Central SMR H2 pipeline delivery	NG via pipeline	Dryer/filter;	SMR; H2 compressor	bulk GH2 storage;	H2 pipeline				CH2 compressor; CH2 storage		CH2 dispenser	Card reader, convenience store, etc.
Hydrogen (from NG)	Central SMR GH2 truck	NG via pipeline	Dryer/filter;	SMR; H2 compressor	bulk GH2 storage;	GH2 truck terminal	GH2 truck			CH2 compressor; CH2 storage		CH2 dispenser	Card reader, convenience store, etc.
Hydrogen (from NG)	Central SMR LH2 truck	NG via pipeline	Dryer/filter;	SMR; H2 Liquefier	bulk LH2 storage;	LH2 truck terminal	LH2 truck			LH2 pump/ vaporizer ; LH2 storage;	CH2 biuffer storage	CH2 dispenser	Card reader, convenience store, etc.
H2/NG Blends	Blended NG/H2 deilivery w/ H2 separation	NG via pipeline	Dryer/filter;	SMR; H2 compressor	bulk GH2 storage; blend station to add H2	NG pipeline (w/blend H2)		H2 Separation equipment		CH2 compressor; CH2 storage		CH2 dispenser	Card reader, convenience store, etc.
H2/NG Blends	Blended NG/H2 deilivery no H2 separation	NG via pipeline	Dryer/filter;	SMR; H2 compressor	bulk GH2 storage; blend station to add H2	NG pipeline (w/blend H2)				Blend gas compressor; Blend gas storage		Blend gas dispenser	Card reader, convenience store, etc.

Fig. 4. Compatibility of natural gas pathways with hydrogen.

Melaina et al., 2013a; Miller et al., 2017; Mitchell, 2015; Sandia National Laboratories, 2014; Steen, 2015; USDOE, 2016).

At a hydrogen refueling station, hydrogen gas is compressed to 5,000–10,000 psi and stored in heavy-duty storage tanks. The fuel is then delivered to the vehicle via a dispenser. These items are analogous to corresponding equipment in the CNG pathway; however, they require much higher pressures as well as special materials. Because the volumetric energy density of H2 is only a third that of natural gas, H2 is typically compressed to a higher storage pressure than CNG and thus requires a more powerful compressor and a stronger storage tank plus a dispenser which can handle such pressures. Further, hydrogen can embrittle and degrade materials commonly used to store and transport natural gas and requires the use of different, potentially more expensive, materials. Hydrogen storage tanks are made of stainless steel plus an interior polymer lining to prevent against embrittlement and permeation. Higher hydrogen storage pressure adds to compressor costs, as well. In addition the differing physical properties of hydrogen and natural gas require different compressor designs.

It is technically possible that a CNG station could overbuild storage tanks or compressors to ensure forward compatibility with hydrogen. However, the UC Davis study estimated that the additional costs of overbuilding CNG equipment would outweigh the benefit of forward compatibility with hydrogen. The study concluded that overbuilding CNG stations for future hydrogen compatibility is not economically attractive (Jaffe et al., 2017).

Physical properties of the two fuels can also effect the type of safety equipment required for hydrogen and CNG stations. Leak detection is more challenging for hydrogen: odorants such as mercaptans, which are commonly used to aid in natural gas detection, are unsuitable for hydrogen use. Hydrogen burns with a pale blue flame that is virtually invisible in daylight, so that special detection systems are required. (Barilo 2017a, 2017b; PNNL, 2017).

3.2.2. Compatibility of the natural gas pipeline system with hydrogen and hydrogen blends

The idea of utilizing hydrogen in the existing natural gas pipeline grid has been analyzed in various studies going back to the 1980s. Recent studies suggest that blending hydrogen with natural gas in low concentrations (< 5–15% H2 by volume), appears viable without significantly increasing risks (Alliat et al., 2009; Brydol et al., 2017; Bünger et al., 2014, 2015; IEA, 2003; JRC 2014; Melaina et al., 2013a; Sandia National Laboratories, 2014; Steen, 2015;). This level of hydrogen blending does not provide a threat or cause potential damage to end-use devices (such as household appliances), nor does it reduce overall public safety, or jeopardize the durability and integrity of the existing NG pipeline network (Melaina et al., 2013a). However, these studies stress that though 5–15% hydrogen by volume is often given as a "rule of thumb" value, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis.

Recent European studies assessing the hydrogen tolerance of the natural gas grid also stress that a system perspective must be taken considering end-use systems and hydrogen transmission and distribution (JRC, 2014). A German case study examined hydrogen blend limits for diverse types of equipment used in various end-use applications and delivery components in the existing natural gas system. The allowable hydrogen fraction varies widely depending on the application (Schiebahn et al., 2015). Compressors, gas turbines and CNG tanks need modification above only a few percent hydrogen concentrations, while pipelines can tolerate a higher hydrogen fraction, depending on maintenance conditions.[5] This illustrates why it is difficult to determine blend limits for a particular natural gas grid without detailed knowledge of the equipment in the system. European natural gas grids currently have regulations that limit hydrogen to concentrations of 0.1–12% by volume (Minter, 2014).

3.2.3. Using the natural gas pipeline system to deliver hydrogen and hydrogen blends for transportation: technical limits and carbon emission considerations

Blending renewable hydrogen into the natural gas grid has been suggested a first step toward widespread use of zero carbon hydrogen in fuel cell vehicles. As discussed above, there are technical limits on the fraction of hydrogen that could be transported in the natural gas system as part of a NG/H2 blend. (The exact limits will depend on the specifics of the natural gas system considered.) This has implications for the amount of renewable hydrogen energy that could be transported via the natural gas grid as part of a blend, the potential for reducing greenhouse gas emissions, and the number of hydrogen vehicles that might be fueled via a blending strategy.[6]

A NG/H2 blend could be combusted directly in an internal combustion engine vehicle, but this would lead to only a small reduction in GHG emissions, even with renewable hydrogen, because of the limits on the H2 blend fraction (see footnote 6). Alternatively, H2 could be separated from the blend for use in a fuel cell vehicle. FCVs, which run on pure H2, are perhaps twice as energy efficient as ICEVs, and have zero tailpipe emissions. Using FCVs significantly reduces well to wheel GHG emissions as well as SO2, NOx, and PM (IEA, 2003; Schiebahn et al., 2015; Bünger et al., 2014). Further, separating hydrogen for use in a fuel cell vehicle is a more efficient use of renewable hydrogen energy than combusting it as part of a blend.

However, separation adds to the cost of hydrogen transportation fuel (Melaina et al., 2013a; Schiebahn et al., 2015). For example, analysts at the National Renewable Energy Laboratory estimated that using a Pressure Swing Adsorption (PSA) system to separate 10–20% hydrogen (by volume) from a NG/H2 blend might add $2–9/kg to the delivered cost of hydrogen fuel (Melaina et al., 2013a).[7] This is a significant added cost, compared to estimates of near to mid-term costs for delivered hydrogen transportation fuel of $5–7/kg, and longer term goals of $2–4/kg.

In the NREL analysis, a major part of the separation cost is due to natural gas recompression for injection back into a high pressure pipeline, after hydrogen is removed. However, if hydrogen were separated from natural gas at a utility "pressure reduction" facility at the "city gate", recompression of natural gas would not be needed and separation costs might be reduced to $0.3–1.3/kg. The delivered cost of hydrogen at the pump also depends on the specific situation. For example, if the separated hydrogen had to be stored and delivered to stations remote from the city gate, this might add costs totaling several $/kg (Yang and Ogden, 2013). Locating a hydrogen station at a pressure reduction facility might avoid these hydrogen handling costs, although the city gate station location might not be ideal from the vehicle owners' point of view. Clearly, there are trade-offs and the viability of H2 blending, separation and delivery as a fuel will depend on the particular situation.

How much hydrogen could be transported in existing natural gas

[5] Natural gas pipelines would have to be assessed for hydrogen compatibility with respect to the materials used, and for the presence of pipeline cracks or imperfections in welds that might be subject to enhanced crack growth in the presence of hydrogen (Melaina et al., 2013).

[6] It is important to note that hydrogen has only 1/3 the volumetric energy density of natural gas. Adding renewable hydrogen to natural gas reduces the heating value of the blend fuel, as well as its carbon content. In a NG/H2 blend containing 5–15% hydrogen by volume, hydrogen contributes only about 1.7–5% to the heating value of the gas. On an energy basis, the blend fuel carbon content per MJ is reduced by only 1.7–5%. Thus, combusting a blend with 5–15% green H2 by volume might reduce GHG emissions by 1.7–5% compared to combusting natural gas (assuming that the same quantity of energy is combusted).

[7] This range of separation costs assumes a NG/H2 blend is delivered to a refueling station in a 300 psi pipeline, serving hydrogen refueling stations with capacity 100–1000 kg/d. The costs of H2 separation tend to increase for smaller size PSAs, and lower fractions of hydrogen (Melaina et al., 2013).

pipelines, given the technical limits on blending? How does this compare to demands for hydrogen transportation fuel in a future low carbon transportation system? Answering these questions requires a detailed, network-specific analysis of blend limits.

A review of potential power to gas markets by the European Commission “CertifHy” project (2015b, 2015c) estimated that the total amount of hydrogen that might be shipped in European natural gas pipelines, assuming a blend fraction of 1–5% H2 by volume, was 800–8000 t per day.[8] We calculate that this might be enough to fuel about 1–11 million FCVs (assuming an average hydrogen use of 0.7 kg/day per vehicle), out of a total projected European vehicle population of 240 million (about 0.5–5% of the total fleet). This is enough hydrogen to help supply early markets for FCVs, but not enough to materially impact energy use and achieve deep cuts GHGs from transportation.

Blending renewable hydrogen into natural gas lines could be a desirable strategy from the point of view of the electric utility, which would find a market for curtailed renewable power. Further, blending green hydrogen throughout the natural gas grid could lower GHG emissions from fuel combustion in appliances, burners, etc. by a few percent compared to natural gas. However, several studies estimate that green hydrogen could be significantly more expensive than natural gas, so blending hydrogen will increase the cost of the fuel gas, making it uncompetitive as a direct replacement for natural gas in appliances or combustion systems (Bünger et al., 2014; Schiebahn et al., 2015). Additional costs must be weighed against the benefit of providing a more sustainable and low-carbon gas product to consumers. In the longer term, to supply pure hydrogen transportation fuel at the high levels of FCV market penetration (25–50%) implied by some 2 degree scenarios, it would be necessary to develop zero carbon hydrogen supplies far beyond the amount of hydrogen that could be delivered as part of a blend in natural gas lines.

3.3. Review of regional scenarios for natural gas and hydrogen in transport and implications for natural gas as a bridge to hydrogen

Several case studies were reviewed as specific examples of natural gas to hydrogen transitions.

3.3.1. California scenario for adoption of natural gas and hydrogen vehicles and infrastructure buildout to 2035

First, we review a study conducted by UC Davis for the California Air Resources Board (Jaffe et al., 2017). To better understand how adoption of natural gas and hydrogen vehicles might unfold over the next two decades, and the implications for natural gas and hydrogen infrastructures, UC Davis researchers developed transportation energy scenarios for California to 2035 (Miller et al., 2017). The goal of this analysis is to understand possible synergies between natural gas and hydrogen infrastructure and the extent to which natural gas infrastructure might enable adoption of H2 vehicles.

3.3.1.1. Natural gas vehicle infrastructure in California. California has a commercial natural gas fueling infrastructure with about 330 stations (284 CNG; 46 LNG), equivalent to about 3% of gasoline and diesel refueling stations statewide. These serve a fleet of about 22,000 heavy duty vocational vehicles, and 25,000 buses. Natural gas is not widely used today in medium duty delivery vehicles, or heavy duty freight trucks, but these are seen as potential growth markets. LNG is also seen as a potential fuel for long-haul trucks in California (Jaffe et al., 2015; Fan et al., 2017).

3.3.1.2. Hydrogen infrastructure in California. Hydrogen fuel cell vehicles are being introduced in California under its Zero Emission Vehicle program. California has launched a deployment program to accelerate hydrogen fueling infrastructure in several pilot locations such as Los Angeles, Oakland and Sacramento. At present there are about 2000 fuel cell vehicles operating in California, with tens of thousands expected by 2020 (California Air Resources Board (CARB), 2016). California had 25 hydrogen stations open and another 25 in various stages of completion at the end of 2016, with 100 stations expected by the early 2020 s and has allocated up to $20 million per year for this purpose through AB-8, California's Alternative Fuel and Vehicle Technologies Funding Program (CARB, 2016).

Renewable hydrogen is likely to play a growing role in California's hydrogen transportation fuel supply. Through California's SB1505 regulation, 33% of state-funded stations must be renewable, with a similar regulation applying to privately built hydrogen stations once a statewide “trigger” level of 10,000 kg H2/day is reached. This corresponds to fuel for about 10,000–20,000 fuel cell vehicles on the road, a level expected in the early 2020s. SB 1505 is essentially a renewable portfolio standard for hydrogen. As California's renewable hydrogen requirement becomes more important, hydrogen production will shift away from fossil sources toward options like reforming renewable natural gas or electrolysis using renewable electricity.

3.3.1.3. Scenarios for near to mid term adoption of natural gas and hydrogen vehicles and infrastructure buildout in California. UC Davis researchers developed scenarios for the timing and scale for adoption of natural gas and hydrogen as transport fuels in California to 2035 (Miller et al., 2017; Jaffe et al., 2017). The scenarios included light duty vehicles, and various types of trucks: long haul heavy duty, short haul heavy duty, buses and medium and heavy duty vocational trucks (Ogden et al., 2014; Jaffe et al., 2015; Miller et al., 2017). The scenarios modeled the vehicle mix and required fuel infrastructures over time.

Scenario highlights are described below (also see Tables 2–5):

- By 2035 the number of hydrogen fuel cell light duty vehicles reaches 4 million, about 13% of the on-road light duty fleet. Natural gas is not used in California's light duty vehicles.
- LNG is widely adopted for long-haul heavy duty trucks (Jaffe et al., 2015; Fan et al., 2017). By 2035, LNG fuels 14% of long-haul heavy duty freight trucks (about 70,000 vehicles).
- Numbers of CNG buses and heavy duty vocational vehicles grow relatively slowly (from 48,000 vehicles in 2015 to 66,000 in 2035). CNG and H2 FCVs are used increasingly in medium duty delivery trucks (MD Urban) and short haul heavy duty applications, and FCVs appear in buses, HD vocational trucks and HD pick-up trucks (totaling about 60,000 fuel cell MD/HD vehicles by 2035).
- There is significant refueling infrastructure buildout for both natural gas and hydrogen. By 2035, 4000 public H2 stations serve passenger FCVs, 600 CNG stations serve buses and truck fleets, 400 H2 stations serve buses and truck fleets, and 100 LNG stations serve long haul HD trucks. Public H2 stations far outnumber refueling stations needed for LNG, hydrogen or CNG fleets.
- The scenario does not envision a major switch from CNG to hydrogen in fleet trucks and buses by 2035. Instead, CNG and H2 coexist as low carbon fuels. New hydrogen stations are added rapidly after 2025, while the number of CNG stations serving fleets remains fairly constant.
- Public H2 stations serving passenger vehicles are largely located in urban areas with a few “connector” or “destination” stations to enable long distance travel. By contrast, LNG long haul freight trucks operate along key freight corridors, and are fueled in relatively few, large “truck stop” stations located along interstate highways (Fan et al., 2017). The most spatial and technical

[8] ”The amount of hydrogen that can be injected in the natural grid is limited by the maximum allowed volumetric concentration for injection in the grid at a specific point. This amount, different in each country, can be used to calculate the technical capacity limit of hydrogen injection in the gas grid country by country….” (European Commission, 2015b, 2015c. CertifHy project).

Table 2
Scenario for hydrogen fuel cell light duty vehicle rollout and hydrogen station development in California [a].

	2015	2020	2025	2030	2035
Number of H2 FCVs on road	197	23,500	270,000	1.5 million	4 million
H2 use for LDVs (kg/d) (assumes 0.7 kg H2/FCV/d)	138	16,200	189,000	1.1 million	2.8 million
H2 Stations serving LDVs in California	21	100	400	1500	4000
Average capacity of H2 stations in network kg/d	100	300	700	900	1000
Delivered cost H2 ($/kg)	32	9	7	6	6
Assumed H2 station capital costs at specified ave. sta. capacity $ million	1.5	2.0	2.5	4.4	4.4
Cumulative capital investment in H2 stations in California ($ millions)		200	1100	6200	17,000
Energy use gge/day	137	16,027	186,978	1,088,230	2,770,041

[a] Ogden et al., 2014.

Table 3
Scenario for Hydrogen Fuel Cell medium and heavy duty fleet vehicles and associated hydrogen Stations in California[a].

	2015	2020	2025	2030	2035
# H2 Fleet Vehicles On-road (% of on-road fleet vehicles)	0	660	12,316	29,972	58,812
Buses	0	660	2040	3500	7400
Heavy Duty Short Haul	0	0	816	2532	5232
Medium Duty Delivery Vehicles	0	0	4800	10,200	18,000
Other fleet vehicles MD and HD vocational trucks; HD pickups	0	0	4660	13,740	28,180
H2 fuel use for fleet vehicles (gge/d)	0	5985	61,977	149,216	299,726
Buses (5–17 kg/d)	0	5985	18,458	31,601	66,549
Heavy Duty Short Haul (7.8 gge/d)	0	0	6343	19,683	40,673
Medium Duty Delivery Vehicles (3.8 gge/d)	0	0	18,167	38,605	68,127
Other fleet vehicles MD and HD vocational trucks; HD pickups (1–9 gge/day)	0	0	190,08	59,327	124,377
H2 STATIONS SERVING H2 FLEET VEHICLES	0	17	89	213	428
Average capacity of H2 stations in network kg/d	–	500	1000	1000	1000
Delivered cost H2 ($/kg)		7	6	6	6
Assumed H2 station capital costs at specified ave. sta. capacity ($million)		2.5	4.4	4.4	4.4
Cumulative capital investment in H2 fleet stations in CA ($ millions)		42.5	359	905	1851

[a] Miller et al., 2017.

Table 4
Scenario for CNG Fleet vehicles and CNG Station Development in California [a].

	2015	2020	2025	2030	2035
# CNG fleet vehicles on-road (% of on-road fleet vehicles)	47,894	49,502	52,524	58,168	66,630
Buses	25,676	24,705	24,336	23,743	23,050
Heavy Duty Short Haul	38	197	408	1055	2180
Medium Duty Delivery Vehicles	280	1200	2880	6970	13500
HD vocational trucks	21,900 (30%)	23,400 (30%)	24,900 (30%)	26,400 (30%)	27,900 (30%)
CNG fuel use for fleet vehicles (gge/d)	1,291,836	1,299,190	1,331,875	1,381,486	1,451,488
Buses (30 gge/d)	843,243	808,762	791,899	761,877	721,028
Heavy Duty Short Haul (21 gge/d)	788	4086	8462	21,882	45,215
Medium Duty Delivery Vehicles (9 gge/d)	2445	10,477	25,145	60,855	117,867
HD vocational trucks (20 gge/day)	445,360	475,865	506,369	536,873	567,377
Stations serving cng fleet vehicles	538	563	570	634	580
Average capacity of CNG stations in network gge/d	3000	3000	3000	3000	3000
Assumed CNG station capital costs at specified ave. sta. capacity ($million)	1.6	1.6	1.6	1.6	1.6
Cumulative capital investment in CNG fleet stations in CA ($ millions)					900

[a] Miller et al., 2017.

infrastructure "overlap" between CNG and H2 occurs for urban heavy and medium duty fleets (buses, medium duty delivery trucks, and short haul HD trucks), that operate in the same geographic areas, such as cities or ports.

- The study concluded that overbuilding CNG stations for future hydrogen compatibility is not likely to be economically attractive even to investors who expect hydrogen trucks to become a sizable market. This is true because of the much higher cost of hydrogen station equipment and the timing of the markets: a large scale hydrogen MD/HD vehicle rollout won't begin for 10 years or more, suggesting that eventual phase out of CNG stations could be done in a planned fashion, with no need for an abrupt switch to hydrogen.
- Jaffe et al. (2017) also suggest that certain port and urban locations might favor renewable natural gas resources initially, but may be able to link to H_2 supply chains in the longer term.

Overall, the study concludes that there is no compelling economic case for overbuilding CNG stations for future hydrogen compatibility.[9] Further, this report found that injection of hydrogen into natural gas pipelines might be technically possible, but would have to be carefully evaluated on a case by case basis.

[9] Although this result is well known in the hydrogen infrastructure technical community, it is nonetheless important for US decision-makers. Given the low cost of natural gas in the US, the possible growth of low emission natural gas fueled trucks and the longer term goals for zero emissions trucks in states like California, there has been strong interest from planners and policymakers in repurposing today's natural gas infrastructure for eventual use with hydrogen.

Table 5
Scenario for development of natural gas infrastructure for heavy duty long and short haul trucking [a, b].

	2015	2020	2025	2030	2035
Number of NG Heavy Duty Trucks (assuming trucks travel 100 K mi/yr)	729	738	14,231	48,748	74,545
NG use for trucks (million gge/yr)	9.6	9.6	190	600	1490
NG Stations serving trucks in California	CNG: 8 LNG: 9	CNG: 8 LNG: 9	CNG: 8 LNG: 37	CNG: 10 LNG: 73	CNG: 11 LNG: 93
Average capacity of NG stations gge/d	CNG: 3400 LNG: 10,000	CNG: 3400 LNG: 10,000	CNG: 3400 LNG: 20,000	CNG: 6000 LNG: 28,000	CNG: 4000 LNG: 32,000
Assumed NG station costs at specified ave. sta. capacity					
Capital cost(million $)					
CNG	1.6	1.6	1.6	1.9	1.7
LNG	1.5	1.5	2.2	2.8	3.0
Cumulative capital investment in stations for Long Haul NG trucks $million		26	88	193	255
NG Energy use gge/d	25,418	25,727	495,916	1698,827	2597,999

[a] Jaffe et al., 2015.
[b] Fan et al., 2017.

3.3.2. Scenarios for power to gas, adoption of hydrogen vehicles and infrastructure buildout in Europe

We reviewed several European case studies that examine the long term role of power to gas from renewable electricity in providing hydrogen as a transport fuel (Bünger et al., 2014, 2015; European Commission, 2015a, 2015b, 2015c; Goetz et al., 2016; Schiebahn et al., 2015;).

In a 2014 study, conducted for the German Ministry of Transport and Digital Infrastructure, on "Power to Gas (PtG) in Transport," Bünger et al. (2014) assessed three scenarios to 2050, using renewable "power to gas" derived methane or hydrogen in transportation. These are: "1) high market penetration with methane-operated internal combustion engines, but no PtG; 2) high market penetration with methane-operated internal combustion engines, fuel demand entirely covered with PtG; 3) considerable shares of both methane-operated internal combustion engines and fuel cell electric engines, fuel demand entirely covered with PtG."

The study found that using hydrogen in FCVs is considerably more energy-efficient than using methane in internal combustion engines, enabling better utilization of renewable energy. While noting that hydrogen and FCVs need further technological development and scale up to improve economics, they recommended that " future energy policy measures should favor renewable hydrogen in FCVs over the utilization of renewable methane in internal combustion engines, particularly in settings that do not allow for the operation of BEVs."

Critical benefits of using PtG in transport were identified. Two insights are especially relevant for power to hydrogen.

- Of the various power to gas applications analyzed in Bünger et al. (2014), only power-to-hydrogen for FCV transport had a clear business case. "In the medium-term, PtG offers business opportunities for the application of hydrogen as a fuel for the transport sector only. In all other sectors (electricity, gas, industry, methane as fuel) PtG is unlikely to be an economic option even in the long-term. "
- The study also foresaw development of a dedicated hydrogen infrastructure initiated by transportation. "..the transport sector plays a pivotal role as a forerunner and initiator for hydrogen-based PtG pathways as well as for the establishment of the corresponding hydrogen infrastructure. The overall energy systems and all energy sectors are likely to benefit from such development."

In another paper, Bünger at al. (2015) assessed how large underground storage of hydrogen from power to gas might be integrated into a renewable intensive future energy system. Again, they found that fuel cell vehicles in transportation was the only application with a mid-term business case. NG/H2 blends were too expensive to compete with natural gas as a combustion fuel.

A review of potential power to gas markets by the European Commission "CertifHy" project (2015b, 2015c) also stressed the likely importance of green hydrogen in transportation, in a future low carbon European energy system.[10] The total amount of hydrogen that might be shipped in European natural gas pipelines, assuming a blend at 1–5% H2 by volume, was estimated to be 800–8000 t per day.[11] We calculate that this might be enough to fuel about 1–11 million FCVs, as discussed in Section 3.2.2.

Schiebahn et al. (2015) compared the technologies and economics of three possible applications for renewable power to gas in a future grid:

- "Use of hydrogen from renewable power (RPH) in a dedicated infrastructure for applications which require hydrogen, i.e. fuel-cell-based transportation and industrial processes.
- "Direct feed-in of RPH into the natural gas grid with regard to the maximum allowable H2 concentration.
- "Methanation of the produced H2 with CO2 and subsequent feed-in of the renewable power methane (RPM) into the natural gas grid in unlimited quantities."

Of the various applications, they found that renewable hydrogen distributed in a dedicated H2 system for transport applications had the best chance to become economically competitive. Blending hydrogen into the natural grid was considered only as a replacement for natural gas combusted in appliances.

Overall, the European studies identified hydrogen fuel cell transportation as a promising application for renewable power to gas. Further, they saw a long term role for a dedicated hydrogen infrastructure in supplying fuel cell vehicles with renewable hydrogen.

4. Conclusions and policy implications

We conducted a literature review to explore whether natural gas might help enable a transition to longer term use of hydrogen in zero emission fuel cell vehicles.

Referring to our initial questions, our literature review suggested the following.

[10] "'Green hydrogen' will be more important in the emerging mobility market, than for industry, given that the main driver for the development of the mobility market is the reduction of greenhouse gas emissions and local emissions. It is therefore expected for the long term, that a large percentage of the hydrogen for mobility will be green.'.

[11] "The amount of hydrogen that can be injected in the natural grid is limited by the maximum allowed volumetric concentration for injection in the grid at a specific point. This amount, different in each country, can be used to calculate the technical capacity limit of hydrogen injection in the gas grid country by country…." (European Commission, 2015. CertifHy project).

- With respect to roles for natural gas and hydrogen in transport applications: a degree of market segmentation may emerge in the United States, with hydrogen fuel cells being introduced for light duty passenger cars, liquefied natural gas for long haul freight trucks, and both natural gas and hydrogen serving buses, and medium and heavy duty short haul fleets. In the longer term liquid hydrogen fueled trucks might serve long haul markets as well.
- A variety of infrastructure options could be implemented for delivering natural gas or hydrogen to vehicles. However, market, technical, economic and geographic/refueling network design factors will constrain the degree of potential overlap between natural gas and hydrogen refueling infrastructures. The main overlap for hydrogen and natural gas appears to be in truck or bus fleet applications now served by CNG.
- Even for similar applications, converting or overbuilding NG refueling stations for hydrogen is problematic. Repurposing LNG infrastructure for hydrogen is not technically possible. Converting or overbuilding compressors or storage in CNG refueling stations for hydrogen service might be technically possible, but expensive and economically unattractive.
- Several US studies suggest that transporting H2/NG blends in the NG pipeline grid appears technically possible at fractions of 5–15% hydrogen by volume. European countries have enacted limits of 0.1–12% hydrogen by volume. The appropriate blend concentration depends on the specific condition of the pipeline and the other components, varying significantly between pipeline network systems and natural gas compositions. Compatibility must therefore be assessed on a case-by-case basis. If NG/H2 blending were implemented, a host of measures would be required to assess the suitability of each natural gas network for hydrogen and assure safety and efficient operation. More detailed analysis was recommended by both US and European studies to investigate the potential for blending.
- "Green" hydrogen could be produced via low carbon pathways such as electrolysis powered by curtailed renewable electricity. Blending green hydrogen into the natural gas grid has been suggested as a first step in a transition toward large scale renewable hydrogen. This blending strategy offers multiple potential benefits: it could create a market for uneconomic excess renewable power that would otherwise be curtailed, provide a way of storing and transporting renewable hydrogen, reduce carbon content of the NG/H2 gaseous blend fuel and ultimately help enable use of zero emission hydrogen in transportation, assuming the hydrogen could be cost effectively separated from the blend and dispensed to vehicles.
- To realize large "well to wheels" GHG reductions from blending "green hydrogen", the hydrogen must be separated and used in a high efficiency end-use device such as a fuel cell. However, separation (and subsequent delivery of hydrogen to vehicles) might add significant costs depending on the system configuration.
- Given hydrogen blend limits it seems unlikely that enough blended hydrogen could be transported in the existing natural gas system to provide fuel for the large numbers of fuel cell vehicles needed for a long term "2 degree" energy scenario. Results from a case study for Europe suggest that the amount of hydrogen that could be delivered in the natural gas system as part of a NG/H2 blend would be enough for a few percent of the fleet, far less than the numbers needed in a near zero carbon world, where 25–50% of light duty vehicles might be FCVs by 2050.
- Transportation was found to be an important end-use for "power to gas". Of the various power to gas applications analyzed by Bunger et al. (2014), and the European Commission CertifHy project (2015b, 2015c), only power-to-hydrogen for FCV transport had a promising mid-term business case.
- Several European authors suggest that it may be better from a GHG point of view to build a parallel infrastructure to deliver pure renewable hydrogen to fuel cell vehicles rather than blending hydrogen with natural gas (Bünger et al., 2015; European Commission, 2015; Schiebahn et al., 2015).
- Many of the studies reviewed suggested that detailed, geographically specific, case by case analysis would be needed to assess the best ways to provide hydrogen for transportation via zero carbon pathways, and the potential role of the natural gas system. Policy recommendations center on rigorously defining the allowable conditions for using hydrogen and hydrogen blends in the natural gas system and doing case by case technical and economic assessments of the potential for renewable hydrogen production and blending.

Our review suggests that technical limits would make it difficult to utilize the existing NG system to deliver hydrogen transportation fuel at the scale needed to achieve deep cuts in transportation related GHGs. In a 2 degree world, demand for hydrogen transportation fuel would far outstrip the ability of the NG system to deliver hydrogen as part of a blend. In the long term, a dedicated renewable hydrogen system would be needed.

The outlook for synergies during an early transition to zero carbon transportation is more complex. Clearly, it will not be economically attractive to re-purpose or overbuild NG fueling station equipment for future hydrogen service. The main potential synergy for the near to mid-term appears to be blending renewable hydrogen into the natural gas system. Transporting H2/NG blends in the NG pipeline grid, appears technically possible at modest fractions of 5–15% hydrogen by volume, but requires careful case by case assessment and could be expensive. Blending does not enable major reductions in well to wheels GHG emissions from transport, unless hydrogen can be cost effectively separated from the blend and delivered to highly efficient fuel cell vehicles. There may be specific situations where excess renewable power could be used to make electrolytic hydrogen, blend it with natural gas, separate it and find an economically viable use in FCVs. This is a topic for future study and geographic case studies.

To utilize the natural gas infrastructure with a greener fuel in the near to mid-term, Scheitrum et al. suggest that biogas might be a better fit than hydrogen (Scheitrum et al., in this issue). They conclude that fossil natural gas networks might be more easily utilized to advance a renewable natural gas industry than to launch hydrogen as a transport fuel. Further analysis is needed to clarify when a strategy to "green" natural gas by adding biogas is economically attractive.

For the long term, biogas may not be able to deliver the GHG reductions that H2 could because of the smaller size of biogas resource, the higher efficiency of hydrogen fuel cell vehicles compared to natural gas combustion engine vehicles, and abundant options for zero-carbon H2 production.

Ultimately, we will need to build a large scale dedicated H2 infrastructure that co-exists with the natural gas system, to fuel a growing number of zero emission fuel cell vehicles in a very low carbon transportation system.

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