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# The Role of Clean Fuel Systems in a California Hydrogen Transition

A Comparison of Hydrogen, Synthetic Natural Gas, and Related Fuels

ITS-Davis Technical Report

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# Table of Contents

Foreword.....	1
1. Executive Summary.....	2
2. Introduction .....	6
3. Energy demand in California and biomass potential .....	6
4. Pathways to SNG and hydrogen: the chemistry .....	7
5. SNG and H2 as renewable fuels in transportation and power generation.....	9
Production of SNG from biomass.....	9
Economic analysis of SNG production .....	10
CO2 emissions analysis of SNG .....	12
SNG and LCFS Credit Values .....	12
Costs of using NG, SNG, SMR, and CCS to produce H2 .....	13
6. Transporting SNG and H2 in pipelines .....	15
H2/NG blends in pipelines .....	15
Recovery of hydrogen from blended flows.....	17
Pressure Swing Adsorption (PSA).....	17
Advanced hydrogen separation systems .....	19
Membrane hydrogen separation .....	20
Electrochemical hydrogen compression and purification .....	22
The role of a dedicated pipeline network in distributing NG/H2/SNG .....	24
Hydrogen distribution by pipelines.....	25
7. The role of hydrogen storage in energy system electrification .....	27
Hydrogen storage in the pipeline network .....	28
Long duration underground storage.....	29
Modeling of hydrogen storage costs in underground caverns.....	33
Above ground tank storage of hydrogen .....	35
8. Summary and conclusions .....	35
References .....	37

## Foreword

This report presents our analysis of hydrogen pathways for a future hydrogen system design, scale-up and optimization within California. We published a major [modeling report](#) on many of the larger system design elements in Spring 2023; this report extends our analysis to cover biomass pathways for hydrogen and compare costs with electrolysis on a side-by-side basis. This will assist assessing the potential role of the biogas and more broadly, “synthetic natural gas” (SNG) system as part of a hydrogen system. SNG includes methane from biomass or other organic sources, as well as that derived from electrolytic processes. We consider SNG used directly in gas pipeline systems and when used to produce hydrogen as part of a broader hydrogen system.

Other parts of the analysis, such as the transportation system evolution with fuel-cell vehicles, hydrogen station infrastructure, electric power system integration, and hydrogen demands from other sectors, were conducted separately. With this work added to the larger project, a more complete picture of a future hydrogen system could be assessed in follow up UC Davis studies.

This report includes coverage of:

- Natural gas (NG) and synthetic natural gas (SNG)-relevant pathways both as end use fuels and to produce hydrogen for transportation uses.
- Comparisons of biomass to electrolytic pathways for producing hydrogen
- Role of carbon capture, utilization and storage (CCUS) and life cycle assessment (LCA) impacts
- The potential role of the pipeline system to move hydrogen
- Gas pathways for power generation
- Some scenario development work

These are also covered to varying degrees in [other reports](#) developed by UC Davis in our current hydrogen research projects; here we provide a particular summary of our findings in key areas related to synthetic natural gas and biomass-derived hydrogen that may not be covered as well elsewhere in project outputs. There are many questions to continue to explore beyond what is presented here, but it is hoped that this report provides a contribution to the relevant topics.

## 1. Executive Summary

One strategy to achieve carbon neutrality in California by 2045 is to utilize renewable hydrogen (RH<sub>2</sub>) and synthetic natural gas (SNG) as clean fuels. These fuels can be produced from biomass and other renewable (e.g. solar/wind) energy as carbon-neutral or even net carbon-negative, resulting in large reductions in CO<sub>2</sub> emissions. These reductions can be applied in nearly all sectors of the economy since natural gas is used in all sectors. SNG as a replacement for natural gas can be distributed using the existing pipeline network and it can use the same appliances as NG to meet the same heat and electrical power generating applications. In the transportation sector, while many vehicles can be battery-electric powered by renewable electricity, RH<sub>2</sub> holds particular promise since it can be used in fuel cell powered vehicles, with zero emissions from the vehicle. This may provide an important complement to battery electric vehicles and even prove superior for some vehicle types and applications. Within the electric sector, hydrogen can be effective for energy storage, especially seasonal and provide resiliency benefits. Hydrogen along with biomass components and CO<sub>2</sub> can be used to produce a wide variety of synthetic carbon-neutral hydrocarbon fuels that can meet the ongoing energy needs of vehicles reliant on liquid fuels, such as for existing trucks and in aviation and marine applications. All the renewable clean fuels can be carbon-negative when the CO<sub>2</sub> emissions from their production and/or use are captured and stored (CCS).

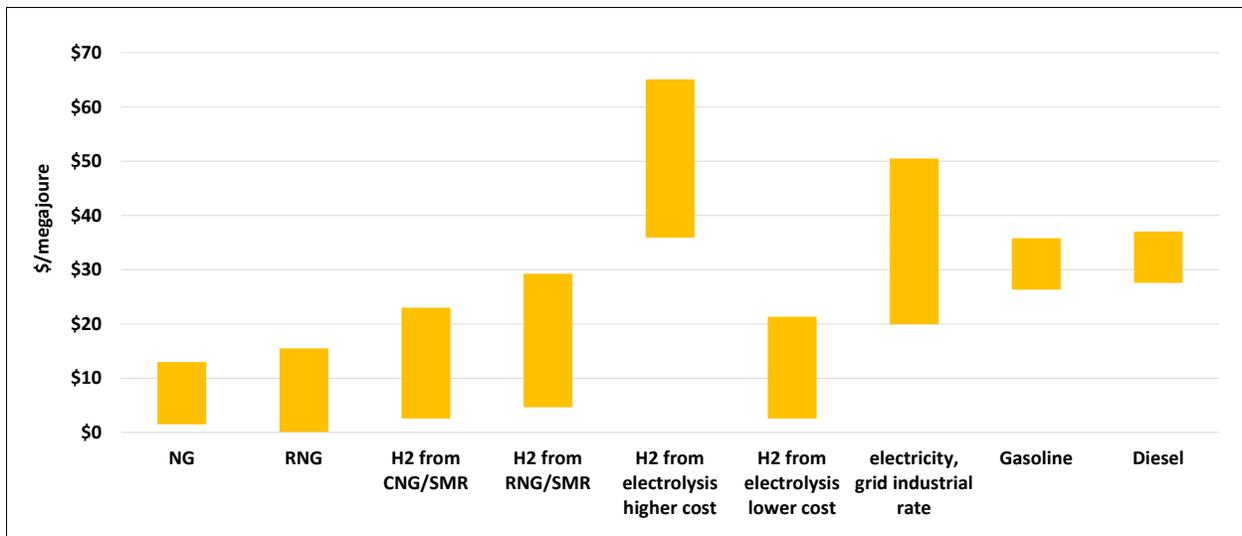
Based on our literature review, and a range of analysis presented in this report, we have estimated the cost (\$/GJ) and CO<sub>2</sub> emissions (gCO<sub>2</sub>/MJ) from using the various fuels within California, on an energy basis. These are shown in Table ES-1. This table also includes the potential low-carbon fuel standard (LCFS) credits or debits for an example scenario (\$150/ton CO<sub>2</sub>, 85 g/mj target). This reduces the net price of low carbon fuels like SNG and hydrogen from SNG or low-carbon electricity, while raising the cost of fossil fuels. Figure ES-1 shows this comparison, and that the resulting cost ranges are fairly similar for CNG, SNG, H<sub>2</sub> from SNG and H<sub>2</sub> from low-cost electrolysis (that may take some years to achieve).

In addition, the relatively low net CO<sub>2</sub> emissions from SNG are evident from the table, nearly as low as electricity from renewable electrolysis. Given the availability of biomass resources within the state, SNG and biomass-based-hydrogen should be considered as potential transportation fuels; SNG for its convenience to use as a replacement for NG and relatively low cost and low CO<sub>2</sub> emissions; hydrogen for its similar potential and additional benefit as a zero-vehicle-emission option, the only such option for road vehicles besides electricity.

**Table ES-1: Comparison of production costs and LCFS credit impacts for various fuels and feedstocks**

	<b>Cost in own units and GJ</b>	<b>LCFS CO2 content g/GJ fuel (EER adjusted)</b>	<b>LCFS Credit value (\$/GJ) @ \$150 /ton CO2, target set at 85 g/MJ</b>	<b>Final price range with credit (\$/GJ)</b>
<b>NG (\$3-10/GJ)</b>	3-10 GJ	70-100	(2.3) -2.3	0.8 – 12.3
<b>SNG (\$7-15/GJ)</b>	7-15 GJ	0-50	(12.8) – (5.3)	(5.8) – 9.8
<b>H2 from CNG/SMR (CNG \$3-10/GJ )</b>	1-3/kg (8-25/GJ)	42-67	(6.5) – (2.8)	1.8 – 22.3
<b>H2 from SNG/SMR (SNG \$7-15/GJ)</b>	2-4/kg (17-37/GJ)	0-25	(12.8) – (9.0)	3.9 – 28.5
<b>H2 from electrolysis higher cost (\$0.07-0.10 grid electricity, \$500-750 electrolyzer cost, 50% cap factor)</b>	5-8 kg (42-67 GJ)	42-69	(6.5) – (2.3)	35.2 – 64.3
<b>H2 from electrolysis lower cost (\$0.02-04 renewable electricity, \$200-300 electrolyzer cost, 33% cap factor)</b>	1.5-3.5 kg (13-29 GJ)	14-28	(10.7) – (8.6)	1.8 – 20.6
<b>Electricity grid industrial rate (\$0.10-0.20/kWh)</b>	0.1-0.2 kg (28-56 GJ)	28-46	(8.6) – (5.8)	19.2 – 49.8
<b>Gasoline (\$3-4/gal)</b>	\$3-4/gal (25-33/GJ)	91-99	0.9 – 2.1	25.6- 35.1
<b>Diesel (\$3-4/gal gasoline equivalent)</b>	\$3-4/galge (25-33/GJ)	99-107	2.1 – 3.3	26.8 – 36.3

Note: For LCFS credit column, parentheses indicate a credit (and fuel cost reduction), no parentheses mean a debit (and fuel cost increase).



**Figure ES-1: Fuel prices for various pathways, including underlying feedstock prices and LCFS debit/credit values from Table ES-1**

A primary uncertainty in comparing these approaches is the cost (\$/GJ) of SNG produced from biomass. SNG is presently more expensive than NG, which is by far the lowest cost fuel (see Table 19). It seems likely SNG will be considerably lower cost than H2 when the SNG production technology becomes mature in large plants. The low cost of NG and SNG are evident from the table and the net emissions from SNG are nearly as low as electricity from electrolysis. Hence SNG is a convenient replacement for NG with a low cost and low CO<sub>2</sub> emissions.

The various sections of this report discuss how these clean fuels could be produced and how their net CO<sub>2</sub> emissions (emission at final use minus the upstream emissions of the biomass as it has grown) are either zero or negative if CCS is used in the production and final use of the fuel.

Consideration is given to the difficulties and cost of distributing hydrogen in tube-trailers, pipelines, and blends and using hydrogen in place of NG or SNG for thermal heat and electrical power generation. These difficulties are eliminated when SNG is used rather than hydrogen. Large quantities of clean, renewable hydrogen are certainly needed in the proposed carbon-neutral strategies, but hydrogen is used when its use is necessary and cost-effective. This is the case both in the production of SNG and other synthetic hydrocarbon fuels and in transportation applications of fuel cell powertrains.

We identify a set of priority strategies. These are:

- 1) Using electricity (especially renewable solar/wind electricity) directly in vehicles whenever possible and practical, given their efficiency and cost considerations.
- 2) Continuing to develop electrolytic hydrogen and use low cost, potentially off-grid renewable electricity to develop this hydrogen pathway.
- 3) Developing the use of biomass resources to produce both SNG and H2 wherever the cost is (or could eventually be) competitive, given LCFS credits and their values. Ensuring a role for cost-effective SNG and biomass hydrogen should not be neglected as hydrogen systems grow.

SNG can be (and is) directly used in vehicles, though the strong push toward zero-emission electric vehicles (ZEVs) in California suggests that conversion to H<sub>2</sub> and use in fuel cell electric vehicles (FCEVs) is

likely to be a much more important pathway. Given the need for long distance, high payload trucking, hydrogen and FCEVs appear likely to play an important role in the state's transportation sector by 2030; the most obvious market is for heavy duty trucking, but possible demand for FCEVs in smaller truck and LDV segments could result in an even larger role for hydrogen overall. For SNG and especially hydrogen from SNG and biomass to succeed, more work is needed to understand the situations when these fuels can be produced at low cost, with low net GHG emissions, the scale potential for them in California, and how the transportation use cases compare to other possible uses. This paper provides some foundational information, but more research into these topics is needed.

## 2. Introduction

In 2018, California Governor Edmund G. Brown, Jr. signed Executive Order B-55-18 [1], establishing the goal “to achieve carbon neutrality as soon as possible, and no later than 2045, and achieve and maintain net negative emissions thereafter.” A number of studies of the best strategies for California to meet the decarbonization mandate are discussed in [2-4]. Those studies have concluded that the best approach is electrification and development of clean fuels, which include hydrogen, biogas, synthetic natural gas, biofuels from biomass, and synthetic liquid fuels using CO<sub>2</sub> and hydrogen (E-fuels). Renewable electricity from wind and solar are a key part of that strategy, but clean fuels are needed to make the electrification strategy reliable, resilient, and affordable.

The recently concluded hydrogen transition study at UC Davis [5] has analyzed/simulated in depth a decarbonization program for California that has much in common with the discussions in [2-4]. A number of topics dealing with clean fuels that are of particular relevance to clean fuels are reviewed in this report based on studies done during the UC Davis program. Those topics include the technology and economics of SNG and hydrogen production, and the roles of hydrogen pipelines, blending, storage, and CCS in transition to carbon neutrality.

Consideration of SNG as a drop-in replacement for NG was not included in the UC Davis hydrogen study [5], but SNG along with H<sub>2</sub> can be key components in reaching carbon-neutrality in California by 2045. Using biomass as the carbon source for the alternative fuel results in a carbon neutral fuel or in many applications, a fuel process with negative kgCO<sub>2</sub> /kg used.

The following sections cover a range of technical topics related to biomass, SNG and H<sub>2</sub> production from biomass and SNG. These have provided underlying data and analysis that we have used in the table and figure in the executive summary above, as well as for our modeling work published separately. We will continue to do more modeling of hydrogen systems making greater use of the biomass and SNG-related information contained in this report.

## 3. Energy demand in California and biomass potential

California used 2100 billion scf of NG in 2021 and  $2.77 \times 10^5$  GWh of electricity from all sources [6]. About 45% of the NG or  $2.74 \times 10^5$  GWh was used to produce electricity with 21% used in the residential sector, 25% in the industrial sector, and 9% in the commercial sector. Thus the energy content of the NG used in all sectors is a factor of 2.2 greater than that of the total electricity produced and that the NG energy demand in other sectors than electricity in California is  $3.34 \times 10^5$  GWh. To match the energy content of the NG used in the non-electricity sectors would require 10 million tons of H<sub>2</sub>/yr or 1160 billion scf/yr of SNG. To produce 1155 billion scf of SNG would require about 42 billion tons of cellulosic biomass (0.53 kg SNG/kg biomass). An estimate of the biomass available in California [6] is shown in Table 1. There seems to be adequate biomass available in California to produce large amounts of SNG (synthetic methane).

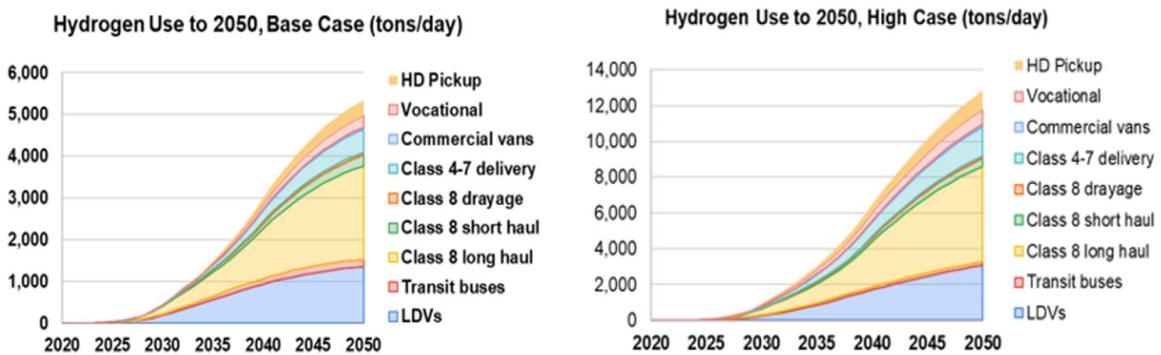
**Table 1: Summary of biomass availability in California [6]**

Category	2025 Amount	2045 Amount
Agriculture residue	10.4 M BDT/yr	12.7 M BDT/yr
Municipal solid waste	12.3 M BDT/yr	13 M BDT/yr
Landfill and anaerobic digester gas (gaseous waste)	7.1 M tons/yr	6.1 tons/yr
Forest biomass	24 M BDT/yr	24 M BDT/yr
<b>Total</b>	<b>54 M tons/yr</b>	<b>56 M tons/yr</b>

BDT = bone dry metric tons

The UC Davis ITS California Hydrogen Analysis Project has developed scenarios of future potential hydrogen use in California, with a particular emphasis on road transportation. As indicated in Figure 1 [5], our Base Case for the hydrogen needed for fuel cell vehicles (cars, trucks and buses) on the road by 2050 could be over 10 thousand tons/day or close to 4 million tons/yr. While it is expected that much of the hydrogen will be produced using electrolysis, there will be a need for other hydrogen feedstocks; biomass sources should be seriously considered as part of the mix. As a rough guide, if solar/wind electricity can provide half of this hydrogen, there still could be demand for 2 million tons per year from biomass. Including SNG used in the natural gas system (even with much of the residential/industrial NG applications eventually electrified), we estimate the need for hydrogen and SNG to be on the order of 1-2 x10<sup>5</sup> GWh.

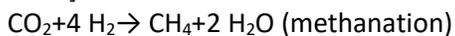
**Figure 1: Projected hydrogen required by fuel cell vehicles in 2050 [4]**



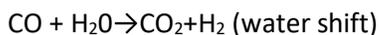
#### 4. Pathways to SNG and hydrogen: the chemistry

There are several pathways [8-12] for producing synthetic natural gas (SNG) and hydrogen which will be discussed in later sections of the report. In some pathways the production of SNG and H<sub>2</sub> are linked. H<sub>2</sub> can also be produced from SNG with the SMR process (Steam Reforming Methane).

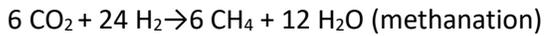
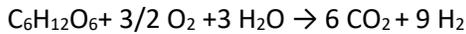
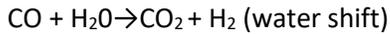
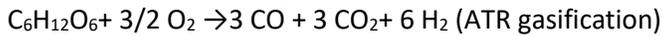
SNG is simply synthetic methane CH<sub>4</sub> formed by reacting CO<sub>2</sub> and H<sub>2</sub> in the methanation reaction shown below [13-15].



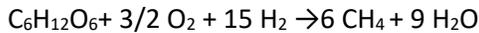
CO<sub>2</sub> can be contributed from biomass or collected from another process or from the air. H<sub>2</sub> be produced from water using electrolysis and grid or solar/wind electricity and the water shift reaction as shown below.



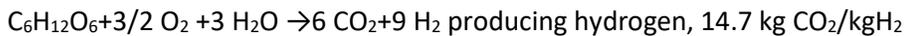
The sequence of reactions using cellulosic biomass is shown below [12].



The overall reaction produces methane and no CO<sub>2</sub>

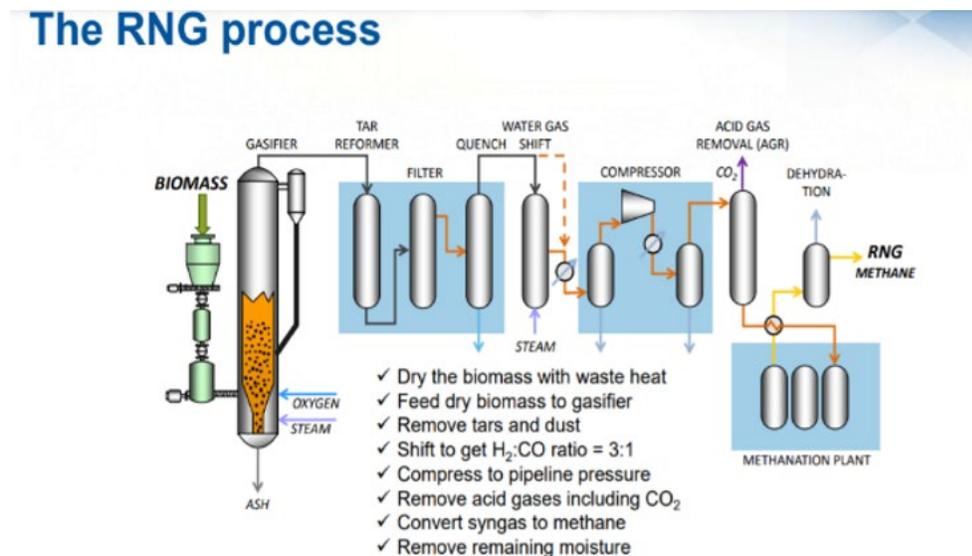


Hydrogen can also be produced from biomass and methane, but with generation of CO<sub>2</sub>.



One mole of cellulosic biomass yields 6 moles of CH<sub>4</sub> and requires 15 added moles of H<sub>2</sub>. The added H<sub>2</sub> can be generated from electrolysis of water using solar/wind photovoltaic (PV) electricity. One advantage of the gasification process is that in principle all the CO<sub>2</sub> generated from the biomass is utilized internally to the overall processes to form CH<sub>4</sub> and as result the overall process can have very low CO<sub>2</sub> emissions. Note that after the water shift reaction the product stream is only CO<sub>2</sub> and H<sub>2</sub>. Hence the process to this point can be considered a pathway to producing hydrogen from cellulosic biomass. In a later section, the cost and CO<sub>2</sub> emissions of producing both renewable natural gas (RNG) and RH<sub>2</sub> from the unit shown in Figure 2 are considered.

Figure 2: A schematic of the RNG process



## 5. SNG and H<sub>2</sub> as renewable fuels in transportation and power generation

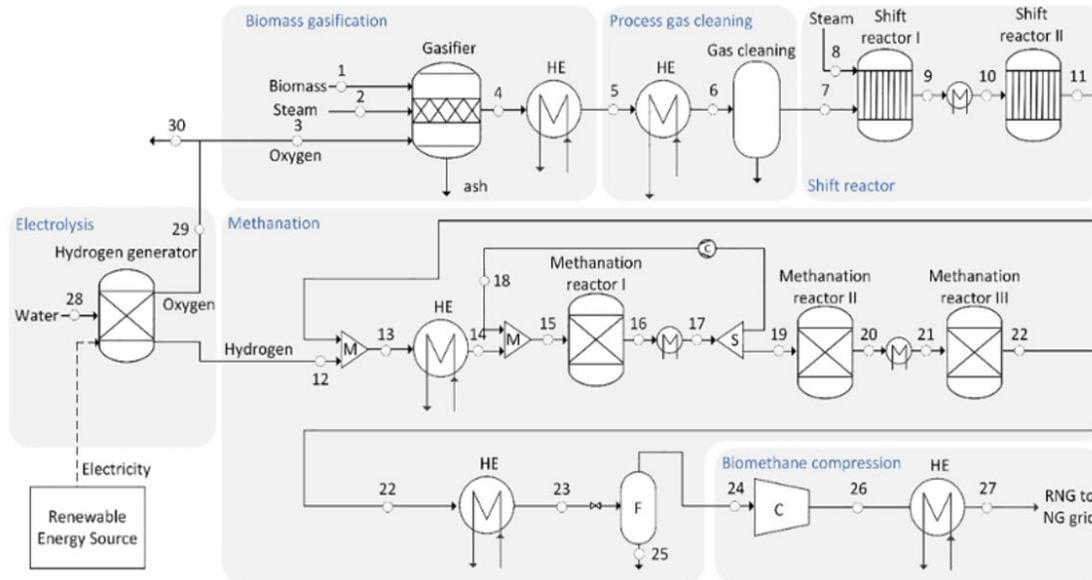
Two sectors that use a large amount of energy are transportation and electric power generation. Power generation presently uses a high volume of natural gas and transportation is dominated by gasoline and diesel fuel from fossil energy sources. In the future, transportation will be dominated by electricity and hydrogen and power generation by solar and wind energy, but resiliency of the power generation system will require H<sub>2</sub> and SNG. In the case of transportation, battery-powered vehicles will use electricity directly and fuel cell vehicles will use hydrogen produced primarily from electricity. SNG will be produced from biomass, CO<sub>2</sub>, and H<sub>2</sub> and used for electricity generation as needed and for thermal generation in industry and residences/commercial buildings.

Both H<sub>2</sub> and SNG must be produced with net zero release of CO<sub>2</sub>/carbon into the environment. A net negative release can be achieved by producing H<sub>2</sub> and SNG from biomass and utilizing carbon capture and storage (CCS) as needed [16]. Most of the hydrogen will be produced using electrolysis and solar/wind electricity, which is a carbon neutral process. This approach will result in large reductions in CO<sub>2</sub> emissions and an eventual reduction in the CO<sub>2</sub> concentration in the atmosphere. Drop-in SNG would permit the use of the existing pipeline network for distribution and residential/industrial appliances and /processes for use. Hydrogen would be used primarily for transportation and long-term energy storage.

### Production of SNG from biomass

Production of SNG from biomass could be important to achieving carbon-neutrality by 2045. Methane is one of the simplest fuels to synthesis from H<sub>2</sub> and CO<sub>2</sub>. The technology and economics of that process is reviewed in this section of the report [16-20]. A schematic of the hardware system needed to perform the overall conversion process [17] is shown in Figure 3. Note that in addition to the gasifiers and methanation units there are numerous heat exchangers, gas mixers, and gas cleaning components.

**Figure 3: A schematic of the system with biomass gasification, hydrogen generator, and methanation reactor to produce SNG [17]**



### Economic analysis of SNG production

We undertook a simplified comparison of SNG production with considerations of plant size and specific assumptions about input costs. We also compare these to natural gas prices and include these in the executive summary table and figure.

The methodology of our analysis follows closely that given in [17, 18]. The inputs used in our analysis for the different plant sizes are based on data in [6-11]. The costs of the various components were scaled up based on the data given in Table 2.

**Table 2: Component costs and scale up factors**

Installation costs data used for the analysis.

Equipment	Base cost, k€	Design variable	Base capacity	Unit	Scaling factor
Anaerobic digestion	1 749	Biogas stream	783	kg/h	0.6
Biogas cleaning	121	Biogas stream	756	kg/h	0.6
CO <sub>2</sub> capture	268	Biogas stream	783	kg/h	0.6
Hydrogen generator	1 290	Nominal power	1000	kW	0.6
Methanation	2 000	RNG chemical energy	5000	kW	0.6
Shift reactor	2 700	Feed gas stream	150	kg/s	0.5
RNG compression	490	Compressor power	413	kW	0.6
Injection to the grid	75	RNG chemical energy	1000	kW	0.6

The results of the economic analyzes are given in Table 3. The bottom row of the table shows that the total levelized cost (capital plus operating cost) of the SNG from small (1 MW) plants of around \$14/GJ and from large and very large plants (5-100 MW) are \$7-\$11/GJ with the lowest cost being for a 100 MW

plant. A major contributor (\$4-\$6/GJ) to the total levelized cost of the SNG is the cost of the electricity to operate the electrolyzer that generates the hydrogen needed in the methanation process. This is even the case using low cost electricity (\$20/MWh). The projected cost of SNG is higher than the cost of natural gas (NG) which is often in the range of \$3-5/GJ though has recently risen at times to \$10/GJ. This suggests potential economic attractiveness in the future for very large SNG plants especially with low cost biomass and renewable electricity.

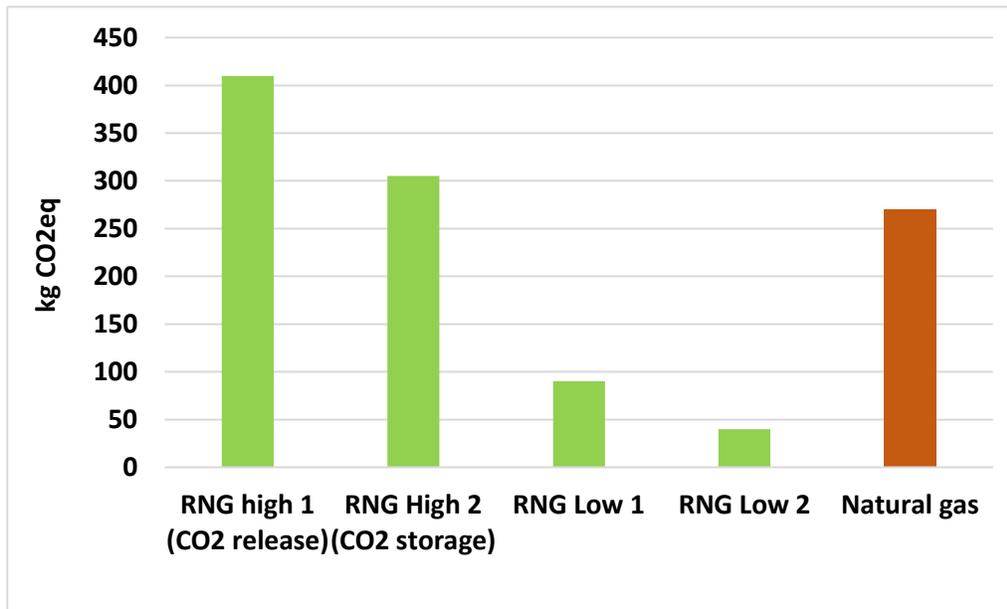
**Table 3: Projections of levelized SNG cost for plants of various capacities**

<b>Component capital costs</b>	<b>2020 1 MW</b>	<b>Future 1 MW</b>	<b>Future 5 MW</b>	<b>Future 100 MW</b>
<b>Capital costs</b>				
<b>Interest %</b>	5	5	5	5
<b>Life years</b>	20	20	20	20
<b>Capital recovery factor</b>	.08	.08	.08	.08
<b>Electrolyzer</b>				
<b>Capital cost \$</b>	1,990,500	559,235	1067242	8876746
<b>Annual cost recovery \$</b>	159,240	44,739	85,379	710,140
<b>Methanation</b>				
<b>Capital cost \$</b>	955,000	477,450	909,082	7,575,000
<b>Annual cost recovery \$</b>	76,400	38,196	72,726	606,000
<b>Biomass gasifier</b>				
<b>Capital cost \$</b>	729,560	328,900	599,025	4,750,000
<b>Annual cost recovery \$</b>	58,365	26,312	47,922	380,000
<b>Balance of plant</b>				
<b>Capital cost \$</b>	647,000	485,000	1,940,000	4,850,000
<b>Annual cost recovery \$</b>	51,760	38,800	155,200	388,000
<b>Total annual cost recovery \$</b>	345,765	148,047	361,227	2,084,140
<b>Annual SNG production GJ</b>	28,900	28,900	144,450	2,890,000
<b>Levelized capital cost \$/GJ</b>	12.0	5.1	2.5	0.72
<b>Variable costs</b>				
<b>Electricity \$/yr</b>	486,300	179,774	838,947	12,584,208
<b>Biomass feedstock \$/yr</b>	156,940	88,440	422,100	6,432,000
<b>Total annual operating costs \$</b>	643,240	268,214	1,261,047	19,016,208
<b>Levelized operating cost \$/GJ</b>	22.2	9.3	8.7	6.5
<b>Total levelized cost of SNG \$/GJ</b>	34.2	14.4	11.2	7.2

## CO2 emissions analysis of SNG

Various studies, such as [17], suggest potentially very low net CO2 emissions from SNG on a life-cycle basis. Figure 4 indicates that the CO2 emissions from SNG production in favorable cases (such as case 3 and 4) are far lower than those that would result from the combustion of NG. Case 3 results in about 0.5 kgCO2/kgSNG compared to at least 2.75 kgCO2/kgNG from burning NG. Hence the net CO2 emissions from burning the SNG with CCS would be 85% less than burning NG. SNG can be produced with low CO2 emissions from biomass because the carbon in the biomass is integrated into the synthetic fuel rather than forming CO2. In this case, the synthetic fuel is carbon neutral if it is burnt in an engine or powerplant and net CO2 negative (-2.3 kgCO2/kgSNG) if burnt in a powerplant with CCS [21, 22].

**Figure 4: CO2 emissions from SNG production (1 MW) from biomass [17]**



## SNG and LCFS Credit Values

SNG is presently eligible for LCFS credits [23]. The credit is based on the reduction in CO2 emissions resulting from substituting (burning) SNG in place of NG. At the present time, most of the SNG available is biogas from agricultural waste. The LCFS credit can be calculated from the following equation:

$$\text{LCFS credit (\$/kg SNG)} = ((\text{kgCO}_2/\text{kg NG}) - (\text{kgCO}_2/\text{kg SNG})) * 10^{-3} * \$/\text{tonCO}_2, \$/\text{MJ} = (\$/\text{kg SNG})/45, \$/\text{GJ} = \$/\text{kg SNG} * 22.2$$

The LCFS credit for SNG can be large. For example, with kg CO2/kg NG=3.3, kg CO2/kg SNG=0.5, LCFS credit price \$/tonCO2 = 150, then the price \$/kg SNG = 0.42, \$/GJ=9.3. This value could be higher than the price of NG. Producers of biogas are actually collecting these LCFS credits at the present time [24]. Hence the price of SNG can be quite low including the LCFS credit.

As noted previously, the gasifier and water shift produce a significant quantity of hydrogen, which can be considered a product of the unit in Figure 3. It is of interest to estimate the cost (\$/GJ and \$/kg) of that hydrogen. The appropriate capital cost was determined by subtracting the costs of the methanation

unit and the electrolyzer from the total cost of the plant (see Table 1). The operating cost to produce the H<sub>2</sub> was the total cost of the feedstock and 10% of the total electricity cost of operating the SNG plant. The mass (kg/yr) and energy content (GJ/yr) of hydrogen was calculated from the biomass feedstock (kg/h) using the chemical equations of the processes. The results of these calculations and resultant hydrogen costs are given in Table 4. The hydrogen produced as an intermediate product in the SNG plant from biomass appears to be a low cost path to hydrogen. The downside of producing hydrogen from biomass is that the CO<sub>2</sub> generated in the process is high, being 14.7 kg CO<sub>2</sub>/kgH<sub>2</sub>. Producing hydrogen from NG or SNG via SMR produces only 5.5 kgCO<sub>2</sub>/kgH<sub>2</sub>. This difference is unavoidable because the carbon in the biomass forms CO<sub>2</sub> in the processes that free the hydrogen. Low or near zero CO<sub>2</sub> emissions from the production of hydrogen from biomass or fossil fuels will require CCS regardless of the process used.

**Table 4: Cost of SNG and RH<sub>2</sub> from the 100MW SNG plant**

Fuel	GJ/kg	kg biomass/yr	MW	GJ/yr	CapEx \$	\$/GJ	\$/kg
SNG	.048	.975x10 <sup>6</sup>	111	2.9x10 <sup>6</sup>	21x10 <sup>6</sup>	7.2	.35
H <sub>2</sub>	.12	.975x10 <sup>6</sup>	46	1.2x10 <sup>6</sup>	8x10 <sup>6</sup>	6.7	.80

Hydrogen is also eligible for LCFS credit when it is used to replace a transportation fuel such as gasoline or diesel.

$$\text{LCFS credit: } (\$/\text{kgH}_2) = (CI_{O_1} - CI_{H_2}) / (EER)_{FCV} * (EER)_{FCV} * 120 * 10^{-6} * (\$/\text{Mt CO}_2), EER_{FCV} = 2.5$$

The LCFS credits for SMR and solar hydrogen are shown in Table 5, for a given trajectory of CI fuels target.

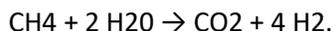
**Table 5: Potential LCFS hydrogen credits over the period 2020-2050**

Year	Target* (CI <sub>0</sub> )	Hydrogen (CI*)		H <sub>2</sub> Credit \$/kgH <sub>2</sub>	
		SMR	Solar	SMR	Solar
<b>2020</b>	91	98	10	2.80	4.70
<b>2025</b>	85	98	10	2.53	4.43
<b>2030</b>	80	73	10	2.67	3.99
<b>2035</b>	72	49	10	2.36	3.06
<b>2040</b>	64	24	10	2.29	2.52
2045	50	15	10	1.78	1.86
2050	40	10	10	1.46	1.46

\*CI =gCO<sub>2</sub>/MJ

### Costs of using NG, SNG, SMR, and CCS to produce H<sub>2</sub>

In the H<sub>2</sub> transition strategy analyzed in the UCD study, it is anticipated that after 2030, most of the H<sub>2</sub> produced will be from electrolysis with solar/wind electricity. In terms of cost (\$/kg), the lowest cost hydrogen is from NG and SMR. If the cost of SNG is close to that of NG, which could be possible if SNG is produced in a very large plant, the cost of RH<sub>2</sub> via SMR could make sense economically. Otherwise, the cost of RH<sub>2</sub> from solar electrolysis could be lower. Even in that case, the ease of distribution of SNG to remote SMR sites would be advantageous compared to the distribution of RH<sub>2</sub> from electrolysis. The chemistry of the SMR process to produce H<sub>2</sub> from CH<sub>4</sub> is simply



Hence the ideal CO<sub>2</sub> emissions are 5.5kg CO<sub>2</sub>/kgH<sub>2</sub>. The CO<sub>2</sub> emissions of reforming SNG will be the same as reforming NG to produce H<sub>2</sub>, but there will be net negative CO<sub>2</sub> emissions to be credited in the case of SNG. The production of SNG from biomass resulted in about 15% of the CO<sub>2</sub> from the combustion of CH<sub>4</sub> so the net CO<sub>2</sub> emissions from producing H<sub>2</sub> from SNG is

$$44\text{kg CO}_2 - 18 \text{ kgSNG} \cdot .85 \cdot \text{kgCO}_2/\text{kgNG} = 44 - 18 \cdot .85 \cdot 2.75 = 1.925 \text{ kg CO}_2 = .24 \text{ kgCO}_2/\text{kgH}_2$$

If the CO<sub>2</sub> emissions are captured and sequestered, the net CO<sub>2</sub> emissions are negative 5.0kgCO<sub>2</sub>/kgH<sub>2</sub>.

Many studies have estimated the cost of producing H<sub>2</sub> from SMR using NG, with and without CCS. For example in [25], calculations were made of the CO<sub>2</sub> emissions producing H<sub>2</sub> from SMR of NG with CCS and with electrolysis using grid electricity in various countries. SMR results are shown in Table 5 for grey (no CCS) and blue (with CCS) H<sub>2</sub>. CCS reduced the CO<sub>2</sub> emissions from 8.5 kgCO<sub>2</sub>/kgH<sub>2</sub> to 1.2 kgCO<sub>2</sub>/kgH<sub>2</sub>. The cost with CCS was \$1.31/kgH<sub>2</sub> compared to \$.96/kgH<sub>2</sub> without CCS, suggesting a CCS cost of \$0.35/kgH<sub>2</sub>.

**Table 6: Summary of SMR H<sub>2</sub> production with and without CCS [25]**

Summary of the main results for grey and blue hydrogen production.

	Unit	Value
<i>Grey hydrogen production</i>		
Hydrogen produced	kg H <sub>2</sub> /h (t/d)	20,830 (500)
Power demand <sup>a</sup>	kWh/kg H <sub>2</sub>	0
Excess heat available <sup>b</sup>	kWh/kg H <sub>2</sub>	2.9
Water demand (SMR + WGS)	kg H <sub>2</sub> O/kg H <sub>2</sub>	9.7
<i>Grey hydrogen production</i>		
NG demand	kg NG/kg H <sub>2</sub>	3.2
Specific CO <sub>2</sub> emissions	kg CO <sub>2</sub> /kg H <sub>2</sub>	8.5
CAPEX	\$/kg H <sub>2</sub>	0.15
OPEX	\$/kg H <sub>2</sub>	0.81
Hydrogen production cost <sup>c</sup>	\$/kg H <sub>2</sub>	0.96
<i>Blue hydrogen production (Maximum Removal<sup>d</sup>)</i>		
NG demand	kg NG/kg H <sub>2</sub>	3.4
Specific CO <sub>2</sub> emissions	kg CO <sub>2</sub> /kg H <sub>2</sub>	1.2
CAPEX	\$/kg H <sub>2</sub>	0.28
OPEX	\$/kg H <sub>2</sub>	0.88
CO <sub>2</sub> Transportation and storage <sup>e</sup>	\$/kg H <sub>2</sub>	0.15
Hydrogen production cost <sup>e</sup>	\$/kg H <sub>2</sub>	1.31

<sup>a</sup> Plant power demands are met using excess heat.

<sup>b</sup> Remaining excess heat after heat integration/co-generation.

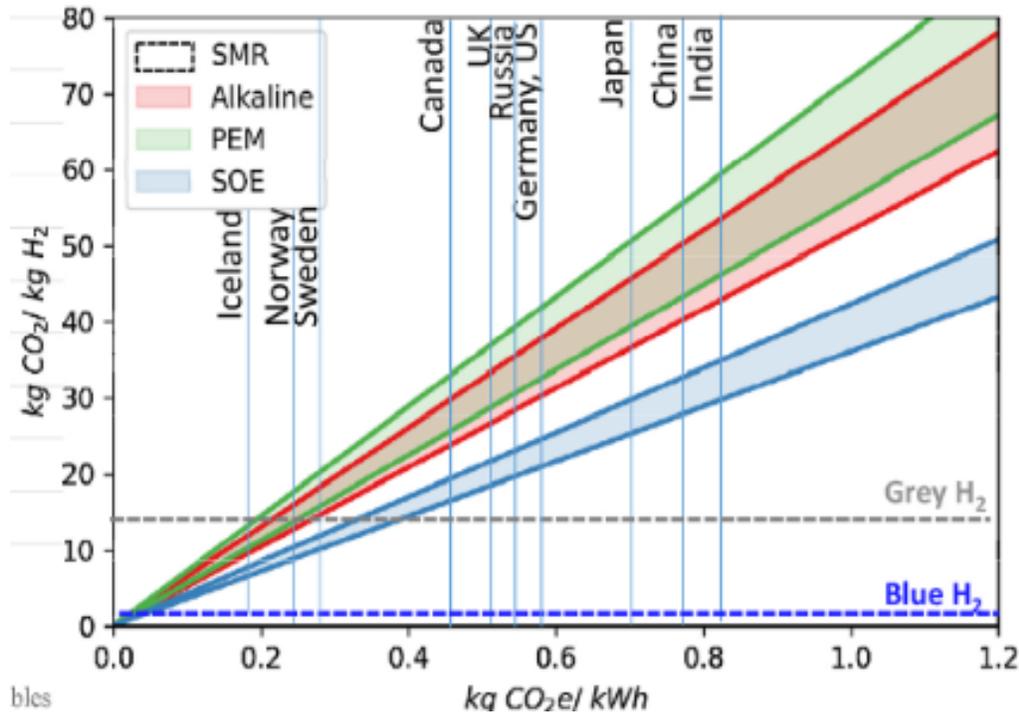
<sup>c</sup> Assuming a NG price of \$3.7/GJ.

<sup>d</sup> Considering the case of maximum CO<sub>2</sub> removal (90%).

<sup>e</sup> Assumes a mid-range transportation cost of \$20/t CO<sub>2</sub> (ZEP, 2011).

The H<sub>2</sub> production using electrolysis and grid electricity were also calculated. The CO<sub>2</sub> emission results for electrolysis including powerplant emissions are shown in Figure 5. This suggests that electrolysis only makes sense using solar/wind electricity. Otherwise, SMR is much better both from the CO<sub>2</sub> emissions and H<sub>2</sub> cost points -of-view.

Figure 5: Effect of powerplant emissions on kgCO<sub>2</sub>/kgH<sub>2</sub> using electrolysis [25]



## 6. Transporting SNG and H<sub>2</sub> in pipelines

Natural gas (primarily methane CH<sub>4</sub>) is distributed throughout the United States via a network of pipelines of various sizes (diameters) and lengths. There have been numerous papers [26-33] dealing with how this network could be leveraged to support the clean energy transition through blending or repurposing existing infrastructure with potential with cost savings, and a shorter timeline for hydrogen infrastructure development. . This section of the paper is concerned with the characteristics of H<sub>2</sub>/NG blends and how blends of various H<sub>2</sub> concentrations can be used to transport H<sub>2</sub>. Special attention is given to the recovery of pure H<sub>2</sub> from the blends for use in fuel cells and the net reduction in CO<sub>2</sub> emissions (kgCO<sub>2</sub>/kgH<sub>2</sub> when the blends are used as a substitute for NG in heating and power generation applications).

### H<sub>2</sub>/NG blends in pipelines

Mixing gases on a volume basis (%H<sub>2</sub> by volume) is not difficult and devices/systems for performing this task are readily available. From the analysis point-of-view, the primary parameter is the mass fraction of hydrogen (m<sub>H<sub>2</sub>f</sub>) as a function of hydrogen concentration (% by volume c<sub>H<sub>2</sub>v</sub>). m<sub>H<sub>2</sub>f</sub> depends on the density of the gases being mixed.

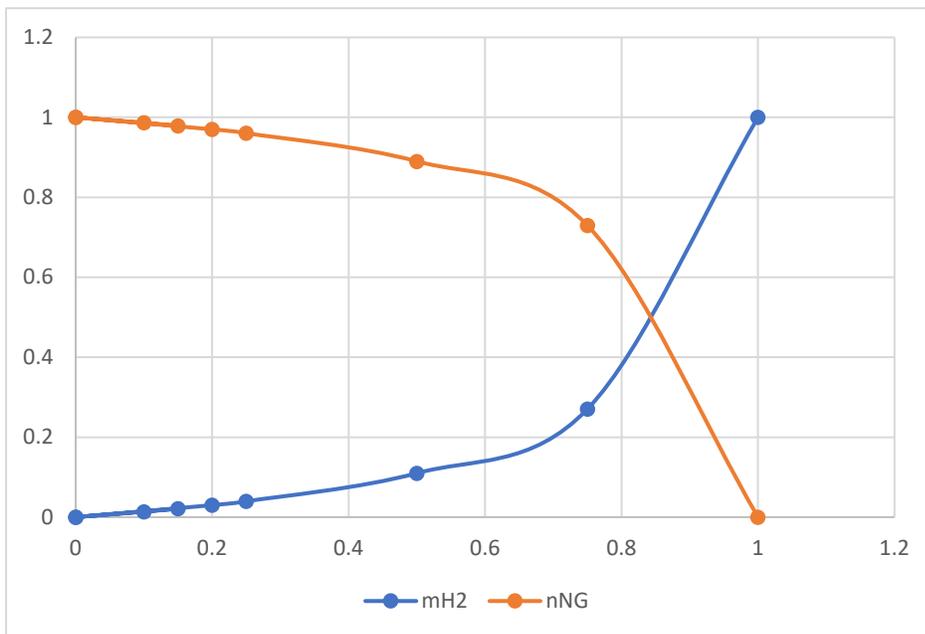
- (1)  $m_{H_2f} = \frac{c_{H_2v} \rho_{H_2}}{c_{H_2v} \rho_{H_2} + (1 - c_{H_2v}) \rho_{NG}}$
- (2)  $m_{NGf} = 1 - m_{H_2f}$

The mixing can be done at any pressure and the mass fractions do not change as the mixture is pressurized. It is convenient to use the densities of H<sub>2</sub> and NG at standard conditions (1 atm. and 15 deg C) to calculate the mass fractions. At SC conditions,  $\rho_{scNG} = .68 \text{ kg/m}^3$  and  $\rho_{scH_2} = .084 \text{ kg/m}^3$ .

The mass fraction of H<sub>2</sub> as a function of % H<sub>2</sub> vol in the NG blend are shown in the table below and in Figure 6. Note that for mixtures of gases with large differences in density like H<sub>2</sub> and NG, the mass fraction of the light gas (H<sub>2</sub>) remains small until its concentration becomes relatively high. In all likelihood, the %H<sub>2</sub> of the H<sub>2</sub>/NG blends will be 20% or less.

% H <sub>2</sub> vol.	kgH <sub>2</sub> /kg
0	0
10	0.014
15	0.021
20	0.030
25	0.040

**Figure 6: Mass fractions of H<sub>2</sub> and NG as a function of %H<sub>2</sub> vol.**

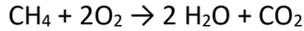


Many of the utilities are interested in distributing hydrogen with natural gas as a blend in the NG pipeline network [29, 30]. There have been a number of studies [31, 32] related to the safety of utilizing NG pipelines to transport hydrogen and H<sub>2</sub>/NG blends. Those studies indicate that the %H<sub>2</sub> in the blend should be limited to about 20% by volume.

H<sub>2</sub>/NG blends are of interest as a pathway to reducing CO<sub>2</sub> emissions from utilizing H<sub>2</sub> in heating and power generation applications in buildings and industry. Hydrogen has a heating value of 120 MJ/kg (33.3 kWh/kg) and NG has a heating value of about 48 MJ/kg (13.3 kWh/kg). The heating value of a blend is given by

$$(\text{kWh/kg})_{H_2/NG \text{ blend}} = (m_{H_2V}) (33.3) + (m_{NGV}) (13.3)$$

NG produces CO<sub>2</sub> when it burns with oxygen.



The result is 44 kg of CO<sub>2</sub> produced per 16 kg of NG burnt or 2.75 kg CO<sub>2</sub>/kg NG. It is assumed in this paper that all hydrogen is produced by electrolysis so that including H<sub>2</sub> in the blend produces no CO<sub>2</sub>. The CO<sub>2</sub> emissions that would be saved by distributing hydrogen in the blends are shown in Table 7. In all cases, the energy flow of the blends is the same as that of the pure natural gas flow. The results indicate that distributing blends is not a very effective way to reduce CO<sub>2</sub> emissions by injecting hydrogen from electrolysis and that on the basis of the cost (\$/tCO<sub>2</sub>sav), it is expensive. Injecting biogas or SNG into the pipelines at an early stage can be done without difficulty and is more cost effective.

**Table 7: Summary of CO<sub>2</sub> emissions saved using H<sub>2</sub>/NG blends of different %H<sub>2</sub> by vol**

%H <sub>2</sub> by vol.	Mass frac H <sub>2</sub>	kgCO <sub>2</sub> sav/ kgH <sub>2</sub> *	Fraction CO <sub>2</sub> saved*	Cost* \$/tCO <sub>2</sub> sav
.1	.0135	6.88	.033	726
.15	.0213	6.88	.052	726
.2	.030	6.88	.072	726
.25	.040	6.88	.093	726

\*price H<sub>2</sub> \$5/kg

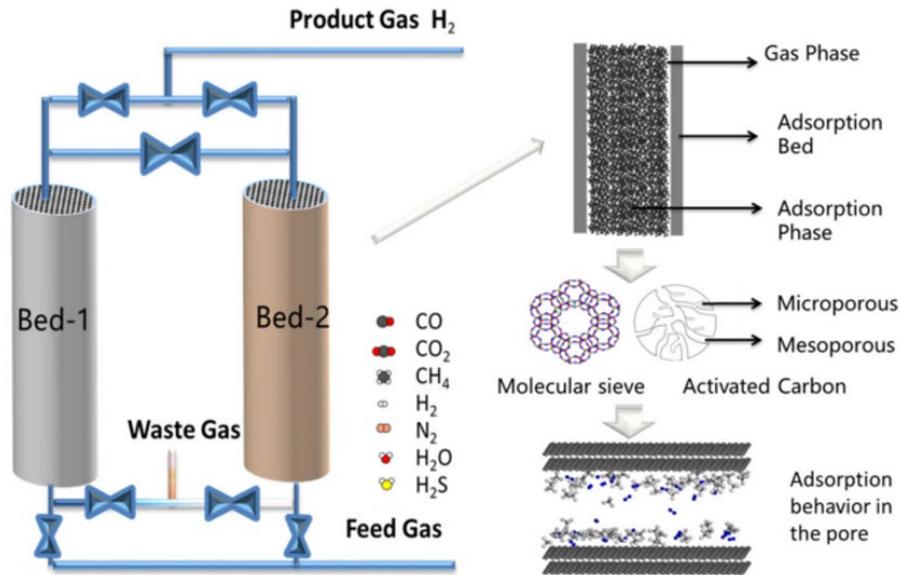
### Recovery of hydrogen from blended flows

There are some applications of hydrogen, such as fuel cells, for which the hydrogen in the blend must be separated from the NG before it can be used. There are several technical approaches to do this-(1) pressure swing adsorption (PSA), (2) membrane separation (MBS), and (3) electrochemical hydrogen compression and purification (EHCP). PSA is the most highly developed of these technologies especially for concentrating oxygen and nitrogen from air. In the case of hydrogen, PSA has been used to separate hydrogen from CO<sub>2</sub> in SMR production of H<sub>2</sub> and in the purification of H<sub>2</sub> being collected in the field. In most cases using PSA, the initial concentration of the product gas (oxygen, nitrogen, or hydrogen) to be removed is high compared to that of contaminant gases. In the case of hydrogen separation in blends, the concentration of the hydrogen is low compared to that of NG. This case is better suited for the membrane (MBS) and electrochemical (EHCP) approaches which are in earlier stages of development than PSA. The purity of the hydrogen separated is particularly critical for fuel cell applications which requires a purity of 99.99 or 99.999. The MBS and EHCP approaches can provide the very high purity required for use in fuel cells.

### Pressure Swing Adsorption (PSA)

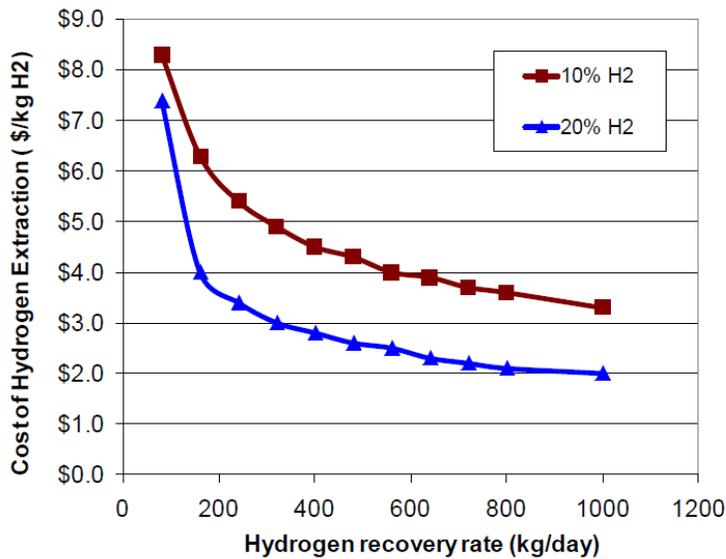
As indicated in Figure 7, PSA involves the adsorption and desorption of gases in tanks containing special microporous materials that adsorb/desorb the gases of interest as the pressure or temperature in the tanks is varied. PSA systems have been assembled with 2, 4, 6, 8 tanks to yield high purity products.

**Figure 7: Schematic of a PSA system for separating H<sub>2</sub>**



Information available [34-36] on the cost for PSA systems for H<sub>2</sub> separation indicates their cost (\$/kgH<sub>2</sub>) is high being \$2-7/kgH<sub>2</sub> for hydrogen from blends. The hydrogen costs using the PSA approach are uncertain as they are affected by the size (kg/day) of the facility and the magnitude of the pressure swing required and if there is a need for recompression of the NG after the separation. This uncertainty is shown in Figure 8.

**Figure 8: Cost of hydrogen separation using PSA**



## Advanced hydrogen separation systems

Development of membrane separation (MBS) and electrochemical hydrogen separation (EHS) technologies are active areas of research at the present time [37-39]. These technologies are well suited for separating hydrogen from H<sub>2</sub>/NG blends for fuel cell applications. As shown in Figures 9 and 10, the components in these technologies are more compact than those in PSA and more compatible with fuel cell and battery technology. There is only limited information [37-39] concerning the cost of the membrane and electrochemical hydrogen separation technologies at this time. Linde has recently opened a pilot plant in Germany [40] using membranes (MBS) for hydrogen purification and HyET in the Netherlands [41, 42] is developing the EHCP technology for hydrogen separation from blends.

**Figure 9: Schematics of hydrogen separation using membranes (MBS)**

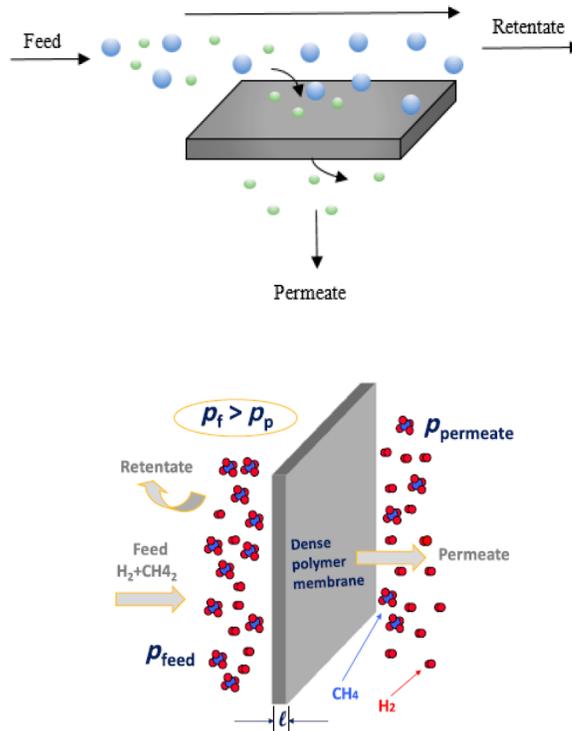
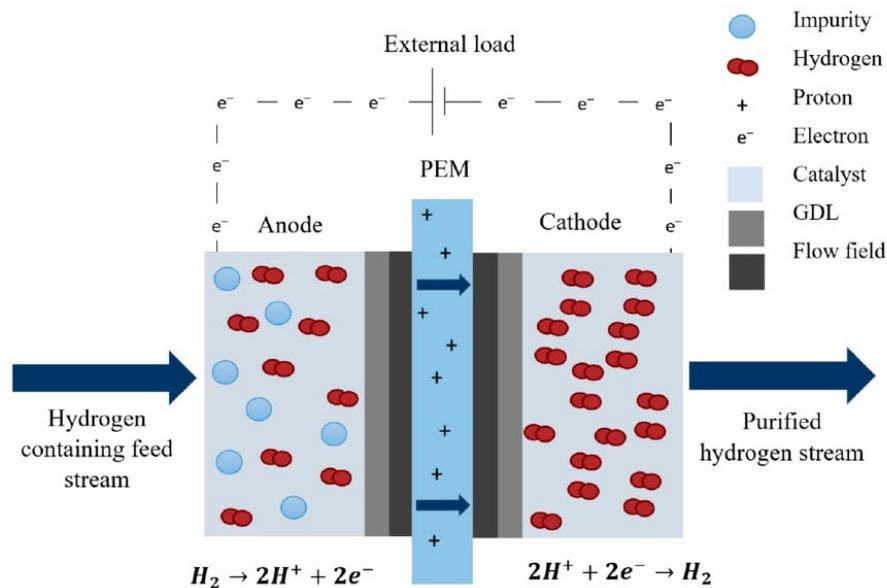
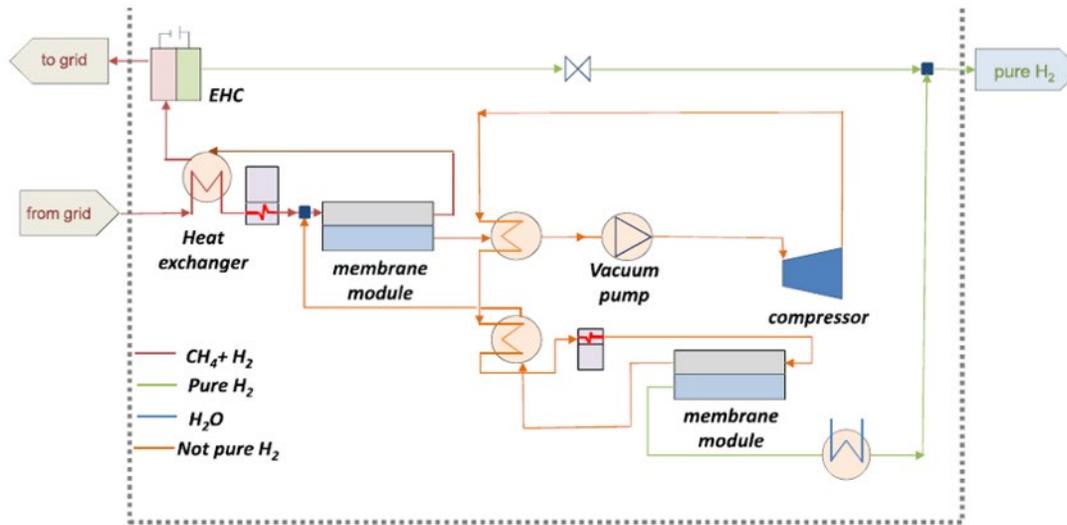


Figure 10: Schematic of an EHCP cell [44]



### Membrane hydrogen separation

A model was developed of an MBS unit to separate hydrogen from a H<sub>2</sub>/NG blend for use of the H<sub>2</sub> in fuel cell vehicles. This requires a hydrogen purity of 99.99 to 99.999. The model is based on the analysis of membrane separation in [43]. The unit analyzed for this paper is shown above in Figure 8 with the EHC cell removed. The unit has two membranes in series with a second membrane needed to obtain hydrogen at very high purity. The key parameters to characterize the membranes are permeance and selectivity. Permeance ( $P_{mH_2}$ ) is defined as the quantity of H<sub>2</sub> that the membrane can remove from a blend per unit time and area (m<sup>2</sup>) as a function of the pressure difference across the membrane.

$$P_{mH_2} = \text{mol H/sec/m}^2/\text{Pa}$$

A summary of the  $P_{mH_2}$  characteristics of various membranes is shown in Table 8 [43]. The membranes used in this study were the metallic type of supported Palladium (Pd). Other possibilities are given in Table 8. The permeance of the Pd membranes is about  $10^{-6}$ . Selectivity is the number of H atoms that pass through the membrane for each contaminant atom that passes through. In the present calculations, selectivity of 65000 and 100000 were used.

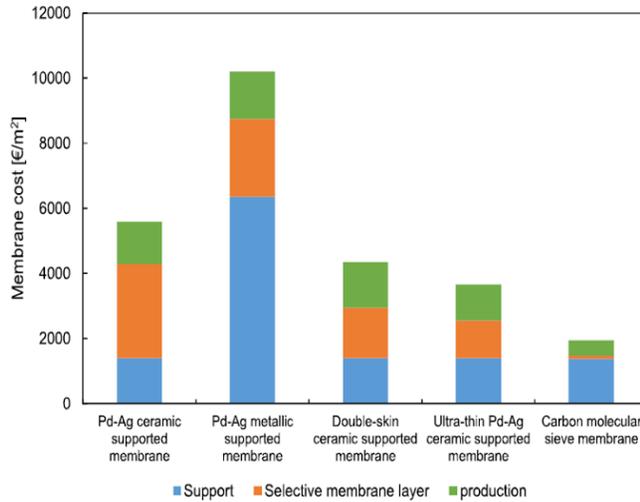
**Table 8: Permeance and selectivity of various membranes for hydrogen separation [43]**

**Table 1 – Description of details of the different configurations; c-PdDS: ceramic supported double-skin Pd–Ag membrane, m-Pd: metallic supported Pd–Ag membrane; CMSM composite alumina-carbon molecular sieve membrane, c-Pd; ceramic supported Pd–Ag membrane (4–5  $\mu\text{m}$ ); c-tPd: ceramic supported thin Pd–Ag membrane (2–3  $\mu\text{m}$ ).**

Configuration	Membrane type	Membrane permeance [mol/s/m <sup>2</sup> /Pa]	Membrane ideal-selectivity	Membrane 2 permeance	Membrane 2 ideal selectivity	Retentate pressure [bar]	Permeate pressure [bar]	Sweep gas flow rate [mol/h]
A	c-PdDS	$2 \cdot 10^{-6}$	65,000	–	–	8	0.15	–
A1	m-Pd	$10^{-6}$	200,000	–	–	8	0.15	–
A2	c-PdDS	$2 \cdot 10^{-6}$	65,000	–	–	8	0.15	–
A3	c-PdDS	$10^{-6}$	200,000	–	–	40	0.15	–
A4	CMSM	$2 \cdot 10^{-6}$	65,000	–	–	40	0.15	–
A5	c-PdDS	$2 \cdot 10^{-6}$	65,000	–	–	8	0.15	–
A6	EHC	–	–	–	–	8	8	–
B	c-tPd	$4 \cdot 10^{-6}$	5000	$2 \cdot 10^{-6}$	20,000	8	0.15	–
C	c-tPd	$4 \cdot 10^{-6}$	5000	$2 \cdot 10^{-6}$	20,000	40	3	–
C1	CMSM	$5 \cdot 10^{-8}$	1000	$2 \cdot 10^{-6}$	20,000	40	3	–
C2	c-tPd	$4 \cdot 10^{-6}$	5000	$2 \cdot 10^{-6}$	20,000	40	2.5	–
C3	c-tPd	$4 \cdot 10^{-6}$	5000	$2 \cdot 10^{-6}$	20,000	40	2	–
C4	CMSM	$7 \cdot 10^{-8}$	550	$2 \cdot 10^{-6}$	20,000	40	2.5	–
C5	CMSM	$7 \cdot 10^{-8}$	550	$2 \cdot 10^{-6}$	20,000	40	2	–
D	c-tPd	$4 \cdot 10^{-6}$	5000	$2 \cdot 10^{-6}$	20,000	8	1	1000
D1	c-PdDS	$2 \cdot 10^{-6}$	65,000	–	–	8	1	1000
D2	m-Pd	$10^{-6}$	200,000	–	–	8	1	1000

The major cost of the MBS unit is that of the membrane ( $\$/\text{m}^2$ ). The future cost for membranes in large quantity is uncertain. The membrane costs assumed in [43] are shown in Figure 11 for several membrane types. All the membranes seem to be expensive. It is assumed their costs will be reduced in the future after further development and large-scale production.

**Figure 11: Cost (\$/m<sup>2</sup>) of various types of membranes including support, selective membrane layer and production costs [43]**



Note: Figure is in Euros, about €1.00 = \$1.08 as of November 2023

In the spreadsheet model prepared, a steady flow of hydrogen was assumed through the membranes- first through membrane 1 and then through membrane 2 as shown above in Figure 8. Costs of the membrane separation units were calculated for a series of membrane costs. The results are shown in Table 9. The costs are relatively high until the membrane cost (\$/m<sup>2</sup>) is reduced. Hence projections of the cost of separating the hydrogen from NG blends are uncertain at the present time.

**Table 9: Costs of membrane hydrogen separation units calculated with the model**

	\$/m <sup>2</sup>				
Membrane 1	10000	7000	5000	3000	2000
Membrane 2	8000	5000	4000	2000	1500
H2 \$/kg	2.08	1.53	1.27	.90	.77

### Electrochemical hydrogen compression and purification

A schematic of an electrochemical compression and purification cell is shown in Figure 9. These cells separate hydrogen from the blend by pumping it across a membrane (PEM) under the force of an electric field imposed by a voltage difference. The cells also compress the hydrogen for storage onboard the fuel cell vehicles. The membrane in the EHCP cells would be much like the nafion membrane in PEM fuel cells or electrolyzers. The present price of the PEM membrane is about \$500 /m<sup>2</sup>, but the price is projected to decrease to about \$50/m<sup>2</sup> in the near future as high production of PEM fuel cells occurs [22]. Hence the cost of membranes for EHCP cells should not be a barrier to their development and application.

The EHCP cells are electrochemical devices. Their characteristics are analyzed in the following paragraphs following [44].

The electrical current  $I$  in the cell is governed by Faraday's Law

$$(3) \frac{dn}{dt} = I/2F$$

where  $n$  is the moles of ions transferred and  $F$  is the Faraday constant.

$$F=96485 \text{ coul/gm-mole}$$

In the case of the EHCP cell, the gm-mole is 1 gm or  $1 \cdot 10^{-3}$  kg. Applying Faraday's Law to a typical blend recovery case of 100 kgH<sub>2</sub>/h,

$$I = 2F \cdot 100 \cdot 10^3 / 3600 = 5.36 \cdot 10^6 \text{ Amps}$$

This is a high current. If the current density in the EHCP cell is .5 A/cm<sup>2</sup>, the area of the membrane would be about 1000 m<sup>2</sup>. This is a very large membrane and that could be a problem.

The voltage across the membrane depends on both the pressure ratio across it and its ionic resistance. The voltage due to pressure is governed by the Nernst equation.

$$(4) V = (RT/2F) \ln(p_c/p_a)$$

Assuming a pressure ratio of 35,

$$\Delta V_{pr} = (8.314 \cdot 340 / 2 \cdot 96485) \cdot 3.56 = .052$$

Assuming a 50  $\mu$  thick membrane with a resistance of 25 mS/cm, the resistance of the membrane will be about .02 mOhm. For this typical cell, the Ohmic voltage contribution will be

$$\Delta V_{ohmic} = I \cdot .02 \text{ mOhm} = 5.36 \cdot 10^6 \cdot 2 \cdot 10^{-8} = .107$$

The cell voltage is then

$$V_{cell} = .052 + .107 = .158, \text{ Power} = .158 \cdot 5.36 \cdot 10^6 = .85 \text{ MW}$$

The energy use of the cell is .85 MW/100 kgH<sub>2</sub>/h = 8.5 kWh/kgH<sub>2</sub>. The cell voltage is low so the current per cell is reduced by arranging the cells in series/parallel arrays much like cells in batteries and fuel cells. This is illustrated above in Figure 6 for the HyET technology. As in the case of fuel cells, there are gas (H<sub>2</sub> and NG) management issues in the EHCP cell design.

If the membrane cost [22] is \$500/m<sup>2</sup> and electricity cost \$.05/kWh, the cost of H<sub>2</sub> recovery from the blend would be the following:

$$\text{Annual H}_2 \text{ recovery } 100 \cdot 24 \cdot 365 = 876000 \text{ kgH}_2/\text{yr}$$

$$\text{Annual electricity costs } .05 \cdot 876000 = \$43800$$

$$\text{Cost of membranes } 1000 \cdot 500 = \$500,000$$

$$\text{Additional investment } \$500000$$

$$\text{Fixed annual costs } \$100000$$

$$\text{Total annual cost } 1,000,000 \cdot .13 + 43800 + 100000 = 273800$$

$$\text{H}_2 \text{ recovery cost } \$273800 / 86000 \text{ kgH}_2 = .312$$

This is a low recovery cost and includes pressurizing the hydrogen to 350 bar.

A summary of the characteristics of the various technologies being developed to separate the hydrogen in the blends are given in Table 10. The cost of each of the technologies is very uncertain as they are in an early stage of development. However, prospects seem best for the EHCP technology because of its close relationship to the fuel cell and electrolyzer technologies that are key to advancing the hydrogen economy in coming years. Large government and private investments are being made in the development and manufacturing of fuel cells and electrolyzers. Hydrogen separation from the blend can be done at large central plants with many ton capacity or at small facilities at hydrogen refueling stations for fuel cell vehicles to take advantage of the compression capability of the EHCP technology.

**Table 10: Summary of the characteristics of various technologies for hydrogen separation**

Technology	Driving forces	Design features	H2 Purity	\$/kgH2
Pressure swing adsorption (PSA)	Pressure.- temperature. swings absorption-desorption	Selectivity of materials, magnitude of p and T swings	99.9	>1
Membrane separation (MBS)	Press difference across membrane atomic diffusion	Permeance and selectivity of membrane magnitude of press.	99.99	.5-1
Electrochemical H2 compression.- purification (EHCP)	Voltage across PEM membrane ionic current like FC	Voltage and currents, pressure of compression bar	99.999	.3-.5

### The role of a dedicated pipeline network in distributing NG/H2/SNG

SNG can be distributed using the same pipeline network as is available for NG. However, facilities will have to be constructed to inject the SNG into the network where it is produced. This should not be a problem as SNG has the same properties as NG for compression and pipeline transport.

A mature hydrogen pipeline infrastructure (~1600 miles) currently operates in the United States, primarily serving industrial markets with feedstock in the refining and petrochemical sectors. Currently, hydrogen is produced close to where it is used. Commercializing an “at-scale” hydrogen economy in the future will require the development of a safe and resilient hydrogen infrastructure that is capable of transporting hydrogen from geographically dispersed producers to a diverse spectrum of end users at demand centers. Hence, the cost-effective transportation of hydrogen is important to the development of a hydrogen distribution network. Hydrogen is produced as a low-pressure gas, but it must be distributed as a high-pressure gas or a cryogenic liquid. Hydrogen can be transported in tanks by truck and rail or as a flowing medium in pipes. High pressure gaseous hydrogen is transported in tube-trailers that are driven to refueling stations as needed. The tube-trailers can carry 300-400 kgH2 at 228 bar pressure and up to 600 kg at 300 bar. Liquid hydrogen is transported in large insulated tank-trailers that hold 4000 to 8000 kg LH2. The LH2 in the insulated tanks is held at 1.7 bar, 20 deg K. Boil off is a concern with LH2, but the tanks have boil off of only .3-.6% per day. Hydrogen is often delivered as LH2 to refueling stations even when the hydrogen is stored at the station as a gas because of the large difference in kgH2 delivered and the cost (\$/kg) of the delivery for LH2 compared to CH2

Hydrogen can be cost effectively distributed by pipelines where an appropriate network is available much like natural gas is presently distributed throughout the United States. The main pipes are 18-36 inches in diameter and transport the gas at 90 bar [46]. Transporting LH2 in pipes is difficult, but some insulated double-wall pipes have been constructed for short distances near large central liquefaction plants [47]. The key consideration in transporting hydrogen is the cost (\$/kg) added to the pump price for distribution. The cost of distribution is summarized for truck delivery in Table 11. The cost for compressed gas is about \$.8/kg and for LH2 it is \$.3/kg for reasonably short, urban distances.

**Table 11: Cost of transporting H2 in trucks**

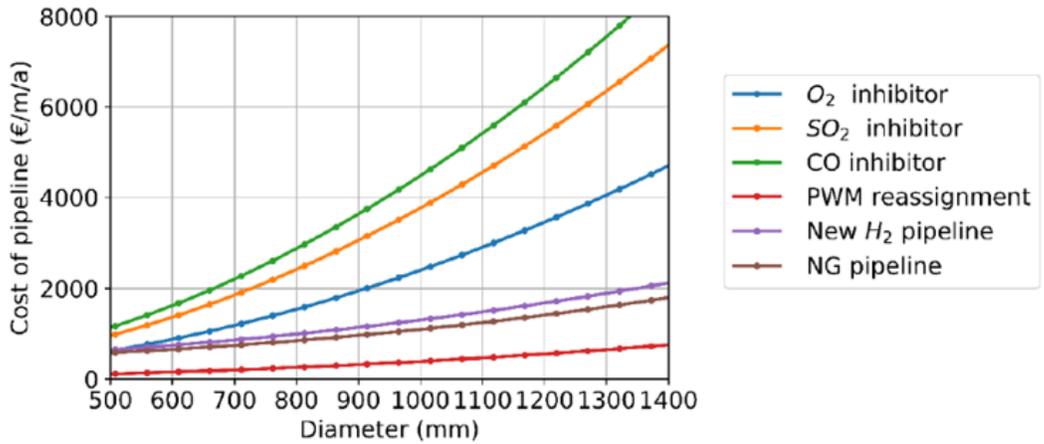
Table 5. Cost ranges for H<sub>2</sub> transport via truck

	Truck cost (\$k/unit)	Capacity (kg/unit)	Capital cost (\$/kg)	Operating cost (\$/kg/100 km)
<i>Gas tube trailer—20 MPa</i>				
Reddi (2016)	250	250	1000	
Petipas and Aceves (2018)	200–300	200	1000–1500	0.76
Chang (2007)—China	280	298	940	0.20–0.25
<i>Gas tube trailer—optimized</i>				
Reddi (2016)	626	800	783	
Composite—25 MPa (2018)	613–847	600–790	1020–1070	0.9–1.3
T4 54 MPa trailer (2018)	1300	1200	1080	0.26
<i>Liquid trailer</i>				
Reddi (2016)	718	4300	167	
Hydrogenics (2017)	1200	4000	300	0.10
Chang (2007)—China est.	370	4000	93	0.01–0.02

### Hydrogen distribution by pipelines

Since transporting hydrogen long distances to market is often necessary, assessing the cost of the pipelines and the resultant cost (\$/kgH<sub>2</sub>) to the dispensed H<sub>2</sub> is important. There have been numerous studies [48, 49] of the cost of new and repurposed NG pipelines for transport of hydrogen. Figure 12 shows the cost results as a function of pipe diameter for new, repurposed, and NG pipelines.

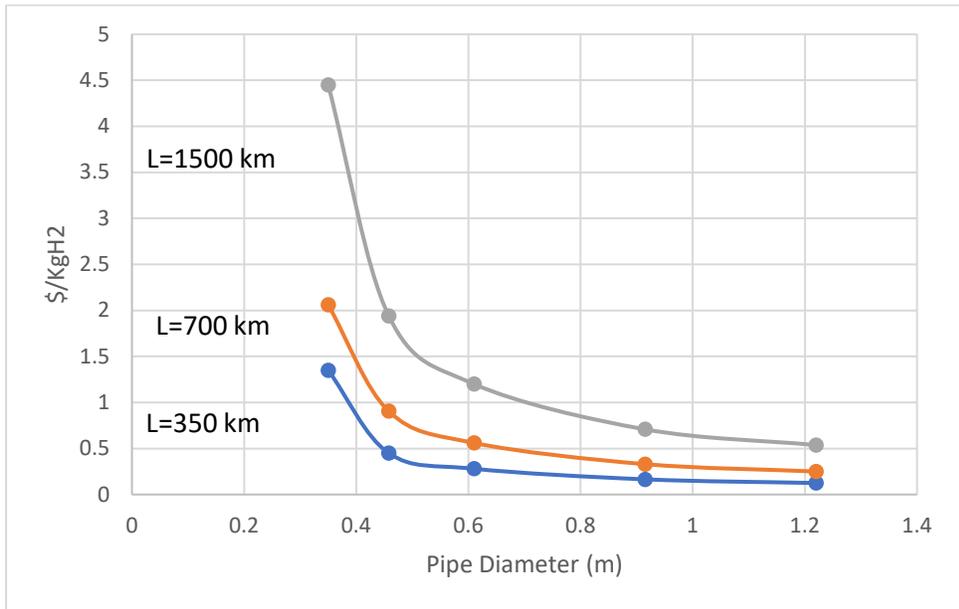
**Figure 12: Cost comparisons of pipeline reassignment alternatives and new H2 pipelines [48]**



Note: Figure is in Euros, about €1.00 = \$1.00 in November 2023

The transport costs were then calculated for a new H2 pipeline for various combinations of pipeline design and pressure operating conditions based on the costs given in Figure 11. As indicated in Figure 13 and Table 12, the transport costs (\$/kgH<sub>2</sub>) vary over a wide range depending on pipe diameter, pipe length, and flow through the pipe. For all large diameter pipes, the cost is less than \$.5/kgH<sub>2</sub>, but for small diameter, relatively long pipelines, the cost can be high (> \$2/kgH<sub>2</sub>). Hence in assessing transport costs for pipelines, knowing the diameter and length of the pipeline is required.

**Figure 13: Transport cost (\$/kgH2) of H2 in pipelines of various diameter and length**



**Table 12: Transport cost (\$/kgH2) of different H2 in pipelines\***

Pipe diameter, meter (inch)	Capacity, Mt/yr	Pipe length <sup>†</sup>					
		100 km	200 km	350 km	700 km	1500 km	2500 km
		Cost (\$/kgH2)					
<b>.31 (12)</b>	.024	.29	.59	1.4	2.1	4.5	7.3
<b>.46 (18)</b>	.055	.13	.26	.45	.91	1.9	3.2
<b>.61 (24)</b>	.960	.08	.16	.28	.56	1.2	2.0
<b>.92 (36)</b>	2.2	.05	.09	.17	.33	.71	1.2
<b>1.2 (48)</b>	3.9	.03	.06	.13	.25	.54	.90

\* Pipeline pressure 100 bar, flow velocity 15 m/sec

† Pipe length is also H2 movement distance.

It is of interest to compare the costs of transporting hydrogen by pipelines and truck. There have been several detailed analyses of the transport cost of hydrogen by truck as a compressed gas or as a cryogenic liquid [50, 51]. Results from those studies are compared with the pipeline transport cost calculations in Table 13. In general, the cost (\$/kgH2) is significantly lower for transport in pipelines than in trailer-trucks even for distances of 100 km. The cost of H2 transport as a cryogenic liquid is close to that in pipelines for 12inch diameter pipes, but for larger diameter pipes, the pipelines offer lower transport costs. Transport of H2 as a high-pressure gas by tube-trailer truck is high compared to pipelines for all diameters and distances.

**Table 13: Comparisons of the cost (\$/kgH2) of H2 transport in pipelines\* and trucks**

Distance km	Hi Press Gas Truck [50]	Cryogen Liquid Truck [51]	Pipeline 12 inch	Pipeline 18 inch	Pipeline 24 inch	Pipeline 36 inch
<b>100</b> 100 mi	1.4	.4	.29	.13	.08	.05
<b>200</b> 200 mi	2.0	.6	.59	.26	.16	.09
<b>350</b> 300 mi	2.6	.9	1.35	.45	.28	.165
<b>700</b>		1.25	2.06	.905	.56	.33

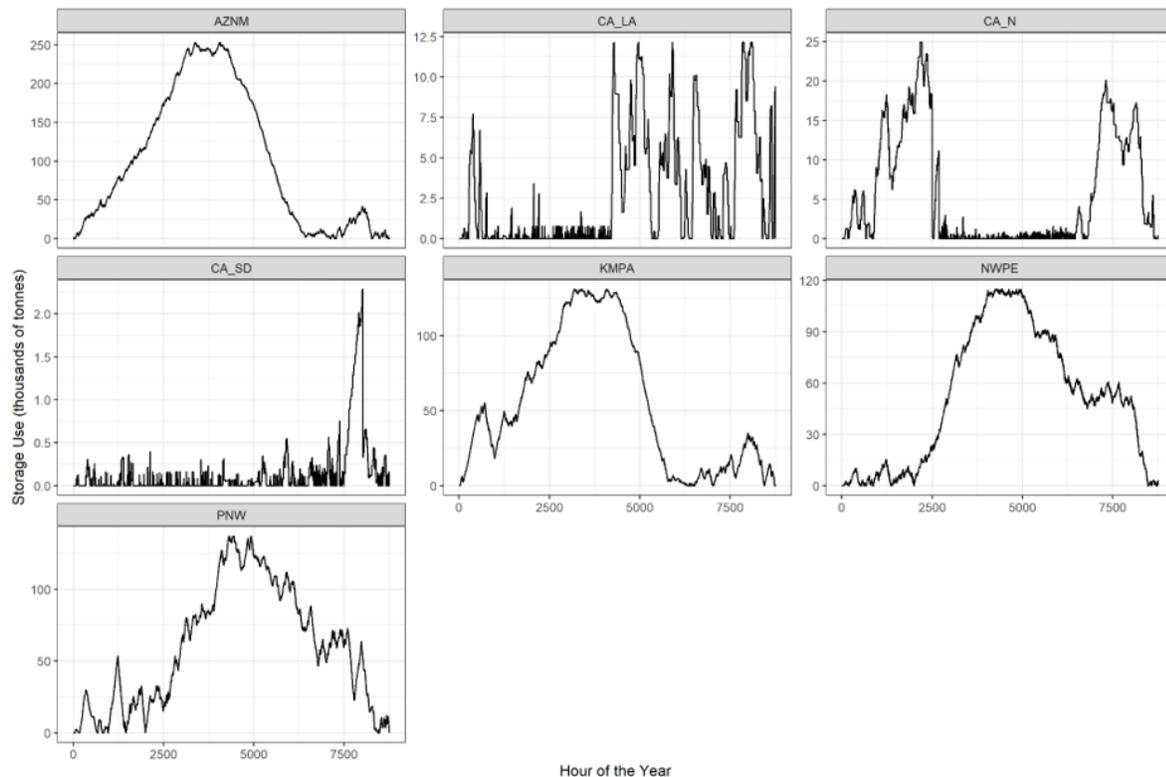
\* Pipeline pressure 100 bar, flow velocity 15 m/sec

## 7. The role of hydrogen storage in energy system electrification

The UC Davis hydrogen study has shown [5] that large-scale, long-time (seasonal) storage of hydrogen will be needed to balance the demand for electricity and hydrogen over the year with the availability of solar/wind electricity to produce hydrogen at various times of the year. The stored hydrogen can be used directly for use in fuel cell vehicles or converted to electricity for the grid by fuel cells or gas turbines. This section of the report is concerned with the technology and cost of long-term, underground storage of hydrogen and its role in the transition to the use of hydrogen in the electrified energy system.

As part of the UC Davis hydrogen study, the operation of the electrical grid system in the Western States with battery-electric and fuel cell vehicles, hydrogen, and solar/wind electricity generation was simulated over a year. The use of hydrogen storage was included in the simulations. The need for hydrogen storage in a number of regions is shown in Figure 14. The maximum projected H2 storage requirements are 100-200 thousand tons with cycle times of thousands of hours. It appears that underground seasonal H2 storage will be needed to take full advantage of the renewable solar/wind electricity capability installed in the Western region.

**Figure 14: The use of hydrogen storage in various regions of California and Western States [5]**



### Hydrogen storage in the pipeline network

If an extensive pipeline network were developed for hydrogen transmission and distribution, a considerable volume of hydrogen would be stored in that network of pipes. This has been the case for natural gas (NG) in the existing pipeline network developed to distribute it. It is of interest to compare the energy (MJ) stored in that network with NG to what could be stored as hydrogen. This comparison is shown in Table 14. The calculations indicate that in the same volume NG stores 4 times the energy at 90 bar as stored in H2 at the same pressure. If the present NG network consisted of all 36 inch pipes, it would store at any one time about 4% of annual NG usage of 31 trillion MJ. For the same annual usage, H2 would store about 1%. In the case of NG, 4% is usage for about 15 days and for H2, it is usage for about 4 days. In both cases, line pipe storage is only short time storage for several days or less. In the case of H2, it is likely only storage for one day. The data given in Table 14 show that underground storage for NG is 1.3 billion SC m<sup>3</sup> storing 4.7 Trillion MJ. The size (volume) of H2 underground storage

would have to be 4 times larger (5.2 billion m<sup>3</sup>) to store the same MJ at 90 bar pressure. Hence H2 will require very large caverns for storage.

**Table 14: Comparison of the storage of natural gas (NG) and hydrogen (H2) in the US NG pipeline network**

<b>Natural Gas (NG)</b>		Stored in 36 inch pipe 37.3x10 <sup>3</sup> ft <sup>3</sup> /mi	Stored in 24 inch pipe 16.5x10 <sup>3</sup> ft <sup>3</sup> /mi	Stored in 18 inch pipe 9.3x10 <sup>3</sup> ft <sup>3</sup> /mi
Total energy NG 2019	31 trillion MJ (1 Scf =1 MJ)			
NG stored Underground MJ	4.7 Trillion MJ (15.2%) 1.3 billion m <sup>3</sup>			
Total transmission pipelines in US	321,000 miles			
Stored in pipelines at 90 bar		25 billion kg 1.3 Trillion MJ 4.2%	11 billion kg .58 Trillion MJ 1.9%	6.3 billion kg .325 Trillion MJ 1.05%
<b>Hydrogen (H2)</b>	31 trillion MJ Total annual H2 consumption			
H2 stored in pipelines at 90 bar		2.6 billion kg 312 billion MJ 1%	1.14 billion kg 137 billion MJ , .44%	.647 billion kg 78 billion MJ .25%
15% H2/NG mix At 90 bar		4.7 million kg H2 568 million MJ .0018%		
H2 underground volume ft <sup>3</sup> needed to store 15% (4.65 trillion MJ H2) at 90 bar	.177 trillion ft <sup>3</sup> H2, .044 trillion ft <sup>3</sup> for NG. H2 is 4 times greater 5 billion m <sup>3</sup>			

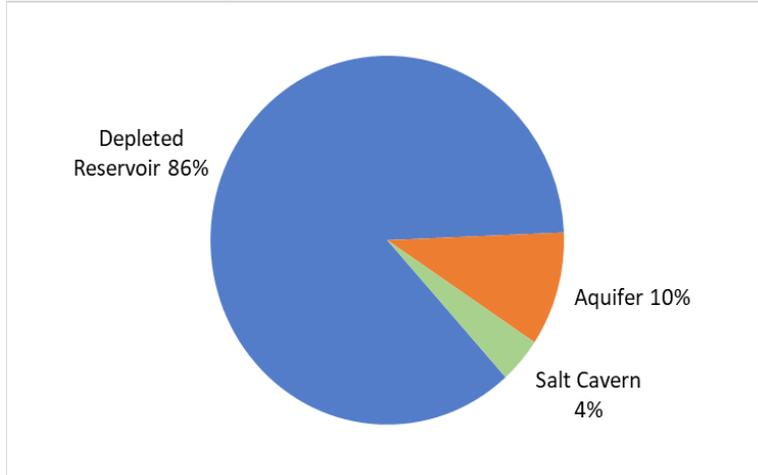
The data in Table 14 indicates that the hydrogen stored in a pipeline network could function as daily storage for hydrogen. This type of storage is often referred to as line pack storage. There is considerable analysis in the literature of line packing with NG [52-54], but little work considering line packing with hydrogen [55].

### Long duration underground storage

There has been considerable experience and literature [56-58] on storing natural gas underground. The data on storage of NG given in Table 14 show that there is capability for storing underground about 15%

of annual usage of NG. This is about 1.3 billion m<sup>3</sup> in which 3.7 trillion MJ of NG can be stored. In this same volume, 9 billion kgH<sub>2</sub> could be stored at 90 bar. Most of the NG has been stored in depleted oil and gas reservoirs (Figure 15). Hence there has been limited experience with salt and rock caverns with NG.

**Figure 15: Working U.S. reservoirs for natural gas, capacity by type of storage in 2001 [56]**



There are several different strategies for underground storage of hydrogen, including salt caverns, depleted oil and gas wells, and hard rock caverns. The IEA has evaluated these types of storage. As shown in Table 15, there are strengths and weaknesses for each type of storage, though salt caverns have the strongest set of positives overall. There are a few negative (minus sign) or neutral aspects (o) for oil or gas field storage, while salt caverns have inherent advantages in each of several key aspects, including investment and operation cost.

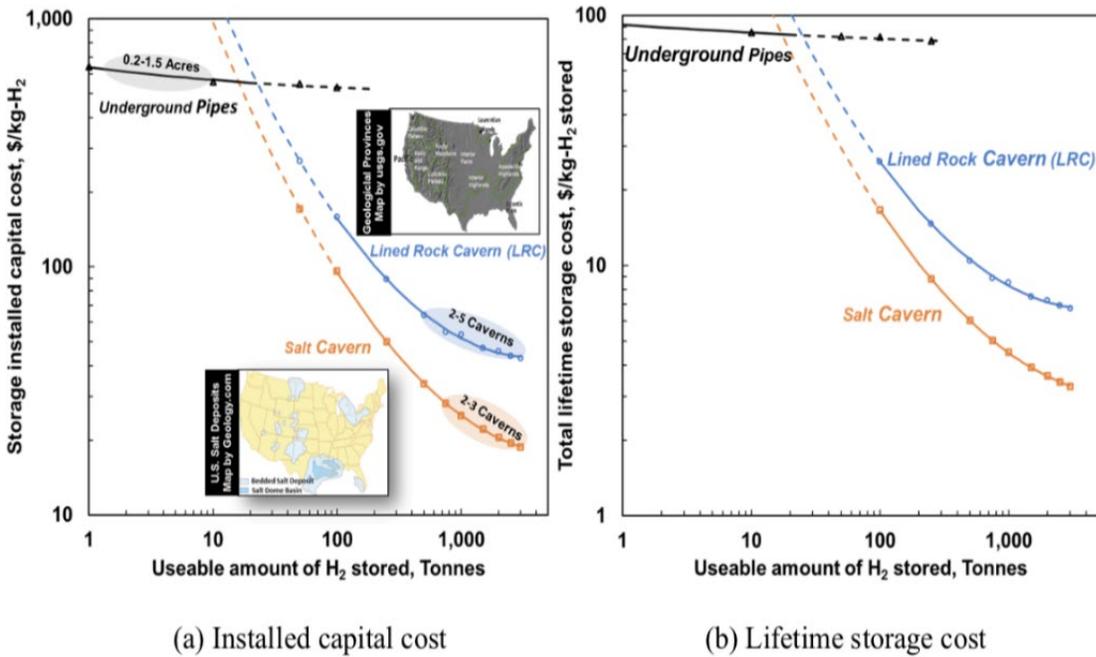
**Table 15: Characteristics of various underground storage options for hydrogen [59]**

	Salt caverns	Depleted oil fields	Depleted gas fields	Aquifers	Lined rock caverns	Unlined rock caverns
<b>Safety</b>	++	+	-	-	-	-
<b>Technical feasibility</b>	+	++	++	++	0	-
<b>Investment costs</b>	++	0	0	0	+	+
<b>Operation costs</b>	++	-	0	+	++	+

Source: adapted from HyUnder (2013) *Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Seasonal Storage of Renewable Electricity by Hydrogen Underground Storage in Europe – Benchmarking of Selected Storage Options*.

As with many large-scale infrastructure projects, the size of the project significantly affects the overall economics. Figure 16 shows the capital cost per unit of hydrogen storage capacity, and annual storage cost for salt caverns and lined rock caverns of different sizes [60, 61].

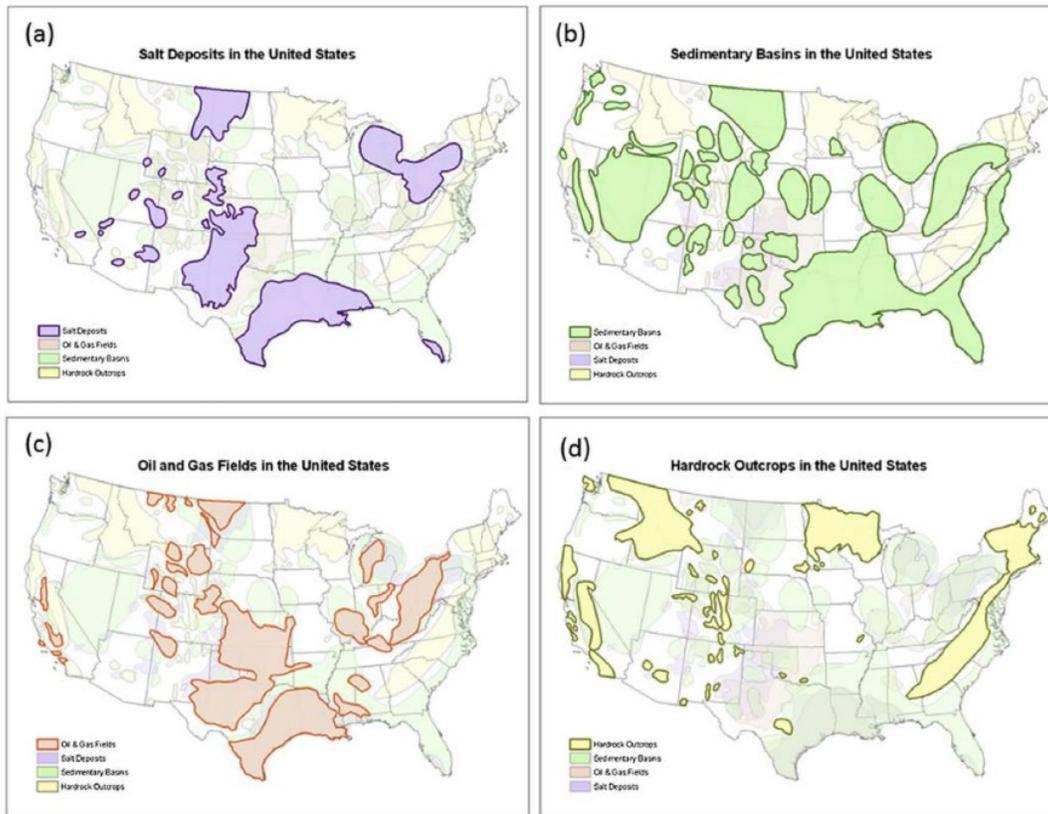
Figure 16: Installed and lifetime costs of large caverns for storing H<sub>2</sub> [60, 61]



It is clear that the costs are strongly dependent on the size of the storage (tonnesH<sub>2</sub>). The cost curves are still falling at 1000 tons and a capital cost of about \$30/kgH<sub>2</sub>.

Figure 17 provides a general sense of the distribution of potential geological storage sites throughout the US. Salt deposits, which provide the lowest cost geological storage are not particularly common in the Western US.

Figure 17: Distributions of underground storage sites for hydrogen in the United States [1, 62, 63]



There have been several detailed projections of the cost of building cavern facilities for storing hydrogen [1, 64]. Complete cost data for storing hydrogen in salt caverns is given in Tables 16 and 17. This cost data is used in a cost analysis of H<sub>2</sub> storage later in this report.

Table 16: Breakdown of capital and operating costs for a salt cavern [61]

Unit/Description	Value	Unit
Storage capacity	500,000	kg
Cushion gas needed	84,085	kg
Compressor cost (installed)	3,535,794	\$
Pipe to H <sub>2</sub> production facility	749,130	\$
Valves and instrumentation	112,370	\$
Cushion gas	420,423	\$
Land cost	313,769	\$
<i>Aboveground costs</i>	<i>5,131,486</i>	<i>\$</i>
Labor cost	252,000	\$/year
Maintenance cost	150,047	\$/year
Electricity cost	11,982	\$/year
Property tax \$ insurance	102,630	\$/year
<i>Total O&amp;M</i>	<i>516,659</i>	<i>\$/year</i>

### Modeling of hydrogen storage costs in underground caverns

A spreadsheet model was prepared to analyze the cost of storing hydrogen underground in caverns and above ground in tanks. The small scale tank approach is suitable for short duration storage (several days) and the underground approach could be used for longer duration, seasonal (120-150 day) storage. The cost of tank storage is often quoted as \$400-600/kgH<sub>2</sub>, which is expensive, and that of underground storage as \$.2- .3/kgH<sub>2</sub>, which is very low. This could lead the reader to conclude that the tank storage contribution to the cost of hydrogen dispensed is high and that the contribution of underground storage is low. The analysis discussed in this section will show that is not usually the case.

The results yielded by any model depend on the inputs used to make the calculation. In the case of the underground hydrogen storage model, the key inputs and associated values are shown in Table 17. The values used in the calculations are based on those found in the literature [62-64]. Underground storage is long duration or seasonal storage of many days to several months. The model results shown in Table 18 indicate that the hold time in storage has a large effect on the contribution of storage to hydrogen cost (\$/kgH<sub>2</sub>). In fact, for a few days storage the cost of storage is less than \$.2/kgH<sub>2</sub> and for several months the cost is more than \$1/kgH<sub>2</sub>. In assigning a cost to seasonal storage, the effect of hold time must be considered. The expected cost of seasonal storage will not be low.

**Table 17: Input parameters for the underground storage model**

<b>Parameter</b>	<b>Range of values</b>
Cavern size tons kg	500-1000
Cavern cost \$/kgH <sub>2</sub>	20-40
Storage pressure bar	150-200
Average hold time in storage days	15-150
Max fill rate kg/h	5000-10000
Compressor cost \$/kg/h kWh/kgH <sub>2</sub>	200-400
Electricity cost \$/kWh	.8-1
Capital cost recovery factor CFR	.05-.10
	.08-.11-

**Table 18: Model results for underground H2 storage**

Parameter	Value
Cavern size tons kg	500
Cavern cost \$/kgH2	20
Storage pressure bar	150
Max fill rate	3 days
Compressor cost \$	2221k
Cavern cost \$	9999k
Electricity cost \$/kWh	0.05
Average hold time days	Lev \$/kgH2
15	0.235
30	0.429
60	0.815
120	1.59

The stand-alone storage costs (\$/kgH2) for various storage media and hold times are shown in table 19. These costs are independent of the system they are used in and do not include the cost of electricity to fill or dispense the storage unit. For some systems, the annual electricity costs are greater than the annual levelized capital cost of the storage unit. The hydrogen storage cost in a system is always much higher than the stand-alone storage cost of the storage unit(s) used in the system. This can be seen from comparing the results for cavern storage in Tables 18 and 19.

**Table 19: Stand-alone storage cost of hydrogen (\$/kgH2)**

H2 storage	Hod duration days	Storage cost \$/kgH2
High pressure gas \$500/kgH2	1	.14
	7	.96
	15	2.1
	30	4.1
LH2 \$50/kgH2	1	.014
	7	.096
	15	.21
	30	.41
Underground in cavern as gas \$20/kgH2	15	.082
	30	.16
	60	.33
	90	.49
	120	.66

## Above ground tank storage of hydrogen

In a hydrogen refueling station, there is a need for hydrogen storage in order to rapidly refuel successive vehicles. The hydrogen can be stored as a high-pressure gas or cryogenic liquid (LH2). The hydrogen storage unit is one component in the station and it functions along with other components such as compressors. The capital costs of storage units are shown in Table 20. An estimation of the stand-alone storage costs (see Table 19) for the units are given by the relationships below.

$$(\$/\text{kgH}_2)_{\text{storage}} = (\text{kgH}_2)_{\text{stored}} \times (\$/\text{kgH}_2)_{\text{stored}} \times \text{CRF} / (\text{kgH}_2/\text{yr})$$

$$(\text{kgH}_2/\text{yr}) = 365 \times (\text{kgH}_2)_{\text{stored}} / (\text{days hold in storage})$$

**Table 20: Capital costs of storing hydrogen as a compressed gas and cryogenic liquid [60-61]**

Hydrogen phase	Temperature Deg K	Pressure Atm	Density Kg/L	Cost \$/kgH2
Compressed gas 1500 kg	300	350	.0235	700 steel with liner
Compressed gas 1500 kg	300	350	.0235	650 Steel concrete composite
LH2- 3000 kg	15-20	5-10	.075	70 highly insulated
LH2-1000 kg	15-20	5-10	.075	105  Highly insulated

Consider the case of hydrogen storage in a refueling station. For a 1250 kgH<sub>2</sub>/da, high pressure gas hydrogen station, the capital cost of the tank storage (625 kg) was \$600/kgH<sub>2</sub> or \$375000. All the H<sub>2</sub> dispensed at the station passes through the storage tank. As a result, the tank will have stored up to 1250 kgH<sub>2</sub> each day. This means the tank stores for small periods of time up to 1250 x 365 = 456,250 kgH<sub>2</sub>/yr. The annual levelized value of the tank cost is 375000 x CFR = \$37500. The levelized stand-alone cost of the storage is \$31800/365000 = \$.082/kgH<sub>2</sub>. From detailed modeling of this station, the station fuel cost was \$.32/kgH<sub>2</sub> even though the stand-alone hydrogen storage cost in the tank was only \$.14/kgH<sub>2</sub> for the 1 day storage in the station. Hold time is a critical factor in determining the cost (\$/kgH<sub>2</sub>) of storage in a particular situation, but detailed modeling is needed to determine the expected \$/kgH<sub>2</sub> in a particular application. In the case of hydrogen storage in caverns, the system cost of storage is comparable to tank storage at a refueling station only for hold times that are not useful for the cavern applications.

## 8. Summary and conclusions

One strategy to achieve carbon neutrality in California by 2040 is to utilize renewable hydrogen (RH<sub>2</sub>) and synthetic natural gas (SNG) as clean fuels. These fuels can be produced from biomass and solar/wind energy as carbon-neutral or carbon-negative resulting in large reductions in CO<sub>2</sub> emissions in nearly all sectors of the economy. SNG as a replacement for natural gas can be distributed using the existing pipeline network and it can use the same appliances as NG to meet the heat and electrical

power generating applications. In the transportation sector, many vehicles can be battery-electric powered by renewable electricity. RH<sub>2</sub> can be used in fuel cell powered vehicles to provide an important complement and even prove superior in some vehicle types. Within the electric sector, hydrogen can be effective for energy storage (especially seasonal). Hydrogen along with biomass and CO<sub>2</sub> can be used to produce a wide variety of synthetic carbon-neutral hydrocarbon fuels that can meet the needs of vehicles such as in aviation and marine applications. All the renewable clean fuels can be carbon-negative when the CO<sub>2</sub> emissions from their production and/or use are captured and stored (CCS). SNG can have CO<sub>2</sub> emissions nearly as low as H<sub>2</sub> from electrolysis using electricity from solar/wind. Hence SNG is convenient to use as a replacement for NG and it has relatively low cost and low CO<sub>2</sub> emissions.

As we show in our executive summary table, given overall cost and efficiency considerations, it makes sense to use electricity directly in battery-electric vehicles when possible, given the practicality limits (such as related to range, recharge time, and payload). Where this proves impractical, hydrogen used in FCEVs is an appropriate alternative. The costs of this hydrogen can be fairly low if made from low-cost electricity or from low-cost biomass feedstocks. Identifying the cost reductions needed, when these can be achieved, and the amount of electricity or biomass available for this has been discussed in this paper but more work is needed on each of these questions to develop a full roadmap.

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