Hydrogen Transitions in a Greenhouse Gas Constrained World

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Abstract

In order to realize the promise of a hydrogen economy in this United States, it is essential to couple it with a simultaneous commitment to improve energy efficiency and increase the use of renewable energy. In this study, using detailed scenario analyses for the country as a whole and for urban areas, we found that a large-scale switch to hydrogen produced by a clean energy system would lead to twice the environmental benefits compared to would be achieved in a hydrogen transition under a business-as-usual energy mentality. By 2050, when a "clean" transition to hydrogen would be nearly complete, greenhouse gas emissions would be roughly half of what they are today, compared to about a billion tons more, even with hydrogen produced from coal and natural gas. We found that introducing energy efficiency and renewable programs around the country early on will be important to pave the way for a hydrogen transition by freeing up some of the nation's electricity, natural gas and coal infrastructure. Having broader energy goals, such as those established by greenhouse gas emission constraints that involve energy efficiency and the increased use of renewables, will actually make the hydrogen transition easier.

1 Introduction

Hydrogen has captured the imagination of researchers, private investors, policy makers, and the general public. In an attempt to deal, once and for all, with the problems of energy insecurity, air pollution, and climate change - all of which are linked intimately to our oil economy - a wholesale recreation of the national energy system is now creeping into the energy agenda (Ogden, 1999; Rifken, 2002; Sperling and Cannon, 2004).

Hydrogen, an energy carrier that can be produced from domestic zero-carbon sources and can be consumed in nearly zero-pollution devices, can potentially solve these problems. Energy security could be enhanced if hydrogen is produced from secure, abundant, domestic sources of energy such as wind, solar, biomass, and coal. Air pollution arising from our vehicles, buildings, and industries could be virtually eliminated as hydrogen is consumed in zero-pollution end-use devices. And climate change, the driving concern that motivated this study, could be affected as hydrogen made from close to zero-carbon sources for use in transportation and cogeneration could eliminate carbon emissions that come from using fossil fuels in vehicles, buildings, and industry.

As an energy carrier, like electricity, hydrogen has applications in virtually any sector where it can be utilized by end-use devices to provide services. Much of current research and development interest is directed towards the conversion of hydrogen to electricity using fuel cells to provide motive power to run motor vehicles, although considerable attention is also paid to combined heat and power applications for residential, commercial and industrial sectors. As many have argued, however, the benefits of hydrogen are contingent on how, and from what sources, it is produced (Bossel et al, 2003; Romm, 2004; Demirdoven and Deutsch, 2004).

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As attractive as hydrogen might be, there are a number of reasons why a national transition to a hydrogen economy will pose serious challenges. Foremost among them is the considerable research and development that is yet needed throughout the hydrogen supply chain, from production through transport, delivery, and storage to final conversion for specific end-uses. Each of these elements shows technological and commercial promise, but the entire package is very expensive at the present time and will require considerable technological learning to improve performance, reduce costs and iron out problems.

Second, the US economy has committed enormous investments over the past century or more to conventional energy technologies and to an infrastructure based on petroleum, natural gas, coal, and electricity. These investments are ubiquitous and possess a high degree of inertia inhibiting a transition toward a different energy infrastructure. A transition to hydrogen would likely have to occur over several decades to allow for a gradual stock turnover in vehicles and production equipment.

Third, the passenger transportation sector in particular, but also other sectors to varying degrees, face the notorious “chicken-and-egg” problem: there must be a widespread hydrogen refueling infrastructure before anyone will buy hydrogen vehicles, but conversely there must be a demand for hydrogen before the private sector will invest in a hydrogen refueling infrastructure. Who would purchase a hydrogen vehicle with no confidence that it can be conveniently refueled? And who would risk building a hydrogen supply infrastructure and assume that a robust demand for fuel will materialize, absorbing in the meantime the costs of low-capacity utilization while demand slowly grows?

All these factors strongly suggest that if a transition to a hydrogen economy were to happen it would have to take place over a number of years, through a series of “seeding” experiments, demonstration projects, transitional technologies, and risk-reducing incentives, comprising together a clear strategy for getting over the challenges during the intermediate years. Through such a transitional strategy, small, sequential, steps can provide the basis upon which a full-scale infrastructure can be built. It would likely involve direct government involvement, at least initially.

This paper presents the results of a 3-year study regarding how a hydrogen transition could plausibly unfold in four metropolitan areas - Boston, Denver, Houston, and Seattle – as well as in the USA as a whole. The analysis takes a full fuel cycle approach and seeks to answer three main questions for a transition to hydrogen in each of the five regions, namely, what are the new infrastructure requirements? What are the carbon dioxide savings, and what are the costs?

The need for a transition in Boston, Denver, Houston, and Seattle – or in the USA for that matter - is by no means a foregone conclusion. There are other energy carriers that provide competing solutions to the motivating problems we mentioned at the outset – air pollution, climate change, and energy security – specifically, electricity from renewable resources and biofuels. These are strong contenders that are each generating considerable interest in their own right. This paper does not attempt to justify a hydrogen transition in these regions as the preferred route, but aims, rather, to explore its implications.

2 Scenario Framework

Any transition to a hydrogen economy will inevitably be a long-term process spanning several decades. Our study looks out from the present to the year 2050, characterizing and comparing our current context without extensive hydrogen use to a future context in which a transition to high levels of hydrogen use gradually unfolds.

The implications of undertaking a hydrogen transition depend strongly on the features of the context in which that transition takes place. The economic, policy, and technological environment is an important determinant of the details of the transition. Certain ambient features will ease the transition, while others make it more difficult. For example, if the electric sector is highly carbon-intensive, then electrolytic hydrogen produced using grid electricity would also be carbon-intensive. Expensive and highly constrained natural gas supplies would mean that hydrogen made from natural gas would be more costly.

Because these types of interactions are so important, we explored the hydrogen transition in two contrasting policy contexts. In one, policies, consumer behavior, and energy investments continue along the trajectory on which they are now moving, reflecting a "business-as-usual" view of the future such as that embodied in Energy Information Agency's *America's Energy Outlook* Reference Case (EIA, 2003). In the other, policies, consumer behavior, and energy investments shift toward a trajectory with a strong focus on energy efficiency and renewable energy, reflecting a "GHG-Constrained" future (Bernow, et al, 1999).

These two ways of viewing the future provide two contrasting "counterfactual" or "base case" scenarios. We then constructed two hydrogen transition scenarios, one based on the Business-as-usual scenario, and the other on the GHG-Constrained scenario. We also conducted a third scenario experiment in which an urgent hydrogen transition is required in the BAU world. In this scenario, the need for a hydrogen transition is precipitated suddenly by some kind of "shock" occurring in the year 2025. Before this precipitating event, no transitional steps are taken, and afterward the pace of the transition is fast enough to achieve the same level of hydrogen penetration as in the normal hydrogen scenario.[5] An overview of the scenario framework appears in Table 1, including the shorthand names given to each scenario. In the remainder of this report, we refer to each of the scenarios by their shorthand names.

Table 1: Scenarios considered

Scenario	Business-as-usual	GHG-Constrained
Base Case	**BAU**	**GHG**
Gradual hydrogen transition scenario	**BAU+H2**	**GHG+H2**
"Shock" hydrogen transition scenario	**BAU+Shock H2**	

These scenarios are not forecasts. The future course of development in Boston, Denver, Houston, and Seattle, as well as the USA as a whole, over the coming five decades faces too much uncertainty to allow a forecast with any credibility. Some of this uncertainty arises due to an incomplete knowledge regarding the natural and physical constraints of our world, such as the size of the global oil and gas resources, and the basic scientific phenomena that will determine the course of technological innovation and the limits of technological performance. Most of this uncertainty, however, comes from the central role of human choice in determining the future. Fundamentally, society shapes it's own future.

Nor are these scenarios optimized representations of the future. While in theory it may be possible to construct an optimal hydrogen transition for a given base case, it would be completely dependent on the underlying techno-economic assumptions, which themselves are profoundly uncertain. We believe that a study claiming to use rigorous optimization algorithms would yield results having false precision.

Rather than forecasts or optimizations, these scenarios are plausible, techno-economically defensible futures. They are based on our current understanding of the energy sector and hydrogen technologies, and of reasonable assessments of emerging technologies. They force us to make explicit quantitative assumptions about the techno-economic course of the transition, and then allow us to explore the resulting economic, environmental, and policy implications of each scenario.

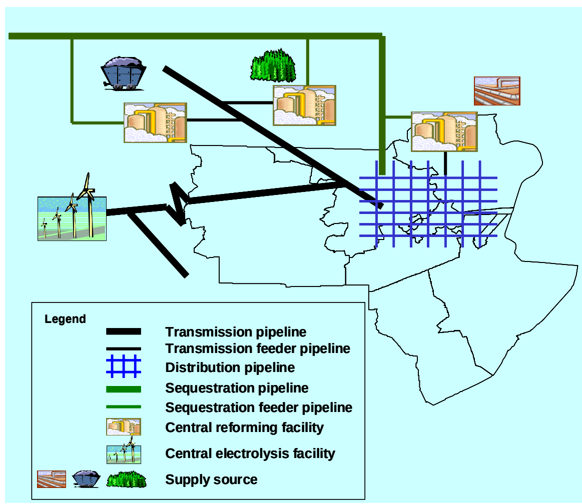
[5] One possible shock that could induce such a change would be the sudden knowledge that GHG constraints are much more stringent and immediate than previously thought, forcing the need for a rapid transition away from fossil-based transport fuels.

3 Hydrogen Supply

One of the primary appeals of hydrogen is that it can be produced from several energy sources and delivered in various ways. We considered hydrogen from natural gas, coal, biomass, grid electricity and electricity from dedicated renewable energy. Hydrogen can be produced by either small on-site units installed at refueling stations, or centrally produced at large stations remote from the demand source. We considered hydrogen delivery, which can be by tube trailer and/or by pipeline, to be provided by an integrated transmission and distribution pipeline network. Finally, the carbon produced from centralized hydrogen production activities can be captured and sequestered. An overview of the basic elements of the hydrogen supply infrastructure are outlined on Figure 1.

As many studies have pointed out, the chain connecting a primary energy source to end-use energy service is – energetically speaking – long and tenuous (e.g., Wang, 2001). Hydrogen production suffers from considerable conversion, distribution, and end-use losses, which are generally comparable to – or greater than – the losses in energy pathways for other energy carriers, such as gasoline and electricity, despite the relatively efficient end-use devises made possible by fuel cells that consume the hydrogen (ADL, 2002)

Figure 1: Hydrogen supply network



Hydrogen Production

A technologically conservative approach was taken in the analysis. Only those hydrogen production technologies that are either commercial, proven, or are capable of being proven without the need for further technological breakthroughs or engineering advancements were considered.

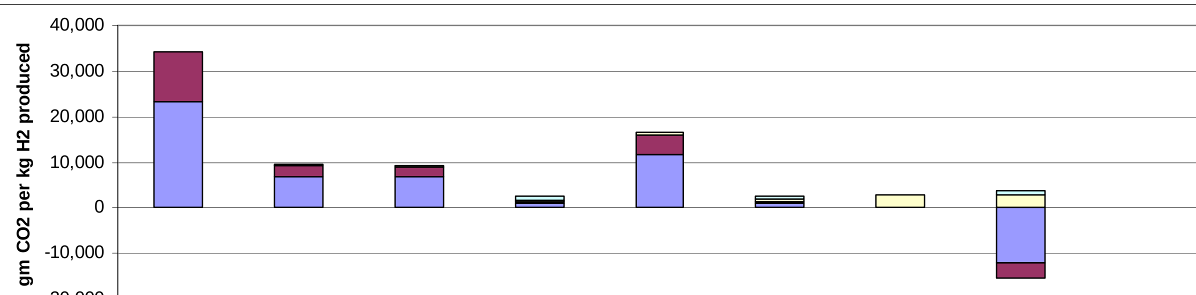
Hydrogen production from natural gas is well proven and deployed on a commercial scale already. A large percentage of the hydrogen produced today in the US is produced by steam reforming of natural gas. Though not nearly so widely practiced, hydrogen production from coal via gasification and syngas reforming is also proven on an industrial scale, primarily for production of hydrogen as an input to ammonia fertilizer. Hydrogen production from biomass via gasification and syngas reforming is a process very similar to hydrogen production from coal. Biomass gasification is well-demonstrated (and under continuing development for power production), and the downstream synthesis steps are highly analogous, and indeed simplified by the lower level of sulfur and heavy-metal contaminants in biomass compared to coal. Electrolytic production of hydrogen is also commercially practiced, generally at small scale.

Each of these hydrogen production technologies displays different carbon emission characteristics, as summarized in Figure 2. The importance of carbon capture and sequestration is highlighted (in comparing columns with and without sequestration), as is the contrast between central biomass reforming and the other production technologies. Centralized biomass reforming has net negative emissions per kg of hydrogen produced because the biomass feedstock is used sustainably without sequestration, thereby emitting no net GHGs. Centralized electrolysis from the use of power generation by large dedicated windfarms is the only zero-carbon technology considered in this study. For some of these technologies, there are likely to be improvements over time on the efficiency of the production process.

Of course, there are many other options, most of them longer-term and still very much in the development phase (Lippman, 2004). These are not included among the hydrogen production options in our scenarios although they may ultimately prove important. These include various chemical, biological, and nuclear paths to hydrogen production that are currently under development. Chemical paths involve using chemical reagents acting under high temperature conditions to disassociate water and segregate the oxygen and hydrogen into separately recoverable streams.

Nuclear paths involve using nuclear reactor heat either coupled with electrolysis ("hot electrolysis") or chemical cycles to disassociate water and recover hydrogen. Biological paths (other than biomass gasification) employ hydrogenic algae to use sunlight to produce hydrogen. The chemical, biological, and nuclear options are in various stages of research and development, and any of them could conceivably prove competitive in the long-term with the conventional options on which this study is based. Indeed, it would be surprising – and disappointing – if the options considered in this study remain the most technologically attractive and cost-effective options throughout the coming half-century. To the extent that other hydrogen production options might become viable, the scenarios constructed here are technologically conservative.

Figure 2: CO_2 emissions per kg hydrogen for various production technologies



	on-site electrolysis	on-site NG reforming	Central NG reforming (no sequestration)	Central NG reforming (with sequestration)	Central coal reforming (no sequestration)	Central coal reforming (with sequestration)	Central biomass reforming (no sequestration)	Central biomass reforming (with sequestration)	Central electrolysis (from wind)
Sequestration	0	0	0	816	0	816	0	816	0
Process fuels	0	188	399	399	399	399	2,930	2,930	0
Feedstock losses	10,994	2,628	2,073	311	4,491	404	0	-3,576	0
Feedstock	23,337	6,756	6,756	1,013	11,545	1,039	0	-11,973	0

Note: "Feedstock" accounts for carbon content of one kg H2-equivalent of feedstock fuel, and "Feedstock losses" account for the carbon content of additional feedstock fuel used due to conversion inefficiencies.

Delivery

Hydrogen delivery is important for two main reasons. The first is that it is a challenging and costly element of the hydrogen transition. As many observers have pointed out, hydrogen has a much lower energy density than fuels we are more accustomed to using such as gasoline and diesel oil. This adds technical difficulty and cost to all the major modes of delivery – gaseous hydrogen tube trailers, liquid hydrogen tanker trucks, and pipelines. Tube trailers can typically carry 300 kg of gaseous hydrogen, or approximately 20 passenger vehicles worth of fuel. In contrast, a typical gasoline tanker truck carries roughly 300 passenger vehicles worth of fuel. Tanker trucks can carry more hydrogen – approximately 4,000 kg of liquid hydrogen or about 265 passenger vehicles. However, liquid hydrogen suffers from a grievous energy penalty due to the compression requirements for hydrogen liquefaction. Neither tube trailer nor tanker delivery can be a major part of the long-term hydrogen delivery infrastructure, though they might well play transitional or niche roles. Tanker ship and rail delivery are further options that might play roles in particular geographic settings.

With respect to the long-term strategies for providing the end-user with a reliable hydrogen supply, we have focused this analysis on the two major options: on-site hydrogen production at the refueling station, and centralized production with pipeline delivery. On-site production is preferred to centralized hydrogen production when both absolute hydrogen demand and hydrogen demand density are relatively low.[6] Pipeline delivery becomes economically feasible when absolute hydrogen demand grows large enough to warrant a large centralized facility, and demand density becomes high enough to make pipeline distribution less costly than the on-site alternative. Without pipelines, the use of hydrogen cannot have any carbon reduction benefits in cogeneration, or significant benefits in the transport sector. Our analysis shows that by 2050 a large fraction of hydrogen demand in the four cities and the USA would be in areas where there is high hydrogen demand density.

Carbon Capture and Sequestration

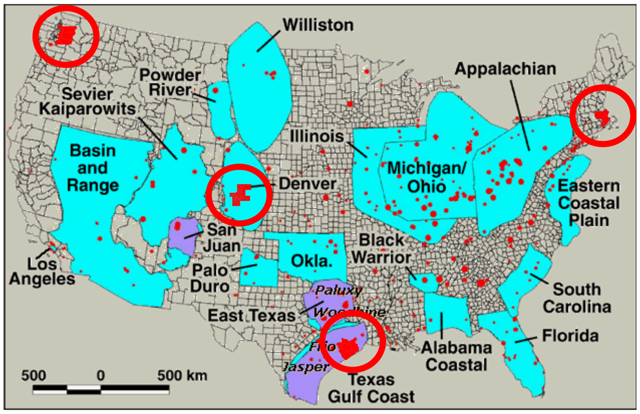
We included geological sequestration of carbon dioxide as a technological option that can be coupled with the production of hydrogen from natural gas, coal, and biomass in large-scale centralized facilities. We haven't considered it an option for small-scale hydrogen production at refueling stations. In principle, this would be technologically possible, but the additional cost of a pipeline system for collecting carbon dioxide from multiple dispersed refueling stations would be prohibitively costly. From centralized facilities, carbon sequestration adds additional cost, but is costly.

It is important to note that we have not been as technologically conservative with respect to carbon sequestration as we have been with respect to hydrogen production. While carbon capture relies on straightforward and well-understood technology, sequestration is more speculative. Sequestration in depleted oil and gas wells is already practiced widely, for the purpose of enhanced recovery from oil and gas fields. However, these sequestration sites are not widely distributed, and the total storage capacity is limited. In the continental United States, estimated storage capacity in oil and gas fields is approximately 98 billion $MtCO_2$ (Stevens, et al, 1999). For comparison, the cumulative amount of carbon dioxide emissions in the BAU scenario associated with the various end uses where hydrogen is introduced is about 160 billion $MtCO_2$ by 2050.

In contrast, deep saline aquifers are widely distributed and the total storage capacity could be much greater than the capacity contained in depleted oil and gas fields (see the figure below with the four cities superimposed). However, experience with sequestration in saline aquifers is much more limited. Questions remain regarding the long-term security of sequestered carbon dioxide, and the potential for environmental impacts due to the acidification of groundwater by carbon dioxide and the subsequent mobilization of heavy metals.

[6] Hydrogen demand density, a variable central to our city-based analysis refers to the amount of hydrogen consumed within an area of demand, and is expressed in units of energy per land area (i.e., trillion btu per square mile)

Figure 3: Deep saline aquifers in the USA (source: NREL)



Acknowledging the uncertainty surrounding sequestration, especially in deep saline aquifers, but recognizing the potential for sequestration to contribute to addressing the climate problem, we have created twin variants of each of the main hydrogen scenarios – a variant which does not use carbon capture and sequestration, and a variant that does.

4 Hydrogen Demand

Since hydrogen is a carrier, much like electricity, it can be employed in a variety of applications. The greatest demand for hydrogen will likely be in transport sector, which currently accounts for roughly one-third of primary energy demand in the US, about three quarters of which is consumed by passenger travel demand and the rest by freight. All transportation modes other than aircraft can potentially use hydrogen as a fuel using near-term technology, potentially displacing significant amounts of petroleum by 2050.[7] We assume that hydrogen displaces gasoline and diesel (non-military) in cars, light trucks, heavy duty vehicles, marine vessels, and trains. In 2000, total energy consumed by these on- and off-road categories represented about 80% of total transportation energy use.

Hydrogen for other sectors can be employed most fruitfully in cogeneration applications, by providing heat and electricity for industrial, residential and commercial establishments. Here, the growth of a hydrogen supply infrastructure faces different constraints than in the transport sector. For stationary applications, the 'chicken-egg' problem is mitigated by the fact that the hydrogen supply infrastructure need not be ubiquitous – it can be confined to a bounded region where significant demand exists. On the other hand, the benefits of using hydrogen are modest (or non-existent), and are substantial only when coupled with a carbon capture and sequestration strategy. In 2000, total energy consumed in cogeneration facilities represented about 5% of total energy use in the residential, commercial, and industrial sectors.

Cars and Light Trucks

The greatest impact of hydrogen will be for cars and light trucks, or light-duty vehicles (LDVs), which currently comprise the largest stock of vehicles (over 200 million) and greatest share of energy demand (about 58%) in the transportation sector. The average fuel economy of LDVs has actually declined over the past two decades, primarily because of a trend toward increasing sales of heavier vehicles, including light-duty trucks.

[7] While air travel is the fastest growing mode in transportation and is a significant source of greenhouse gas emissions, hydrogen is not under serious consideration as an aviation fuel except in some early research programs, in large part because of hydrogen's low density and the challenge posed by storage for long-haul flights.

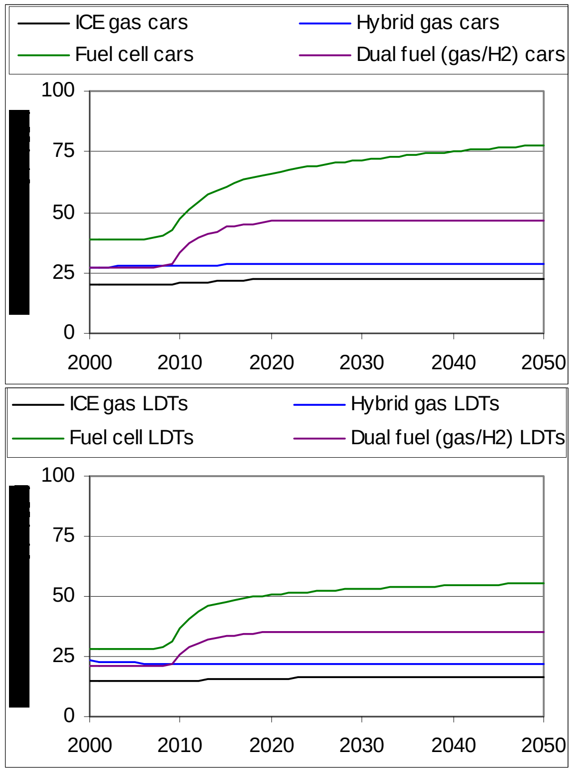
On the basis of per unit of service delivered—in this case, passenger miles traveled—the switch to hydrogen could potentially provide large efficiency improvements over today's vehicles. This is so not only because fuel cells offer substantial efficiency gains over conventional internal combustion engines, but because today's internal combustion engine vehicles (ICEVs) are currently well below their potential efficiency levels compared to technically feasible and commercially viable choices for conventional combustion and hybrid-electric technologies. Figure 4 illustrates fuel economy assumptions for new LDVs.

As shown in the figure, hydrogen fuel cell vehicles (HFCVs) stand to offer marked improvements over internal combustion vehicle technologies, including hybrids. Hydrogen offers the possibility of dramatically reduced transport sector emissions, providing upstream carbon emissions associated with hydrogen production and delivery are low or zero. Figure 5 shows the "well-to-wheels" greenhouse gas emissions of various car-fuel chain combinations assuming current year fuel economies.[8] This figure illustrates the level of greenhouse gas emissions that occur between extraction and delivery to the vehicle ("'upstream" emissions) and those that occur during operation of the vehicle ("vehicle" emissions).

The factory costs of HFCVs are expected to be anywhere from 20-60% above those of ICEVs (AD Little, 2001; USDOE, 2000; Ogden et al., 2003; Demirdöven and Deutch, 2004) at production volumes reaching 500,000 units per year. Further learning may bring the cost premium down, but significant technological challenges remain, including on-board hydrogen storage, further reducing the need for noble metal catalysts, and increasing the lifetime of the fuel cell stack. On-board storage is a particularly thorny issue, given the high storage pressure and the associated cost and weight of the pressure vessel to meet reasonable vehicle ranges. Breakthrough technologies, such as carbon nano-tubes and metal and chemical hydrides, are at incipient stages of development and as yet do not fully satisfy storage requirements. For the purposes of our analysis, however, we assume that most, if not all, of these problems will have been resolved over a 20-year timeframe.

Figure 4: New car and light duty truck fuel economy assumptions

[8] The fuel economy assumptions noted on this chart reflect values expected at the end of the scenario period. Domestic natural gas assumed for NG reforming options.

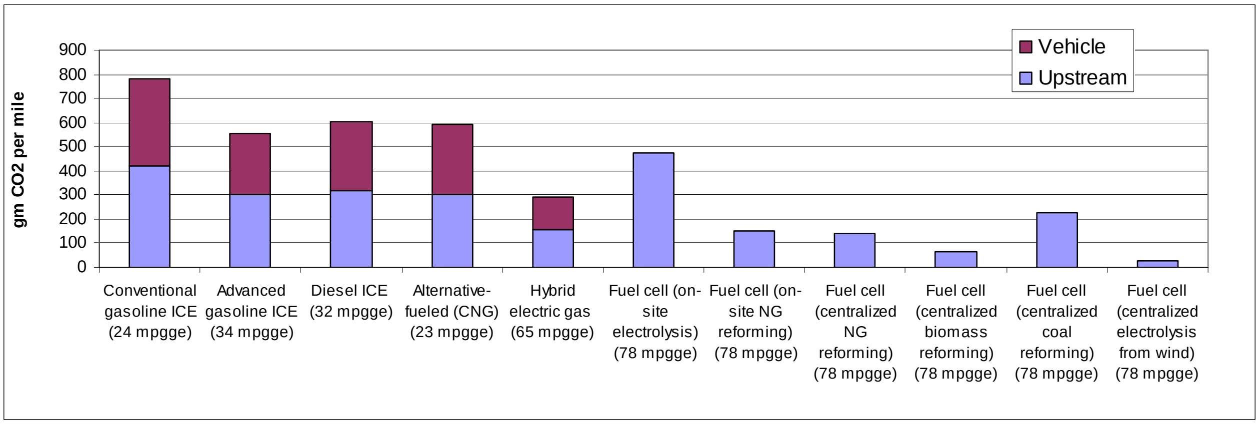


The BAU+H2 and GHG+H2 hydrogen transition scenarios employ two main transitional strategies for light duty vehicles to help overcome the notorious chick-and-egg problem plaguing the hydrogen transition. The first strategy is to involve private and government fleets (currently comprising close to one-fifth of annual vehicle sales) as early adopters of HFCVs, since many have dedicated refueling facilities and do not depend on the existence of a universally available hydrogen retail refueling infrastructure. By building up demand among vehicle fleets, and providing fleet operators incentives to provide hydrogen on a retail basis to private vehicles over time, fleets can help launch the "take-off" phase of hydrogen transition. The first such fleet vehicles are introduced in 2006.

The second transitional strategy is the limited introduction of dual-fuel ICEVs (with hybrid-electric technology for efficiency gains) during the early years of the hydrogen transition in both the passenger and fleet markets. ICEVs that can burn either gasoline or hydrogen are already available from BMW, and ones that run only on hydrogen are being developed by Mazda and Ford (Cho, 2004). Like fleet vehicles, these duel-fuel vehicles can help overcome the chicken-and-egg problem by providing an early source of demand for hydrogen without the need for a ubiquitous hydrogen refueling infrastructure. Given that the technology for dual-fuel ICEVs is readily available, they can serve as a transitional technology that helps build demand for hydrogen (and the corresponding supply infrastructure) at relatively low risk to consumers, timed to pave the way for the commercialization of private HFCVs. We assume that first such vehicles are introduced in 2006, with the hydrogen share gradually increasing from 25% to 100% by 2021.

Of course, building up a hydrogen demand through fleets and through dual-fuel vehicles will require financial incentives for suppliers and consumers during the early years of the transition. Dual-fuel hybrid ICEVs will likely be less efficient than FCEVs or even advanced hybrid gasoline ICEVs, but the efficiency penalty may be a justified price to pay to facilitate the speedier adoption of FCEVs when they are introduced into the market.

Figure 5: Well-to-Wheels comparison of CO_2 emissions per mile for cars



In the BAU+Shock H2 hydrogen transition scenarios, these same two transitional strategies applies though they are delayed by 10 years and once in place they are accelerated in order to promote a more rapid penetration of hydrogen consuming LDVs. To account for the need for a faster ramp up, an additional strategy is introduced that focuses on a gradual phase-out of conventional vehicles once they reach an age of 5 years, with a replacement with new fuel cell LDVs. Through this strategy roughly the same HFCV stock levels are reached by 2050.

Heavy Duty & Off-Road Vehicles

Collectively, heavy-duty vehicles (HDVs) marine vessel, and trains currently consume close to a third of total energy use in the transportation sector. Heavy-duty vehicles considered in this study include commercial delivery trucks, medium to heavy freight trucks, as well as transit, intercity, and school buses. Marine vessels include domestic shipping used in the transport of cargo and passengers, as well as recreational boats. Rail applications are focused on transit and freight trains.

A doubling or so in the efficiency of this segment of the transport sector could be expected as a result of conversion toward hydrogen fuel cells. HDVs, marine and rail vehicles are, in some ways, better candidates than LDVs for hydrogen fuel cells because they have less severe volume constraints, and hence sufficient capacity for hydrogen storage tanks. Similarly, while long-haul freight trucks will need a national network of hydrogen fueling stations, their needs could well be met by centralized fueling facilities.

Combined Heat and Power

There are limited opportunities for significant gains in efficiency for stationary uses of hydrogen. Nevertheless, one potentially strategic end use is for cogeneration at small commercial and large industrial facilities. Combined heat and power in small commercial facilities and large industrial facilities with excess electricity sold back into the central grid offers important reliability benefits.

In the base case scenarios, cogeneration at commercial and industrial facilities are assumed to use natural gas. For the BAU, annual levels of natural gas demand for CHP are based directly on outputs from AEO2003 up through 2025, and extrapolated to 2050. In the GHG-constrained scenario increased levels of cogeneration were assumed up to the technical potential (roughly 75% more demand by 2050).In the hydrogen transition scenarios, cogeneration uses gaseous hydrogen piped from central production facilities.

5 Supply & Demand Integration

This section describes the approach we use to integrate hydrogen supply and demand in an analytical framework using H_2M, a full fuel cycle model developed to analyze hydrogen transitions over the 2000 to 2050 time period. The aim of the approach is to determine energy, carbon, cost impacts with an expanding demand for hydrogen in each of the four study cities, given certain assumptions about the city, and set against the context of a broader transition to hydrogen occurring in the USA. Underlying our modeling approach are several premises and issues briefly discussed below.

Modeling Framework

Hydrogen transitions were modeled in H_2M using a scenario approach. Two counterfactual scenarios were considered. The BAU counterfactual scenario was benchmarked to the national results of the EIA's Annual Energy Outlook 2003 (AEO2003) to define key features of transportation, commercial, and industrial energy demand through 2025. The GHG-constrained counterfactual scenario was based in large part on *America's Global Warming Solutions* (Bernow et al, 1999), a study exploring options for achieving deep economy-wide GHG reductions. Three hydrogen scenarios were modeled: one relative to the GHG-constrained counterfactual; the other two relative to BAU conditions.

H_2M incorporates assumptions that address regional energy supply and regional demand characteristics, including refueling station information, hydrogen production facility cost & performance characteristics, fossil fuel prices, electric system characteristics, annual vehicle sales, fuel economy trajectories, and so forth. The model projects changes in the national and regional energy systems by a focus on hydrogen demand density, vehicle/equipment stock turnover, upstream/end use carbon emissions, and cumulative costs associated with hydrogen infrastructure requirements.

Equivalent Mobility

The largest share of hydrogen demand will be in the transport sector for cars and light trucks. A fundamental premise of our analysis is that the same levels of mobility exist in each of the hydrogen scenarios as there is in the base case. Insofar as the ability to drive in gasoline-fueled vehicles between cities, states, or regions is available today it should be so in the hydrogen scenarios. Refueling infrastructure should therefore be as ubiquitous and dependable after the transition to hydrogen as it is in the currently oil-based system.

One implication of this assumption is that rural areas that may be located far from any centralized hydrogen production facilities should have access to hydrogen comparable to the access to conventional fuels available now. Given the challenges of supplying hydrogen to areas of very sparse demand, it is conceivable that fuels other than hydrogen might turn out to be preferable in remote areas. However, since the purpose of this study is to focus on the hydrogen transition, we have deliberately chosen not to explore scenarios in which the fuel infrastructure is bifurcated, with hydrogen being supplied in urban areas and another fuel supplied in rural areas.

National Context

Equivalent mobility only makes sense when speaking of a hydrogen transition as a wide-scale, simultaneous, national transition, rather than as a transition isolated to the four metropolitan areas that are the focus of this study. We therefore embed our four-city analysis in a context of a concurrent national transition. While this study includes a detailed city-specific, spatial analysis for the four selected metropolitan areas, a parallel analysis of the hydrogen transition at the national scale is also necessary since energy supply systems are highly interconnected in the USA and demand for hydrogen in any of the four cities will affect the energy supply chains for producing the hydrogen needed well beyond the cities' borders.

For example, the cost of delivered hydrogen is highly dependent on the price of whatever fuel is needed to produce the hydrogen. Since fuel prices are responsive to overall fuel demand, not just demand in the cities, it is necessary to understand overall fuel demand levels in order to determine actual prices levels that will prevail in the regions where the cities are located. Another reason the national context is relevant is because it is overall cumulative demand that drives the process of technological learning, which ultimately affects the cost and performance of hydrogen supply and demand technologies.

Feedstock Supply Constraints

Understanding the national hydrogen transition context is also essential because the use of energy resources in four study cities, set against the backdrop of comparable transition pathway to be mirrored in other cities, will have implications for the overall energy balance in the USA. Since hydrogen production requires the use of energy feedstocks, a careful comparison of the annual and cumulative energy resource requirements with available resource levels is essential. Therefore, a starting point for properly integrating supply and demand is to ensure that sufficient energy feedstock is available annually to meet expected demand for hydrogen without exceeding available supplies and without triggering price shocks stemming from approaching resource scarcity.

An assessment of coal resources shows they are plentiful and could be widely used for hydrogen production. On the other hand, national supplies of natural gas are highly constrained relative to future projected demand even for non-hydrogen applications and will increasingly be replaced by imported liquefied natural gas.

Regarding renewable resources, considerable amounts of biomass could become available for hydrogen production, were agricultural residues widely exploited and energy crop production initiated. Moreover there are plentiful remote intermittent renewable energy resources, above and beyond the quantity that could cost-effectively be absorbed onto the electric grid, which could be used to meet growing demand for hydrogen.

Metropolitan Area Distinctives

Just as clear regional variations exist in current profiles of energy demand and production across cities and regions in the USA, there will doubtless be significant regional variations in the shape of hydrogen transition. The four cities, with their distinctive features regarding demographic patterns, travel behavior, economic activity, fuel prices, electric supply systems, and land use characteristics, offer a spectrum of underlying conditions that can provide insights into the range of possible transition futures that could be implemented across the USA

For this reason, there is an emphasis in the integration of supply and demand to use as much city-specific information and characteristics as possible. Key characteristics include population distribution patterns, land area included in the metropolitan area, characteristics of the refueling station infrastructure, characteristics and projected patterns in the electric supply systems, residential and commercial energy use patterns, location relative to marine transport corridors, and so forth.

Stock Turnover Strategies

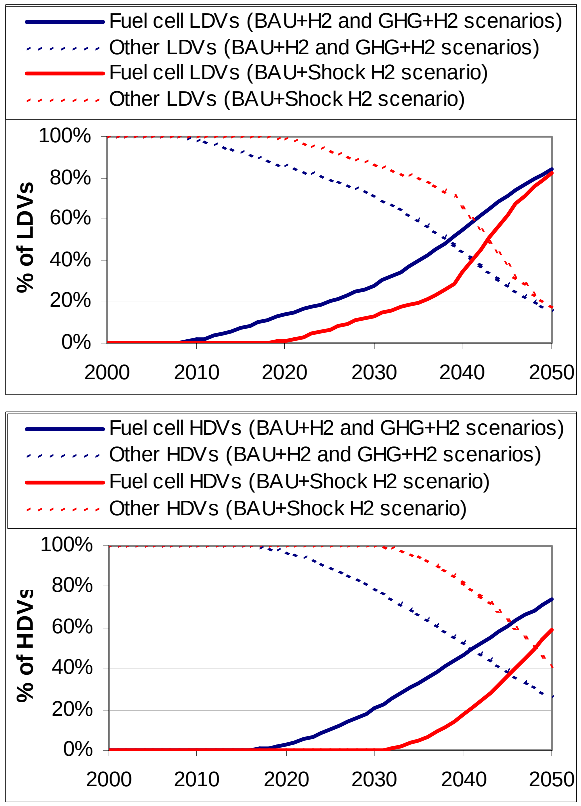
One of the key “rate limiting factors” in the hydrogen transition is the large inertia inherent in the large stock of light and heavy duty vehicles. According to AEO2003, light and heavy duty vehicle stock totaled about 200 million in 2000. To fully capture the process of the gradual evolution of this large number of vehicles, and account for the hydrogen demand in the various light- and heavy-duty vehicle classes, a detailed stock turnover model is used for each of the study cities, as well as the USA as a whole.

H_2M’s stock turnover model for light and heavy duty vehicles accounts for the range of factors that affect energy use in the transport sector, including local vehicle sale levels, VMT decline (as a function of vehicle vintage), vehicle scrappage schedules, fuel economy degradation by vehicle vintage, and so forth.

Because of the importance of centrally-fueled fleet vehicles as a transitional strategy, the stock turnover model also accounts for the short lifetime of fleet vehicles and their rollover into the passenger market.

We assume that fuel cell vehicle sales reach nearly 100% of cars and light trucks and diesel-fueled heavy duty trucks/buses for all regions and scenarios by 2050. Due to the time required for complete turnover of on-road vehicles, the overall stock of light and heavy duty vehicles becomes fully hydrogen-consuming sometime after 2050, as illustrated in Figure 6.

Figure 6: Fuel cell vehicle stock turnover levels



For cogeneration in the commercial and industrial sectors, as well as marine and rail transport, a simplified approach was taken that estimates annual new facility requirements based on techno-economic estimates of capital lifetime but without undertaking detailed stock modelling, and accounting for expected service lifetime and production capacities. We assume stock turnover is less than the on-road rate (i.e., 43% of marine, and 34% of rail transport energy demand is met by hydrogen by 2050 in all regions and scenarios). For cogeneration at the national level, we assume about 20% (BAU+H2, BAU+Shock H2 scenarios) and 50% (GHG+H2 scenario) of energy demand is met by hydrogen by 2050. Depending on regional industrial and commercial activity profiles, these levels vary at the city level.

Transition Pathways

The various hydrogen infrastructure components reflect the evolutionary course of the hydrogen transition. First, in response to the low and relatively dispersed initial demand, on-site hydrogen production units (i.e, at the refueling stations) form the basis for hydrogen production in the early period of the transition. On-site production units are assumed to be small (roughly 250 kg/day capacity) and modular and can be relocated to other areas once they are rendered unnecessary by the emergence of a hydrogen pipeline network. On-site production includes electrolysis and natural gas reforming units, and are intended to meet initial demand from vehicle fleets as well as long-term transportation hydrogen demand in rural areas where hydrogen pipeline delivery is implausible.

Once demand has increased considerably, it becomes possible to start shifting from small-scale on-site facilities to large centralized facilities with pipeline delivery. Because of the national variation in the size of hydrogen demand centers - varying from large metropolitan areas to relatively small towns - we have considered the option of either large (roughly 340 tonnes/day) or small (roughly 50 tonnes/day) units, using coal, biomass, natural gas, or remote non-grid-connected wind. Hydrogen from these units will meet demand in high hydrogen use areas by delivery through a transmission and distribution pipeline delivery system that is connected to refueling stations and industrial/commercial cogeneration facilities. Subsequently, as carbon sequestration is implemented, pipelines will be needed to transport the waste streams of carbon dioxide from centralized hydrogen production facilities to storage reservoirs.

Hydrogen Production Shares

A major aspect of integrating supply and demand for each of the hydrogen scenarios is determining the shares of central versus on-site production, and the mix of production technologies used. The former is based on an assessment of "hydrogen demand density" discussed in the section below. The latter is based primarily on local resource availability, set against the larger context of national resource constraints, and energy policy goals.

At the national level, we expect the BAU+H2 scenario to be primarily fossil fuel based (i.e., coal and natural gas), consistent with the AEO outlook for future trends in the energy sector at large. On the other hand, we expect the national GHG+H2 scenario to be primarily based on renewables (biomass, municipal waste, and remote non-grid-connected renewables), consistent with the trends toward greater reliance on renewable energy. Actual central production feedstock shares for the USA in each hydrogen scenario were constructed to ensure that feedstock constraints are not exceeded.

At the city level, we also expect the production mix in each transition scenario to be consistent with the basic policy contexts. In addition, local resources, conditions, and constraints factor heavily in production choices. These assumptions result in significant regional variation in feedstock supply mix across regions and scenarios, as illustrated in Figure 7.

Hydrogen Demand Density

The nature of hydrogen demand in a given region is a key factor in the transition. In particular, the density of demand determines whether hydrogen can be cost-effectively supplied by pipeline. If so, then hydrogen production in centralized facilities is viable. If not, then it is necessary to rely on on-site production of hydrogen (or, even less optimally, distribution by tube trailers or tanker trucks). Even within the relatively dense metropolitan areas represented by the four study cities, there are areas that are suburban, or even rural, in character, with correspondingly different demand level for hydrogen and implications for costs and carbon emissions.

This study accounted explicitly for these large spatial variations in hydrogen demand density. Though population density data are readily available, they do not provide very good proxy for fuel demand, because vehicle ownership varies so widely depending on settlement patterns. We instead used refueling station density as a proxy for demand for fuel. The location and number of refueling stations, both retail and fleet, was determined from underground fuel storage tank databases maintained by state-level EPA offices.[9] After aggregate hydrogen demand levels were determined for a given metropolitan area, they were spatially allocated based on the spatial distribution of refueling stations.

Pipelines are highly capital intensive. Their cost benefits from tremendous economies of scale, largely because of the high installation costs that are roughly independent of pipeline throughput and material costs that are less than linear with throughput. Pipeline delivery of hydrogen to the retail and fleet stations

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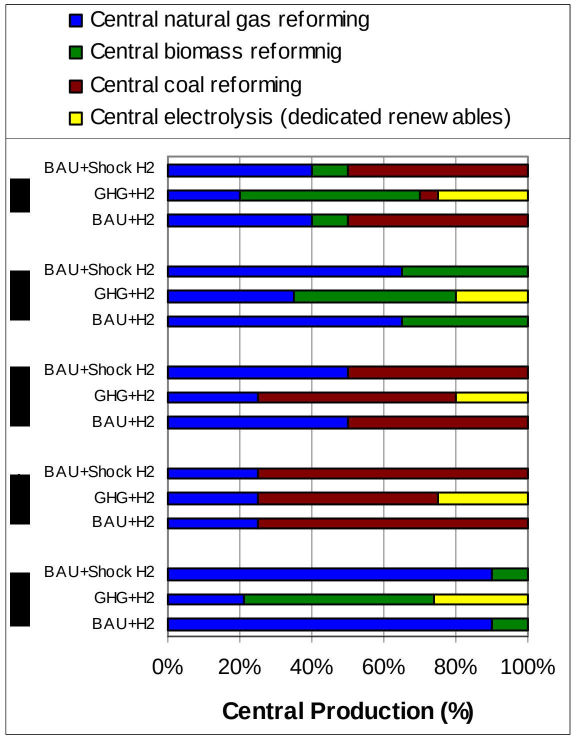
[9] The spatial distribution of hydrogen demand from fleet vehicles is tracked separately from that of privately-owned vehicles in order to model the effect of the fleet transitional strategy discussed earlier.

shown above would therefore not be cost-effective at the outset of a hydrogen transition when demand is still low and highly dispersed. The dispensed volume at the refueling stations will have to grow to a certain level before pipeline delivery becomes cost-effective compared to on-site production or delivery by other modes such as tube trailer or tanker truck.

Figure 7: Hydrogen production share assumptions - centralized facilities



This analysis assumes that hydrogen pipeline delivery will not be cost-effective in a given area until critical thresholds in two indicators of demand are exceeded. First, the *hydrogen demand density* must reach a certain threshold, which we calculate to be 240 kg H_2 per day per square mile (or 0.01 trillion btu of hydrogen per mi^2). This is equivalent to approximately 500 passenger cars per square mile, or roughly one refueling station per six square miles. Below this threshold, the demand is so dispersed that the shear length of pipeline needed to supply a given quantity of demand makes pipeline delivery prohibitively costly, contributing on the order of $1 per kg of H_2 delivered.

Second, the *total demand* for a contiguous area must reach an absolute threshold corresponding to the output of a centralized hydrogen production facility, which we take to be roughly 170 tonnes H_2 per day. Until this absolute demand threshold is met, we consider that there is insufficient market to warrant building and operating a centralized hydrogen production facility. Once these two hydrogen demand thresholds are met – both demand density and absolute demand – then it becomes cost-effective to transition from on-site hydrogen production to centralized hydrogen production integrated with a pipeline delivery network.

Economy-wide Interactions

The supply and demand integration framework explicitly models several interactive effects related to technology capital costs and fuel prices. These interactions, which can be either positive or negative, are essentially impacts on cost or price in one city or region based on changes in the overall market. Regarding technology interactions, large-scale hydrogen production and consumption will use technologies that, while technologically proven, are not currently commercialized. Past experience with new technologies shows that initially high capital costs are reduced over time as fabrication processes become more efficient and scale economies can be exploited.

Regarding price interactions, the large-scale use of fuels as a hydrogen feedstock will likely effect fuel prices given the price elasticity with respect to consumption. This is also true for electricity used for electrolysis. Technology capital cost effects for hydrogen production and fuel cell technologies are accounted for by using a 15% progress ratio, a figure typical of relatively new technologies.

Electric Sector Expansion

Insofar as electricity is needed to produce hydrogen, the hydrogen transition will affect how the electric system expands. We model these impacts assuming that the electric sector will evolve in a manner consistent with the underlying premises of the corresponding base case situation. Up through 2025, electric sector expansion is modeled using the EIA's National Energy Modeling System (NEMS) and the results mapped to the four cities.

Beyond 2025, we continue the trends in the preceding period so as to meet the regional distribution of the evolving electricity demand, and consistent with the local and national resource constraints. For the BAU, base case electric sector expansion continues to be based primarily on fossil fuel power plants, and nuclear facilities are relicensed as per current NRC rules so as to maintain a relatively constant total level of generation without calling for future new facility construction. For the GHG base case, the electric sector reduces its dependence on coal power, increases natural gas power somewhat, and significantly increases its use of dispatchable and intermittent renewable power. The overwhelming feature, though, is the strong increase in demand side energy efficiency that markedly decreases electricity demand.

For the hydrogen transition scenarios electric sector expansion is consistent with these same general features. The hydrogen transition in the BAU unfolds in the context of an electric sector primarily fueled by fossil fuels. The hydrogen transition in the GHG world unfolds in the context of an electric sector with lower overall demand that is increasingly powered by renewable energy.

Carbon Capture and Sequestration

Since the purpose of this study is to explore the impacts of a hydrogen transition in a greenhouse gas constrained world, we consider both the case where carbon sequestration is a safe and viable option that is broadly pursued, and the case where carbon sequestration is not pursued, in which case fossil-based hydrogen has carbon emissions at the point of production.

The availability and efficacy of carbon capture and sequestration options have large uncertainty bounds. In this study, we assume that future improvements occur in carbon capture and storage technology such that greenhouse gas emissions from central reforming units can be sequestered at reasonable carbon capture levels - 91% for coal and biomass, 85% for natural gas. Nevertheless, given the inherent uncertainties regarding long-term storage, this study also considers a no-sequestration sensitivity

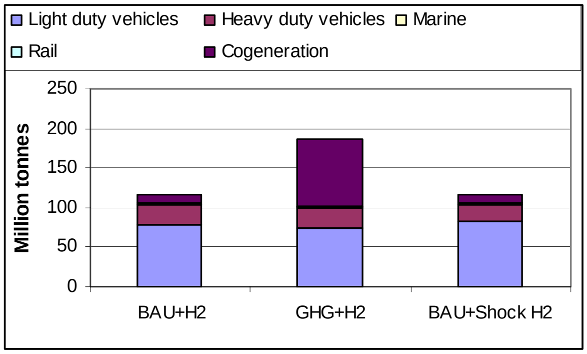
6 National Hydrogen Transition

At the national level, the results show that overcoming the inertia inherent in current energy infrastructure based on petroleum, natural gas, coal, and electricity will require substantial investment in new infrastructure and technology. On the other hand, the results indicate that significant reductions of greenhouse gas emissions can be achieved, especially when coordinated with national energy policy that seeks to contain economy-wide growth in greenhouse gas emissions for non-hydrogen consuming end uses.

Hydrogen Demand and Supply

Total hydrogen demand by 2050 reaches between 120 and 190 million tonnes, depending on the scenario (see Figure 8). Most of this demand – about 70% - is taken up by light duty fuel cell vehicles, except for the GHG+H2 scenario where cogeneration in the commercial and industrial sectors has a roughly equal share as transport hydrogen demand.

Figure 8: Hydrogen demand by 2050, USA



In the early years of the transition, all hydrogen supply is produced on-site. By 2050, about 80% of hydrogen supply is centrally produced and delivered via pipeline in metropolitan and micropolitan areas. Rural areas - as well as low hydrogen demand density zones within metropolitan areas – maintain an on-site production system throughout the transition. Meeting the levels of hydrogen demand indicated in the above figure will require substantial investments in new production and delivery infrastructure, as indicated in Table 2.

Table 2: New hydrogen infrastructure, 2050

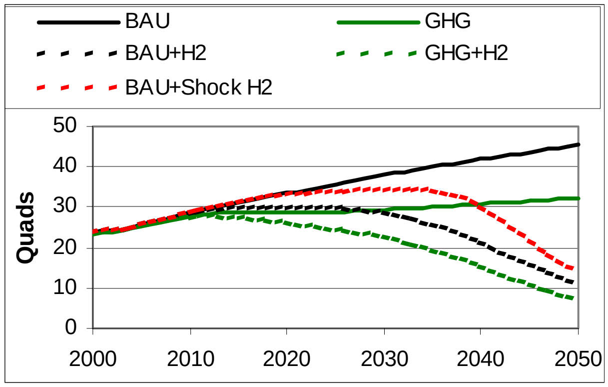
Type of Infrastructure	**BAU+ H2**	**GHG+ H2**	**BAU+ Shock H2**
Hydrogen refueling stations			
Total	200,000	200,000	200,000
On-site production units			
on-site electrolysis	19,750	36,512	20,861
on-site NG reforming	19,734	23,954	20,853
Total	39,484	60,466	41,714
Centralized production units			
Large NG reforming	329	270	334
Large biomass reforming	83	672	84
Large coal reforming	411	68	418
Centralized electrolysis	0	279	0
Small NG reforming	397	278	265
Small biomass reforming	100	693	67
Small coal reforming	496	70	332
Total	1,816	2,330	1,500
Pipelines (miles)			
Transmission	105,447	389,520	91,811
Distribution	382,814	371,988	219,277
Sequestration	151,532	135,793	133,018
Total	639,793	897,301	444,106

It is important to note that massive scale of new infrastructure required in a national transition to hydrogen. For the BAU+H2 scenario, nearly 650 thousand miles of new pipeline, 1,800 central production facilities, and 40,000 on-site units would be needed. Infrastructure investments are even greater in the GHG+H2 scenario due in large part to the reliance on centrally produced hydrogen from intermittent renewables and piping over long distances to metropolitan and micropolitan areas. A transition based on a shock scenario results in similar infrastructure investments by 2050 as in the BAU+H2 scenario though on a more rapid scale.

Crude Oil Demand

The transition away from gasoline and diesel fuels toward hydrogen results in sharp reductions in the use of crude oil as a feedstock in the national energy system. By 2050, the need for crude oil supplies dips below year 2000 levels – regardless of scenario as shown in Figure 9.

Figure 9: Crude oil demand, USA

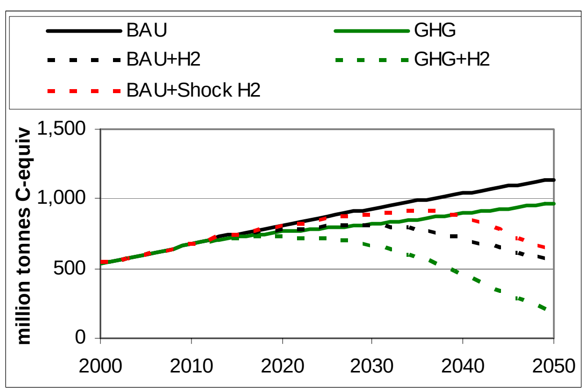


These reductions in oil demand range from about 70% in the GHG+H2 scenario to about 40% in the BAU+H2 scenario (relative to year 2000 crude oil supply levels). The BAU+Shock H2 reaches similar levels as the BAU+H2 transition scenario despite a 10-year delay in mobilizing the transition. The majority of the oil displaced is associated with the operation of light duty and heavy duty vehicle in the transport sector that rely on other feedstocks for the production of hydrogen.

Greenhouse Gas Emissions

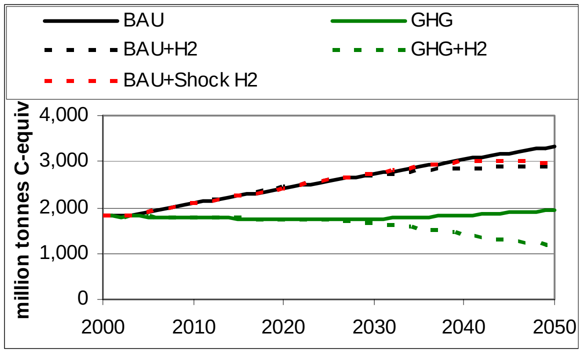
For end-use categories where hydrogen displaces gasoline, diesel, or natural gas, significant carbon reductions result, as shown in Figure 10. Notably, all three hydrogen scenarios achieve greater reductions than the GHG counterfactual, due to lower fuel cycle emissions and high levels of vehicle and equipment stock turnover.

Figure 10: Carbon emissions - hydrogen-consuming end uses, USA



Across all sectors in the US economy – hydrogen consuming and non-hydrogen consuming – there are also significant carbon reductions achieved, as shown in Figure 11 below. Relative to the counterfactual scenarios, reductions are less prominent due to lower hydrogen penetration shares of the overall economy and additional increases associated with providing electricity for hydrogen production.

Figure 11: Carbon emissions - all end uses, USA

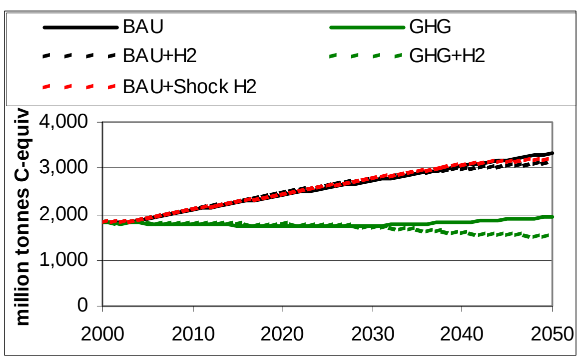


In the BAU counterfactual scenario, greenhouse gas emissions nearly double by 2050. With a large-scale switch to hydrogen in the BAU+H2 scenario about 400 million tonnes is avoided relative to BAU conditions in 2050, slightly less for the BAU+Shock H2 scenario. In the GHG counterfactual scenario, greenhouse gas emissions are slightly greater in 2050 than they were in 2000. A large-scale switch to hydrogen in the GHG+H2 scenario avoids nearly 800 million tonnes relative to GHG conditions in 2050 - over 2 billion tonnes relative to BAU conditions in that year.

The economy-wide emission trajectories illustrate the importance of the energy policy context. In the BAU+H2 and BAU+Shock H2 scenarios, with their continued dependence on fossil fuels and lack of aggressive energy efficiency and renewable energy strategies, switching to hydrogen still leads to about 1 billion *more* tonnes of carbon released in 2050 relative to year 2000 levels. In the GHG+H2 scenario, with its underlying support for energy efficiency and renewable energy, switching to hydrogen leads to over 600 million *less* tonnes of carbon released in 2050 relative to year 2000 levels.

This point is further emphasized when one considers hydrogen transitions without carbon sequestration. Given the uncertainties regarding the long-term security of sequestered carbon dioxide, it's possible that investments in the required carbon capture and sequestration may not be warranted. In such a case, the carbon reduction benefits from a transition to hydrogen would be roughly halved relative to the scenarios with sequestration by 2050, as illustrated in figure 12.

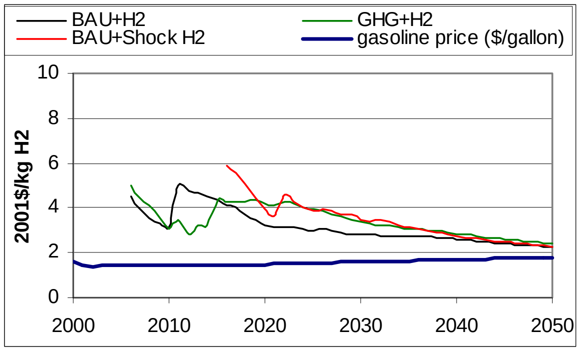
Figure 12: Carbon emissions for all end uses without sequestration, USA



Delivered Costs of Hydrogen

Figure 13 shows the annual delivered costs of hydrogen for the USA over the period 2000-2050. Embedded in the delivered costs of hydrogen are the annualized capital costs (on-site and centralized facilities, and pipelines), fixed and variable operating and maintenance costs associated with operating hydrogen production facilities and pipelines, fuel costs associated with the hydrogen production fuel cycle, as well as incremental costs associated with electric sector expansion to meet new hydrogen loads. The national gasoline price in the BAU scenario is shown for contrast (in units of \$/gallon).[10]

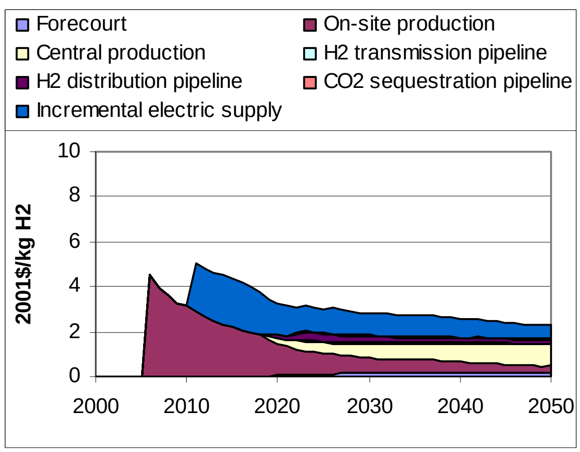
Figure 13: Delivered cost of hydrogen, USA



By 2050, delivered costs of hydrogen converge to around \$2.3/kg H2 in the BAU+H2 and BAU+Shock H2 scenarios, and to just over \$\$2.4/kg H2 in the GHG+H2 scenario, or roughly between 1.4 and 1.5 times the projected price of gasoline in the BAU scenario in 2050.

Delivered costs for hydrogen are volatile during the early years of the transition – as further illustrated in Figure 14 for the BAU+H2 scenario (as an example). This graph shows a breakdown of the various components associated with cost of delivered hydrogen. Around 2011 (about 5 years after the start of the transition), new electric infrastructure is required to meet the increasing loads associated with on-site electrolysis. Between 2020 and 2025, there is a small spike in costs associated with new pipeline installation, scrappage of on-site units that have reached the end of their service life, and new central production facilities.

Figure 14: Delivered hydrogen cost components (BAU+H2 scenario)

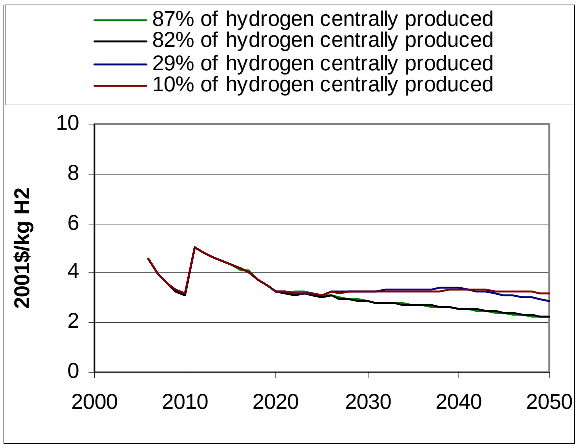


Delivered costs decrease steeply in the first 10 years of the transition as demand density increases and production units are able to operate at higher capacity factors. They continue to decrease thereafter, though more moderately, as capital cost reduction from economies of scale and improvements in hydrogen production efficiency become widespread.

[10] Gasoline price projections are based on the EIA's AEO2003 estimates. Sensitivity analyses, as discussed later, considered a doubling and tripling of the EIA estimates price trajectories.

The delivered cost of hydrogen is highly sensitive to the nature of the hydrogen production and distribution network. A transition relying primarily on on-site production rather centrally produced hydrogen with pipeline distribution is more costly, as Figure 15 shows for the BAU+H2 scenario for the USA. There is about a 30% cost premium by 2050 for hydrogen transitions relying on on-site production. A large part of the higher costs are associated with new electric load demand on an already constrained central electric grid system, incurring higher costs for upgrading and extending the transmission and distribution networks.

Figure 15: Delivered cost of hydrogen, USA



Costs of Saved Carbon

A transition to hydrogen can be directly compared to other carbon reduction strategies by considering the costs on both the supply and demand side to achieve carbon reductions. We calculate the costs saved carbon relative to the counterfactual scenarios by dividing the cumulative incremental discounted costs by the undiscounted cumulative carbon reductions (see Table 3).

Table 3: Costs of saved carbon, USA

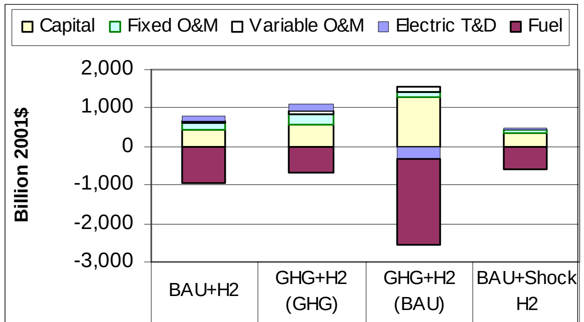
Hydrogen scenario	Counterfactual scenario	2001$/tonne of CO2 reduced
BAU+H2	BAU	-$14
GHG+H2	GHG	$12
GHG+H2	BAU	-$6
BAU+Shock H2	BAU	-$13

Negative cost of saved carbon values indicate that there are net economic benefits – rather than net additional costs - associated with a national hydrogen transition strategy. While this may be surprising given the very large incremental capital costs on both the supply and demand side associated with new hydrogen infrastructure and fuel cell vehicles, this is more than offset by the gasoline and diesel fuel savings achieved, as illustrated in Figure 16.

We tried to account for the possibility of a peak oil situation and its potential for introducing sharp and volatile increases in fuel price trajectories for gasoline and diesel in the transport and industrial sectors. In such a situation, net economic benefits from a transition to hydrogen would be even higher. We considered two sensitivities in H_2M –a doubling and a tripling of gasoline and diesel fuel prices by 2050 relative to the prices in that year for the BAU counterfactual. Costs of saved carbon are -$123 and -$233 per tonne of CO2 reduced, respectively.

Positive costs of saved carbon in the GHG+H2 scenario indicate that there are incremental costs associated with a hydrogen transition strategy. Since large fuel savings have already been achieved through the introduction of efficiency and renewable energy, additional costs are attributed in large part to the introduction of high levels of centralized electrolysis from dedicated intermittent renewables, with its accompanying high transmission pipeline investments.

Figure 16: Incremental costs of hydrogen



	BAU+H2	GHG+H2 (GHG)	GHG+H2 (BAU)	BAU+Shock H2
Fuel	-968	-693	-2,230	-591
Electric T&D	117	167	-304	61
Variable O&M	29	99	99	15
Fixed O&M	184	257	150	97
Capital	445	567	1,286	330

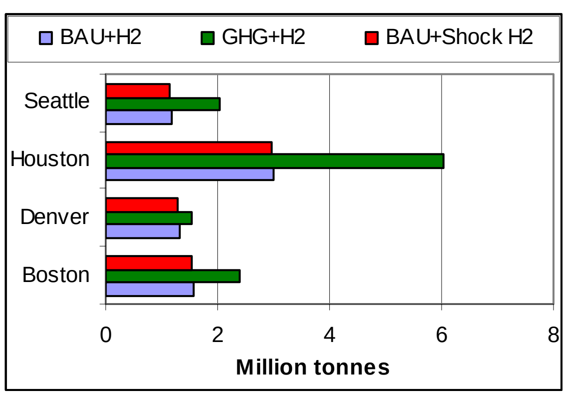
7 City Hydrogen Transitions

At the city level, trends are similar to national results regarding the level of new investments required and significant GHG reductions achievable. The results also show that some metropolitan areas are better positioned than others - on a delivered cost of hydrogen basis - to embark on a transition to hydrogen. As discussed in the subsections below, this is due to a number of city-specific factors such as demographic characteristics, feedstock resource availability, regional fuel prices, travel behavior, and industrial activity.

Hydrogen Demand and Supply

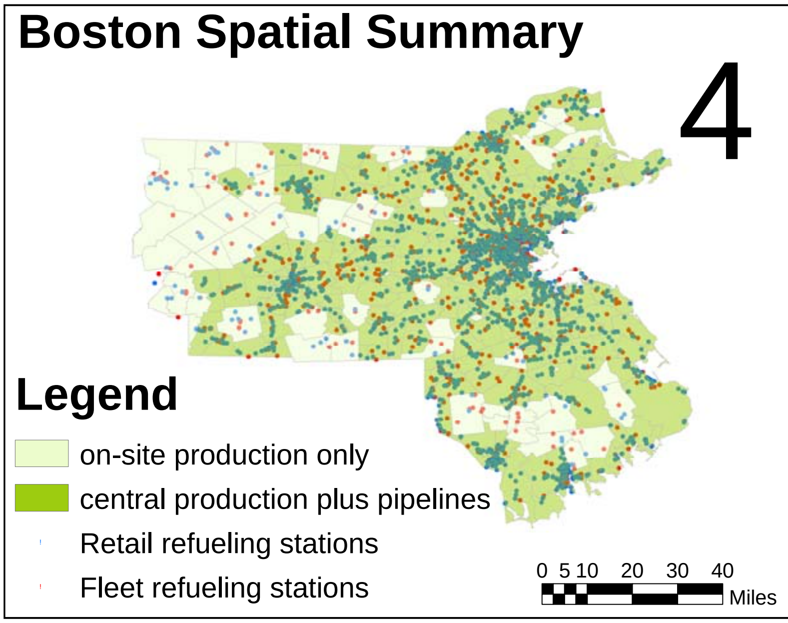
Across the three transition scenarios, hydrogen demand levels vary between 1 and 6 million tonnes by 2050, depending on the city and the particular scenario (see Figure 17). Houston in the GHG+H2 scenario has the greatest demand in great part to large levels of hydrogen used in cogeneration in the industrial and commercial sectors. This level is at least twice as high compared to any other city.

Figure 17: Hydrogen demand by 2050

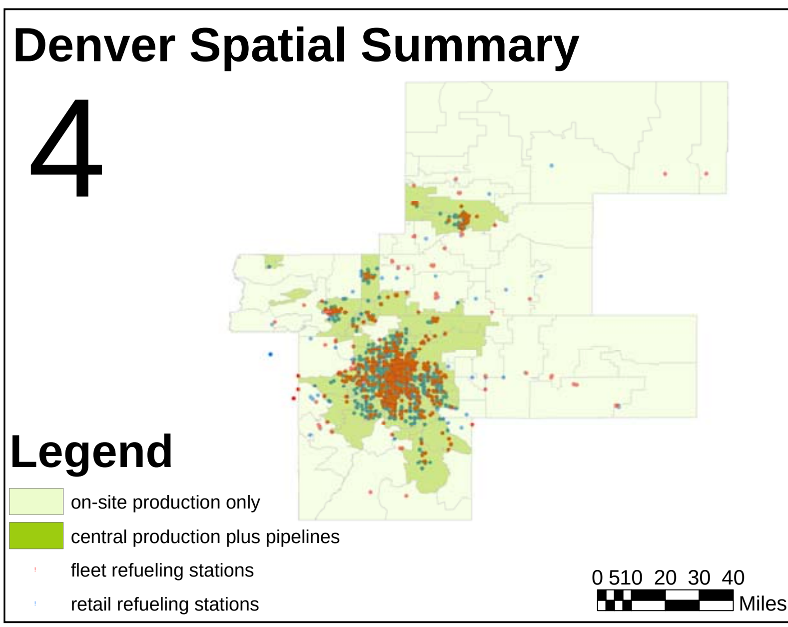


By 2050, total hydrogen demand – as well as the spatial distribution of areas serviced by central facilities and pipeline distribution networks - shows significant variation across the cities, as shown in Figures 18 (Boston and Denver) and 19 (Houston and Seattle) for the BAU+H2 scenario in the year 2050. The left side of these figures provides a spatial summary of hydrogen infrastructure. It shows the location of all hydrogen refuelling stations, with blue dots referring to retail refuelling stations and red dots referring to fleet refuelling stations. It also illustrates the area (shaded dark green) within the overall metropolitan region where hydrogen distribution pipelines are connected to refuelling stations. These dark green shaded areas represent the spatial boundaries within the overall metropolitan area where the demand for hydrogen is large enough so that production of hydrogen from central facilities is more cost-effective than production from on-site equipment.

Figure 18: Hydrogen transition summary in Boston and Denver, BAU+H2 scenario in 2050



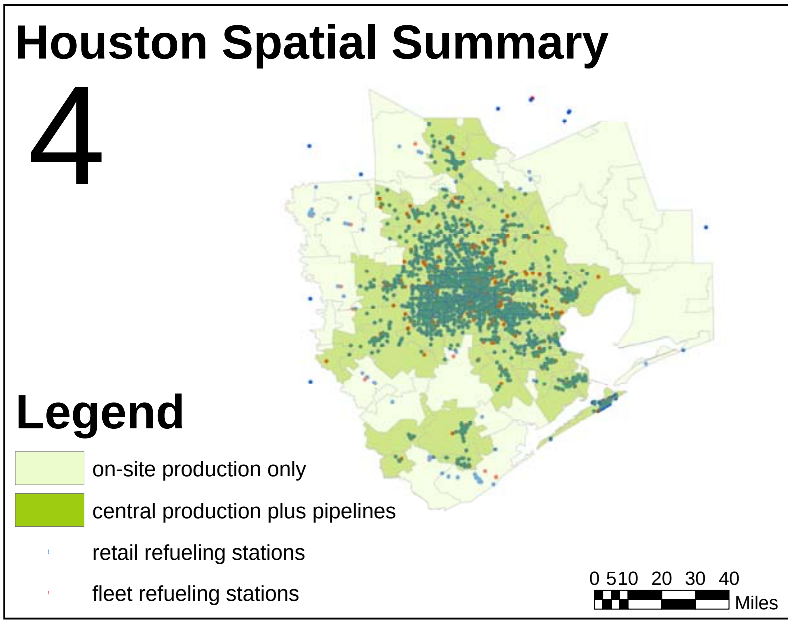
H_2 demand (trillion btu)	178
H_2 production (trillion btu)	187
- on-site production	8
- central production	180
H_2 refueling stations	3,214
- forecourts only	3,013
- on-site electrolysis	105
- on-site natural gas reforming	96
Central production facilities	18
- natural gas reforming	16
- biomass reforming	2
- coal reforming	0
- electrolysis (renewables)	0
Pipelines (miles)	3,977
- transmission	560
- hydrogen distribution	2,857
- CO2 sequestration	560
Delivered H_2 cost	
- 2001$/mmbtu	16.4
- 2001$/kg H_2	1.87



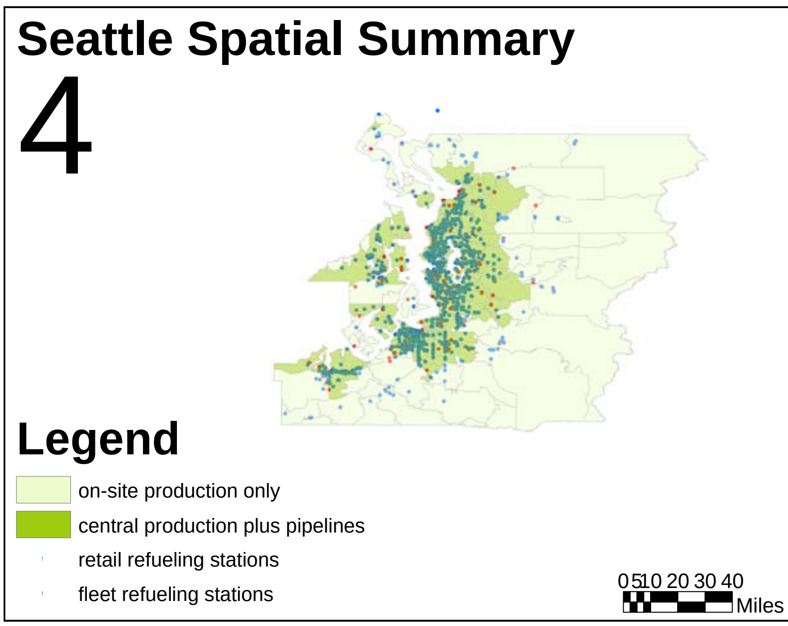
H_2 demand (trillion btu)	150
H_2 production (trillion btu)	158
- on-site production	13
- central production	145
H_2 refueling stations	1,864
- forecourts only	1,608
- on-site electrolysis	135
- on-site natural gas reforming	121
Central production facilities	15
- natural gas reforming	4
- biomass reforming	0
- coal reforming	11
- electrolysis (renewables)	0
Pipelines (miles)	1,765
- transmission	500
- hydrogen distribution	765
- CO2 sequestration	500
Delivered H_2 cost	
- 2001$/mmbtu	15.5
- 2001$/kg H_2	1.76

The right side of these figures provides a tabular summary of hydrogen demand, infrastructure requirements, and delivered costs. Specifically, they summarize the annual hydrogen demand, the total number of hydrogen refuelling stations, the number and type of on-site units still in service by 2050, the number and type of central facilities operating to meet municipal demand, total lengths of the various types of pipelines installed and delivered costs in units of \$/mmbtu and \$/kg of hydrogen.

Figure 19: Hydrogen transition summary in Houston and Seattle, BAU+H2 scenario in 2050



H_2 demand (trillion btu)	342
H_2 production (trillion btu)	356
- on-site production	18
- central production	339
H_2 refueling stations	7,764
- forecourts only	4,380
- on-site electrolysis	1,698
- on-site natural gas reforming	1,686
Central production facilities	31
- natural gas reforming	15
- biomass reforming	0
- coal reforming	16
- electrolysis (renewables)	0
Pipelines (miles)	3,205
- transmission	820
- hydrogen distribution	1,565
- CO2 sequestration	820
Delivered H_2 cost	
- 2001\$/mmbtu	13.0
- 2001\$/kg H_2	1.48



H_2 demand (trillion btu)	133
H_2 production (trillion btu)	139
- on-site production	14
- central production	125
H_2 refueling stations	2,091
- forecourts only	950
- on-site electrolysis	582
- on-site natural gas reforming	559
Central production facilities	13
- natural gas reforming	8
- biomass reforming	5
- coal reforming	0
- electrolysis (renewables)	0
Pipelines (miles)	1,678
- transmission	460
- hydrogen distribution	758
- CO2 sequestration	460
Delivered H_2 cost	
- 2001\$/mmbtu	24.1
- 2001\$/kg H_2	2.74

While all four cities show distribution pipeline networks concentrated around the urban core, there is considerable variation across the cities regarding the metropolitan area serviced by central production facilities and pipeline networks. Boston and Houston are at the high end of coverage with about 80% of their total metropolitan area being pipeline-connected. Seattle and Denver are at the other end with only about a coverage of about 25%.The total length of hydrogen distribution pipelines mirrors this variation as Boston and Houston – having the highest number of refuelling stations – together require a distribution pipeline network that is about three times the combined length required in Seattle and Denver. Transmission and sequestration pipeline lengths show considerably less variation across the cities due to the relative similarities regarding distances to resource supplies and deep saline aquifers for carbon sequestration.

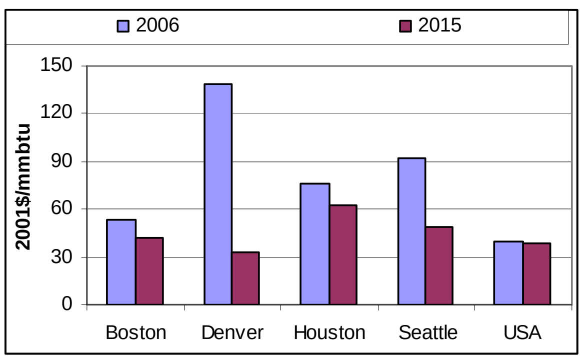
By 2050, the overwhelming majority of demand for hydrogen is met by central production facilities for all four cities, with a central production share of total hydrogen produced being at least 90%. Most of the on-site production facilities that were installed in the early years of the transition have been removed and installed in other rural areas of the country, or have been scrapped if they have reached the end of their service life.

Early Stages of the Hydrogen Transition

The switchover from on-site production to centralized production starts in 2016 for Houston and 2021 for the other cities. This difference in the switchover year is due to higher concentrations of hydrogen demand in certain parts of the Houston metropolitan area in comparison to the other cities. This pattern is evident across all scenarios.

Figure 20 shows delivered hydrogen costs in the years just before the switchover to central production in each city and the USA – 2006 to 2015 for the BAU+H2 scenario when hydrogen is produced exclusively on-site at fleet and private refueling stations. The costs in these early years show wide variation. Denver's delivered costs are nearly twice that of the other cities in 2006, due in large part to Denver's more dispersed demand that result in lower capacity factors for on-site production facilities in the early years. By the end of this initial period, All regions shows sharp cost reductions, with Denver's delivered costs decreasing to about one fourth of the first year costs, the largest and most rapid decrease for any city.

Figure 20: Delivered costs in first 10 years, BAU+H2 scenario



Rural and Urban Distinctions

Each metropolitan area consists of three basic land zone types - dense city core, suburban areas, and rural tracts. While most of the demand for hydrogen is concentrated in the dense and suburban zones, there are still non-trivial levels of hydrogen demand in low population areas that needs to be met by on-site production.

By 2050, Boston has the lowest such demand areas – 4% of its total hydrogen demand located in about 30% of its overall land area. Seattle is at the other extreme at 10% of its total hydrogen demand spread out over 70% of its land area. This is an important point with respect to the length of the hydrogen pipeline distribution system, delivered costs for hydrogen (on-site production of hydrogen is roughly double the costs for centrally produced hydrogen by 2050) and GHG emissions (sequestration is only possible at central facilities).

Greenhouse Gas Emissions

National patterns for greenhouse gas emission reductions are also evident at the city level, though at smaller scales. Table 4 shows cumulative carbon reductions for each city, for each hydrogen scenario including sequestration. Were each of the cities to embark on the transition represented by the scenarios it would lead to cumulative carbon savings ranging from 286 million tonnes in the BAU+Shock H2 to about 630 million tonnes in the GHG+H2.

Table 4: Cumulative emission reductions by 2050 (million tonnes of C-equivalent)

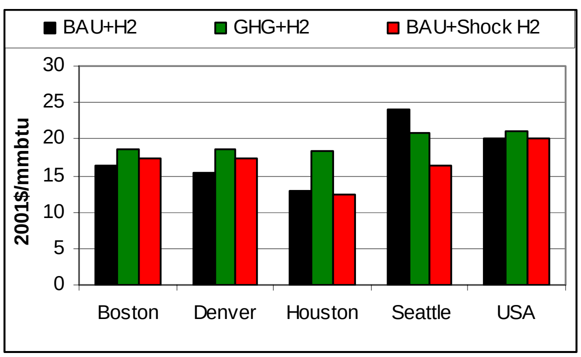
City	BAU+H2	GHG+H2	GHG+H2	BAU+Shock H2
Counterfactual >>>	*BAU*	*GHG*	*BAU*	*BAU*
Boston	105	136	604	58
Denver	52	60	531	25
Houston	128	274	1,193	67
Seattle	61	105	427	22
Total	347	576	2,756	172

To put these numbers in some perspective, 576 million tonnes, which are the combined savings for all cities in the GHG+H2 scenario relative to the GHG counterfactual, is roughly equivalent to eliminating the emissions from all the gasoline-fueled light duty vehicles in the four cities for about 43 years.[11] Moreover, if one were to compare the emissions in GHG+H2 scenario relative to the BAU counterfactual scenario (rather than the GHG scenario), cumulative GHG emission reductions are about 2.8 billion tonnes, a 4-fold increase.

Delivered Costs of Hydrogen

Figure 21 shows the delivered costs of hydrogen for the four cities and the USA in 2050. Embedded in the delivered costs of hydrogen are the cost categories described in the previous national transitions section.

Figure 21: Delivered costs, 2050



7 Conclusions

The following points are the broad, high-level lessons and conclusions that can be drawn from this study. They are reasonably robust to modest changes in the techno-economic assumptions that underlie this analysis. Of course, there is considerable uncertainty in how hydrogen and fuel cell technologies will develop, and how the socio-economic and political context will evolve.

[11] Based on average fuel economy and LDV stock levels in 2000 for the four cities.

A hydrogen transition won't happen "spontaneously"

The high incremental costs associated with each of the transition scenarios emphasize the fact that a large-scale shift to hydrogen is only likely to occur if it is driven by a formidable political will. Delivered costs of hydrogen remain considerably more costly than liquid fuels derived from conventional oil resources throughout the entire period of this study. Moreover, lifecycle costs of fuel cell vehicles, even after considerable technological progress, learning, and economies of scale, are still more costly than conventional combustion vehicles.

Finally, and perhaps even more fundamentally, the hydrogen transition can not happen "spontaneously" because of the built-in inertia of our current energy system, with its complex and interdependent parts subject to the decisions of distinct corporate actors and private individuals.

Hydrogen could be an important part of a national climate policy

Hydrogen alone cannot fully address the problems of climate change – or air pollution and energy insecurity for that matter. The BAU+H2 scenario, which shifts to hydrogen but otherwise resembles a very conventional evolution of the energy system, does not nearly as effectively address these problems as the GHG+H2 scenario, which embraces a varied suite of energy efficiency and renewable energy measures. Indeed, as reflected in the charts above, *the BAU+H2 scenario does not even match the benefits of the GHG base case*, let alone the GHG+H2 scenario.

Without complementing a hydrogen transition with a shift toward non-polluting devices and secure zero-carbon energy sources, a hydrogen transition will not adequately the nation's energy challenges. The GHG+H2 scenario more effectively reduces energy consumption in the first place, and more effectively meets the remaining energy demand with renewable energy sources. The comparison of cumulative emission reductions in the cities only reinforces this point, as does the fact that hydrogen use will likely remain unavailable to some end uses, notably fast-growing air travel energy demands.

Hydrogen has stiff competition

While hydrogen as an energy carrier can indeed help address climate change, there are other options such as electricity and biofuels that are strong contenders as well. Battery technologies for electric vehicles continue to advance. Although the rate of progress hasn't been as rapid as was once hoped, advances continue and there is still potential for electric vehicles to meet the stringent requirements energy storage, recharge, lifetime, and cost requirements of the transportation market. Lithium ion battery technology in particular has progressed significantly in the recent past, primarily owing to demand driven by the consumer electronics market. Transportation fuels produced from biomass feedstocks are a second set of options. Ethanol, methanol and biodiesel, in particular, have the potential for making a significant contribution to total fuel supply.

Hydrogen is only as compelling as its feedstock supply

The benefits of hydrogen do not derive from its greater life-cycle efficiency, but rather from the prospect of using hydrogen to exploit clean, zero-carbon energy supply options. As this study has shown, the only sources of zero-carbon, or near-zero-carbon for hydrogen production are:

- Biomass (converted to hydrogen through gasification or pyrolysis and reforming)
- Fossil fuels (converted to hydrogen through gasification and gasification/reforming) with CO_2 capture & sequestration
- Renewable energy (dedicated intermittent sources converted to hydrogen through large scale electrolysis)
- Grid-connected electricity in the GHG+H2 scenario

The first three options require pipeline delivery from centralized hydrogen production facilities. These options cannot be carried out on-site at the location of the hydrogen demand, whether the demand is from dispersed vehicle refueling stations or cogeneration systems in buildings.

The fourth production option does not require pipelines, as it can be implemented using on-site units connected to the central electric grid. This option is pointless for cogeneration, however, since there is no benefit to be gained from consuming grid electricity to produce hydrogen to again generate electricity.

For transportation, carbon reductions are possible only once the electrical supply sector has evolved to the point where its generating stations are sufficiently low-carbon that FCVs consuming electrolytic hydrogen are less GHG-intensive than ICEVs consuming gasoline. The carbon-intensity of electricity that would make a HFCV (assuming 78 mpgge) roughly comparable to a gasoline hybrid ICEV (assuming 65 mpg) is 425 gCO2/kWh (accounting for upstream emissions, power for hydrogen compression, etc.). Our study shows that in the BAU+H2 and BAU+Shock H2, the average carbon intensity of the electric grid never decreases below at least 600 gCO2/kWh, eliminating grid electricity as a climate-friendly options in a hydrogen transition.

On the other hand, the average carbon intensity in the GHG+H2 scenario reaches 135 gCO2/kWh, rendering grid electricity for on-site production a near-zero carbon source. Compared to hybrid ICEVs with a fuel economy of 65 mpgge fuel, fuel cycle GHG emissions from a HFCVs using hydrogen from on-site electrolysis are about 70 lower. This is particularly important because there remains between 10% and 15% of total hydrogen demand will be located in rural areas where grid-based onsite production is likely the favored choice.

Hydrogen represents a step backward in the early years

The primary near-term hydrogen supply options – though an unavoidable part of a hydrogen transition – will have negative benefits. The long-term hydrogen supply options, which are able to yield the GHG benefits that make hydrogen attractive, are all centralized options. They would be preceded by a considerable period of time during which only on-site options would be feasible, and therefore during which the GHG benefits would be marginal.

The carbon intensity of the hydrogen transition scenarios, averaged across the national system, is higher between 2006 and 2010 than in the respective base cases During this period, hydrogen is produced electrolytically from grid electricity and via on-site reforming from natural gas, which are less efficient processes than centralized options. There is actually a GHG penalty to be paid in the near-term, before the longer-term benefits are realized. In other words, the hydrogen transition ventures through some not particularly attractive options en route to cleaner future energy state. Hence, hydrogen, while being a strong contender for a long-term climate solution, is likely to have unsavory but potentially inevitable transitional implications.

This fact underscores again the importance of not relying on hydrogen alone to the climate challenge. Efforts to advance a hydrogen transition should be complemented with measures directed at immediate GHG benefits, for which there continue to be many near-term opportunities. Moreover, a set of regulations and mechanisms targeted at GHG-reductions *per se*, such as a carbon tax or a cap and trade system, while not inducing direct progress toward a hydrogen transition, could nevertheless be an important element in the broader energy policy context.

A coherent national effort is required to create a hydrogen transition

Combined, the above observations suggest that without a coherent national effort whose objective is to foster an orderly shift away from conventional energy carriers and toward hydrogen, it is implausible that markets will spontaneously transform and that a hydrogen transition will happen. A coherent transition strategy would have to include the following:

- *Invest in R&D.* Progress is especially needed on cost reduction, performance improvement, and lifetime extension of fuel cells; hydrogen storage; hydrogen production from renewable energy; and technological and environmental aspects of carbon capture and sequestration. It is certainly true that the private sector is already carrying out R&D, and indeed the technologies are advancing. But it is also true that the private sector historically has tended to underinvest in R&D generally, because it cannot be confident of the ability to fully internalize the financial benefits of the resulting technological advances. On these grounds, and because of the economic and political importance of energy, the recent presidential panel has strongly advised more public support for energy technology R&D (NCEP, 2004), including the R&D challenges listed above.

- *Identify niche applications and targeted incentives.* Promising niches start with applications that do not require a ubiquitous hydrogen refueling infrastructure. In this study, we've focused on two important niches: centrally-fueled vehicles fleets and dual-fuel ICEVs, each of which can help build demand based on a limited hydrogen refueling system. There are other possibilities, based on locally specific sources and potential end-uses of hydrogen, that will help build demand for hydrogen and advance hydrogen technologies, without the need for a wholesale commitment to a hydrogen transition.

- *Develop transitional technologies*. Certain transitional technologies can play important roles in creating early markets for hydrogen. Dual-fuel vehicles are a promising transition technology, since, like centrally-fueled fleet vehicles, they do not require a ubiquitous hydrogen refueling infrastructure. Other technologies are also consistent with progress toward a hydrogen-based energy system, such as hybrid electric vehicles (which help advance electric drive-train technologies) and low-weight vehicle materials (which help improve vehicle efficiencies regardless of drive train technology), small-scale cogeneration technologies (which helps build experience with building-scale cogeneration, grid interconnecting, power management), gasification technologies (which are relevant for power production as well as hydrogen production), and carbon sequestration technologies. All of these are valuable in their own rights, as well as useful stepping-stones toward a hydrogen transition.

- *Incentivize hydrogen demand.* Early potential sources of demand, such as centrally-fueled fleets and dual-fuel vehicles, will only be realized if potential owners and operators are offered incentives to actually buy these hydrogen-consuming vehicles and operate them using hydrogen. Historically, alternative fuel vehicle (AFV) programs have had minimal success, primarily because incentives (such as tax benefits) for purchasing vehicles have not been complemented with incentives (such as fuel cross-subsidies) for consuming the alternative fuel. Incentives for hydrogen production should be consistent with the underlying objectives of a hydrogen transition: to shift to secure, low-pollution, low-GHG energy sources. Incentives should recognize the energy security impacts of energy sources (e.g., dependence on imported oil or natural gas, and the proliferation hazards associated with reliance on nuclear fuels). Incentives should recognize the environmental costs associated with certain types of energy extraction or production (e.g., coal extraction via mountain top removal, and nitrate pollution high-input biomass feedstock production). Incentives should recognize the upstream GHG costs arising from use of energy sources (e.g., emissions from the generation of grid electricity for producing electrolytic hydrogen, as well as any benefits of geological sequestration). Without taking these impacts into account in transitioning to a hydrogen system, the results will be be no better, and likely even worse, than our current energy system.

- *Ensure policy consistency across sectors.* Perverse results could arise if policies aren't consistent across sectors, specifically with respect to GHG emissions. There are numerous measures that can be taken in the near term that should not be edged out in favor of hydrogen. In particular, even though vehicles are a large source of our society's GHG emissions, coal-burning power plants are arguably a much more pressing target for GHG emissions. The development of renewable energy resources would – if avoiding GHG emissions were the primary criterion – be directed toward displacing coal-based electricity rather than to producing hydrogen to displace gasoline consumption. As the graph below illustrates, one megawatt-hour worth of renewable electricity (e.g., wind and solar electricity) or biomass feedstock[12] would have a greater GHG impact if targeted at displacing coal-based electricity rather than used for hydrogen production to displace gasoline consumption in vehicles.

8 Parting Thoughts

Even with a concerted effort and a coordinated strategy to shift toward hydrogen, an orderly transition that avoids serious economic disruption would likely require a long period of transition. In the BAU+H2 and GHG+H2 scenarios that we've modeled, the hydrogen transition gradually unfolds over the course of roughly 50 years.

To summarize the lessons and recommendations from this study, it seems clear that there are several reasons why the complete transition could require at least this amount of time, and perhaps more. First, there is still the need for continued research and development, as discussed above, in fundamental aspects of a hydrogen system before hydrogen-producing and hydrogen-using technologies reach targets for performance and cost-effectiveness.

Second, the shear scale of the existing energy capital stock implies a considerable amount of inertia. Time would be needed for stock turnover in vehicles (which have decade-long lifespans), auto manufacturing facilities (with similar lifespans), and especially energy infrastructure (which can have several decade lifespans and significant siting issues).

Third, the chicken-and-egg problems inherent in the transformation of the energy system call for a staged approach, whereby initial niche markets are exploited before the broad market is accessible to hydrogen technologies, and hydrogen supply grows in stride with hydrogen demand.

In closing, the fact that an orderly transition would take a long time presents a difficulty in the context of problems such as climate change, which suffer from important uncertainties that will take time to resolve. We do not yet fully understand how sensitive the climate system is to our GHG emissions, and hence we do not now how severely we will need to curtail our GHG reductions, nor how soon. If we wait long enough for these uncertainties to be incontrovertibly resolved, and we find that a hydrogen transition is indeed a necessary part of the response to climate change, it might be too late to engineer a deliberate, orderly transition. To preserve the option of an orderly wholesale shift to hydrogen, should it prove necessary, the first cautious steps will probably have to be implemented under a significant degree of uncertainty about the final state.

Although an orderly transition would proceed over as much as five decades, it is conceivable that the transition could happen more quickly. Indeed, it quite plausible that it would have to happen quicker, as the demands of a vulnerable climate and the limits of oil resources force us to respond more quickly than we would otherwise choose. It is possible to initiate a hydrogen transition before all the cost and performance goals are met, but would be more expensive and provide lower environmental benefits and consumer amenities. It is possible to deploy major new technologies at a rate that is faster than the time-scale of the capital stock it is replacing, but would require the costly premature retirement of existing capital stock. And it is possible to accelerate the spread of hydrogen, but it might require greater subsides and come with the risk of demand-supply mismatches, with FCV owners overtaxing too few refueling stations, or capital-intensive investments in hydrogen supply waiting for demand to catch up.

[12] One megawatt-hour of biomass feedstock is energetically equivalent to approximately 3.4 MMBtu.

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