Liberty Keene Gas Supply Upgrades

Liberty Utilities

April 14, 2022

→ **The Power of Commitment**

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Printed date	4/14/2022 2:26:00 PM
Last saved date	April 14, 2022
File name	12569693 -RPT-1 Liberty Keene Gas Supply Upgrades.docx
Author	Jim Volk
Project manager	Nicholas Schilling
Client name	Liberty Utilities
Project name	Liberty Keene Gas Supply Upgrade
Document title	Liberty Keene Gas Supply Upgrades
Revision version	Rev [00]
Project number	12569693

Document status

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S4		Jim Volk	N. Schilling	Nicholas Schilling	N. Schilling	Nicholas Schilling	2/15/20
S4		Jim Volk	N. Schilling	Nicholas Schilling	N. Schilling	Nicholas Schilling	4/14/20
[Status code]							
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[Status code]							

Executive Summary

This report is subject to, and must be read in conjunction with, the limitations set out in Section 1 and the assumptions and qualifications contained throughout the Report.

Liberty Utilities (Liberty) is evaluating options to alter the fuel gas delivery infrastructure for Keene, NH, which is currently arranged into two independent delivery systems. Zone 1 primarily feeds residential customers and is supplied with a propane-air fuel gas mixture. Zone 2 is a compressed natural gas (CNG) system that distributes de-pressurized natural gas to a commercial district within the city limits. Each of the two zones present different opportunities and challenges to update the distribution network and fuel gas constituents.

The propane-air facility of Zone 1 has been identified to have reached the end of its useful life barring major capital investments made by Liberty. Liquid propane is trucked to this facility, offloaded to storage tanks, and mixed with air prior to distribution. The need for investments has presented a unique opportunity for the city of Keene and Liberty to re-assess the gas distribution philosophy for the Zone 1 users.

The CNG facility for Zone 2 feeds primarily commercial customers that are already accustomed to natural gas as a source of energy. CNG is trucked into the distribution center where it is de-pressurized prior to distribution to the customers. This system can continue to run without the need for significant investment to upgrade at this time. Based upon the differing states of Zone 1 and Zone 2, different options are available for consideration for each distribution sector.

Both Keene and Liberty have stated goals to de-carbonize their energy consumption in the near and long term. The focus of this study was to evaluate options to meet Keene and Liberty’s sustainability goals. The different options have been evaluated based upon on economical, technical, and environmental considerations.

Summary of Results

GHD assessed a wide range of potential scenarios for Zone 1 and 2, including various sources of renewable natural gas (RNG) and hydrogen for blending into the distribution networks. The conversion from propane/air to LNG/CNG had both a lower overall fuel carbon intensity but also a lower commodity price. The ability to blend Zone 1 with landfill gas (LFG), biogas or wastewater treatment gas (WWTP) represents a significant decarbonization opportunity at the lowest cost per metric ton of CO2 removed. This pathway also allowed for future blending with hydrogen derived from renewables and is consistent with Liberty’s energy transition narrative with the desire to deliver clean, economic, reliable and safe energy.

The table below presents a summary comparison of six scenarios for Zone 1, including considerations for project implementation difficulty, potential timing, the carbon intensity of the fuel used, cost per delivered energy unit of gas, lifecycle emissions from combustion of the supplied fuel in the network, emissions reductions in comparison to the CNG scenario, cost per delivered kg of hydrogen (for the applicable scenarios), and a high-level look at potential capital costs. A cost per tonne of CO2 removed scenario was also developed, based on an assumed longer-term $1/kg hydrogen price. Based on this scenario, there were several significant benefits to Keene customers, including a significantly lower cost to decarbonize with hydrogen ($/tonne CO2 removed), as well as the fact that a $1/kg price for green hydrogen represents an equivalent price of $6.89/MMBTU (based on the HHV of hydrogen). This is lower than the $15/MMBTU base case natural gas price. The summary of all eight scenarios (for zone 1and zone 2) are shown in Table 3.2 in Section 3.5 of this report.

Summary Comparison of Conversion Scenarios for Zone 1

Parameter	Propane / Air Mix	Convert to CNG/LNG Facility	Convert to CNG/RNG 50% Blend - Zone 1	H2 Electrolyzer 20% Blend Zone 1	H2 Electrolyzer 20% Blend Zone 1	H2 Electrolyzer 100% Blend Zone 1
Implementation	Baseline	Readily Implementable	Reasonably Implementable with RNG Source	Difficult - Requires Demonstration Project	Difficult - Requires Demonstration Project	Difficult - Requires Demonstration Project
Timing		2-5 years	2-5 years	5-10 years Start process concurrent with CNG Conversion	5-10 years	10+ years
Fuel Carbon Intensity (gCO_2e/MJ)	Propane: 83	Natural Gas: 79	RNG from LFG or WWTP Biogas: 35	H_2 from Renewable Electricity: 0	H_2 from Keene Grid Electricity: 73	H_2 from Renewable Electricity: 0
$/MMBtu Commodity Delivered Gas*	$19.97	$15.00	$30.00	$80.00	$80.00	$50.00
Lifecycle Emissions from Fuel Use (metric tonnes CO_2e)	10,112	10,002	7,210	9,290	9,946	0
Emissions Reductions (tonnes CO_2e per year) Compared to NG	N/A	N/A	2,792	712	56	10,002
Emissions Reductions (%) Compared to NG	0%	0%	28%	7%	1%	100%
$/tonne CO_2 removed (compared to NG)	N/A	N/A	RNG from LFG: $643	Green H2: $795	Keene Grid H2: $10,000	Green H2: $398
$/kg H2	N/A	N/A	N/A	$10.80	$10.80	$6.50
$/tonne CO_2 removed based on $1/kg H2	N/A	N/A	RNG from LFG: $643	Green H2: $91	Keene Grid H2: $1,150	Green H2: $86
Capital Investment ($1000)	$4,670	$7,360	$450	$3,970	$3,970	$20,000

Notes: * $/MMBTU show n for RNG and H2 commodity only

Summary of Recommendations

Based on the conclusions described within this report, GHD recommends Liberty continue to investigate the conversion from propane-air to LNG/CNG followed by a near-term and long-term schedule for blending hydrogen produced from renewables, as an opportunity to meet Liberty's long-term decarbonization goals. Hydrogen blending should first start as a demonstration program with eventual implementation based on availability of RNG, LFG, Biogas, and WWTP gas. In addition to any hydrogen blending demonstration, GHD recommends establishing a potential R&D hydrogen blending facility (most likely in NYS) as a method to test different blending volumes, evaluate the performance of blending percentages with various natural gas appliances and provide essential community outreach for future blending implementation plans.

A recommended overall implementation schedule is shown in Section 6 of this report.

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1. Introduction

This report: has been prepared by GHD for Liberty Utilities and may only be used and relied on by Liberty Utilities for the purpose agreed between GHD and Liberty Utilities

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

In the race to transform our energy systems, a greener gas economy is emerging at an exponential rate. Renewable natural gas (RNG) and hydrogen can be blended into the gas supply to improve supply security and lower the greenhouse gas (GHG) intensity of the gas network. Hydrogen blending is no longer a distant dream; it's here - happening now, with accelerating advancements from around the world. Blending lower-carbon compatible fuels into the gas network is a key element of the near-term energy transition: greener gas blended with natural gas can deliver cleaner, low-emission energy for heating, cooking, and industry applications. RNG and hydrogen blending provides an immediate opportunity to begin decarbonizing these difficult-to-decarbonize sectors and drive demand for green gas hubs.

This report focuses on scenarios that reflect four (4) new gas supply options for the City of Keene, New Hampshire, which considers the integration and implementation of these options. These scenarios reflect the technical and operational requirements for the practical integration of the New Gas Supply Options into the existing legacy gas distribution system in Keene. The existing gas distribution system is comprised of two islanded gas networks, Zone 1 and Zone 2, which are not connected to a pipeline gas supply. Liquified propane gas (LPG) is delivered, gasified, and delivered to customers as a propane-air blend in Zone 1 which serves approximately 1,250 residential and commercial customers. In Zone 2, compressed natural gas (CNG) is delivered via truck and compressed into the pipeline to serve approximately 30 major customers.

The following initial new gas supply options for Keene were identified for evaluation in this study:

1. Conversion of Zone 1 from propane-air to CNG with RNG blending – deal with customer conversions for higher energy content of the gas.
2. Conversion of Zone 1 from propane-air to CNG/RNG with co-blending of hydrogen (H_2) to maintain same delivered energy content as previous.
3. Gradual conversion of both zones at various percentages of H_2 blending (up to 100% hydrogen) over time after CNG/RNG conversion, based on compatibility with current pipeline materials of construction.
4. Conversion to 100% H_2 without CNG as intermediate step.

For each new gas supply option identified, GHD evaluated the following characteristics:

1. Economics
   a. Feasibility (+/- 50%) capex for each and $/MMBtu expected
   b. Project funding opportunities
   c. Decarbonization benefits for each in terms of lifecycle GHG emissions for fuel use
   d. Decarbonization costs for each option ($/ton CO_2-equivalent), based on the capex estimates
   e. Rates and tariffs
2. Technical Complexity
   a. Availability of equipment/system
   b. Operational risk/issues
   c. Established, multiple vendors
   d. General integration considerations

3. Regulatory
    a. NHPUC requirements
    b. Established regulatory framework
4. Environmental and Social Co-Benefits

1.1 Assumptions

GHD has prepared this report on the basis of information provided by Liberty Utilities.

GHD has prepared the preliminary CAPEX and OPEX estimates set out in section this report ("Cost Estimate") using information reasonably available to the GHD employee(s) who prepared this report; and based on assumptions and judgments made by GHD. Key assumptions are documented in the CAPEX and OPEX estimates.

Gaseous Tube Trailer Hydrogen Blending Assumptions:

– Delivery FOB Suffield, CT
– Tube Trailer Volume: 350 KG
– Product Cost: $2.5/100SCF
– Delivery Charge: $5.25/mile
– Delivery Distance: 180 miles RT
– Tube Trailer Lease Fee: $3,000/month
– Discount Rate: 6%
– Term: 10 years

Liquid Hydrogen Blending Assumptions:

– Delivery FOB Niagara Falls, NY
– Product Cost: $2.13/100 SCF
– Delivery Charge: $5.25/mile
– Delivery Distance: 800 miles RT
– Liquid Equipment (tanks, pumps, scheduled O&M) Lease Fee: $18,000/month
– Estimated tanker Truck capacity: 1,800,000 SCF
– Liquid Storage Tank Capacity: 15,000 Gallons
– Discount Rate: 6%
– Term: 10 Years

Electrolyzer Blending Assumptions:

– NEL C30 Electrolyzer: 65 KG hydrogen /24 hours, efficiency 61 kwhrs/kg
– NEL MC250 Electrolyzer: 531 KG hydrogen /24 hours, efficiency 54.2 kwhrs/kg
– NEL M2000 Electrolyzer: 4,247 KG hydrogen /24 hours, efficiency 54.2 kwhrs/kg
– Discount Rate: 6%
– Term: 20 Years
– Electricity Cost: $.08/Kwhr.
– O&M: 1.5% of Capital

Greenhouse gas (GHG) emissions reductions assumptions are described under that section of this report.

2. Background

Liberty Utilities has several needs, obligations, and challenges in providing safe, reliable, economical gas-energy supplies for the City of Keene, NH (Keene). Among the more significant and vital issues affecting Liberty's commercial business operations in Keene include the following:

– The existing Keene gas supply system primarily involves the blending of propane and air to achieve a normalized caloric content of approximately 740 BTU/SCF. This propane gas mixture is distributed to Zone 1 and accounts for most of the Keene gas customers.
– The propane air system is nearing the end of its useful service life and will require upgrades and/or replacement of major infrastructure with the next 5 to 7 years based upon previously completed evaluations. Liberty has a goal to replace the propane/air handling facility with a natural gas system within 3 to 7 years.
– Keene has established a sustainability goal that all electricity consumed in Keene will come from renewable energy sources by the year 2030 and that 100% of all thermal energy and energy used for transportation come from renewable energy sources by the year 2050[1]. As such, Keene is interested in exploring and discussing potential gas supply options with Liberty.
– Keene's sustainability goals align well with Liberty's ESG goals, including the reduction of GHG emissions by 1 million metric tons from 2017 levels by 2019-2023 (already surpassed).
– Due to the lack of available, interconnected natural gas transmission lines and the relatively small service area of Keene, Liberty believes that there is a unique opportunity for a potential transition to alternative, low carbon gas supplies for their existing and future customers in Keene.

3. Gas Supply Upgrade Options

3.1 Propane-Air Mixture

The current propane-air facility has been in operation since 1969 and provides a maximum daily throughput of up to 2100 MSFD of the propane-air mix for Zone 1. The BTU rating for this mixture is 740 BTU/SCF. This will be important when evaluating implications for converting to a natural gas distribution system.

Following an independent evaluation of the facility, significant capital investment was identified as necessary in the short term (5 to 7 years) to continue operation of the facility in a safe and reliable manner. Due to the compact layout and proximity to the surrounding community, another key finding of the evaluation was the inability to upgrade the facility for reasons other than to increase the safety and reliability of the equipment. Future capacity or additional equipment cannot reasonably be added to the current location.

Based on a cost estimate provided by others, a capital investment of $4.67 MM would be required to install a new LPG facility. This would provide the necessary capacity for expected future growth of Liberty's distribution network and would be required to meet future projections.

3.2 CNG/LNG Facility

To replace the existing propane-air facility, a new CNG/LNG facility has been evaluated by others. Capital costs, major equipment and capacities have been included in the previous evaluation. Preliminary facility siting requirements and preliminary thermal radiation and vapor dispersion modeling have all been completed as part of the study. The final

[1] https://keenenh.gov/sustainability/news/city-keene-ep3-100-renewable-energy-press-release

buildout for the LNG/CNG facility was sized to provide natural gas to the City of Keene, Zone 1, at a rate of 9,600 MSCFD. Expected capital required for the new LNG/CNG facility is $7.36 MM.

Based on historical gas usage for the community it is not anticipated that the full demand can be reasonably provided by CNG tube trailer deliveries alone. And when considering the growth projections for the distribution network the need for LNG is likely, especially during high demand months.

An appliance or end-use equipment survey would be conducted during the planning stage of LNG/CNG implementation to identify impacts to the users when the higher BTU natural gas replaces the propane-air mixture.

Zone 2 has an existing CNG facility and modifications for that system would not be needed to convert the propane-air users to natural gas.

3.3 LNG/CNG Conversion Benefits

Assuming Liberty can procure LNG/CNG for similar pricing as the current Zone 2 pricing, a conversion to LNG/CNG provides an operating savings in annual fuel costs and provides the ability to co-blend RNG, biogas or WWTP gas as a low-cost method of decarbonizing. It also allows for the longer-term blending of hydrogen from renewables as another pathway towards meeting Liberty's net zero goals.

The conversion to CNG is consistent with Liberty's energy transition narrative with the desire to deliver clean, economic, reliable and safe energy. The "Greening" of propane is not as flexible or progressive as natural gas, it can be blended with hydrogen, however, natural gas represents a more direct and economical path with CNG/RNG/Hydrogen – as demonstrated by GHD's analysis (lower commodity cost and lower Carbon Intensity).

Economical Energy

As a "manufactured gas," propane is highly influenced by spot pricing, plus weather supply and logistics issues.

Fifty percent of propane is still produced via petroleum refining. As refiners move away from fossil fuels and towards electrification this could result in more volatility in propane pricing.

Building a dedicated propane system may have adverse financial impacts on customers, including increased energy bills – but more importantly new customers will most likely purchase high-efficiency appliances that require equivalent natural gas heating values for optimum efficiency

Expansion of the 1,250 propane/air customer base will most likely require a CNG supply.

Safe, Reliable, and Resilient Energy

As a utility, delivering safe, reliable, and resilient energy needs to also consider a long-term view on energy transition. Looking at key commercially viable energy transition options, propane fails to offer competitive value against alternative options. GHD's research indicates that clean energy moved by pipelines will be primarily based on natural gas transitioning to renewable naturel gas and eventually hydrogen.

Investing in a propane system has the highest potential risk of stranding those assets as most gas utilities pursue RNG/Hydrogen.

3.4 CNG and RNG Blended Supply

Once the investment is made to install a new LNG/CNG facility, it will become immediately possible to begin blending RNG into the distribution network. RNG could be sourced from multiple options with the most readily available likely being from landfill gas. However, other opportunities exist and may present additional benefits to Liberty's decarbonization initiatives.

The only limitation for RNG blending would be the ability to secure trailer deliveries and the number of decanting stations installed at the new facility. Any blended RNG would produce immediate results in lowering the lifecycle emissions for the Keene distribution network. Preliminary usage calculations estimate one tube trailer delivery per day would be required of RNG for a 50% blend.

The infrastructure necessary to operate with a blended RNG component would all be installed as a result of the LNG/CNG facility built to replace the existing propane distribution system.

3.5 CNG and H2 Blended Supply

3.5.1 Merchant Hydrogen Delivery Options

GHD evaluated two different merchant hydrogen delivery options using Zone 2 as a basis and evaluated the feasibility of gaseous and cryogenic hydrogen delivery at a nominal 20% hydrogen blending percentage. GHD also evaluated cryogenic liquid hydrogen delivery for a 100% hydrogen case. For Zone 1 only a 100% liquid hydrogen blending option was considered.

A summary ($/MMBTU equivalent) for both gaseous and liquid hydrogen blending options in order to maintain the same monthly and yearly energy demand requirements are shown in Table 3.2.

These two options included:

1. Gaseous tube trailer hydrogen delivery
2. Cryogenic liquid hydrogen truck delivery

Gaseous Tube Trailer Hydrogen Delivery

Gaseous, or tube trailer hydrogen delivery, is a common method of hydrogen supply for end-users that have exceeded typical cylinder delivery volumes but do not yet require higher delivery volumes of hydrogen via cryogenic liquid hydrogen truck delivery. Since 99.9% of all hydrogen in N. America is produced via steam methane reformation of natural gas, this type of hydrogen is most commonly referred to as “grey hydrogen.” If the hydrogen is sourced from non-renewable natural gas, the Carbon Intensity Index (CII) for hydrogen produced by this method is higher than that of conventional natural gas.

For this study GHD assumed the tube trailer hydrogen being sources is considered “grey” and product cost estimates were based on budgetary Linde quotes FOB Linde’s Suffield, CT hydrogen facility (approximately 90 miles from Keene).

Below are typical tube trailer delivery options:

Typical Gaseous Tube Trailer Delivery

– 300 Kg hydrogen tube trailer capacity
– 120,000 SCF tube trailer capacity
– 2,5000 psig delivery pressure

Zone 2 Gaseous Hydrogen at 20% Blending

As shown in Table 3.2 below, the overall capital cost of hydrogen (hydrogen delivery and blending) on a $/MMBTU is approximately $216/MMBTU or $29/Kg H2 for the 20% blending case.

Tube trailer delivery has several advantages for very small-scale hydrogen demand applications and in the case of Keene, would be the preferred hydrogen delivery mode for an initial smaller project demonstration.

This mode of hydrogen delivery would not be economically feasible for any large-scale blending applications since the limited volume (300 kg) of hydrogen would result in a significant number of truck deliveries to maintain the current energy demand for either zone any customer expansion plans.

During the high demand months for zone 1, a 20% blending percentage would require a minimum of one hydrogen tube trailer deliveries per day. For Zone 1 at a 100% hydrogen blend it would require a minimum of 18 tube trailer deliveries per day. Capex and Opex estimates were obtained through budgetary estimates provided by several industrial gas companies. Capex includes the overall cost for concrete pads, manifolds and other piping required to accommodate several tube trailers. It also included the cost for a hydrogen blending system. Opex estimates included monthly lease fees for the tube trailer as well as delivery fees.

The high Opex cost ($/Kg H2), limited delivery volumes and high Carbon Intensity Index limit tube trailer hydrogen delivery to demonstration blending project opportunities only.

Figure 3.1 Compressed Hydrogen Tube Trailer

Cryogenic Liquid Hydrogen Delivery

Cryogenic liquid hydrogen involves the liquefaction of gaseous hydrogen to a temperature of minus 253 degrees C or (-423 degrees F). There are currently only two merchant liquid production facilities within any reasonable distance from Keene. These include the 9 ton per day Becancour, Quebec, facility owned and operated by Air Liquide and the 50 ton per day facility in Niagara Falls, NY, owned and operated by Linde Gas.

Typically, liquid hydrogen is preferred as customers exceed tube trailer delivery quantities. Below is a typical liquid hydrogen delivery option:

Typical Cryogenic Liquid Delivery

– 17,000 gallons tanker capacity
– 1,800,000 SCF tanker capacity
– 15,000-gallon tank typical onsite storage

Liquid hydrogen delivery is not considered as a long-term viable option for Keene blending. GHD evaluated using liquid hydrogen for a 20% zone 2 blending option and a 100% hydrogen option for both Zone 1 and Zone 2.

Liquid hydrogen delivery, although providing customers with larger volume deliveries and larger onsite storage volumes, has a limited market since distance from production to end-use can add significant costs to the overall product cost. In the case of Keene, liquid hydrogen delivered from Niagara Falls would result in an 800-mile round trip delivery that also adds an additional $7/MMBTU to the cost of the delivered product (based on a 100% hydrogen scenario for Zone1).

Since most liquefied hydrogen is derived from SMR hydrogen production it is typically considered as grey hydrogen with a CII even higher than gaseous tube trailer hydrogen. Because of this GHD did not evaluate the CII for liquefied hydrogen. As more green liquefied hydrogen capacity becomes available this could provide an option for Liberty to consider, although onsite hydrogen production from renewable energy sources would probably still be the best economic solution.

Zone 1 and 2 Liquid Hydrogen at 20% and 100% Blending

Table 3.2 shows the overall capital cost of hydrogen (hydrogen delivery and blending) on a $/MMBTU basis and $/KG hydrogen basis. As indicated in the table, liquid hydrogen as a blending is not a viable option for either 20% or 100% blending percentages. In fact, the CII would be even greater than gaseous hydrogen and with very limited opportunity to source “green” liquid hydrogen from limited sources.

A 100% hydrogen supply option for Zone 1 would require over 30 liquid tanker truck deliveries per month and would require a minimum of 30,000 gallons of cryogenic liquid hydrogen storage. This creates additional safety review, permitting and reporting and does not allow for any customer base expansion, given the huge volumes of product required for delivery and storage.

Figure 3.2 ***Cryogenic Liquid Hydrogen Container***

3.5.2 On-Site Electrolysis Hydrogen Delivery

Hydrogen production with co-located blending into the existing natural gas infrastructure presents local, regional, and national benefits for energy storage, resiliency, and emissions reductions. During periods of excess low-carbon power supply, hydrogen can be produced from renewable, nuclear, or other resources and subsequently injected into natural gas pipelines. This pathway of power-to-gas-to-pipeline reduces the need for pure hydrogen storage and transport if hydrogen blending can be co-located with the production, reducing costs and providing an immediate solution for managing increasing variable renewable power supply. The City of Keene’s power supply, which is largely nuclear baseload with high penetration of variable renewables and approximately 30-35% natural gas power generation, provides a potential opportunity for low carbon hydrogen production during periods of low electricity demand when natural gas peaking plants comprise less of the generation mix.

There are two types of electrolyzer units commercially available: Alkaline and Polymer Electrolyte Membrane (PEM). Although Alkaline and PEM units are functionally similar, the electrolysis reaction in the stack is different (DC power is used to decompose the water to hydrogen and oxygen in the stack) and this means each type have different characteristics and costs, which can provide relative advantages and disadvantages.

For this study GHD utilized Proton Exchange Membrane (PEM) electrolysis for the hydrogen blending scenarios. PEM electrolyzers offer greater flexibility in operation and can respond to load changes more quickly than alkaline units. In addition, their turndown range is better than that of alkaline units.

The higher responsiveness and operating range are of particular advantage, when coupled with dynamic energy sources, such as solar and wind and the performance of smaller models, (around 0.5 to 2 MW), is better understood and are more commercially available for the size requirements with a Keene blending program.

For this study GHD utilized three NEL Hydrogen electrolyzer product lines. These were chosen based on matching their hydrogen production capacity with both Zone 1 and 2 blending scenarios. There are several other electrolyzer manufacturers that also have commercially available systems. These include Plug Power, Cummins, Siemens and ITM Power (Linde).

Figure 3.3 NEL Hydrogen MC250 Electrolyzer (531 kg/day)

GHD evaluated 20% and 100% blending scenarios based on electrolysis-based hydrogen production. A summary of the estimated capital costs ($/MMBTU and $/KG) for each scenario are shown in Table 3.2.

There are several observations based on these scenarios:

1. Hydrogen production via electrolysis is becoming more competitive with many other production options, especially as costs of electrolyzer units continue to improve as well as the ability to couple the input power requirements with renewable energy sources such as solar, wind or hydro power.
2. Liberty's seasonal natural gas demands tend to favour use of a PEM electrolyzer that can follow monthly demand swings and has a very good turn-down ratio.
3. Since most PEM units are container-based additional units can be added to increase hydrogen production as the demand increases.
3. The main variable cost (in addition to water supply) is power. Leveraging cheaper, renewable power will help the overall economics. For example, a typical Keene commercial power rate of $.08/Kwhr contributes to an

equivalent cost of hydrogen of $36/MMBTU for the type of electrolyzer considered in this study. The lower the electricity rate the lower the equivalent cost of hydrogen.

4. A staged approach toward hydrogen blending provides the ability begin the decarbonization process while managing overall project and capital costs, especially if either state or federal funding is available. Monitoring carbon offset credit market development, electrolyzer costs over time as well as securing potential low cost sources of renewable power will help drive the next phases of increased hydrogen blending. Table 3.1 below shows the contribution lower cost power has on overall hydrogen costs via electrolysis.

Table 3.1 Variable Cost of Hydrogen Production at Various Electricity Costs

	Electrolyzer Sensitivity	
$/Kwhr	**$/Kg**	**$/MMBTU**
$0.08	$11.60	$86.0
$0.07	$11.03	$82.0
$0.06	$10.49	$78.0
$0.05	$9.95	$74.0
$0.04	$9.40	$70.0
$0.03	$8.90	$66.0

3.5.3 Hydrogen Blending Equipment

Based on the estimated costs associated with gaseous and liquid hydrogen delivery options for Zone 2, it was determined that gaseous electrolyzer-based hydrogen production systems will provide hydrogen at adequate pressures (400 psig) for blending into existing natural gas distribution pipelines, especially if the blending takes place at individual customer locations.

For this study, typical blending apparatus was used including hydrogen mass flow meters and flow controllers, hydrogen blend percentage analyzers, appropriate valves, instrumentation, and controls. For budget purposes a capital cost of $500,000 was used for the blending system.

3.6 Summary of Cost Comparison for Hydrogen Blending Scenarios

GHD evaluated several scenarios for hydrogen blending in natural gas for Zone 1 and Zone 2 based on the information described above. The results for 20% hydrogen blending and 100% conversion to hydrogen are provided in Table 3.2 below and visualized in Figure 3.4. The results indicate the high cost of liquified hydrogen in comparison to gaseous hydrogen, especially for the smaller scale at 20% blending by volume where the costs are prohibitive. Economy of scale is seen for a larger hydrogen supply for 100% heating demand, but conversion to 100% hydrogen would require overcoming significant technical hurdles particularly for network equipment and end-use equipment. This is discussed further in Section 5 of this report.

Table 3.2 Summary of Cost Comparison for Hydrogen Blending Scenarios

	Lifecycle Cost per kg H2 blended				Lifecycle Cost per MMBTU H2 blended			
	CAPEX	OPEX	O&M	**Total**	CAPEX	OPEX	O&M	**Total**
Zone 1								
20% H2 from Grid Electrolysis	$5.40	$4.70	$0.70	**$10.80**	$40.00	$34.89	$5.40	**$80.29**
100% H2 from Grid Electrolysis	$1.90	$4.70	$0.30	**$6.90**	$14.00	$34.89	$2.00	**$50.89**
100% LH2 and Dispensing	$1.10	$11.00	$ -	**$12.10**	$8.00	$81.61	$ -	**$89.61**
Zone 2								
20% GH2 and Dispensing	$7.59	$18.74	$3.00	**$29.33**	$56.29	$139.08	$21.13	**$216.50**
20% LH2 and Dispensing	$36.66	$29.24	$0.57	**$66.47**	$272.07	$216.94	$4.23	**$493.24**
20% H2 from Grid Electrolysis	$11.00	$5.25	$1.47	**$17.72**	$91.78	$38.97	$10.90	**$141.65**
100% LH2 and Dispensing	$2.73	$11.33	$0.05	**$14.11**	$20.22	$84.11	$0.34	**$104.67**
100% H2 from Grid Electrolysis	$4.00	$4.70	$0.64	**$9.34**	$29.00	$34.90	$4.75	**$68.65**

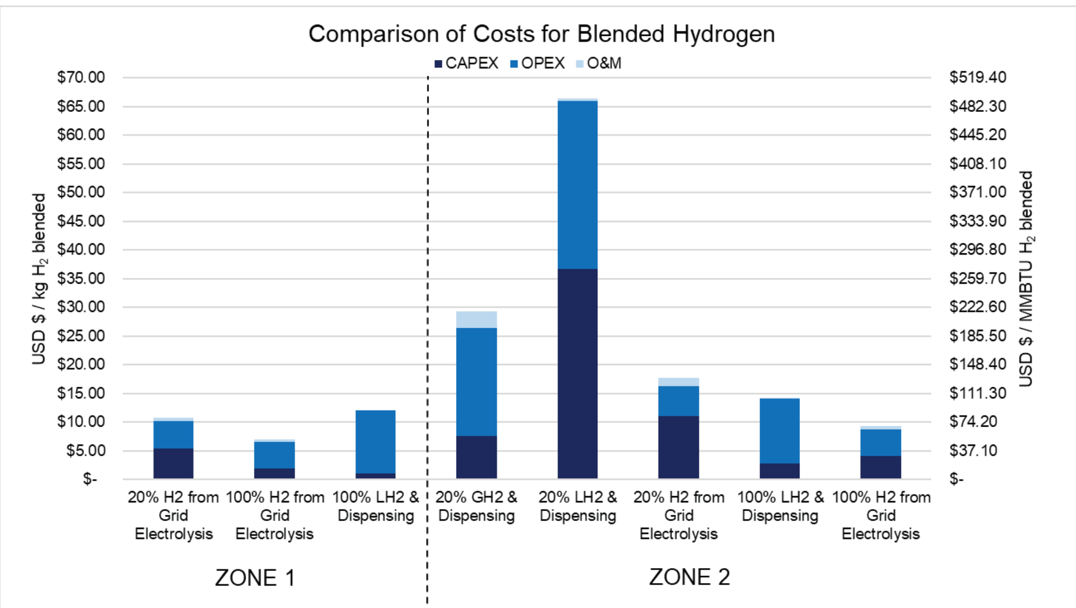


Figure 3.4 Hydrogen Supply Cost Comparison for Hydrogen Blending Scenarios

4. Greenhouse Gas Emissions Reductions

4.1 Introduction

Potential GHG emissions reductions were evaluated for multiple gas supply scenarios for Zone 1 and Zone 2 of the Keene gas network, including the following:

– Zone 1:
  - Baseline: Propane-air fuel mix
  - Conversion to 100% natural gas
  - Conversion to natural gas with hydrogen blending at 2, 5, 10, 15, 20, and 100% hydrogen by volume, considering 3 possible sources of hydrogen (grey, green, and Keene grid electrolysis)
  - Conversion to natural gas with RNG blending at 20 and 50% RNG by volume, considering 3 possible sources of RNG (manure, source separated organics, and landfill or wastewater treatment plant)

– Zone 2:
  - Baseline: Natural gas
  - Hydrogen blending at 2, 5, 10, 15, 20, and 100% hydrogen by volume, considering 3 possible sources of hydrogen (grey, green, and Keene grid electrolysis)
  - RNG blending at 20 and 50% RNG by volume, considering 3 possible sources of RNG (manure, source separated organics, and landfill or wastewater treatment plant)

Full tabulated results are provided in Appendix A. An overview of results are presented and discussed in this section.

4.2 Approach and Uncertainties

For a fuel blending and switching project, lifecycle carbon intensities for the baseline and alternative fuels provide a generally accepted method for evaluating the change in emissions considering the options for production, delivery, and combustion of the fuels. The lifecycle carbon intensity (CI) is a measure of the carbon dioxide-equivalent emissions produced per unit of energy of fuel produced, delivered and combusted (typically, measured as gCO_2e/MJ of fuel) and allows for relative comparison of different fuel production and delivery pathways on a common basis. The importance of using a *lifecycle* carbon intensity becomes clear when considering hydrogen fuels – hydrogen produces no GHG emissions when combusted, rather it is the production of hydrogen fuel that can be emissions intensive depending on the process. Hydrogen produced from natural gas or coal without carbon capture and sequestration, for example, which are the most common methods for industrial hydrogen production today, are highly emissions intensive. Lifecycle carbon intensity allows for the inclusion of these upstream emissions when comparing fuel options.

That said, it is important to understand the uncertainties and limitations associated with a CI-based GHG evaluation for the project, particularly given the current lack of standardization in CI assessment methodologies.

There are multiple sources that a fuel's CI can be referenced or determined from. Overall, carbon intensities should be evaluated using a lifecycle approach following the guidance in the following international standards:

– ISO Standard 14040:2006 - Environmental management - Life cycle assessment - Principles and framework
– ISO Standard 14044:2006 - Environmental management - Life cycle assessment - Requirements and guidelines

The guidance given in the international standards is focused on product life cycle assessments, which include a variety of social and environmental impacts such as water demand and waste production in addition to GHG emissions. There is plenty of room for assumptions and varying methods in these international standards, and it is important to understand that just because a CI assessment follows the international standard does not mean it will be accepted by a local regulator or investor as basis for emissions reductions.

For local acceptance, a CI should be reviewed and approved under an applicable program, such as the California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS), or the Oregon Clean Fuels Program. Both programs use the GREET model for evaluating fuel carbon intensity, which is produced and updated by the Argonne National Laboratory.

CARB is the most well-established program in the US with a large database of published carbon intensities. The results given in the database emphasize the uncertainty around CIs: for similar fuel pathways, a large range of CIs are approved, dependent on project-specific information for energy supply, facility energy consumption, transport and storage, compression and/or liquefaction, etc. For example, Table 4.1 below presents a snapshot of current hydrogen production pathways approved under CARB, as of January 2022[2].

Table 4.1 Currently Approved Hydrogen Production Pathways and Carbon Intensities under CARB

Applicant and Pathway Description	Facility Location	Feedstock	Fuel Type	Current Certified CI
Fuel Producer: Alameda-Contra Costa Transit District (A149) Facility Name: Division 2 (F1600). Hydrogen production via electrolysis using solar electricity	California	Solar Electricity via Electrolysis	Hydrogen	0.00
Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps. (Provisional)	California	North American NG	Hydrogen	165.88
Fuel Producer: FirstElement Fuel (E426): North American fossil NG to Hydrogen (H2) gas production by Steam Reforming of methane via pipeline to California then liquefied, re-gasified, and trucked to multiple H2 dispensing locations	California	North American Natural Gas	Hydrogen	151.01
Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed Hydrogen from co-product hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps) and transported by truck to fueling stations in California (Provisional)	Canada	Sodium Chlorate Production Process	Hydrogen	56.06
Compressed H2 produced in California from central SMR of North American fossil-based NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	NA	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51
Compressed H2 produced in California from electrolysis using California average grid electricity	NA	Grid Electricity (039)	Gaseous Hydrogen (HYG)	164.46
Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	151.01

[2] Current fuel pathways spreadsheet accessed online January, 2022, from: https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities

Applicant and Pathway Description	Facility Location	Feedstock	Fuel Type	Current Certified CI
Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	105.65
Compressed H2 from on-site reforming of NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	105.13
Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	176.43
Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using California average grid electricity	California	Grid Electricity (039)	Gaseous Hydrogen (HYG)	164.46
Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI HYER (F00226); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51
Fuel Producer: Element Markets EV, LLC (C1093); Facility Name: 32-505 Harry Oliver Trail (F00233); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51
Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Fuel Producer: Air Products and Chemicals, Inc. (C1042); Facility Name: APCI Wilmington Transfill (F00095); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67

Applicant and Pathway Description	Facility Location	Feedstock	Fuel Type	Current Certified CI
Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources.	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51

As can be seen in the table above, the CI for a gaseous hydrogen source can vary significantly depending on the production method and feedstock and any required compression and truck transport from production site to end-user. Liquefaction adds to the CI due to the additional energy demand.

The range in approved CIs is even more dramatic for RNG, which can range from as low as about -600 gCO_2e/MJ for some diary manure-to-RNG pathways and as high as positive 70+ gCO2e/MJ for some LFG to RNG pathways that include additional natural gas consumption.

Given the uncertainty and range in potential CIs for hydrogen and RNG supply, for the purposes of this analysis, GHD has considered 3 representative pathways and CI values for each fuel. For RNG, median CIs are taken for manure-to-RNG, source separated organic waste to RNG, and LFG or wastewater treatment plant biogas to RNG. For hydrogen, appropriate values are taken from the approved pathways for grey and green hydrogen sources, and the potential CI for hydrogen produced on-site via electrolysis from average Keene grid electric supply.

The CI of the baseline incumbent fuels used in Keene's gas grid is equally important for the GHG assessment results, as the GHG impact is evaluated by comparing the CI of the alternative fuels to the incumbent fuel being displaced. LPG is currently supplied to Zone 1 to provide a propane-air fuel mix in the gas grid, and CNG is currently supplied to Zone 2. The actual CIs for these will depend heavily on the source facility and required truck transport to Keene. Since the actual CIs are not known, we once again look at CARB approved pathways for the most relevant CI to use.

For LPG supply, there is only a single currently approved pathway and CI in CARB for "Fossil LPG from crude oil refining and natural gas processing used as a transport fuel", which is non-specific to a production facility and does not appear to include trucking the LPG from a production facility to end-use site (which of course will be project-specific). For CNG or LNG supply, there are a number of approved project-specific CIs and a single general CI for "Compressed natural gas from pipeline average North America". Project-specific CIs include transport to California for end-use, as well as varying compression, liquefaction, and re-gasification steps. The CIs selected for the purposes of the present GHG assessment are the only LPG pathway and the general CNG pathway as it is the most comparable to the CI score available for LPG. This means that the emissions associated with truck transport of these fuels from production facilities to Keene is not considered in this GHG evaluation, which is a notable limitation of the results.

GHD recommends that a project-specific CI assessment be completed for the actual potential alternative fuel sources and incumbent LPG and CNG supply sources. This information can then be used for a more accurate assessment of potential GHG emissions reductions, which may be vital for project funding, approvals, and community acceptance. GHD emphasizes that the GHG assessment presented in this report is indicative only and results will change once project-specific information is accounted for in the fuel CIs.

4.3 Assumptions

As described above, GHG emissions reductions were evaluated based on fuel consumption using the carbon intensities of the baseline and project fuels. The limitations and uncertainties associated with this approach are described in the previous section.

Assumptions and background data used in the GHG assessment include:

– Carbon intensities of fuels were determined from approved carbon intensities under the CARB LCFS Pathway Certified Carbon Intensities[3], or evaluated using the Argonne GREET Model[4]:
  - Grey hydrogen: 117.67 gCO_2e/MJ, the approved CI under CARB for central steam methane reforming (SMR) of natural gas to produce hydrogen without carbon capture and storage (CCS).
  - Green hydrogen: 0 gCO_2e/MJ, represents approved CI under CARB for hydrogen produced via electrolysis powered by 100% on-site renewable or nuclear electricity supply (no additional compression and transport needed as the hydrogen production is assumed co-located with the injection and blending site).
  - Hydrogen produced from Keene electric grid: 73 gCO_2e/MJ, determined by evaluating the CI for hydrogen from electrolysis in GREET using average New Hampshire electricity grid data from the Energy Information Administration (EIA)[5]. Electricity supply mix is 33% natural gas fired, which contributed 73 gCO_2e/MJ to the final CI results, 54% nuclear power, which contributes 0 gCO_2e/MJ, and 13% renewables, which likewise contributes 0 gCO_2e/MJ.
  - Propane: 83.19 gCO_2e/MJ of propane utilized, which is the approved CI under CARB for fossil liquified petroleum gas (LPG) from crude oil refining and natural gas processing.
  - Natural gas: 79.21 gCO_2e/MJ, which is the approved CI under CARB for average North America compressed natural gas in pipeline. This CI is selected for comparability with the only LPG CI available from CARB. Both CIs do not include emissions associated with truck transport to Keene and it is recommended that a project-specific CI assessment is completed to refine the GHG results.
  - Renewable natural gas (RNG): The CI for RNG can vary greatly depending on production method, energy consumption, co-products produced, and most importantly, attributable emissions offsets. Emissions offsets for utilizing organic waste diverted from landfill are for avoided landfill gas methane emissions, and emissions offsets for utilizing manure feedstock are for avoided manure methane emissions during stockpiling and land application. Emissions offsets vary from project to project resulting in vastly different CI scores for similar production processes. For the purposes of this assessment, GHD looked at 3 generalized/averaged CI scores for RNG:
    – RNG from manure: Dairy cattle manure to RNG projects have the lowest (most negative) CI scores in CARB, as low as -600 gCO_2e/MJ. The median of manure to RNG projects lands around -300 gCO_2e/MJ, which is used in this study to represent a likely CI for RNG from manure.
    – RNG from source separated organics (SSO): This represents RNG from the anaerobic digestion and subsequent biogas upgrading of food and/or yard waste, which can be collected from residential, commercial, or potentially industrial sources. Generally, SSO utilized to produce RNG can be considered diverted from landfill, resulting in moderately negative scores that range from close to 0 gCO_2e/MJ to -80 gCO_2e/MJ in the CARB approved pathways. A CI of -40 gCO_2e/MJ is used in the present study to represent this case.
    – RNG from landfill gas (LFG) or wastewater treatment plant (WWTP) biogas: This represents RNG produced from upgrading collected LFG or biogas at existing WWTP operations (typically from the anaerobic digestion of wastewater sludge). The CI results in CARB's database vary greatly for these projects, with scores from 28 to 67 gCO_2e/MJ for LFG to RNG pathways approved in 2020 and 2021, and from 19 to 52 gCO_2e/MJ for RNG from WWTP operations. For the purposes of this study, a median value of 35 gCO_2e/MJ is used to represent RNG from LFG or WWTP sludge.

[3] Current fuel pathways spreadsheet accessed online January, 2022, from: https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities
[4] The Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model, developed by Argonne National Laboratory and sponsored by the US Department of Energy (DOE), is generally the accepted model across the United States for evaluating fuel carbon intensities.
[5] EIA data for New Hampshire accessed January, 2022, from: https://www.eia.gov/state/data.php?sid=NH

– Other assumptions:
  - Propane-air fuel heating value: 0.748 million British thermal units (MMBTU) per thousand standard cubic feet (MCF), from the average of monthly 2021 propane/air delivery data provided by Liberty
  - LPG density: 1.885 kg/gallon
  - LPG energy density: 49.3 MJ/kg
  - Hydrogen heating value: 0.325 MMBTU/MCF
  - Hydrogen density: 2.362 kg/MCF
  - Hydrogen energy density: 142 MJ/kg
  - Natural gas heating value: 1.027 MMBTU/MCF
  - RNG heating value: for simplicity, assumed the same as natural gas. In reality, the RNG heating value will likely be slightly less than natural gas, although this will need to be confirmed by the RNG producer.
  - Customer base energy consumption: GHD's calculations are based on delivering the same energy content to customers as in the 2021 data provided by Liberty.

4.4 Results and Discussion

Detailed results for all scenarios assessed are provided in Appendix A. Table 4.2 below provides an overview of results for key potential scenarios, visualized in Figures 4.1 and 4.2 on the following page. Note that the comparison for change in emissions for Zone 1 is evaluated compared to the 100% natural gas scenario rather than the current baseline of propane-air fuel mixture, as natural gas represents the lower-emission and lower-cost scenario to compare the hydrogen and RNG blending options against.

Note in the that a positive value for change in emissions represents an increase in emissions, while a negative value represents a decrease in emissions.

Table 4.2 Summary of Results for Select Scenarios and Emissions Change from Baseline

Scenarios	Emissions	Change in Emissions from 100% NG Case	% Change
Zone 1			
Baseline Propane-Air Fuel	10,112.30	110.35	1.1%
100% Natural Gas (NG)	10,001.96	-	0.0%
NG + 20% Hydrogen Blending - Grey H2	10,341	339.46	3.4%
NG + 20% Hydrogen Blending - Green H2	9,290	(711.53)	-7.0%
NG + 50% RNG Blending - RNG from LFG/WWTP	7,211	(2,791.23)	-27.6%
NG + 50% RNG Blending - RNG from Dairy Manure	(13,940)	(23,941.69)	-236.8%
Zone 2			
Baseline Natural Gas	2,060.35	-	-
NG + 20% Hydrogen Blending - Grey H2	2,131	71.07	3.4%
NG + 20% Hydrogen Blending - Green H2	1,913	(147.76)	-7.2%
NG + 50% RNG Blending - RNG from LFG/WWTP	1,486	(574.40)	-27.9%
NG + 50% RNG Blending - RNG from Dairy Manure	(2,881)	(4,941.00)	-239.8%

As can be seen in the results, hydrogen blending only provides emissions reductions if low-carbon hydrogen, preferably green hydrogen with a carbon intensity of 0 gCO_2e/MJ, is secured. An on-site electrolyzer can be power by renewable energy, or perhaps connected to the Keene electric grid with a control system in place to optimize power consumption for periods of high nuclear and renewables generation. Producing hydrogen from electrolysis of electricity provided from natural gas firing is highly inefficient and significantly impacts the resulting CI of the produced hydrogen. Liberty should aim to avoid producing hydrogen from power during periods of high gas generation for this reason.

RNG blending presents a significant opportunity for emissions reductions, especially if low carbon intensity RNG can be secured. RNG blending is less technically challenging than hydrogen blending due to similar gas properties with natural gas, and can be initiated today without introducing additional safety or network integrity concerns.

Hydrogen blending on the other hand, is technically challenging with increased risk for pipeline and valve integrity, safety, network management, and end-use customers that must be evaluated and managed. This is discussed further in Section 5.

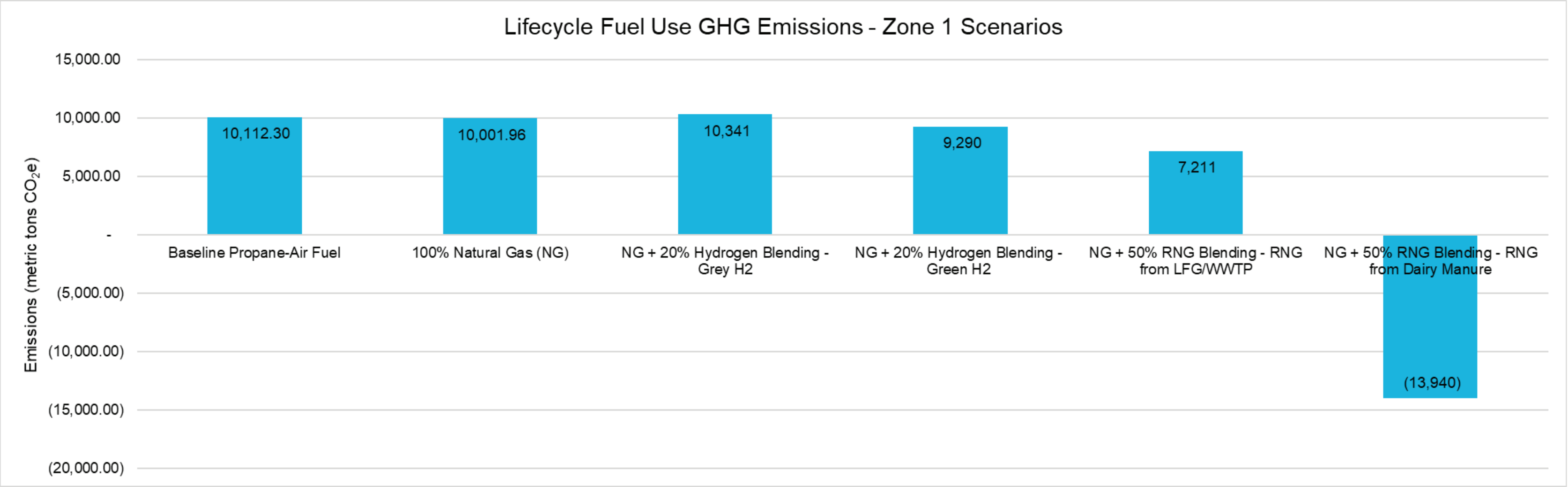


Figure 4.1 Emissions from Fuel Use for Select Zone 1 Scenarios

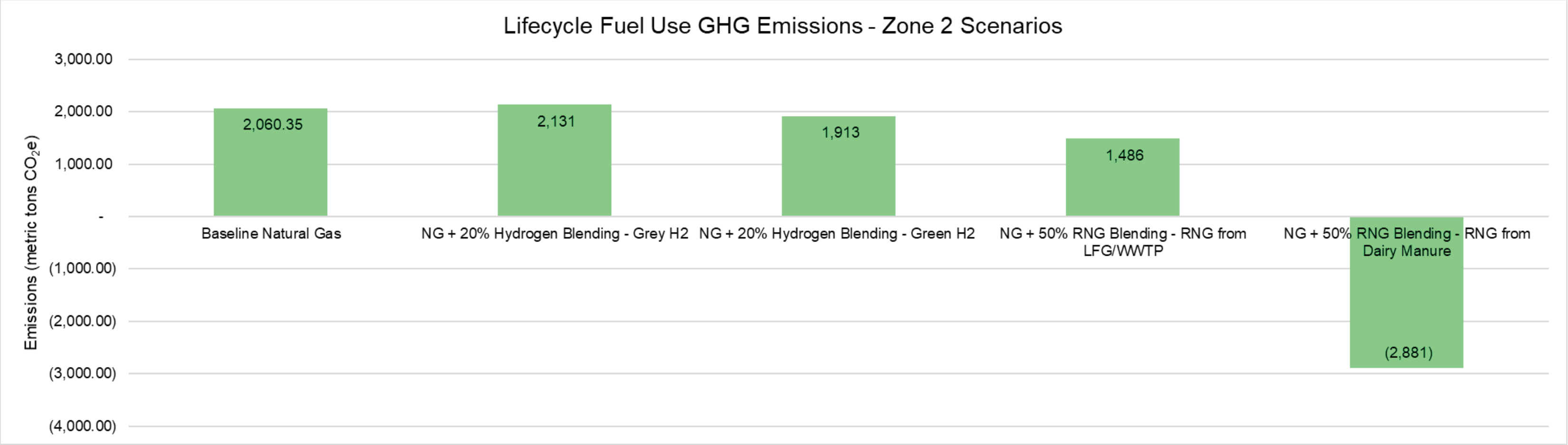


Figure 1.2 Emissions from Fuel Use for Select Zone 2 Scenarios

5. Technical Gas Blending Considerations

As of today, hydrogen blending in natural gas systems has been demonstrated successfully through several projects around the world. However, there is a notable lack of data and standards for blending, and remaining gaps in knowledge in key applications, that need to be addressed for blending to be implemented on a larger scale. This section discusses, at a high level, the technical considerations of hydrogen blending in natural gas and compatibility with Keene's gas supply infrastructure.

Notable hydrogen blending demonstration projects include:

– HyDeploy Keele Pilot, United Kingdom – Successfully demonstrated blends of up to 20% hydrogen by volume to date at the Keele University campus, supplying 100 residential homes and 30 faculty buildings. Phase 2 of HyDeploy will replicate this demonstration into a gas supply network in Northeast UK, feeding approximately 670 customers.

– Hawaii Gas Town Gas, US – Hawaii Gas has been delivering a town gas blend comprising approximately 12% hydrogen by volume to customers on the island of Oahu since the 1970s.

– University of California, Irvine (UCI), US – UCI has been blending and testing hydrogen in the campus' isolated gas distribution network since 2016, recognized as the first power-to-gas hydrogen blending pilot in mainland US. Blending up to 3.8% has been demonstrated.

– GRHYD, France – Led by ENGIE and involving a consortium of members, this is a power-to-hydrogen demonstration project in a small, isolated, low pressure gas distribution grid in France. Blending was successfully demonstrated for up to 20% hydrogen by volume.

– Power-to-Gas Ameland, Netherlands – Successful demonstration of up to 20% hydrogen blending in the Ameland islanded natural gas distribution network with a variety of customers. Prior to the demonstration, laboratory testing of end-use equipment up to 30% hydrogen was completed with no issues identified.

– ATCO residential appliance testing – ATCO has tested typical and vintage residential home appliances in Alberta, Canada, for up to 40% hydrogen by volume successfully.

– Testing Hydrogen Admixture for Gas Application (THyGA), Belgium – Testing and demonstration of hydrogen blending in various end-use equipment including residential/commercial gas appliances. A recent publication summarized the results to date in residential and commercial gas appliances, and is available open-source online[6].

5.1 Note on Percent Blend of Hydrogen

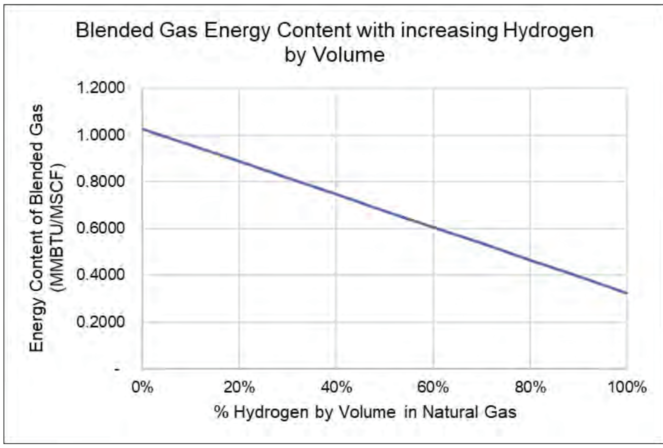
For the majority of this report, hydrogen blending levels in natural gas are discussed as a percent *by volume*. While discussing blend level on a percent by volume basis allows for consistent discussion and assessment across applications, it is important to understand that in many cases the impact of hydrogen admixing is heavily driven by the *partial pressure* of hydrogen in the mixture.

The partial pressure of hydrogen in a natural gas-hydrogen blend is the pressure exerted by the hydrogen component. The percent hydrogen blend is equivalent to the contribution of the partial pressure of hydrogen to the total gas mixture pressure. For example, in a 200 psi distribution pipeline, a 5% hydrogen blend by volume translates to 10 psi partial pressure of the hydrogen component. In a 1,200 psi transmission pipeline, a 5% hydrogen blend by volume translates to 60 psi hydrogen partial pressure. In a 5,000 psi underground storage site, a 5% hydrogen blend level corresponds to partial pressure of 250 psi.

[6] Leicher, J., *et al.,* (2022) ***The Impact of Hydrogen Admixture into Natural Gas on Residential and Commercial Gas Appliances***, in Energies (2022) 15(3), 777. Available online at https://www.mdpi.com/1996-1073/15/3/777

The partial pressure of hydrogen in the mixture is important to consider as it is often the governing factor on whether or not hydrogen has an effect on mechanisms such as diffusion or embrittlement of steel grades. The solubility of gases correlates with their partial pressure in the gaseous phase. Higher partial pressure corresponds to great risk of embrittlement and diffusion.

Further, due to the significantly lower energy content of hydrogen, percent blend by volume is significantly different than the percent blend by energy. Emissions reductions are correlated with the percent blend by energy rather than the percent blend by volume. Figure 5.1 below indicates the relationships between (a) blended gas energy content and hydrogen blend percent by volume, and (b) percent of hydrogen content by energy versus by volume.



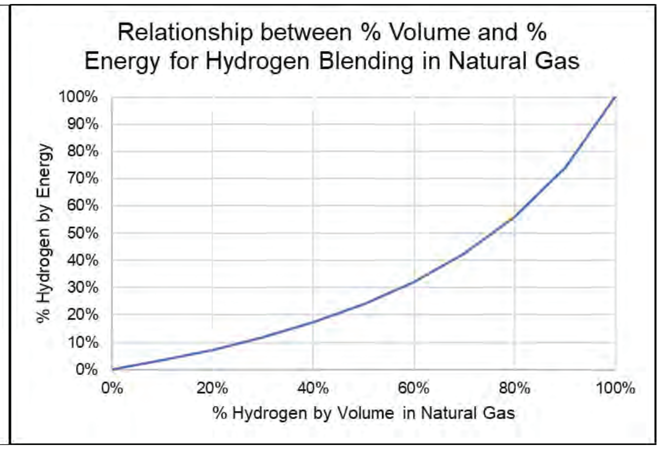


Figure 2.1 *Relationships between (a, left) blended gas energy content and hydrogen blend percent by volume, and (b, right) percent of hydrogen content by energy versus by volume*

5.2 Technical Considerations and Risks with Hydrogen Blending

Hydrogen is a substantially different molecule than methane – lighter, faster, and with a wider explosivity range. Hydrogen has been used in various industries for decades with established safety cases, codes, and standards. Hydrogen has a low energy density by volume (approximately ¼ that of gasoline, ⅓ of natural gas) but a high energy density by mass (approximately 3-times that of gasoline). Hydrogen burns fast, has a wide flammable region, high diffusivity, and low ignition energy when compared to natural gas. Admixing hydrogen in natural gas will impact various properties of the fuel, such as explosivity, dispersion, ignition, and flammability. This section discusses the technical considerations for hydrogen blending in a low pressure gas distribution system such as Keene's. Four key information sources are recommended for further details on the challenges briefly discussed here:

– Pipeline Research Council International's (PRCI's) 2020 *Emerging Fuels – Hydrogen: State-of-the-Art, Gap Analysis, and Future Project Roadmap,* prepared by GHD with input from subject matter experts from over 20 organizations
– The National Renewable Energy Laboratory's (NREL's) 2013 *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, which is currently being updated through the DOE initiative *HyBlend* (no published results as of yet)
– The European Gas Research Group's (GERG's) 2019 *Admissible Hydrogen Concentrations in Natural Gas Systems*
– The ThyGA research project's 2022 report The Impact of Hydrogen Admixture into Natural Gas on Residential and Commercial Gas Appliances

The key technical challenges for hydrogen blending can be summarize into the following topics:

– Pipeline and materials integrity
– Safety and risk
– Gas quality, metering and measurement
– End-use equipment compatibility

A brief overview of these challenges and importance to Liberty's Keene gas supply grid is discussed below, followed by a compatibility evaluation with Keene's existing gas infrastructure. The information discussed and conclusions drawn are based on desktop literature review of state-of-the-art hydrogen blending challenges and solutions, including experimental and field pilot results, and are meant to provide indicative information at this early stage of project planning. GHD recommends that, prior to initiating a hydrogen blending pilot, Liberty conduct a detailed hydrogen blending feasibility study including survey of statistically significant infrastructure and end-use equipment followed by engineering critical assessment, and quantitative risk assessment and/or hazards and opportunities study. An implementation and testing/monitoring plan can then be developed to ensure public safety and acceptance as the pilot begins.

5.2.1 Pipeline and Materials Integrity

Hydrogen does not cause degradation of polyethylene pipe. Rather, the primary concern is with permeation of hydrogen through the pipe leading to losses and impact to the blended gas ratio. Hydrogen has a significantly higher permeation rate than natural gas. Compared to methane, hydrogen permeation rates are 4 to 5 times higher through typical polymer pipes used in the U.S. natural gas distribution system [1]. Generally, plastic piping is preferred for hydrogen blending projects as hydrogen does not cause embrittlement and subsequent failure concerns for plastic pipe.

Hydrogen has an active electron which can easily migrate into the crystal structure of most metals, causing embrittlement and accelerated cracking and failure. High-strength steels are particularly susceptible, and the effect is drive by the partial pressure of hydrogen putting transmission systems at significantly higher risk than low pressure distribution systems. Steel pipes – and particularly the steel welds – used for pipeline infrastructure can suffer from hydrogen embrittlement and accelerated growth of cracking after continuous exposure to hydrogen. However, steel pipes in U.S. low-pressure distribution systems are primarily made of low-strength steel, typically API 5L A, B, X42, and X46, and these are generally not susceptible to hydrogen-induced embrittlement under normal operating conditions [1]. At the pressures and stress levels occurring in the natural gas distribution system, hydrogen induced failures are not major integrity concerns for steel pipes. For the other metallic pipes— including ductile iron, cast and wrought iron, and copper pipes—there is no concern of hydrogen damage under general operating conditions in natural gas distribution systems.

For valves and threaded or flanged connections, a higher leak rate by volume should be anticipated with hydrogen blending, but in general the amount of energy leaking is not expected to be higher as with natural gas. Threaded connections are widely used for steel distribution piping, especially on meter set assemblies, and a variety of thread sealants have been used. Threaded connections are common leak sources, even with 100% natural gas. It seems likely that the addition of hydrogen would increase leak rates, but additional data is needed to understand the magnitude of the impact.

Hydrogen permeates almost all materials and has the potential to diffuse into sealing materials causing damage. Specific design parameters regarding seal compression and base materials for the seals should be considered. Incompletely cured sealing materials (i.e. non-cross linked polymers) may cause the seal to appear greasy, with the liquid polymer coming out of the seal. The resulting loss in seal volume can cause the seal to no longer function properly (i.e. loss of compression). Some seal materials can become embrittled and/or have voids trapped inside of the material, which, when subjected to a rapid depressurization, could lead to total seal failure.

For the reasons discussed above, a hydrogen blending pilot project should be accompanied by a robust inspection and maintenance program to monitor system integrity.

5.2.2 Safety and Risk

Hydrogen blending impacts to key safety-related properties are summarized below.

– **Explosivity:** Studies have shown that there are virtually no changes to the lower explosivity limit (LEL) for hydrogen blending up to 10%, with only minor changes for higher blends to 100%. The upper explosivity limit (UEL) of the blended gas increases exponentially with increasing hydrogen addition, although the impact is negligible for blends to 10% hydrogen and minimal for blends up to 25% hydrogen. At blending levels of 50% or greater, there is a significant increase in explosivity severity. Table 5.1 and Figure 5.2 below provide a summary of theoretical and experimental data for explosivity risk impacts from hydrogen blending in methane and natural gas.

Table 5.1 – Explosion limits of methane/hydrogen and natural gas/hydrogen mixtures [2]

hydrogen fraction in fuel gas blend	Methane/hydrogen			natural gas/hydrogen		
	LEL	UEL	LOC	LEL	UEL	LOC
0 mole%	4.2	16.6	10.1	3.8	16.2	9.7
5 mole%	4.2	17.4	9.8	3.8	17.2	9.7
10 mole%	4.2	18.2	9.6	3.8	17.8	9.4
25 mole%	4.2	21.2	9.1	4.0	21.0	8.9
50 mole%	4.0	29.0	7.9	3.8	28.4	7.6
100 mole%	4.1	75.6	4.3	4.1	75.6	4.3

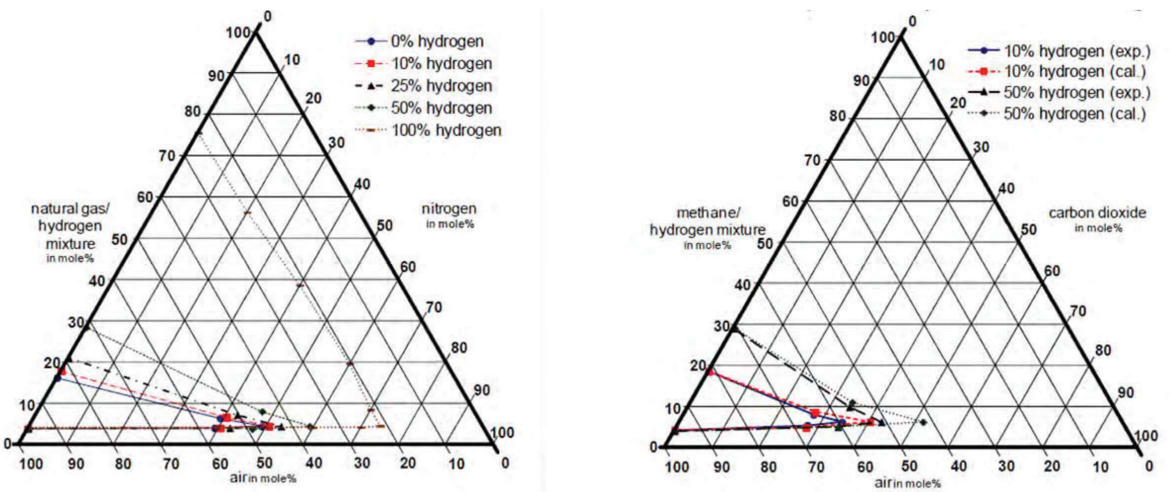


Figure 5.2 Explosive regions for: (Left) natural gas-hydrogen blends in nitrogen and air and (Right) methane-hydrogen blends in carbon dioxide and air [2]

– **Gas build-up and dispersion:** Hydrogen is a lighter and faster molecule that methane with higher diffusivity (approximately 4 times) and dispersion speed and lower density. Experimental research has shown gas flow rate increases for leaks as hydrogen concentration increases, thus causing an increased leak risk for hydrogen blending projects. However, this effect is minimal for low blend levels, becoming significant for blends of greater than 50% hydrogen by volume. The percent hydrogen in the gas mixture, height of the release point from the ground, wind conditions, flow rate of the leak, air/gas mixture and venting in the enclosure, and direction of the gas being released will influence the potential gas accumulation in an enclosure following a leak. There has been extensive experimental research in this area to prove the safety case for hydrogen blending, which has generally concluded that hydrogen and natural gas do not separate for leaks in ventilated, enclosed spaces, meaning that the natural gas odorant and other detection methods can generally be used for low blend levels.

- **Ignition:** Generally, minimum ignition energy decreases as the hydrogen content increases. There is sufficient experimental data on minimum ignition current (MIC) and maximum experimental safe gap (MESG) for methane-hydrogen blends with up to 20% hydrogen. The MIC of a gas can determine its sensitivity to electric or electrostatic sources. Methane-hydrogen blends containing less than or equal to 6% hydrogen have MIC ratios greater than 0.9; blends containing 8 to 14% hydrogen have MIC ratios between 0.8 and 0.9, and blends containing 16 to 20% hydrogen have MIC ratios less than 0.8 [3] [4] [5].
- **Flammability:** Hydrogen is highly flammable and has wider flammability limits than natural gas at ambient temperature and pressure. This relates to a flammability range in % by volume of 4.4–17% for pure natural gas and 4.0–75% for pure hydrogen. This wider flammability range of hydrogen needs to be considered in detailed risk assessment and safety review. Flammable limits and limiting oxygen for combustion for hydrogen-methane blends can be calculated using Le Chatelier's rule.
- **Safety Zones:** Safety zones are well defined for natural gas networks and equipment, typically governed by codes and standards applicable to each region. North America and Europe have their own hazardous location classification system (NFPA code in North America, ATEX directives in Europe). Area classifications are based on Classes, Divisions and Zones that together define hazardous conditions of a specific area. As discussed above, the introduction of hydrogen into natural gas networks impacts key safety characteristics such as flammability, explosivity, ignition and dispersion. Therefore, safety zone distances will need to be adjusted as a function of hydrogen blending percentage. There are no known resources addressing safety zone calculations for natural gas pipelines and equipment under hydrogen blending. This presents a notable gap that will need to be addressed for regulators to confidently adjust safety zones based on increasing hydrogen blending in distribution grids.
- **Flame Visibility:** Hydrogen burns hot and clean with a pale blue flame that is almost invisible during daylight hours and produces low radiant heat. A pure hydrogen fire is almost impossible to see with the naked eye, will not produce any smoke, and a person may not realize a fire is present until they are very close to the flame. Standard infrared flame (IR) detection is ineffective for hydrogen flames due to reduced flame luminosity, and therefore ultraviolet (UV) detection is required. For hydrogen blending in natural gas, increasing hydrogen content results in reduced flame visibility. Portable and stationary flame detectors may need to be replaced with units capable of UV flame detection as hydrogen blending increases. The figures below indicate the impact of hydrogen on flame visibility for low blend percentages, produced by Enbridge for the company's 2% hydrogen blending pilot in Markham, Ontario.

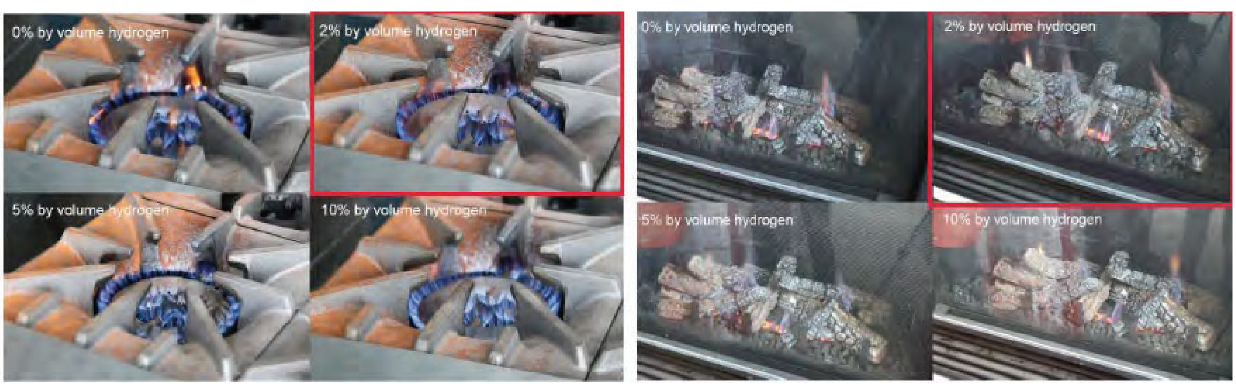


Figure 5.3 Stove (left) and fireplace (right) images of natural gas-hydrogen blends from 0% to 10% hydrogen by volume, sourced from Enbridge [6]

5.2.3 Gas Quality, Metering and Measurement

As discussed previously, hydrogen has a significantly lower calorific value by volume than natural gas and the introduction of hydrogen into a natural gas system will therefore reduce the energy content of delivered, blended gas. Accurate measurement and knowledge of the calorific value of delivered gas is important for a number of reasons. These include determining the transaction value of natural gas, quality control based on heating value standards, controlling plant combustion equipment for stable operation, and controlling air-fuel ratios for gas turbine generators that require precise combustion control.

Since the addition of hydrogen into natural gas changes the properties of the gas, accuracy and compatibility of existing metering equipment with the presence of hydrogen needs to be understood. Billing credits may be deemed necessary to ensure accurate billing for customers on an energy-content basis.

There are challenges with typical gas chromatography once hydrogen is introduced. Typical hydrocarbon gas chromatographs (GCs) existing in the gas network use helium as the gas carrier, which cannot carry and therefore cannot detect hydrogen content. Hydrogen impact on heating value measurements are related to the low sensitivity of currently employed GC thermal conductivity detectors (TCDs). Heating value measurement uncertainty increases with the amount of hydrogen added.

New GCs are being developed that may be compatible with up to 20% hydrogen by volume, where an argon carrier single column set or a dual-column with two carrier gases is used. Further testing is required to prove the accuracy of these solutions.

Alternatively, meters using sound and light measurements (i.e. RIKEN OPT-SONIC™) may be viable alternatives for accurately measuring hydrogen concentrations up to 10% by volume, although this technique is still under research and development.

Figure 5.4 H2Scan's HY-OPTIMA 2700 Series analyzer outputs hydrogen concentration in real time

There are commercial meter options for specifically measuring the hydrogen content in a mixed gas, which are not cross-sensitive to other gases. For example, the HY-OPTIMA™ 2700 Series Explosion-Proof In-Line Hydrogen Process Analyzer by H2Scan is a relatively newly commercialized solution specifically meant for hydrogen blending applications. This meter measures partial pressure of hydrogen in the process stream in real time, with one model (model 2710) validated for blends of 0.1% to 10% hydrogen and at least two others for 0.5% to 100%. The HY-OPTIMA™ 2700 Series uses a solid-state, non-consumable sensor that is configured to operate in process gas streams. The H2Scan thin film technology provides a direct hydrogen measurement that is not cross-sensitive to other gases.

Gas volume measurement can also be a challenge with hydrogen admixing, depending on the meter type. Hydrogen is considered a difficult industrial gas to measure, due to its low molecular weight and therefore low operating density. Traditional technologies such as differential pressure, vortex, or thermal mass experience difficulties measuring pure hydrogen flow. For hydrogen blending, inferential measurement meters such as orifice meters, ultrasonic meters and turbine meters may be less accurate with increasing hydrogen content, especially above 10%, while direct measurement meters (or positive displacement meters) such as diaphragm meters and rotary meters are expected to be less impacted by hydrogen addition.

5.2.4 End-Use Equipment Compatibility

Hydrogen blending impacts gas quality criteria such as relative densities, calorific values and Wobbe Indices of the fuel, as well as other key combustion parameters such as adiabatic combustion temperatures, flame shape and positioning, and laminar combustion velocities.

For residential and commercial end-use, natural gas is exclusively used as a fuel to provide low-temperature heat for space heating, cooking, or to heat water, to name the most common applications. Testing completed through a number of demonstration and experimental project (see the list of relevant projects at the beginning of Section 5 of this report) has shown that generally, hydrogen is expected to be acceptable in residential and commercial gas equipment for blends at least up to 20% by volume. However, a survey of end-use equipment in the network should be completed (to a statistically significant level) and evaluated against published experimental data for any gaps in confidence. As most gas appliances in operation today were not designed with hydrogen blending in mind, it is important to assess hydrogen acceptability on a case-by-case basis.

5.3 Hydrogen Blending Compatibility with Keene’s Gas Supply Infrastructure

Using the information discussed in Section 5.2 above and particularly relying on the conclusions published by PRCI, NREL, and GERG, Table 5.2 below presents the compatibility of Keene’s existing gas supply infrastructure with increasing hydrogen blending content by volume in natural gas operated at a maximum pressure of 60 psig.

Table 5.2 - Hydrogen Blending Compatibility with Keene's Gas Supply Infrastructure

Legend
No modifications required
Potential modification/replacement required, further investigation and data needed
Replacement needed with compatible alternative

Maximum operating pressure: 60 psig

	Compatibility with Hydrogen Blending at % H2 by volume in NG							
	2%	5%	10%	20%	30%	40%	50%	100%
System piping at 60 psi								
Plastic pipeline[1]								
Steel pipeline (cathodically protected)[2]								
Cast/wrought iron pipeline[3]								
System meters and valves								
Diaphragm flow meteres[4]								
Rotary flow meters[4]								
PE ball valves[5]								
Steel multi-turn gas valves[6]								
Customers and End-Use								
Residential/Commercial - building heating, stoves, fireplaces[7]								
Industrial[8]								

Notes:

1. PE piping is generally expected to accept hydrogen blending without material integrity issues. Little or no interaction between hydrogen gas (or any non-polar gas) and polyethylene should be expected. Green lighted to 30% blend by volume given successful demonstrations globally. Orange for 50% and above due to lack of experimental data and demonstration.

2. H_2 blending poses embrittlement and subsequent fracture concerns for high strength steels in high pressure systems. The steel grades (API 5L A, B, X42 and X46) used in natural gas distribution pipeline are relatively low strength steels, and 60 psi operating pressure is relatively low pressure compared to transmission systems. The predominant concern for low strength steels is loss of tensile ductility or blistering, and with hydrogen, they usually fail in a ductile mode instead of catastrophic brittle fracture. Fatigue cracking could become an issue with frequent pressure cycling. Blends above 5% should be initiated carefully with increased monitoring and inspections to evaluate system integrity.
3. Many cast iron systems in the US were installed over 50 years ago and originally used to transport town gas, which contained as much as 10-30% hydrogen. However, given the age of these assets, Liberty may wish to err on the side of caution by replacing iron pipe sections with plastic ahead of hydrogen introduction.
4. Direct measurement meters (or positive displacement meters) such as diaphragm meters and rotary meters have been found to be less impacted by hydrogen addition than inferential meters such as ultrasonic and orifice meters. It is unclear whether these meter types will be fully compatible with 100% hydrogen gas flows. Accuracy and safety (through increased hydrogen leakage) will possibly decrease as more hydrogen is blended into the mix but the practical upper limit is not yet known and may vary from model to model.
5. The main concern with valves in the low-pressure distribution system is higher leakage due to hydrogen's high diffusivity and low density. The NaturalHy project found that blends of up to 30% hydrogen by volume do not significantly increase leak risk.
6. Steel valves may be susceptible to fatigue cracking under hydrogen service. Increased monitoring and inspection recommended for any percent hydrogen blend, or full replacement with PE valves ahead of hydrogen introduction.
7. Multiple assessments of typically residential/commercial natural gas equipment have been completed for blending demonstration projects. Blending of up to 20% does not require modifications, and some evaluations have shown no issues with blending up to 40% (ex. ATCO). However, some modification may be required for higher blends (ex. replacing burner tips), which should be assessed.
8. Generally, gas engines, turbines, and boilers can accept up to 5% hydrogen without modifications due to designed gas quality limits. Higher blends need to be evaluated on case by case basis, and the OEM should be contacted for hydrogen compatibility limits. Some boilers may be able to handle up to 30%, and many new turbines and engines are being designed to handle 30%+ hydrogen blending. Older equipment is of higher concern and will likely require replacement for blends above 5%. Any customers using direct-fired equipment (i.e. kilns) may need to be isolated from hydrogen as the hydrogen can impact product quality even at low blends of 2%.

6. Recommendations

Based on Liberty's proposed plan to convert Zone 1 from a propane-air system to LNG/CNG, the overall carbon intensity for both supply options are similar, however the opportunity to blend renewable natural gas (RNG) into the CNG/LNG supply mix provides a significant reduction in carbon intensity as shown in Table 3.2.

Development of a hydrogen blending demonstration program provides a pathway to improve decarbonization options over time and creates the ability to define infrastructure modifications, hydrogen production options and an opportunity to expand Liberty's customer base in Keene

Below is a recommended implementation schedule.

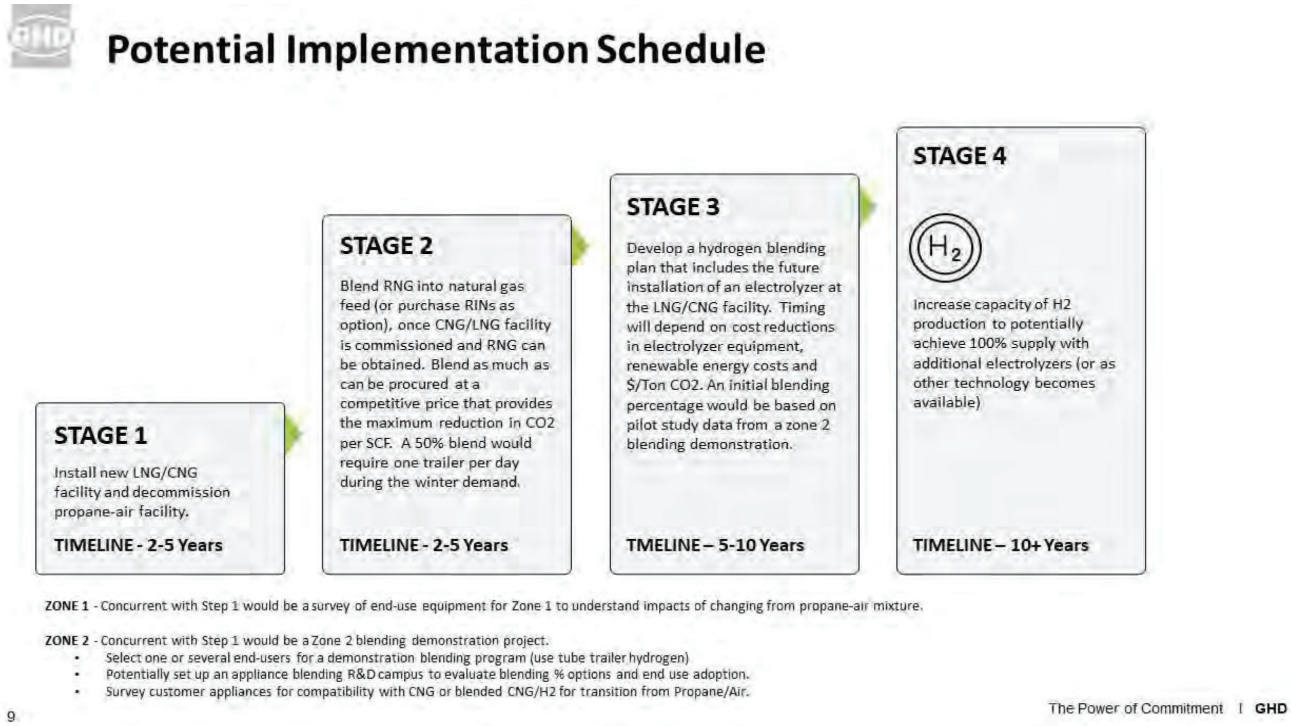


Figure 5.5 Potential Implementation Schedule

Stage 1: Install new LNG/CNG facility and decommission propane-air facility.
Short-Term (2-5 years).

Stage 2: Blend RNG into natural gas feed, once CNG/LNG facility is commissioned and RNG can be obtained. Blend as much as can be procured at a competitive price that provides the maximum reduction in CO2 per SCF. A 50% blend would require one trailer per day during the winter demand.
Short-Term (2-5 years)

Stage 3: Develop a hydrogen production and blending plan that includes the future installation of an electrolyzer at the LNG/CNG facility: Timing will depend on anticipated cost reductions in electrolyzer equipment and renewable energy costs as well as any market-based costs per ton of CO2. An initial blending percentage would be based on pilot study data from a zone 2 blending demonstration.
Mid-Term (5-10 years).

Stage 4: Increase capacity of H2 production to potentially achieve 100% supply with additional electrolyzers (or as other technology that becomes available)
Long-Term (10+ years)

Concurrent with Step 1 would be a survey of end-use equipment for Zone 1 to understand impacts of changing from propane-air mixture.

The implementation of the pilot program for Zone 2 would provide the following:

- Early adoption of H2 at a minimized overall project cost and to demonstrate safe and reliable use.
- Higher probability of receiving either state or federal funding.
- Provides a well-defined community, and fire marshal engagement plan based on a smaller scale (reduced overall safety and risk issues).
- Allows for further piping and component and end user survey and analysis prior to additional blending or customer system upgrades.
- Allows for future expansion as piping systems improve and customer base increases.
- Allows for further procurement options for renewable power sources for the electrolyzer.

Additional Value-added opportunities:

Since the energy demand in Keene is seasonal, any capex invested for hydrogen supply will not be fully utilized during low demand months.

1. Consider producing hydrogen (if via electrolysis) for other potential applications such as fuel cell vehicle H2 fueling program, EV fast charging and back-up power for critical facilities (police, fire, first responders, etc). Additional funding would be required. This improves the overall economics and capacity factor of the electrolyzer unit.
2. Consider utilizing the heat given off from the electrolyzer (up to 50% of the total energy input) to pre-heat any of the high pressure CNG prior to let-down. This could improve the overall economics and efficiency of the electrolyzer system.
3. Investigate tax credit and other funding opportunities for renewable H2 production, grants and NH-based appliance incentive programs for eventual transition to CNG.
4. Consider development of an Advanced Fuel Lab concept in NYS. The concept consists of building a series of small sheds (buildings) that can be strategically placed to simulate a typical “community” setting. Each shed could house different NG appliances such as furnaces, heaters, hot water tanks, stoves, cooktops, etc. Each shed would be supplied NG via conventional residential delivery (plastic pipe, regulators, meters).

   Hydrogen would be supplied via cylinders such that the overall onsite storage capacity of hydrogen was minimized. GHD or others can design a hydrogen blending system that would include mass flow controllers/meters, tubing, instrumentation and controls, safety features, etc, that could test various blending percentages of hydrogen. Small flowrates (500 SCFH Max) would suffice for appliance testing and the blending site could be set up at a Liberty or Algonquin training or testing facility that already has access to land and NG supply. This creates a low cost, highly effective means to engage Liberty and Algonquin staff, local permitting entities, local fire marshals and local stakeholders prior to expanding to a full-scale blending demonstration.

   The lab also provides media, PR thought leadership and training value to the Liberty and Algonquin brands.

7. References

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Appendix A

Detailed Results from GHG Assessment of Gas Supply Options

Zone 1 - Propane/Air Fuel Mix in Baseline, Pure NG, NG + H2, and NG + RNG in Project

GHD, January 2022

Assumptions and Unit Conversions

Propane		
Propane-Air Mix Heating value	0.748	MMBTU/MCF
Lifecycle CI of LPG	83.19	gCO2e/MJ Propane
LPG density	1.885	kg/gallon
LPG energy density	49.3	MJ/kg

Hydrogen		
Heating value	325	BTU/SCF
	0.325	MMBTU/MSCF
Density	2.362	kg/1000SCF
Lifecycle carbon intensities		
Grey - trucked	117	gCO2e/MJ
Keene Grid - on-site	73	gCO2e/MJ
100% Solar/Wind avg	0	gCO2e/MJ
Energy density (HHV)	142	MJ/kg

Natural Gas		
Heating value	1027	BTU/SCF
	1.027	MMBTU/MSCF
Lifecycle CI	79.21	gCO2e/MJ

Renewable Natural Gas (RNG)		
Heating value	Assumed same as NG for simplicity.	
Lifecycle carbon intensities		
RNG from manure	-300	gCO2e/MJ
RNG from SSO AD	-40	gCO2e/MJ
RNG from WWTP/LFG	35	gCO2e/MJ

Conversions		
1 MMBTU =	1055	MJ

Replacing Propane-Air Fuel with Natural Gas

	Baseline (2021 Data)					Natural Gas Equivalent for same MMBTU			
	LPG Use	**Propane/Air Fuel Mix**			**Fuel Use Emissions**	**Natural Gas Use**		**Fuel Use Emissions**	**Change in Emissions**
Month	Gallons	MCF	MMBTU	BTU/SCF	tonnes CO2e	MCF	MMBTU	tonnes CO2e	tonnes CO2e
January	227,988	28,010	20,861	745	1,762.55	20,312.91	20,861.36	1,743.31	(19.24)
February	216,424	26,581	19,803	745	1,673.15	19,282.60	19,803.23	1,654.89	(18.26)
March	164,196	20,156	15,024	745	1,269.38	14,629.27	15,024.26	1,255.53	(13.86)
April	99,652	12,234	9,118	745	770.40	8,878.63	9,118.36	761.99	(8.41)
May	59,861	7,330	5,477	747	462.78	5,333.40	5,477.40	457.73	(5.05)
June	40,917	5,002	3,744	749	316.32	3,645.56	3,743.99	312.87	(3.45)
July	38,250	4,672	3,500	749	295.71	3,407.94	3,499.95	292.48	(3.23)
August	38,209	4,614	3,496	758	295.39	3,404.28	3,496.20	292.17	(3.22)
September	42,237	5,139	3,865	752	326.53	3,763.16	3,864.77	322.97	(3.56)
October	59,879	7,324	5,479	748	462.92	5,335.00	5,479.05	457.87	(5.05)
November	142,849	17,508	13,071	747	1,104.35	12,727.33	13,070.97	1,092.30	(12.05)
December*	177,577	21,788	16,249	746	1,372.83	15,821.81	16,249.00	1,357.87	(14.96)
Totals	1,308,039	160,358	119,689	748	10,112.30	116541.9026	119688.5339	10001.95785	(110.35)

* Assumed totals via averages for first 7 days of the month

Hydrogen Blending in Natural Gas Scenarios - Quantities & Emissions Offsets

Hydrogen blending quantities for 2, 5, 10, 15, and 20% hydrogen

				2%	by volume	0.62%	by energy	5%	by volume	1.59%	by energy
	100% Natural Gas			2% Hydrogen Blend				5% Hydrogen Blend			
MMBtu/MCF	1.0270	MMBTU/MCF		1.02178	MMBTU/MCF			1.0005	MMBTU/MCF		
Month	NG MCF	MMBTU	NG MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	20,312.91	20,861.36	22,008,733	20,417	964	21,871,776	136,956.7	20,852	2463	21,659,041	349,691.8
February	19,282.60	19,803.23	20,892,406	19,381	916	20,762,396	130,010.0	19,794	2338	20,560,452	331,954.7
March	14,629.27	15,024.26	15,850,597	14,704	695	15,751,961	98,635.7	15,018	1774	15,598,750	251,846.6
April	8,878.63	9,118.36	9,619,867	8,924	422	9,560,004	59,862.9	9,114	1076	9,467,019	152,847.9
May	5,333.40	5,477.40	5,778,658	5,361	253	5,742,699	35,959.6	5,475	647	5,686,842	91,815.8
June	3,645.56	3,743.99	3,949,907	3,664	173	3,925,327	24,579.6	3,742	442	3,887,147	62,759.2
July	3,407.94	3,499.95	3,692,449	3,425	162	3,669,471	22,977.5	3,498	413	3,633,780	58,668.5
August	3,404.28	3,496.20	3,688,491	3,422	162	3,665,538	22,952.9	3,495	413	3,629,885	58,605.6
September	3,763.16	3,864.77	4,077,332	3,782	179	4,051,960	25,372.6	3,863	456	4,012,549	64,783.8
October	5,335.00	5,479.05	5,780,396	5,362	253	5,744,425	35,970.5	5,477	647	5,688,553	91,843.4
November	12,727.33	13,070.97	13,789,873	12,792	604	13,704,060	85,812.1	13,065	1543	13,570,768	219,104.2
December	15,821.81	16,249.00	17,142,695	15,903	751	17,036,019	106,676.2	16,242	1918	16,870,319	272,376.4
Totals	116,541.9	119,688.5	126,271,403	117,137.3	5,533.6	125,485,637	785,766.3	119,634.7	14,128.9	124,265,105	2,006,297.8

	10%	by volume	3.29%	by energy	15%	by volume	5.13%	by energy	20%	by volume	7.11%	by energy
	10% Hydrogen Blend				15% Hydrogen Blend				20% Hydrogen Blend			
MMBtu/MCF	0.9649	MMBTU/MCF			0.9294	MMBTU/MCF			0.8938	MMBTU/MCF		
Month	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	21,620	5107	21,283,582	725,151.1	22,447	7953	20,879,398	1,129,335.0	23,340	11026	20,443,062	1,565,670.8
February	20,524	4848	20,204,036	688,370.0	21,309	7550	19,820,354	1,072,052.9	22,156	10467	19,406,150	1,486,256.9
March	15,571	3678	15,328,346	522,250.8	16,166	5728	15,037,255	813,342.3	16,809	7941	14,723,007	1,127,589.6
April	9,450	2232	9,302,908	316,958.6	9,812	3476	9,126,242	493,624.6	10,202	4819	8,935,523	684,344.0
May	5,677	1341	5,588,261	190,397.2	5,894	2088	5,482,138	296,520.5	6,128	2895	5,367,573	411,085.8
June	3,880	916	3,819,764	130,142.8	4,029	1427	3,747,225	202,681.7	4,189	1979	3,668,916	280,990.9
July	3,627	857	3,570,789	121,660.0	3,766	1334	3,502,978	189,470.8	3,916	1850	3,429,773	262,675.7
August	3,623	856	3,566,961	121,529.6	3,762	1333	3,499,223	189,267.7	3,912	1848	3,426,097	262,394.1
September	4,005	946	3,942,991	134,341.3	4,159	1473	3,868,112	209,220.3	4,324	2043	3,787,277	290,055.8
October	5,678	1341	5,589,941	190,454.4	5,896	2089	5,483,786	296,609.7	6,130	2896	5,369,187	411,209.4
November	13,546	3200	13,335,519	454,353.3	14,065	4983	13,082,272	707,600.3	14,624	6908	12,808,880	980,992.5
December	16,840	3978	16,577,872	564,823.3	17,484	6195	16,263,051	879,643.8	18,180	8588	15,923,187	1,219,507.6
Totals	124,042.4	29,298.8	122,110,971	4,160,432.5	128,787.4	45,629.4	119,792,034	6,479,369.4	133,909.7	63,259.0	117,288,630	8,982,773.1

GHG Emission & Reductions - Annual Totals

	Baseline - Propane	100% NG		2% Hydrogen Blend		5% Hydrogen Blend		10% Hydrogen Blend		15% Hydrogen Blend		20% Hydrogen Blend	
	Emissions from Fuel Use (Lifecycle)	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline
	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e
Grey H2	10,112.30	10,001.96	(110.35)	10,031.65	(80.65)	10,077.78	(34.53)	10,159.18	46.88	10,246.81	134.51	10,341.42	229.11
Keene grid H2	10,112.30	10,001.96	(110.35)	9,997.08	(115.23)	9,989.50	(122.80)	9,976.12	(136.18)	9,961.72	(150.58)	9,946.17	(166.13)
Green H2	10,112.30	10,001.96	(110.35)	9,939.72	(172.59)	9,843.04	(269.26)	9,672.41	(439.89)	9,488.73	(623.58)	9,290.43	(821.87)

RNG Blending Scenarios - Quantities & Emissions Offsets

RNG Blending Quantities

				20%				50%			
	100% Natural Gas			20% RNG Blend by Volume				50% RNG Blend by Volume			
Month	NG MCF	MMBTU	NG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ
January	20,312.9	20,861.4	22,008,732.7	16,250.3	4,062.6	17,606,986.1	4,401,746.5	10,156.5	10,156.5	11,004,366.3	11,004,366.3
February	19,282.6	19,803.2	20,892,406.4	15,426.1	3,856.5	16,713,925.1	4,178,481.3	9,641.3	9,641.3	10,446,203.2	10,446,203.2
March	14,629.3	15,024.3	15,850,596.8	11,703.4	2,925.9	12,680,477.5	3,170,119.4	7,314.6	7,314.6	7,925,298.4	7,925,298.4
April	8,878.6	9,118.4	9,619,867.0	7,102.9	1,775.7	7,695,893.6	1,923,973.4	4,439.3	4,439.3	4,809,933.5	4,809,933.5
May	5,333.4	5,477.4	5,778,658.3	4,266.7	1,066.7	4,622,926.6	1,155,731.7	2,666.7	2,666.7	2,889,329.1	2,889,329.1
June	3,645.6	3,744.0	3,949,906.6	2,916.4	729.1	3,159,925.3	789,981.3	1,822.8	1,822.8	1,974,953.3	1,974,953.3
July	3,407.9	3,500.0	3,692,448.8	2,726.3	681.6	2,953,959.1	738,489.8	1,704.0	1,704.0	1,846,224.4	1,846,224.4
August	3,404.3	3,496.2	3,688,490.9	2,723.4	680.9	2,950,792.7	737,698.2	1,702.1	1,702.1	1,844,245.5	1,844,245.5
September	3,763.2	3,864.8	4,077,332.3	3,010.5	752.6	3,261,865.9	815,466.5	1,881.6	1,881.6	2,038,666.2	2,038,666.2
October	5,335.0	5,479.0	5,780,395.9	4,268.0	1,067.0	4,624,316.7	1,156,079.2	2,667.5	2,667.5	2,890,198.0	2,890,198.0
November	12,727.3	13,071.0	13,789,872.5	10,181.9	2,545.5	11,031,898.0	2,757,974.5	6,363.7	6,363.7	6,894,936.3	6,894,936.3
December	15,821.8	16,249.0	17,142,695.0	12,657.4	3,164.4	13,714,156.0	3,428,539.0	7,910.9	7,910.9	8,571,347.5	8,571,347.5
Totals	116,541.9	119,688.5	126,271,403	93,234	23,308	101,017,123	25,254,281	58,271	58,271	63,135,702	63,135,702

RNG Blending Emissions and Emissions Reductions from Baseline

	Baseline - Propane	100% NG		20% RNG Blend		50% RNG Blend	
	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions from Baseline tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e
RNG from manure	10,112.30	10,001.96	(110.35)	425.28	(9,687.02)	(13,939.73)	(24,052.03)
RNG from SSO AD	10,112.30	10,001.96	(110.35)	6,991.40	(3,120.91)	2,475.55	(7,636.75)
RNG from WWTP/LFG	10,112.30	10,001.96	(110.35)	8,885.47	(1,226.84)	7,210.73	(2,901.57)

Zone 2 - Natural Gas in Baseline, NG + H2 and NG + RNG in Project

Assumptions and Unit Conversions

Hydrogen		
Heating value	325	BTU/SCF
	0.325	MMBTU/MSCF
Density	2.362	kg/1000SCF
Lifecycle carbon intensities		
Grey - trucked	117	gCO2e/MJ
Keene Grid - on-site	73	gCO2e/MJ
100% Solar/Wind avg	0	gCO2e/MJ
Energy density (HHV)	142	MJ/kg

Natural Gas		
Heating value	1027	BTU/SCF
	1.027	MMBTU/MSCF
Lifecycle CI	79	gCO2e/MJ

Renewable Natural Gas (RNG		
Heating value	Assumed same as NG for simplicity.	
Lifecycle carbon intensities		
RNG from manure	-300	gCO2e/MJ
RNG from SSO AD	-40	gCO2e/MJ
RNG from WWTP/LFG	35	gCO2e/MJ

Conversions		
1 MMBTU =	1055	MJ

Hydrogen Blending Scenarios - Quantities & Emissions Offsets

Hydrogen blending quantities

				2% by volume		0.63% by energy		5% by volume		1.60% by energy	
	Baseline - 0% H2			2% Hydrogen Blend				5% Hydrogen Blend			
MMBtu/MCF	1.0274 MMBTU/MCF			1.0130 MMBTU/MCF				0.9919 MMBTU/MCF			
Month	NG MCF	MMBTU	NG MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	3597.3	3690.9	3,893,900	3644	172	3,869,457	24,442.1	3721	439	3,831,497	62,402.6
February	3186.9	3271.7	3,451,644	3230	153	3,429,977	21,666.0	3298	390	3,396,328	55,315.1
March	2699.9	2772.9	2,925,410	2737	129	2,907,047	18,362.9	2796	330	2,878,528	46,881.8
April	1701.7	1745.8	1,841,819	1723	81	1,830,258	11,561.1	1760	208	1,812,303	29,516.5
May	1385	1420.2	1,498,311	1402	66	1,488,906	9,404.9	1432	169	1,474,299	24,011.5
June	1029.4	1059	1,117,245	1045	49	1,110,232	7,013.0	1068	126	1,099,340	17,904.7
July	1100.5	1129.4	1,191,517	1115	53	1,184,038	7,479.2	1139	134	1,172,422	19,094.9
August	949.6	971.2	1,024,616	959	45	1,018,184	6,431.5	979	116	1,008,196	16,420.2
September	1114.5	1144	1,206,920	1129	53	1,199,344	7,575.9	1153	136	1,187,578	19,341.8
October	1346.5	1386.2	1,462,441	1368	65	1,453,261	9,179.8	1398	165	1,439,004	23,436.7
November	2598.8	2686.2	2,833,941	2652	125	2,816,152	17,788.7	2708	320	2,788,525	45,416.0
December	3350.5	3443.2	3,632,576	3399	161	3,609,774	22,801.8	3471	410	3,574,361	58,214.7
Totals	24,060.6	24,720.7	26,080,338.5	24,404.4	1,152.9	25,916,632	163,706.8	24,922.6	2,943.4	25,662,382	417,956.5

	10% by volume		3.32% by energy		**15%** by volume		5.17% by energy		**20%** by volume		7.17% by energy	
	10% Hydrogen Blend				15% Hydrogen Blend				20% Hydrogen Blend			
MMBtu/MCF	0.9568 MMBTU/MCF				0.9217 MMBTU/MCF				0.8866 MMBTU/MCF			
Month	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	3858	911	3,764,516	129,383.6	4004	1419	3,692,433	201,466.2	4163	1967	3,614,643	279,256.2
February	3419	808	3,336,955	114,688.7	3550	1258	3,273,059	178,584.3	3690	1743	3,204,104	247,539.2
March	2898	685	2,828,206	97,203.4	3008	1066	2,774,052	151,357.6	3128	1477	2,715,610	209,799.6
April	1825	431	1,780,620	61,198.6	1894	671	1,746,525	95,293.7	1969	930	1,709,731	132,088.5
May	1484	351	1,448,526	49,784.8	1541	546	1,420,790	77,521.0	1602	757	1,390,858	107,453.4
June	1107	261	1,080,122	37,123.0	1149	407	1,059,440	57,805.1	1194	564	1,037,120	80,124.7
July	1180	279	1,151,926	39,590.9	1225	434	1,129,869	61,647.8	1274	602	1,106,066	85,451.2
August	1015	240	990,571	34,045.2	1054	373	971,603	53,012.5	1095	517	951,134	73,481.7
September	1196	282	1,166,817	40,102.7	1241	440	1,144,475	62,444.8	1290	610	1,120,364	86,555.9
October	1449	342	1,413,848	48,592.9	1504	533	1,386,776	75,665.1	1564	739	1,357,560	104,880.9
November	2807	663	2,739,777	94,164.1	2914	1033	2,687,316	146,625.1	3030	1431	2,630,701	203,239.8
December	3599	850	3,511,875	120,700.6	3736	1324	3,444,630	187,945.6	3884	1835	3,372,061	260,515.0
Totals	25,836.9	6,102.7	25,213,760	866,578.4	26,820.8	9,502.6	24,730,970	1,349,368.8	27,882.6	13,171.7	24,209,952	1,870,386.1

GHG Emission & Reductions - Annual Totals

	Baseline	**2% Hydrogen Blend**		**5% Hydrogen Blend**		**10% Hydrogen Blend**		**15% Hydrogen Blend**		**20% Hydrogen Blend**	
	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e
Grey H2	2,060.35	2,067	6	2,076	16	2,093	33	2,112	51	2,131	71
Keene grid H2	2,060.35	2,059	(1)	2,058	(3)	2,055	(5)	2,052	(8)	2,049	(11)
Green H2	2,060.35	2,047	(13)	2,027	(33)	1,992	(68)	1,954	(107)	1,913	(148)

RNG Blending Scenarios - Quantities & Emissions Offsets

RNG Blending Quantities

				20%				50%			
	Baseline - 0% RNG			20% RNG Blend by Volume				50% RNG Blend by Volume			
Month	NG MCF	MMBTU	NG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ
January	3597.3	3690.9	3,893,900	2877.84	719.46	3,118,096	779,524	1798.65	1798.65	1,948,810	1,948,810
February	3186.9	3271.7	3,451,644	2549.52	637.38	2,762,367	690,592	1593.45	1593.45	1,726,479	1,726,479
March	2699.9	2772.9	2,925,410	2159.92	539.98	2,340,241	585,060	1349.95	1349.95	1,462,651	1,462,651
April	1701.7	1745.8	1,841,819	1361.36	340.34	1,475,013	368,753	850.85	850.85	921,883	921,883
May	1385	1420.2	1,498,311	1108	277	1,200,501	300,125	692.5	692.5	750,313	750,313
June	1029.4	1059	1,117,245	823.52	205.88	892,272	223,068	514.7	514.7	557,670	557,670
July	1100.5	1129.4	1,191,517	880.4	220.1	953,900	238,475	550.25	550.25	596,188	596,188
August	949.6	971.2	1,024,616	759.68	189.92	823,102	205,775	474.8	474.8	514,439	514,439
September	1114.5	1144	1,206,920	891.6	222.9	966,035	241,509	557.25	557.25	603,772	603,772
October	1346.5	1386.2	1,462,441	1077.2	269.3	1,167,130	291,783	673.25	673.25	729,456	729,456
November	2598.8	2686.2	2,833,941	2079.04	519.76	2,252,609	563,152	1299.4	1299.4	1,407,880	1,407,880
December	3350.5	3443.2	3,632,576	2680.4	670.1	2,904,173	726,043	1675.25	1675.25	1,815,108	1,815,108
Totals	24,060.6	24,720.7	26,080,339	19,248	4,812	20,855,439	5,213,860	12,030	12,030	13,034,650	13,034,650

RNG Blending Emissions and Reductions

	Baseline	20% RNG Blend		50% RNG Blend	
	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e
RNG from manure	2,060.35	83	(1,977)	(2,881)	(4,941)
RNG from SSO AD	2,060.35	1,439	(621)	508	(1,552)
RNG from WWTP/LFG	2,060.35	1,830	(230)	1,486	(574)

Appendix B

Draft Liberty Utilities Regulatory Review Report

Regulatory Review

Keene, New Hampshire Project

Liberty Utilities

March 23, 2022

The Power of Commitment

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Printed date	2022-04-18 3:27:00 PM
Last saved date	April 18, 2022
File name	C:\Users\cbravo\Desktop\12569693-RPT-2-Liberty Utilities Regulatory Review - RD Edit - March 21 2022 (002).docx
Author	Fred Taylor
Project manager	Morgan MacGregor
Client name	Liberty Utilities
Project name	Liberty Keene Gas Supply Upgrade
Document title	Regulatory Review | Keene, New Hampshire Project
Revision version	Rev [00]
Project number	12569693-RPT-2

Document status

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S0	DRAFT	Fred Taylor	Rob Dysiewicz		Fred Taylor		

The Power of Commitment

Executive summary

This report is prepared for Liberty Utilities (Liberty) to provide key regulatory considerations for integrating hydrogen into Liberty's current or future assets and operations to support Liberty's Keene Gas Supply Upgrade Strategy and other U.S. projects, specific to hydrogen. These key considerations will need to be further tracked and evaluated by Liberty as policies and regulations develop further regarding the green and blue hydrogen economy. There are currently regulations that govern grey hydrogen production, storage, distribution and use but significant policies and regulatory changes are being developed to support green and blue hydrogen supply chains (e.g., blending with natural gas and carbon sequestration). It also is apparent that significant funding and incentives will continue to be put in place to support cleaner hydrogen use and this is important for industry until supply chain costs decrease to make acceptance more economically feasible. The faster international growth of cleaner hydrogen supply chains is also important to track to see how they have developed and the policies and regulatory changes that have been adopted to support this growth. There is a significant overlap with other considerations in the regulatory requirements for the design, permitting, installation and use of hydrogen in operations and as such and for completeness this report should be read in conjunction with the separate Fuel Source and System Review Report.

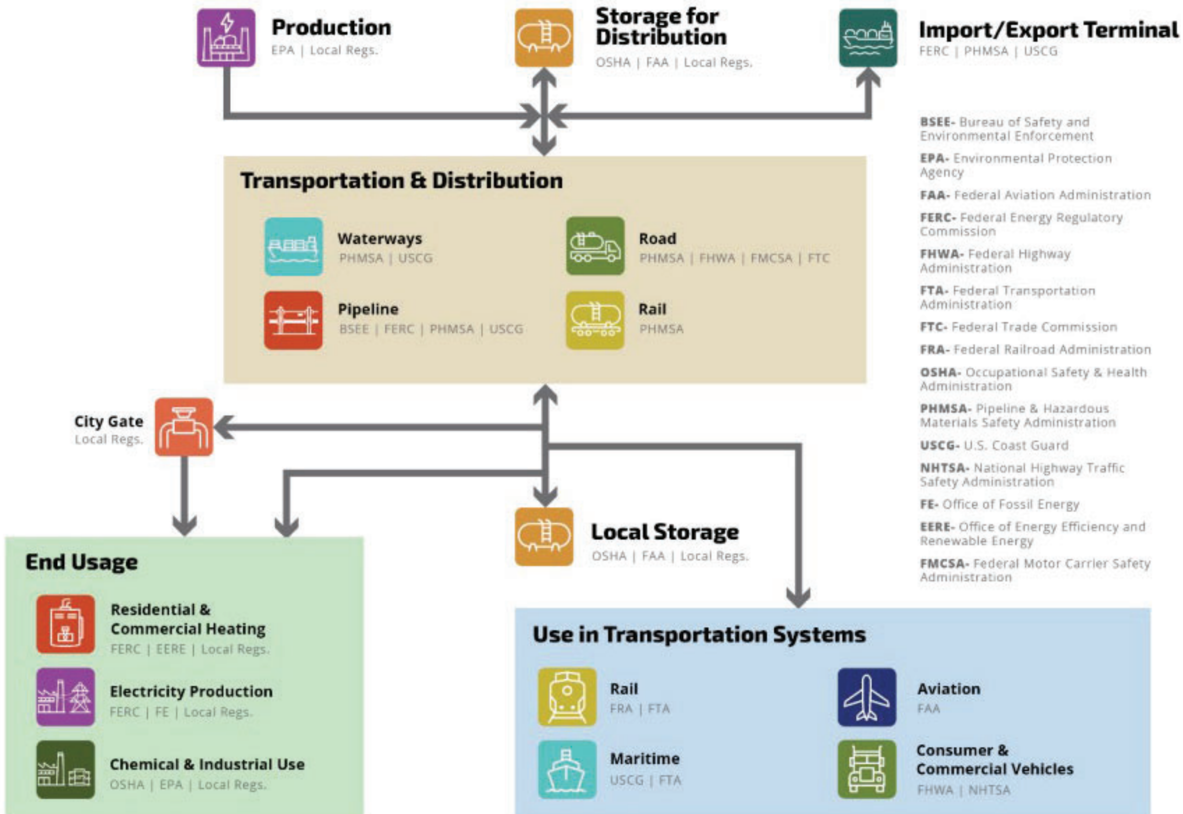
The confluence of several trends (e.g., environmental, social and governance (ESG), global decarbonization, and Federal clean energy/infrastructure initiatives) is supporting a cleaner hydrogen industry directed at decarbonization efforts. The acceptance and build-out of a hydrogen economy will require significant physical asset development but also substantial policy and regulatory changes. One of the largest global pure hydrogen infrastructure systems is in North America and several agencies have regulations addressing hydrogen which provides permitting and approvals for the design, construction and operation and maintenance of this infrastructure. There also are regulations which have permitted the widespread use of hydrogen in refineries, chemical manufacturing and other industrial operations for many decades. However, these regulations generally don't directly address the use of intentional hydrogen blends in natural gas infrastructure and carbon sequestration. Non-methane compounds are present in natural gas at low levels (e.g., 1 to 2 %) but are not specifically regulated other than indirectly by gas purity regulations and producers and distributors specifications. It also is important to note that historically hydrogen was a major component of town gas generated from coal (there were a substantial number of manufactured gas plants in the US northeast) that was widely used prior to the development of the natural gas industry. In some jurisdictions like Hawaii, 12 to 14% hydrogen has been present in the natural gas supply for over 30 years with no significant operational issues. Regulations are evolving for green hydrogen production from electrolysis, hydrogen fuelcells, and other industrial hydrogen applications, as well as more recent EPA regulations and procedures that provide for the permitting and approval of carbon sequestration by deep well injection to support carbon capture, utilization and storage (CCUS) projects or blue hydrogen production.

A hydrogen economy will require more comprehensive and deliberate regulation of hydrogen generation, storage, transportation and use as has been rapidly developing in other global regions (i.e., the United Kingdom, Europe and Australia). Of the agencies whose mandates include hydrogen, the most significant Federal regulatory actions are likely to come from FERC, DOE, EPA, OSHA and DOT/PHMSA. With respect to oil and gas infrastructure repurposed for hydrogen transmission, various State agencies also will play a role in regulating hydrogen in oil and gas infrastructure. Oil and gas entities and a number of national and state member associations lobby and influence policy and regulation on both Federal and State levels. There have been hydrogen associations and government agencies working to advance the field for a few decades. More recently the oil and gas and other industry associations and regulatory agencies have included hydrogen as a topic of interest to members and new organizations have formed such as local Hydrogen Councils to advance understanding and discussions around the use of hydrogen in oil and gas operations to reduce GHG emissions and provide cleaner energy to customers.

Section 1 provides the purpose of the report, the scope and limitations, and the assumptions that have been used in the development of the report.

Federal Regulatory Framework

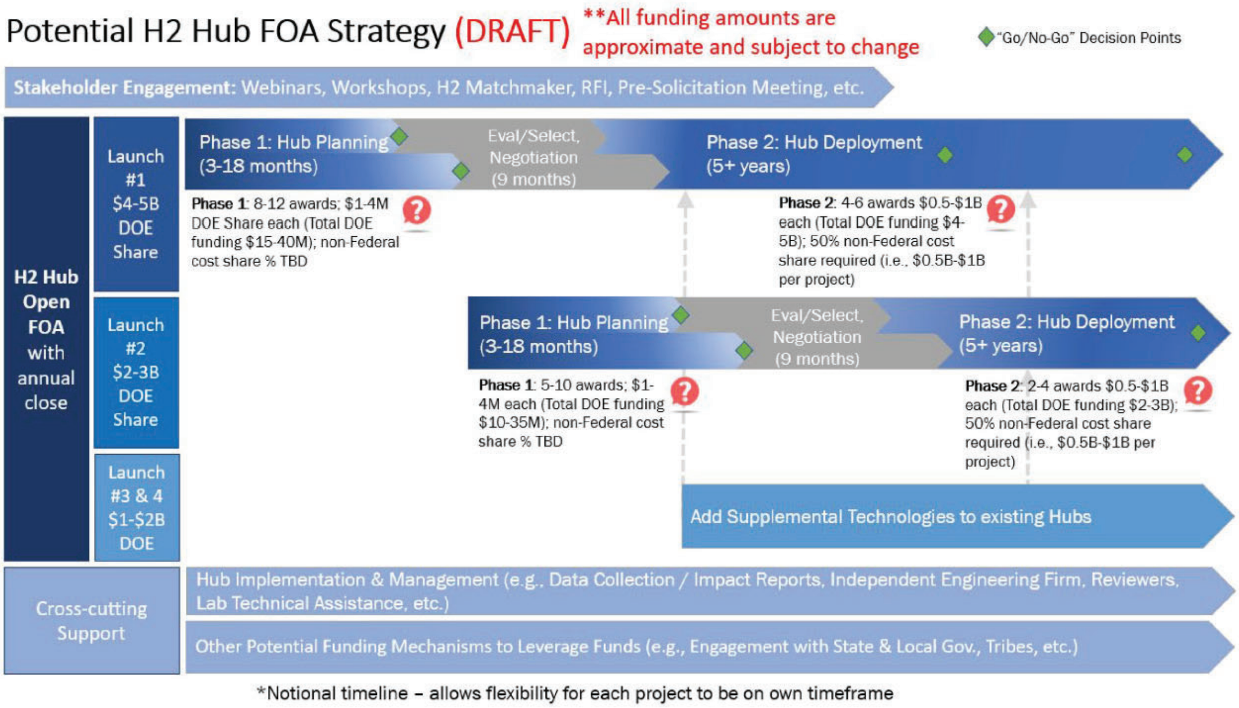
Section 2 details key Federal regulatory departments and agencies that are currently guiding policy and regulation development.



– Federal Energy Regulatory Commission (FERC) – As Liberty's gas supply system in Keene is islanded and not connected across state lines, FERC will not play a significant role for permitting and regulating any change of use with existing assets unless there is an addition of assets that would operate on an interstate basis. Current assets that are FERC regulated would require permit amendments to allow hydrogen use in those assets even if those assets to be converted to a hydrogen blend are only in one state.

– Department of Energy (DOE) – DOE has a long history of significant funding applied to hydrogen research and development and this is expected to increase at a more significant rate with substantially higher funding. DOE recently released a Hydrogen Program Plan outlining how the department plans to coordinate additional efforts to advance the affordable production, transport, storage, and use of hydrogen across different sectors of the economy. The Plan involves participation from the Offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy, Electricity, Science, and the Advanced Research Projects Agency–Energy. Significant DOE funding will continue to be available to support demonstration projects and Liberty should consider participating in DOE programs to help offset Hydrogen Strategy development costs.

  In February 2022, DOE launched a $8.5B initiative to support multi-year development of at least 4 large scale hydrogen Hubs across the U.S. A summary of the initiative is provided below. GHD has significant experience in Hub development in Australia and New Zealand and is participating in multiple potential hubs in the U.S. In March 2022, GHD also submitted a response to DOE's RFI to provide information based on our global experience on lessons learned and key considerations for Hub development. A copy of GHD's submittal is provided in Appendix A. GHD advises Liberty that the development of small and medium scale hubs also will occur and some ongoing review of activities would be prudent to identify jurisdictions that Liberty may want to have a role(s) in hub development.



– US Environmental Protection Agency (EPA) – EPA's most recent and relevant regulatory effort in the hydrogen space is the development of guidelines and application processes for deep well CO_2 injection for sequestrations projects (e.g., includes blue hydrogen). This program is a continuation of EPA's program for deep well injection permits and a new call of well (Class VI) has been developed specifically for sequestrationprojects. The technical process to apply for a permit is quite onerous as it must be demonstrated that the geological feature to be injected into is well understood, is amenable to long term, stable storage and sufficient measures can be put in place to provide adequate monitoring of long- term storage.

  EPA also regulates hazardous substances and in some cases (e.g., large volumes) hydrogen could be considered a hazardous substance. This determination is more of a safety issue though due to hydrogen's flammability and explosive properties which are somewhat increased over natural gas. The release of hydrogen to the environment is not as much of a concern as it vents and does not contribute to greenhousegases when combusted or released as pure hydrogen.

– Occupational Safety and Health Administration (OSHA) – OSHA requires owners or operators to develop a Process Safety Management (PSM) program (or modify the existing program to include the additional risk posed with the addition of hydrogen) for any interconnected process (i.e., in storage, process vessels, and piping) with a triggering threshold of 10,000 lbs of hydrogen under the control of a single entity.

– US Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) – PHMSA currently regulates approximately 1,600 miles of pure hydrogen pipelines and associated infrastructure operated by merchant hydrogen producers since this infrastructure began development in the mid-1900s. These regulations are primarily based on natural gas regulations, with the definition of gas being "flammable gas", which would include hydrogen. Since the primary focus of these regulations is natural gas, certain characteristics of hydrogen are not necessarily fully contemplated in some of the existing regulations' design requirements. PHMSA (and many other companies, research and other institutions) continues to conduct research regarding hydrogen's effects on steel pipelines and associated equipment and materials. There is a considerable body of technical information and experience regarding the use of hydrogen in pipelines and related infrastructure. This knowledge and experience is used by qualified professionals to design, construct, operate, and maintain pure hydrogen infrastructure, as well as infrastructure that is going tohave a change in use to hydrogen or blends of hydrogen in natural gas.

Currently the purity of natural gas is typically 70 to 90% in methane content. Other gases and non-fossil fuel contaminants (e.g., ethane, propane and carbon dioxide) are present due to the nature of natural gas production. Some natural gas also contains traces of hydrogen already and 1-2% of hydrogen present in natural gas would very generally be considered acceptable. Intentional blending at higher levels (e.g., 5 to 10% in a lower pressure distribution system) would not be considered an impurity and would require specific notification to PHMSA/State agencies and related approvals.

– On March 31, 2021, the Biden Administration unveiled the $2 trillion American Jobs Plan which requires congressional approval. The Plan includes a wide array of investment allocations for various infrastructure and industries, with the energy sector receiving about 25% of the total proposed funding spread out over grid modernization and clean energy incentives. Hydrogen is specifically called out within a $15 billion allocation to RD&D projects, with mention of 15 decarbonized hydrogen demonstration projects in distressed communities with a new production tax credit.

  Hydrogen projects and funding may also find relevance among $50 billion investment in the National Science Foundation (NSF), $35 billion investment in solutions needed to achieve technology breakthroughs that address the climate crisis, and $5 billion in funding for other climate-focused research. As of this report, the Plan has not been passed into law.

Section 3 considers the states in which Liberty is operating and highlights key trends on the local and regionalpolicies and regulations concerning hydrogen and other emerging fuels technologies. There are publicly available tools which can be used to track policy and regulation changes by State, and two of these tools are referenced. A number of electrolyzer and hydrogen blending demonstration projects are identified in various states and Liberty can learn from these projects regarding regulatory approaches and requirements. Details of these projects are provided in Appendix B.

Section 4 provides key insights into how regulations related to hydrogen have been developing internationally to provide some global perspective. Generally, initiatives and framing of regulation and policy is driven at the Federal level, with significant policy and regulation, codes and standards initiatives, capital investments and coordinated research, development & demonstration (RD&D) programs. Nations that have developed structured national hydrogen strategies with road maps include specific ramping up of production volumes, economic implications of transitioning away from traditional fuels, and considerations for the balancing of international trade supply and demand between now and beyond 2050. Countries with excess energy are making major plays into hydrogen export. These developments, while specific to each country, have been developed ahead of North American policies and regulatory changes and provide insights to how the process will develop and the key changes that are considered to more specifically adopt and account for hydrogen. While many international oil and gas codes and standards were developed based on American ones the faster growth of cleaner hydrogen use in other global regions has resulted in changes that can be learned from for American adoption.

Blending Injection Limits

Section 5 provides descriptions of hydrogen blending injection limits (volume %) in countries that have adopted or indicated adoption of blending is planned. This experience provides Liberty with a perspective on what blending limits have been approved in other gas networks.

Hydrogen Associations & Coalitions

Section 6 details key domestic and international associations pushing the development of the hydrogen economy. Generally, these associations include industry players that will have critical roles with existing assets that will be impacted by increased widespread hydrogen adoption. Associations collaboratively develop and advance member interests and help drive policy and regulation. Liberty could consider joining a number of organizations as a member, such as the Clean Hydrogen Future Coalition (CHFC), Zero Carbon Hydrogen Coalition and Pipeline Research Council International (PRCI), and support organizations such as the Gas Technology Institute (GTI).

Recommendations for Liberty

Throughout the regulatory review, a variety of initiatives and considerations are identified, which are summarized below. Liberty should consider pursuing some of these initiatives as part of their Hydrogen Strategy, including and beyond Keene. Liberty could position themselves to help guide policies, regulations, safety and technical aspects of hydrogen use in the industry, while remaining flexible to capture market growth and opportunistic investment opportunities.

1. NHPUC will largely govern approval of gas supply changes and upgrades.
2. Other select Federal, State, and local regulations, standards and by-laws will have applicability for the design, construction and safe operation of gas supply upgrades depending on the specific activities.
3. For hydrogen gas blending, Liberty can learn about specific regulatory requirements from other demonstration projects that are planned and/or in operation in various states such as NY, OH, NJ, AZ, NV, FL, in Canada and internationally. GHD is involved with a number of these projects and can provide more detailed information and/or support discussions with the utilities doing the projects.
4. GHD has significant activity in the RNG space in many jurisdictions and can provide more detailed information and/or support discussions with the utilities/parties doing the projects.
5. In February 2022, DOE launched a $8.5B initiative to support multi-year development of at least 4 large scale hydrogen Hubs across the U.S. The development of small and medium scale hubs also will occur and some ongoing review of activities would be prudent to identify jurisdictions that Liberty may want to have a role(s) in hub development.

More generally, GHD recommends that Liberty continue to consider pursuing/supporting the following activities:

1. Lobby for incentives (e.g., tax credits) for adoption of hydrogen in natural gas systems.
2. Promote clear definitions, classifications, and appropriate permitting and monitoring requirements for the intentional addition and use of hydrogen in natural gas networks, both high pressure transmission and low-pressure distribution networks.
3. Pursue DOE, other Federal and State funding for demonstration projects to offset initial costs for Liberty's HydrogenStrategy and gain experience with designing, constructing and operating and maintaining hydrogen, hydrogen/natural gas, and CCUS assets.
4. Continue considering joining additional associations and supporting groups that can advance Liberty's interests in hydrogen development.
5. Consider developing an internal cost of carbon to evaluate capital projects and strategic initiatives to incorporate a measure of economic and ESG impact consistent with the widespread external developmentand adoption of numerous carbon accounting, credit and other GHG type measures.
6. Lobby for clear definitions, industry standards, and classification of hydrogen 'colors', Carbon Intensities (CIs), Full Life Cycle Analyses (LCAs) and green certificates of origin etc.

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1. Introduction

1.1 Purpose of This Report

The report examines existing U.S. Federal and State-specific legislation (including regulations, policy, and reference standards) that pertain to the emergence of future fuels such as hydrogen, syngas, or biogas into existing natural gas infrastructure. The regulatory review includes standards across all aspects of the value chain (generation and manufacturing, storage, transmission, distribution, and use) relevant to introduction of fuels into existing gas infrastructure.

1.2 Scope and Limitations

The first stage of the regulatory review project comprised of document and desktop review of existing regulations, legislation, and policies covering all state and federal jurisdictions across gas network transmission supply chain, and relevant value chain components that would complement Liberty in their overall strategy of pursuing hydrogen market entry. The focus of this regulatory review is on capturing the breadth of regulation across sectors that influence existing gas network functioning including:

- Technical legislation
- Environmental and land use planning and development
- Economic legislation
- Other legislation that may be sensitive to the types of fuel used or contained within gas infrastructure

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GHD otherwise disclaims responsibility to any person other than Liberty arising in connection with this report. GHDalso excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report (refer to section 1.3 of this report). GHD disclaims liability arising from any of the assumptions being incorrect.

1.3 Assumptions

At the time of writing, hydrogen injection and blending into natural gas distribution and transmission networks is an emerging process for which the implications are not fully understood. Most countries do not yet have standards developed that govern the percent of hydrogen by volume that can be blended. Some jurisdictions, however, are ahead in this regard, with standards implemented to limit the hydrogen content for existing natural gas pipelines. With that in mind, this review will serve as a snapshot in time regarding regulation at the time of completion and will need to be complemented with the evolving regulatory advancements over time.

1.4 Foreword

Regulation and policy concerning hydrogen as an energy carrier is spread across a variety of industries, markets, and positions within value chains, with varying levels of respective detail and specificity. For potential market entrants, the ambiguity of prescriptive legislation and concrete frameworks do not allow for exploitation of new business models and emerging competitive landscapes. Further, Liberty's assets beyond Keene are located in a number of States and are thus subject to both State and Federal regulation which are not always congruent with one another. However, current regulation and policy frameworks of the emerging hydrogen economy provide a sound basis with technical limitations increasingly researched and refined. Several existing standards developed in the U.S. and international markets which allow for the safe use, distribution, and storage of pure hydrogen, with increasing comprehension of blended natural gas and hydrogen pipeline networks. These standards are primarily focused on the current hydrogen infrastructure, including building codes, fire codes, and items pertaining to technologies used to transport and store pure hydrogen.

Shipping hydrogen by dedicated pipeline is not new in the United States, but the existing hydrogen pipeline infrastructure (about 1,600 miles) is small compared to that of the nation's natural gas and oil pipeline systems (2 million miles of natural gas distribution mains and pipelines and 321,000 miles of gas transmission and gathering pipelines). The hydrogen pipeline network required to support a hydrogen-based U.S. energy strategy would need to be much larger and with much broader geographic reach than that in place today. Hydrogen also historically has been blended with natural gas in some U.S. natural gas pipelines, and currently is being shipped this way in significant volumes overseas, but there currently are barriers and limitations to the blending approach. Establishing a national network of dedicated hydrogen pipeline infrastructure, or reconfiguring existing natural gas systems to carry hydrogen, poses numerous challenges related to regulation.

Legislative frameworks have not always caught up with development ambitions of the developing hydrogen economy. As such, another key challenge that has emerged is the lack of a clear legal and regulatory framework for hydrogen as an energy carrier. Due to the different nature and use of hydrogen, existing gaseous energy carrier frameworks are not always appropriate and market players would benefit from the introduction of a clear regulatory framework to encourage the development of a hydrogen economy. Despite hydrogen's similarity to natural gas as an energy carrier, this emerging technology's unique characteristics need to be respected such that legal and regulatory frameworks, investment cases, financing structures, operational requirements, revenue stream arrangements, among other elements, are taken into consideration to formulate effective commercialization models.

Multiple agencies have authority that touch at least tangentially on hydrogen, but there is currently no comprehensive hydrogen regulatory regime for the United States. Agencies are often aware of their ability to regulate hydrogen, and recent developments - such as the Department of Energy's (DOE) newly revised Hydrogen Program Plan - indicate that they are starting to act. Currently, the main agencies with the ability to influence the development of hydrogen industry and infrastructure include: the DOE, the Federal Energy Regulatory Commission (FERC), the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Environmental Protection Agency (EPA). Hydrogen regulations are not a central part of these agencies' missions, but the agencies will continue to play an important role as hydrogen becomes more prevalent and technologies advance and change and are detailed below.

2. Federal Programs and Incentives

Despite the lack of a comprehensive regulatory scheme, the U.S. government has recognized hydrogen's potential as a fuel source. Thus far, the federal government's major initiative regarding hydrogen as a fuel source has been to incentivize research in the area, including by funds made available through programs in multiple agencies. One of the most important programs is DOE's $100 million pledge, which reflects DOE's intention to invest up to this amount in two new DOE National Laboratory-led consortia to advance hydrogen and fuel cells technology research, development, and demonstration (RD&D) over the next five years. One consortium will develop affordable, commercial scale electrolyzers, which use electricity to divide water into hydrogen and oxygen, and the other consortium will assist in accelerating the development of fuel cells for vehicles, specifically for long-haul trucks. DOE recently released its updated Hydrogen Program Plan, which underscores DOE's department-wide commitment to facilitating the growth of hydrogen as a source of energy and provides a "strategic framework for the Department's hydrogen RD&D activities."

As the hydrogen economy continues to develop and include more players across the energy sector, the U.S. federal government will need to incorporate hydrogen into its broader regulatory scheme for hydrogen to truly become part of the energy infrastructure in the U.S. Several federal agencies already address hydrogen in their regulations; however, they only address it incidentally, as one of the many substances regulated under their regimes. For example, most environmental regulations on hydrogen deal with hydrogen's properties, such as its flammability/explosivity (which often requires it to be regulated as a hazardous substance) as detailed in the Technical and Safety Review. These regulations are scattered throughout the Code of Federal Regulations (C.F.R.) and are not organized to address hydrogen in a cohesive manner. Instead, disparate regulations touch upon a portion of the hydrogen industry or issues related to the characteristics of hydrogen itself, but do not focus on regulation of the hydrogen industry as a whole and specific to how midstream gas players are to be regulated as they enter the hydrogen market.

2.1 Federal Energy Regulatory Commission (FERC)

Key highlights:

- FERC regulations involving hydrogen are currently tied to interstate natural gas pipeline measures and lack uniformity with state-based regulatory advancement.
- FERC issued a Notice of Proposed Rulemaking (October 2020) to amend PURPA definition of "useful thermal energy output" to include thermal energy produced via Solid Oxide Fuel Cells that then uses the thermal energy to reform methane and produce hydrogen for electricity production.

FERC could seek to establish regulatory provisions for the interstate transportation of hydrogen. Pursuant to the Natural Gas Act (NGA), FERC regulates the siting, construction, and operation of interstate natural gas pipelines and storage, and the rates and terms of service offered by these pipelines.[1] While FERC has not utilized this authority to regulate pipelines exclusively transporting hydrogen, and may not have jurisdiction to do so under the NGA or other existing statutes, it is possible that FERC could regulate the transportation of hydrogen if it is transported in a blended stream with natural gas. While gaseous hydrogen generally is currently transported through designated hydrogen- specific pipelines,[2] it also can be found alongside natural gas in natural gas transmission pipelines. Several groups have posited that one way to transport hydrogen and make the end-use of hydrogen cheaper could be to integrate thetransportation of gaseous hydrogen into existing natural gas pipelines in greater quantities, blending hydrogen with thenatural gas stream.[3] The transportation and construction of natural gas pipelines is squarely within FERC's authority under the NGA, and accordingly, transportation of hydrogen blended in these pipelines could subject hydrogen transportation to regulation by FERC.

FERC's regulations of natural gas pipelines extend beyond the regulation of construction of pipeline facilities and also apply to the terms and conditions of transportation services. FERC regulations require natural gas companies to file a tariff that sets forth the terms and conditions of service on the natural gas company's pipeline, including terms and conditions related to the quality of the gas being transported. Including greater quantities of hydrogen in the natural gas stream on FERC-regulated natural gas pipelines could require modification of existing gas quality provisions in a pipeline's tariff, and likely would require coordination with shippers and other pipelines in order to accommodate additional hydrogen content. This coordination and the balance of pipeline and shipper interests is familiar territory for FERC and its regulated natural gas companies, and the existing regulatory regime may have benefits if applied to the transportation of hydrogen.

Construction and operation of 100% dedicated hydrogen pipelines within existing FERC-regulated gas transmission easements may also trigger an additional FERC permit depending on the easement conditions with respect to the

1 FERD. 2018. An Overview of the FERC and Federal Regulation of Public Utilities.
2 https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed March 2021.
3 https://www.energy.gov/eere/fuelcells/hydrogen-pipelines Access March 2021.

original FERC approval. It is typical that the pipeline system and lands (including easements) is part of the approval and placing another pipeline in the easement is generally subject to the original approval conditions. Additionally, it is common in many jurisdictions that there is a constraint on what other pipelines can be placed in an easement for a gas pipeline system. A hydrogen pipeline in a natural gas pipeline easement may also require a renegotiation of the easement with all the relevant landowners, as it may be outside the easement conditions.

FERC may encourage hydrogen production by classifying it as a "useful thermal energy output" that would entitle some cogeneration facilities to beneficial regulatory treatment.[4] FERC is also responsible for implementing regulations under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA provides a number of benefits to certain qualifying electricity generating facilities, including the right to sell energy or capacity to certain utilities, the right to purchase certain services from utilities, and relief from certain regulatory burdens.[5] FERC has announced that it is considering whether to expand its PURPA regulations to allow a specific hydrogen-based technology, a solid oxide fuel cell system, "that then uses the thermal energy it produces to reform methane and produce hydrogen for electricity generation", to qualify for this beneficial regulatory treatment. FERC issued the Notice of Proposed Rulemaking on this issue on October 15, 2020, and comments were due to FERC on November 25, 2020. If the proposed rule is issued after FERC's review, the resulting Final Rule could open another avenue of support for hydrogen production through better rate and regulatory treatment.

2.2 Department of Energy (DOE)

Key highlights:

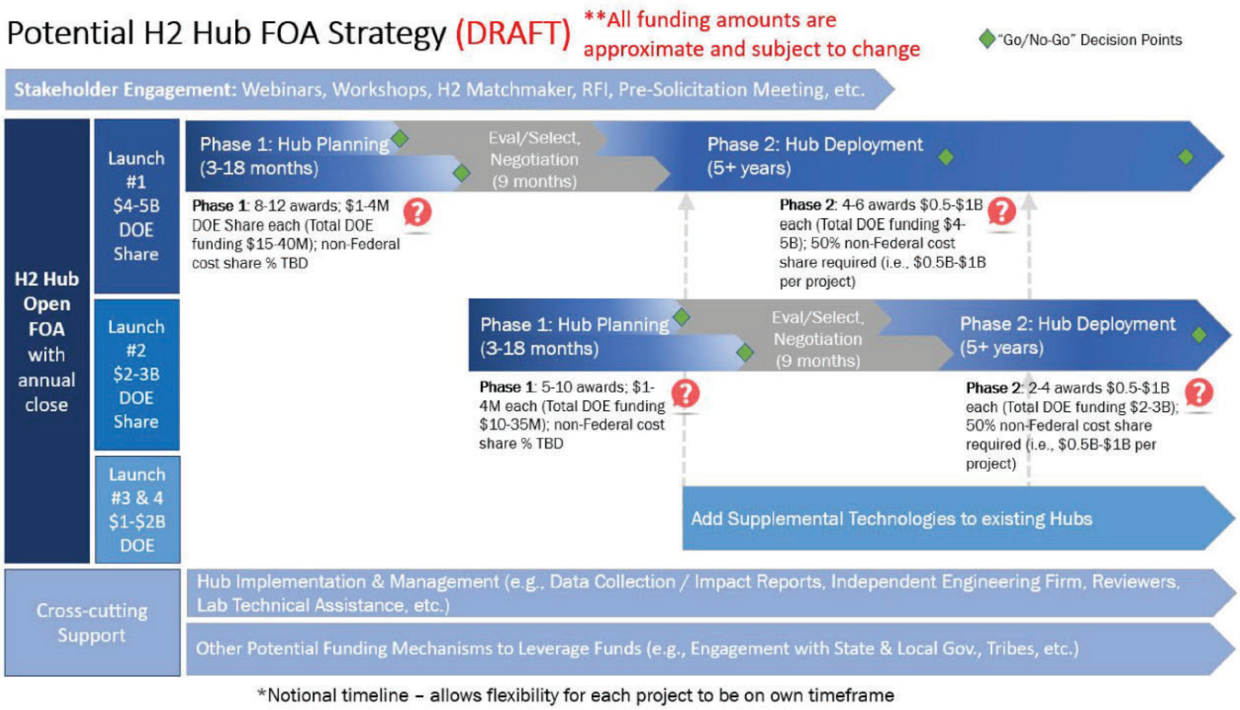
– DOE Hydrogen Program Plan released in 2020, outlines efforts to advance the affordable production,transport, storage, and use of hydrogen across different sectors of the economy.

– Since 2019, H2@Scale initiative has overseen funding initiatives worth over $100M for hydrogen-focused projects aimed to advance research, development, and demonstration projects across multiple energy sectors.The Consolidated Appropriations Act for Fiscal Year (FY) 2021 provided $150 million to HFTO which governs H2@Scale.

– In February 2022, DOE launched a $8.5B initiative to support multi-year development of at least 4 large scale hydrogen Hubs across the U.S. A summary of the initiative is provided below. GHD has significant experience in Hub development in Australia and New Zealand and is participating in multiple potential hubs in the U.S. In March 2022, GHD also submitted a response to DOE’s RFI to provide information on lessons learned and key considerations for Hub development. A copy of GHD’s submittal is provided in Appendix A. GHD advises Liberty that the development of small and medium scale hubs also will occur and some ongoing review of activities would be prudent to identify jurisdictions that Liberty may want to have a role(s) in hub development.

[4] A cogeneration facility is a facility that produces a useful thermal energy output and electricity. Fuel Cell Thermal Energy Output, 173 FERC 61,050 at PP 8-9 (2020) ("Notice of Proposed Rulemaking").

[5] 16 U.S.C. § 824a–3 (2018); PURPA Qualifying Facilities, Fed. Energy Reg. Comm'n, https://www.ferc.gov/qf.



The DOE will continue to play a significant role in the development and testing of new hydrogen technologies. The DOE recently issued its Hydrogen Program Plan which describes DOE's high-level, cross-agency strategy for fostering the hydrogen economy by funding research and development. The Hydrogen Program Plan analyzes potential uses of funding for hydrogen development, primarily focusing on hydrogen's role in power generation and transportation, sectors in which hydrogen could become more prevalent if technological advances made it financially accessible and environmentally sustainable. The Hydrogen Program Plan likewise discusses potential advances to bemade in chemical and industrial processes, where hydrogen traditionally has been used. DOE also envisions itself playing a role in incentivizing the use of hydrogen in fuel cells, especially for long-haul trucks.

In addition, DOE's Hydrogen Program Plan examines the production, storage, and transportation of hydrogen, specifically methods to make carbon-neutral or carbon-negative hydrogen an affordable reality. This means evaluating all possible methods of producing hydrogen – fossil fuels, renewable energy, nuclear energy, and methanol. DOE seeks to enable the hydrogen transition, primarily through research and development and funding, and appears to be preparing for a role as the thought leader on the integration of hydrogen into the broader energy scheme. While the Hydrogen Program Plan does not specifically seek to regulate hydrogen itself, the Plan lays out a comprehensive strategy to foster the development of hydrogen as a substantial component of the energy and transportation sectors.

2.2.1 Hydrogen Program Plan

The DOE Hydrogen Program is a coordinated Departmental effort to advance the affordable production, transport, storage, and use of hydrogen across different sectors of the economy. The Plan involves participation from the Offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy, Electricity, Science, and the Advanced Research Projects Agency–Energy.

	Transportation Applications	Chemicals and Industrial Applications	Stationary and Power Generation Applications	Integrated/Hybrid Energy Systems
Existing Growing Demands	• Material-Handling Equipment • Buses • Light-Duty Vehicles	• Oil Refining • Ammonia • Methanol	• Distrubuted Generation: Primary and Backup Power	• Renewable Grid Integration (with storage and other ancillary services)
Emerging Future Demands	• Medium-and Heavy-Duty Vehicles • Rail • Maritime • Aviation • Contruction Equipment	• Steel and Cement Manufacturing • Industrial Heat • Bio/Synthetic Fuels	• Reversible Fuel Cells • Hydrogen Combustion • Long-Duration Energy Storage	• Nuclear/Hydrogen Hybrids • Gas/Coal/Hydrogen Hybrids with CCUS • Hydrogen Blending

Figure 1 ***DOE Outline of Existing and Emerging Demands for Hydrogen***
Source: DOE Hydrogen Program Plan, 2020

The DOE Hydrogen Program Plan provides a strategic view of how the Department conducts and coordinates hydrogen research, development, and demonstration (RD&D) activities under the DOE Hydrogen Program. With participation from the Offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy, Electricity, Science, and ARPA-E, the DOE Hydrogen Program is a coordinated Departmental effort to advance the affordable production, transport, storage, and use of carbon-neutral hydrogen across different sectors of the economy. This version of the Plan updates and expands upon previous versions, including the Hydrogen Posture Plan and the DOE Hydrogen and Fuel Cells Program Plan, and provides a coordinated high-level summary of hydrogen-related activities across DOE. Figure 2 provides an overview of DOE's organizational structure with respect to the Hydrogen Program Plan.

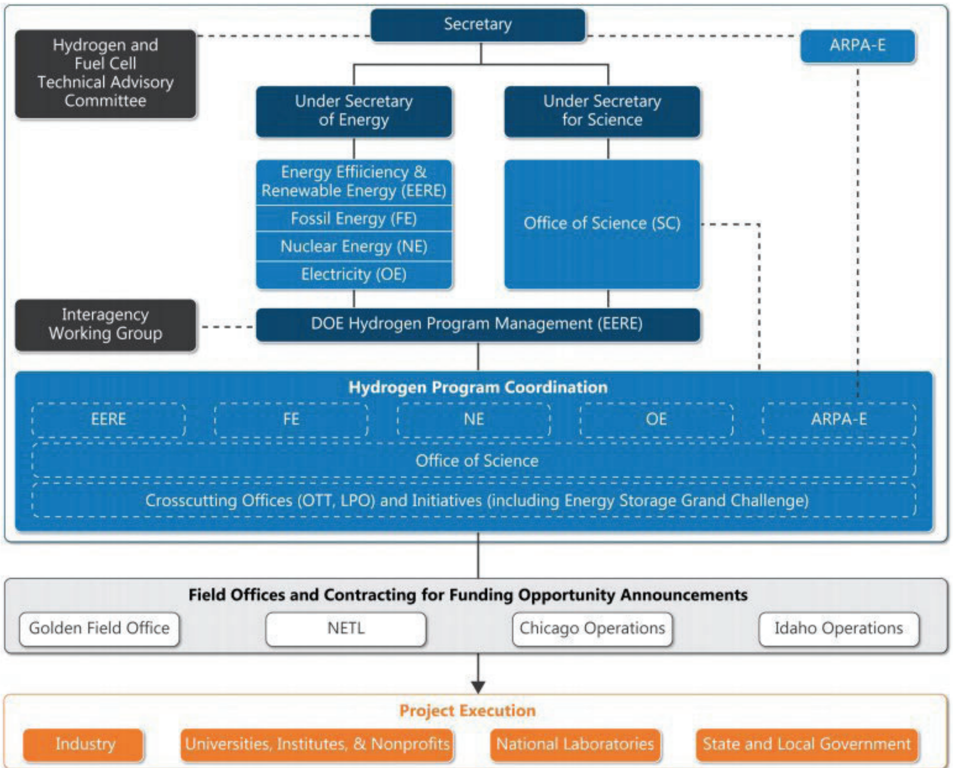


Figure 2 *DOE Hydrogen Program Organization Structure*
Source: DOE Hydrogen Program Plan, 2020

2.2.2 Office of Energy Efficiency and Renewable Energy

The Office of Energy Efficiency and Renewable Energy (EERE) leads a comprehensive strategy focusing on RD&D and innovations across a broad portfolio of renewable energy technologies (solar, wind, biomass, geothermal, water power, and renewable hydrogen), energy efficiency in buildings and the industrial sector, transportation technologies across applications (vehicles, trucks, marine, rail, air), advanced manufacturing, and crosscutting activities (the Federal Energy Management, Weatherization, and Intergovernmental Programs).

2.2.3 Hydrogen and Fuel Cell Technologies Office

The Hydrogen and Fuel Cell Technologies Office (HFTO), leading DOE's Hydrogen Program including H2@Scale, supports RD&D and innovation to advance diverse technologies and infrastructure for hydrogen production, delivery, storage, and utilization. HFTO conducts RD&D at the materials-, component- and system-levels, to address the cost, performance, durability, and safety requirements for widespread adoption of hydrogen across the transportation, industrial, and stationary power sectors. RD&D focus areas include: electrolyzers and other advanced water-splitting approaches; advanced liquefaction and carriers for hydrogen delivery; advanced high-pressure tanks, liquid hydrogen storage, and material-based storage systems; and low- and medium-temperature fuel cells. HFTO coordinates with FE on various topics including reversible solid oxide fuel cells; with NE and OE, particularly on integrating renewables into the grid using hydrogen as an energy storage medium; and with SC and ARPA-E on basic science and next generation technologies.

Through this CRADA call, DOE's Hydrogen and Fuel Cell Technologies Office seeks to accelerate development of hydrogen fueling technologies for medium- and heavy-duty fuel cell vehicles, address priority R&D barriers to enabling hydrogen blending in natural gas pipelines at scale, and increase industrial and stakeholder engagement in H2@Scale through investment and active participation in the associated projects.

H2@Scale is a DOE initiative that supports innovations to produce, store, transport, and utilize hydrogen across multiple sectors. The intent of H2@Scale is for hydrogen to enable—rather than compete with—energy pathways across applications and sectors. Up to $24 million in DOE funding is available for collaborative projects at national laboratories in two priority areas of R&D:

– Hydrogen fueling technologies for medium- and heavy-duty fuel cell vehicles

  Areas of interest include, but are not limited to, compressors, dispensers, cryogenic pumps, analysis to inform fueling station design, and heavy-duty fueling methods that can inform standards development organizations leading fueling protocol development.

– Technical barriers to hydrogen blending in natural gas pipelines

  Specific R&D priorities include materials compatibility, pipeline compressors, hydrogen combustion in end uses, technologies for separating hydrogen from blends downstream of injection, compatibility of blends with underground reservoirs, and techno-economic and life cycle analysis.

Selected projects include one or more national laboratories and also include partners from one or more of the following: industry, universities, non-profits, institutes, codes and standards organizations, associations, or other relevant stakeholders. Support from the Hydrogen and Fuel Cell Technologies Office will fund the national laboratory services, staff time, and facilities necessary to support each selected project.

2.2.4 Office of Fossil Energy

The Office of Fossil Energy (FE) seeks to advance transformative science and innovative technologies that enable the reliable, efficient, affordable, and environmentally sound use of fossil fuels. The office conducts diverse RD&D efforts, including advanced power generation; power plant efficiency; water management; carbon capture, utilization, and storage (CCUS) technologies; executing natural gas regulatory responsibilities; and technological solutions for the prudent and sustainable development of unconventional oil and gas domestic resources. Two major FE programs are currently conducting fossil energy based hydrogen RD&D:

– The Office of Clean Coal and Carbon Management (CC&CM) is focused on advancing technologies for producing hydrogen from coal with CCUS, including through modular systems and co-gasification with biomass and waste plastics. Key priorities are hydrogen-combustion turbines and reversible solid-oxide fuel cell systems for large scale power generation as well as integration with gasification islands for large chemicalco-production (e.g., ammonia and polygeneration). Reversible solid oxide fuel cell R&D is conducted in coordination with EERE's HFTO to ensure there is no duplication of efforts. FE will also coordinate with EERE,NE, and other offices on hybrid energy systems where reversible SOFCs can be integrated. RD&D emphasis includes combustion and fuel science, catalysis, gasification, separations, as well as CCUS to enable the utilization of carbon-neutral (or even carbon-negative when co-firing biomass) hydrogen at scale. In addition, the office will evaluate the use of hydrogen in energy storage systems and technologies for storing large volumes (>100 tons) on site. Such volumes could be used for emergency supply (when there are fuel supply disruptions at gas turbine facilities such as seen during extreme weather events or other emergencies). Finally, carbon dioxide-utilization programs will require hydrogen for the manufacture of polymers, chemicals, and other products that will support both manufacturing and reduction of carbon dioxide emissions.

– The Office of Oil and Natural Gas (ONG) works to increase the energy and economic security of oil and natural gas supplies and typically focuses on early-stage research in natural gas infrastructure and gas hydrates. ONG leverages insight and expertise in oil and natural gas production, transport, storage, and distribution to support RD&D to enable the use of natural gas supply and storage infrastructure and the large-scale delivery and storage (e.g., geological storage) of hydrogen. Focus areas include RD&D to enable the transmission and storage of hydrogen and hydrogen blends in the existing national network of natural gas pipelines and underground reservoirs. Other RD&D areas include: hydrogen-based approaches for mitigating mid-stream emissions from natural gas infrastructure; technologies to convert flared or vented gas to hydrogen products; and technologies to convert natural gas to solid carbon products, hydrogen, and othervalue-added products.

– FE also leads DOE's CCUS efforts and collaborates with EERE on opportunities to co-locate hydrogen production with CCUS sites and large-scale hydrogen storage sites to enable the use of hydrogen and carbondioxide to produce synthetic chemicals and fuels.

2.2.5 DOE Office of Nuclear Energy

The Office of Nuclear Energy (NE) works to advance nuclear power to meet the nation's energy supply, environmental, and national security needs. RD&D objectives include enhancing the long-term viability and competitiveness of the existing U.S. reactor fleet and developing advanced nuclear reactor concepts. As part of these efforts, NE is working with partners in EERE and industry to conduct RD&D to enable commercial-scale hydrogen production using heat and electricity from nuclear energy systems. In addition to emissions-free electricity, nuclear reactors produce large amounts of heat, which can be used to improve the economics of hydrogen production. NE's efforts related to hydrogen production include:

– Demonstration of both high-temperature and low-temperature electrolysis systems at operating light water reactors that can provide the low-cost heat necessary for these processes to produce hydrogen economically.NE, in coordination with industry, utilities, and vendors, is also developing the necessary control systems to readily apportion energy and electricity based on market demands.
– Modeling, simulation, and experimentation to develop and advance concepts and technologies needed to integrate hydrogen production methods with existing and future reactors in ways that optimize the system-level economic, environmental, and safety performance as they operate in concert with other generation sources and end-use technologies.
– Development of advanced reactors that will operate at very high temperatures, making them well suited for promising new thermally driven hydrogen production processes. These advanced reactors are now being developed by NE through directed laboratory R&D, university programs, and partnerships with domestic nuclear industry vendors.
– NE and EERE have collaboratively initiated hydrogen production pilot projects to demonstrate the initialfeasibility of such systems at currently operating U.S. nuclear power plants.

2.2.6 Advanced Research Projects Agency – Energy

The Advanced Research Projects Agency-Energy (ARPA-E) catalyzes transformational energy technologies to enhance the economic and energy security of the United States. ARPA-E funds high-potential, high-impact projects that are too early for private sector investment but could disruptively advance the ways energy is generated, stored, distributed, and used. Some programs at ARPA-E have sought to develop technologies involving renewable energy and natural gas, with applications in the transportation, commercial, and industrial power sectors; in these areas, there are a number of efforts related to hydrogen. Focused R&D programs relevant to hydrogen or related technologies have included:

– Range Extenders for Electric Aviation with Low Carbon and High Efficiency (REEACH)
– Duration Addition to electricitY Storage (DAYS)
– Methane Pyrolysis Cohort
– Innovative Natural-Gas Technologies for Efficiency Gain in Reliable and Affordable Thermochemical Electricity-Generation (INTEGRATE)
– Integration and Optimization of Novel Ion-Conducting Solids (IONICS)
– Renewable Energy to Fuels through Utilization of Energy-dense Liquids (REFUEL)
– Reliable Electricity Based on ELectrochemical Systems (REBELS)

2.2.7 Unsolicited Proposals

An unsolicited proposal is an application for support of an idea, method, or approach, which is submitted by an individual, business, or organization based solely on the proposer's initiative rather than in response to a DOE solicitation. Funding of unsolicited proposals is considered a non-competitive action.

DOE's central point of receipt for all Unsolicited Proposals is the National Energy Technology Laboratory (NETL) as outlined in the link below which includes all DOE Program Research Areas. DOE encourages organizations and individuals to submit self-generated, unsolicited proposals that are relevant to DOE's research and development mission.

An unsolicited proposal is an application for support of an idea, method, or approach, which is submitted by an individual, business, or organization based solely on the proposer's initiative rather than in response to a DOE solicitation. Funding of unsolicited proposals is considered a non-competitive action.

The proposal document should persuade the staff of DOE and other qualified members of the scientific and engineering community who review the proposed work, that the project represents a worthwhile approach to the investigation of an important, timely problem. Each proposal should be self-contained and written with clarity and thoroughness.

The proposal must present:

- Objectives that show the pertinence of the proposed work to DOE
- Rationale of the approach
- Methods to be pursued
- Qualifications of the investigators and the institution (if applicable)
- Level of funding required to attain the objectives.

A number of regulations relate to criteria governing acceptance and funding of an unsolicited proposal:

- Title 48 Code of Federal Regulation (CFR), Chapter 1, The Federal Acquisition Regulation (FAR) Subpart 15.6 Unsolicited Proposals
- Title 48 CFR, Chapter 9, the Department of Energy Acquisition Regulation (DEAR) Subpart 915.6 Unsolicited Proposals; and 2 CFR, Part 200

DOE considers proposals in all areas of energy and energy-related research and development with emphasis on long-term, high-risk, high-payoff technologies. DOE may accept an unsolicited proposal if it:

- Demonstrates a unique and innovative concept or a unique capability of the submitter
- Offers a concept or service not otherwise available to the Federal government
- Does not resemble the substance of a recent, current or pending competitive solicitation

2.3 Environmental Protection Agency (EPA)

Key highlights:

- EPA’s current regulations suggests that they may be ill-fitting to a future where hydrogen has moved froma peripheral to a core focus for energy companies, but the EPA may develop new regulatory standards for hydrogen production that are distinct from fossil fuel processing.

The EPA regulates substances that have an impact on human health and the environment.[6] This mandate includes a broad array of substances, including hydrogen. The EPA's regulations on hydrogen are a prime example of the haphazard way in which hydrogen has been regulated by the U.S. federal government to date. Primary regulation of

6 https://www.epa.gov/aboutepa Accessed March 2021.

hydrogen by EPA is found under the Mandatory Greenhouse Gas Reporting Program (GHG Reporting), Effluent Standards under the Clean Water Act, and Chemical Accident Prevention program. In each instance, hydrogen is listed not due to any systematic consideration by EPA of regulations that may be needed for hydrogen under the agency's mandate, but instead because of hydrogen's relationship to that program.

Both the GHG Reporting and Effluent Standards regulate production of hydrogen as an offshoot of regulations on fossil fuel processing. The broader program for GHG Reporting, found in 40 C.F.R. Part 98, requires reporting of greenhouse gas data from large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the U.S.[7] 40 C.F.R. § 98.160 specifically imposes these reporting requirements onto hydrogen production from process units that produce hydrogen by transforming feedstocks (e.g., the methane steam reformation process used to produce grey hydrogen).[8] Any such hydrogen production source that emits 25,000 metric tons of CO_2 must comply with GHG reporting, as specified in 40 CFR § 98.160 et seq., which also includes monitoring requirements as well as quality assurance and quality control procedures. The Effluent Standards also derive from the regulation of hydrogen production from fossil fuel sources. Not only do the Effluent Standards apply to discharges of materials to water that result from the production of hydrogen as a refinery by-product, but the standards themselves ultimately refer back to those regulations in the petroleum refining part of the chapter.

Similarly, the EPA's Chemical Action Prevention scheme only regulates hydrogen tangentially. The regulations are found in 40 C.F.R. Part 68 and were created to implement part of the Clean Air Act. This scheme is not specifically focused on hydrogen but establishes requirements for chemical risk management applicable to facilities storing certain listed substances in quantities above a certain threshold.[9] These regulations require a risk management program complying with certain requirements (and including provisions for accident prevention and response) for facilities storing hydrogen in a quantity over a threshold amount of 10,000 pounds.[10]

While these regulations all address hydrogen, they suggest that hydrogen was not the focal point of the regulatory process establishing these regulations. If hydrogen (particularly green hydrogen) grows as a fuel source and becomes material to economic channels, then EPA will likely need to revisit its regulatory approach.

EPA may develop new regulatory standards for hydrogen production that are distinct from fossil fuel processing. EPA's regulatory mandate is wide, and there are multiple potential touchpoints as a hydrogen economy is developed. Many of these will depend on trends in the industry that will require some trial-and-error to establish, such as preferred distribution channels. EPA has not yet provided significant guidance on how it sees its role in a hydrogen economy; however, a survey of EPA's current regulations suggests that they may be ill-fitting to a future where hydrogen has moved from a peripheral to a core focus for energy companies. EPA may, therefore, decide it needs to expand its regulations within the hydrogen economy.

For example, effluent discharges from grey hydrogen production are currently only related to by-products of the petroleum refining process; however, if already processed fossil fuels are being directed specifically for hydrogen production, then it is less clear that EPA's current regulations would capture those discharges. Similarly, the EPA's GHG Reporting requirements for hydrogen production only apply to hydrogen produced from feedstocks, not electrolysis. If fossil fuels, or even renewables, are used for the electrolysis, then any environmental characteristics of that energy currently are not captured in the GHG Reporting requirements related to hydrogen production. While the EPA may not need to change its mechanism or standard of review under any of these statutory schemes in order to accommodate hydrogen, the EPA may need to expand its review of hydrogen with respect to impacts on human health and the environment, which may require the creation of more detailed and comprehensive hydrogen regulations. While many of these regulations would likely be created in dialogue with the development of the hydrogen industry, they provide several avenues for EPA to revise or expand upon current regulations for the new industry.

[7] https://www.epa.gov/ghgreporting Accessed March 2021.
[8] 40 C.F.R. § 98.160 (2020).
[9] 40 C.F.R. § 68.12(a).
[10] 40 C.F.R. § 68.130, Table A.

CO_2 Sequestration

EPA's most recent and relevant regulatory effort in the hydrogen space is the development of guidelines and application processes for deep well CO_2 injection for sequestrations projects (e.g., includes blue hydrogen). This program is a continuation of EPA's program for deep well injection permits and a new call of well (Class VI) has been developed specifically for sequestration projects. EPA has received applications from some proponents already. The technical process to apply for a permit is quite onerous as it must be demonstrated that the geological feature to be injected into is well understood, is amenable to long term, stable storage and sufficient measures can be put in placeto provide adequate monitoring of long- term storage.

Risk Management Plan (RMP)

USEPA requires owners or operators to develop a Risk Management Plan (RMP) for any interconnected process (i.e.,in storage, process vessels, and piping) with a triggering threshold of 10,000 lbs of hydrogen under the control of a single entity. RMPs are intended to enhance safety and emergency planning to protect the off-site public and potentialreceptors. See Technical and Safety Review for more details.

Low Carbon Fuel Standards Renewable Identification Numbers

One way to prove hydrogen carbon intensity is via a Guarantee of Origin system, similar to California's Low Carbon Fuel Standard program and how the EU tracks the source of electricity (see CertifHy program). This credit-based chain of custody would aim to provide transparent and credible information regarding trust and definitions of renewably sources carbon to those customers willing / required to pay more for low carbon fuels.

Decarbonization factor / Sustainability of hydrogen highly depends on the energy source it is obtained from. 95%+ hydrogen produced today is sources from fossil fuels, high intensity carbon sources such as gas, coal, and through processes such as steam methane reforming (SMR). Variable renewable energy systems such as wind power solar photovoltaics that can power electrolyzers that alone produce hydrogen and oxygen gases offer alternate means of hydrogen production. Ambiguity of sustainability and carbon content of hydrogen arises with energy source to produce hydrogen through gas grid with increasing blends of hydrogen injection as well as electricity with increasing penetrations of VRES systems specific to time of use:

– EPA currently oversees the RIN Market for biofuels and a similar system could be instated for hydrogen.
– Potential for parallel system of certifications for colored hydrogen, Guarantee of Origin (GOs).
– Chain of custody systems would trace hydrogen production and consider system boundaries where hydrogenis injected, with promotion of trade of GOs where systems are interlinked.

2.4 US Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)

Key highlights:

– Of the 1,600 total miles of dedicated hydrogen pipelines in the U.S., PHMSA currently regulates approximately 700 miles under their pipeline safety jurisdiction. These regulations are primarily based on existing natural gas regulations, but the definition of gas under this provision includes “flammable gas”, which brings hydrogen into play.
– Due to PHMSA’s goals and the intent of its regulations, PHMSA currently is conducting research regarding hydrogen’s effects on steel pipelines.

PHMSA's mission is to protect human health and the environment by promoting the safe transportation of energy and other hazardous materials by creating national policy, setting and enforcing industry standards, and conducting research.[11] PHMSA currently regulates approximately 700 of the 1,600 (44%) total U.S. miles of hydrogen pipelines

11 https://www.phmsa.dot.gov/about-phmsa/phmsas-mission Accessed April 2021.

via 49 C.F.R. Part 192.[12] These regulations are primarily focused on natural gas, but the definition of gas under this provision includes "flammable gas", which brings hydrogen into play.[13] However, due to the fact that the primary focus of these regulations is natural gas, certain characteristics of hydrogen are not necessarily fully contemplated in some of the existing regulations' design requirements. Nonetheless, in light of PHMSA's goals and the intent of its regulations, PHMSA currently is conducting research regarding hydrogen's effects on steel pipelines.[14]

PHMSA does administer some regulations that more specifically focus on hydrogen. For example, 40 C.F.R. §§ 173.230, 173.301, and 173.302 regulate hydrogen in transportation. In addition, 40 C.F.R. § 173.230 imposes certain requirements for the design, filling, and marking of hydrogen fuel cells, and 40 C.F.R. §§ 173.301 and 173.302 impose general requirements on the transportation of compressed gases, including compressed hydrogen. These regulations provide some guidance on the use of hydrogen but fall short of creating a comprehensive regulatory regime that will guide the development of the entire industry.

PHMSA may introduce hydrogen-specific storage and transportation requirements. PHMSA has stated that it has a "need to focus on supporting activities to ensure that hydrogen is transported safely" and identified that it needs a "clear technical focus regarding safety implications of infrastructure materials, designs and systems; preparations to address any regulatory barriers towards a hydrogen economy; research in support of additional industry consensus standards; [and] efforts to educate and prepare emergency responders." As discussed above, PHMSA's regulations that govern hydrogen transported in pipelines were created to handle natural gas. However, given the molecular differences between the two substances, regulations focused on natural gas may not be enough to fully encompass the needs of a hydrogen pipeline system. For example, hydrogen can embrittle and accelerate the growth of cracks in pipelines, and can more easily permeate elastomer seals and plastic pipe than natural gas, all of which increase the risk of pipeline failure.[15] The existing safety regulations likely only contemplated small-scale usage of hydrogen,[16] and will need to be expanded to handle hydrogen transportation on a larger, commercial scale. Based on these industry- identified concerns, PHMSA determined several key research items that will lead to the development of specific standards and engineering designs and systems for the transport of hydrogen by pipeline:

- The correlations among pressure, temperature, and loss of mechanical properties for hydrogen pipelines,as more research and testing are needed to obtain definitive guidance for regulations and standards developers[17]
- The loss of fatigue resistance and impact strength in hydrogen pipelines
- Research to understand the entire pipeline system using high-strength steels to enhance performance of hydrogen pipelines
- Assessment to understand the effects of hydrogen on natural gas pipelines

PHMSA may need to create new regulations or expand the existing regulations based on the results of the research tasks described above in order to combat the risks associated with hydrogen transportation by pipeline.

2.5 Occupational Safety and Health Administration(OSHA)

OSHA requires owners or operators to develop a Process Safety Management (PSM) program (or modify they existing program to include the additional risk posed with the addition of hydrogen) for any interconnected process (i.e., in storage, process vessels, and piping) with a triggering threshold of 10,000 lbs of hydrogen under the control of a single entity.

2.6 Federal Legislation / American Jobs Plan

Early in 2021, the U.S. Senate introduced the Carbon Capture, Utilization, and Storage Tax Credit Amendments Act. This legislation would enable carbon capture, utilization, and storage (CCUS) and direct air capture (DAC) projects to

12 https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed April 2021.
13 49 C.F.R. § 192.3.
14 https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed April 2021.
15 Pacific Gas and Electric, White Paper – Pipeline Hydrogen, September 2018.
16 Alastair O'Dell, PE Live: Regulation Needs to Catch Up With Hydrogen Development, Petroleum Econ.
17 https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed April 2021.

access necessary federal incentives for reducing CO_2 emissions. The bill would enhance the 45Q tax credit for CCUS and DAC by extending the commence construction window by an additional five years, as well as increasing the credit value for DAC projects from $50 to $120 per metric ton of CO_2 captured and stored in saline formations, and from $35to $75 per ton for geological storage in oil and gas fields. It would also create a direct pay option for the 45Q and 48A tax credits and make several technical fixes to ensure that the tax credits are usable.

On March 31, 2021 the Biden Administration unveiled the $2 trillion American Jobs Plan which requires congressional approval. The Plan includes a wide array of investment allocations for various infrastructure and industries, with the energy sector receiving about 25% of the total proposed funding spread out over grid modernization and clean energy incentives. Hydrogen is specifically called out within a $15 billion allocation to RD&D projects, with mention of 15 decarbonized hydrogen demonstration projects in distressed communities with a new production tax credit.

Hydrogen projects and funding may also find relevance among $50 billion investment in the National Science Foundation (NSF), $35 billion investment in solutions needed to achieve technology breakthroughs that address the climate crisis, and $5 billion in funding for other climate-focused research.

As of this report, the Bipartisan Infrastructure Legislation (BIL) has not been passed into law. This legislation will provide generational impacts to by fostering infrastructure and clean energy projects across the country.

3. State Programs and Incentives

Liberty owns, operates, and maintains assets across a number of states; each state has a wide variance of state and local jurisdictional regulation, policy, and legal frameworks that all require deliberate and precise consideration for implementing projects within Liberty's business operations.Specific to hydrogen and its primitive state of regulation, that variance increases on which states address hydrogenwithin their respective regulatory frameworks.

There are two main sources of state policy and incentives are recommended to be utilized for staying current on the evolving regulatory landscape over the broad geographical spectrum of Liberty's assets:

– **Database of State Incentives for Renewables & Efficiency® - DSIRE (dsireusa.org)**

  DSIRE is a comprehensive source of information on incentives and policies that support renewable energy and energy efficiency in the United States. Established in 1995, DSIRE is operated by the N.C. Clean Energy Technology Center at N.C. State University. Since 2015, EERE of DOE has partnered with the N.C. State to expand and enhance the database's capabilities. The DSIRE database also includes a search tool that filters incentives and policies by type, state, technology, implementing sector, and eligible sector.

– **Alternative Fuels Data Center: All Laws and Incentives Sorted by Type (energy.gov)**

  The Alternative Fuels Data Center (AFDC) provides information, data, and tools to help fleets and other transportation decision makers find ways to reach their energy and economic goals through the use of alternative and renewable fuels, advanced vehicles, and other fuel-saving measures. The AFDC is a resourceof the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy's Vehicle TechnologiesOffice administered by the National Renewable Energy Laboratory.

3.1 Domestic Projects of Interest

There are a number of programs and projects of interest to Liberty where the results will help shape early decisions for policy and regulation.

UC Irvine and SoCalGas Advanced Power and Energy Program

The University of California, Irvine ("UCI"), in collaboration with SoCalGas, is running a demonstration project through its Advanced Power and Energy Program ("APEP") to utilise excess renewable power by converting it to hydrogen and blending it into the natural gas system. In 2016, UCI engineers successfully implemented the first power-to-gas hydrogen pipeline injection project in the US. SoCalGas is exploring ways that their existing infrastructure could be leveraged to enable other power-to-gas opportunities:

– $32M Estimate Budget.
– Project components: Literature review and laboratory research, Demonstration of injection into newer distribution system and collecting operational and performance data, Demonstration of injection into older distribution system and collecting operations and performance data, and Demonstration of injection into transmission system and collecting operational and performance data.
– Summary of pipeline fatigue and fracture behavior: Fatigue accelerated >10% and fracture resistance reduced by >50%, Welds of comparable strength have similar performance to base metals when residual stresses are accounted for, fatigue and fracture are affected by magnitude of pressure, and even small amounts of hydrogen have large effects.

Mitsubishi Power Americas Inc. in Northeast Hydrogen-powered Gas Turbines

The developers of three natural gas-fired generation projects in New York, Ohio and Virginia announced the selection of Mitsubishi Power Americas Inc. to supply hydrogen-compatible gas turbines, along with associated equipment for the generation and storage of hydrogen from renewable sources for the planned power stations. The projects, with a proposed aggregate capacity of 3,000 MW, are being developed by Danskammer Energy LLC, Balico LLC and EmberClear and scheduled to complete in 2022 and 2023. It is intended that all three projects (with an estimated aggregate value of US$3 billion) will, gradually, transition to 100 percent green hydrogen, while at the same time utilizing excess renewable energy to produce and store hydrogen on-site.

Other Electrolyzer and Blending Demonstration Projects

There are numerous hydrogen electrolyzers operating in the US and there are a number of planned or operating hydrogen natural gas blending demonstration projects. GHD has provided some detailed information on these facilities and projects in Appendix B. Liberty can obtain information and learn from these other projects in terms of approaches and requirements for regulatory approvals.

4. International Perspective

Key highlights:

– There is an increasing number of nations bullish with hydrogen strategies and investment road maps.
– National strategies often share regional goals of decarbonization, generation pathways, import/export schemes, and integration of renewables.

Hydrogen activities are well spread around the globe with major interests in Europe, Asia, and the Pacific region, as well as in the Americas. Most strategies have been developed and announced recently, i.e., in 2020 or in late 2019, (AU, NL, NO, DE, EU, ES) with three countries establishing their strategy prior to 2019 (JP, FR, KR). Figure 3 details which countries have addressed hydrogen from a national perspective and how advanced each strategy has developed to date.

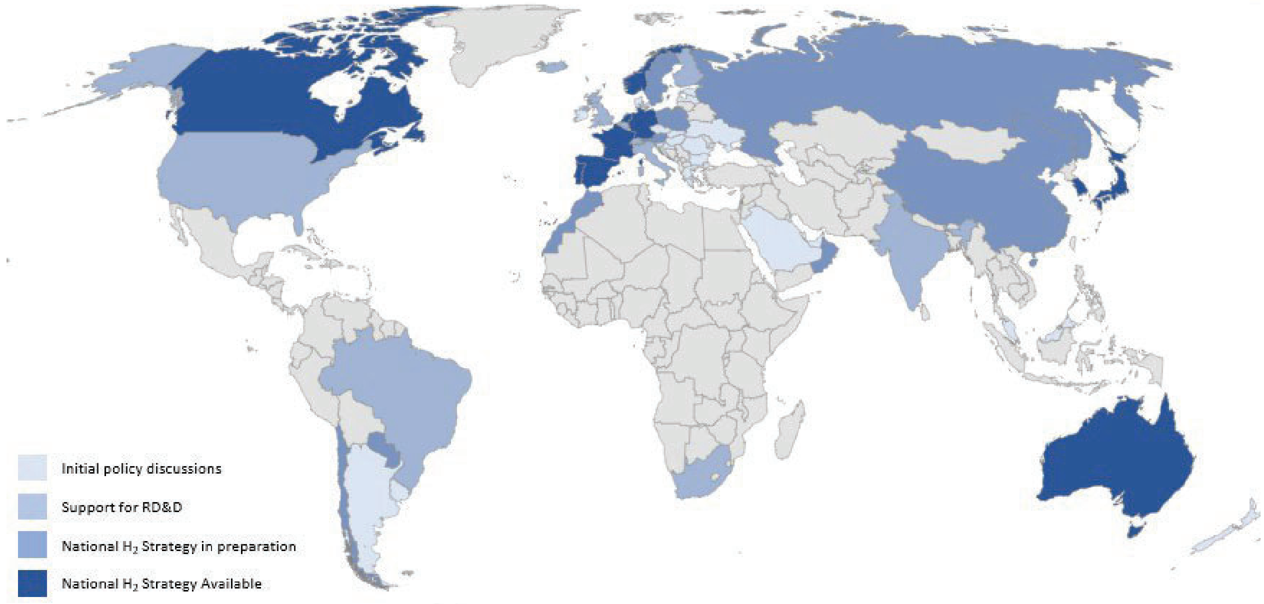


Figure 3 ***Current Status of International Hydrogen Strategies and Road Maps***
Source: Respective National Hydrogen Strategies, GHD Analysis

Main drivers for this development are GHG emission reduction goals, the integration of renewables, as well as the opportunity for economic growth. While national strategies differ in detail, reflecting particular country interests and industrial strengths, there is substantial international momentum behind the universal recognition of hydrogen playing an essential and indispensable role with decarbonized energy systems. Figure 4 highlights key motivators and strategic goals for selected nations.

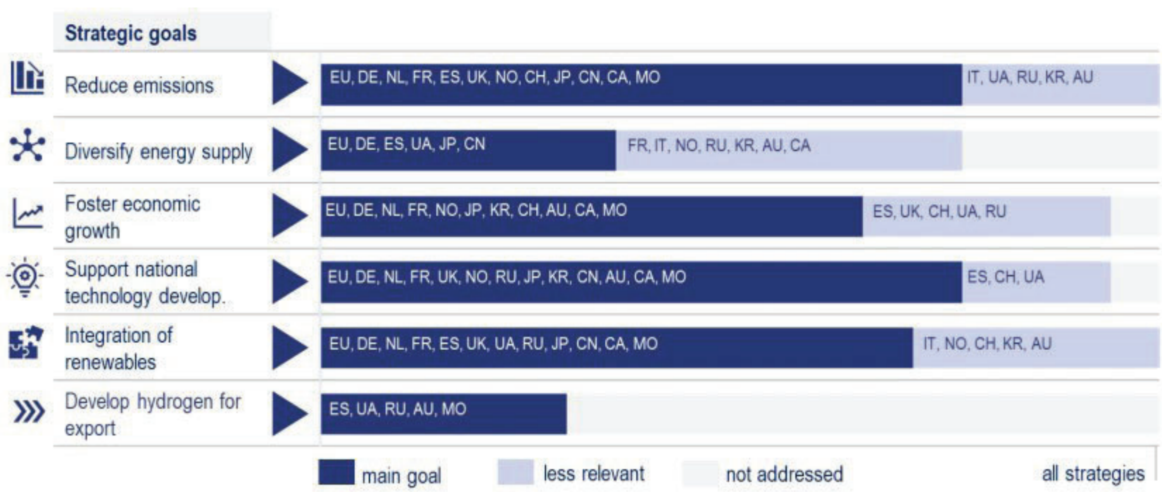


Figure 4 ***Strategic Goals for Selected Nations' Hydrogen Strategies and Road Maps***
World Energy Council

In this section, an overview of work being undertaken by nations at the forefront of developing their own respective hydrogen economies and status of regulatory frameworks.[18]

18 World Energy Council, International Hydrogen Strategies, September 2020.

4.1 National Hydrogen Strategies

Generally, initiatives and framing of regulation and policy is driven at the Federal level, with significant capital investments and coordinated RD&D programs. Nations that have developed structured national hydrogen strategies or road maps include specific ramping up of production volumes, economic implications of transitioning away from traditional fuels, and considerations for the balancing of international trade supply and demand between now and beyond 2050. These developments, while specific to each nation, may serve as guidance and motivation for US regulatory and policy framing and are thus critical to follow moving forward:

– Strategies are largely congruent with one another: RD&D to frame regulation and policy.
– Each country's focus specific to existing strengths, potential for customers, and availability of resources toproduce hydrogen in near vs long term (Generation, transport / storage, off-takers).
– Following countries provide examples of significant investment, progress with strategy, and cohesionamong domestic priorities with of subtle differences between each other.
– End effect: strategy and RD&D will develop into concrete policy and regulation.

Canadian National Hydrogen Strategy

In December 2020, Canada released a National Hydrogen Strategy. Development of an at-scale, clean hydrogen economy is a strategic priority for Canada, needed to diversify the future energy mix, generate economic benefits and achieve net-zero greenhouse gas emissions by 2050. This will require a radical transformation of Canada's energy system. Canada has all the ingredients necessary to develop a competitive and sustainable hydrogen economy.

Canada's hydrogen strategy has been developed to reflect the input and views expressed in wide consultation with stakeholders and partners. The recommendations will inform the development of concrete actions by all players needed to lay the foundation for and support the growth of diversification and expansion of the hydrogen ecosystem in Canada. Recommendations have been proposed across 8 key pillars:

1. Strategic Partnerships - Use existing and new partnerships strategically to collaborate and map the futureof hydrogen in Canada.
2. De-risking of Investments - Establish funding programs, long-term policies, and business models toencourage industry and governments to invest in growing the hydrogen economy.
3. Innovation - Take action to support further R&D, develop research priorities, and foster collaborationbetween stakeholders.
4. Codes and Standards - Modernize existing codes and standards to keep pace with this rapidly changingindustry and remove barriers to deployment, domestically and internationally.
5. Enabling Policies and Regulations - Ensure hydrogen is integrated into clean energy road maps andstrategies at all levels of government to incentivize its application.
6. Awareness - Lead at the national level to ensure individuals and communities are aware of hydrogen'ssafety, uses, and benefits during a time of rapidly expanding technologies.
7. Regional Blueprints - Implement a multi-level, collaborative government effort to facilitate the developmentof regional hydrogen blueprints to identify specific opportunities and plans for hydrogen production and end use.
8. International Markers - Work with international partners to ensure the global push for clean fuels includes hydrogen.

German National Hydrogen Strategy

In June 2020, Germany rolled out a national hydrogen strategy that eyes a 200-fold increase in electrolyzer capacity—of up to 5 GW by 2030. This corresponds to 14 TWh of green hydrogen production and will require 20 TWh of renewables-based electricity. An additional 5 GW of capacity may be added by 2035 and no later.[19]

[19] BMWi, German National Hydrogen Strategy, 2020.

Within this context of extending the range of hydrogen as an energy source within Germany, the Federal Ministry of Economic Affairs and Energy (BMWi) in 2019 announced 20 federally funded projects intended to progress the implementation of large-scale projects intended to bolster its domestic hydrogen economy. These Reallabore, or Living Sandboxes, focus on the production, storage, and utilization of hydrogen within various real environments, and the results will help guide Germany's long-term strategy and roadmap concerning their hydrogen economy. They offer companies the opportunity to implement their technical and fundamental innovations and test them in a real environment in cooperation with researchers. Further, an immediate and large-scale application of relevant technologies can show where and how regulatory barriers can be overcome to accelerate the market establishment of hydrogen-based energy innovations.

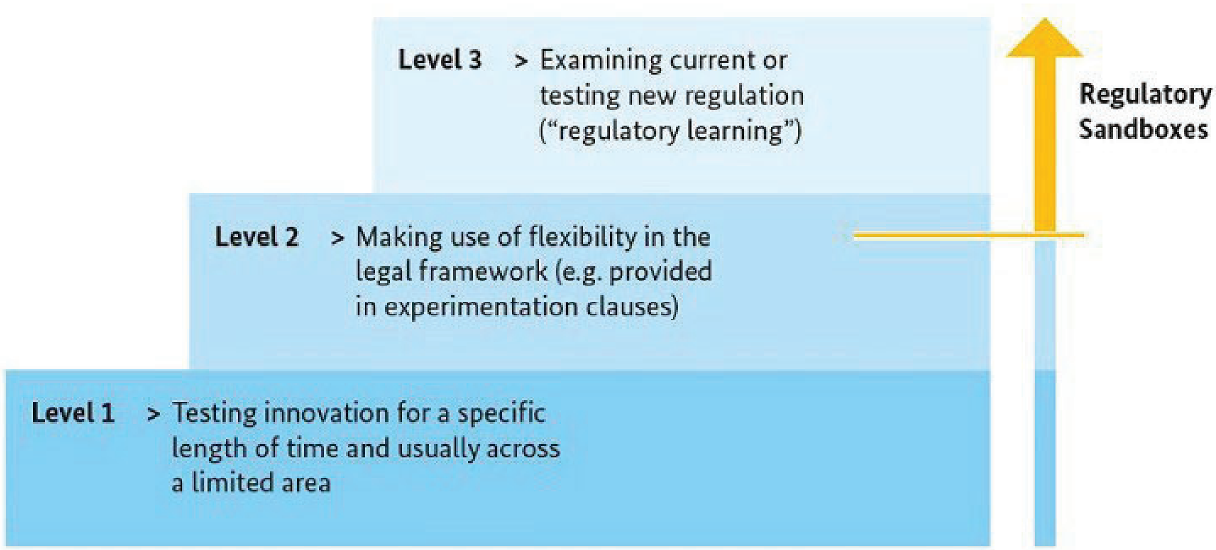


Figure 5 *Overview of German Pathway for Regulatory Sandboxes to Drive Regulation*
Source: BMWi, National Hydrogen Strategy, 2020

Australian National Hydrogen Strategy

Australia's National Hydrogen Strategy, developed in 2019[20], lays out an adaptive pathway to clean hydrogen growth:

– Support an adaptive approach to industry development that means Australia can be ready to move quicklyto scale up as signs of large-scale markets emerge. A 'review-revise-adapt' feedback loop will support andrefine actions as technology and markets change. This adaptive approach will focus on actions that remove market barriers, efficiently build supply and demand, and accelerate the global hydrogen cost- competitiveness of Australia's hydrogen industry.
– Support an approach guided by four underpinning principles, namely to:
  - Take an adaptive and nationally coordinated approach to support industry development, includingregulatory reviews
  - Prioritize regulatory consistency and a coordinated approach to project approvals
  - Support partnerships to activate the market
  - Put safety, environmental sustainability, and benefits to Australians at the forefront
– Support actions themed around seven areas: developing production capacity, supported by local demand; responsive regulation; international engagement; innovation and R&D; skills and workforce; community confidence; and national coordination.

[20] COAG Energy Council, Australia's National Hydrogen Strategy, 2019.

– Support a pathway for developing a local industry, initially by removing regulatory barriers to hydrogen use and encouraging it through policies to help early movers overcome investment barriers. Mandating use of hydrogen will require evidence that a net benefit to consumers will result, or there is a consumer willingness to pay where appropriate, and that industry can meet regulated requirements.

Japan's Strategic Roadmap for Hydrogen and Fuel Cells

In March 2019 the Government of Japan released its third Strategic Roadmap for Hydrogen and Fuel Cells. Japan considers its domestic uptake of hydrogen as a viable way to increase its energy self-sufficiency; decarbonize its economy; increase industrial competitiveness; and position Japan as a fuel cell technology exporter. At this stage, Japan is prioritizing the reduction of the production cost of hydrogen. The key consideration for large-scale uptake of hydrogen in Japan will be cost, and Japan is pursuing hydrogen produced using fossil fuels and utilizing CCUS technology which is currently more economically competitive. Japan is looking for international cooperation to build a hydrogen supply chain, increase the scale of production, and reduce costs. Japanese companies continue to actively seek engaged international partners to undertake demonstration projects that deliver tangible results which presents an opportunity for Australia and New Zealand with their renewable energy credentials, and both Government's strong support for hydrogen. Japan is interested in importing green hydrogen if the price is competitive, and two Japanese companies have invested in, or are looking to invest in, green hydrogen projects in both Australia and NewZealand. Initial proof of concept projects will likely produce hydrogen with either coal or carbon-based feedstocks.

The total government budgetary support for hydrogen for this financial year (ending March 2021) is 70 billion yen and includes:

– Subsidies for fuel cell vehicles
– Subsidies for hydrogen refueling stations
– Research and development on fuel cell technologies
– Hydrogen supply infrastructure
– International research collaboration projects for innovative technologies in clean energy (for exampleCCS)
– Pilot projects to develop the hydrogen supply chain
– Development to produce, store and utilize hydrogen

In January 2020 the Japan Bank for International Cooperation designated hydrogen as an "essential resource", unlocking more government funding for hydrogen projects (covering the entire supply chain including production, transportation, supply and utilization) to be undertaken in developed countries. Japan was planning to use the 2020 Olympic and Paralympic Games as a platform to promote it hydrogen technology by using fuel cell vehicles and buses, and powering the athletes' village with hydrogen. Japan may consider showcasing a scaled down version of its hydrogen technology at the Olympic and Paralympic Games postponed to 2021. Japan considers Expo 2025 in Osaka as another opportunity to showcase Japan's hydrogen technology and share its plans for a hydrogen economy.

Japan also considering ammonia as a potential fuel to decarbonize its economy. Japan is also actively considering ammonia as a viable fuel to:

– Decarbonize the maritime industry
– Transport hydrogen
– Store energy

An industry group called the Green Ammonia Consortium operates in Japan which is working to build an international supply chain for ammonia as a way to decarbonize economies.

The strategy notably seeks to achieve cost parity with competing fuels, such as liquefied natural gas for power generation. It has also set out concrete cost and efficiency targets per application, targeting electrolyzer costs of \$475/kW, efficiency of 70% or 4.3 kWh/Nm^3, and a production cost of \$3.30/kg by 2030. It also has multiple projects underway for international trade in hydrogen. The Hydrogen Energy Supply Chain, for example, is committed to delivering hydrogen converted from coal gasification from Victoria's Latrobe Valley in Australia. The first liquid hydrogen ship was delivered in December 2019, and the first blue ammonia (ammonia from gas reforming with carbon capture) shipment arrived in September 2020.

European Union

The aim of the EU Hydrogen Strategy is to decarbonize hydrogen production and expand its use in sectors where it can replace fossil fuels. Although the main focus lies on green hydrogen, the EU Hydrogen Strategy recognizes the role of other low-carbon hydrogen in the transition phase in the short to medium term.

The most relevant goal of the EU Hydrogen Strategy is the build-up of additional hydrogen production capacity (i.e., building electrolyzers). The EU Hydrogen Strategy provides targets of installing (i) in phase 1, at least 6 GW of renewable hydrogen electrolyzers in the EU by 2024 and (ii) in phase 2, 40 GW of renewable hydrogen electrolyzers in the EU, along with an additional 40 GW electrolyzer capacity target in the eastern and southern 'neighborhoods' of Europe, e.g., Ukraine, as the priority partners for cross-border trade in hydrogen.

The EU Hydrogen Strategy highlights that support schemes are likely to be required for some time to enable renewable hydrogen to become cost-effective on the scale envisaged. In this regard the EU Hydrogen Strategy considers an amendment of the EU Emission Trading System. In the next revision of the ETS, the Commission may consider how to incentivize the production or renewable and low-carbon hydrogen while considering the risk of carbon leakage. If differences in climate targets around the world continue, the Commission will propose a Carbon Border Adjustment Mechanism in 2021.

According to the EU Hydrogen Strategy, Carbon Contracts for Differences could be another valuable support mechanism. The Strategy Document envisages where the public counterpart would remunerate the investor by paying the difference between the carbon strike price and the actual strike price in the ETS.

5. Hydrogen Injection Blending Limits

Specific to blending limits on an international level, the following table provides an overview of the existing limits. Some demonstration projects, such as the HyDeploy project in the UK, have gained exemption to blend beyond the regulatory limits presented.

Table 5.1 Overview of Existing Blending Limits

Country	Standard/Regulation/Specification &Comments	Blend Limit	Limitation Includes
Austria	ÖVGW-RL 31	4%vol	Natural gas distribution and transmission
		2%vol	If a natural gas refueling station is downstream of injection point
France	Decree n°2004-555 describes requirements for non-natural gas injection into the grid (i.e., Wobbe index, density, etc.). GRTgaz published technical guidelines based on this Decree for hydrogen injection and blending, specifying the blend limit given.	6%vol	Natural gas distribution and transmission
Germany	DVGW Standard G 262	10%vol	Natural gas distribution system
		2%vol	If a natural gas refueling stationis downstream of injection point

Country	Standard/Regulation/Specification &Comments	Blend Limit	Limitation Includes
Italy	Snam Gas Grid Code – Snam is a large gas grid operator in Italy. There are no national- level regulations or standards in place. In 2019, Snam began injecting 5% hydrogen intoa local gas grid, announcing intentions to jumpto 10% in December 2019. Therefore it is likely Snam's Gas Grid Code referenced is superseded.	0.5-1%vol	Natural gas distribution system
Latvia	Overall legislation for mixture in gas networkbased on gas quality (not targeted for hydrogen injection and blending)	0.1%vol	Natural gas distribution and transmission
Netherlands	Dutch Gas Act	0.02%vol	High-pressured Dutchtransmission grid
		0.5%vol	Natural gas distribution andregional transport grids
Spain	Ministerio de Industria, Turisme y Comercio de España, Boletín Oficial del Estado n°238	5%vol	Uncertain
United Kingdom	Gas Safety Management Regulations 1996 – sets the UK gas quality specification and Wobbe Index range, including stated limit forhydrogen	0.1%vol	All natural gas

Source: PRCI report PR-720-20603-R01 Emerging Fuels - Hydrogen SOTA Gap Analysis and Future Project Roadmap.

6. Hydrogen Coalitions and Associations

International or regional platforms for stakeholders in the hydrogen industry may collectively facilitate and promote the best interests of the hydrogen sector from a regulatory perspective. Current coalitions and associations are scoped at both federal and state levels.

6.1 North America

Clean Hydrogen Future Coalition (CHFC)

The Clean Hydrogen Future Coalition (CHFC) was launched in March 2021 with over 20 organizations, including Liberty, to support federal clean hydrogen policies promoting clean hydrogen as a key pathway for US decarbonization and competitiveness. 'The coalition is identifying specific actions that the U.S. can undertake to scalethe full supply chain for clean hydrogen production, transport, storage, and use, as well as the technology development and infrastructure needs across multiple sectors.'[21]

[21] https://cleanh2.org/ Accessed April 2021.

Figure 6 *Clean Hydrogen Future Coalition (CHFC) Members*
Source: cleanh2.org

Zero Carbon Hydrogen Coalition

The Zero Carbon Hydrogen Coalition is a coalition of companies who are working together to persuade Congress to open the Innovation Tax Credit and Production Tax Credit to allow renewable natural gas (RNG) and renewable hydrogen (RH2) projects to qualify for the tax credit. The Coalition was just formed earlier this year and plans to run through 2021.

Hydrogen Forward

Hydrogen Forward is a coalition of 11 organizations formed in February 2021 to advance hydrogen development in the

U.S. The coalition aims to educate decisionmakers and stakeholders on the value hydrogen delivers today and the important role that it should play in the future. The consortium 'support the establishment of a national hydrogen that outlines a clear, comprehensive approach to hydrogen and related infrastructure development.'[22]

Members of the Hydrogen Forward coalition are making significant domestic investments and driving specific projects across the nation to bring these technologies to scale. From the manufacturing and sale of hydrogen fuel cell electric vehicles (FCEVs) to supporting the fueling stations that keep FCEVs moving, Hydrogen Forward members are on the leading edge of transportation innovation. Likewise, member company hydrogen storage solutions and partnerships with local utility companies are helping to harness renewable energy and decarbonize the power generation sector.[23]

[22] https://www.hydrogenfwd.org/about/ Accessed April 2021.
[23] Bloom Energy. 2021. Press Release on Hydrogen Forward Coalition.

Figure 7 ***Hydrogen Forward Founding Members***
Source: hydrogenfwd.org

Fuel Cell and Hydrogen Energy Association (FCHEA)

The Fuel Cell and Hydrogen Energy Association (FCHEA) represents more than 50 companies and organizations that are advancing innovative, clean, safe, and reliable energy technologies. FCHEA drives support and provides a consistent industry voice to regulators and policymakers on the environmental and economic benefits of fuel cell and hydrogen energy technologies. The mission of FCHEA is to advance the commercialization of and promote the markets for fuel cells and hydrogen energy.

FCHEA primary activities include:

– Leading national advocacy to encourage all levels of government to support fuel cell and hydrogentechnology research, development, and deployment.
– Providing the industry a voice in shaping regulations, codes, and standards to enable commercial growth,while ensuring the highest levels of consumer safety and satisfaction.
– Educating the public and key opinion and policy leaders on the economic and environmental benefits offuel cell and hydrogen technologies.

To achieve these goals, FCHEA operates a number of working groups and committees, collaborating with itsmembers on specific initiatives and technologies to help the industry thrive.

Pipeline Research Council International (PRCI)

Pipeline Research Council International (PRCI) is a not-for-profit corporation, comprising about 70 organizations from around the world, primarily energy pipeline companies, as well as equipment manufacturers and service providers.

PRCI membership consists of gas network operators and institutions globally, invested in the advancement of the industry with a particular focus on gas transmission pipelines. Liberty will want to continue leveraging the knowledge and partnership opportunities as hydrogen plays an increasing role within the community of PRCI members.

PRCI recognizes an increasing interest, particularly in Europe, North America, and Australia, in blending hydrogen into the natural gas network as both a way to decarbonize the natural gas grid and enable the transition to a hydrogen economy through existing pipeline transport. Due to this development, PRCI funded a research effort to address hydrogen blending in a report released to members in 2020.

The goal of the effort was to assess the key technical knowledge gaps associated with introducing hydrogen to natural gas systems and identify research priorities to ensure the safe, reliable and cost-effective injection and blending of hydrogen in existing pipelines. This state-of-the-art study provides PRCI members with valuable up-to-date information on the key technical challenges and ongoing research and project efforts, while advising PRCI with regards to future research needed to advance this industry.

American Gas Association (AGA)

The American Gas Association (AGA), founded in 1918, represents more than 200 local energy companies that deliver natural gas. AGA's core strengths include developing standards, advocating for natural gas industry issues, regulatory constructs and business models. AGA's new chair, David Anderson, President and CEO of Northwest Natural, recognizes the key roles of renewable natural gas and hydrogen in decarbonizing the US natural gas distribution system.

Gas Technology Institute (GTI)

GTI is a research, development and training organization addressing energy and environmental challenges. GTI has decades of experience with hydrogen research and technology development, including generation, storage & delivery, transportation and end uses.

6.2 State-level

A main emphasis of hydrogen and fuel cells initiatives in the U.S. is centered on the mobility sector with varying magnitudes of incentives dependent on State and/or municipality.

Clean Cities Coalition Network

A coordinated group of nearly 100 coalitions serve as the foundation of Clean Cities, working in communities across the country to help local decision makers and fleets understand and implement alternative and renewable fuels, idle- reduction measures, fuel economy improvements, new mobility choices, and emerging transportation technologies. The U.S. Department of Energy's (DOE) Vehicle Technologies Office (VTO) within the Office of Energy Efficiency andRenewable Energy facilitates national coordination of the coalitions through its Technology Integration Program.

Together, Clean Cities coalitions and VTO focus on advancing affordable, domestic transportation fuels, energy efficient mobility systems, and other fuel-saving technologies and practices.

Figure 8 *DOE Map of Clean Cities Coalition Network Participants*
Source: Clean Cities Coalition Network, 2020

As Liberty continues to build out their hydrogen strategy, including prospective mobility markets within the CleanCities Coalition Network serves as a valuable collaboration point for establishing potential hydrogen off-takers.

California Fuel Cell Partnership (CalFCP)

Founded in 1999, the California Fuel Cell Partnership (CalFCP) is an industry/government collaboration aimed at expanding the market for fuel cell electric vehicles powered by hydrogen to help create a cleaner, more energy- diverse future with no-compromises zero emission vehicles. Staff from member organizations participate on standingcommittees and project teams that help ensure that vehicles, stations, regulations and people are in step with each other as the market grows.[24]

Connecticut Hydrogen-Fuel Cell Coalition (CHFCC)

The Connecticut Hydrogen-Fuel Cell Coalition, administered by the Connecticut Center for Advanced Technology, is comprised of representatives from Connecticut's fuel cell and hydrogen industry, academia, government, and other stakeholders. CCAT and the Connecticut Hydrogen-Fuel Cell Coalition works to enhance economic growth in Connecticut through the development, manufacture, and deployment of fuel cell and hydrogen technologies and associated fueling systems.

The Connecticut Hydrogen-Fuel Cell Coalition is made up of companies and organizations that do business with each other and/or have common needs for talent, technology, and infrastructure. Connecticut companies now lead the world in the development of molten carbonate and phosphoric acid fuel cells and are among the leaders in proton

[24] https://cafcp.org/about_us Accessed April 2021.

exchange membrane (PEM) and other electrochemical technology applications. Connecticut companies in hydrogen generation are leaders in both proton exchange membrane electrolysis systems and in converting natural gas or petroleum products to hydrogen through reforming processes.[25]

6.3 International Coalitions

Hydrogen Council

The Hydrogen Council is a global CEO-led initiative that brings together leading companies with a united vision and long-term ambition for hydrogen to foster the clean energy transition. Using its global reach to promote collaboration between governments, industry and investors, it provides guidance on accelerating the deployment of hydrogen solutions around the world.

The Hydrogen Council believes that hydrogen has a key role to play in the global energy transition by helping to diversify energy sources worldwide, foster business and technological innovation as drivers for long-term economic growth, and decarbonize hard-to-abate sectors.

Acting as a business marketplace, the Hydrogen Council brings together a diverse group of 109 companies based in 20+ countries and across the entire hydrogen value chain, including large multinationals, innovative SMEs, and investors. The Hydrogen Council serves as a resource for safety standards and an interlocutor for the investment community, while identifying opportunities for regulatory advocacy in key geographies.

The Hydrogen Council is currently composed of CEOs and chairpersons from the following companies:

– Steering members: 3M, Airbus, Air Liquide, Air Products, Alstom, Anglo American, Audi AG, BMW GROUP, BP, CF Industries, Chemours, Bosch, China Energy, CMA CGM, CNH Industrial (via IVECO), Cummins, Daimler, EDF, ENEOS Corporation, ENGIE, Equinor, Faurecia, General Motors, Great Wall Motor, Honda, Hyundai Motor, Iwatani, Johnson Matthey, Kawasaki, KOGAS, Linde, Michelin, Microsoft,MSC Group, Plastic Omnium, SABIC, Saudi Aramco (via the Aramco Overseas Company), Schaeffler Group, Shell, Siemens Energy, Sinopec, Solvay, thyssenkrupp, Total, Toyota, Uniper and Weichai.
– Supporting members: ACME, AFC Energy, AVL, Baker Hughes, Ballard Power Systems, Black & Veatch, Chart Industries, Chevron, Clariant, Delek US Holdings, ElringKlinger, Enbridge Gas, Faber Industries, First Element Fuel (True Zero), Fortescue Metals Group, Galp, W. L. Gore, Hexagon Composites, ILJIN Composites, ITOCHU Corporation, Liebherr, MAHLE, MANN+HUMMEL, Marubeni, McDermott, McPhy, Mitsubishi Corporation, Mitsubishi Heavy Industries Ltd., Mitsui & Co, Nel Hydrogen, NGK Spark Plug Co.,Nikola Motor, NYK Line, PETRONAS, Plug Power, Port of Rotterdam, Power Assets Holdings, Re-Fire Technology, Reliance Industries Limited, Sinocat, SinoHytec, Sinoma Science & Technology, Snam, Southern California Gas, Sumitomo Mitsui Banking Corporation, Sumitomo Corporation, Technip Energies, Tokyo Gas, Toyota Tsusho, Umicore, Vopak, and Woodside Energy.
– Investor Group: Antin Infrastructure Partners, BNP Paribas, Crédit Agricole, GIC, John Laing, Mubadala Investment Company, Natixis, Providence Asset Group and Société Générale.

Asia-Pacific Hydrogen Association

Established in December 2019, the Asia-Pacific Hydrogen Association is the leading industry association for the hydrogen sector in Asia-Pacific. The Asia-Pacific Hydrogen Association acts as the regional platform for all stakeholders in the hydrogen industry to collectively promote the best interests of the hydrogen sector. Members include utilities, power project developers, equipment manufacturers, technical consultants, financial institutions, regional associations and other institutions in the hydrogen sector.

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25 http://chfcc.org/ Accessed March 2021.

Hydrogen Europe

Hydrogen Europe brings together diverse industry players, large companies and SMEs, who support the delivery of hydrogen and fuel cells technologies. Hydrogen Europe represents the European hydrogen and fuel cell sector with(as per April 2021) 260+ companies and 27 National Associations.

Hydrogen Europe Research (HER) is an international non–profit association composed of 91 universities and Research & Technology Organizations (RTO) from 26 countries all over Europe and beyond. Hydrogen Europe members are active within the European hydrogen and fuel cell sector.

HER is one of the three participants of the European Joint Undertaking (JU) on Hydrogen, alongside its industry counterpart Hydrogen Europe (HE) and the European Commission. From 2008 to 2020, the Fuel Cells and Hydrogen JUs (FCH JU & FCH 2 JU) have been unique public private partnerships supporting Research, Technological development and Demonstration (RTD) activities in fuel cell and hydrogen technologies in Europe. HER will continueto participate in the future Institutionalized European Partnership (IEP) on hydrogen, entitled Clean Hydrogen Joint Undertaking (CH JU), from 2021 to 2027.

HER's members contribute to the preparation of the Clean Hydrogen JU's Multi-Annual and Annual funding priorities. In cooperation with Industry, they have the unique possibility to shape the focus of the Program. Concretely, HER members participate in the different Technical Committees and roadmaps shared with HE where annual strategic priorities are discussed and topics for future Calls for proposals are drafted. The Technical Committees and roadmaps are included in the three pillars of the JU (Pillar 1: Hydrogen production; Pillar 2: Hydrogen storage, transport and distribution; Pillar 3, Hydrogen end-uses).[26]

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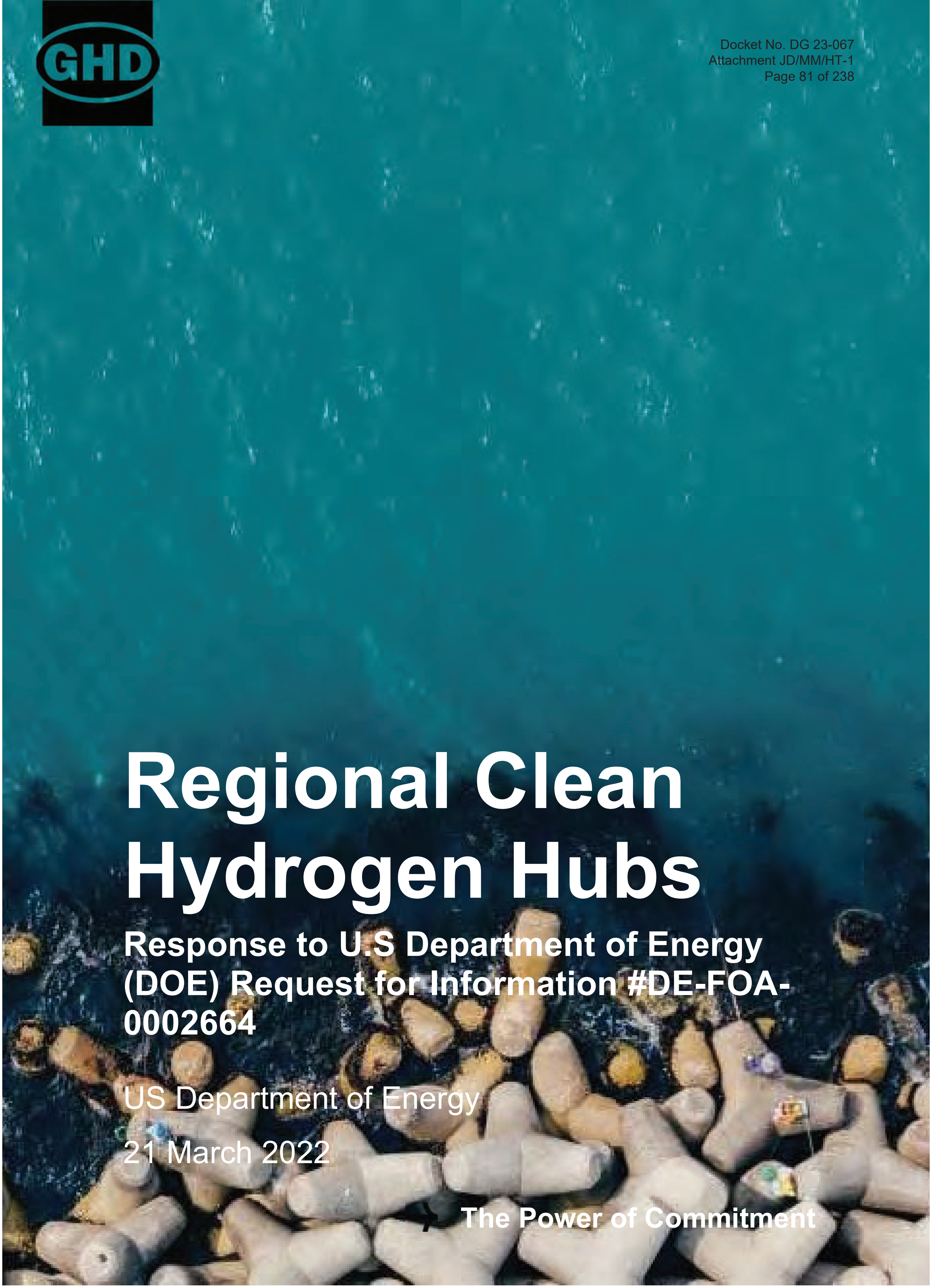
Appendix A

GHD DOE Hydrogen Hub RFI Response March 2022



Regional Clean Hydrogen Hubs

Response to U.S Department of Energy (DOE) Request for Information #DE-FOA-0002664

US Department of Energy

21 March 2022

The Power of Commitment

DOE ref: Request for Information #DE-FOA-0002664.0002

21 March 2022

Dr. Sunita Satyapal
US Department of Energy
Director, Hydrogen & Fuel Cell Technologies Office
1000 Independence Ave SW
Washington D.C.
20585

Regional Clean Hydrogen Hubs

Dear Dr. Sunita Satyapal

Thank you for the opportunity to respond to this Request for Information issued by the U.S. Department of Energy's Hydrogen Program to obtain public input regarding the solicitation process and structure of a DOE Funding Opportunity Announcement (FOA) to fund regional clean hydrogen hubs. We are delighted to respond to this request.

GHD is one of the world's leading professional services companies operating in the global markets of water, energy and resources, environment, property and buildings and transportation. We are 100% employee-owned, operating for more than 90 years, employing over 10,000 people in 200+ office locations to deliver projects with high standards of safety, quality and ethics across the entire asset value chain.

We have been working in the hydrogen space for over 50 years in the U.S. and Canada, and in the Middle East, UK, Asia, Australia and New Zealand in the last 10 years.

GHD is very excited about this Program. We also see that hydrogen will play a key role in unlocking decarbonization pathways as the zero-emissions energy commodity of the future. We believe, hydrogen will not just transform energy systems, it will transform economies and communities. GHD has a strong desire to support this collective ambition to make a difference.

We are fortunate to have worked on more than 50 hydrogen-related projects in the last five years alone, including the world-first hydrogen export supply chain project, known as HESC, with Kawasaki Heavy Industries, Marubeni, Iwatani and JPOWER, in Australia – this remains the only fully-operational hydrogen supply chain that has just proven how to produce, transport, store, ship and use hydrogen as a zero-emissions power source for Japan.

Given the fledgling nature of the industry, we understand the significance of collaborating closely with policymakers, shareholders, investors, and the community at large, from the very beginning. GHD is proud to have established itself as a trusted advisor in the low carbon hydrogen and ammonia and other fuels area.

Developing the global hydrogen economy will require strong partnerships and a shared vision. DOE will require advisors who have globally connected technical know-how and a deep knowledge of the U.S hydrogen supply chain players.

Our proposition to DOE in the development of Hydrogen Hubs for the U.S.

We would like to have the opportunity to help DOE drive important outcomes for the development of a thriving, and sustainable hydrogen industry, based on our first-hand experience working across the U.S. on hydrogen and many other projects, and supporting hub development in other jurisdictions.

- **Hydrogen Project Development expertise:** **Technical, commercial, and social learnings extracted from first-hand hydrogen supply chain experience.** GHD has worked on both the Government-side advising policy-makers and decision-making Agencies and Authorities, as well as Proponent-side developing hydrogen projects across a range of different Countries and contexts.

- **Market activation:** We start with the market when it comes to hubs – it is important for DOE to be able to work with an independent engineering firm who has impartial industry connectivity across the full value chain with an appreciation of the key drivers of each of the stakeholders. We understand the levers to pull to activate the market and the connected network that sits behind success of hydrogen hubs (renewables, gas, investment, community, safety, regulation.)
- **Global learnings for U.S hydrogen hubs:** **Our first-hand experience with the successes and failures elsewhere allows us to advise you on an optimal U.S. roll out.** Our execution experience means we know where the opportunities and challenges are in rolling out a program of this scale. We can de-risk process.
- **Established hydrogen industry networks:** We know the market, the operators and their assets, the geographic factors, and we understand what the community needs to know. This informs our ability to support the DOE in the development of an effective Solicitation Process, the FOA Structure, and the H2Hubs Implementation Strategy, as outlined in our formal RFI response below.
- **We understand the key consumer sectors:** Progressive oil and gas players moving to a lower carbon future, the mining sector and other hard-to-abate industries, and energy players who are deeply vested in renewables. We work with these sector leaders daily.
- **We are committed to the energy transition.** GHD has made a collective commitment; a promise to bring everything we have - talented people, diverse perspectives, and deep project experience – to this important global endeavour. As a connected team of advisors and engineers who work across the value chain, we are uniquely placed to make a positive difference.

We have a purpose that guides everything we do: Together with our clients, we create lasting community benefit. 'Together' means we work in partnership, with our clients and with each other. 'Create' means that we come up with new ideas and innovative solutions to meet the challenges that our clients face. 'Lasting community benefit' means we have, at our core, a deep sense of responsibility to make the world in which we live and work a better place.

The pivot away from fossil fuels is well underway and promises to reimagine our energy systems – for the better. Policymakers, shareholders, investors and the community at large are demanding and accelerating this change. To achieve lasting global benefit, we believe both dramatic and incremental improvement – solutions large and small – are required to harness the opportunities we see on the horizon, while addressing the challenges at hand.

We are committed to leading this change for good. Thank you again for providing GHD with the opportunity to share our experiences in this RFI to drive the global energy transition founded by a thriving hydrogen industry.

Sincerely,

Dr. Tej Gidda
Global Leader – Future Energy and Hydrogen

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- **Background on the hydrogen hub grant programs GHD has been involved:**
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  2. **Canadian pillars for development of Hydrogen Hubs**

Category 1

Regional Clean Hydrogen Hub Provision and Requirements

1. Category 1: Regional Clean Hydrogen Hub Provisions and Requirements

1. The BIL defines a "regional clean hydrogen hub" as "a network of clean hydrogen producers, potential clean hydrogen consumers, and connective infrastructure located in close proximity."
   a. *What should qualify as 'close proximity' in context of the hub requirements?*

Any hub should consider existing demand and future growth from the onset. In this respect, there is existing hydrogen production in the United States at a volume of approximately 10 million metric tons per annum. Most of this is consumed in existing oil refineries, for the production of ammonia for the agricultural sector, chemicals production, and additional use in the production, food processing and electronics sector. When considering the hub model in the US, mapping the existing hydrogen usage is a critical component of determining relative proximity, as offtake markets in the short-term will largely dictate the placement of the initial hubs. Future hubs will likely be placed in proximity to emerging hydrogen markets in the US, such as power generation, transportation, industrial applications, and in the heating sector.

For example, the proposed Ethane storage & distribution hub close to Pittsburgh mapped out consumers 300 miles away from the hub, which represented the range of same-day / one-day delivery by truck. Some RNG spoke & hub, feedstock to renewable natural gas (RNG) facility facilities, are designed to a radius of ~100 miles for movement of raw feedstock. A current limitation of hydrogen gas by trailer is that it is feasible for short distances close to 100 miles. However, with increase adoption and technology optimization truck transport will be able to increase reach and capacity in the medium term. In addition, pipeline blending will allow for a much larger reach.

Ideally, the initial hubs also should be in proximity to production feedstock (i.e. availability of wind/solar/hydroelectric/nuclear/natural gas/water), which may conflict with offtake markets. The one disruptor in this space that extends the applicability of the hub model is the use of the existing fossil fuel natural gas pipeline network for the conveyance of hydrogen.

We are executing significant studies and demonstration projects in the blending of hydrogen into the natural gas transmission and distribution system, which offers the ability to close the gap between feedstock production and offtake markets, and that further addresses an emerging market for hydrogen, such as hard to decarbonize industries and the heating sector. Consideration of the existing pipeline networks as part of defining practical hubs is a critical consideration of the model, in our view.

b. *What existing facilities and infrastructure, including pipelines and storage facilities, could be most easily leveraged by the H2Hubs?*

Ideally, available infrastructure such as ports, storage, natural gas networks,end users (e.g. fossil power plants), underground caverns, and reservoirs should be repurposed for H2-hubs. However, leveraging existing infrastructure may be challenging at material scale, as likely the infrastructure either won't have capacity, or is not fit for purpose.

While there may be some opportunities for retooling existing infrastructure, it is our view that **investment in shared-use infrastructure is the key catalyst needed to kick start the hydrogen economy.** There are numerous assets in the US market currently servicing the fossil fuel industry that can be repurposed. In our experience creating and designing hydrogen hubs across Canada, the UK and Australia, where we have been consulting with the government, we find that one of the most valuable assets are existing planning overlays and corridors which can provide an easier pathway for augmentation/expansion; these planning overlays are typically found in concurrent Water, Renewable Energy, Transmission Lines, Logistics and other projects.

From the aforementioned opportunities we think two pieces of infrastructure are salient:

1) Pipelines: As noted, existing pipelines, particularly for natural gas, are key conveyance mechanisms for hydrogen from production to offtake. There are 3 million miles pipelines transporting natural gas across the lower 48. The ability to utilize the full capacity of these pipelines (i.e. 100% hydrogen conveyance) is not currently feasible; however, blending 10% – 15% hydrogen into natural gas is possible, and represents a very large quantity of hydrogen with respect to the DOE's hub model. Recovery of blended hydrogen is possible, as is the use of the blended product; both options should be considered to leverage the use of this existing conveyance network.
2) Storage: Salt caverns have been proven effective to store hydrogen and other fuels in the US and globally; and, multiple hydrogen storage projects are rapidly emerging in the US and in Europe. Hydrogen production from renewables, in particular, requires storage mechanism. Emerging options, such as the use of depleted oil reservoirs for hydrogen storage, further leverage pore space options that open up storage options far beyond salt caverns. This additionally allows for repurposing of existing assets for the hydrogen hubs.

c. *What types of new 'connective infrastructure' will be needed by the H2Hubs (e.g., pipelines, storage, etc.)?*

It would depend on the customer base and proximity to production – pipelines are efficient at large scale but non-economic at small scale. As mentioned above, shared infrastructure and access to pricing arrangements are very important when there are multiple customers/producers

If feedstock is natural gas (blue hydrogen), connection of blended NG & H2 gas pipelines with pure hydrogen pipelines will be required, as well as connections with storage facilities and CO2 pipelines associated with blue hydrogen production. Dedicated hydrogen pipeline is in place in areas (such as Texas and Louisiana), but is at limited capacity currently compared to hub scale; expanding this capacity is a key consideration to connect H2Hub infrastructure. As noted, additional conveyance for supply of natural gas as feedstock into Steam Methane Reformers (SMRs) for generation of H2, with subsequent blending or direct use opportunities, will be important.

For SMR options, this also requires careful consideration of storage reservoirs for CO2, all of which is unlikely to find a home in the utilization network. Pore space suitable to subsurface storage of CO2 thus becomes a critical infrastructure point for definition of the hubs. In this latter respect, we would expect CO2 storage hubs developing south of the Great Lakes down to the Gulf areas, as well as discreet north-south hub lines along the east and, to a lesser degree, along the west coast. Given the lack of defined CO2 pipeline in the US just now (less than 3,000 miles total), this will represent a significant infrastructure requirement.

Transmission connections to the existing power grid would also be required for the electrolytic production of hydrogen (green hydrogen). In other instances, transmission connections would be required to connect local renewable energy assets (hydro, solar and wind.). Certainly, a large amount of new transmission infrastructure and interconnect hardware will be required to motivate one of the largest new sectors for renewable energy in the US, that being the offshore wind market. With recent announcements by NYSERDA in New York State, with an ultimate goal of 9,000 MW of new offshore wind generation by 2035, infrastructure for tying this to electrolysis plants and then subsequent conveyance of hydrogen (by pipeline, for example) or direct use in local hubs, will formulate a connective system of infrastructure that formulates H2Hub options. Similar considerations for offshore wind exist on the west coast, where one of the first ports redeveloping for deployment (Humboldt Bay) has limited connection to the overall transmission network – but that could use the renewable electricity created directly into a local hub.

Water supply is a key element for both blue and green hydrogen. Connection to water supply is necessary. Conversely, connection to water treatment and reuse systems would need to be integrated. There is a potential for regions with access to the ocean to supply water into green and blue hydrogen systems.

d. *What supportive activities would make the hydrogen hubs successful and sustainable (e.g., workforce development, community-based organization engagement, domestic manufacturing, labor standards, etc.)?*

A hydrogen hub will achieve scale through the foundational establishment of enabling infrastructure and “market activation” in the form of domestic use applications. We believe there are seven key elements that will facilitate the creation of a successful hydrogen hub. It is important, to map these elements as part of the complex system that is presented by the H2Hub model, and we would suggest a comprehensive digital mapping of offtake markets, labor availability, existing and intended renewables infrastructure, existing and planned pipeline networks for gaseous fuels, and location of enabling infrastructure such as carbon sequestration reservoirs. This can be achieved digitally to map out the most efficient deployment of hubs, through the lens of a commercial model.

The seven key elements are:

1) Community & Social Considerations: Across industries, successful industrial hubs require: social license or community acceptance to operate, emergency preparedness, orderly growth of the community with industry expansion, and understanding of hydrogen, particularly safety. All of this would be enabled by raising public knowledge and awareness of hydrogen via continuous stakeholder engagement aiming to build trust with critical stakeholders. Community perception of fairness in the distribution of resources will also need to be addressed in the medium term, as the community needs to understand that access to energy (and water, given the demand requirement for production of either green or blue hydrogen product) will not be impaired. Concern related to the project is typically managed through consultations where there is the intention to acknowledge and address any problems raised, enhancing cohesion between developers and residents, and through continuous collaboration with safety and regulatory agencies such as OSHA.

2) Users: a) Market activation of domestic and global carbon-intensive industries to hydrogen consumers, e.g.,. deployment and servicing of connected appliance such as furnaces, boilers, stoves etc. b) Displacement of carbon intensive practices e.g., coal use in steel manufacturing and c) Access to domestic and export supply chains. All enabled by key “market activation” pilot projects to take place over the short term to ensure the decarbonisation of industries across supply chains will occur and by establishing MoUs with diverse key national and global partners to lend credence and weight to the hub creation. As noted, there is an existing market for hydrogen in the US that consumes more hydrogen than the H2Hubs would produce, and that is even before taking into account emerging markets such as transportation (vehicle fuelling - especially long-haul vehicles and transit fleets, and possibly rail), heating (displacement of MMBTU's of natural gas), and power production.

3) Workforce development / Human Capital: a) Training & research institutions offering hydrogen specific training, b) Skilled workforce that are willing to transition to a hydrogen-based industry, and workforce development plans to attract and retain workers. These elements may be enabled by the fact that the US has a strong workforce presence across fossil and renewable energy operations plus advanced manufacturing that can be leveraged to support initial hydrogen investments. Ideally, this would be supported by government, industry and education and training organisations working together to develop and deliver quality education and training programs, specific to the hydrogen industry, in some ways similar to programs developed for oil production in Texas as an example, or for mining in the Sudbury cluster in Canada. A clear example of this is the use of expertise from the oil and gas space to motivate the carbon capture, utilization and storage industry that is key to blue hydrogen; our approach has been to utilize deep exploration and subsurface reservoir modelling expertise from the extraction side of the business to provide the converse activity for storage of CO2. The abundance of skilled staff in the US market, primarily from oil and gas, presents an opportunity for retraining that is of a generational scale.

4) Renewable Energy: Is a key input into the production of green hydrogen for generation and transmission, leveraging enabled existing renewable energy across the US, as well as intended new renewable infrastructure such as the noted developments on the east coast and the west coast (where the former will be developed more quickly). Power purchase agreements (PPA's) will be needed to ensure that the hydrogen hub can access 100% renewable energy, and to reduce variability in output. The establishment of a system around PPA's to wheel renewable electricity over the transmission/distribution grid will be further enabler of the H2Hubs. Likely, it will be found that some existing renewable assets can accommodate additional power generation but funding will be required to expand transmission capacity. A notable component of this is hydroelectric power. There is a total of approximately 60,000 MW of renewable power generated by hydroelectric assets across the US, with the top 10 plants accounting for about 20,000 MW of this. There is additional underutilized capacity in this space due to demand-side limitations and infrastructure constraints that could be repurposed to green hydrogen production.

5) Water & Waste-Water: Is another key input to the production of hydrogen, Dams and transmission plus disposal and/or treatment and recycling of wastewater from production process are key elements for the production process. Water assets guaranteeing quality and availability are crucial with appropriate management of water rights and uses for facilities and surrounding communities. This element can be enabled by ensuring that essential upgrades to water infrastructure are completed to provide adequate water for the scale and required timeframe of initial hydrogen production. For instance in our experience, water required for input and cooling is estimated to be 6 - 7.5 million liters/day (1,100 to 1,400 gpm) for a 300 MW electrolyser.

6) Port and logistic supply: Our experience in hydrogen hubs shows that having proximity to deep water ports, preferably with bulk liquid infrastructure, is key, allowing the transport of gaseous hydrogen and ammonia to domestic and export markets. This includes intermodal hubs and port facilities with density of potential hydrogen users and hydrogen fuelling infrastructure; and transport corridors and elements to enable safe and efficient distribution of hydrogen as well as appropriate land zoning in port vicinity for production and storage of ammonia. For instance, our experience shows that a 300 MW hydrogen facility can produce 45,000 tpa of hydrogen equivalent to ~250 ktpa of ammonia; leveraging existing port infrastructure would be crucial for transportation and exports; however, modifications to port infrastructure to accommodate transport of ammonia (a hydrogen carrier) will be required (e.g. piping and manifolds for loading and berths to transport product from storage to ship among others)

7) Open Source Market Research & Statistics: Similar to the work EIA or NRCAN in Canada perform for Oil & Gas, providing clear H2 market analysis, forecasting and production data that could potentially attract private investment

2. The BIL states that H2Hubs must (1) demonstrably aid the achievement of the clean hydrogen production standard developed under Section 822(a) [defined as 2 kg CO2e/kg H2 at the point of production]; (2) demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen; and (3) can be developed into a national clean hydrogen network to facilitate a clean hydrogen economy.

a. *What CO2 equivalent emissions should be met within the project and its supply chain? What strategies are available for, and how can DOE incentivize, the H2Hubs to reduce emissions not only at the point of production but also including upstream emissions? What challenges are there in measuring CO2 equivalent emissions?*

In general, a strategy to reduce emissions would be the creation of an evaluation matrix that highlights, and rewards based on project value (defined by price of 'delivered' energy vs. cost) as represented by $/tonne of emission avoidance (as evaluated against the entire supply chain - encouraging complimentary transition of industry and transportation). As the DOE is aware, the concept of Carbon Intensity is regularly in-use for the transaction of renewable natural gas from point of origin to point of sale, with the vast majority of these development accounting for virtual transaction of green molecules through the pipeline network. The premise of Carbon Intensity (CI), is the use of a life cycle greenhouse gas model that evaluates upstream and downstream components of the project. One suggestion is the development of a specific set of pathways to drive CI evaluation of hydrogen production cross the various colors. There is ample precedent for this in RNG, where strongly negative CI scores also generally command the highest pricing offtakes for the product.

If natural gas is a feedstock for blue hydrogen, incentivizing emerging certifications (e.g. MiQ) to produce “Responsible Sourced Gas” (i.e. minimizing / avoiding fugitive emissions) will incentivize elimination of upstream emissions. In addition, promoting third-party verification of carbon intensity values across hubs and implementing protocols to disclose carbon emissions to the public would also drive a culture of emissions elimination. An assurance protocol, similar to ISO 14064 in the greenhouse gas inventory assessment world, would provide certainty on the transaction of molecules that may be part of either blended or virtual transactions. Assurance mechanisms must be built into CO2 measurement schemes at the onset, in addition to the precise guidance on pathways for developing CI assessments via pathway definition. With a link to price points, this should drive the H2Hubs to reduce emissions on the upstream side.

b. *Please specify CO2e/kg H2 you anticipate at the point of production in addition to well to gate (i.e., including upstream emissions).*

Emissions from green hydrogen production will depend on the source of power (e.g. grid-power, distributed generation, etc.) Hubs could initially receive carbon credits to achieve specific carbon intensity goals, allowing hubs to grow while the carbon intensity of grid reduces over time. The means of interrupting the proximity considerations leveraging existing infrastructure (such as pipelines carrying natural gas) to isolate cost-effective renewable power and intersect with offtake markets, is a means of driving down the carbon intensity of hydrogen production. We would note that this also helps achieve the notional goal of getting to under $1/kg hydrogen. In our mind, hubs are highly energized by the use of existing infrastructure to both build up suitable commercial models, to focus on viable offtake markets (such as those noted above), while driving down carbon intensity.

c. *Given the level of funding, and with the ultimate goal of developing a national clean hydrogen network, would four (4) large H2Hubs that each produce more than a certain amount of hydrogen (e.g., more than 1,000 tonnes/day, see question 3 to specify amount) or 6-10 H2Hubs of varying size be more effective?*

Smaller and more diverse hubs may prove more beneficial in the early initiation of hubs and testing of new hydrogen technologies and its applications. This would attract wider audience and investment, encouraging innovation and entrance of non-traditional market players, which will ultimately result in large scale adoption, improved learning curves, improved economies of scope, and fostering a more extensive hydrogen infrastructure, which in turn would lead to improved hydrogen logistics reliability and availability between supply and demand reducing risks in the process (e.g. feedstock availability & hydrogen supply risks), which would lead to less volatility in hydrogen pricing and potentially faster and more widespread acceptance across stakeholders.

As an additional benefit, smaller hubs could help develop strategies for smaller and off grid communities whom are dealing with energy transition, either by choice (e.g. mining) or by circumstance (e.g. island nations such as Hawaii or native American communities).

In our view, the adoption of smaller hubs as a starting point, to develop commercial and technical models that integrate existing infrastructure, is a reasonable starting point for a staged approach towards expanding into and developing larger hubs that service existing hydrogen usage and that are compatible with the emerging hydrogen markets. The implementation of more hubs also drives towards additional scale and cost price reduction in hydrogen production, a model that the DOE utilized successfully in the solar equation.

d. *What policies, infrastructure, or other considerations could be put in place to enable the H2Hubs to develop into a national clean hydrogen network in the future?*

As mentioned above, creating a larger number of Hydrogen hubs would enable a national clean hydrogen network in the future. In our experience in Australia, the role of state policy and funding is fundamental to do this. The biggest challenge would be coordinating with states to align with federal outcomes.

Other factors that would aid establishing this network are the nexus with national and regional transportation networks such as supporting transition of heavy-duty transport sector, trains, planes and shipping. It is paramount that production is matched with demand/consumption in order to facilitate a stable and growing market, which is one of the reasons why the hubs will need policies that survive election cycles and incentives the OEM sector to produce equipment that consumes hydrogen as fuel or feedstock.

Specifically, we envision Federal tax incentives and environmental policies need to be overhauled to provide similar incentives for clean hydrogen as exists for clean energy. In addition, federal funding will likely be required to develop “last-mile” hydrogen logistics infrastructure to deliver hydrogen to users.

e. *How should the H2Hubs be asked to measure progress toward the administration’s goal of transforming the economy by 2050 to achieve net-zero emissions goals? Please be as specific as possible.*

Measurement metrics of H2Hubs performance should include:

- Emissions reduction compared to baseline emissions (business as usual - BAU case); this can be accomplished by building reasonable and clear pathways for carbon assessment, as discussed
- Cost efficiency between hubs, leveraging the models further that demonstrated better capital efficiency. Cost price of hydrogen on a $/kg basis will be a key metric, against the DOE’s vision of a $1/kg hydrogen future
- Community benefits such as number of jobs generated and widespread community acceptance and positive impacts to disadvantaged communities
- Environmental impact measurement beyond carbon reductions, taking into account lifecycle positive impacts against factors that would be typically associated with the traditional energy production sector, including acidification, eutrophication, and land use.
- Benchmarking against other alternative technologies or strategies contributing to 2050 net zero goals

3. FEEDSTOCK DIVERSITY: “To the maximum extent practicable– (i) at least 1 regional clean hydrogen hub shall demonstrate the production of clean hydrogen from fossil fuels; (ii) at least 1 regional clean hydrogen hub shall demonstrate the production of clean hydrogen from renewable energy; and (iii) at least 1 regional clean hydrogen hub shall demonstrate the production of clean hydrogen from nuclear energy.”

   a. *Should DOE require a minimum level of hydrogen production per regional clean hydrogen hub, and if so, what should that minimum amount be (i.e., X tonnes/day)? Should this requirement vary for clean* *hydrogen produced from fossil fuels with carbon capture and storage (CCS), renewable energy, and nuclear energy? If a minimum is not specified, how may DOE incentivize larger capacity hubs?*

Hydrogen production rates and size of the hubs should be a combination of current and future demand and the unique attributes associated with candidate sites / regions. We envision a short list of multiple sites that should be analyzed for their strengths, risks and opportunities resulting in a site selection business case. Each one of these regions / sites should then be prioritized according to the strength of this business case.

Nevertheless, if a minimum production threshold is set, it should be phased in as hubs grow over time. Even if using blue hydrogen as transition to green hydrogen, the hubs' focus should be on low carbon energy and aiming towards fossil fuel reduction and elimination. In our mind, if the feedstock equation to the hubs is expanded by leveraging existing infrastructure such a pipelines, this also increases the scale of hubs, so this should be a key consideration. We do not see any clear motivation to set different threshold sizes for hydrogen production as a function of feedstock. The use of PPA's that are targeted for the H2Hubs improves access to feedstock from nuclear plants and renewables; access to pipeline networks improves the ability to serve offtake markets, which are a crucial component, all while reducing overall cost and creating competitive markets.

Beyond production "quotas" DOE could consider establishing percentage (%) targets of green hydrogen over time horizons (e.g. 2025 to 2030, 2030 to 2040 and so forth.) Over time, markets will choose the production technologies that have the best combination of environmental, technical and economic attributes

Moreover, GHD believes H2hubs are feasible under the right conditions. Selecting the proper scale, the right approach, the right project phasing, the right partners, the right hub location / region, and the right innovation processes will yield a successful hydrogen hub. If the business case doesn't achieve policy objectives then the hub should be discarded.

Finally, in line with our view of having more and smaller hubs, it might be beneficial if one of the hubs contemplated purely academic components based on industry centers of excellence evaluating other emerging technologies such as turbo-expander for hydrogen production.

As mentioned before, **our experience across hydrogen hubs in Canada, UK and Australia is that starting with smaller hubs and more of them allows for testing of the relevant, technical, environmental and economic considerations to propel scale**, especially as emerging markets come on-line.

b. *Related to 3a, how should DOE take into account specifying minimum required hydrogen production when considering capacity factors and* *the potential intermittency of generation, which would increase the cost and requirement for hydrogen storage?*

As mentioned above hydrogen demand and proximity to the hub or infrastructure to transport the hydrogen should be considered as primary factors. Viable offtake in the existing and possible emerging uses for hydrogen will dictate viable commercial models. Minimum hydrogen production should be linked to offtake. The dimension of offtake versus production is best achieved by mapping these considerations through commercial model development that accounts for existing infrastructure potential, such as pipeline, as well as intended renewable infrastructure (such as offshore wind).

In our experience, business models address potential challenges from capacity factors and intermittency. In Australia we are the architects of major hubs with intermittent renewables in very remote locations, considering that:

- At scale, the economics work, but it is key to first establish firm demand, a crucial point in Australia, as hydrogen is largely for export. This is a fundamental difference in the US model, where there is ample domestic existing hydrogen production, as well as the emerging domestic markets.
- The US has the mitigating factor that there is an expectation of having the capability of selling renewable energy to existing electricity customers. As such, these hubs will have the added advantage of having two business models: one that sells energy at arbitrage prices or stores it as hydrogen. Use of hydrogen as storage mitigates the intermittency issues, leveraging existing subsurface hydrogen storage assets or the potential for new approaches (such as metal hydride) that allow for aboveground hydrogen storage at scale.

These capacity factors and intermittency challenges may be potentially solved inherently by the market and hydrogen hub proponents.

A virtual power purchase agreement system or issuing of market credits could serve useful to locate hubs in favorable locations with close proximity to markets. As noted, the renewable natural gas market works on a virtual model that has greatly motivated the creation of RNG assets through the US, that participate in decarbonization assets. The use of this virtual model in both the provision of renewable electricity (through PPA's or other mechanisms) and the use of pipeline networks for (nearly unlimited) storage and transmission/distribution allows for the creation of virtual H2Hubs that offer improved commercial models because the feedstock and offtake dimension of hydrogen are no longer connected by physical proximity.

c. *What terms should be required for an H2Hub powered by renewable energy to demonstrate clean production (e.g., a power purchase* *agreement with a renewable generator, or direct connection to a co-located renewable generator)?*

Direct connection to co-located renewable generators, or, if charging from the grid, either PPAs with renewable generators or demonstration of offsetting energy used for production with RECs purchased in the open market are reasonable. As noted, PPA's greatly expand the ability to target the desired forms of low-carbon electricity, including nuclear. Physical proximity of viable feedstock to acceptable, scalable offtake markets will provide some options, but not to the same extent that virtual transactions will provide. The overall model for this is well-established in the US..

Leaving open the option for either of these would be acceptable. We would not recommend forcing co-location of renewables as a market goal is to let the renewable producers generate where they can most efficiently. We should furthermore let the hydrogen producers do the same.

Introduction of a Guarantee of Origin (GO) Scheme which certifies the clean status of electrons and thus hydrogen should be considered in the verification of clean production. If the American hydrogen industry is to thrive, then a GO Scheme will need to be established expeditiously to optimise America's competitive advantage, particularly for those states with excess renewable energy. Early extension to liquified hydrogen and ammonia should be planned for due to the number of projects currently selecting this route for transporting low carbon energy.

d. *Should DOE prioritize the repurposing of historic fossil infrastructure in the regional hub(s) focused on production from fossil fuels and if so, over what time frame? If yes, should DOE incentivize an eventual transition from fossil fuels to another fuel source? What conditions should DOE place on the carbon intensity of the fossil fuels (with CCS) used in this hub other than what is already specified in the BIL?*

DOE should look to repurpose historic fossil infrastructure only if the economics make sense. As mentioned above, this should also be market decision based on having a well grounded business case. Repurposing of fossil assets needs to be strategic, starting with the end in sight (e.g. delivering green hydrogen to a steel plan) and then deciding whether retooling existing infrastructure makes sense.

Of course, repurposing assets like natural gas plants to utilize clean hydrogen will be beneficial by avoiding stranding assets, reducing project costs and leveraging existing pipeline, storage, and electric transmission assets. Similarly, existing natural gas pipelines can be used to blend or be converted to fully transport clean hydrogen.

Incentives should be established to help the conversion, but the incentives should follow the supply and demand cycles. But all of this repurposing has to be grounded in solid economics.

As noted, leveraging existing pipeline networks is a key connector in the feedstock-offtake agreement. With millions of miles of natural gas pipeline in the US, this provides an opportunity, should the economics prove favorable.

Moreover, it is important to consider that natural gas network is highly dependent of energy exchange hubs. The ability to leverage, repurpose and transition those hubs is equally important for transmission and utility clients – as it is for large consumers of energy such as industry, power generation, etc. Some hubs may also be located near advantageous geological storage facilities.

e. *How might hydrogen production be constrained by the availability of clean electricity or natural gas supply and distribution? Will hydrogen producers provide a sustainable market/revenue stream for clean electricity and natural gas that encourages new investments to expand electricity generation and natural gas production capacity? Are separate federal, state, or local incentives to expand clean electricity generation or natural gas production capacity available, necessary, or adequate?*

Hydrogen production should be based on market demand. A hydrogen producer is a market for renewable energy but unless there is a market for hydrogen, hydrogen as a product is not necessary. Demand location should define the location of the hubs. Ideally hydrogen "feedstock" availability (i.e. water, natural gas and renewable energy should be close to the hubs) but it should not be the first concern. Indeed, hydrogen production location should find a balance between demand and availability plus underutilized renewable resources, with availability or capacity for building out capacity in a cost-effective manner, whether that is through direct federal/state funding or incentives to renewable producers.

As noted earlier, taking into account planned renewable capacity at scale should be undertaken, especially the offshore wind market on east and west coasts. As noted, underproduction in the hydroelectric sector can also be leveraged to generate additional hydrogen from this sector, should a demand beyond electricity exist for that untapped capacity.

Perhaps in some States particularly in the west coast (e.g. CA, WA, OR) hydrogen can be made cost competitive with natural gas by continued increasing costs of greenhouse gas credits and increasing transportation costs. Incentives to hydrogen production similar to renewable emissions credits will further aid the production of hydrogen. Electrolytic production must be not be limited to local renewable energy production (e.g. daylight or local wind resources) to increase capacity factors.

Should H2Hub funding be made available to upgrade or develop new dedicated clean electric or heat generating energy resources (e.g., renewables or other clean generation sources) needed to produce clean hydrogen?

Aside from incentivizing upgrade or new clean electric or heat generating sources the DOE should consider incentivizing the use of clean hydrogen on the demand side. Markets are established with demand. Additionally, funding should be allocated to existing renewable capacity that can be optimized, such as the hydroelectric sector.

Given the surplus of renewable energy in some areas of the country during at least some hours, existing or already planned renewable electricity could be considered for hydrogen production, but only if there is a strong business case rooted on demand. As hydrogen production scales, new and or repurposed and dedicated renewable energy facilities will likely need to be built. On the whole, business cases with sound fundamentals related to viable offtake markets should drive additional renewable capacity on the supply side of the equation.

4. END-USE DIVERSITY: "To the maximum extent practicable– (i) at least 1 regional clean hydrogen hub shall demonstrate the end-use of clean hydrogen in the electric power generation sector; (ii) at least 1 regional clean hydrogen hub shall demonstrate the end-use of clean hydrogen in the industrial sector; (iii) at least 1 regional clean hydrogen hub shall demonstrate the end-use of clean hydrogen in the residential and commercial heating sector; and (iv) at least 1 regional clean hydrogen hub shall demonstrate the end-use of clean hydrogen in the transportation sector."

   a. *What are the ideal timing and desirable features, terms, and conditions of offtaker agreements that would encourage construction and development of hydrogen hub infrastructure and long-term sustainability leading to local economic prosperity including union jobs and benefits to disadvantaged communities? Would hubs that supply multiple end users provide advantages, and in what ways?*

DOE should prioritize H2Hubs that supply multiple end users in order to leverage limited federal dollars, create a diversified and sustainable end-use market, and better respond to disadvantaged communities.

The H2Hubs will need predictable, stable production costs and rates. This would allow non-volatile contracts. Refueling stations would provide predictable rates to customers. Generation would provide predictable costs to the grid, etc. The new hydrogen economy will also need predictable/stable rates in the gas transportation system.

Open-source and public agreements (similar to the forum provided by the Chicago Mercantile Exchange) with standardized properties (purity & delivery pressure) will provide legitimacy in hydrogen as a stable fuel to be traded and trusted.

Domestic off-take arrangements with state entities such as the provision of hydrogen refuelling for bus fleets, government owned cars or heating contracts for government buildings will reduce development uncertainty and potentially could lead to deeper market penetration and market normalisation more rapidly.

b. *What approaches can applicants use to guarantee off-taker commitments and matching of supply and demand?*

DOE should prioritize H2Hub applicants that include Memorandum of Understanding MOUs with off-takers, especially in the existing and very large use of hydrogen in the oil refining, agricultural, and other sectors. in their plans. DOE should also consider providing additional structure and recommendations for shorter term contracting, as technologies reach economies of scale, and economies of scope and learning curves are overcome resulting in the reduction of capital and operating costs as the hydrogen economy expands. This would effectively reducie investment and first-mover risks and allow for contracts to follow market rates and conditions more closely.

“Supercharged partnerships” can de-risk hubs creation even further, building supply and demand with utilities, industry and export markets (where applicable). Hub partnerships with gas utilities likely would be the most practical initially. However, others will emerge as new appliances and consumption partners emerge (cement, steel, power generation, etc.). Emerging markets do continue; as of 2025, Arcelor-Mittal will launch the first zero-emission steel plant in Europe, a consideration that is being investigated domestically.

c. *The climate value of displacement may vary across end uses. How should the climate benefit of different hydrogen end uses be considered?*

DOE should consider efficiency of equipment and emissions reduction from conversion to hydrogen. As noted, establishment of viable, transparent pathways for carbon intensity calculation would allow for assessment of end uses, which themselves are predicated on current baseline energy consumption. This can be captured through the life cycle component of carbon intensity calculation.

5. GEOGRAPHIC DIVERSITY: “To the maximum extent practicable, each regional clean hydrogen hub– (i) shall be located in a different region of the United States; and (ii) shall use energy resources that are abundant in that region.”

    a. *A region could be defined as anything from a city, a state, multiple states, tribal communities, or a geographic area. Should DOE define the regions or allow applicants to define them within their proposal? If a definition is preferred, explain how regions should be defined for the purposes of this FOA and provide the rationale.*

    As mentioned above, the location of the clean hubs should be based on market demand. Fortunately, the US has widespread market with diverse needs across different regions. For example, natural gas assets are in proximity to Ammonia plants, which are the current industry with largest consumption profile of Hydrogen, in Oklahoma and Louisiana.

    Strong applicants will likely have MOUs with offtakers and should have the ability to define a region within their proposal that matches their market-based need. As mentioned before, more and diverse smaller hubs may be more beneficial than just four major hubs. More smaller hubs as a starting point would encourage geographical diversity and economic activity. Some states such as Texas or California would benefit from having diverse hubs that take advantage of the different characteristics and opportunities of those areas.

    b. *In addition to sufficient energy and feedstock/water resources, what other regional factors should be considered when identifying and selecting regional hubs (e.g., economic considerations, policy considerations, environmental and energy justice considerations, geology, workforce availability and skills, current industrial and other relevant infrastructure and storage available / repurposed / reused, industry partners, minority-serving institutions [MSIs], minority-owned businesses, regional specific resources, security of supply, climate risk, etc.)?*

    If region and demand is efficiently identified under a hub prioritization framework, H2Hubs may present the opportunity of creating shared-infrastructure for which a hub can support the upgrade or creation of existing infrastructure needs. For instance, hubs can accelerate investment in transmission line upgrades for remote communities or mining operations; or could even build a desalination facility that serves both expanding population needs as well as the H2hub. In terms of other factors that should be considered:

- Geological conditions around depleted reservoirs that offer carbon sequestration, as well as salt cavern opportunities
- Pipeline assets that allow for connection of feedstock to offtake via hydrogen blending
- Upcoming large-scale renewables generation such as offshore wind
- Unspent hydroelectric capacity across the nation that could be repurposed
- Low-Carbon Fuel Standard regulations (such as in California) whose foundational principles could be leveraged for virtual hydrogen hubs
- New disruptive technology advancement such as metal hydride for aboveground hydrogen storage, and waste to hydrogen through pyrolysis and gasification
- Leveraging of existing skills sets in the oil and gas sector that can be repurposed readily into this area, especially given the regular use of hydrogen in the oil refining business
- Existing natural gas storage as part of blended hydrogen storage and distribution networks

As noted previously, a number of these elements can be mapped to define intersection points and opportunities using objective analysis through commercial model consideration.

6. HUBS IN NATURAL GAS-PRODUCING REGIONS: “To the maximum extent practicable, at least 2 regional clean hydrogen hubs shall be located in the regions of the United States with the greatest natural gas resources.”
    a. *What level of natural gas resources should be required to qualify as a region with the “greatest natural gas resources”? How should DOE consider the difference between the available natural gas resources and the current natural gas production of an area when considering hub candidates? How should DOE consider the volatility of natural gas prices and its effect on production levels when defining these regions?*

It is our view, that markets driven by demand should have a greater input on deciding the specific regions selected for clean hydrogen hubs in the pursuit of energy decarbonization. However, if blue hydrogen hubs are necessary, utilization of natural gas as hydrogen feedstock should be minimized to regions where grid carbon intensity is not feasibly reduced in the near to long-term time horizon. In regions where low carbon intensive grid power may be utilized, natural gas should continue to serve its current role, and hydrogen incorporated and integrated as an alternative gaseous energy carrier thus adding a new and flexible element to the energy markets.

In general, four regions hold the largest available natural gas resources: Permian, Anadarko, Haynesville, and Appalachia. If necessary, any of these two hubs will likely be located in one of those regions. DOE could consider giving priority to current production levels over natural gas resources availability, considering that operators are increasingly facing larger obstacles to fund new wells given increasing investor focus in ESG-elements as investment discriminants.

Another dimension would be to consider regions that have a combination of low lifting costs (which could yield better blue-hydrogen economics) and regions with reduced rate of well decline (e.g. the Permian has a high rate of decline in ultimate recovery.)

Finally, certification of responsibly sourced gas is emerging. A clean blue hydrogen hub would benefit of its natural gas operators voluntary auditing and certifying that their operations have near zero carbon emissions (i.e. fugitive emissions are minimized of eliminated.)

b. *How should DOE consider the volatility of natural gas prices and its effect on production levels when defining these regions? Should annual (or average over a five-year period) production and/or available proven reserves be the criteria for the above provision?*

If natural gas begins broad use for hydrogen that then adds transportation, there may become shortages. The divergent aspect of renewable electricity pricing forecasts and natural gas pricing (especially in consideration of global disruptive events such as those currently being encountered), suggests that diversification between blue and green hydrogen is necessary in the short term. Long-term, projections suggest that green hydrogen will have a competitive advantage as electrolyzer technology achieves greater scale and efficiency, and the cost curves for renewables (especially renewables at scale, such as offshore wind, or existing assets such as untapped hydroelectric power) further declines. Natural gas, as a transition fuel, is also a transition feedstock for hydrogen production.

7. EMPLOYMENT: DOE "shall give priority to regional clean hydrogen hubs that are likely to create opportunities for skilled training and long-term employment to the greatest number of residents of the region."

   In keeping with the administration's goals, and as an agency whose mission is to help strengthen our country's energy prosperity, the Department of Energy strongly supports investments that expand union jobs, improve job quality through the adoption of strong labor standards, increase job access, strengthen local economies, and develop a diverse workforce for the work of building and maintaining the country's energy infrastructure and growing domestic manufacturing. The Department intends to use the H2Hubs to support the creation of good-paying jobs with the free and fair choice to join a union and the incorporation of strong labor standards and training and placement programs, especially registered apprenticeship. Respondents to this RFI are encouraged to include information about how this program can best support these goals.

a. *What tools should H2Hubs utilize to meet the goals of creating good union jobs and work opportunities for local residents in the construction phase of the project and in the long-term operations phase of the project?*

It is our experience that hubs and clusters across different industries generate diverse kind of jobs across the H2Hubs ecosystem, and will provide opportunities for the existing gas and coal labor force, including union jobs, to start learning and training on hydrogen as a natural transition due to forecasted gas infrastructure changes, etc. As noted, this is exceptionally convergent with labor from the existing fossil fuel world, where hydrogen is already in use.

In order to maximize its goals, DOE should prioritize consideration of H2Hub applications with existing Project Labor Agreements and Maintenance Labor Agreements. Existing MOUs with respective labor unions will need to be expanded upon for the anticipated scope of work and level of services. Traditionally cities have competed on what makes them liveable focussing on the infrastructure that contributes to our quality of life. With economies becoming increasingly reliant on creative industries, cities are starting to compete on how they can attract the best a talented workforce. Our approach to these challenges is to shift the paradigm to make our urban areas "loveable" by focussing on those elements that contribute to our affinity to a place. While Liveability provides the tangible infrastructure, a loveable approach provides for the intangible; such as the character that contributes to building a sense of place and community and a skilled, resident workforce.

At GHD, we use the concept "Lovable cities" which means that rapid industry expansion is coupled with a balanced development of local communities. We use this term to measure the success of public spaces by the services we need to live in them. With use this "lovable cities" approach to define a social infrastructure audit, social infrastructure needs assessment and social return on investment framework which not only could bolster the acceptance of H2Hubs, but also would guarantee sustainable success. GHD has completed studies on hydrogen and community acceptance which highlight knowledge gaps, key concerns, and how to fix them, amongst other factors, setting the framework for successful hubs.

b. *What tools should H2Hubs utilize to meet the goals of providing opportunities for workers displaced from fossil industries and other industrial or resource-based industries in decline?*

Workforce skills from the fossil industry and fossil-based power industry have much in common with the skills required for the hydrogen industry, starting with a culture of safety first. Hydrogen processing and handling requires different training but nothing unfamiliar to current workforce training. The tools will need to include resources for training. Massive Online Open Courses (MOOCs), trade associations on-site training, and hydrogen workshops may be a good way to start.

c. *How should short-term build-out (i.e., construction phase) employment and long-term operational employment opportunities be measured and evaluated?*

The construction industry and operations are two different forms of employment that should be evaluated separately.

On the long run, DOE can analyze the actual increase in long-term employment metrics and link this to community development, the key metric is that there needs to be a positive outcome for the local community.

On the short term, similar to the fossil industry, the construction phase will likely require more staff. Parts of the H2Hub systems are highly specialized and will require the creation of specialized trade labor, however the bulk of the work will likely be completed by traditional construction workers from other industries (Hydrocarbons, Power, Architecture etc.) For these short term jobs, the DOE can track the incremental number of jobs created per region in addition to the existing construction jobs and the initial (i.e. transitory) induced benefits to the local economy.

d. *What would "success" look like, especially related to Diversity, Equity and Inclusion (DEI) and support for union and energy transition jobs?*

Among many metrics, the success of the H2Hubs will likely be measured against the impacts to DEI for the regions immediately surrounding the specific hub localities. Training and educating local, unionized workforces as well as expanding existing workforces to disadvantaged communities and underrepresented communities will need to be considered early and often as the hubs develop. DOE can establish threshold requirements associated with DEI in

the evaluation criteria and H2Hub applicants will solve for that, for instance they can include requirements for partnerships with local university, etc.
Success would be defined by meeting these thresholds.

e. *How should H2Hubs include workforce development and training activities (e.g., by including institutions of higher education, such as MSIs, community-based organizations, registered apprenticeship programs, joint labor-management apprenticeship programs and quality community-based pre-apprenticeship programs, as project partners)? In addition to each H2Hub having its own workforce development and jobs plan, should there be a nationally coordinated effort between hubs (and other hydrogen activities) to ensure an adequately trained workforce is available? If so, how should this be designed?*

Different hubs will have different areas of expertise. It would be beneficial if that expertise is shared with other hubs to train and educate workers across hubs as well as other hydrogen handling facilities. Training facilities at one hub location could be made available to select workers from other hub locations. In addition, clusters and hubs have always benefitted from linking specialized education between the needs of the hubs and clusters and local universities. For example, the offshore oil production industry in the Gulf of Mexico has mutually reinforcing ties with local universities such as the Subsea Engineering program initiated in the University of Houston in response to demand from operators ((e.g. Chevron and Shell) for subsea experience. These are similar to the Sudbury Mining cluster in Ontario and the Laurentian University School of Mines that offers a series of on-site apprentice programs in partner with private operators such as Vale.

f. *How will the H2Hub training model offer opportunities for a range of jobs across the hydrogen supply chain?*

The hydrogen hubs will provide training opportunities for a wide range of jobs across the hydrogen economy value chain:

Construction->Feedstock -> Hydrogen Production & Processing ->Logistics-> End Users

Each one of these elements of the value chain has a wide range of job distribution, from industrial to management jobs. The DOE could incentivize H2hubs that provide workforce training & education opportunities for workforce transitioning from coal and natural gas industries. As mentioned above, the added benefit would be safety culture instilled specially in the oil & gas industry.

g. *How should labor standards be incorporated in project planning stages to support the creation of high-quality, good-paying jobs?*

H2Hubs will require diverse industry-specific and highly trained labor force for both construction and operations plus maintenance. Labor standards will need to comply with at the very least the same labor standards applied to other heavy industries (i.e. oil, petrochemicals, mining, power, construction etc.) which would enable safety in operating, handling, and using hydrogen and hydrogen systems.

DOE should collaborate with domestic and international organizations to identify gaps and facilitate the creation and adoption of model building codes and equipment standards for hydrogen systems in commercial, residential, and transportation applications; and provide technical resources to harmonize the development of international standards. The DOE can start by looking at labor standards of industries that currently demand and produce hydrogen (e.g. Downstream, Ammonia, Methanol, etc.)

To be able to support the creation of high-quality, good paying jobs it is necessary to understand the business case & economics for each H2Hub, that business case will provide an idea for the potential of good-paying jobs as well as obstacles and limitations.

Category 2

Solicitation process, FOA structure, and H2Hubs Implementation Strategy

2. Category 2: Solicitation Process, FOA Structure, and H2Hubs Implementation Strategy

8. *DOE is evaluating funding mechanisms for the H2Hubs projects in accordance with the BIL. What applicable funding mechanisms are best suited to achieve the purposes of the H2Hubs (e.g., Cooperative Agreements, Grants, Other Transactions Authority)?*

The best mechanism would be grant / subsidy type model to close the economic gap. Using a contract for a different type of approach is also recommended at some stage as it targets the customer demand side of the equation. Given the criticality of the offtake side of the equation, against the existing market where grey hydrogen is sub $2/kg in the US market, providing an incentive contract on hydrogen pricing to normalize against existing hydrogen pricing is also a possible mechanism that presents long-term value to hydrogen hubs. We would suggest that while grant funding for capitalization for the build side is important, normalizing the cost base for hydrogen purchase provides a longer-term and more tangible benefit to the market.

9. *What are the key review criteria (e.g., technical merit, workplan, market transformation plan, team and resources, financial, regional economic benefits, environmental justice, DEI) that DOE should use to evaluate and select the H2Hubs as well as evaluate readiness to move from Phase 1 to Phase 2?*

Selection, Evaluation and Readiness of H2Hubs are three discrete topics. As mentioned above, selection of a hub needs to be rooted in a proper demand -driven business case. The DOE can generate a framework with weighted multi-criteria similar to our experience in Australia, that would help segment and prioritize the best options. In our experience, these metrics can help define the best hub selection:

1) **Projects that will enable the development of a regional industrial hub and accelerate the creation of a clean hydrogen industry, could include**: commercial potential of your hydrogen hub, feasibility risks, opportunities, including potential supply the project will create & demand it could capture and create.
2) **Extent that your project will utilise and support existing industrial capacity and infrastructure to build clean hydrogen capability and contribute to its long-term viability, could include:** proposed nexus with research organizations and other businesses, metrics on how the project will leverage and include local industry content in the region, level of support proponent has with local community and/or government, how the project will

address workforce gaps, proposed strategies for knowledge sharing with other emerging clean hydrogen hubs including lessons learned and understanding of future supply chains

3) **A proponent's capacity, capability and resources to establish a hydrogen hub, including:** Structure of the proponent's consortium and enablers to establish a hub project; Track record of proponent's consortium or individual organisations within the consortium in developing major projects and leveraging additional investment (both national and foreign), access to personnel with relevant skills and experience; Proponent's access to required finance, infrastructure, capital equipment, technology and intellectual property; How will proponent leverage existing capability, including the strength of partnerships and engagement within the proposed hub; Proponent's project plan, including plan to: manage the project including scope, governance, implementation methodology and timeframes, mitigate delivery risks (including national security risks), secure required regulatory or other approvals, including project plan and budget.

4) **Impact of Grant Funding, including:** How proponent's project will enhance the commercial viability of the existing and the future clean hydrogen industry and support industry more broadly; Additional investment that will be leveraged by the proponent's consortium to establish your hub; The broader social, environmental and economic impacts of the hub, including the extent that the project will generate jobs and investment in regional**; C**ommunity support for your hub within local and regional communities.

10. *Does offering multiple launches roughly a year apart, as shown above in Figure 2, help facilitate expanding the hydrogen hub concept to more regions?*

Yes, offering multiple launches over a longer time horizon should facilitate current and future hydrogen hubs.

11. *What specific activities should be conducted in Phase 1 vs. Phase 2? Should Phase 2 be further broken into multiple sub-phases, and if so, what should be included in each sub-phase?*

Before phase 1 and 2, and if the DOE has not executed one yet, a detailed target-oriented hydrogen market study that ascertains current hydrogen regional demand and can project potential future demand growth would be highly beneficial to future H2Hubs. This will also help to drive success for implementation. At minimum, the study should include:

- Current hydrogen market sizing in the US
- Regional market segmentation with end users

- Forecast on hydrogen demand growth and potential mapping of H2 demand growth.
- Sensitivity analysis on forecast per region, and according to different decarbonization scenarios (e.g. hydrogen penetration in transport)
- Summary of existing and future technology
- Assessment of existing asset bases for renewable generation, transmission, distribution, as well as storage options and important corollary factors such as CO2 storage

Results of this study should be open source to all H2Hub proponents.

Beyond that, DOE may consider additional phasing or sub phasing, as the initially planned Hubs are in various phases and will progress at different rates and likely encounter different roadblocks.

12. *How much time will be needed to complete the Phase 1 activities? Have some regional teams already completed analysis and design activities?*

The proposed times seem adequate if demand is aligned with proposed commissioning times. However, it is crucial that hydrogen demand exists with firm off-take agreements before commissioning a facility. Otherwise, following a "build it and they will come" approach may lead to lost revenue and detrimental project economics.

13. *Are the proposed funding levels for Phase 1 and Phase 2 appropriate/adequate?*

Funding levels are consistent with other regional schemes we have exposure to. It will be important to review the adequacy once DOE has visibility of first round responses and scale of projects being proposed.

14. *How much funding should DOE allocate for adding new technologies, capabilities/end-uses, or partners to the existing hubs (i.e., Launches 3 and 4)?*

Funding allocation for new technologies, capabilities and partners to existing hubs should pause for a moment and understand what the market actually needs. It is hard to predict technology requirements without a market need. Conversely, if there is a current unmet demand with a potential solution requiring funding, the DOE should evaluate funding based on the business case and impact of the potential solution.

15. *What safety criteria (e.g., safety plan reviews, outreach to Authority Having Jurisdiction [AHJ] entities such as code/fire officials, training) should DOE use to evaluate readiness to move from Phase 1 to Phase 2?*

Current hydrogen industry works with the *Center for Hydrogen Safety* for vehicle refuelling standards sharing and evaluation. AHJs will need education on NFPA 2 as well as the local implementation of fire and safety codes. Education and sharing best practices of existing hydrogen installations goes a long way to building trust.

16. *What resources might H2Hubs need regarding safety, permitting, and siting, particularly in relation to the Hydrogen Safety Panel and submission of safety plans.*

Permitting is site specific, while local codes and standards tend to lag national and international editions. The Center for Hydrogen Safety should be viewed as an asset to both reviewers and designers. Any national support by H2Hubs should be on an open-source basis that shares best practices while balancing a respect for industry's right to competitive privacy. Providing regulatory certainty is an incentive to stronger private investment. Two key elements that need attention are Legislation and regulation for large scale production and transportation of hydrogen.

17. *What environmental reviews and permitting challenges might H2Hubs encounter? Where can approaches such as "dig once" relating to buried conduits, pipelines, and other infrastructure (e.g., CO2 pipelines) be developed and incentivized to reduce impact? Please provide examples of how community consultation and consent-based siting can successfully be included in the environmental and permitting review process.*

Hydrogen transportation might face obstacles in local regulations which would need legislation/regulatory action before project completion

Greenfield projects may have higher barriers to permitting than adding on to an existing site. While initial thinking could lead to prioritize proposals that utilize existing facilities, what the nascent hydrogen industry requires is strong signs that the pathway to scale will be supported and greenfield expansion is possible. If not, investment with dwindle as existing facilities likely has a limit to expansion or viability.

As noted, hydrogen conveyance through existing pipelines requires consideration of FERC, as well as the materiality of hydrogen in steel pipes and the corresponding effect on long-term maintenance as well as short-term safety considerations.

18. *Are there existing draft or final federal NEPA documents (e.g., environmental assessments and/or environmental impact statements) for similar or related proposals that could inform DOE NEPA reviews for the H2Hubs?*

No Response

19. *What external non-project partners/stakeholders (e.g., CBOs, DACs, tribal groups, state and local governments, economic development organizations, labor representatives) will be critical to the success of the H2Hubs? What types of outreach and engagement strategies are needed to make sure these stakeholders are involved during each phase of the H2Hubs? Are there best practices for equitably and meaningfully engaging stakeholders?*

One of the best practices for meaningful stakeholder engagement is continuous communication across the lifecycle of the project, from concept through decommissioning. Effective communication sources may include but not limited to townhalls, on-going and frequent community education, webinars / engagement on project status. Additional public education components of Hub and site-specific interaction / tours where applicable and safe tailored to the specific needs of each community. Typical on-project stakeholders are Community based organizations (CBOs), disadvantaged communities (DACs), non-governmental organizations (NGOs), tribal groups, air quality boards, OSHA, local governments

20. *The H2MatchMaker tool will be available to help identify potential regional project partners. What specific fields/information would be valuable to include in the tool? What other mechanisms can DOE use to help facilitate teaming?*

The ability to navigate data in a sortable, downloadable and editable spreadsheet styled form for quick filtering. National Labs and their respective capabilities should be included on the tool as they play a critical role furthering the development of technologies and closing of knowledge gaps to make the H2 hubs a reality. Providing this information about what each National Lab is focused on can facilitate teaming with them as well to leverage existing work. Additional data availability should include hydrogen-specific demands and supply quantities and their various site-specific delivery attributes.

21. *Based on EPAct 2005, Section 988, the cost share requirement for demonstration and commercial application projects is 50% cash and/or in-kind and must come from non-federal resources (50% of the total project cost which includes both DOE share and recipient cost share). For example, a $1B award for the Phase 2 Hub Deployment will require $1B in matching cost share. Is it feasible for projects to meet this 50% cost share requirement on an invoice-by-invoice basis?*

50/50 seems reasonable in our experience. GHD hasn't witnessed anything materially different across the globe.

22. *Is there sufficient manufacturing capacity to produce the necessary hydrogen related components / equipment within the U.S. to supply all the eventual*

H2Hubs? What incentives / programs exist or can be put in place to encourage and foster U.S. manufacturing? What potential challenges or opportunities might exist to meet the new Buy American requirements in the BIL?

> No; currently insufficient manufacturing capacity with significant lead times with international orders.
>
> Manufacturers need to be incentivised to automate their processes to lower costs. To do that, they need a lot of orders. That is where the idea of a larger quantity smaller projects will get more orders flowing. Manufacturers should be offered special financing and guarantees to help develop and support prior to the orders arriving.

23. *Please identify any iron, steel, manufactured goods, or construction materials that will be crucial for building out the H2Hubs that would not typically be procured domestically. For each, please specify how H2Hubs could work to procure these items domestically, and any potential barriers to domestic procurement, such as lack of availability or cost.*

> Required materials and manufactured goods will be in line with value chain elements:
>
> Construction->Feedstock -> Hydrogen Production & Processing ->Logistics-> End Users
>
> - Hydrogen Facilities Construction: steel, wood; iridium, yttrium, platinum, strontium, and graphite for manufacturing of electrolyzers and fuel cells
> - Feedstock (Water / Natural Gas / Renewable Electricity): Platinum, PV panels, silicon solar cells, PV modules, and rare earths for solar energy; balsa wood, blades and hubs, and generators for wind energy; filtration membranes for desal water production
> - Hydrogen Production & Processing: Potassium Hydroxide for alkaline electrolizers,
> - Logistics (battery storage / transport): Lithium, magnesium and cobalt for storage

24. *What types of cross-cutting support (e.g., technical assistance) would be valuable from the DOE/national laboratories, and/or from other federal agencies, to provide in proposal development or project execution? Are there other entities that DOE could fund to provide technical assistance across multiple H2Hubs?*

DOE should propose consolidated set of standards on policies, regulation, for hydrogen assets across state lines, considering input including but not limited to PHMSA, NFPA, OSHA, FERC, IEEE, ASME, and SAE.

25. *What data should DOE collect from the H2Hubs to evaluate the impact of the program? How should this data and the program outcomes be disseminated to the public? In addition, EPAct 2005 Section 817 requires that three national labs (the National Energy Technology Laboratory, the Idaho National Laboratory, and the National Renewable Energy Laboratory) will work together to serve as a 'clearinghouse' for the H2Hubs and for the Clean Hydrogen Manufacturing and Recycling Program (Section 815). What data or information should be part of this 'clearinghouse'?*

Increasing offtake demand is essential to drive production. As such the Data should include at a bare minimum: quantity of hydrogen produced and consumed on varying time scales (hourly, daily, annually), quantity of oxygen produced and consumed or vented, emissions of hydrogen producing facilities, emissions of hydrogen consumer end uses, power usage regimes, both from conventional sources and renewable sources, and any increase in utilization of existing resources to reduce curtailment, raw water consumption, wastewater consumption, energy used for water treatment for electrolytic hydrogen production.

Recognizing the phased nature of a transition towards green hydrogen, capturing the volumes of hydrogen produced via the blend of production pathways will allow evaluation of the overall carbon intensity to manage both the adoption of hydrogen usage and transition to clean hydrogen production.

26. *How could funding under other BIL provisions (e.g., Section 40303, Carbon Capture Technology Program) be leveraged by the H2Hubs to maximize the impact of BIL funding?*

No Response

Category 3

Equity, Environmental and Energy Justice Priorities

3. Category 3: Equity, Environmental and Energy Justice (EEEJ) Priorities

EEEJ benefits will be a high priority as the H2Hubs are developed. For the purposes of this RFI, DOE has identified the following non-exhaustive list of policy priorities as examples to guide DOE's implementation of Justice4029 in DACs: (1) decrease energy burden;30,31,32 (2) decrease environmental exposure and burdens; (3) increase access to low-cost capital; (4) increase the clean energy job pipeline and job training for individuals; (5) increase clean energy enterprise creation (e.g., minority-owned or diverse business enterprises); (6) increase energy democracy, including community ownership; (7) increase parity in clean energy technology access and adoption; and (8) increase energy resilience.

27. *What strategies, policies, and practices can H2Hubs deploy to support EEEJ goals (e.g., Justice)? How should these be measured and evaluated for the H2Hubs?*

- The DOE could mandate community benefit returns. That is domestic reserves, minimum return per ton of Hydrogen produced/t of H2 produced.
- Much education is needed in the role of Hydrogen in the energy transition. Need to invest in authentic energy education so that project are able to be accepted by communities and then approved
- Key concerns for local communities around H2Hubs are currently water priority, benefits skepticism, safety, land use and amenity
- H2Hubs can provide training and education programs to develop trade oriented skill sets such as welding and pipe fitting that would be accessible to local residents. Programs of this nature will support local employers needing skilled workers and good paying job opportunities for DACs

  Success could be measured by community acceptance and by evaluating the number of employees performing H2Hub operations and/or construction activities that reside within a DAC boundary.

28. *What EEEJ concerns or priorities are most relevant for the H2Hubs?*

H2Hubs will exist to output fuel in the form of gaseous/liquid hydrogen to displace gasoline, diesel, natural gas, coal, and/or more carbon intense electricity. DACs who are overburdened with air pollution from gasoline/diesel refining, transportation emissions from trucks/buses/cars will directly benefit from adjacent air pollution reduction.

29. *What measures should H2Hub project developers take to ensure that harm to communities with environmental justice concerns, including local pollution, are mitigated?*

- Well established hazardous facility and emergency management procedures are paramount (e.g. well defined blast zones). This is can be compounded when you have co-location with other hazardous facilities like smelters and furnaces
- Local Air Pollution Control/Air Quality Management Districts should be key stakeholders in implementing measurement plans, community/stakeholder feedback, and reporting / enforcement actions.
- Stakeholder engagement and continuous communication of safety issues is also a most

30. *How can H2Hubs ensure community-based stakeholders/organizations are engaged and included in the planning, decision-making, and implementation processes (e.g., including community-based organizations on the project team)?*

Key elements are governance and expectation. Minimum requirements need to be well defined and monitored in their compliance.

Early engagement, communication of similar projects/programs, as well as a focus on the future vision for the community's connection to the wider hydrogen economy will enable impacted people are heard and allowed to shape their future. Proactive connections to job opportunities as well as synergies with local universities/colleges will also build a bench of talent needed for the next generation of hydrogen equipment.

31. *How can DOE support meaningful and sustained engagement with H2Hub relevant disadvantaged communities?*

Local stakeholder groups (Chamber of Commerce, trade unions, faith-based organizations, and other impacted organizations should be engaged using existing governmental and unofficial relationships. Hydrogen should be enabling synergistic growth, a cleaner fuel-tide lifting all boats, rather than leaving anyone behind.

Category 4

Market Adoption and Sustainability of Hubs

4. Category 4: Market Adoption and Sustainability of Hubs

32. *What mechanisms (e.g., tax/other incentives, offtake structures, prizes, competitions, alternative ownership structures for hydrogen production bundling demand, contracts for difference, etc.) would be valuable to incentivize market-based supply and demand?*

A good example for incentivizing this industry is Germany's "Contracts for Difference" (CFDs) which are instruments that help heavy industries such as steel, cement and ammonia finance the transition to low-carbon economies. Specifically, companies committing to cutting CO2 emissions by more than 50% will operate on a basis of 10-yrs CFDs, which in turn will reduce or partially finance the increased OPEX over the OPEX associated with existing processes.

Stateside, the investment Tax Credit (ITC) and Production Tax Credit (PTC) should be expanded to include hydrogen-supported energy storage. Any clean energy market must also provide incentives for clean hydrogen-produced energy storage.

Other ways to incentivise demand includes policies like the California Air Resources Board (CARB) Advanced Clean Truck regulation in California but also proposed in Oregon (which require all class vehicles to be zero tail pipe emission (battery electric or hydrogen fuel cell) provide incentives for quicker development and deployment of end use applications utilizing hydrogen, etc.

33. *What role/actions can DOE take to support reliable supply and demand for potential hydrogen producers and customers?*

DOE should coordinate with state and local officials to ensure that both supply and demand move in lockstep so that the Hubs do not find themselves in a mutually conflicting scenario where demand outpaces supply or supply outpaces demand. One option could be to incentivize states to implement policy or programs to ensure this coordinated growth.

DOE should also engage with regional transmission operators to ensure that there are rules for wheeling renewable resources; the DOE could consider granting hydrogen producers exemption from transmission access charges, and could facilitate rules that would allow the sale of capacity and regulation for the hydrogen producers that turn over production rates to transmission operators to match the fluctuations of renewable resources.

34. *If DOE asks for a market analysis as part of the application process, what should the analysis include so that DOE can be confident that a proposed project will be successful?*

Pursuant to GHD's answer to question 11 in Section 2, project / H2Hub specific market analysis at minimum should include:

- Current hydrogen market demand in the project / H2Hub region
- Identification of hydrogen applications, stakeholders and current end users located within the hydrogen delivery range (e.g. identified hydrogen consumer groups, specific industries/companies)
- Estimated logistics costs (i.e. final delivery costs)
- Forecast on hydrogen demand growth with sensitivity analysis according to decarbonization scenarios (e.g. expansion of Zero emission vehicle (ZEV) mandates, growth of hydrogen penetration in transport); plus identification of potential new hydrogen consumers posed to adopt hydrogen (e.g. municipal transit fleets, buildings / data centers with backup power installations etc.)
- Summary of existing technology hub is planning to use including economic benchmarking of H2 production costs
- Policiy and techno-economic benchmarking of other comparable regions across the world interested in H2 solutions, what are sister cities / comparable regions doing to create hubs
- What potential business models would best benefit the H2Hub project proposed.
- Identification of potential synergies for shared infrastructure with ongoing projects with local industries
- Identification of potential partners to develop hubs and potential stakeholders that would be interested in establishing firm offtake agreements.

Finally, while a market study will increase the success of a H2Hub project and reduce risks, the biggest indicator that a project will be successful is whether there is an offtake agreement connecting supply with demand at the full capacity of the proposed plant (i.e. plants can have more than one offtake agreement.) Other key factors to also consider are whether the counterparty has balance sheet to underwrite or whether the counterparty is financially invested in the project. The objective of this is to have a pathway to a bankable financial plan that would enable the development of the hydrogen hub.

35. *What can DOE provide/do that would be helpful to a project to facilitate its collaborations with potential financing partners?*

Commitment to stick to the program and timeframes. Certainty and responsiveness are key for proponents. Also, DOE can develop viable commercial models that take into account hub factors at the onset, to incentivize the financial community with respect to participation.

36. *How can DOE support the H2Hubs in working together to increase competitiveness and scale?*

> Any support to the larger hydrogen marketplace that helps match producers to consumers with dependable forecasting and price confidence will bring in more market participants. An overarching project authority at the DOE level that allows for connectivity between the hubs and sharing of information and lessons learned would be beneficial.

37. *Which regional and site-specific metrics should DOE track to estimate the impact of hydrogen production on regional water availability?*

> There is large potential for using this program to support the upgrade of water infrastructure, similar to projects in Australia.
>
> DOE should consider the water source in its entirety, how it impacts either the surface water or groundwater supply that is sourced from, and appropriately incentivize hydrogen production to utilize existing or proposed water reuse opportunities. This needs to be considered alongside competing demands for water and allocated with appropriate prioritization. Hence capturing metrics to identify where water infrastructure provides multiple benefits to focus investment accordingly.
>
> Water Reuse makes for a sustainable and viable source for most if not all hydrogen value chain components, dependent on what level of treatment the water is received as. Energy utilized for additional treatment should receive the same incentives that the production components along receive.

38. *Other than greenhouse gas emissions, what sustainability metrics should DOE include in evaluating the hubs (e.g., impact on regional water resources, availability of decarbonized electricity production resources, climate risk impacts on the resilience of the H2Hubs)?*

> DOE should consider at least the following metrics outside of greenhouse gas emissions:
>
> - reductions in local and regional air quality constituents as a direct result of fuel consumption produced by Hydrogen Hubs,
> - Impacts to local and regional hydrology and water resources as a result of hydrogen production
> - Decarbonized electricity production metrics, fleet / transit vehicle fueling conversion to ZEVs (light, medium, heavy duty vehicles, public transit, rail, aviation, marine, …).

39. *The goal is for the H2Hubs to be sustainable beyond the BIL funding (i.e., without additional government funding). To what extent will the H2Hubs be capable of demonstrating a path to economic viability after the BIL funded*

phases and how should the FOA and project (once awarded) be structured to ensure this outcome?

The economic viability may depend on the cost of alternative energy supplies, but the take-away is that the H2Hubs MUST be sustainable beyond BIL funding

Category 5

Other

5. Category 5: Other

40. *Please provide any additional information or input not specifically requested in the questions above that you believe would be valuable to help DOE develop a Regional Clean Hydrogen Hub FOA, including any specific criteria that DOE may take into consideration in implementing the Hub program.*

GHD wishes to supply examples of our work that directly supported to the development and implementation of National Hydrogen Strategies, including the plans at State and National levels. The Government hydrogen frameworks set the conditions for the development of various Funding mechanisms underway in Australia. GHD subsequently supported Proponents to apply for and receive funding. We provided similar advisory services to the government of Canada. In the appendices below, we present our hydrogen qualifications, our response to Australia's National Hydrogen Strategy Issues which adopted a similar consultation approach to the DOE. We also include the Australia's hub implementation grant guidelines as well as Canadian pillars to deploy a hydrogen economy.

Appendices

• GHD Hydrogen Projects Development Technical & Commercial Experience

• GHD's response to the National (Australian) Hydrogen Strategy issues papers

• Background on the hydrogen hub grant programs GHD has been involved:

1. The Australian Government's Activating a Regional Hydrogen Industry- Clean Hydrogen Hubs: Hub Implementation Grants (Round 1) Guidelines (got it)
2. Canadian pillars for development of Hydrogen Hubs

ghd.com → The Power of Commitment

Hydrogen

↳ Services and capabilities

→ **The Power of Commitment**

Hydrogen is rapidly emerging as the clean energy commodity of the future

»

Its versatility of application to power generation, storage, industrial heating, decarbonisation of gas networks and zero emission fuel-cell vehicles has captured the attention of investors and developers the world over.

Developing the global hydrogen economy will require strong partnerships and a shared vision. We are proud to be working on some of the boldest hydrogen projects around the globe, to lead the transition towards a future of affordable, reliable, secure and low-carbon energy.

Committed to the energy transition

Working across key hydrogen sectors to decarbonise power generation, transportation, and industrial applications.

Globally, we partner with universities, industrial companies, associations, vendors, consultants, and laboratories to conduct leading-edge research in hydrogen deployment, production, distribution, and use. GHD has initiated many of these collaborative studies, provided in-kind services and helped apply for government funding where needed:

- Hydrogen generation from organic waste
- Hydrogen generation from landfill gas
- Conventional and renewable hydrogen generation technologies
- Hydrogen storage technologies
- Industrial hydrogen/fertilizer production
- Novel hydrogen land and water transportation modes
- Synergies and integration with renewable energy operations
- Supplement to diesel and other fuels

30+

Hydrogen energy project

across four continents

0%

Zero emissions

Investing in global research to realise a zero emissions clean hydrogen energy future

***April 2018:** Global launch of the first hydrogen export project in Victoria, Australia, a collaboration between the Japanese, Australian and Victorian Governments. GHD is the lead Technical Advisor.*

The GHD difference

Leading hydrogren studies and supply chain projects

Countries all over the world face significant challenges to address energy security and reduce emissions as part of a global push to tackle climate change. Hydrogen is now seen as the clean energy commodity of the future due to its versatility in power generation, storage and zero emission fuelcell vehicles and its ability to be produced with very low or zero green house gas emissions.

GHD is proud to be working on many of the current hydrogen studies and supply chain projects underway across Australia, Canada and the United Kingdom.

We draw from the expertise of colleagues across our global technical teams and leverage our deep experience in the development of similar fledgling industries.

Shaping government policy

There is an exciting and unique opportunity to develop a new clean hydrogen energy export markets in countries with high value renewable resources or large carbon sequestration capacities to meet the growing needs of countries that require clean energy import to achieve decarbonisation.

GHD is the only multi-disciplinary consulting firm to participate in industry workshops to develop the Australian National Hydrogen Strategy and the Canadian Government's H2GO Strategy. Many of our technical leaders are actively engaged in working groups established to navigate the transition to hydrogen from both a technical, regulatory and societal acceptance perspective.

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Fostering strong relationships with our industry peers

- Gas Processors Association (USA)
- Canadian Hydrogen and Fuel Cell Association
- Canadian Biogas Association
- Canadian Natural Gas Vehicle Association
- UK Institution of Mechanical Engineers Renewable Power
- Australian Hydrogen Council
- Australian Pipeline Standards Committee
- BioEnergy Australia
- Australian Pipeline and Gas Association
- Clean Energy Council Australia
- Australian Corrosion Association

Collaborating to shape a hydrogen energy future

Australian Government National Hydrogen Strategy – detailed industry submission, July 2019

Stakeholder in the development of the Canadian Government´s H2GO

Actively supporting Mission Innovation with its 'Innovation Challenge 8: Renewable and Clean Hydrogen'

Australian Government´s Hydrogen Industry Workshop/Taskforce, September 2019

Authored Technical Report, 'Hydrogen to Support Electricity Systems' to inform the National Hydrogen Strategy, February 2020

Tasmanian Government´s Hydrogen Action Plan – Industry submission, January 2020

Multiple clean hydrogen feasibility studies covering most options for generation, storage, transport and use, 2015 onwards

Hydrogen 101

Playing a key role in global decarbonisation

Hydrogen is an excellent carrier of energy, with each kilogram of hydrogen containing about 2.4 times as much energy as natural gas. This energy can be released as heat through combustion, or as electricity using a fuel cell. In both cases the only other input needed is oxygen, and the only by-product is water making it unique among liquid and gaseous fuels in that it emits absolutely no CO2 emissions when burned.

From a consumer perspective, hydrogen is a gas much like natural gas that can be used to heat buildings, generate power and fuel vehicles. Clean hydrogen can also be used to achieve tremendous reduction of green house gas emissions in heavy industry by displacing current sources of hydrogen and fossil fuels and displacing coal as a reducing agent.

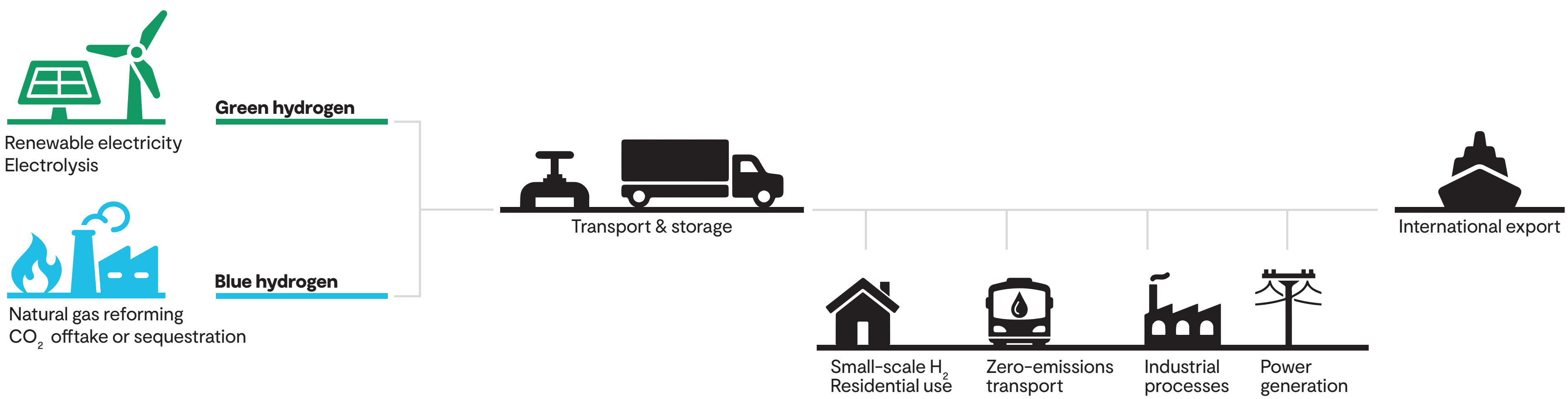
For hydrogen to decarbonise energy systems and industrial processes, it must be produced using renewable electricity or from fossil fuels with carbon capture and storage (CCS) resulting in what has been termed green and blue “clean” hydrogen. Where the transport destination is beyond the reach of a transmission pipeline there are options available to ship the hydrogen in different forms including ammonia, as liquefied or compressed hydrogen or bonded to an organic carrier.

2.4x

as much energy as natural gas is contained in each kilogram of hydrogen

CO2

emissions are zero when hydrogen is burned



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Our integrated services across the value chain

Practical technical experience

We pride ourselves on being a no-fuss partner to our private and public sector clients to deliver services that contribute to a thriving new clean energy future based on deep technical and regulatory knowledge.

From production to application, we have extensive experience in hydrogen systems, including:

- **Hydrogen Production** – coal gasification, electrolysers (PEM, Alkaline and research), methane reforming and thermal devolution
- **Hydrogen Storage and Transmission** – compressed gas, cryogenic liquid or carrier chemical (such as ammonia).
- **Applications/ End use** – Power 2 Gas and Gas to Power, transportation fuel and industry decarbonisation

1. ORIGINATION

- Co-create winning business strategy
- Identify opportunities for capital deployment (public and private capital)

2. COMMERCIAL DEVELOPMENT

- Business case development
- Service delivery options and financing strategy / commercial models for bankability
- Customer strategy and offtake support
- Commercial and technical feasibility
- Due diligence to inform buy side and sell side decisions

3. PLAN & DESIGN

- Technology assessment and selection
- Environmental planning and approvals
- Risk minimisation
- Environmental compliance support
- Environmental monitoring
- Site selection
- Social licence support: community and stakeholder engagement
- Concept design
- Pre-feasibility studies
- Front end engineering and design
- Multi-discipline engineering management
- Detailed design
- Systems integration
- Procurement support and tender development

4. CONSTRUCT & OPERATE

- Systems integration, risk and regulation
- Owners representative/ owners engineer role / project management
- Adoption of new technology risk
- Construction management and EPCM
- Supply chain resilience

5. DISPOSE / RENEW

- End of life services
- Asset closure strategies
- Alternative revenue streams
- Renewal / disposal strategies

OVERARCHING SERVICES

- Greenhouse gas assessments / carbon accounting
- Greenhouse gas assurance services
- Life cycle analysis
- Policy development and advice
- Environmental social and governance (ESG) frameworks

Drawing on the best of multi-sector innovation, consulting, data driven insights and technology to build value

Delivery under alternative risk/reward commercial models

Our work

Feasibility studies, policies & assessments

Waste-to-Energy – hydrogen production

CONFIDENTIAL CLIENT

GHD is providing engineering and other services to a large waste-to-energy client for a hydrogen production and distribution project. The project involves multiple grant applications for the project, engineering design, permitting and construction management, and distribution and marketing planning. The hydrogen facility includes electrolysers, compression, pipeline distribution, private and public fuelling, and tube trailer loading and decanting.

Power-to-Ammonia Concept Study – renewable hydrogen

CONFIDENTIAL CLIENT

GHD prepared a concept study and cost estimate for a small demonstration plant to generate ammonia using renewable energy. Hydrogen would be generated by electrolysis using electricity from PV array. The hydrogen produced would then be integrated with an existing plant generating ammonia using the Haber-Bosch process. The concept study considered a number of sizing combinations and identified integration issues.

Canada National Hydrogen Strategy & H2GO Roadmap

CANADIAN GOVERNMENT

GHD has provided technical, business, and market experience for the development of the H2GO Canada report Developing a Sustainable Approach to Hydrogen Deployment in Canada. Following this report, a number of GHD experts in future energy, hydrogen, and alternative transportation took part in extensive stakeholder engagement workshops by NRCAN to advance the development of the anticipated Canada National Hydrogen Strategy.

GHD supported the practical and meaningful plan to grow the hydrogen market in Canada in a similar manner as other countries such as Japan, Germany, the UK and Australia. GHD leveraged the work it had done to support the Australian Hydrogen Strategy.

Hydrogen to support electricity systems

VICTORIAN DEPARTMENT OF ENVIRONMENT, LAND, WATER & PLANNING

GHD, in partnership with ACIL Allen, provided advice on COAG Energy Council's development of a National Hydrogen Strategy via the 'Hydrogen to support electricity systems' work stream. This work stream focuses on understanding the interactions between hydrogen and Australia's on-grid and off-grid power systems.

The project team undertook an extensive literature review that considered demonstration projects and barriers to hydrogen production and use internationally, developing learnings for Australia's electricity sector. The team also looked at the way that hydrogen production technology could provide benefits to Australian electricity networks. A series of regulatory and policy options were identified that would help electricity markets realise these benefits from the hydrogen sector as it matures.

The team considered the potential for hydrogen opportunities to emerge in interconnected networks with consideration of the physical network characteristics and the markets that may provide future revenue streams for hydrogen producers that rely on power as an input to produce clean hydrogen. The team also developed scenarios that considered different network configurations and isolated power system applications. Through these case studies a series geographical, physical, technical and economic considerations were identified, as well as indicative deployment timeframes based on these factors.

Gladstone & Townsville Hydrogen Opportunities Study

QUEENSLAND GOVERNMENT

The key purpose of this study was to investigate and identify the land use planning, infrastructure and services required to support the development of a hydrogen industry in Queensland, with the purpose of informing the government and investors regarding hydrogen opportunities.

Key outputs were government planning, particularly in the area of integrated land use and ports planning, as well as infrastructure and services corridor planning/programming, including common user infrastructure. The final output of the study was assessment criteria that can be applied to other locations and provided to potential proponents. The study also included the development of a port suitability framework.

Wagga Wagga Special Activation Precinct

NSW REGIONAL GROWTH DEVELOPMENT CORPORATION

GHD worked with the Regional Growth NSW Development Corporation (RGDC) and the Department of Planning, Industry and Environment (DPIE) to assess the potential for adding hydrogen gas infrastructure to the Wagga Wagga Special Activation Precinct (SAP) to supply industry and transport networks in the area. This project supports the NSW Government's goal of net zero CO2 emissions by 2050.

Our work included providing technical, regulatory, planning and compliance support to determine the potential for new hydrogen gas infrastructure in the SAP. Identifying the key risks and drivers of value for the project such as safety perception, uncertain regulation and potential customer base helped us advise RGDC on next steps.

GHD delivered a concept and development framework to help RGDC, DPIE and stakeholders understand the options for achieving the objectives sought in an optimal way to maximise outcomes for the local community and regional economy.

State-of-the-art Hydrogen Blending in Natural Gas Study

PIPELINE RESEARCH COUNCIL INTERNATIONAL (PRCI)

GHD is undertaking a study to map and assess the current state of research and development and industry deployment worldwide regarding H2 injection into natural gas transmission and distribution systems, with a focus on blending up to 20 percent while considering impacts and requirements for higher blends. GHD is leading the study which involves contribution and collaboration from over 20 industry and academic organisations from North America, Europe, and Australia.

Based on the mapping and SOTA analysis, a gap analysis was completed to identify current H2 blending limits based on existing natural gas infrastructure and components, and evaluate the key areas of research needed to achieve technical feasibility for increasing blending goals in the coming years. Additionally, opportunities to collaborate with international organisations on advancing technical knowledge for injection projects was identified.

The gap analysis will guide the identification of proposed R&D topics to pursue starting in 2021. This undertaking is an important initiative for updating and enabling the Pipeline Research Council International's Hydrogen Roadmap.

Hydrogen community education guidelines development

AUSTRALIAN CAPITAL TERRITORY GOVERNMENT

Engaged by the ACT Government, GHD developed educational material about hydrogen to build public understanding and acceptance of the swiftly emerging hydrogen energy industry. In developing these materials, GHD drew on examples from other hydrogen projects around Australia and globally, insights from interviews with industry stakeholders, research literature and real-world hydrogen experience. GHD was selected for our technical knowledge across our global network, capabilities in public communication and community engagement, and extensive experience working with government and hydrogen industry stakeholders.

Renewable power generation – hydrogen / ammonia

BHP NICKEL WEST

GHD is currently performing a study into a 10MW renewable hydrogen facility in Kwinana, Western Australia. Scope includes renewable power generation and transmission and onsite production of hydrogen, oxygen and potentially ammonia.

Whole-of-supply chain projects

Extensive study to develop export-scale renewable hydrogen production facility

BP AUSTRALIA & AUSTRALIAN RENEWABLE ENERGY AGENCY (ARENA)

GHD is working with bp Australia to undertake an extensive study to explore the feasibility of developing an export-scale renewable hydrogen production facility in Western Australia. GHD is advising bp's exploration of the commercial, technical, regulatory and communications challenges of developing a new green industry with potential global scale.

The feasibility study will deliver a detailed technoeconomic evaluation of pilot and commercial scale green ammonia production plants in Geraldton. This will include an evaluation of the different technologies and process configurations required to manufacture green hydrogen and green ammonia.

GHD is working closely with our global client who has set clear ambitions to diversify into hydrogen and ammonia production for both exporting (ammonia) and domestic use (hydrogen). This project has received government funding and has the potential to be large-scale commercial operation in the next five years.

Hydrogen Energy Supply Chain Project

KAWASAKI HEAVY INDUSTRIES & JPOWER

A consortium of Japanese companies is aiming to prove the various supply chain elements to enable hydrogen fuel to become commercially viable in Japan in the future. KHI and JPower are leading the initiative in a world-first attempt to convert Victorian brown coal into hydrogen for open-sea transport (export) in a liquefied form, with significant funding support from the Australian, Victorian and Japanese Governments.

This requires:

- Pilot-scale coal gasification and syngas refining, using a high moisture brown coal feedstock
- Hydrogen transport by road to a port terminal where it is liquefied and stored for export by sea loading of hydrogen onto specialised ships and transport to Japan
- Site selection studies.
- GHD is providing a range of engineering, planning and environmental services to the project consortium:
- Approvals and permitting, including Works approval
- Communication, stakeholder engagement and website development
- Leading licensing and environmental approvals
- Safety systems design and Australian compliance, including hazard identification, HAZOP facilitation, fire and gas detection design
- Process mass balance, detailed civil, structural, mechanical, electrical and control system design and procurement assistance for the pilot scale plant
- Technical (owners engineering) assistance.

Production projects

Feasibility Study – hydrogen refuelling station

COMMONWEALTH SCIENTIFIC & INDUSTRIAL RESEARCH ORGANISATION (CSIRO)

GHD is undertaking a Feasibility Study to determine the viability of the installation of a Hydrogen Refueller Facility within the boundary of the CSIRO Clayton site in Victoria. The Feasibility Study will include reference to current market technology levels and identify any constraints on the physical installation at the Clayton precinct.

GHD is proud to be working with CSIRO who is investing in significant research and development initiatives across the hydrogen energy value chain. CSIRO has established a Hydrogen Industry Mission, to enable the scale-up of domestic hydrogen supply and demand to activate Australia's hydrogen market as a stepping-stone to a world-first clean hydrogen energy export industry.

HyP SA Demonstration Project FEED Study

AUSTRALIAN GAS NETWORKS

Australian Gas Networks engaged GHD to prepare a FEED study for the proposed HyP SA project at Tonsley Park in Adelaide, South Australia. The former Mitsubishi Motors assembly plant at Tonsley was in the process of being completely redeveloped as an integrated employment, education and residential precinct by Renewal SA. It was Australia's first innovation district, connecting businesses with the best and brightest and was one of several innovation projects being developed by industry with support from the Government of South Australia.

The project was based on a 1.25MW electrolyser and included a gas injection facility for blending hydrogen into the natural gas network. The project allowed for future expansion of a second gas network injection point, tubetrailer filling facilities, and connection to a solar power plant located on the Tonsley site.

Renewable Hydrogen / Ammonia Export Project

CONFIDENTIAL CLIENT

GHD carried out a study to investigate the technical requirements and economic viability for a renewable ammonia export facility for our client. This study included a process involving desalination of sea water, producing demineralised water, producing hydrogen using PEM electrolysis technology, using an air separation unit (ASU) to produce nitrogen and delivering nitrogen with hydrogen to an ammonia synthesiser to produce renewable ammonia. Storage and handling facilities at the port were also included in the study.

Assessment of Hydrogen Value Chain Options

STANWELL ENERGY

GHD undertook a study to determine the preferred value chain for hydrogen production based on a 10-25 MW electrolyser. The host site was considered to already have power generation capability. The study considered four potential uses for the hydrogen: compressed and loaded into tube trailers for sale to third parties; used to produce ammonia and loaded into road tankers for sale; used to produce power; or used to produce heat within the existing plant.

Our study considered a number of alternatives to identify preferred technologies and economies of scale. These included:

- Power interconnection options
- Alkaline and PEM electrolysers
- 3 MPa and 25 MPa storage (steel bullets and aluminium tubes)
- Two technologies for micro ammonia plants
- Gas turbines and fuel cells for power generation
- Two heat integration options
- Two hydrogen truck dispatch scenarios.

The study identified viable value chain pathways from the above options and, for these pathways, evaluated the plant requirements, storage volumes, compression requirements, power and water supply, performance, capital costs and operating costs. A SWOT workshop was also undertaken to identify qualitative advantages and disadvantages. The client combined the provided information with current and future market price information to produce preliminary business case models and to identify a preferred pathway.

Innovative electrolyser technology – technical & commercialisation review

AUSTRALIAN RENEWABLE ENERGY AGENCY (ARENA)

GHD undertook a review of a detailed funding application to enable the continued development of an innovative electrolysis technology. The technology had been invented at a university and a dedicated company had been set up to further develop and then commercialise the technology and the associated manufacturing process. The review considered:

- The current and projected performance improvements of the technology
- The current and projected cost reductions due to improvements, increased scale and improved manufacturing processes
- Current and projected performance and costs of existing electrolysers using PEM and alkaline technology
- The commercialisation timetable for various market applications and key trigger points.

Ammonia-to-Hydrogen membrane cracking technology

COMMONWEALTH SCIENTIFIC & INDUSTRIAL RESEARCH ORGANISATION (CSIRO)

GHD undertook an Ammonia-to-Hydrogen membrane cracking technology pre-feasibility study to take this concept to the next stage of development. This is a significant project which has led to vast opportunity to scale-up the production of hydrogen from ammonia leading to a range of new applications for the development of a hydrogen industry for Australia.

Hydrogen Demonstration Project FEED Study

JEMENA

GHD developed a front-end engineering design study for a hydrogen demonstration and test facility in New South Wales. The facility included electrolyser hydrogen production, hydrogen compression, storage, vehicle refuelling, power to gas injection to a local natural gas distribution system, fuel cell power generation, a research building and a combined operation and education building.

GHD prepared key design documents including the design basis manual, site layout, PFD, P&IDs, control system architecture diagram, electrical single line diagrams, hazardous area diagram, electrolyser specification, equipment datasheets and building layouts. GHD also prepared a cost estimate based on vendor pricing, material take-offs and factored indirect costs.

HyP SA Hydrogen Facility Concept Study

AUSTRALIAN GAS INFRASTRUCTURE GROUP (AGIG)

GHD undertook a review of initial options and high-level costs for a hydrogen facility at Tonsley Park, South Australia. The initial schemes included 10MW or 1.25MW electrolysers, PV power supply, power to gas injection, bus and vehicle fuelling station and a tube trailer filling facility.

GHD then prepared a concept study and cost estimate for the staged development of an initial power to gas using a 1.25MW electrolyser, with subsequent additions of a behind the meter PV supply, local power network connection, gas reticulation injection system and a tube trailer filling facility.

10MW green hydrogen facility

CONFIDENTIAL CLIENT

GHD has recently been awarded a feasibility and concept study for a first-of-its-kind 10MW green hydrogen facility in Tasmania.

100 MW Solar – Hydrogen / Ammonia

YARA / ENGIE

GHD provided key inputs into a feasibility study with the goal of designing a green hydrogen plant that would be integrated with Yara's existing ammonia plant in Pilbara, Western Australia. The goal is to transform the plant from one that relies completely on natural gas for hydrogen to one where a significant share of the hydrogen comes from renewable power.

Power-to-Ammonia Study

GLOBAL

GHD prepared a concept study and cost estimate for a small demonstration plant to generate ammonia using renewable energy. Hydrogen would be generated by electrolysis using electricity from PV array. The hydrogen produced would then be integrated with an existing plant generating ammonia using the Haber-Bosch process. The concept study considered a number of sizing combinations and identified integration issues.

Blue hydrogen production concept study & CCS pipeline FEED

SANTOS

GHD is working with Santos to deliver two blue hydrogen-related studies that have potential to pave the way to large-scale export of hydrogen while also decarbonising its operations in the Cooper Basin, South Australia. The concept study is focused on the production of hydrogen from natural gas and includes preliminary technology selection with a focus on identifying suitable options that facilitate maximum CO2 capture on a lifecycle basis and thereby produce hydrogen with the lowest carbon footprint. Integration into the current Cooper Basin operation, pathway to regulatory approvals and a cost estimate are included in the scope.

GHD is also undertaking the front-end engineering design of a pipeline that will transfer dense phase CO2 for injection from Santos' Moomba Gas Plant to depleted reservoirs for permanent storage. The project includes the infrastructure for distributing the CO2 from the pipeline to the injection wells.

Carbon capture and storage is viewed as a critical pathway for enabling rapid growth of Australia's potential hydrogen export industry, while potentially using less water than hydrogen from electrolysis, decarbonising natural gas at its source, and eliminating Scope 3 emissions.

Hydrogen from hydroelectric power for domestic use or export

PACIFIC HYDRO

GHD is undertaking a study to explore the feasibility of using pumped hydro to produce hydrogen in the far north of Western Australia. This is possibly the first project of its kind in Australia using a hydro generation facility as a power source to create green hydrogen and/or ammonia. There is potential to use the hydrogen for remote power and vehicle applications with the ammonia in demand for nearby agricultural uses in the irrigation system.

Our client, PacificHydro, was awarded funding in January 2020 from the WA Government's Renewable Hydrogen Fund to conduct a feasibility study to assess the potential of a collocated hydrogen facility at the Ord Hydro Power Station. The location provides a unique opportunity for hydrogen production, utilising low cost, high availability, dispatchable renewable energy and access to water.

PacificHydro owns and operates the Ord Hydro Power Station, a 30MW hydroelectric power plant located in the Kimberley region. The feasibility study will assess the potential of a co-located hydrogen plant, utilising electricity generated by the Ord Hydro plant, which would have the potential to supply hydrogen or ammonia locally, as well as for export.

Transport routes, pipelines, ports & shipping

Hydrogen Pipeline Project

CONFIDENTIAL CLIENT, UNITED STATES

GHD provided services to one of our long-standing industrial clients for a multi-year, large compressed-hydrogen gas pipeline project. GHD provided input into finding the most feasible route for the pipeline of over 100 miles in the USA.

GHD's role was largely to assist in pre-consulting, preparing applications, and obtaining US Army Corps of Engineers (COE) permits for wetlands and sensitive areas, including one pipeline section installed in the lake bed of a large lake to avoid an urban area.

Shipping fleet analysis – Liquid H2, NH3 & MCH

QUEENSLAND GOVERNMENT

GHD has undertaken analysis of various production volume scenarios (medium, large and very large) across the three products and determined the likely shipping fleet requirements and road and rail delivery options.

This included various options regarding pressure and temperature states for the different products. This work has been part of a study for the Queensland Government Department of State Development to investigate siting options for green H2 development at Townsville and Gladstone.

Transportation options assessment of hydrogen, ammonia & oxygen

BP AUSTRALIA

GHD reviewed the different forms of carriage of H2, NH3 and O2 products for rail, road, ISO tank container and shipping formats (container and bulk) and established costs for each of these supply chain components. This has been integrated into a dynamic techno-economic model with the production process to test the viability of various production and supply chain combinations.

Services included the establishment of the potential risk profiles and operational conditions necessary for the loading of ISO tank containers filled with NH3 product at the Ports of Geraldton and Fremantle. This work provides an overview of the potential ways of moving H2 related production products, the typical payloads and the cost elements associated with these movements.

Long-distance hydrogen pipeline concept design

EPIC ENERGY

Epic Energy has engaged GHD to undertake a concept design and cost estimate for a long distance, large scale transmission pipeline to transport hydrogen to an export facility located at a port. The study includes preliminary route selection, adapting Australian Standard natural gas transmission design methodology to hydrogen and studying options for powering remote pipeline compression facilities.

GHD brings nearly three decades of transmission pipeline design experience to the project including adapting the pipeline design methodologies to other first-of-a-kind applications in Australia.

End-use applications and storage

Hybrid Hydrogen & Battery Energy Storage Systems integrating AI

PROVIDENCE ASSET GROUP

H2Store owned by Providence Asset Group is the world's first company to achieve dense hydrogen storage at room temperature and common household pressure. Providence Asset Group is also the first company to use hybrid hydrogen and battery storage technology to store renewable energy at solar farms.

GHD has been engaged to provide comprehensive consulting and engineering services on the development of a number of demonstration Hydrogen Energy Storage System (HESS) projects across Australia, including a large 102 MW solar farm in Queensland and a portfolio of 20-25 community based solar farms in New South Wales and Victoria.

GHD delivered a range of services to these ground-breaking projects, including initial prospecting, site investigations, feasibility study, business case assessment, concept design, planning and approvals, detailed engineering design, stakeholder engagement, hazardous area and emissions compliance, construction, operation and maintenance.

World-first residential Hydrogen Energy Storage System – product development support

PROVIDENCE ASSET GROUP & LAVO

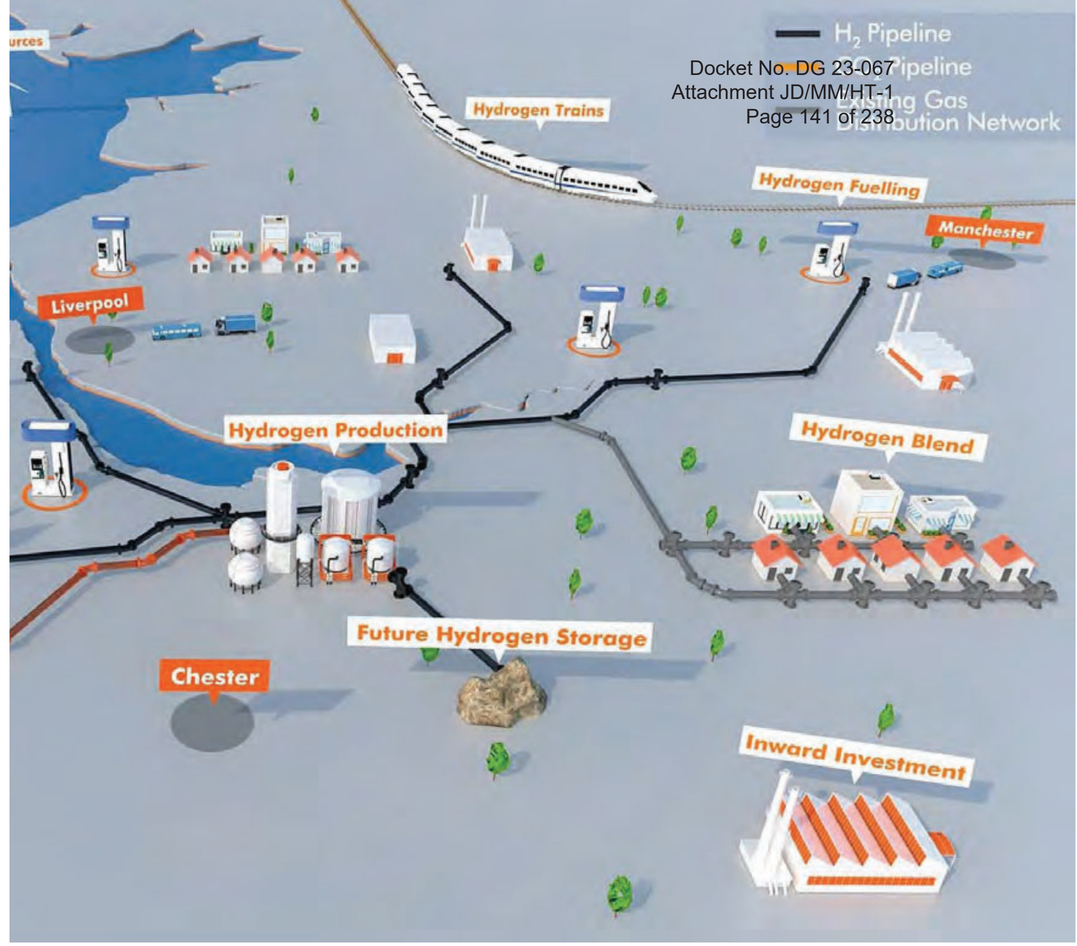
GHD has provided product development support for the world's first household hydrogen energy storage system, known as LAVO, a collaboration between Providence Asset Group and the Hydrogen Energy Research Centre at the University of NSW.

Engineering support – hydrogen as a fuel for industrial process heat

HYNET, UNITED KINGDOM

TGHD is supporting a ground-breaking hydrogen project led by HyNet consortium in the north west of England. GHD's role is to provide engineering design for a key aspect of this landmark project to conduct a live demonstration of using hydrogen as a fuel for industrial process heat.

Funded by the UK Government's Department for Business, Energy and Industrial Strategy (BEIS) under its Industrial Fuel Switching Competition, this project forms part of the wider 'HyNet' initiative (www.hynet.co.uk) coordinated by Progressive Energy and involving a range of industrial and academic stakeholders, including the Essar refinery in Stanlow, the Unilever site at Port Sunlight and the Pilkington glass factory in St Helens, all in the north west of England.



HyNet aims to develop the UK's first net-zero hydrogen cluster and is driving forward many elements of the hydrogen supply chain from production (alongside carbon capture and storage) to distribution and end-use, making an important contribution in helping the UK to reach its goal of being carbon-neutral by 2050.

As engineering design partner on the Industrial Fuel Switching element of the program, GHD is working with Progressive Energy, one of the host industrial sites, and other project participants to design the new plant and equipment needed to convert a boiler system from natural gas to carbon-free hydrogen. The work includes detailed mechanical, electrical and control system design, all set in the context of tight safety and environmental regulations at the site. The ultimate aim of the project is to demonstrate how hydrogen can be used as a substitute fuel for natural gas in the industrial process, helping our client transition to a low-carbon future and leading the way for others to follow.

H2 liquefaction & export terminals

Renewable Hydrogen / Ammonia Export Project

CONFIDENTIAL

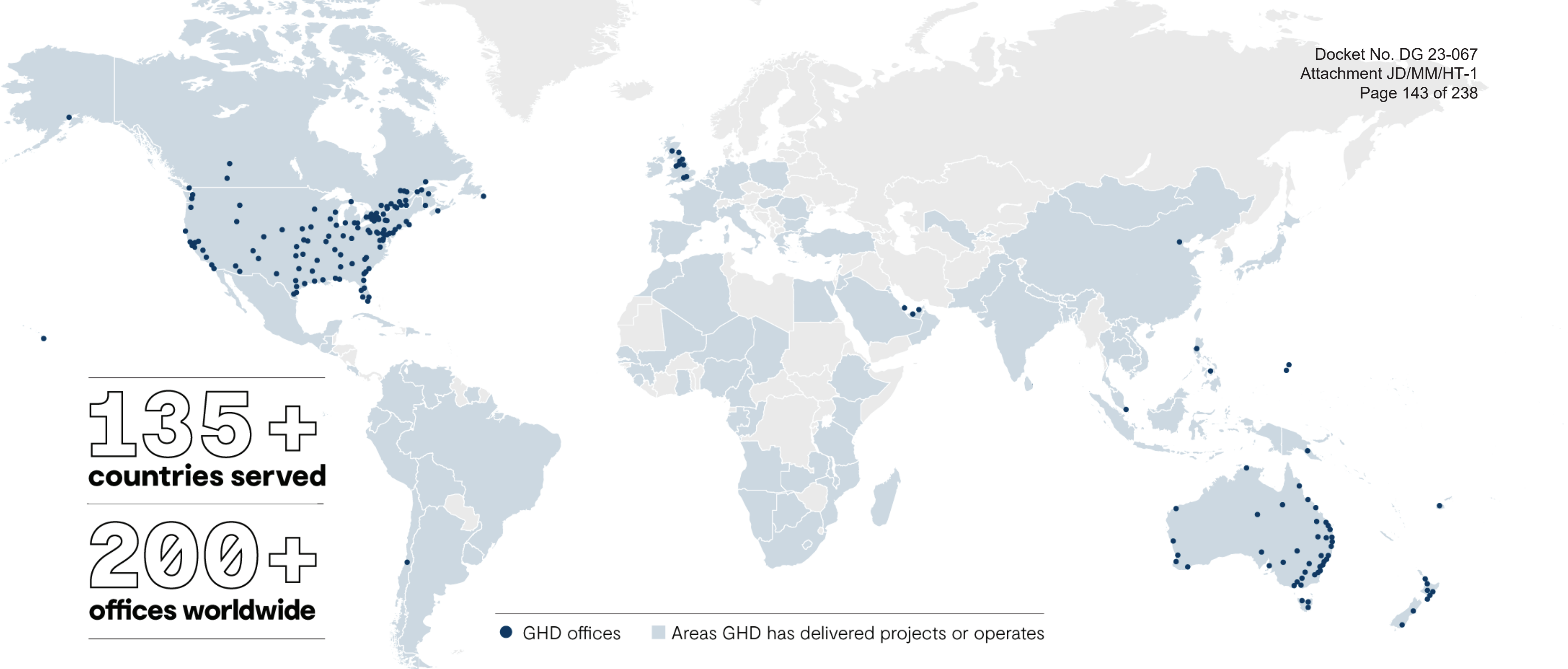
GHD carried out a study to investigate the technical requirements and economic viability for a renewable ammonia export facility for a confidential client. This study included a process involving desalination of sea water, producing demineralised water, producing hydrogen using PEM electrolysis technology, using an air separation unit (ASU) to produce nitrogen and delivering nitrogen with hydrogen to an ammonia synthesiser to produce renewable ammonia. Storage and handling facilities at the port were also included in the study.

Opportunity Study for Hydrogen Exports & Port Development Study

PORT OF HASTINGS DEVELOPMENT AUTHORITY, VICTORIA

GHD prepared the 30-year strategic port development strategy (PDS) for Hastings in line with the requirements of the Port Management Act in Victoria. The project included stakeholder consultation with Government, port users, potential users and the local community providing the basis for a future demand assessment across a range of trades from oil and gas to bulk materials.

The strategy also required retention of a development option for container operations at the port. Potential port options were developed to align with future trade development directions. Broader supply chain infrastructure options were also addressed for road and rail access to the port under demand scenarios. The overall strategy provides a basis for future planning and investment options for the port.



About GHD

GHD recognises and understands the world is constantly changing. We are committed to solving the world's biggest challenges in the areas of water, energy and urbanisation.

We are a global professional services company that leads through engineering, construction and architectural expertise. Our forward-looking, innovative approaches connect and sustain communities around the world. Delivering extraordinary social and economic outcomes, we are focused on building lasting relationships with our partners and clients.

Established in 1928, we remain wholly owned by our people. We are 10,000+ diverse and skilled individuals connected by over 200 offices, across five continents – Asia, Australia, Europe, North and South America, and the Pacific region.

Find out more about us at ghd.com

→ The Power of Commitment

II-370

28 July 2019

Dr Alan Finkel AO
Chairman, Hydrogen Strategy Group
COAG Energy Council
Australian Government

Our ref:

Your ref:

Dear Dr Finkel,

GHD response to the National Hydrogen Strategy Issues Paper Series

On behalf of GHD, thank you for the opportunity to respond to the National Hydrogen Strategy Issues Paper Series.

We acknowledge there is an exciting and unique opportunity to develop a new clean hydrogen energy export market leveraging Australia's high value renewables resource position to respond to unprecedented momentum and potential growing global demand for hydrogen.

We wish to congratulate the Taskforce for implementing a considered and inclusive consultation format across two phases in March and July 2019.

The Issues Papers provided a clear synopsis of the views and threads emerging for consideration in the development of a hydrogen industry for Australia.

Close collaboration between governments, industry, researchers and communities in the coming year will be of great benefit to us all. We see substantial opportunity for technical and professional services firms, such as GHD, to contribute to shaping a sustainable and thriving new industry of which we can all be proud.

GHD is pleased to present responses to six of the nine issues papers, as follows:

- Issues Paper 1: Hydrogen at scale
- Issues Paper 2: Attracting hydrogen investment
- Issues Paper 3: Developing a hydrogen export industry
- Issues paper 5: Understanding community concerns for safety and the environment
- Issues paper 6: Hydrogen in the gas network
- Issues paper 9: Hydrogen for industrial users

Our collective GHD response has been drawn from various highly-experienced technical consultants from across the oil and gas, hydrogen, power generation, renewables, economics, safety, environmental approvals, and communication and engagement disciplines.

To bring a global perspective, we captured insights from GHD consultants located in our Canadian and United Kingdom operations.

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Thank you again for providing the opportunity for us to share our perspectives and contribute to this important policy initiative.

We look forward the release of the final National Hydrogen Strategy later this year.

Regards,

Craig Walkemeyer | A GHD Principal

Australian Market Leader – Energy & Resources

GHD response to National Hydrogen Strategy Issues Papers

Australian Government
Department of Industry, Innovation and Science

COAG Energy Council

GHD

28 July 2019

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Issues paper 1: Hydrogen at scale

Consultation Paper 1: Hydrogen at scale

1. **What scale is needed to achieve scale efficiencies and overcome cost barriers?**

   Scale efficiencies over the value chain vary depending on technology, process and end use. Efficient scale is dependent on the hydrogen application, size/scale of the market, transport mechanisms and production technology. For example, the economic scale of hydrogen from solar/wind to electrolysis is heavily dependent on electrolyser pricing, location, innovations in PV efficiency, and capacity factors. Coal gasification scale is also linked to carbon capture and storage (CCS) costs and capacity.

   The Issues Paper discusses the target hydrogen costs needed to impact the various markets. Scale on its own will not overcome some of the cost barriers because technological advancement is also required. Feasibility studies and cost estimating methodology can forecast scale 'sweet spots' and where further scale increases do not significantly improve the cost basis.

   GHD suggests target scale ranges are not widely promoted without substantiation through studies and participant evaluation, as this may inadvertently discourage valuable investigation and investment to explore and substantiate the ranges.

   Government-funded feasibility studies for exemplar projects that explore the impact of scale for different project and technology configurations would help accelerate progress. Proponents such as the Hydrogen Energy Supply Chain (HESC) project are examples that are sufficiently advanced to be able to suggest scale requirements for their configuration.

   Ventures to export hydrogen from Australia need to be scaled around economic export transport logistics and volumes sufficient to attract long-term supply contracts. Upstream production to meet the export volume could be an agglomeration of projects at smaller scale, with lower entry hurdles and less government support.

   Carbon capture and storage or use (CCS/U) has the potential to dramatically affect the hydrogen production pathways and scale either from gas, oil or coal hydrocarbons or biomass (for carbon negative fuels). Development of flagship CCS/U projects at scale will help reduce uncertainty around the cost of production from carbon based sources and help develop community understanding and acceptance of CCS/U.

2. **What approaches could most effectively leverage existing infrastructure, share risks and benefits and overcome scale-up development issues?**

   GHD has significant exposure to major industry projects in the private sector and believes that, on its own, the private sector can struggle to holistically evaluate and find optimum options to leverage existing infrastructure, achieve the necessary scale and share risks. Government could support and fund feasibility studies of test case examples and lead a transition of schemes to appropriate collaborations of private enterprise. These project examples can also explore the influence of scale on viability.

   Government could lead evaluation of optimum port and export configurations and provide stewardship to establish public/private enterprise to build shared export hubs. This would create an industry foundation that facilitates a much lower 'cost of entry' for many potential upstream hydrogen production proponents. An analogy would be a government under-writing of a gas transmission pipeline that allows many upstream gas producers to get its product to market.

Similarly, Government could establish an entity to lead the development of the first hydrogen transmission pipeline as this would also help the industry overcome another major hurdle to bulk hydrogen export, not just in terms of cost, but also in not needing to be the first to have to navigate hydrogen pipeline regulation and design and construction standards.

Furthermore, Government leadership could maintain these major infrastructure industry components for genuine multiuser access, and thereby maintain significant diversity in upstream producers, promoting healthy competition and technology development pressure. If the large scale export infrastructure is controlled by a private company, the field of hydrogen production proponents could be very limited or monopolised within the region.

GHD is aware of existing plans for CCS/CCUS that exist in the oil and gas, power and mining sectors. For example, Santos has publicised it is pursuing a project to capture CO_2-e emissions from the Moomba processing plant and inject it into the Cooper Basin oil reservoirs and CTSCo has its project in the Surat Basin. In Victoria, the CarbonNet project aims to service a broader industry with CCS and is currently undertaking significant technical studies and community engagement. Other non geo-sequestration initiatives exist. Industry proponents should be encouraged with direct funding support, and through amended and new policy to progress these projects, with the dual benefit of supporting the decarbonisation of existing industry and help achieve the use of CCS/U/US in combination with hydrogen from carbon-based sources if that proves to be a viable and justified option.

Federal and State Government could agree an aligned and efficient policy, regulatory and incentive environment to encourage interstate collaboration, a stable policy environment, and a best for country outcome in establishing Australia as a leading Hydrogen exporter. This would help reduce investment uncertainty which is essential for larger scale ‘make or break’ investments.

3. **What arrangements should be put in place to prepare for and help manage expected transitional issues as they occur, including with respect to transitioning and upskilling the workforce? How do we ensure the availability of a skilled and mobile construction workforce and other resources to support scale-up as needed?**

GHD believes that many of the skills developed for and lessons learned by the oil and gas industry will be transferable to the hydrogen industry.

Incorporating an understanding of the emerging hydrogen energy industry into high school curricula is likely to generate renewed interest in STEM subjects and technical career paths. This should flow into higher uptake in tertiary education and availability of suitably qualified engineers and scientists.

Preparing the trade industry to attract and develop the required workforce and retrain experienced practitioners from allied industries should be undertaken.

GHD observed that the North American experience with CNG showed that a steady increase in offering trade skill courses and training was required to provide sufficient workers to service the new infrastructure and vehicles. Current workers and truck drivers in the utility, resource and industrial sectors can have supplemental training to be qualified to service hydrogen equipment. Minimum qualification requirements and certifications need to be established with industry to ensure sufficient skilled workforce is available to support scale-up at the right time.

There are technical standards and regulations that will need to be implemented. GHD suggests that, as far as is sensible, Australia should involve itself in collaboration with the main international standards bodies with a view to adopting the standards and mirroring regulation where they are being efficiently developed elsewhere. Failure to do this risks delay in the Australian industry and burdening it with additional cost relative to competing countries.

4. <u>What lessons can be learned from the experience of scaling up supply chains in other industries?</u>

GHD agrees with the lessons learned from the QLD CSG to LNG industry that were documented in the Issues Paper 1. Accordingly, GHD believes that Federal and State Government has a significant role to play in preparation for and stewardship of similar new industry including:

- Anticipating and developing policy and regulatory frameworks
- Resourcing its departments to facilitate reasonable approval timeframes, cross-departmental education and awareness raising, and to have the capacity to work with the industry and community to facilitate best for country outcomes
- Anticipate potential environmental and community impacts that will require independent government assessment and or baseline data and arrange the assessments and data gathering
- Working with proponents to collaboratively help inform the public with fact-based information to facilitate community acceptance and support of the industry where justified, maintain focus on genuine issues and achieve best for country outcomes and minimise suboptimal outcomes due to ill-informed but powerful opposition or political gamesmanship
- Strongly guiding major industry proponents where it is clear that collaboration rather than competition will deliver a best for country outcome particularly around major transport infrastructure and achieving sustainable growth and avoiding over-capacity or an overheated and overpriced construction phase.

GHD refers to its comments in Section 2 suggesting Government involvement in the required large-scale export infrastructure, leaving private industry to compete and advance technology development in the upstream supply of the hydrogen and with open access to multi-supplier agglomeration export infrastructure.

To draw on an old analogy in the rail industry, highlighting the importance of a unified approach from Federal and State Government for high capital long life assets, such as hydrogen export port facilities and pipelines, Australia needs to avoid a situation where it does not have a standard rail gauge. Similar learnings could be gained from Australia's historical development of electricity infrastructure and water resource management.

Asymmetrical growth may be observed in the hydrogen supply chain based on technology, infrastructure or end user market readiness. For example, large-scale hydrogen production may be constrained by a lack of export-ready infrastructure or absence of fully developed end user markets. Support from Government for specific supply chain sectors may be required to accelerate capacity growth across the whole supply chain.

Coal gasification (with CCS), as an example, is a relatively efficient pathway to high volume hydrogen production with limited power grid impact. This pathway could promote the early development of major export infrastructure and permit the longer term development of alternative fully renewable pathways with access to developed transport networks and offtake agreements.

With appropriate Government commercial regulation, multi-user access provisions to essential infrastructure can be maintained, allowing smaller production facilities to participate with lower investment risk profiles for participants. This helps avoid the scenario of monopolised supply chain ownership and high barriers to entry to new proponents. Consequently, it also promotes competitive market forces and potential shorter product/technology development cycles, as well as attracting international investment.

5. **When should the various activities needed to prepare for hydrogen industry scale-up be completed by? What measures and incentives are needed to achieve these timings?**

Future technology disruption risk is always present when making an investment but can cause delays if it is already in view. A major investment into large scale port and shipping infrastructure based on one of the main bulk hydrogen transport technologies, such as a liquefaction and cryogenic shipping fleet, may hesitate if a competing, but less mature technology, is showing signs that it could be commercially advantageous.

Technical and commercial readiness of some of the technologies already in view could be expected to take significant time particularly relative to the timeframes indicated by potential Asian customers. Identifying key bulk transportation technology contenders, and supporting and expediting development, should be an early high priority.

Where Australian-developed technology is showing genuine potential to be a competitor to other internationally developed transportation options, it would seem appropriate to have it progressed on a similar footing to the alternatives.

GHD considers that the CSIRO ammonia to hydrogen technology presents an exciting option for transporting bulk hydrogen internationally. The green ammonia export industry may also progress on its own to export Australian renewable energy and help decarbonise the international ammonia market and would also benefit from the focus on the ammonia to hydrogen technology.

In a more general context, GHD suggests that the following activities could and should be commenced on finalisation of the national hydrogen strategy:

- Facilitating, with private industry, well-funded comprehensive feasibility studies of exemplar combinations of competing technology and export options and with information sharing requirements to establish a shared understanding of scale and cost and should include mechanisms to confirm valid, like for like comparison between funded studies.
- Facilitate and fund feasibility studies focused on the development of shared bulk export infrastructure to identify sweet-spot port and pipeline locations, establish estimated processing tariffs to offer to prospective hydrogen producers and stimulate hydrogen production project development and to progress the Australian assessment, adoption and development of necessary technical standards and regulations.
- Review related policy and support to current proposed CCS projects in other industries with a view to encouraging proponents to invest in the project implementation and thereby supporting the decarbonisation of existing industry and potentially paving the way for CCS use in combination with hydrogen from carbon-based sources.
- Support meaningful Australian representation on international standards bodies with the objective of confirming suitability for use in the Australian context.
- Work to harmonise and align and embed State and Federal strategy and policy to reduce complications for prospective proponents and minimise investment risk due to policy change.
- Find and follow best practice in hydrogen policy and regulation with a view to mirroring and adapting for Australia.

Support of pilot facilities and other small projects to progress both technical and commercial readiness of production or transport related technologies that have shown to have merit should occur as and when justified.

The timing of larger government investment to support and stimulate major private sector investments in commercial demonstration or full scale facilities can be determined from the timelines established by the potential major export customers. Since Japan and South Korea are

Australia's target markets for export hydrogen, Australia should aim to grow hydrogen production according to their 'Hydrogen Society' aspirations and strategies.

Note that as Japan advances the commercialization of its hydrogen energy supply chain, it will be evaluating various options for fuel supply, including procurement from other nations like Saudi Arabia and Norway. Japan has further re-iterated its commitment to both renewable and 'brown' hydrogen development, although the latter is contingent upon reliable CCS/U technologies at the commercial scale. Given the extent of Australia's fossil fuel resources, the development of CCS/U technologies at scale is therefore a major enabler for an Australian hydrogen export industry.

Issues paper 2: Attracting hydrogen investment

Consultation Paper 2: Attracting hydrogen investment

1. **What changes to existing government support and additional measures are needed to:**

   • commercialise and scale up the hydrogen industry?

   • ensure an appropriate balance between export and domestic demand?

Measures recommended to help attract hydrogen investment to Australia include:

Attraction strategies – Government has a critical role to play in attracting industry to pilot scale developments. The development and commercialisation of a new industry via pilot scale strategies will enable both government and industry investors to understand pathways to scale.

Industry development and research support - Through subsidies and targeted grants, pilot scale projects offer diverse participants in the future industry an opportunity to establish a full supply chain. Through supported investment for the purpose of commercialising and scaling up the industry, the public and private sector can identify key commercial, regulatory, technical, environmental, and stakeholder challenges and opportunities that form barriers or provide advantage to achieve scale.

Clarity on approvals pathways - In GHD's experience, investors are looking for clear expectations around social and environmental impact mitigation strategies; and minimum approval criteria categories and thresholds. By developing clear approval pathways and expectations, the Government will provide investors with greater certainty that the investment in the pilot scale is just the first step in development through to scale when proven.

Demand side influence – The capital required at scale is significant. This means that the demonstration of bankability will hinge on the identification and establishment of a large customer base (export) combined with a domestic market (important but significantly smaller) where possible. Support on the demand side of the industry will encourage investment and enable industry to invest confidently. This is a key enabler.

Government regulatory and tax mechanisms - A balanced approach to domestic and export demand will depend on the government regulatory and tax mechanisms used to incentivise and structure domestic and export market prices.

Supporting adoption strategies - Domestic 'hydrogen' product adoption strategies can increase the market available. An example of this could be a transition to hydrogen-fuelled public transport and established policy and regulation with respect to domestic gas blending.

Lessons learned - Similar to the bio-fuels industry, Government support will be required to develop the hydrogen economy and in particular the green and blue hydrogen industry in Australia. We could look towards the bio-fuels industry and the lack of development over the last few years to learn what is required to develop the hydrogen industry; clear policy and support from Government at every level will be required.

To ensure an appropriate balance between export and domestic demand, while it will largely dependent on market and pricing, there will need to have a deliberate focus on initiatives such as:

- Continuing with work to study the feasibility of injection into the existing gas network
- Identifying potential demand from existing and new domestic industrial users that could transition to green hydrogen
- Retaining a percentage of production quantities for domestic use to meet agreed long term market plans that are in line with changing community expectations; and
- The prioritisation of studies into related infrastructure eg. refuelling locations for cars, heavy vehicles and trains.

2. **<u>How do we ensure an attractive investment environment for private sector finance? Which methods would be most effective in leveraging maximum private sector finance and which activities should governments prioritise with limited funds? How should these methods change over the short, medium and long term?</u>**

Investors need assurance of strong, consistent and scalable returns.

Investment cost relief – Targeted grants/taxation schemes to encourage investment and offset economic and commercial losses experienced in the development of the sector (i.e. grant funding for feasibility studies and pilot scale projects (short term)), then taxation relief schemes for larger scale investment (long term). In GHD's experience, an effectively structured grant program would enable a partnership approach with private sector finance that requires a return on capital scenario. As an emerging industry, this will require subsidies or some form of investment cost relief (tax relief).

Market Australia's unique conditions – we enjoy an abundance of renewable and fossil fuel feedstocks and a comparatively stable political environment where there is bilateral support from all levels and sides of government.

Policy stability – to amplify investment in the near term, proponents will expect Australia to demonstrate how it will create long-term policy stability as well as clear technical and economic regulations specifically for hydrogen.

Underwrite demand – An alternative model would be for government to underwrite demand in the form of off-take. However this approach is still likely to result in private sector cost while the supply chain and market price is not mature and stable, (i.e cost curves need to drop significantly or government would need to guarantee artificially high demand price).

Transitional support – As scale increases and the commercial model develops, private sector finance will be seeking transitional support through Government levers including regulation, tax, planning approvals certainty and government contribution to supporting infrastructure (such as national grid, ports, roads etc.).

3. **<u>What level of domestic market support is needed to achieve COAG Energy Council's ambition of being a major global player in hydrogen? In particular, what types of support will best provide the necessary domestic skills and capabilities and ensure domestic markets are available in the event that international markets do not emerge as quickly or as extensively as expected?</u>**

The domestic market will play a key role, however the level of support must be considered in the context of the international market, as the two are intrinsically linked. Access to the international market will be required to underpin investment if the ambition is to become a serious global player.

Concurrent development to support a domestic market could be supported by:

Leading position – The domestic market can be used to accelerate investment and intellectual property (IP) with the purpose of remaining ahead of the learning curve globally. Engagement or support of Government agencies and scientific research providers including CSIRO, ARENA, and other domestic supporters will increase the rate of knowledge.

Existing domestic gas injection projects to furthering knowledge – GHD has worked on or is aware of current demonstration projects for clients including Jemena and AGIG. There should be incentives to industry to accelerate these investigations and pilots.

Skills development programs – leveraging export projects to build new skills and attract new talent into the field will prepare us for a domestic market to develop – this could take the form of research institute programs at the university level and STEM program funding support programs.

Transition mechanisms – On market side, Government can influence the market size and accelerate transition to hydrogen through mandating use via strategies including hydrogen fuelled public transport fleets, gas network blend, and de-carbonisation incentives.

4. **<u>What market and revenue designs and settings will best allow for sustainable growth of the hydrogen industry and an appropriate level of benefits flowing back to the Australian public?</u>**

Nil response

5. **<u>What market signals and settings are needed to capture hydrogen's sector coupling benefits? When should these market signals and settings be applied?</u>**

Nil response

Issues paper 3: Developing a hydrogen export industry

Consultation Paper 3: Developing a hydrogen export industry

1. **How do we best position and sell the benefits to international partners of investing in Australia's emerging hydrogen industry?**

   The optimum position for Australia would be as a low cost and reliable industry, combined with the opportunity to position overtly as a guarantee of origin producer. This would be attractive to international investment partners seeking to participate in the long-term green hydrogen supply chain, which has significant demand potential internationally.

   Creating clear and stable national policies, plans and actions to stimulate development of an Australian export market for hydrogen will also facilitate heightened investment activity.

2. **How could governments support the cost competitiveness of Australia's hydrogen exports?**

   Progress the research and development – Investment in development of the domestic market can have a material role in supporting the cost competitiveness of Australia's hydrogen exports.

   By enabling the progress of pilot scale projects, the Government will support industry participants in developing and testing technology, developing IP and evolving to a mature supply chain. Domestic policy reform, subsidies and promotion of domestic supply chains will have a positive impact on R&D investment which will move the industry along the cost curve comparatively sooner. This investment can be leveraged for scale and for the development of an export market.

   Dual focus is key - It is a risk to competitiveness of both domestic and export markets if the support for the export market is limited to a point where domestically we pay for higher costs of hydrogen than international off-takers.

   Provide clarity via a roadmap – Communicate that Australia is following a roadmap that progresses through the development of demonstration facilities to commercial size facilities for export to countries who have already indicated their policy settings.

   Reduce cost of renewable power - Two significant cost components of producing renewable hydrogen are the cost of power for the electrolysis process and the supply chain required to support the industry. Australia has an enormous opportunity to generate renewable energy to produce large quantities of renewable hydrogen but this requires a reduction in the cost of generating renewable energy. Minimising the cost for power will increase cost competitiveness and increase viability.

3. **What could governments do to encourage commercial offtake agreements for export?**

   Guarantee supply - Governments should be involved with hydrogen project developers during the marketing phase to guarantee supply to off-takers. This will provide more confidence to hydrogen off-takers that Australia will be a reliable and sustainable source of hydrogen.

   Support cost reduction of inputs - Government should provide financial grants for the development of large commercial / utility size renewable energy systems to take advantage of economies of scale and falling equipment costs.

4. **How do we balance our global competitiveness with ensuring all Australians benefit when considering the collection of government revenues from hydrogen exports?**

It is important to consider and learn lessons from two Australian precedents in the energy industry - development of the LNG industry and the CSG industry.

CSG developed a domestic market to prove the quality and reliability of delivery. It was encouraged by government mechanisms and investment in infrastructure. The LNG from CSG plants followed after the domestic market had proved the CSG supply chain.

In contrast, the LNG industry developed for export independent of an LNG market in Australia. This meant that the majority of technology, benefit and profits ended up being controlled by multinationals with limited ongoing benefit to Australians.

In any positioning with international investment partners, it will be essential to ensure that Australia fully benefits from its resources advantage as well as the investment partners. A royalty program is a viable consideration.

5. **What can (or should) be done to ensure an appropriate balance between export and domestic demand?**

The main barriers for the use of domestic hydrogen in Australia are:

- the lack of necessary infrastructure
- the availability of sufficient and continuous renewable energy at a sustainable cost to grow to scale.

Strategic development for a domestic and export industry should be integrated to minimise the timeline required to grow the domestic and export industry. Therefore, a number of initiatives should be progressed simultaneously to advance the timeline and commerciality associated with developing a clean hydrogen industry for domestic and export market.

The key areas that would benefit from strategic development are:

- Develop key infrastructure to mitigate the barriers to growing a domestic industry (refer dot points above)
- Developing power technologies to provide a continuous source of renewable power
- Developing a low cost ammonia synthesiser process (to produce ammonia for export)
- Developing biogas production plants that enable biogas to be converted to hydrogen (for domestic consumption)
- Development of transmission pipelines suitable for high concentration hydrogen blends or hydrogen.
- Advance carbon capture and sequestration or use technology to take advantage of using fossil fuel or other carbon sources for producing renewable hydrogen.

6. **How ambitious is the target of fulfilling 50% of Japan and Korea's hydrogen imports by 2030?**

This is an ambitious target given the current status of our hydrogen industry. Moving a demonstration plant from TRL[1] 6 to TRL 9 on to full scale could take this long alone. It is envisaged that the first plant may be a fraction of the capacity required to fulfil 50% of Japan and

[1] TRL – Technology Readiness Level

Korea's hydrogen requirements and Australia may need to develop several commercial plants to satisfy the requirements for Japan and Korea.

The broader issues of energy cost needs to be considered. A coordinated strategy to achieve low cost of energy to make the hydrogen would be required to consider such a target.

Maintaining the very positive collaboration and relationship with major proponents and governments from these regions is imperative to maximising Australia's potential to achieve this target.

Issues paper 5: Understanding community concerns for safety and the environment

Consultation Paper 5: Understanding community concerns for safety and environmental impacts

1. **<u>Do existing regulations adequately manage the potential carbon emissions of a large-scale national hydrogen industry?</u>**

   The key to answering this question depends on how the hydrogen is produced in a new facility.

   For example, if it is produced by creating a syngas from a fossil fuel and separating out the hydrogen then in Victoria it is subject to the requirement to receive an approval from EPA Victoria under the EP Act 1970. In determining whether to grant an approval EPA considers best practice, energy efficiency, greenhouse gas emissions and climate change.

   It is anticipated that any commercial scale project would need to include carbon capture and storage to gain environmental approvals and community support. If a future facility was predicted to have >200,000 tCO_2-e of direct emissions, it would currently need to make a referral to determine whether an Environmental Effects Statement is required for the project or an EPBC approval.

   Currently however, again in Victoria, if the hydrogen is created by electrolysis, then the facility would not require approval from EPA (unless it is not sourcing electricity from the grid and is creating its own electricity using fossil fuels on site). This is because there are no direct emissions from the facility.

   Rather, it is like any other large user of electricity. There may be additional emissions created because of the hydrogen facility but these would occur at the source of the electricity generation.

   The source of electricity generation may be regulated by EPA if it consumes fossil fuels to create the electricity but this regulation does not link back to the end user of the produced electricity. The EES referral/EPBC 200,000 tCO_2-e trigger would not apply to the electrolysis facility as the trigger is for direct emissions not using electricity from the grid.

   At a Federal level, if the hydrogen producing facility produces more than 25,000 tCO_2-e of direct emission or consumes electricity equivalent to 25,000 tCO_2-e, it would need to report its emissions under the National Greenhouse and Energy Regulations (NGER). The NGER, however, currently does not limit the amount of emissions from a facility.

   As stated in Issues Paper 5, the safeguard mechanism (SGM) applies to facilities that emit greater than 100,000 tCO_2-e. New facilities predicted to emit greater than 100,000 tCO_2-e will need to apply to the Clean Energy Regulator for a baseline which will be calculated as production amount multiplied by an emission intensity for that product (currently no emission intensities have been set by DoEE).

   If during operation, actual emissions exceed the baseline set then the facility would need to purchase offsets (Australian Carbon Credit Units – currently approximately $15 per tCO_2-e) to bring emissions back down to the set baseline. This would only apply to hydrogen projects using fossil fuels as raw materials as the SGM only applies to direct emissions.

   The SGM does apply to fossil fuel based electricity generators. However, it currently would allow for considerable amounts of electricity to be supplied to hydrogen generators before any penalty was applied.

2. <u>What are the main community concerns about the use of CCS? How can we better manage these concerns and potential CCS projects in regional areas?</u>

Perceptions of Carbon Capture and Storage

The main concerns, and possibly what is driving those concerns, is an overall lack of knowledge about carbon capture utilisation and storage (CCUS) technology and impacts; and that it is perceived to be unproven technology in Australia. This perception is despite the fact that there has been significant Australian effort in developing CCUS through bodies such as the CO2CRC and Global CCS Institute.

A key point made in Issues Paper 5 is that, 'the risks and opportunities for acceptance of hydrogen will change as awareness grows, and as people start seeing the technology emerge in their lives'. The same is true of CCUS – until it is a reality, it may be difficult to change perceptions on a community-wide level without pointing to the runs on the board.

CCUS is fundamental to enabling a commercial-scale coal-hydrogen energy supply chain pathway, unlocking enormous and immediate export opportunities for Australia, while also supporting our existing coal industries to produce clean, low emissions hydrogen – it has the opportunity to be perceived as a win-win.

When speaking to communities or observing media coverage on the issue, the typical threads around concerns involve environmental impacts associated with storage leakage fears – what impact could that have on the marine environment or other natural assets eg. for offshore CCUS, would leakage change the ocean acidity?

There may also be an ideological rejection of CCUS due to some perceiving it as 'propping up' the coal/fossil fuels industry, rather than perceiving it as playing an important role the in decarbonisation of various industries globally.

What can be done to address concerns?

Addressing perception issues would benefit from a three-pronged approach:

1. Develop a credible Australian plan for CCUS based on science and real-world applications and with reasonable times for technical development.
2. A community-wide educational approach using real-world success stories to demonstrate the results, value and benefits that CCS plays in terms of decarbonisation of key industries, and leveraging industry influencers to be an independent voice and act as a powerful advocate.
3. An on-the-ground locally affected (perceived or real) community approach to address localised concerns, building a long-term, trusted relationship over time.

We need to acknowledge that concerns will likely vary depending on location – the concerns of communities such as Golden Beach in Victoria may be very different to communities neighbouring the CTSCo's Surat Basin CCS project.

Additional perceptions research to gain deeper community-wide understanding

It is tempting for industry and Government to make assumptions and conclusions about the real drivers behind CCS concerns. However, the only way to uncover awareness levels and sentiment is to survey a broad cross-section of the community with a representative sample size, supported by qualitative research such as focus groups.

We agree with CSIRO's comment in Issues Paper 5. There is a need to better understand the community-wide concerns with additional and regular primary research to extend on the initial UQ perceptions study findings – once known, Government and industry will be in a better position to collaborate in order to develop the facts to break down the myths.

Once a solid benchmark of awareness and perceptions is understood, this should be re-tested in a longitudinal study. These findings should be shared with industry proponents, as well as Government, in order for there to be a constant shift in our collective communication and engagement approaches – this can not only be an industry proponent responsibility.

Share lessons learned from those on the ground

In addition to market research, insights can be drawn from on-the-ground, real-time community feedback being collected by CCS entities as an invaluable source of knowledge to help shape the right narrative.

Entities at the front line of community interactions on CCS, like CarbonNet in Victoria, are capturing real-time community feedback about the concerns being raised. Appropriately, their approach has been to be visible and available to locals so people can raise concerns directly with technical leaders in the field and receive immediate information to answer concerns. These insights are invaluable to the rest of the industry.

A key challenge will be to maintain this level of constant communication and engagement in the long-term.

Amplifying key messages to build support

- Amplify the narrative around CCS as being the most cost competitive pathway to hydrogen right now – that it has to be a transition/staged approach
- Build a sense of urgency around the need for change to enable to clean energy future, and CCS's role in responding in the immediate term
- Explain why CCS is central to unlocking a decarbonised future for a variety of industries. Rather than communities or interest groups forming up an immediately negative opinion, we need them to be cheerleaders.
- Look at ways to also develop CCU opportunities for local and regional projects.

3. What are the risks about using desalination plants or water recycling facilities to produce water for electrolysis?

In terms of managing water scarcity concerns, the use of desalination plants or recycled water could present enormous benefits. However, there are still some technical challenges to overcome.

Management of brine generated by desalination plants is both a techno-economic and environmental challenge. Thermal brine treatment processes (e.g evaporator crystallisers) are energy intensive and present numerous operational challenges (scaling, water chemistry). The market for by-product salts is also very limited. The more crude methods of brine treatment (salt dams, deep well injection, surface water disposal etc) also present their own ecological risks on top of risks associated with social licence to operate. The existing, large scale, sea water reverse osmosis desalination plants around Australia with brine discharge to ocean provide advanced learnings and solutions for this challenge.

Modern desalination plants are reverse osmosis based, although other membrane technologies (forward osmosis, VSEP, membrane distillation) are being commercialised and may warrant consideration. Thermal distillation units (MSF, MED) are still employed, particularly in the Middle East.

The choice of desalination technology will have an impact on overall energy requirements and lifecycle cost, and lifecycle carbon emissions, for the production of hydrogen and therefore any desalination method should undergo a focused technology selection study.

Australia’s experience with existing large-scale sea water desalination provides a solid starting point for the cost and energy impact on the hydrogen industry. There are perhaps even potential synergies to be considered for hydrogen infrastructure relative to these existing assets although the required scales are different.

4. **How can we best balance the water and land use requirements for environmental, agricultural, community and hydrogen production uses?**

There is likely to be substantial community concern regarding water security for the environment, human use, and agriculture if plants are proposed in inland regions to produce hydrogen by electrolysis, particularly given the current drought and climate change projections.

There are strategic land use planning frameworks in each state that provide the opportunity for a range of industries to take place, including hydrogen production. If there are specific locations or regions that are better suited to particular types of hydrogen production (i.e. hydrogen production from fossil fuel compared to hydrolysis), a strategic review could be undertaken to determine whether there is sufficient suitably zoned land available.

Strategic land use planning could also consider the potential issues associated with cumulative impacts due to clusters of developments around nodes that are likely to be particularly attractive for development (this is an issue with other industries).

5. **Hydrogen production projects will require significant project and environmental approvals at the local, state and federal level. What approaches could help to manage these approvals to facilitate industry development while providing suitable environmental and natural resource protections and managing community expectations? When do these approaches need to be in place by?**

One of the key challenges is that it is a new industry in Australia and the planning and environmental approval process for large scale production facilities is yet to be tested in some jurisdictions.

This is unlike other industries, including the fossil fuel and renewable energy sector, where legislation has evolved over time and contains specific provisions to permit and control development.

Planning and environmental approval legislation could be reviewed and amended if necessary to ensure that there is a clearly defined pathway, and perhaps provide a streamlined State-led approval pathway that integrates approval requirements.

Flow charts for planning and environmental approval processes could also be developed so this is clear to proponents as well as the community. This would assist to manage community expectations by identifying key points in the process where they will have an opportunity to provide input.

6. What are the most important standards and regulations to have in place to ensure a safe hydrogen industry and address the community expectations?

As noted in Issues Paper 5, community acceptance is strongly linked to perceptions of safety, and those who know more about the properties and uses of hydrogen, are more likely to be supportive. Coupled with highlighting the economic growth and job creation possibilities, this will help with generating better understanding and acceptance.

Based on GHD's community engagement experience on hydrogen projects in Australia, to address concerns and manage community expectations, confirming a clear set of standards (whether they be based on existing or modified for hydrogen) will be important for:

- Hydrogen storage (gas and liquefied)
- Hydrogen transportation (by road)
- Hydrogen gas pipelines
- Hydrogen Liquefaction plants
- Aspects of export terminal design and operations
- Marine shipping routes.

Major Hazard Facility legislation and the associated Safety Case methodology is now mature in all Australia States and Territories and provides a systematic approach to identifying, quantifying and managing risk. Although some hydrogen projects may not trigger MHF thresholds for Scheduled Material storage and use, the methodologies used in the Safety Case preparation are relevant, applicable, well developed and well understood.

The Regulatory Agencies with the requisite skills to review and challenge Safety Cases already exist. Government and industry could choose to apply these methodologies to demonstrate a thorough assessment and understand potential safety impacts from these developments on the community.

The quantified risk assessment approaches used in Safety Cases would enable comparisons of the new hydrogen activities with many other common hazardous activities with which the public is already familiar.

These data and analogies could form a powerful, fact-based community information program and help avert misinformation and misunderstandings occurring that can be difficult to reverse.

GHD foresees a potential challenge is that the above information may emerge too late in the development of the new hydrogen Industry as the requirement for a Safety Case Submission only occurs at the advanced stages of the project execution. Furthermore, many of the smaller pilot and developmental projects may not trigger the MHF Scheduled Material thresholds. Therefore, it is suggested that the national hydrogen strategy should include for these risk assessment activities to be undertaken early in the project phase to help inform policy and the community. This could be achieved, for example, by undertaking the necessary risk quantification for exemplar project configurations.

As highlighted by Hydrogen Mobility Australia in its March submission, if a majority of the environmental and safety aspects associated with the production, distribution, and use of hydrogen can, in fact, be effectively managed through existing regulations, codes and standards, it is of upmost importance that communities are aware of this fact.

Breaking down the fears and normalising hydrogen

Normalising hydrogen applications in our everyday lives could help achieve a shift in safety fears over time. GHD is aware of technology advancements such as work by the University of NSW who developed a hydrogen-fuelled electric bicycle and a domestic-scale BBQ – these small-scale applications could help bring hydrogen applications closer to reality.

7. **<u>As an individual, how would you like to be engaged on hydrogen projects? Which aspects would you like to be kept informed of? Which aspects would you like to be consulted on? Are there any types of issues or challenges that you, or affected communities, would want to be a part of formulating solutions and recommendations?</u>**

Nil response applicable.

8. **<u>What are the best ways of engaging diverse communities in regional and remote areas?</u>**

GHD has worked with government and industry clients to engage regional and rural communities and key agency stakeholders for many years, including in the context of emerging industries, such as the CSG industry.

Key lessons learned to inform the best ways of engaging diverse communities in regional and remote locations include:

Engage the Council: Early involvement by the Local Council in shaping the right approach to engaging their communities is essential – they are a critical voice and have a deep understanding of their community

Acknowledge the diversity of communities: Understanding and acknowledging the differences between each community is key – each will have their own wants and needs in terms of aspirations for their local area – knowing this helps determine what topics or issues are of upmost importance to them and what they will expect to be informed and engaged about

Foster the support of local community opinion leaders as advocates: Regional and remote communities will typically have key opinion leaders/ influencers whom often wear a number of hats eg football club president, fourth generation farmer etc – these people become a primary stakeholder to identify and engage with early and often

Media: The Local newspaper is still a very important source of information – knowing the editor and journalists personally helps to ensure the project team is able to communicate important updates through this platform

Be part of the fabric of that community: Being present and on the ground to develop trust as part of the local community is crucial. – Set up a shop in the main street – be part of the fabric of that town Build trusted relationships: Face-to-face briefings with landholders will be more meaningful and gain better traction in terms of building trust.

Provide independent and scientifically based factual support: Communities are reassured when they can see that key safety and environmental information is not tainted with a potential conflict of interest and when it is delivered in an understandable and relatable form. GHD provided additional suggestions related to this in its answer to Question 6 above.

9. What role could an industry code of conduct play in gaining community support for hydrogen projects? What community engagement principles would you like to see in an industry code of conduct?

Established community engagement and sustainability models

GHD strongly agrees that creating the right framework from the very beginning gives clarity and certainty in terms of what to expect from an emerging hydrogen industry – for the governments funding the projects, for surrounding communities, and for the future industry proponents.

There are a range of established industry best-practice infrastructure sustainability assessment models and community engagement principles that should be leveraged in the development of an overarching industry code of conduct.

International Association of Public Participation (IAP2)

Community engagement practitioners, including GHD, will often develop fit-for-purpose engagement approaches using well-known and widely accepted models like the International Association of Public Participation (IAP2) engagement spectrum. The spectrum provides guidance for the extent to which the public should participate in shaping aspects of project design and implementation, and the appropriate engagement tools.

Infrastructure Sustainability Council of Australia (ISCA)

ISCA has an Infrastructure Sustainability (IS) Rating scheme that facilitates the ratings of infrastructure projects and assets.

The IS Rating scheme is Australia and New Zealand's only rating system for evaluating sustainability across design, construction and operation of infrastructure. IS evaluates the sustainability performance of the quadruple bottom line (Governance, Economic, Environmental and Social) of infrastructure development. This rating scheme could be adopted by industry proponents in order for a proposed project to be assessed on its level of sustainability performance; and provide benchmarks against which to measure each project. This could provide comfort to communities expecting to be impacted by projects in their region.

Developing a hydrogen industry Code of Conduct

GHD has been actively involved in facilitating purposeful and mutually-beneficial community engagement outcomes for over 20 years. In our experience, there is usually inevitable teething problems when industry proponents are unclear about the expectation of their obligations to the communities in which they operate.

As such, GHD believe there are substantial advantages in government leading the way with a code of conduct developed in close collaboration with all levels of government, industry, and the professional infrastructure consulting firms who will inevitably be working on-the-ground and acting as the project ambassadors/representatives.

Finding the right balance will be important – guidelines need to be clear enough to understand the expectation without being too prescriptive and deterring investment.

Engagement principles in a code of conduct should cover topics such as:

- Engaging with Indigenous communities
- Level of public participation - the level of community engagement depending on the phase of work (ie Approvals, Planning, Site Selection, Design, Construction Methods, Operational phase)
- Land access obligations

- Complaints management and escalation procedures
- Decommissioning expectations and legacies
- Local industry participation obligations – local employment and suppliers.

10. <u>What governance structures (such as legislation and regulation) would the federal, state and local governments need to put in place for a large scale hydrogen facility?</u>

Further governance structures would be required where hydrogen production facilities use fossil fuels as the energy source for the hydrogen production, to ensure lifecycle emissions are positively reduced as a result of hydrogen produced.

This could be determined by undertaking a lifecycle analysis of the tCO_2-e produced per kg of hydrogen gas produced, and potentially setting limits on the production of tCO_2-e per kg of hydrogen gas produced. This would further incentivise emission reduction options like carbon capture and storage (CCS). Where hydrogen gas is produced from renewable electricity in electrolysis, this issue is reduced.

Additionally, undertakings from project proponents to purchase Australian Carbon Credit Units (ACCUs) or MWh of renewable energy could be allowed as a means of offsetting the emissions, if fossil fuels are used as the energy source, or while CCS facilities are being developed.

Standards for the requirements for carbon, capture and storage facilities would also needed to be developed to support the use of CCS in these sorts of situation.

It would be advantageous if any rules of these kind where developed on a national level to reduce regulatory risk for project proponents. If a lifecycle analysis approach was proposed, a standardised method to calculating the emissions should be developed. This will ensure consistency between projects. This should be based on the ISO 14040 and ISO 14044 standards. A similar approach has been developed for bioenergy projects, led by the Australian Renewable Energy Agency.

11. <u>What further lessons can we learn from the mining, resources and renewable energy sectors about establishing and maintaining community support?</u>

As an emerging industry, we have the important opportunity to collaborate with governments, project proponents, research institutes and most importantly, communities, to get it right from the very beginning.

Basing our approaches on lessons from oil and gas, mining and other renewable energy sectors, as well as by genuinely acknowledging community concerns of hydrogen project impacts, and working hard to address them in practical and tangible ways, will be key to us developing a sustainable and thriving export market.

Specific approaches and methods which should be considered in order to establish and maintain community support include:

- Explaining why; not just what is happening – bring people on the journey around the pros and cons of transitioning to a clean hydrogen energy future
- Ensure the local benefits are identified and communicated – economic growth, jobs for locals, new skills
- Engage on the solutions – site selection, supporting infrastructure needs, waste and water resources, local impacts during construction
- Engage communities on their preferred engagement and communication channels – tailor those approaches to each community as they will usually have different needs depending

on the local context eg current mining town, in need of economic growth, environmentally-sensitive area, agricultural communities

- Utilise Community Reference Groups appropriately – make them purposeful, have a clear Memorandum of Understanding in place for members to contribute in a meaningful way and avoid wasting people's time
- Utilise Information Sessions carefully – ensure people have access to the right experts and information at the sessions
- Measure the social impacts and social benefit outcomes in a transparent way and report back to communities often
- Be upfront about what happens at the point of decommission – will there by ongoing jobs.

Issues paper 6: Hydrogen in the gas network

Consultation Paper 6: Hydrogen in the gas network

1. **Which existing gas distribution networks or stand-alone systems are 'hydrogen ready' and which are not? What safe upper limit applies? Does this readiness include meters, behind-the-meter infrastructure, and appliances?**

   Issues Paper 6 makes it clear that the main Australian gas distribution companies are already involved in identifying suitability and they are best placed to respond to this.

   For global comparison, GHD is observing that in the UK, the current thinking is most of the existing low pressure gas networks would be suitable to operate with a blend of up to 20% hydrogen.

   Most of the older gas networks used to operate with 'Towns Gas' which was approximately 50% hydrogen. This theory is currently being tested at scale at Keele University in Staffordshire , UK (Hydeploy Project) and this is expected to reach conclusions by Summer 2020. In parallel, other much larger scale trials are being planned in detail. For higher blends and even 100% hydrogen, the work to date in the UK suggests that polyethylene pipe networks are 'hydrogen ready'. However, testing facilities have been set up to test the impact on valves, metal fittings, short sections of older iron mains and other ancillary equipment. These tests are ongoing and no firm conclusions have been reached. The UK's 'Hy4Heat' project has been looking at the practical and safety implications of hydrogen including the safety of domestic fittings and pipework. Again, this work is ongoing, but the general feedback is that there are no unsurmountable problems so far and in some respects hydrogen is safer than methane due to the way it easily disperses.

   SGN (Scottish Gas Networks) are planning to be the first in the UK to implement a 100% hydrogen trial (H100 project) in a location in the Fife region of Scotland. In developing this project, they are working closely with the other UK gas companies.

   The higher pressure gas networks have to be looked at separately as these mains tend to be steel and were designed for use with Methane in the UK. However, there are steel hydrogen pipelines in the UK which have operated for decades, as there are in Norway. It is believed the work being undertaken in the UK by IGEM (Institute of Gas Engineers and Managers) looking at the issue for the UK is forming a view that it will be possible to distribute hydrogen via the existing high pressure gas network as they believe that the risk of hydrogen cracking can be managed. This is an ongoing piece of work.

2. **What is the potential to have a test project of 100% hydrogen use in a small regional location and where?**

   Towns that are currently operated in 'island' mode with reticulation systems from centralised LPG storage could provide lower cost trial options. For a larger scale investment including hydrogen transmission pipelines, a trial similar to the Victorian Regional Gas Infrastructure program that commenced in 2011 could be undertaken.

   The simple approach is for it to be installed as part of a new housing development that is also near an industrial user of hydrogen or an injection point into the gas system. The industrial load or pipeline injection would help smooth out production and demand and the residents would have agreed to be part of the trial as part of arranging to live in the new development.

The other work to develop domestic appliances and boilers etc which can operate on 100% hydrogen would need to be sufficiently advanced.

3. **Which standards and regulations can be harmonised across jurisdictions considering the different structures and market settings (e.g. safety, codes of practice)?**

AS 4564 Specification for general purpose natural gas is currently silent with regard to hydrogen and requires modification for inclusion of hydrogen as part of the composition. Any changes in AS 4564 would require associated changes in standards covering the assets that would convey gas complying with AS 4564.

Australia is looking to develop standards for hydrogen production, transport and storage. Various international standards have been or are under development for various aspects already; but to GHD's knowledge, none of these have been adopted in Australia to date.

For gas networks, AS 4645 and AS 2885 would be expected to be readily modified to enable these standards to cover hydrogen levels allowed under changes to AS 4564. It is common practice in other jurisdictions to have pipeline standards that cover multiple fluid types. Given the likely outcome that existing gas networks may transport gas with hydrogen, it would be efficient to continue to use the same standards as currently used. It is noted that the standards used are asset lifecycle standards, and therefore they not only relate to the design and construction, but also operation and safe management of the gas networks.

If the Australian standards used for gas networks are modified, it would be logical to modify the corresponding primary regulations that govern the safe operations of the gas networks to enable hydrogen levels that are permitted under any changes of AS 4564.

Given the above, it would be reasonable to include purpose built 100% hydrogen gas networks within the scope of the existing standards and regulations.

4. **What roles should government and industry play in addressing any consumer concerns and building social acceptance?**

As highlighted in the response to Issues Paper 5, the Government will play a central role in addressing the concerns and fears of communities, particularly for how the industry will manage risks around hydrogen safety and environmental impacts including water.

As demonstrated from the active opposition surrounding the CSG industry, not taking a proactive approach to providing consistent, timely and accurate information to communities, can lead to significant issues arising with sub-optimal results for both communities and the industry.

Government and industry has an ideal opportunity to be on the front foot with education programs that are tailored to addressing what communities are telling us are their greatest issues. This, coupled with genuine, early and purposeful community engagement starting from the very early stages of any hydrogen-related infrastructure project will help build the type of relationships that fosters trust and lead to community awareness and acceptance.

Communities want to see a united front. Government can work with proponents to collaboratively help inform and influence the public with fact based information but it must be a partnership where the narrative and messages from Government and industry supports and complements the other, and ultimately, provides consistent information to communities to avoid confusion or lack of cohesion.

As noted in the response to Issues Paper 5, achieving small-scale demonstrations early that involve consumers and communities adopting hydrogen (buses, cars, homes etc) will provide tangible proof of suitability to broader society.

5. **<u>How could the actions included in Table 2 be improved? Are there other actions that should be added?</u>**

GHD suggests the following inclusions into the 2020-2022 phase:

- Using quantified risk assessment methodologies that have been developed and matured for MHF Safety Cases to explore risk exposure changes for hydrogen blends up to 100%. This will help inform implementation strategies. These data and developed analogies could form part of a powerful, fact based community information program and help avert misinformation and misunderstandings occurring that can be difficult to reverse. Refer to GHD's response to Paper 5 Question 6 for further detail.

  The quantified risk assessment will also identify key areas that may require exploration with practical testing to further develop the industry's understanding of the risks.
- Identify and implement the necessary skills and training programs required for the early phase
- Develop a roadmap for managing metering impacts as composition and fluid properties change
- Identify impacts on leak detection systems.

Issues paper 9: Hydrogen for industrial users

Consultation Paper 9: Hydrogen for industrial users

1. **Hydrogen as a chemical feedstock**

- **Other than using hydrogen or carbon capture and storage, are there other ways to reduce emissions from the manufacture of metals, particularly steel manufacturing?**

The International Energy Agency estimates that the global iron and steel industry accounts for almost 7% of global CO_2–e emissions. Therefore, a change to this industry could make a large impact on carbon emissions.

Carbon capture and sequestration in the steel industry appears to be a better solution than in power generation, but the potential carbon emissions reduction is still estimated to be limited to approximately 50% of total emissions; due to small and diffused emission sources, lack of space for capture installations, and other issues. Storage-related issues also remain unresolved in many cases. In addition, CCS comes with few co-benefits.

Outside of coupling CCS with existing processes, the only viable way of decarbonising heavy industry is to embark on a systemic change across the full value chain. In the case of steel manufacturing in particular, the following has been implemented or is in the process of being implemented.

The steel industry has made immense efforts to increase their energy efficiency, so that producing one tonne of steel today requires 40% of the energy required in 1960. Replacing less efficient blast furnaces with more efficient ones makes a large difference to carbon emissions from steel making. However, this improvement is unlikely to be repeated with the current steel making process, and more emissions reductions from increased energy efficiency is unlikely.

Recycling of steel also makes a material difference to carbon emissions from the steel industry. A substantial amount of steel is already recycled, with more targeted, as steel is a highly recyclable material. However, for steel recycling to make a large impact on carbon emissions from this industry, energy from renewable sources is required during recycling.

The coal used in steel making could be replaced with bio-carbon, although given the volume of coal required by the steel industry, sources like wood for bio-carbon that are fully environmentally sustainable may not always be practicable.

Utilising hydrogen for the direct reduction of iron ore, combined with an electric arc furnace is currently one of the most promising routes for decarbonisation of the steel industry. The hydrogen would have to be ‘green’; that is produced from electrolysis of water by use of renewable electricity.

Other methods to extract iron from iron ore are under investigation, but these are generally still in the very early stages of development. Commercialisation of new, low carbon technology in the steel industry is likely to take many years. There are significant barriers to new technology adoption. Due to the large number of steel-making facilities around the world and large capital investment already committed in these facilities, change in the steel industry is expected to be slow.

2. **Hydrogen for industrial heat**

- **What other energy sources are industrial users considering to reduce emissions from their industrial heat processes, and how cost-competitive are they compared to the fuel currently used?**

As noted in Issues Paper 9, hydrogen presents an opportunity for Australian industry to reduce emissions across a number of sectors. There are, however, a few additional sources of heat that could be utilised in the industry. It is likely that a combination of hydrogen and these other sources will ultimately lead to decarbonisation of industrial heat processes.

These other sources include the following:

- Heat pumps and renewable power could be used in the electrification of heating systems; however, there are several issues associated with the use of such systems. Heat pumps cannot provide medium to high temperature heating, while electrical heaters cannot simply replace gas-fired or fuel oil systems. This is in particular true for gas processing plants that require large heat transfer areas for heat exchange equipment. The unit costs associated with electrical heating are higher than for fossil fuel heating systems, but this is offset by higher heating efficiency, zero emissions at the point of use and small footprints.
- Biogas appears to be a favoured source for industrial heat supply. It is generally readily available, does not require major reconfiguration of existing systems utilising for example natural gas infrastructure and does not have geographic limitations for producing energy.
- Solar thermal may also be considered. While this is probably one of the more expensive energy sources at present, costs could come down significantly over time and use, as has happened in the solar PV industry. It could therefore become a real contender in the near future.
- Biomass is another source of energy that could be utilised for industrial heat; however, the users typically tend to need to be close to the sources of biomass to make this a viable option. GHD is however aware of potential projects considering mass export of biomass as fuel.

3. **Supplying clean hydrogen for industrial users**

- **What would industrial users of hydrogen need from a hydrogen supply network?**
- **Are there locations around Australia where there is an existing or potential demand for hydrogen from industry that are close to renewable energy or carbon capture and storage resources?**

Large industrial users of gas (for example natural gas or coal seam gas) demand reliability of supply, at a price point that is sustainable over medium and long-term commercial agreements. The importance of consistency in composition and heating value can be equally important for commercial process plants. A hydrogen supply network should not materially change the operability of an industrial facility or its risk profile.

CSIRO and others have targeted Gladstone for demonstration of hydrogen technologies as a location which is well-suited with respect to accessible energy resources, already has thriving industrial and industrial port activity and is geographically close to potentially major hydrogen markets (Japan specifically). The CTSCo CCS project could potentially be linked to this Gladstone focused initiative with a CO_2 pipeline.

Geologically prospective areas for carbon sequestration include the North West Shelf, where the Gorgon Project is located, and Bass Strait. The Gorgon project will store captured carbon in the Dupuy formation beneath Barrow Island. Chevron recently applied for a licence to operate the carbon sequestration portion of the project; once implemented it will be clear how successful this sequestration installation could be. The Cooper Basin may prove to be another suitable location. Distances from industrial centres are a challenge.

Other carbon sequestration methods include (1) soil sequestration, (2) forest and other vegetation sequestration, (3) ocean sequestration and (4) mineral carbonation. Of these, ocean sequestration and mineral carbonation are the most bound to specific locations, while the first two could be undertaken in various locations around Australia.

4. Technical considerations in transition to clean hydrogen

- **What would a conversion to clean hydrogen look like in your industry, in terms of timing, effect on production, equipment changes?**
- **What existing sites might be suitable to demonstrate industrial use of clean hydrogen?**
- **Does existing equipment in industrial heating applications have the technical capability to handle increased NOx emissions?**

Hydrogen can help tackle various critical energy challenges, as it offers ways to decarbonise a range of sectors where it is difficult to meaningfully reduce emissions any other way – like long-haul transport, chemicals, and iron and steel.

A large number of oil and gas firms are investigating how they can add renewables to its production portfolio and supply chain.

Many existing sites already use hydrogen. The overall mass and energy balance of the process would be significantly affected for sites using reformers to generate the hydrogen where as those receiving hydrogen deliveries or generating hydrogen using electrolysers should be able to make the transition more easily. The applications of hydrogen in industry are diverse and may be broadly split into the following areas:

- Fuel production: product upgrading of oils and intermediary fuels in both conventional and bio refineries
- Synthesis agent for the production of ammonia and ammonia based value chains. These include fertilisers, explosives and a number of intermediary commodity chemicals such as urea and methanol.
- Power Plants: Hydrogen is used a cooling agent for large turbo-generators.
- Manufacturing: Hydrogen is used in a variety of industrial sub-sectors as a reagent, primarily because of its reducing capability. These include glass making, food and beverage production, pharmaceuticals and electronics.

In addition, hydrogen is one of the options for storing energy from renewables.

Hydrogen used as energy storage can contribute to the resilience of our major electricity systems in Australia. Long-term energy storage in micro-grid sites, such as remote mine sites could benefit.

To understand conversion issues, the principal differences in hydrogen versus, for example natural gas, must be understood. The properties of low specific volume, high heating value, high flame speed and temperature, low flame visibility, low molecular weight and low (volumetric) energy density would all contribute to significant changes for a conversion plan.

The molecular properties of hydrogen require specific strategies for the mitigation of risk related to hydrogen embrittlement and leakage, which impacts design and construction of pressure vessels and process piping. Collectively these properties materially affect the way in which safety should be managed on an industrial site.

The oil and gas industry is in the fortunate position where safety and design standards are already in place which can serve to a large extent in a hydrogen industry.

The Toyota Ecopark Hydrogen Demonstration Project is a good example of how a decommissioned site can be put to good use for development of the hydrogen industry. This site used to be a car manufacturing facility, and is now utilised to produce green hydrogen and test storage methods and automobile refuelling. There are more such unused industrial sites around Australia (for example aluminium refineries) that could be put to good use to advance the hydrogen industry through test and demonstration work.

5. Hydrogen safety and regulation for industrial users

- **Are there examples nationally and internationally that illustrate best practice for industrial hydrogen safety regulation and handling expertise?**

There are currently no Australian Standards that deal specifically with hydrogen safety regulation and handling. The International Organization for Standardisation (ISO) body has developed some critical standards that cover various aspects of potential hydrogen supply chains including: basic hydrogen safety (ISO15916), water electrolysis for industrial application (ISO 22734), fuelling stations (ISO 19880), PSA systems for hydrogen purification (ISO 19883) , fuel quality (ISO 14867) and gaseous hydrogen storage (19884) amongst others. The ISO body continues to refine and develop new standards as the industry matures.

It is understood that Standards Australia is engaging the ISO body to request membership for the hydrogen technologies technical committee (ISO/TC 97).

Many of the major international oil refiners could be expected to have mature company standards for hydrogen. Experienced engineering and operating companies, especially ones already in the oil and gas, and in particular the CSG and LNG industry, can assist to develop these standards required for hydrogen production, transport, storage and utilisation.

6. Role for governments in supporting a transition to clean hydrogen

- **Are there any gaps in the existing mechanisms for government support for Australian industry to transition to hydrogen?**

A clear, stable policy that puts a price on CO_2-e emissions linked to Australia's international commitments for emissions reductions in the Paris agreement would provide a firmer foundation to allow industry to start modelling the benefit of transitioning to hydrogen as a fuel source.

The Safeguard Mechanism, which is part of the current National Greenhouse and Energy Reporting and Emissions Reduction Fund legislation, could be used for this purpose if it were to be amended to result in tighter caps in direct scope 1 emissions at a facility level.

Clear policy agreed at a State and Federal level, for the decarbonisation of the electricity sector would lead to greater incentive for the further growth in the use of renewable energy – and potential use of carbon capture and storage for fossil fuel sources, in the generation of electricity. This is clearly required to ensure that our economy wide targets for the emissions reduction under the Paris agreement are met at a reasonable cost.

The support of State Governments is important as is demonstrated by the Victorian Hydrogen Investment Program, the Queensland Government, and now the Western Australian Government industry development fund, which is to be implemented soon.

While Australia has a highly skilled workforce, there is still a gap in skills when it comes to the hydrogen industry. The government could assist to provide a framework for additional education and research and development in the hydrogen industry.

www.ghd.com

Australian Government
Department of Industry, Science, Energy and Resources

Business

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Grant Opportunity Guidelines

Activating a Regional Hydrogen Industry - Clean Hydrogen Industrial Hubs

Hub Implementation Round 1 Grants

Opening date:	28 September 2021
Closing date and time:	17:00 Australian Eastern Standard Time on 22 November 2021 Please take account of time zone differences when submitting your application.
Commonwealth policy entity:	Department of Industry, Science, Energy and Resources
Administering entity:	Department of Industry, Science, Energy and Resources
Enquiries:	If you have any questions, contact us on 13 28 46.
Date guidelines released:	20 September 2021
Type of grant opportunity:	Open competitive

Template Version – February 2020

Contents

1. Hub Implementation Round 1 processes

The Activating a Regional Hydrogen Industry: Clean Hydrogen Industrial Hub program is designed to achieve Australian Government objectives

This grant opportunity is part of the above grant program, which contributes to the Department of Industry, Science, Energy and Resources Outcome 2. The Department of Industry, Science, Energy and Resources works with stakeholders to plan and design the grant program according to the *Commonwealth Grants Rules and Guidelines.*

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The grant opportunity opens

We publish the grant guidelines on business.gov.au and GrantConnect.

↓

You complete and submit a grant application

You complete the application form, addressing all the eligibility and assessment criteria in order for your application to be considered.

↓

We assess all grant applications

We review the applications against eligibility criteria and notify you if you are not eligible.

We assess eligible applications against the assessment criteria including an overall consideration of value with relevant money and compare it to other eligible applications.

↓

We make grant recommendations

We provide advice to the decision maker on the merits of each application.

↓

Grant decisions are made

The decision maker decides which applications are successful.

↓

We notify you of the outcome

We advise you of the outcome of your application. We may not notify unsuccessful applicants until grant agreements have been executed with successful applicants.

↓

We enter into a grant agreement

We will enter into a grant agreement with successful applicants. The type of grant agreement is based on the nature of the grant and proportional to the risks involved.

↓

Delivery of grant

You undertake the grant activity as set out in your grant agreement. We manage the grant by working with you, monitoring your progress and making payments.

↓

Evaluation of the Activating a Regional Hydrogen Industry: Hydrogen Hub Grant

We evaluate the specific grant activity and grant opportunity as a whole. We base this on information you provide to us and that we collect from various sources.

2. About the Activating a Regional Hydrogen Industry - Clean Hydrogen Industrial Hubs program

Unless otherwise specified, references to hydrogen in this document refer to clean hydrogen as defined in section 14 in the Glossary.

The Australian Government is committed to being a world leader in the clean hydrogen industry. Australia's *National Hydrogen Strategy* highlighted the potential for an Australian hydrogen industry to generate more than 8,000 jobs and over $11 billion a year in GDP by 2050. Through the Government's Technology Investment Roadmap, the Australian Government has set a stretch goal of producing clean hydrogen for under $2 per kilogram. Achieving this goal will bring down the costs of hydrogen production will require a focus on market activation, creating demand and innovation so the industry can scale-up quickly and cost effectively. Clean hydrogen is hydrogen produced using renewable energy or using fossil fuels with substantial carbon capture and storage (CCS).

'Hydrogen Hubs' are regions where various producers, users and potential exporters of hydrogen across industrial, transport, export and energy markets are co-located. These Hubs are identified in Australia's National Hydrogen Strategy as an efficient early-stage approach to create demand and scale up the industry, which will help to support other existing industrial sectors in these regions. Clean Hydrogen Industrial Hubs will create economies of scale to drive down costs of production, unlocking further demand for hydrogen as costs fall, while creating efficiencies by leveraging and supporting the existing industrial capabilities and workforces in these regions. Hubs will stimulate innovation and increase workforce skills development, as well as support other existing industrial sectors in these regions to lower both emissions and costs in doing business.

This program aims to support the establishment of hydrogen hubs in regional Australia, and, in turn, support the growth of Australia's clean hydrogen industry. This will assist Australia to achieve its emission reduction goals while continuing to grow our export industries and expand choice for consumers. The program will build Australia's potential to supply international trading partners with low cost clean energy.

The program has a broad scope and recognises the potential diversity within industry that may be combined to form a Hub. The program is not seeking that these hubs be focussed on any single industry in recognition of the diversity of sectors and applications that hydrogen can support. In general, hydrogen hubs are likely to have:

- a pre-existing large industrial energy demand
- a skilled workforce, capable of delivering large projects
- existing infrastructure that can be utilised, like port facilities, gas pipelines, carbon capture and storage reservoirs or high voltage connections to the grid.
- proximity to energy resources either high capacity factor renewables and/or coal and gas resources, as well as access to required water resources
- co-located sources of potential demand and hydrogen production.

The objectives of the program are to:

- leverage existing infrastructure, knowledge and workforce for a least cost pathway to a viable clean hydrogen industry
- progress the establishment of hubs that stimulate demand and facilitate the production of clean hydrogen for domestic and export markets
- enable economic, environmental and social opportunities in regional communities by locating hubs in regional areas of Australia

- support the growth and jobs of Australian industry in the production and application of clean hydrogen
- support innovation in processing, distribution and use of clean hydrogen
- support complementary industries establishing and thriving around hydrogen supply chains by encouraging sector coupling
- build and strengthen international partnerships, build export pathways and encourage technological exchange and innovation.

The intended outcomes of the program are to make progress towards:

- making clean hydrogen available for domestic and export use
- establishing domestic clean hydrogen supply chains
- establishing clean hydrogen export pathways
- supporting existing industry to use clean hydrogen
- creating new industry being built around clean hydrogen availability in a local area
- creating new regional jobs and increased capability of local workforce
- reducing the cost of clean hydrogen production.

This program comprises two grant streams:

- **Hub Development and Design Grants**: supporting Australian industry on the initial development, feasibility and design work needed to advance Hydrogen Hub concepts
- **Hub Implementation Round 1 Grants:** supporting Australian industry to roll-out and establish Hub projects in regional Australia.

These two processes will allow those proponents who are already prepared to go to the Implementation stage to make applications for this funding. At the same time, it will also allow for other industry proponents in earlier stage of development to access Government support for early works before moving to the Implementation stage.

The Development and Design grants will be delivered through two successive funding rounds. Further Implementation grants may be awarded in a subsequent round subject to availability of program funds.

We will deliver each of the Activating a Regional Hydrogen Industry: Clean Hydrogen Industrial Hubs grant rounds through stand-alone, open competitive selection processes. You are encouraged to consider applying for both Development and Design grants and Implementation grants, as well as other related Commonwealth, State and Territory or International funding opportunities. For example, the Commonwealth government will shortly launch the CCUS Hubs and Technology program, the Australian Renewable Energy Agency (ARENA) is funded to support the development of Hydrogen technology, and the Clean Energy Finance Corporation has established a $300 million concession finance facility to support hydrogen projects.

If you are successful in more than one grant opportunity you must ensure activities and expenditure for each grant are clearly separated.

Guidelines for both grant opportunities, including the opening and closing dates of funding rounds and any other relevant information are available on business.gov.au and GrantConnect. Information on subsequent rounds will also be published on business.gov.au and GrantConnect.

We administer the program according to the *Commonwealth Grants Rules and Guidelines* (CGRGs)[1].

[1] https://www.finance.gov.au/government/commonwealth-grants/commonwealth-grants-rules-guidelines

2.1. About the Hub Implementation Round 1 grant opportunity

These guidelines contain information for the Hub Implementation Round 1 grants.

The Australian Government is focused on the timely establishment of Clean Hydrogen Industrial Hubs and the realisation of regional benefits. The Australian Government considers the following locations to be priority prospective hub locations, based on interest of industry and the location's existing capability, infrastructure and resources:

- Bell Bay (TAS)
- Darwin (NT)
- Eyre Peninsula (SA)
- Gladstone (QLD)
- Hunter Valley (NSW)
- La Trobe Valley (VIC)
- Pilbara (WA)

Although these locations are considered the most advanced, applications for the Hub Implementation Round 1 Grants are not restricted to these locations and applicants are able to define the 'region' to which their application relates.

This document sets out:

- the eligibility and assessment criteria
- how we consider and assess grant applications
- how we notify applicants and enter into grant agreements with grantees
- how we monitor and evaluate grantees' performance
- responsibilities and expectations in relation to the opportunity.

We have defined key terms used in these guidelines in the glossary at section 14.

You should read this document carefully before you fill out an application.

3. Grant amount and grant period

The Australian Government has announced $464 million from 2021-22 over five years for the Activating a Regional Hydrogen Industry - Clean Hydrogen Industrial Hubs program. This includes an estimated $30 million of funding to support the Development and Design of Hydrogen Hubs. This grant opportunity has $434 million available for Hub Implementation Round 1 Grants.

3.1. Project period

The maximum project period is 3.5 years.

We may approve a further extension in exceptional circumstances, provided you complete your project by 31 March 2026.

3.2. Grants available

The grant amount will be up to 50 per cent of eligible project expenditure (grant percentage).

- The minimum grant amount is $30 million.
- The maximum grant amount is $70 million.

You are responsible for the remaining at least 50 per cent of eligible project expenditure plus any ineligible expenditure, which we consider your contribution. Your contribution must be cash. We anticipate you may need to use some funding from other Commonwealth, State, Territory or local government grants to fund the project expenditure not covered by this program (such as the CCUS Hubs and Technology program). However, no more than 50 per cent of your total eligible project expenditure can be funded from Commonwealth government grants.

The Minister may approve a reduced grant offer within the parameters above. In this circumstance, you may be required to develop and agree a reduced project scope.

4. Eligibility criteria

We cannot consider your application if you do not satisfy all eligibility criteria.

4.1. Who is eligible?

To be eligible you must:

- have an Australian Business Number (ABN)

and be one of the following entities:

- an entity, incorporated in Australia
- an Australian State/Territory Government agency or body.

Your application must be a joint application with at least one and preferably multiple project partners. Joint applications must have a lead organisation who is the main driver of the project and is eligible to apply. If your application is successful, the lead applicant is responsible for managing the project on behalf of the consortium.

For further information on joint applications, refer to section 7.2.

4.2. Additional eligibility requirements

We can only accept applications:

- where you can provide evidence from your board (or chief executive officer or equivalent if there is no board) that the project is supported, and that you can complete the project and meet the costs of the project not covered by grant funding
- where you agree to publicly share knowledge and information about and resulting from your project (refer item 13.2 regarding the management of confidential information).
- where you provide all mandatory attachments.

We cannot waive the eligibility criteria under any circumstances.

4.3. Who is not eligible?

You are not eligible to apply if you are:

- an organisation, or your project partner is an organisation, included on the National Redress Scheme's website on the list of 'Institutions that have not joined or signified their intent to join the Scheme' (www.nationalredress.gov.au)
- an individual
- partnership
- unincorporated association

- any organisation not included in section 4.1
- a corporate or non-corporate Commonwealth entity.

5. What the grant money can be used for

5.1. Eligible activities

To be eligible your project must:

- be aimed at establishing a hydrogen industrial hub consisting of co-located sources of hydrogen demand and production to stimulate demand and facilitate the production and use of clean hydrogen for domestic and export markets, leveraging the existing industrial and energy resources in the region
- have at least $60 million in eligible expenditure.

Eligible activities may include

- establishing partnership/joint venture arrangements
- activities to firm up export markets, for example negotiating off-take agreements or investment from overseas
- utilising or modifying existing infrastructure to produce, transport, store and handle clean hydrogen and associated processes (e.g. carbon capture and storage)
- utilising or modifying existing industrial processes or assets to integrate clean hydrogen and associated processes
- establishing new industrial infrastructure directly related to the production or use of clean hydrogen
- purchasing clean hydrogen production and/or storage equipment
- developing clean hydrogen production technology
- running trials or pilots
- establishing demonstration sites or projects
- establishing initiatives that promote sector coupling and demand stimulation
- innovative use of technology or services in the commercial delivery of clean hydrogen
- developing a workforce strategy (including planning and training)
- local employment and skill development schemes in regional areas
- engaging with the community, including on hydrogen safety
- adapting and demonstrating international clean hydrogen technology in an Australian context
- sharing knowledge that would assist other Australian or international hydrogen projects.

We may also approve other activities.

Activities that are not eligible for funding include:

- research projects without a clear, short to medium term pathway to establishing a hub for the production and use of clean hydrogen for domestic and export markets.

If you are successful, you must participate in Australian international engagement activities associated with achieving relevant National Hydrogen Strategy and Low Emissions Technology

Statement goals for hydrogen, including working with the Special Adviser on Low Emissions Technology. This will be a requirement of your Grant Agreement.

5.1.1. Detailed implementation plan

If successful, you must provide a detailed implementation plan for establishing your hydrogen hub project in the first six months of the project or earlier. Your implementation plan must include:

- project narrative (including scope definition)
- project governance
- project schedule including critical path dependencies
- project finance arrangements including detailed financial modelling
- project engineering requirements
- risk assessment and risk mitigation plan
- commercialisation and scale up pathway
- permitting and approvals planning
- workforce plan
- knowledge sharing plan
- community engagement plan
- safety management strategy.

A committee comprised of or advised by independent technical and industry experts and Australian government representatives, convened by the department, must endorse your implementation plan. The committee may request additional information relating to your implementation plan and may seek additional advice from external experts.

If the committee does not consider your implementation plan satisfactory, we may terminate your grant agreement.

5.2. Eligible expenditure

You can only spend grant funds on eligible expenditure you have incurred on an agreed project as defined in your grant agreement.

- For guidance on eligible expenditure, see appendix A.
- For guidance on ineligible expenditure, see appendix B.

Not all expenditure on your project may be eligible for grant funding. The Program Delegate (who is an AusIndustry general manager within the department with responsibility for the program) makes the final decision on what is eligible expenditure and may give additional guidance on eligible expenditure if required.

To be eligible, expenditure must:

- be a direct cost of the project
- be incurred by you for required project audit activities.

You must incur the project expenditure between the project start and end date for it to be eligible unless stated otherwise.

You must not commence your project until you execute a grant agreement with the Commonwealth.

6. The assessment criteria

You must address all assessment criteria in your application. We will assess your application based on the weighting given to each criterion.

The application form asks questions that relate to the assessment criteria below. The amount of detail and supporting evidence you provide in your application should be relative to the project size, complexity and grant amount requested. You should provide evidence to support your answers. The application form displays size limits for answers.

We will only consider funding applications that score at least 50 per cent against each assessment criterion, as these represent best value for money.

6.1. Assessment criterion 1

The extent that your proposed project will facilitate the development of a regional industrial hub and accelerate the creation of an export and domestic clean hydrogen industry (30 points).

You should demonstrate this by describing:

a. the commercial potential of your hydrogen hub, including risks to its viability and appropriate risk management strategies, including the potential quantum of domestic and international hydrogen supply and/or demand your project may create

b. how your project will increase demand for clean hydrogen domestically, including estimated volumes and sectors impacted

c. how your project will create, leverage and advance export linkages, supply chains and international partnerships and/or offtake arrangements

d. how well your project connects with existing Australian industry and provides a clear pathway, in the short and medium term, to producing clean hydrogen, lower the production costs of hydrogen and/or transforming existing industrial processes to use clean hydrogen in your nominated hub location.

6.2. Assessment criterion 2

The extent that your project will utilise and support existing industrial capacity and infrastructure to build an ongoing Australian clean hydrogen capability and contribute to its long-term viability (20 points)

You should demonstrate this by describing:

a. your existing and proposed linkages with research organisations and other businesses, including current research or pilot activities

b. how your project will leverage and support co-located industry in the region

c. the level of support your project has from the relevant state/territory government, and/or local level of government

d. your proposed strategy for knowledge sharing with the emerging Australian clean hydrogen industry including learnings and understanding of future export supply chains

e. how your proposed project will address workforce capability gaps and contribute to sector-wide workforce development strategies and build on the existing local workforce's capability

f. how your proposed hub complements and builds on other activity intended to grow the Australian clean hydrogen industry.

6.3 Assessment criterion 3

Your capacity, capability and resources to establish a hydrogen hub (30 points)

You should demonstrate this by describing:

a. the structure of the consortium and why it is suited to delivery of this hub project

b. the track record of your consortium, or individual organisations within the consortium, in developing major projects and leveraging additional investment (from both within Australia and oversea), and your access to personnel with relevant skills and experience, including project management and technical expertise

c. your access to required finance, infrastructure, capital equipment, technology and intellectual property

d. how you will leverage existing capability, including the strength of your partnerships and engagement within the proposed hub

e. your project plan, including your plan to:

   - manage the project including scope, governance, implementation methodology and timeframes
   - mitigate delivery risks (including national security risks)
   - secure required regulatory or other approvals.

You must attach a project plan and budget to your application.

6.4. Assessment criterion 4

The impact of grant funding (20 points).

You should demonstrate this by describing:

a. how your project will enhance the commercial viability of the existing and the future Australian clean hydrogen industry and support Australian industry more broadly

b. additional investment that will be leveraged by your consortium to establish your hub

c. the broader social, environmental and economic impacts of your hub, including the extent that your project will generate jobs and investment in regional Australia

d. community support for your hub within local and regional communities.

7. How to apply

Before applying you should read and understand these guidelines, the sample application form and the sample grant agreement published on business.gov.au and GrantConnect.

To apply, you must:

- complete the online application form via business.gov.au
- provide all the information requested
- address all eligibility and assessment criteria
- include all necessary attachments.

You can view and print a copy of your submitted application on the portal for your own records.

You are responsible for making sure your application is complete and accurate. Giving false or misleading information is a serious offence under the *Criminal Code Act 1995* (Cth). If we consider that you have provided false or misleading information we may not progress your application. If you find an error in your application after submitting it, you should call us immediately on 13 28 46.

If we find an error or information that is missing, we may ask for clarification or additional information from you that will not change the nature of your application. However, we can refuse to accept any additional information from you that would change your submission after the application closing time.

If you need further guidance around the application process, or if you are unable to submit an application online, contact us at business.gov.au or by calling 13 28 46.

7.1. Attachments to the application

You must provide the following documents with your application:

- project plan
- project budget
- evidence of support from the board, CEO or equivalent
- a letter of support from each project partner.

Project plan, budget and letter templates are available on business.gov.au and GrantConnect.

You may also attach documentation to support your response to assessment criteria, for example any documentation listed as components of the detailed implementation plan as outlined in section 5.1.1.

You must attach supporting documentation to the application form in line with the instructions provided within the form.

7.2. Joint applications

Your application must be a joint application with at least one and preferably multiple project partners (a consortium). You must appoint a lead organisation who will be the main driver of the project. Only an eligible lead applicant can submit the application form on behalf of project partners and enter into the grant agreement with the Commonwealth. The application should identify all other members of the consortium and must include a letter of support from each of the project partners. Each letter of support should include:

- details of the project partner
- an overview of how the project partner will work with the lead organisation and any other project partners in the group to successfully complete the project
- an outline of the relevant experience and/or expertise the project partner will bring to the group
- the roles/responsibilities the project partner will undertake, and the resources it will contribute (if any)
- details of a nominated management level contact officer.

You must have a formal arrangement in place with all parties prior to execution of the grant agreement.

7.3. Timing of grant opportunity

You can only submit an application between the published opening and closing dates. We cannot accept late applications.

If you are successful we expect you will be able to commence your project around March 2022.

Table 1: Expected timing for this grant opportunity

Activity	Timeframe
Selection process	12 weeks
Negotiations and award of grant agreements	4 weeks
Notification to unsuccessful applicants	2 weeks
Earliest start date of project	On execution of grant agreement
End date of grant commitment	31 March 2026

8. The grant selection process

We first review your application against the eligibility criteria. If eligible, we will then assess it against the assessment criteria. Only eligible applications will proceed to the assessment stage.

We consider your application on its merits, based on:

- how well it meets the criteria
- how it compares to other applications
- whether it provides value with relevant money.

When assessing whether the application represents value with relevant money, we will have regard to:

- the overall objectives of the grant opportunity
- the evidence provided to demonstrate how your project contributes to meeting those objectives
- the relative value of the grant sought.

We will establish a committee comprised of or advised by independent technical and industry experts and Australian government representatives to assess applications. The committee may also seek additional advice and undertake due diligence using external experts.

The committee will assess your application against the assessment criteria and compare it to other eligible applications, taking into account the spread of projects nationally and the program objectives before making recommendations on which projects to fund. You may be required to attend an interview with the Committee as part of the assessment of your application. The Committee will make a recommendation to the Minister on which projects to fund. Committee members are subject to probity requirements as outlined in section 13.

If the selection process identifies unintentional errors in your application, we may contact you to correct or clarify the errors, but you cannot make any material alteration or addition.

8.1. Who will approve grants?

The Minister decides which grants to approve taking into account the recommendations of the committee and the availability of grant funds.

The Minister's decision is final in all matters, including:

- the grant approval
- the grant funding to be awarded
- any conditions attached to the offer of grant funding.

We cannot review decisions about the merits of your application.

The Minister will not approve funding if there is insufficient program funds available across relevant financial years for the program.

The Minister may approve a reduced grant offer. In this circumstance you may be required to develop and agree a reduced project scope.

9. Notification of application outcomes

We will advise you of the outcome of your application in writing. If you are successful, we advise you of any specific conditions attached to the grant.

10. Successful grant applications

10.1. Grant agreement

You must enter into a legally binding grant agreement with the Commonwealth. The grant agreement has general terms and conditions that cannot be changed. A sample grant agreement is available on business.gov.au and GrantConnect.

We must execute a grant agreement with you before we can make any payments. Execute means both you and the Commonwealth have signed the agreement. You must not start any Activating a Regional Hydrogen Industry - Hydrogen Hub activities until a grant agreement is executed.

The approval of your grant may have specific conditions determined by the assessment process or other considerations made by the Minister. We will identify these in the offer of grant funding.

If you enter an agreement under the Activating a Regional Hydrogen Industry: Clean Hydrogen Industrial Hub program, you cannot receive other grants for the same activities from other Commonwealth granting programs. We acknowledge that you may need to use funding from other Commonwealth, State, Territory or local government grants to fund the balance of project expenditure not covered by the grant.

If you are successful in more than one grant opportunity you must ensure activities and expenditure for each grant are clearly separated.

The Commonwealth may recover grant funds if there is a breach of the grant agreement.

10.2. Project governance

The committee will provide oversight of your project over the grant period.

The committee must endorse an implementation plan for your hydrogen hub provided by you in the first six months of the project or earlier.

You may be required to review and update your implementation plan annually over the period of your project, with each update endorsed by the committee.

10.3. Project/ specific legislation, policies and industry standards

You must comply with all relevant laws and regulations in undertaking your project. You must also comply with the specific legislation/policies/industry standards that follow. It is a condition of the grant funding that you meet these requirements. We will include these requirements in your grant agreement.

In particular, you will be required to comply with:

- State/Territory legislation in relation to working with children
- Any relevant export control requirements
- Australian Industry Participation requirements in accordance with the AIP Plan User Guide, refer industry.gov.au/aip.

10.3.1. Building and construction requirements

Wherever the government funds building and construction activities, the following special regulatory requirements apply.

- *Code for the Tendering and Performance of Building Work 2016* (Building Code 2016) [2]
- Australian Government Building and Construction WHS Accreditation Scheme (WHS Scheme)[3]

These regulations are subject to the level of funding you receive as outlined below.

10.3.1.1. Building Code

The Building Code is administered by relevant State and Territory administrations under relevant State or Territory legislation on behalf of the Australian Building and Construction Commission.[4]

The Building Code applies to all construction projects funded by the Australian government through grants and other programs where:

- the value of Australian Government contribution to a project is at least $5 million and represents at least 50 per cent of the total construction project value; or
- regardless of the proportion of Australian Government funding, where the Australian Government contribution to a project is $10 million or more.

[2] https://www.abcc.gov.au/building-code/building-code-2016

[3] http://www.fsc.gov.au/sites/fsc/needaccredited/accreditationscheme/pages/theaccreditationscheme

[4] https://www.abcc.gov.au/

10.3.1.2. WHS Scheme

The WHS Scheme is administered by the Office of the Federal Safety Commissioner[5].

The Scheme applies to projects that are directly or indirectly funded by the Australian Government where

- the value of the Australian Government contribution to the project is at least $6 million and represents at least 50 per cent of the total construction project value; or
- the Australian Government contribution to a project is $10 million (GST inclusive) or more, irrespective of the proportion of Australian Government funding; and
- a head contract under the project includes building work of $4 million or more (GST Inclusive).

10.4. How we pay the grant

The grant agreement will state the:

- maximum grant amount we will pay
- proportion of eligible expenditure covered by the grant (grant percentage)
- any financial contribution provided by you or a third party.

We will not exceed the maximum grant amount under any circumstances. If you incur extra costs, you must meet them yourself.

We will make payments according to an agreed schedule set out in the grant agreement. Payments are subject to satisfactory progress on the project.

10.5. Tax obligations

If you are registered for the Goods and Services Tax (GST), where applicable we will add GST to your grant payment and provide you with a recipient created tax invoice. You are required to notify us if your GST registration status changes during the project period. GST does not apply to grant payments to government related entities[6].

Grants are assessable income for taxation purposes, unless exempted by a taxation law. We recommend you seek independent professional advice on your taxation obligations or seek assistance from the Australian Taxation Office. We do not provide advice on tax.

11. Announcement of grants

We will publish non-sensitive details of successful projects on GrantConnect. We are required to do this by the *Commonwealth Grants Rules and Guidelines* unless otherwise prohibited by law. We may also publish this information on business.gov.au. This information may include:

- name of your organisation
- title of the project
- description of the project and its aims
- amount of grant funding awarded
- Australian Business Number
- business location

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[5] http://www.fsc.gov.au/sites/FSC

[6] See Australian Taxation Office ruling GSTR 2012/2 available at ato.gov.au

- your organisation's industry sector.

12. How we monitor your grant activity

12.1. Keeping us informed

You should let us know if anything is likely to affect your project or organisation.

We need to know of any key changes to your organisation or its business activities, particularly if they affect your ability to complete your project, carry on business and pay debts due.

You must also inform us of any changes to your:

- name
- addresses
- nominated contact details
- bank account details.

You must also inform us of any material changes to:

- partners involved in the project (i.e. partners joining or withdrawing)
- foreign affiliations of any project partners or key personnel (as outlined in Section 13.3)
- any foreign funding contributing to the project.

If you become aware of a breach of terms and conditions under the grant agreement you must contact us immediately.

You must notify us of events relating to your project and provide an opportunity for the Minister or their representative to attend.

12.2. Reporting

You must submit reports in line with the grant agreement. We will provide the requirements for these reports as appendices in the grant agreement. We will remind you of your reporting obligations before a report is due. We will expect you to report on:

- progress against agreed project milestones
- project expenditure, including expenditure of grant funds
- contributions of participants directly related to the project.

The amount of detail you provide in your reports should be relative to the project size, complexity and grant amount.

We will monitor the progress of your project by assessing reports you submit and may conduct site visits to confirm details of your reports if necessary. Occasionally we may need to re-examine claims, seek further information or request an independent audit of claims and payments.

12.2.1. Progress reports

Progress reports must:

- include details of your progress towards completion of agreed project activities
- show the total eligible expenditure incurred to date
- include evidence of expenditure
- be submitted by the report due date (you can submit reports ahead of time if you have completed relevant project activities).

We will only make grant payments when we receive satisfactory progress reports. We may seek advice from the committee or other independent experts to assist with the review of your reports.

You must discuss any project or milestone reporting delays with us as soon as you become aware of them.

12.2.2. End of project report

When you complete the project, you must submit an end of project report.

End of project reports must:

- include the agreed evidence as specified in the grant agreement
- identify the total eligible expenditure incurred for the project
- include a declaration that the grant money was spent in accordance with the grant agreement and to report on any underspends of the grant money
- be submitted by the report due date.

12.2.3. Post project report

We may ask your to submit one or more post project reports. Post project reports provide an update on the outcomes of your project and allow us to gather information to support evaluation of the program.

12.2.4. Ad-hoc reports

We may ask you for ad-hoc reports on your project. This may be to provide an update on progress, or any significant delays or difficulties in completing the project.

12.3. Independent audits

We will ask you to provide an independent audit report annually. An audit report will verify that you spent the grant in accordance with the grant agreement. The audit report requires you to prepare a statement of grant income and expenditure. The report template is available on business.gov.au and GrantConnect.

12.4. Compliance visits

We may visit you during the project period, or at the completion of your project to review your compliance with the grant agreement. We may also inspect the records you are required to keep under the grant agreement. We may also visit you after you finish your project. We will provide you with reasonable notice of any compliance visit.

12.5. Grant agreement variations

We recognise that unexpected events may affect project progress. In these circumstances, you can request a variation to your grant agreement, including:

- changing project milestones
- extending the timeframe for completing the project but within the maximum time period allowed in these guidelines
- changing project activities.

The program does not allow for:

- an increase of grant funds.

If you want to propose changes to the grant agreement, you must put them in writing before the project end date. We can provide you with a variation request template.

If a delay in the project causes milestone achievement and payment dates to move to a different financial year, you will need a variation to the grant agreement. We can only move funds between financial years if there is enough program funding in the relevant year to allow for the revised payment schedule. If we cannot move the funds, you may lose some grant funding.

You should not assume that a variation request will be successful. We will consider your request based on factors such as:

- how it affects the project outcome
- consistency with the program policy objective, grant opportunity guidelines and any relevant policies of the department
- changes to the timing of grant payments
- availability of program funds.

12.6. Evaluation

We will evaluate the grant opportunity to measure how well the outcomes and objectives have been achieved. We may use information from your application and project reports for this purpose. We may also interview you and/or your project partners, or ask you and/or your project partners for more information to help us understand how the grant impacted you and to evaluate how effective the program was in achieving its outcomes.

We may contact you up to two years after you finish your project for more information to assist with this evaluation.

12.7. Grant acknowledgement

If you make a public statement about a project funded under the program, including in a brochure or publication, you must acknowledge the grant by using the following:

‘This project received grant funding from the Australian Government.’

If you erect signage in relation to the project, the signage must contain an acknowledgement of the grant.

13. Probity

We will make sure that the grant opportunity process is fair, according to the published guidelines, incorporates appropriate safeguards against fraud, unlawful activities and other inappropriate conduct and is consistent with the CGRGs.

13.1. Conflicts of interest

Any conflicts of interest could affect the performance of the grant opportunity or program. There may be a conflict of interest, or perceived conflict of interest, if our staff, any member of a committee or advisor and/or you or any of your personnel:

- has a professional, commercial or personal relationship with a party who is able to influence the application selection process, such as an Australian Government officer or member of an external panel
- has a relationship with or interest in, an organisation, which is likely to interfere with or restrict the applicants from carrying out the proposed activities fairly and independently or

- has a relationship with, or interest in, an organisation from which they will receive personal gain because the organisation receives a grant under the grant program/ grant opportunity.

As part of your application, we will ask you to declare any perceived or existing conflicts of interests or confirm that, to the best of your knowledge, there is no conflict of interest.

If you later identify an actual, apparent, or perceived conflict of interest, you must inform us in writing immediately.

Conflicts of interest for Australian Government staff are handled as set out in the Australian Public Service Code of Conduct (Section 13(7))[7] of the *Public Service Act 1999* (Cth). Committee members and other officials including the decision maker must also declare any conflicts of interest.

We publish our conflict of interest policy[8] on the department's website.

13.2. How we use your information

Unless the information you provide to us is:

- confidential information as per 13.2.1, or
- personal information as per 13.2.3,

we may share the information with other government agencies for a relevant Commonwealth purpose such as:

- to improve the effective administration, monitoring and evaluation of Australian Government programs
- for research
- to announce the awarding of grants.

13.2.1. How we handle your confidential information

We will treat the information you give us as sensitive and therefore confidential if it meets all of the following conditions:

- you clearly identify the information as confidential and explain why we should treat it as confidential
- the information is commercially sensitive
- disclosing the information would cause unreasonable harm to you or someone else
- you provide the information with an understanding that it will stay confidential.

13.2.2. When we may disclose confidential information

We may disclose confidential information:

- to the committee and our Commonwealth employees and contractors, to help us manage the program effectively
- to the Auditor-General, Ombudsman or Privacy Commissioner
- to the responsible Minister or Assistant Minister

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[7] https://www.legislation.gov.au/Details/C2019C00057

[8] https://www.industry.gov.au/sites/default/files/July%202018/document/pdf/conflict-of-interest-and-insider-trading-policy.pdf?acsf_files_redirect

- to a House or a Committee of the Australian Parliament.

We may also disclose confidential information if

- we are required or authorised by law to disclose it
- you agree to the information being disclosed, or
- someone other than us has made the confidential information public.

13.2.3. How we use your personal information

We must treat your personal information according to the Australian Privacy Principles (APPs) and the *Privacy Act 1988* (Cth). This includes letting you know:

- what personal information we collect
- why we collect your personal information
- to whom we give your personal information.

We may give the personal information we collect from you to our employees and contractors, the committee, and other Commonwealth employees and contractors, so we can:

- manage the program
- research, assess, monitor and analyse our programs and activities.

We, or the Minister, may:

- announce the names of successful applicants to the public
- publish personal information on the department's websites.

You may read our Privacy Policy[9] on the department's website for more information on:

- what is personal information
- how we collect, use, disclose and store your personal information
- how you can access and correct your personal information.

13.2.4. Freedom of information

All documents in the possession of the Australian Government, including those about the program, are subject to the *Freedom of Information Act 1982* (Cth) (FOI Act).

The purpose of the FOI Act is to give members of the public rights of access to information held by the Australian Government and its entities. Under the FOI Act, members of the public can seek access to documents held by the Australian Government. This right of access is limited only by the exceptions and exemptions necessary to protect essential public interests and private and business affairs of persons in respect of whom the information relates.

If someone requests a document under the FOI Act, we will release it (though we may need to consult with you and/or other parties first) unless it meets one of the exemptions set out in the FOI Act.

13.3. National Security

Collaboration with foreign entities must be transparent, undertaken with full knowledge and consent, and in a manner, that avoids harm to Australia's national interests. It is your responsibility

[9] https://www.industry.gov.au/data-and-publications/privacy-policy

to consider the national security implications of the proposed project and identify and manage any risks, including risks relating to the unwanted transfer of sensitive knowledge technology.

You should ensure that you are informed about who you are collaborating with by undertaking appropriate due diligence, proportionate to the risk and subject to available information, of your global partners and their personnel participating in the project. This should take into account any potential security, ethical, legal and reputational risks, and where necessary, you should be prepared to demonstrate how you will manage and mitigate any identified risks.

You and any entities participating in the project must disclose all foreign ownership (including foreign government ownership), affiliations with foreign governments, organisations, institutions or companies, or membership of foreign government talent programs. You must report any material changes in the nature of the activity or key personnel involved, including affiliations/links with foreign governments or companies.

If you have acknowledged in the declaration that, you can appropriately manage national security risks, we may ask you to provide a satisfactory risk assessment plan outlining your approach as a condition of funding.

13.4. Disclosure of financial penalties

You must disclose whether any of your board members, management or persons of authority have been subject to any pecuniary penalty, whether civil, criminal or administrative, imposed by a Commonwealth, State, or Territory court or a Commonwealth, State, or Territory entity. If this is the case, you must provide advice to the department regarding the matter for consideration.

13.5. Enquiries and feedback

For further information or clarification, you can contact us on 13 28 46 or by web chat or through our online enquiry form on business.gov.au.

We may publish answers to your questions on our website as Frequently Asked Questions.

Our Customer Service Charter is available at business.gov.au. We use customer satisfaction surveys to improve our business operations and service.

If you have a complaint, call us on 13 28 46. We will refer your complaint to the appropriate manager.

If you are not satisfied with the way we handle your complaint, you can contact:

Head of Division
AusIndustry
Department of Industry, Science, Energy and Resources
GPO Box 2013
CANBERRA ACT 2601

You can also contact the Commonwealth Ombudsman[10] with your complaint (call 1300 362 072). There is no fee for making a complaint, and the Ombudsman may conduct an independent investigation.

[10] http://www.ombudsman.gov.au/

14. Glossary

Term	Definition
Application form	The document issued by the Program Delegate that applicants use to apply for funding under the program.
AusIndustry	The division of the same name within the department.
Clean hydrogen	Clean hydrogen is hydrogen produced using renewable energy or using fossil fuels with substantial carbon capture and storage (CCS).
Department	The Department of Industry, Science, Energy and Resources.
Eligible activities	The activities undertaken by a grantee in relation to a project that are eligible for funding support as set out in 5.1.
Eligible application	An application or proposal for Activating a Regional Hydrogen Industry - Clean Hydrogen Industrial Hubs activity under the program that the Program Delegate has determined is eligible for assessment in accordance with these guidelines.
Eligible expenditure	The expenditure incurred by a grantee on a project and which is eligible for funding support as set out in 5.2.
Eligible expenditure guidance	The guidance that is provided at Appendix A.
Grant agreement	A legally binding contract between the Commonwealth and a grantee for the grant funding.
Grant funding or grant funds	The funding made available by the Commonwealth to grantees under the program.
GrantConnect	The Australian Government's whole-of-government grants information system, which centralises the publication and reporting of Commonwealth grants in accordance with the CGRGs.
Grantee	The recipient of grant funding under a grant agreement.
Guidelines	Guidelines that the Minister gives to the department to provide the framework for the administration of the program, as in force from time to time.
Hydrogen	Unless otherwise specified, references to hydrogen in this document refer to Clean Hydrogen.
Minister	The Commonwealth Minister for Energy and Emissions Reduction.

Term	Definition
Personal information	Has the same meaning as in the *Privacy Act 1988* (Cth) which is: Information or an opinion about an identified individual, or an individual who is reasonably identifiable: a. whether the information or opinion is true or not; and b. whether the information or opinion is recorded in a material form or not.
Program Delegate	An AusIndustry general manager within the department with responsibility for the program.
Program funding or Program funds	The funding made available by the Commonwealth for the program.
Project	A project described in an application for grant funding under the program.
Sector coupling	The integration of hydrogen production, supply chain and end-use sectors to maximise services and benefits (as described in the National Hydrogen Strategy).
Short to medium term	3 - 5 years

Appendix A. Eligible expenditure

This section provides guidance on the eligibility of expenditure.

The Program Delegate makes the final decision on what is eligible expenditure and may give additional guidance on eligible expenditure if required.

To be eligible, expenditure must:

- be incurred by you within the project period
- be a direct cost of the project
- be incurred by you to undertake required project audit activities

meet the eligible expenditure guidelines.

A.1 How we verify eligible expenditure

If your application is successful, we will ask you to verify the project budget that you provided in your application when we negotiate your grant agreement. You may need to provide evidence such as quotes for major costs.

The grant agreement will include details of the evidence you may need to provide when you achieve certain milestones in your project. This may include evidence related to eligible expenditure.

If requested, you will need to provide the agreed evidence along with your progress reports.

You must keep payment records of all eligible expenditure, and be able to explain how the costs relate to the agreed project activities. At any time, we may ask you to provide records of the expenditure you have paid. If you do not provide these records when requested, the expense may not qualify as eligible expenditure.

You will be required to provide an independent financial audit of all eligible expenditure from the project annually.

A.2 Plant and equipment expenditure

We consider costs of acquiring, or construction of, plant and equipment, as well as any related commissioning costs as eligible expenditure. You must list commissioning costs as a separate item within the project budget in the application form, and on reports of expenditure during project milestones.

We cannot consider any expenditure paid before the project start date as eligible expenditure. Commissioning and installation costs of plant and equipment paid for before the start date is not eligible expenditure even if these costs are paid after the project start date.

You may purchase, lease (finance lease or operating lease under certain conditions) or build plant and equipment. In claiming the purchase price of capital items, you must take out any costs related to financing, including interest. You can claim related freight and installation costs on capital expenditure.

Eligible costs for plant and equipment will normally need to be on your balance sheet.

We will only consider costs for plant and equipment not on your balance sheet under certain circumstances. We will only consider project costs with an operating lease to be eligible if:

- you integrate the plant or equipment into your manufacturing process; and
- you cannot transfer the plant or equipment and the lease period is at least 4 years.

Where you need to pay in instalments to purchase capital items (for example deposits, payment on installation, or payment on commissioning), you can claim the grant amount for the items progressively across multiple progress reports up to the end of the project period. Alternatively, you can choose to claim the full amount in a single report, when you pay for the capital item.

For leased items, you will need to show an executed copy of the lease identifying the capital cost of the item and the lease period. We can pay you the full grant entitlement when:

- you have received the capital item
- you have entered into a formal lease agreement, and
- you make the initial payment.

You may show expenditure on plant and equipment by providing evidence of

- purchase price
- payments (e.g. tax invoices and receipts from suppliers confirming payment)
- commitment to pay for the capital item (e.g. supplier contract, purchase order or executed lease agreement)
- receipt of capital items (e.g. supplier or freight documents)
- associated costs such as freight and installation (e.g. supplier documents)
- the capital item on your premises (e.g. date stamped photographic evidence).

If you claim expenditure for the construction of plant and equipment, we limit this to

- the costs of materials
- direct construction labour salary costs
- contractor costs

freight and establishment costs.

Evidence for construction expenditure may include purchase orders, invoices, payment documentation, photographic evidence (date stamped) of the capital item in your premises and details of labour costs.

Grant payments for capital items may affect your tax obligations. We recommend that you seek independent professional advice on tax related matters.

A.3 Labour expenditure

Eligible labour expenditure for the grant covers the direct labour costs of employees you directly employ on the core elements of the project. We consider a person an employee when you pay them a regular salary or wage, out of which you make regular tax instalment deductions.

We consider costs for project management activities eligible labour expenditure. However, we limit these costs to 10 per cent of the total amount of eligible labour expenditure claimed.

We consider costs related to administrative staff (such as accountants and lawyers) eligible expenditure where they relate specifically to this project. We do not consider labour expenditure for leadership (such as CEOs and, CFOs) as eligible expenditure, even if they are doing project management tasks.

Eligible salary expenditure includes an employee's total remuneration package as stated on their Pay As You Go (PAYG) Annual Payment Summary submitted to the ATO. We consider salary-sacrificed superannuation contributions as part of an employee's salary package if the amount is more than what the Superannuation Guarantee requires.

The maximum salary for an employee, director or shareholder, including packaged components that you can claim through the grant is $175,000 per financial year.

For periods of the project that do not make a full financial year, you must reduce the maximum salary amount you claim proportionally.

You can only claim eligible salary costs when an employee is working directly on agreed project activities during the agreed project period.

A.4 Labour on-costs and administrative overhead

You may increase eligible salary costs by an additional 30% allowance to cover on-costs such as employer paid superannuation, payroll tax, workers compensation insurance, and overheads such as office rent and the provision of computers.

You should calculate eligible salary costs using the formula below:

$$\text{Eligible salary costs} = \text{Annual salary package} \times \frac{\text{Weeks spent on project}}{\text{52 weeks}} \times \text{percentage of time spent on project}$$

You cannot calculate labour costs by estimating the employee's worth. If you have not exchanged money (either by cash or bank transactions) we will not consider the cost eligible.

Evidence you will need to provide can include:

details of all personnel working on the project, including name, title, function, time spent on the project and salary

ATO payment summaries, pay slips and employment contracts.

A.5 Contract expenditure

Eligible contract expenditure is the cost of any agreed project activities that you contract others to do. These can include contracting:

- another organisation
- an individual who is not an employee, but engaged under a separate contract.

All contractors must have a written contract prior to starting any project work—for example, a formal agreement, letter or purchase order which specifies:

- the nature of the work they perform
- the applicable fees, charges and other costs payable.
- Invoices from contractors must contain:
- a detailed description of the nature of the work
- the hours and hourly rates involved
- any specific plant expenses paid.

Invoices must directly relate to the agreed project, and the work must qualify as an eligible expense. The costs must also be reasonable and appropriate for the activities performed.

We will require evidence of contractor expenditure that may include:

- an exchange of letters (including email) setting out the terms and conditions of the proposed contract work

- purchase orders
- supply agreements
- invoices and payment documents.

You must ensure all project contractors keep a record of the costs of their work on the project. We may require you to provide a contractor's records of their costs of doing project work. If you cannot provide these records, the relevant contract expense may not qualify as eligible expenditure.

A.6 Travel and overseas expenditure

Eligible travel and overseas expenditure may include

- domestic travel limited to the reasonable cost of accommodation and transportation required to conduct agreed project and collaboration activities in Australia
- overseas travel limited to the reasonable cost of accommodation and transportation required in cases where the overseas travel is material to the conduct of the project in Australia.

Eligible air transportation is limited to the economy class fare for each sector travelled; where non-economy class air transport is used only the equivalent of an economy fare for that sector is eligible expenditure. Where non-economy class air transport is used, the grantee will require evidence showing what an economy air fare costs at the time of travel.

We will consider value for money when determining whether the cost of overseas expenditure is eligible. This may depend on

- the proportion of total grant funding that you will spend on overseas expenditure
- the proportion of the service providers total fee that will be spent on overseas expenditure
- how the overseas expenditure is likely to aid the project in meeting the program objectives

Overseas travel must be at an economy rate and you must demonstrate you cannot access the service, or an equivalent service in Australia.

Eligible overseas activities expenditure is generally limited to 10 per cent of total eligible expenditure, unless agreed by the program delegate.

A.7 Other eligible expenditure

Other eligible expenditures for the project may include:

- building modifications where you own the modified asset and the modification is required to undertake the project, for example installing a clean room. Modifications to leased buildings may be eligible. You must use the leased building for activities related to your manufacturing/industrial process.
- staff training that directly supports the achievement of project outcomes
- financial auditing of project expenditure
- costs you incur in order to obtain planning, environmental or other regulatory approvals during the project period. However, associated fees paid to the Commonwealth, state, territory and local governments are not eligible
- contingency costs up to a maximum of 10% of the eligible project costs. Note that we make payments based on actual costs incurred.

Other specific expenditures may be eligible as determined by the Program Delegate.

Evidence you need to supply can include supplier contracts, purchase orders, invoices and supplier confirmation of payments.

Appendix B. Ineligible expenditure

This section provides guidance on what we consider ineligible expenditure.

The Program Delegate may impose limitations or exclude expenditure, or further include some ineligible expenditure listed in these guidelines in a grant agreement or otherwise by notice to you.

Examples of ineligible expenditure include:

- research not directly supporting eligible activities, for example research projects without a clear, short to medium term pathway to establishing a hub for the production and use of hydrogen for domestic and export markets
- activities, equipment or supplies that are already being supported through other sources or as business as usual
- costs incurred prior to execution of the grant agreement.
- any in-kind contributions
- financing costs, including interest
- capital expenditure for the purchase of assets such as office furniture and equipment, motor vehicles, computers, printers or photocopiers
- costs involved in the purchase or upgrade/hire of software (including user licences) and ICT hardware (unless it directly relates to the project)
- non-project-related staff training and development costs
- insurance costs (the participants must effect and maintain adequate insurance or similar coverage for any liability arising as a result of its participation in funded activities)
- debt financing
- costs related to obtaining resources used on the project, including interest on loans, job advertising and recruiting, and contract negotiations
- maintenance costs
- site preparation activities which are not directly related to, or for, the main purpose of establishing a hydrogen hub
- costs of manufacturing production inputs, not directly related to your project
- routine operational expenses, including communications, accommodation, office computing facilities, printing and stationery, postage, legal and accounting fees and bank charges
- costs related to preparing the grant application, preparing any project reports (except costs of independent audit reports we require) and preparing any project variation requests
- travel or overseas costs that exceed 10% of total project costs except where otherwise approved by the Program Delegate.

This list is not exhaustive and applies only to the expenditure of the grant funds. Other costs may be ineligible where we decide that they do not directly support the achievement of the planned outcomes for the project or that they are contrary to the objective of the program.

You must ensure you have adequate funds to meet the costs of any ineligible expenditure associated with the project.

HYDROGEN STRATEGY FOR CANADA

Seizing the Opportunities for Hydrogen

A Call to Action

Draft Executive Summary – July 9, 2020

Hydrogen Strategy for Canada: Draft Executive Summary

Context

The world's energy systems are undergoing radical transformation driven by the need to decarbonize and mitigate climate change. Development of a low carbon hydrogen economy as a strategic priority to drive its use at-scale is a key opportunity to diversify Canada's future energy mix to achieve 2050 net-zero emissions.

Hydrogen is a versatile carbon-free chemical fuel that can be made from feedstocks that are abundant across Canada. Hydrogen can be used:

- directly as a fuel for transportation and power production
- to provide heat for industry and the built environment through burning directly or as a blend with natural gas
- as a feedstock for a range of existing and emerging industrial processes

Canada has played an important role in the development of the growing global hydrogen economy, starting more than a century ago with innovation in hydrogen production technology and four decades ago as pioneers in fuel cell technology.

Canada continues to be an R&D and technology leader in the sector. Canada's expertise and technologies are exported and used in countries around the world, demonstrating the opportunity for growth and deployment on an international scale. Despite this success, there are currently few domestic large-scale hydrogen projects.

Hydrogen can be a used in hard-to-abate sectors to meet Canada's 2030 and 2050 decarbonization objectives. Full scale commercial and demonstration projects in the near term can set us on a path for widespread deployment in the medium and longer term. By applying its world-class expertise at home, Canada can showcase hydrogen's real-world applications and benefits and the role hydrogen can play in transforming our energy system.

Canada is not alone in seeing hydrogen as a critical piece of the puzzle to combat climate change and improve air quality, while driving economic growth in a carbon-constrained world. Countries around the world have developed strategies to inform the optimal supply pathways and end-use applications for hydrogen, as well as to define export strategies. The demand for hydrogen in global energy systems is dramatically increasing, with projections indicating at least a tenfold increase in demand in the coming decades. Studies indicate that hydrogen could provide up to 24%[1] of global energy demand by 2050. The number of countries with polices that directly support investment in hydrogen technologies is increasing, along with the number of sectors they target.

As the world's 4th largest producer of both natural gas and oil, hydrogen serves as a critical opportunity to support a net-zero moon shot for Canada's petroleum sector. By leveraging industry's significant energy expertise and infrastructure, Canada has the opportunity to decarbonize and diversify into a leading global clean fuels exporter.

For three years, NRCan has been working with private sector stakeholders and governments at all levels to inform the

[1] BloombergNET: Hydrogen Economy Outlook, March 20, 2020, https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

development of the *Hydrogen Strategy for Canada.* NRCan has also commissioned several key studies that have informed the writing of this strategy, which are publically available.

The Government of Canada has also undertaken significant research, regulatory development activities, pilot deployments and stakeholder engagement, through a variety of *fora*, including workshops, teleconferences, bilateral discussions, and ongoing dialogue through existing working groups

Consultations were held with stakeholders from across the value chain to ensure engagement opportunities were as comprehensive as possible.

Canada's Advantages

Canada has unique competitive and comparative advantages that position it to become a world leading producer, user, and exporter of clean hydrogen, as well as hydrogen technologies and services. A strong hydrogen economy will lead to financial, environmental, and health benefits for Canadians.

The following strategic advantages position Canada for long-term success in developing a strong hydrogen economy:

- Rich in feedstocks to produce hydrogen

  Canada has one of the lowest carbon intensity electricity supply in the world, abundant fossil fuel reserves, potential for growth in variable renewables, (new renewable power generation – solar, wind, offshore wind, hydro, and marine energy resources) and freshwater resources, all of which can be leveraged to produce hydrogen.

- Leading innovation and industry position

  Canada is known for its leading hydrogen and fuel cell technology companies and expertise. As of 2017, there were >100 established companies, employing >2100 people, generating revenues >$200 million.

  Canada also has significant expertise in carbon capture technology, which is fundamental to the production of blue hydrogen from fossil fuels.

- Strong energy sector

  Canada's energy sector accounted for 900,000 direct and indirect jobs as of 2017, with assets valued at $596 billion[2]. This skilled labour force and strategic infrastructure assets position Canada to rapidly pivot to include hydrogen as an energy currency.

- Established international collaborations

  Canadian government, industry and academia are involved in international collaborations related to hydrogen that position Canada as a leader both from an innovation and commercial perspective.

- Head start

2 https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/10-Key-Facts-on-Canada_s-Energy-Sector-2018-en%20.pdf

Canada is one of the top 10 hydrogen producers in the world today. An estimated 3 million tonnes are produced per year from natural gas.

- Energy export channels to market

  Canada's proximity to hydrogen import markets including Japan, South Korea, California, and Europe along with export assets such as deep water ports and established pipeline networks as well as natural gas and oil transportation companies, position Canada to be an exporter of hydrogen as the global economy evolves.

By leveraging these advantages to develop a vibrant and robust low carbon hydrogen economy in Canada, benefits will be created for Canadians including:

- Economic growth

  Canada's hydrogen economy will create new green jobs in R&D, manufacturing, and services. Hydrogen will also become a new export currency for the energy sector, including regional energy economies in Western, Central, and Eastern Canada, and will allow Canadian energy companies to move up the value chain as an end-use fuel provider in a zero emission transportation future.

- Energy resilience

  Hydrogen can act as an energy carrier to enable increased penetration of renewables by providing time shifting and energy storage capabilities.

- Moonshot for Canada's petroleum sector

  Hydrogen is critical to achieving a net-zero moon shot for oil and natural gas industries, it provides an opportunity to leverage our valuable energy and infrastructure assets, including fossil fuel reserves and natural gas pipelines, in a way that is carbon-free at the point of use, providing a pathway to avoid underutilizing or stranding these assets in a 2050 carbon neutral future.

- Cleaner air

  Hydrogen does not produce greenhouse gases, black carbon, particulates, SOx, or ground-level ozone. When used in an electrochemical fuel cell, it emits nothing but water. Increased hydrogen adoption for use in fuel cells can lead to cleaner air, and cleaner air means improved health outcomes for Canadians.

- Meeting decarbonization goals

  Hydrogen closes the gap in hard-to-abate, energy intensive applications (such as long-haul freight, mining, industrial processes) and is needed to meet Canada's decarbonization commitments.

Opportunities

Production

Canada's rich feedstock reserves, skilled energy labour force, strategic energy infrastructure assets, and leading position in innovation and industry in the hydrogen and fuel cell sector position us to become one of the top three global producers of clean hydrogen.

Canada is one of the top ten global producers of hydrogen today, producing an estimated 3 million tonnes annually via steam methane reformation (SMR) of natural gas. While steam methane reformation is not considered a clean hydrogen pathway, Canada is well placed to transition to clean pathways going forward.

Colours are often used to represent the different hydrogen production pathways:

- **Grey hydrogen:** produced by SMR without carbon capture and sequestration (CCS). Canada has established production and supply chains, primarily in Alberta for fuel refining and fertilizer production. Over time this will shift to lower carbon intensity pathways.
- **Blue hydrogen**: produced by SMR, with CCS. As the 4th largest global natural gas producer, there exists a significant opportunity to drive this pathway forward. Alberta's Quest project has been in operation since 2015, with >1 million tonnes / year of CO_2 from an SMR plant injected and stored more than 2 km underground. Canadian companies also continue R&D on the production of blue hydrogen from oil reservoirs.
- **Green hydrogen:** produced from water by electrolysis using renewable electricity such as hydroelectricity, wind or solar. Air Liquide is installing a 20 MW electrolyzer plant in Becancour, the largest in the world producing 3,000 tonnes H_2 annually.

There are also several other pathways for which no colour is clearly defined, but which are fully viable with strong potential in Canada, including:

- **Biomass conversion** – using either gasification or anaerobic digestion to produce hydrogen are considered both renewable and carbon-neutral and is a viable hydrogen production pathways in Canada.
- **Nuclear:** producing hydrogen via electrolysis, using off-peak nuclear electricity, or via high-temperature thermal processes, using waste heat from the nuclear process are viable production pathways in Canada. This leverages Canada's expertise in nuclear technologies (including conventional and the emerging small modular reactor sector) to produce low carbon hydrogen.
- **Industrial by-product** hydrogen in Canada that are currently vented and can be captured, purified, and used directly.

Hydrogen production in Canada is expected to be based on a mix of the various pathways.

The carbon intensity of the hydrogen is a more important factor, than the pathway by which it is produced. To that end, Canada is working with countries around the world to develop a common methodology to determine the carbon intensity of hydrogen, negating the need to define production pathways by colour.

Canada is the world's fourth largest producer and sixth largest exporter of natural gas. Provinces with the highest natural gas production are Alberta, British Columbia, and Saskatchewan, and these are the provinces most suited for production of blue hydrogen. In Alberta, a new Task

Force has been announced[3] to advance the hydrogen economy in Alberta's Industrial Heartland and to seize this transformative opportunity.

The completion of the world's largest carbon capture pipeline – the Alberta Carbon Trunk Line – highlights the opportunity that exists in Alberta to bring clean tech and petroleum together to advance the hydrogen economy.

Six provinces have been identified as having sufficient power capacity for green hydrogen production via industrial scale electrolysis: British Columbia, Manitoba, Ontario, Quebec, New Brunswick and Newfoundland & Labrador. As increasing amounts of wind and solar generation are brought into Canada's energy mix, they offer the potential to expand the production of green hydrogen and to reduce costs. Hydrogen can in turn improve the economics of intermittent renewables by providing large-scale energy storage that optimizes the utilization of these power generation assets.

There are also synergies between hydrogen production and nuclear electricity. Given Canada's position as a tier one nuclear country, we can leverage our experience and expertise in both nuclear technologies (conventional, and the growing small modular reactor sector) and hydrogen production technologies as an additional pathway for domestic low-carbon hydrogen production.

The hydrogen supply network in Canada could include both large-scale centralized plants in Canada's natural-gas rich provinces or in remote regions with high penetration of low-cost renewables, and smaller-scale distributed electrolytic production near demand centers. Delivered hydrogen costs of $1.50-3.50/kg will be achieved as production scale is realized and investment is made in distribution infrastructure.

Industry and provincial governments will play an important role in determining which hydrogen production pathways will come to fruition in Canada, and over what timeframes. Overall, a balanced, regional approach to developing Canada's hydrogen supply is recommended. This diversification of fuel sources enables production volumes to support the development of domestic and export markets, competing against other global producers to diversify Canada's energy export portfolio

End-Use

Domestic deployment of hydrogen is critical to supporting Canada's world-leading hydrogen and fuel cell sector, as well as to meeting climate change objectives. The earlier deployment starts, the sooner infrastructure development and end-user acceptance will come into place, allowing the realization of longer-term projections on uptake and associated benefits.

Adoption of hydrogen can be expected to primarily be focused on energy-intense applications where electrification is challenging or not technically viable, and where economics that today rely on low-cost natural gas are more suited to energy dense fuels. This includes using hydrogen as a fuel for long-range transportation and power generation, to provide heat for industry and buildings, and as a feedstock for industrial processes.

[3] Source: https://mailchi.mp/6726559fb647/new-task-forceto-advance-hydrogen-economy-in-albertas-industrial-heartland?e=7bfdb418c6

Fuel for Transportation

Hydrogen can be used directly as a fuel in fuel cell electric vehicles (FCEVs), which have two times the efficiency of combustion engines and which have zero emissions at the tailpipe. Fuel cell light-duty passenger vehicles and transit buses are commercially available today globally, and in limited numbers in Canada. Fuel cells are also commercially available in off-road equipment, including lift trucks, and power back-up applications.

Heavy-duty trucks and light-rail passenger trains have also been commercially deployed in limited numbers globally. Pilot demonstrations of small marine vessel prototypes are also underway, and show promise. Longer-term, fuel cell applications may expand to include long-haul freight (rail and road), and trans-oceanic marine vessels.

The Government of Canada has set federal targets for zero-emission vehicles to reach 10% of light-duty vehicles sales per year by 2025, 30% by 2030 and 100% by 2040. Canada considers battery electric vehicles, fuel cell electric vehicles, and plug-in hybrid electric vehicles to qualify as zero emission vehicles. BC and Quebec have led provincially with the adoption of ZEV regulations, and both of these provinces have started to deploy hydrogen fueling infrastructure and fuel cell vehicles.

Electric vehicles are expected to take a significant portion of the market share for light duty applications in Canada, base don these targets. These electrification options include battery electric, and fuel cell electric vehicles. Canadian consumers have shown increasing demand for larger vehicles, with 80% of nationwide spending on new vehicles in 2019 going to trucks, vans, or SUVs.[4] Trends such as autonomous driving and ride sharing may also drive greater demand for hydrogen fuel cell electric vehicles.

Canadian cities need public transportation, and it must be zero emission for Canada to become carbon neutral and to improve air quality in urban centers. Canada has unique potential for a 'made-in-Canada' solution with New Flyer Industries and Ballard Power Systems leading the market with commercial fuel cell electric bus deployments in North America.

The zero emission bus initiative[5] underway in Canada encourages government to support school boards and municipalities in purchasing 5000 zero emission buses over the next 5 years. Canada is home to world leading fuel cell and electric bus manufacturers and can leverage this industry to provide economic value if fuel cell electric buses are a portion of the mix. These buses are well suited to longer routes and cold weather climate that Canadian transit agencies service.

Fuel cells will play a significant role in medium and heavy-duty trucks, rail, and ships where batteries are not likely to be technically feasible. For example, in heavy-duty trucks travelling long distances with heavy payloads, the weight of the batteries to provide the energy needed would result in reduced cargo load carrying capacity that is unacceptable to operators. Long charging times could also impact operations negatively. The improved energy density and fast fill characteristics of fuel cell

[4] Souce: Statistics Canada. Table 20-10-0002-01 New motor vehicle sales, by type of vehicle

[5] https://cutaactu.ca/en/blog-posts/new-federal-government-unveils-its-priorities

electric trucks could make them an optimal choice for certain applications.

There is a similar value proposition for hydrogen use in mining equipment. For the mining industry, hydrogen presents an opportunity to reduce widespread reliance on diesel power for mine production vehicles. Instead of battery technology which may reduce capacity of payloads, hydrogen presents itself as a viable option for heavy transportation due to it`s accessibility and adaptability.

In the near term as costs and availability of fuel cells challenge uptake, hydrogen-diesel co-combustion in truck applications may offer a feasible pathway to create the demand for hydrogen and support infrastructure development.

Fuel for Power Generation

Hydrogen can be used as a fuel for power production through either hydrogen combustion in turbines or use in stationary fuel cell power plants. Hydrogen provides load management, energy storage, and a path to market that enables the growing intermittent renewable power sector.

In the longer term, hydrogen can play a role in greening Canada's electricity grids where there is still a reliance on fossil fuels for power production. Hydrogen can also provide stability for off-grid renewables based power solutions in remote communities and remote industrial sites such as mines.

Mines in northern and remote regions are largely dependent on expensive, highly-emitting diesel power, the mining industry is uniquely-positioned to be an early adopter and major beneficiary of hydrogen fuel cells, to meet energy needs in these regions.

Heat for Industry and Buildings

As a heating fuel, hydrogen is a clean-burning molecule that can be a zero-carbon substitute for fossil fuels in applications where high-grade heat is needed and where electric heating is not technically or economically viable. Hydrogen can be burned directly or blended with natural gas to reduce carbon emissions in hard-to-abate applications like industrial heating, space heating for homes and buildings.

Feedstock for Industry

Hydrogen is used as a feedstock in several industrial processes in Canada today. Most feedstock hydrogen is currently produced via steam methane reforming.

Hydrogen is used as a feedstock for:

- Petroleum refining
- Bitumen upgrading
- Ammonia production
- Methanol production
- Steel production

The greatest use of hydrogen globally today is for refining and upgrading crude oil, where hydrogen-based processes remove impurities like sulphur and process heavy hydrocarbon chains into lighter components. The majority of hydrogen required for refining is produced on-site either from dedicated production facilities or as a by-product. Because of this integration of hydrogen production within refining facilities, production is primarily supplied by natural gas reforming methods. The most significant opportunity to reduce emissions associated with hydrogen in the oil and gas industry is retrofitting existing conversion technology with carbon capture and storage. In the Canadian context, this has the special potential to help decarbonize a portion of oil sands operations in Alberta.

Adoption of the Clean Fuel Standard is expected to drive demand for clean hydrogen in these industries. Switching to lower carbon intensity hydrogen offers a compliance pathway.

Availability of low cost, low carbon intensity hydrogen has the potential to create new industry in Canada as well. This includes synthetic liquid fuel production, an innovative process combining renewable hydrogen and carbon captured from the air to produce carbon-neutral, energy dense liquid fuels that are well suited to applications such as aviation and large marine vessels. Renewable fertilizer production also presents an opportunity for new Canadian industry.

Hydrogen also can be a key to reducing emissions from mining. The Canadian Minerals and Metals Plan (CMMP) aims to capitalize on opportunities to strengthen Canada's competitive position within the global mining sector. The CMMP emphasizes the importance of developing and adopting clean technologies and alternative energy sources, such as hydrogen.

Export

It is clear that with worldwide demand for hydrogen increasing, and energy importers actively looking to Canada as a potential supplier, there is a significant opportunity for Canada. The British Columbia Hydrogen Study completed in 2019 shows export potential of $15 billion by 2050 from that Province alone. The growth of this export industry would serve to diversify Canada's energy export portfolio. Canadian oil and natural gas exports alone totalled $122 billion in 2019.

Remaining Challenges

Costs

The main limiting factor for hydrogen use in many applications are economic rather technology-based. The reason that clean hydrogen is not currently used in many potential applications is that it is not yet economically viable compared to other conventional fuel options. This cost barrier can be addressed through strong government capital and production incentives to encourage scale, and through de-risking industry investment as the demand for hydrogen grows. Financial measures for end-use adoption can be effective in de-risking these investments.

Over time, Canada's rich resource base, skill set, and existing energy supply chain provides the opportunity to be cost competitive in global markets

Policy and Regulation

Clean hydrogen projects around the world have primarily been in regions with a combination of supporting policies and regulations. Policies and regulations that encourage the use of hydrogen technologies include low carbon fuel regulations, carbon price, vehicle emissions regulations, zero emission vehicle mandates, creation of emission-free zones, and renewable gas mandates in natural gas networks. Mechanisms to help de-risk investments for end-users to adapt to regulations can be beneficial. A more cohesive national framework could provide a clear signal of the importance of hydrogen and avoid a patch-work of policies and regulations across jurisdictions.

Availability of hydrogen

There is a need to transport and store hydrogen from the site of production to the end-user. This includes refuelling infrastructure for transportation uses.

Over time, as the domestic production and demand grow, there will may be a need for dedicated infrastructure. The cost of these technologies will continue to drop, as advancements are made, and the markets grow.

Codes and Standards

The deployment of hydrogen is in the early stages across many jurisdictions and sectors in Canada, and there are some gaps in existing codes & standards which need to be addressed to enable adoption.

This includes tools that enable and accelerate hydrogen use beyond demonstrations and pilot projects. Harmonizing codes and standards across jurisdictions (provincial and international) will ensure that best practices are applied across the global hydrogen economy to facilitate the growth of trade and export markets.

Canada is also working with countries around the world to develop and align codes and standards, through efforts like the Canada/US Regulatory Cooperation Council, and throughout the UN-ECE. These efforts also include developing and aligning common methodology to determine the carbon intensity of hydrogen production pathways.

Path Forward

Vision for 2050

If Canada seizes the opportunities for hydrogen, by 2050 we could realize the following:

- >5 million fuel cell electric vehicles
- Nationwide hydrogen fueling network
- >50% of energy supplied today by natural gas is supplied by hydrogen through blending in existing pipelines and new dedicated pipelines
- Established supply base of low carbon intensity hydrogen with delivered prices of $1.50 - $3.50/kg
- New industries enabled by low-cost hydrogen supply network
- Established export market
- Diversification of Canada's petroleum sector – with hydrogen established as major energy export for Canada
- >100,000 hydrogen sector jobs
- >$5 billion in hydrogen sector revenue
- >100 Mt CO_2e annual GHG reduction
- Canada is one of top 3 global clean hydrogen producers

Near Term: Laying the Foundation

The focus of the next 5-years will be on laying the foundation for the hydrogen economy in Canada. This includes developing new hydrogen supply and distribution infrastructure to support early clusters of deployments in mature applications while supporting Canadian demonstrations in emerging applications, such as long haul trucking, light-rail and small marine vessels. Early actions are fundamental to driving investment in the sector.

Canada's petroleum sector is a major driver of investment, with $52 billion in 2019. Despite the oil price downturn and uncertainty over the COVID-19 recovery, an opportunity exists for government to partner with industry to drive commercial blue hydrogen projects as part of the sector's net-zero agenda.

Hydrogen use in the near-term will be dominated by mature market applications at or near the commercial market Technology Readiness Level (TRL) including fuel cell electric vehicles and fuel cell electric buses for transit operation. Pre-commercial applications such as heavy-duty trucks, seaport goods movement equipment, power generation, heat for the built environment, and industrial feedstock applications will be introduced as pilot projects in regional clusters.

These regional clusters will be strongly influenced by:

- Regulatory approvals for blending hydrogen and natural gas to decarbonize the utility distribution system.
- Availability of technical evidence from pilots to inform the safe integration of fuel cells into domestic regulatory regimes, i.e. Railway Safety Act, Motor Vehicle Safety Act.
- Increased production of RNG and biogas due to favorable policies will drive low carbon hydrogen production.
- Zero-Emission Vehicle mandates for passenger vehicles such as the existing legislation in Quebec and British Columbia.
- There will be variances in CFS compliance plans that will drive low carbon hydrogen generation for industrial applications including the upgrading of transportation fuel products.
- Existing hydrogen generation, distribution and dispensing infrastructure that can be leveraged e.g. liquefaction capacity in Quebec, or steam methane reforming with carbon sequestration in Alberta.

Mid Term: Growth and Diversification

Activities to ignite the sector in the next 5 years will be followed by growth and diversification of the sector in the 2025 – 2030 timeframe.

As the technology matures and the full suite of end-use applications is at or near commercial technology readiness levels, hydrogen use in the mid-term will be focused on applications that provide the best value proposition relative to other zero-emission technologies. For example, fuel cell electric vehicles and transit buses will enter the rapid expansion phase as the market for fuel cell and battery technology becomes more defined. For example, fuel cells will gain traction where charging times, energy requirements, range, grade ability, and operation in extreme climates make battery technology technically challenging for specific market segments

Class 8 heavy-duty trucking in corridors that require heavy payloads and drayage equipment in regions with regulated air sheds will move into the commercial phase of deployment. New, larger scale hydrogen production in the mid-term will allow H2/NG blending for industry, the built environment and as a feedstock for chemical production and hydrocarbon upgrading to be commercialized in regional clusters during this period.

Pre-commercial applications like Class 5-7 delivery trucks, operating in urban zero-emission zones, passenger and freight rail where gantry infrastructure need to electrify the line is prohibitively expensive, mining vehicles and smaller domestics marine vessels

A regulatory framework, and market ready technologies enable early deployment of hydrogen in mining operations, toward the later part of this timeframe.

Long Term: Rapid Market Expansion

In the 2030-2050 timeframe, Canada will start to realize the full benefits of a hydrogen economy as the scale of deployments increase and number of new commercial applications grows, supported by Canada's foundational backbone supply and distribution infrastructure.

In the long-term, it is anticipated that with advances in battery and charging technology there will be a more defined division between battery and fuel cell utilization in Canada for transportation purposes. This will result in the higher power demand applications (utility biased) predisposed toward hydrogen energy storage and the lower power demand applications (efficiency biased) using batteries for energy storage. New transportation applications will move into the commercial and rapid expansion phases during this period.

In parallel, economies of scale in the production of hydrogen, coupled with regulatory pressures, will lead to accelerating growth in the blending of hydrogen in the natural gas distribution system and construction of new dedicated hydrogen pipelines supplying fuel to full hydrogen-based communities. Power generation applications will continue to grow, complementing increased penetration of intermittent renewable power sources in Canada's energy systems.

As low carbon intensity hydrogen is more widely available throughout Canada, new industries are expected to emerge including production of liquid synthetic fuels, ammonia and renewable fertilizer.

Time to Act

The time to act is now. Governments around the world are releasing and executing hydrogen strategies that are building global momentum. In 2019 Canada seized this momentum by developing and launching a new Hydrogen Initiative under the Clean Energy Ministerial, designed to be the cornerstone for global hydrogen deployment.

Now, one year later, Canada is poised to again leverage this momentum, to grow the domestic opportunity for hydrogen production and end-use, while also benefiting from growth in global demand, via this Strategy. Although the COVID-19 pandemic has shaken all sectors of the economy, the recovery can also present a unique opportunity for change.

Recommendations

The next five years will determine Canada's trajectory for achieving the 2050 vision and associated benefits. Eight pillars of actions have been identified, as follows:

Pillar 1: Strategic Partnerships

Themes include enabling and encouraging collaboration between private sector stakeholders, governments at all levels, and academia to coordinate actions and activities.

Pillar 2: De-Risking of Investments

Themes include driving investment to establish supply and distribution infrastructure, support regional deployment clusters, and establish manufacturing capabilities in Canada.

Pillar 3: Innovation

Themes include a strategy for sustained support for research, development and demonstration, that includes domestic industry, academia, and government collaboration, as well as international collaborations. Support for demonstrations and early deployments that include the full value chain from supply, to distribution, to end use can serve as a living lab to support Canada's innovators in the sector and ensure these technologies can be integrated in a safe and timely manner.

Pillar 4: Regulations, Codes and Standards

Themes include developing codes, standards, and regulations that enable and accelerate the production, distribution and use of hydrogen within domestic and international regulated energy markets. These regulatory instruments can range from national codes and standards, to industry specific established practices, technical requirements, safety assessments, and terminologies for products, services, and systems.

Pillar 5: Enabling Policies

Themes include developing a Canadian policy framework that is technology-neutral and accelerates hydrogen adoption and levels the playing field between low-carbon hydrogen and other fuels. Approaches to developing tools that are flexible enough to meet the changing demands associated with new, emerging technologies will be explored.

Pillar 6: Awareness

Themes include communicating the hydrogen sector as a priority sector and raising public awareness and confidence in hydrogen systems and fuel cell technologies through a combination of outreach campaigns and highly visible flagship projects.

Pillar 7: Regional Blueprints

Themes include developing regional specific blueprints to focus on unique considerations that may differ from region to region. Blueprints will provide recommendations for actions and roles/ responsibilities for all levels of government and the private sector to ensure each region is well positioned to seize their specific opportunities.

Pillar 8: International Markets

Themes include developing an export strategy and action plan to complement the Hydrogen Strategy for Canada.

Roles and Responsibilities

Development of a strong Canadian hydrogen economy requires a coordinated and collaborative effort between industry, governments, academia, and non-government associations driven by a common vision and strategy.

Implementation Plan

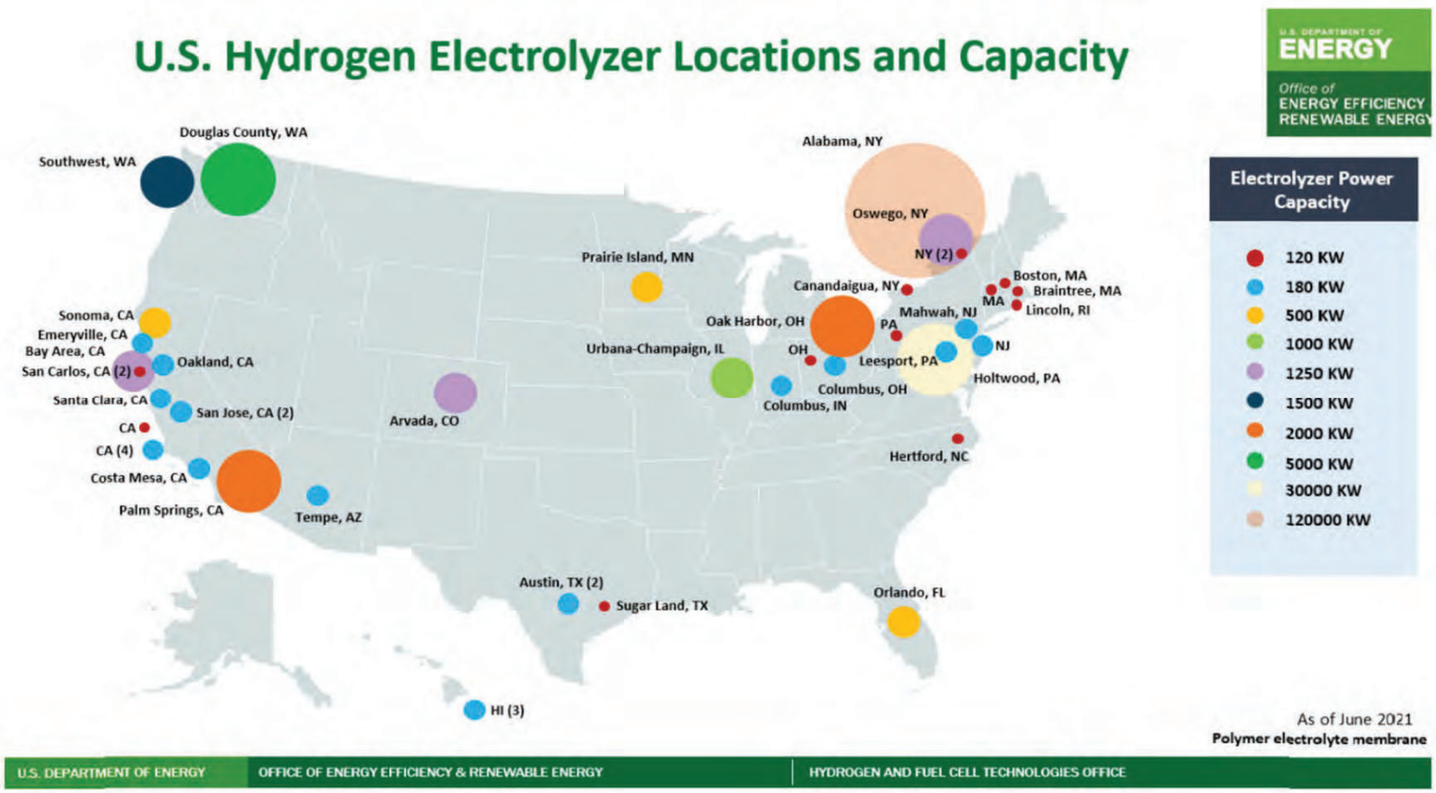
Following the release of this *Hydrogen Strategy for Canada*, there will be ongoing engagement with public, private and Indigenous stakeholders, to continue the momentum, initiate and track activities related to the recommendations, follow progress, and identify new priority areas as the market evolves. It is proposed, that this engagement will be formalized through an Implementation and Steering Committee and Working Groups.

Appendix B

North American Electrolyzer and Blending Demonstration Projects

13. “Skid based” electrolyzer systems in North America

Map of current or planned installations of PEM electrolyzers in the US as of June 2021



Source: DOE Hydrogen Program Record 20009: Electrolyzer Capacity Installations in the United States (energy.gov)

13. PEM electrolyzer systems in North America

Current and planned installations of PEM electrolyzers in the US as of June 2021.

Location	Power (kW)	Status	
Alabama, NY	120,000	Planned/Under Construction	Plug Power
Arvada, CO	1,250	Installed	NEL
Austin, TX	180	Installed	
Austin, TX	180	Installed	
Bay Area, CA	1,250	Installed	
Braintree, MA	120	Installed	
Boston, MA	120	Installed	
CA	120	Installed	NEL
CA	180	Planned/Under Construction	
CA	180	Planned/Under Construction	
CA	180	Planned/Under Construction	
CA	180	Planned/Under Construction	
Canandaigua, NY	120	Installed	
Champaign, Urbana, IL	1,000	Installed	NEL
Columbus, OH	180	Installed	
Columbus, IN	180	Installed	
Costa Mesa, CA	180	Installed	
Emeryville, CA	180	Installed	
Hertford City, NC	120	Installed	
HI	180	Installed	
HI	180	Installed	
HI	180	Installed	
Holtwood, PA	30,000	Planned/Under Construction	
Leesport, PA	180	Installed	
Lexington, MA	180	Installed	
Lincoln, RI	120	Installed	
MA	120	Installed	
Mahwah, NJ	180	Installed	
NJ	180	Installed	
NY	120	Planned/Under Construction	
NY	120	Planned/Under Construction	
Oakland, CA	180	Installed	
OH	120	Installed	
Oak Harbor, OH	2,000	Planned/Under Construction	NEL
Orlando, FL	500	Planned/Under Construction	
Oswego, NY	1,250	Installed	NEL
PA	120	Installed	
Palm Springs, CA	2,000	Installed	NEL
Prairie Island, MN	500	Planned/Under Construction	
San Carlos, CA	120	Installed	
San Carlos, CA	120	Installed	
San Jose, CA	180	Installed	
San Jose, CA	180	Installed	
Santa Clara, CA	180	Installed	
Sonoma, CA	500	Installed	
Southwest WA	1,500	Installed	NEL
Sugar Land, TX	120	Installed	
Tempe, AZ	180	Installed	
Douglas County, WA	5,000	Planned/Under Construction	
Total	**172,390 (Rounded to 172 MW)**		

+ Nuclear to hydrogen demonstrations co-funded by the U.S. Dept. of Energy's Nuclear Energy and Hydrogen and Fuel Cell Technologies Offices.
* Potential up to 3MW
** Potential up to 1MW

Total:

- 37 installed (13 MW)
- 12 planned/under construction (159 MW)

Source: DOE Hydrogen Program Record 20009: Electrolyzer Capacity Installations in the United States (energy.gov)

13. PEM electrolyzer systems in North America

Canadian Hydrogen Electrolyzer Installations and Capacities.

Project Name	Technology	MW	Status	Supplier
Air Liquide, Bécancour, Québec	PEM	20	Installed	Cummins
Markham Energy Storage, Ontario	PEM	2.5	Installed	Cummins

Sources:

Video Case Study: Cummins HyLYZER® PEM electrolyzer in Bécancour, Quebec | Cummins Inc.

In its second year, North America's first multi-megawatt power-to-gas facility shows hydrogen's potential | Cummins Inc.

13. PEM electrolyzer systems in North America

Markham Energy Storage, Ontario

- A collaboration between Cummins and Enbridge the energy storage facility is designed and built as a 5MW plant that features Cummins' PEM electrolyzer technology. The current 2.5MW plant occupies just 126 square meters, and its capacity can be doubled on the same footprint.
- Located in Markham, Ontario, the 2.5MW facility was commissioned in May 2018 and is dispatched by the IESO to help manage real-time supply and demand imbalances for Ontario's electricity grid and ensures its reliable operation.

Bécancour, Québec

- The installation of the 20 MW Proton Exchange Membrane (PEM) electrolyzer at Air Liquide in Bécancour, Québec is the largest in the world to generate green hydrogen.
- In commercial operation since the end of 2020, the 4 compact pressurized electrolyzers were designed and built by Hydrogenics (acquired by Cummins in September 2019).
- This unit is producing up to 8.2 tonnes of low carbon hydrogen per day.

Varennes, Quebec

- Installation of 88 MW plant for Hydro-Quebec (CAD 200 million capex)
- Plant is expected to produce 11,000 T/year of green hydrogen. Hydrogen will be used as a gasification agent to convert non-recyclable waste into biofuels
- Commissioning scheduled for late 2023

GHD is aware of approx. 20 larger scale (20 to 150 MW) projects in feasibility study, preliminary development across Canada.

Sources:

In its second year, North America's first multi-megawatt power-to-gas facility shows hydrogen's potential | Cummins Inc.

Air Liquide inaugurates the world's largest low-carbon hydrogen membrane-based production unit in Canada | Air Liquide

First green hydrogen project becomes reality: thyssenkrupp to install 88 megawatt water electrolysis plant for Hydro-Québec in Canada

13. PEM electrolyzer systems in North America

ThermH2, Utah

- Dominion Energy pilot project to understand long-term potential to blend 5% H2 into NG pipelines
- Trial began in 2021, blending into a test gas distribution system

Arizona and Nevada

- Partnership with University of Nevada Las Vegas (UNLV) and Arizona State University in Tempe (ASU) to understand hydrogen blending into natural gas systems.
- First phase to being in 2022, injecting hydrogen into Southwest Gas' Emergency Response Training Facility (EMRF) in both cities
- Study seeks to understand:
  - The optimal, hydrogen/natural gas blend percentage, and performance relative to natural gas
  - Safety considerations of hydrogen-blending
  - Impacts of hydrogen blending on natural gas distributions systems and customer infrastructure
  - The economics of hydrogen blending

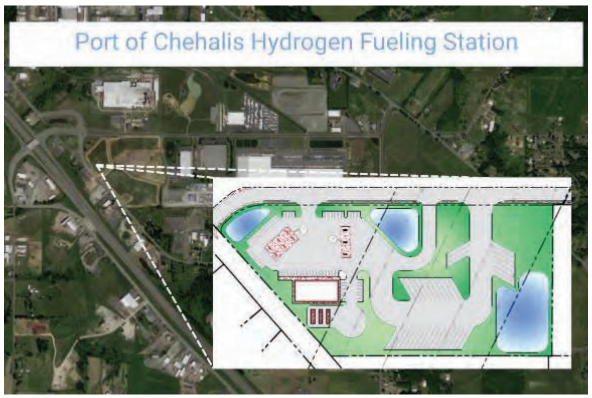
Sources:

Southwest Gas Announces Groundbreaking Hydrogen-Blending Pilot Programs with Arizona and Nevada Universities (prnewswire.com)

13. PEM electrolyzer systems in North America

Port Chehalis, Washington

- Green hydrogen to be generated at production site and then transported to the fueling station at the Port
- Planned opening for late 2022, hydrogen to power local transport agency Twin Transit's bus fleet



PLUG POWER

Alabama, NY

- Announced in Feb 2021, the hydrogen facility will be located at the New York Science, Technology and Advanced Manufacturing Park (STAMP)
- $290 M investment to produce hydrogen for decarbonization of freight transportation and logistics
- 120 MW PEM electrolyzers to produce 45 T/d of green hydrogen utilizing NY hydropower

Sources:

Plans for State's First Hydrogen Fueling Station Move Forward in Chehalis | The Daily Chronicle (chronline.com)

Port of Chehalis approves hydrogen station on its property - Energy News Agency

Plug Power to Build North America's Largest Green Hydrogen (globenewswire.com)

13. PEM electrolyzer systems in North America

Niagara Falls, NY

- PEM electrolyzer to produce green hydrogen on a commercial scale by 2023.
- The facility will utilize existing infrastructure at the Niagara Falls facility and will be powered by renewable energy sourced from the Robert Moses Niagara Hydroelectric Power Station.
- Once produced, the hydrogen will be supplied to customers through existing infrastructure at the Linde Niagara Falls site.

Florida

- Florida Power and Light Co (FPL) recently announced their intentions to develop the Cavendish NextGen hydrogen hub.
- Cummins will supply the 25 MW electrolyzer at the site, which will be supplied with solar generated electricity.
- Hydrogen produced will be blended with natural gas and used to power an existing combustion turbine at the co-located FPL Okeechobee Clean Energy Center.

Oswego, NY

- In 2021, Nel Hydrogen US, received a contract for a 1.25 megawatt (MW) containerized PEM electrolyzer from Exelon Generation, a nuclear power plant.
- The MC250 electrolyzer will supply hydrogen to meet the power plant's turbine cooling and chemistry control requirements.
- A primary project outcome includes the successful operation and control of what will be the first PEM electrolyzer at a nuclear generating plant in the US configured for dynamic dispatch.
- In addition, the project will demonstrate the economic feasibility of hydrogen production at nuclear sites and provide a blueprint for large scale carbon-free hydrogen export in support of DOE's H2@Scale program objectives.

Sources:

$17.3m eletrolyser plant unveiled for New York - Hydrogen Forward (hydrogenfwd.org)

Nel ASA: Receives contract for a 1.25 MW containerized PEM electrolyzer for DOE H2@Scale project in the US | Nel Hydrogen ghd.com

The Power of Commitment

Liberty Keene Gas Supply Upgrades

Liberty Utilities

April 14, 2022

→ **The Power of Commitment**

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Printed date	4/14/2022 2:26:00 PM
Last saved date	April 14, 2022
File name	12569693 -RPT-1 Liberty Keene Gas Supply Upgrades.docx
Author	Jim Volk
Project manager	Nicholas Schilling
Client name	Liberty Utilities
Project name	Liberty Keene Gas Supply Upgrade
Document title	Liberty Keene Gas Supply Upgrades
Revision version	Rev [00]
Project number	12569693

Document status

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S4		Jim Volk	N. Schilling	Nicholas Schilling	N. Schilling	Nicholas Schilling	2/15/20
S4		Jim Volk	N. Schilling	Nicholas Schilling	N. Schilling	Nicholas Schilling	4/14/20
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The Power of Commitment

Executive Summary

This report is subject to, and must be read in conjunction with, the limitations set out in Section 1 and the assumptions and qualifications contained throughout the Report.

Liberty Utilities (Liberty) is evaluating options to alter the fuel gas delivery infrastructure for Keene, NH, which is currently arranged into two independent delivery systems. Zone 1 primarily feeds residential customers and is supplied with a propane-air fuel gas mixture. Zone 2 is a compressed natural gas (CNG) system that distributes de-pressurized natural gas to a commercial district within the city limits. Each of the two zones present different opportunities and challenges to update the distribution network and fuel gas constituents.

The propane-air facility of Zone 1 has been identified to have reached the end of its useful life barring major capital investments made by Liberty. Liquid propane is trucked to this facility, offloaded to storage tanks, and mixed with air prior to distribution. The need for investments has presented a unique opportunity for the city of Keene and Liberty to re-assess the gas distribution philosophy for the Zone 1 users.

The CNG facility for Zone 2 feeds primarily commercial customers that are already accustomed to natural gas as a source of energy. CNG is trucked into the distribution center where it is de-pressurized prior to distribution to the customers. This system can continue to run without the need for significant investment to upgrade at this time. Based upon the differing states of Zone 1 and Zone 2, different options are available for consideration for each distribution sector.

Both Keene and Liberty have stated goals to de-carbonize their energy consumption in the near and long term. The focus of this study was to evaluate options to meet Keene and Liberty's sustainability goals. The different options have been evaluated based upon on economical, technical, and environmental considerations.

Summary of Results

GHD assessed a wide range of potential scenarios for Zone 1 and 2, including various sources of renewable natural gas (RNG) and hydrogen for blending into the distribution networks. The conversion from propane/air to LNG/CNG had both a lower overall fuel carbon intensity but also a lower commodity price. The ability to blend Zone 1 with landfill gas (LFG), biogas or wastewater treatment gas (WWTP) represents a significant decarbonization opportunity at the lowest cost per metric ton of CO2 removed. This pathway also allowed for future blending with hydrogen derived from renewables and is consistent with Liberty's energy transition narrative with the desire to deliver clean, economic, reliable and safe energy.

The table below presents a summary comparison of six scenarios for Zone 1, including considerations for project implementation difficulty, potential timing, the carbon intensity of the fuel used, cost per delivered energy unit of gas, lifecycle emissions from combustion of the supplied fuel in the network, emissions reductions in comparison to the CNG scenario, cost per delivered kg of hydrogen (for the applicable scenarios), and a high-level look at potential capital costs. A cost per tonne of CO2 removed scenario was also developed, based on an assumed longer-term $1/kg hydrogen price. Based on this scenario, there were several significant benefits to Keene customers, including a significantly lower cost to decarbonize with hydrogen ($/tonne CO2 removed), as well as the fact that a $1/kg price for green hydrogen represents an equivalent price of $6.89/MMBTU (based on the HHV of hydrogen). This is lower than the $15/MMBTU base case natural gas price. The summary of all eight scenarios (for zone 1and zone 2) are shown in Table 3.2 in Section 3.5 of this report.

Summary Comparison of Conversion Scenarios for Zone 1

Parameter	Propane / Air Mix	Convert to CNG/LNG Facility	Convert to CNG/RNG 50% Blend - Zone 1	H2 Electrolyzer 20% Blend Zone 1	H2 Electrolyzer 20% Blend Zone 1	H2 Electrolyzer 100% Blend Zone 1
Implementation	Baseline	Readily Implementable	Reasonably Implementable with RNG Source	Difficult - Requires Demonstration Project	Difficult - Requires Demonstration Project	Difficult - Requires Demonstration Project
Timing		2-5 years	2-5 years	5-10 years Start process concurrent with CNG Conversion	5-10 years	10+ years
Fuel Carbon Intensity (gCO_2e/MJ)	Propane: 83	Natural Gas: 79	RNG from LFG or WWTP Biogas: 35	H_2 from Renewable Electricity: 0	H_2 from Keene Grid Electricity: 73	H_2 from Renewable Electricity: 0
$/MMBtu Commodity Delivered Gas*	$19.97	$15.00	$30.00	$80.00	$80.00	$50.00
Lifecycle Emissions from Fuel Use (metric tonnes CO_2e)	10,112	10,002	7,210	9,290	9,946	0
Emissions Reductions (tonnes CO_2e per year) Compared to NG	N/A	N/A	2,792	712	56	10,002
Emissions Reductions (%) Compared to NG	0%	0%	28%	7%	1%	100%
$/tonne CO_2 removed (compared to NG)	N/A	N/A	RNG from LFG: $643	Green H2: $795	Keene Grid H2: $10,000	Green H2: $398
$/kg H2	N/A	N/A	N/A	$10.80	$10.80	$6.50
$/tonne CO_2 removed based on $1/kg H2	N/A	N/A	RNG from LFG: $643	Green H2: $91	Keene Grid H2: $1,150	Green H2: $86
Capital Investment ($1000)	$4,670	$7,360	$450	$3,970	$3,970	$20,000

Notes: * $/MMBTU show n for RNG and H2 commodity only

Summary of Recommendations

Based on the conclusions described within this report, GHD recommends Liberty continue to investigate the conversion from propane-air to LNG/CNG followed by a near-term and long-term schedule for blending hydrogen produced from renewables, as an opportunity to meet Liberty's long-term decarbonization goals. Hydrogen blending should first start as a demonstration program with eventual implementation based on availability of RNG, LFG, Biogas, and WWTP gas. In addition to any hydrogen blending demonstration, GHD recommends establishing a potential R&D hydrogen blending facility (most likely in NYS) as a method to test different blending volumes, evaluate the performance of blending percentages with various natural gas appliances and provide essential community outreach for future blending implementation plans.

A recommended overall implementation schedule is shown in Section 6 of this report.

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Appendices

1. Introduction

This report: has been prepared by GHD for Liberty Utilities and may only be used and relied on by Liberty Utilities for the purpose agreed between GHD and Liberty Utilities

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

In the race to transform our energy systems, a greener gas economy is emerging at an exponential rate. Renewable natural gas (RNG) and hydrogen can be blended into the gas supply to improve supply security and lower the greenhouse gas (GHG) intensity of the gas network. Hydrogen blending is no longer a distant dream; it's here - happening now, with accelerating advancements from around the world. Blending lower-carbon compatible fuels into the gas network is a key element of the near-term energy transition: greener gas blended with natural gas can deliver cleaner, low-emission energy for heating, cooking, and industry applications. RNG and hydrogen blending provides an immediate opportunity to begin decarbonizing these difficult-to-decarbonize sectors and drive demand for green gas hubs.

This report focuses on scenarios that reflect four (4) new gas supply options for the City of Keene, New Hampshire, which considers the integration and implementation of these options. These scenarios reflect the technical and operational requirements for the practical integration of the New Gas Supply Options into the existing legacy gas distribution system in Keene. The existing gas distribution system is comprised of two islanded gas networks, Zone 1 and Zone 2, which are not connected to a pipeline gas supply. Liquified propane gas (LPG) is delivered, gasified, and delivered to customers as a propane-air blend in Zone 1 which serves approximately 1,250 residential and commercial customers. In Zone 2, compressed natural gas (CNG) is delivered via truck and compressed into the pipeline to serve approximately 30 major customers.

The following initial new gas supply options for Keene were identified for evaluation in this study:

1. Conversion of Zone 1 from propane-air to CNG with RNG blending – deal with customer conversions for higher energy content of the gas.
2. Conversion of Zone 1 from propane-air to CNG/RNG with co-blending of hydrogen (H_2) to maintain same delivered energy content as previous.
3. Gradual conversion of both zones at various percentages of H_2 blending (up to 100% hydrogen) over time after CNG/RNG conversion, based on compatibility with current pipeline materials of construction.
4. Conversion to 100% H_2 without CNG as intermediate step.

For each new gas supply option identified, GHD evaluated the following characteristics:

1. Economics
   a. Feasibility (+/- 50%) capex for each and $/MMBtu expected
   b. Project funding opportunities
   c. Decarbonization benefits for each in terms of lifecycle GHG emissions for fuel use
   d. Decarbonization costs for each option ($/ton CO_2-equivalent), based on the capex estimates
   e. Rates and tariffs
2. Technical Complexity
   a. Availability of equipment/system
   b. Operational risk/issues
   c. Established, multiple vendors
   d. General integration considerations

3. Regulatory
   a. NHPUC requirements
   b. Established regulatory framework
4. Environmental and Social Co-Benefits

1.1 Assumptions

GHD has prepared this report on the basis of information provided by Liberty Utilities.

GHD has prepared the preliminary CAPEX and OPEX estimates set out in section this report ("Cost Estimate") using information reasonably available to the GHD employee(s) who prepared this report; and based on assumptions and judgments made by GHD. Key assumptions are documented in the CAPEX and OPEX estimates.

Gaseous Tube Trailer Hydrogen Blending Assumptions:

- Delivery FOB Suffield, CT
- Tube Trailer Volume: 350 KG
- Product Cost: $2.5/100SCF
- Delivery Charge: $5.25/mile
- Delivery Distance: 180 miles RT
- Tube Trailer Lease Fee: $3,000/month
- Discount Rate: 6%
- Term: 10 years

Liquid Hydrogen Blending Assumptions:

- Delivery FOB Niagara Falls, NY
- Product Cost: $2.13/100 SCF
- Delivery Charge: $5.25/mile
- Delivery Distance: 800 miles RT
- Liquid Equipment (tanks, pumps, scheduled O&M) Lease Fee: $18,000/month
- Estimated tanker Truck capacity: 1,800,000 SCF
- Liquid Storage Tank Capacity: 15,000 Gallons
- Discount Rate: 6%
- Term: 10 Years

Electrolyzer Blending Assumptions:

- NEL C30 Electrolyzer: 65 KG hydrogen /24 hours, efficiency 61 kwhrs/kg
- NEL MC250 Electrolyzer: 531 KG hydrogen /24 hours, efficiency 54.2 kwhrs/kg
- NEL M2000 Electrolyzer: 4,247 KG hydrogen /24 hours, efficiency 54.2 kwhrs/kg
- Discount Rate: 6%
- Term: 20 Years
- Electricity Cost: $.08/Kwhr.
- O&M: 1.5% of Capital

Greenhouse gas (GHG) emissions reductions assumptions are described under that section of this report.

2. Background

Liberty Utilities has several needs, obligations, and challenges in providing safe, reliable, economical gas-energy supplies for the City of Keene, NH (Keene). Among the more significant and vital issues affecting Liberty's commercial business operations in Keene include the following:

– The existing Keene gas supply system primarily involves the blending of propane and air to achieve a normalized caloric content of approximately 740 BTU/SCF. This propane gas mixture is distributed to Zone 1 and accounts for most of the Keene gas customers.
– The propane air system is nearing the end of its useful service life and will require upgrades and/or replacement of major infrastructure with the next 5 to 7 years based upon previously completed evaluations. Liberty has a goal to replace the propane/air handling facility with a natural gas system within 3 to 7 years.
– Keene has established a sustainability goal that all electricity consumed in Keene will come from renewable energy sources by the year 2030 and that 100% of all thermal energy and energy used for transportation come from renewable energy sources by the year 2050[1]. As such, Keene is interested in exploring and discussing potential gas supply options with Liberty.
– Keene's sustainability goals align well with Liberty's ESG goals, including the reduction of GHG emissions by 1 million metric tons from 2017 levels by 2019-2023 (already surpassed).
– Due to the lack of available, interconnected natural gas transmission lines and the relatively small service area of Keene, Liberty believes that there is a unique opportunity for a potential transition to alternative, low carbon gas supplies for their existing and future customers in Keene.

3. Gas Supply Upgrade Options

3.1 Propane-Air Mixture

The current propane-air facility has been in operation since 1969 and provides a maximum daily throughput of up to 2100 MSFD of the propane-air mix for Zone 1. The BTU rating for this mixture is 740 BTU/SCF. This will be important when evaluating implications for converting to a natural gas distribution system.

Following an independent evaluation of the facility, significant capital investment was identified as necessary in the short term (5 to 7 years) to continue operation of the facility in a safe and reliable manner. Due to the compact layout and proximity to the surrounding community, another key finding of the evaluation was the inability to upgrade the facility for reasons other than to increase the safety and reliability of the equipment. Future capacity or additional equipment cannot reasonably be added to the current location.

Based on a cost estimate provided by others, a capital investment of $4.67 MM would be required to install a new LPG facility. This would provide the necessary capacity for expected future growth of Liberty's distribution network and would be required to meet future projections.

3.2 CNG/LNG Facility

To replace the existing propane-air facility, a new CNG/LNG facility has been evaluated by others. Capital costs, major equipment and capacities have been included in the previous evaluation. Preliminary facility siting requirements and preliminary thermal radiation and vapor dispersion modeling have all been completed as part of the study. The final

[1] https://keenenh.gov/sustainability/news/city-keene-ep3-100-renewable-energy-press-release

buildout for the LNG/CNG facility was sized to provide natural gas to the City of Keene, Zone 1, at a rate of 9,600 MSCFD. Expected capital required for the new LNG/CNG facility is $7.36 MM.

Based on historical gas usage for the community it is not anticipated that the full demand can be reasonably provided by CNG tube trailer deliveries alone. And when considering the growth projections for the distribution network the need for LNG is likely, especially during high demand months.

An appliance or end-use equipment survey would be conducted during the planning stage of LNG/CNG implementation to identify impacts to the users when the higher BTU natural gas replaces the propane-air mixture.

Zone 2 has an existing CNG facility and modifications for that system would not be needed to convert the propane-air users to natural gas.

3.3 LNG/CNG Conversion Benefits

Assuming Liberty can procure LNG/CNG for similar pricing as the current Zone 2 pricing, a conversion to LNG/CNG provides an operating savings in annual fuel costs and provides the ability to co-blend RNG, biogas or WWTP gas as a low-cost method of decarbonizing. It also allows for the longer-term blending of hydrogen from renewables as another pathway towards meeting Liberty's net zero goals.

The conversion to CNG is consistent with Liberty's energy transition narrative with the desire to deliver clean, economic, reliable and safe energy. The "Greening" of propane is not as flexible or progressive as natural gas, it can be blended with hydrogen, however, natural gas represents a more direct and economical path with CNG/RNG/Hydrogen – as demonstrated by GHD's analysis (lower commodity cost and lower Carbon Intensity).

Economical Energy

As a "manufactured gas," propane is highly influenced by spot pricing, plus weather supply and logistics issues.

Fifty percent of propane is still produced via petroleum refining. As refiners move away from fossil fuels and towards electrification this could result in more volatility in propane pricing.

Building a dedicated propane system may have adverse financial impacts on customers, including increased energy bills – but more importantly new customers will most likely purchase high-efficiency appliances that require equivalent natural gas heating values for optimum efficiency

Expansion of the 1,250 propane/air customer base will most likely require a CNG supply.

Safe, Reliable, and Resilient Energy

As a utility, delivering safe, reliable, and resilient energy needs to also consider a long-term view on energy transition. Looking at key commercially viable energy transition options, propane fails to offer competitive value against alternative options. GHD's research indicates that clean energy moved by pipelines will be primarily based on natural gas transitioning to renewable naturel gas and eventually hydrogen.

Investing in a propane system has the highest potential risk of stranding those assets as most gas utilities pursue RNG/Hydrogen.

3.4 CNG and RNG Blended Supply

Once the investment is made to install a new LNG/CNG facility, it will become immediately possible to begin blending RNG into the distribution network. RNG could be sourced from multiple options with the most readily available likely being from landfill gas. However, other opportunities exist and may present additional benefits to Liberty's decarbonization initiatives.

The only limitation for RNG blending would be the ability to secure trailer deliveries and the number of decanting stations installed at the new facility. Any blended RNG would produce immediate results in lowering the lifecycle emissions for the Keene distribution network. Preliminary usage calculations estimate one tube trailer delivery per day would be required of RNG for a 50% blend.

The infrastructure necessary to operate with a blended RNG component would all be installed as a result of the LNG/CNG facility built to replace the existing propane distribution system.

3.5 CNG and H2 Blended Supply

3.5.1 Merchant Hydrogen Delivery Options

GHD evaluated two different merchant hydrogen delivery options using Zone 2 as a basis and evaluated the feasibility of gaseous and cryogenic hydrogen delivery at a nominal 20% hydrogen blending percentage. GHD also evaluated cryogenic liquid hydrogen delivery for a 100% hydrogen case. For Zone 1 only a 100% liquid hydrogen blending option was considered.

A summary ($/MMBTU equivalent) for both gaseous and liquid hydrogen blending options in order to maintain the same monthly and yearly energy demand requirements are shown in Table 3.2.

These two options included:

1. Gaseous tube trailer hydrogen delivery
2. Cryogenic liquid hydrogen truck delivery

Gaseous Tube Trailer Hydrogen Delivery

Gaseous, or tube trailer hydrogen delivery, is a common method of hydrogen supply for end-users that have exceeded typical cylinder delivery volumes but do not yet require higher delivery volumes of hydrogen via cryogenic liquid hydrogen truck delivery. Since 99.9% of all hydrogen in N. America is produced via steam methane reformation of natural gas, this type of hydrogen is most commonly referred to as “grey hydrogen.” If the hydrogen is sourced from non-renewable natural gas, the Carbon Intensity Index (CII) for hydrogen produced by this method is higher than that of conventional natural gas.

For this study GHD assumed the tube trailer hydrogen being sources is considered “grey” and product cost estimates were based on budgetary Linde quotes FOB Linde’s Suffield, CT hydrogen facility (approximately 90 miles from Keene).

Below are typical tube trailer delivery options:

Typical Gaseous Tube Trailer Delivery

– 300 Kg hydrogen tube trailer capacity
– 120,000 SCF tube trailer capacity
– 2,5000 psig delivery pressure

Zone 2 Gaseous Hydrogen at 20% Blending

As shown in Table 3.2 below, the overall capital cost of hydrogen (hydrogen delivery and blending) on a $/MMBTU is approximately $216/MMBTU or $29/Kg H2 for the 20% blending case.

Tube trailer delivery has several advantages for very small-scale hydrogen demand applications and in the case of Keene, would be the preferred hydrogen delivery mode for an initial smaller project demonstration.

This mode of hydrogen delivery would not be economically feasible for any large-scale blending applications since the limited volume (300 kg) of hydrogen would result in a significant number of truck deliveries to maintain the current energy demand for either zone any customer expansion plans.

During the high demand months for zone 1, a 20% blending percentage would require a minimum of one hydrogen tube trailer deliveries per day. For Zone 1 at a 100% hydrogen blend it would require a minimum of 18 tube trailer deliveries per day. Capex and Opex estimates were obtained through budgetary estimates provided by several industrial gas companies. Capex includes the overall cost for concrete pads, manifolds and other piping required to accommodate several tube trailers. It also included the cost for a hydrogen blending system. Opex estimates included monthly lease fees for the tube trailer as well as delivery fees.

The high Opex cost ($/Kg H2), limited delivery volumes and high Carbon Intensity Index limit tube trailer hydrogen delivery to demonstration blending project opportunities only.

Figure 3.1 Compressed Hydrogen Tube Trailer

Cryogenic Liquid Hydrogen Delivery

Cryogenic liquid hydrogen involves the liquefaction of gaseous hydrogen to a temperature of minus 253 degrees C or (-423 degrees F). There are currently only two merchant liquid production facilities within any reasonable distance from Keene. These include the 9 ton per day Becancour, Quebec, facility owned and operated by Air Liquide and the 50 ton per day facility in Niagara Falls, NY, owned and operated by Linde Gas.

Typically, liquid hydrogen is preferred as customers exceed tube trailer delivery quantities. Below is a typical liquid hydrogen delivery option:

Typical Cryogenic Liquid Delivery

– 17,000 gallons tanker capacity
– 1,800,000 SCF tanker capacity
– 15,000-gallon tank typical onsite storage

Liquid hydrogen delivery is not considered as a long-term viable option for Keene blending. GHD evaluated using liquid hydrogen for a 20% zone 2 blending option and a 100% hydrogen option for both Zone 1 and Zone 2.

Liquid hydrogen delivery, although providing customers with larger volume deliveries and larger onsite storage volumes, has a limited market since distance from production to end-use can add significant costs to the overall product cost. In the case of Keene, liquid hydrogen delivered from Niagara Falls would result in an 800-mile round trip delivery that also adds an additional $7/MMBTU to the cost of the delivered product (based on a 100% hydrogen scenario for Zone1).

Since most liquefied hydrogen is derived from SMR hydrogen production it is typically considered as grey hydrogen with a CII even higher than gaseous tube trailer hydrogen. Because of this GHD did not evaluate the CII for liquefied hydrogen. As more green liquefied hydrogen capacity becomes available this could provide an option for Liberty to consider, although onsite hydrogen production from renewable energy sources would probably still be the best economic solution.

Zone 1 and 2 Liquid Hydrogen at 20% and 100% Blending

Table 3.2 shows the overall capital cost of hydrogen (hydrogen delivery and blending) on a $/MMBTU basis and $/KG hydrogen basis. As indicated in the table, liquid hydrogen as a blending is not a viable option for either 20% or 100% blending percentages. In fact, the CII would be even greater than gaseous hydrogen and with very limited opportunity to source “green” liquid hydrogen from limited sources.

A 100% hydrogen supply option for Zone 1 would require over 30 liquid tanker truck deliveries per month and would require a minimum of 30,000 gallons of cryogenic liquid hydrogen storage. This creates additional safety review, permitting and reporting and does not allow for any customer base expansion, given the huge volumes of product required for delivery and storage.

Figure 3.2 Cryogenic Liquid Hydrogen Container

3.5.2 On-Site Electrolysis Hydrogen Delivery

Hydrogen production with co-located blending into the existing natural gas infrastructure presents local, regional, and national benefits for energy storage, resiliency, and emissions reductions. During periods of excess low-carbon power supply, hydrogen can be produced from renewable, nuclear, or other resources and subsequently injected into natural gas pipelines. This pathway of power-to-gas-to-pipeline reduces the need for pure hydrogen storage and transport if hydrogen blending can be co-located with the production, reducing costs and providing an immediate solution for managing increasing variable renewable power supply. The City of Keene’s power supply, which is largely nuclear baseload with high penetration of variable renewables and approximately 30-35% natural gas power generation, provides a potential opportunity for low carbon hydrogen production during periods of low electricity demand when natural gas peaking plants comprise less of the generation mix.

There are two types of electrolyzer units commercially available: Alkaline and Polymer Electrolyte Membrane (PEM). Although Alkaline and PEM units are functionally similar, the electrolysis reaction in the stack is different (DC power is used to decompose the water to hydrogen and oxygen in the stack) and this means each type have different characteristics and costs, which can provide relative advantages and disadvantages.

For this study GHD utilized Proton Exchange Membrane (PEM) electrolysis for the hydrogen blending scenarios. PEM electrolyzers offer greater flexibility in operation and can respond to load changes more quickly than alkaline units. In addition, their turndown range is better than that of alkaline units.

The higher responsiveness and operating range are of particular advantage, when coupled with dynamic energy sources, such as solar and wind and the performance of smaller models, (around 0.5 to 2 MW), is better understood and are more commercially available for the size requirements with a Keene blending program.

For this study GHD utilized three NEL Hydrogen electrolyzer product lines. These were chosen based on matching their hydrogen production capacity with both Zone 1 and 2 blending scenarios. There are several other electrolyzer manufacturers that also have commercially available systems. These include Plug Power, Cummins, Siemens and ITM Power (Linde).

Figure 3.3 NEL Hydrogen MC250 Electrolyzer (531 kg/day)

GHD evaluated 20% and 100% blending scenarios based on electrolysis-based hydrogen production. A summary of the estimated capital costs ($/MMBTU and $/KG) for each scenario are shown in Table 3.2.

There are several observations based on these scenarios:

1. Hydrogen production via electrolysis is becoming more competitive with many other production options, especially as costs of electrolyzer units continue to improve as well as the ability to couple the input power requirements with renewable energy sources such as solar, wind or hydro power.
2. Liberty's seasonal natural gas demands tend to favour use of a PEM electrolyzer that can follow monthly demand swings and has a very good turn-down ratio.
3. Since most PEM units are container-based additional units can be added to increase hydrogen production as the demand increases.
3. The main variable cost (in addition to water supply) is power. Leveraging cheaper, renewable power will help the overall economics. For example, a typical Keene commercial power rate of $.08/Kwhr contributes to an

equivalent cost of hydrogen of $36/MMBTU for the type of electrolyzer considered in this study. The lower the electricity rate the lower the equivalent cost of hydrogen.

4. A staged approach toward hydrogen blending provides the ability begin the decarbonization process while managing overall project and capital costs, especially if either state or federal funding is available. Monitoring carbon offset credit market development, electrolyzer costs over time as well as securing potential low cost sources of renewable power will help drive the next phases of increased hydrogen blending. Table 3.1 below shows the contribution lower cost power has on overall hydrogen costs via electrolysis.

Table 3.1 Variable Cost of Hydrogen Production at Various Electricity Costs

	Electrolyzer Sensitivity	
$/Kwhr	**$/Kg**	**$/MMBTU**
$0.08	$11.60	$86.0
$0.07	$11.03	$82.0
$0.06	$10.49	$78.0
$0.05	$9.95	$74.0
$0.04	$9.40	$70.0
$0.03	$8.90	$66.0

3.5.3 Hydrogen Blending Equipment

Based on the estimated costs associated with gaseous and liquid hydrogen delivery options for Zone 2, it was determined that gaseous electrolyzer-based hydrogen production systems will provide hydrogen at adequate pressures (400 psig) for blending into existing natural gas distribution pipelines, especially if the blending takes place at individual customer locations.

For this study, typical blending apparatus was used including hydrogen mass flow meters and flow controllers, hydrogen blend percentage analyzers, appropriate valves, instrumentation, and controls. For budget purposes a capital cost of $500,000 was used for the blending system.

3.6 Summary of Cost Comparison for Hydrogen Blending Scenarios

GHD evaluated several scenarios for hydrogen blending in natural gas for Zone 1 and Zone 2 based on the information described above. The results for 20% hydrogen blending and 100% conversion to hydrogen are provided in Table 3.2 below and visualized in Figure 3.4. The results indicate the high cost of liquified hydrogen in comparison to gaseous hydrogen, especially for the smaller scale at 20% blending by volume where the costs are prohibitive. Economy of scale is seen for a larger hydrogen supply for 100% heating demand, but conversion to 100% hydrogen would require overcoming significant technical hurdles particularly for network equipment and end-use equipment. This is discussed further in Section 5 of this report.

Table 3.2 Summary of Cost Comparison for Hydrogen Blending Scenarios

	Lifecycle Cost per kg H2 blended				Lifecycle Cost per MMBTU H2 blended			
	CAPEX	OPEX	O&M	**Total**	CAPEX	OPEX	O&M	**Total**
Zone 1								
20% H2 from Grid Electrolysis	$5.40	$4.70	$0.70	**$10.80**	$40.00	$34.89	$5.40	**$80.29**
100% H2 from Grid Electrolysis	$1.90	$4.70	$0.30	**$6.90**	$14.00	$34.89	$2.00	**$50.89**
100% LH2 and Dispensing	$1.10	$11.00	$ -	**$12.10**	$8.00	$81.61	$ -	**$89.61**
Zone 2								
20% GH2 and Dispensing	$7.59	$18.74	$3.00	**$29.33**	$56.29	$139.08	$21.13	**$216.50**
20% LH2 and Dispensing	$36.66	$29.24	$0.57	**$66.47**	$272.07	$216.94	$4.23	**$493.24**
20% H2 from Grid Electrolysis	$11.00	$5.25	$1.47	**$17.72**	$91.78	$38.97	$10.90	**$141.65**
100% LH2 and Dispensing	$2.73	$11.33	$0.05	**$14.11**	$20.22	$84.11	$0.34	**$104.67**
100% H2 from Grid Electrolysis	$4.00	$4.70	$0.64	**$9.34**	$29.00	$34.90	$4.75	**$68.65**

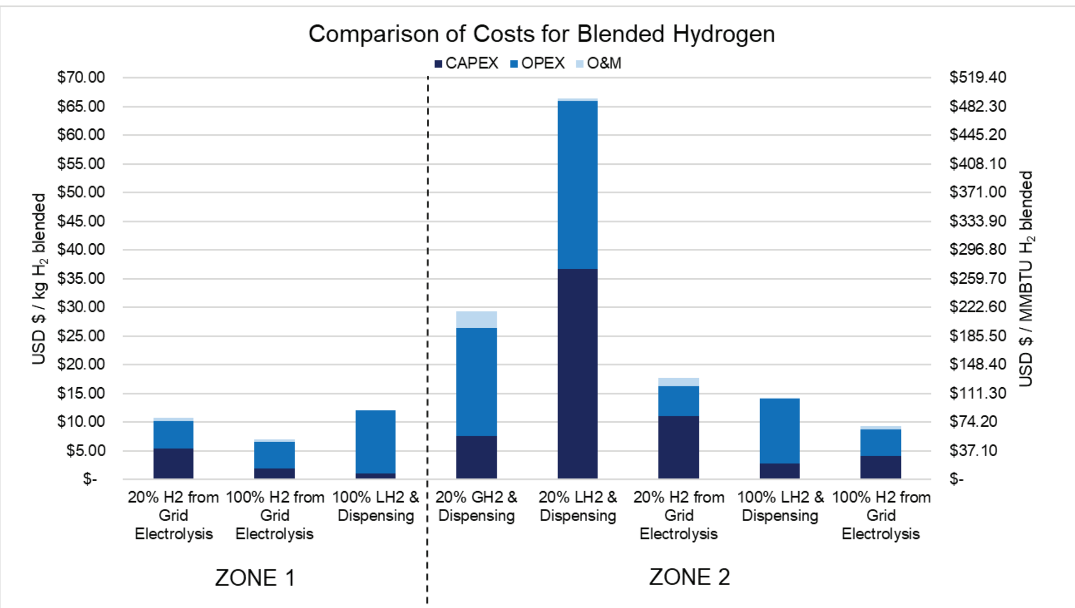

Figure 3.4 Hydrogen Supply Cost Comparison for Hydrogen Blending Scenarios

4. Greenhouse Gas Emissions Reductions

4.1 Introduction

Potential GHG emissions reductions were evaluated for multiple gas supply scenarios for Zone 1 and Zone 2 of the Keene gas network, including the following:

– Zone 1:
  - Baseline: Propane-air fuel mix
  - Conversion to 100% natural gas
  - Conversion to natural gas with hydrogen blending at 2, 5, 10, 15, 20, and 100% hydrogen by volume, considering 3 possible sources of hydrogen (grey, green, and Keene grid electrolysis)
  - Conversion to natural gas with RNG blending at 20 and 50% RNG by volume, considering 3 possible sources of RNG (manure, source separated organics, and landfill or wastewater treatment plant)

– Zone 2:
  - Baseline: Natural gas
  - Hydrogen blending at 2, 5, 10, 15, 20, and 100% hydrogen by volume, considering 3 possible sources of hydrogen (grey, green, and Keene grid electrolysis)
  - RNG blending at 20 and 50% RNG by volume, considering 3 possible sources of RNG (manure, source separated organics, and landfill or wastewater treatment plant)

Full tabulated results are provided in Appendix A. An overview of results are presented and discussed in this section.

4.2 Approach and Uncertainties

For a fuel blending and switching project, lifecycle carbon intensities for the baseline and alternative fuels provide a generally accepted method for evaluating the change in emissions considering the options for production, delivery, and combustion of the fuels. The lifecycle carbon intensity (CI) is a measure of the carbon dioxide-equivalent emissions produced per unit of energy of fuel produced, delivered and combusted (typically, measured as gCO_2e/MJ of fuel) and allows for relative comparison of different fuel production and delivery pathways on a common basis. The importance of using a *lifecycle* carbon intensity becomes clear when considering hydrogen fuels – hydrogen produces no GHG emissions when combusted, rather it is the production of hydrogen fuel that can be emissions intensive depending on the process. Hydrogen produced from natural gas or coal without carbon capture and sequestration, for example, which are the most common methods for industrial hydrogen production today, are highly emissions intensive. Lifecycle carbon intensity allows for the inclusion of these upstream emissions when comparing fuel options.

That said, it is important to understand the uncertainties and limitations associated with a CI-based GHG evaluation for the project, particularly given the current lack of standardization in CI assessment methodologies.

There are multiple sources that a fuel's CI can be referenced or determined from. Overall, carbon intensities should be evaluated using a lifecycle approach following the guidance in the following international standards:

– ISO Standard 14040:2006 - Environmental management - Life cycle assessment - Principles and framework
– ISO Standard 14044:2006 - Environmental management - Life cycle assessment - Requirements and guidelines

The guidance given in the international standards is focused on product life cycle assessments, which include a variety of social and environmental impacts such as water demand and waste production in addition to GHG emissions. There is plenty of room for assumptions and varying methods in these international standards, and it is important to understand that just because a CI assessment follows the international standard does not mean it will be accepted by a local regulator or investor as basis for emissions reductions.

For local acceptance, a CI should be reviewed and approved under an applicable program, such as the California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS), or the Oregon Clean Fuels Program. Both programs use the GREET model for evaluating fuel carbon intensity, which is produced and updated by the Argonne National Laboratory.

CARB is the most well-established program in the US with a large database of published carbon intensities. The results given in the database emphasize the uncertainty around CIs: for similar fuel pathways, a large range of CIs are approved, dependent on project-specific information for energy supply, facility energy consumption, transport and storage, compression and/or liquefaction, etc. For example, Table 4.1 below presents a snapshot of current hydrogen production pathways approved under CARB, as of January 2022[2].

Table 4.1 Currently Approved Hydrogen Production Pathways and Carbon Intensities under CARB

Applicant and Pathway Description	Facility Location	Feedstock	Fuel Type	Current Certified CI
Fuel Producer: Alameda-Contra Costa Transit District (A149) Facility Name: Division 2 (F1600). Hydrogen production via electrolysis using solar electricity	California	Solar Electricity via Electrolysis	Hydrogen	0.00
Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps. (Provisional)	California	North American NG	Hydrogen	165.88
Fuel Producer: FirstElement Fuel (E426): North American fossil NG to Hydrogen (H2) gas production by Steam Reforming of methane via pipeline to California then liquefied, re-gasified, and trucked to multiple H2 dispensing locations	California	North American Natural Gas	Hydrogen	151.01
Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed Hydrogen from co-product hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps) and transported by truck to fueling stations in California (Provisional)	Canada	Sodium Chlorate Production Process	Hydrogen	56.06
Compressed H2 produced in California from central SMR of North American fossil-based NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	NA	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51
Compressed H2 produced in California from electrolysis using California average grid electricity	NA	Grid Electricity (039)	Gaseous Hydrogen (HYG)	164.46
Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	151.01

[2] Current fuel pathways spreadsheet accessed online January, 2022, from: https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities

Applicant and Pathway Description	Facility Location	Feedstock	Fuel Type	Current Certified CI
Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	105.65
Compressed H2 from on-site reforming of NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	105.13
Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	176.43
Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using California average grid electricity	California	Grid Electricity (039)	Gaseous Hydrogen (HYG)	164.46
Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI HYER (F00226); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51
Fuel Producer: Element Markets EV, LLC (C1093); Facility Name: 32-505 Harry Oliver Trail (F00233); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51
Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67
Fuel Producer: Air Products and Chemicals, Inc. (C1042); Facility Name: APCI Wilmington Transfill (F00095); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	117.67

Applicant and Pathway Description	Facility Location	Feedstock	Fuel Type	Current Certified CI
Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources.	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	10.51

As can be seen in the table above, the CI for a gaseous hydrogen source can vary significantly depending on the production method and feedstock and any required compression and truck transport from production site to end-user. Liquefaction adds to the CI due to the additional energy demand.

The range in approved CIs is even more dramatic for RNG, which can range from as low as about -600 gCO_2e/MJ for some diary manure-to-RNG pathways and as high as positive 70+ gCO2e/MJ for some LFG to RNG pathways that include additional natural gas consumption.

Given the uncertainty and range in potential CIs for hydrogen and RNG supply, for the purposes of this analysis, GHD has considered 3 representative pathways and CI values for each fuel. For RNG, median CIs are taken for manure-to-RNG, source separated organic waste to RNG, and LFG or wastewater treatment plant biogas to RNG. For hydrogen, appropriate values are taken from the approved pathways for grey and green hydrogen sources, and the potential CI for hydrogen produced on-site via electrolysis from average Keene grid electric supply.

The CI of the baseline incumbent fuels used in Keene's gas grid is equally important for the GHG assessment results, as the GHG impact is evaluated by comparing the CI of the alternative fuels to the incumbent fuel being displaced. LPG is currently supplied to Zone 1 to provide a propane-air fuel mix in the gas grid, and CNG is currently supplied to Zone 2. The actual CIs for these will depend heavily on the source facility and required truck transport to Keene. Since the actual CIs are not known, we once again look at CARB approved pathways for the most relevant CI to use.

For LPG supply, there is only a single currently approved pathway and CI in CARB for "Fossil LPG from crude oil refining and natural gas processing used as a transport fuel", which is non-specific to a production facility and does not appear to include trucking the LPG from a production facility to end-use site (which of course will be project-specific). For CNG or LNG supply, there are a number of approved project-specific CIs and a single general CI for "Compressed natural gas from pipeline average North America". Project-specific CIs include transport to California for end-use, as well as varying compression, liquefaction, and re-gasification steps. The CIs selected for the purposes of the present GHG assessment are the only LPG pathway and the general CNG pathway as it is the most comparable to the CI score available for LPG. This means that the emissions associated with truck transport of these fuels from production facilities to Keene is not considered in this GHG evaluation, which is a notable limitation of the results.

GHD recommends that a project-specific CI assessment be completed for the actual potential alternative fuel sources and incumbent LPG and CNG supply sources. This information can then be used for a more accurate assessment of potential GHG emissions reductions, which may be vital for project funding, approvals, and community acceptance. GHD emphasizes that the GHG assessment presented in this report is indicative only and results will change once project-specific information is accounted for in the fuel CIs.

4.3 Assumptions

As described above, GHG emissions reductions were evaluated based on fuel consumption using the carbon intensities of the baseline and project fuels. The limitations and uncertainties associated with this approach are described in the previous section.

Assumptions and background data used in the GHG assessment include:

- Carbon intensities of fuels were determined from approved carbon intensities under the CARB LCFS Pathway Certified Carbon Intensities[3], or evaluated using the Argonne GREET Model[4]:
  - Grey hydrogen: 117.67 gCO_2e/MJ, the approved CI under CARB for central steam methane reforming (SMR) of natural gas to produce hydrogen without carbon capture and storage (CCS).
  - Green hydrogen: 0 gCO_2e/MJ, represents approved CI under CARB for hydrogen produced via electrolysis powered by 100% on-site renewable or nuclear electricity supply (no additional compression and transport needed as the hydrogen production is assumed co-located with the injection and blending site).
  - Hydrogen produced from Keene electric grid: 73 gCO_2e/MJ, determined by evaluating the CI for hydrogen from electrolysis in GREET using average New Hampshire electricity grid data from the Energy Information Administration (EIA)[5]. Electricity supply mix is 33% natural gas fired, which contributed 73 gCO_2e/MJ to the final CI results, 54% nuclear power, which contributes 0 gCO_2e/MJ, and 13% renewables, which likewise contributes 0 gCO_2e/MJ.
  - Propane: 83.19 gCO_2e/MJ of propane utilized, which is the approved CI under CARB for fossil liquified petroleum gas (LPG) from crude oil refining and natural gas processing.
  - Natural gas: 79.21 gCO_2e/MJ, which is the approved CI under CARB for average North America compressed natural gas in pipeline. This CI is selected for comparability with the only LPG CI available from CARB. Both CIs do not include emissions associated with truck transport to Keene and it is recommended that a project-specific CI assessment is completed to refine the GHG results.
  - Renewable natural gas (RNG): The CI for RNG can vary greatly depending on production method, energy consumption, co-products produced, and most importantly, attributable emissions offsets. Emissions offsets for utilizing organic waste diverted from landfill are for avoided landfill gas methane emissions, and emissions offsets for utilizing manure feedstock are for avoided manure methane emissions during stockpiling and land application. Emissions offsets vary from project to project resulting in vastly different CI scores for similar production processes. For the purposes of this assessment, GHD looked at 3 generalized/averaged CI scores for RNG:
    - RNG from manure: Dairy cattle manure to RNG projects have the lowest (most negative) CI scores in CARB, as low as -600 gCO_2e/MJ. The median of manure to RNG projects lands around -300 gCO_2e/MJ, which is used in this study to represent a likely CI for RNG from manure.
    - RNG from source separated organics (SSO): This represents RNG from the anaerobic digestion and subsequent biogas upgrading of food and/or yard waste, which can be collected from residential, commercial, or potentially industrial sources. Generally, SSO utilized to produce RNG can be considered diverted from landfill, resulting in moderately negative scores that range from close to 0 gCO_2e/MJ to -80 gCO_2e/MJ in the CARB approved pathways. A CI of -40 gCO_2e/MJ is used in the present study to represent this case.
    - RNG from landfill gas (LFG) or wastewater treatment plant (WWTP) biogas: This represents RNG produced from upgrading collected LFG or biogas at existing WWTP operations (typically from the anaerobic digestion of wastewater sludge). The CI results in CARB's database vary greatly for these projects, with scores from 28 to 67 gCO_2e/MJ for LFG to RNG pathways approved in 2020 and 2021, and from 19 to 52 gCO_2e/MJ for RNG from WWTP operations. For the purposes of this study, a median value of 35 gCO_2e/MJ is used to represent RNG from LFG or WWTP sludge.

[3] Current fuel pathways spreadsheet accessed online January, 2022, from: https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities
[4] The Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model, developed by Argonne National Laboratory and sponsored by the US Department of Energy (DOE), is generally the accepted model across the United States for evaluating fuel carbon intensities.
[5] EIA data for New Hampshire accessed January, 2022, from: https://www.eia.gov/state/data.php?sid=NH

– Other assumptions:
  - Propane-air fuel heating value: 0.748 million British thermal units (MMBTU) per thousand standard cubic feet (MCF), from the average of monthly 2021 propane/air delivery data provided by Liberty
  - LPG density: 1.885 kg/gallon
  - LPG energy density: 49.3 MJ/kg
  - Hydrogen heating value: 0.325 MMBTU/MCF
  - Hydrogen density: 2.362 kg/MCF
  - Hydrogen energy density: 142 MJ/kg
  - Natural gas heating value: 1.027 MMBTU/MCF
  - RNG heating value: for simplicity, assumed the same as natural gas. In reality, the RNG heating value will likely be slightly less than natural gas, although this will need to be confirmed by the RNG producer.
  - Customer base energy consumption: GHD’s calculations are based on delivering the same energy content to customers as in the 2021 data provided by Liberty.

4.4 Results and Discussion

Detailed results for all scenarios assessed are provided in Appendix A. Table 4.2 below provides an overview of results for key potential scenarios, visualized in Figures 4.1 and 4.2 on the following page. Note that the comparison for change in emissions for Zone 1 is evaluated compared to the 100% natural gas scenario rather than the current baseline of propane-air fuel mixture, as natural gas represents the lower-emission and lower-cost scenario to compare the hydrogen and RNG blending options against.

Note in the that a positive value for change in emissions represents an increase in emissions, while a negative value represents a decrease in emissions.

Table 4.2 Summary of Results for Select Scenarios and Emissions Change from Baseline

Scenarios	Emissions	Change in Emissions from 100% NG Case	% Change
Zone 1			
Baseline Propane-Air Fuel	10,112.30	110.35	1.1%
100% Natural Gas (NG)	10,001.96	-	0.0%
NG + 20% Hydrogen Blending - Grey H2	10,341	339.46	3.4%
NG + 20% Hydrogen Blending - Green H2	9,290	(711.53)	-7.0%
NG + 50% RNG Blending - RNG from LFG/WWTP	7,211	(2,791.23)	-27.6%
NG + 50% RNG Blending - RNG from Dairy Manure	(13,940)	(23,941.69)	-236.8%
Zone 2			
Baseline Natural Gas	2,060.35	-	-
NG + 20% Hydrogen Blending - Grey H2	2,131	71.07	3.4%
NG + 20% Hydrogen Blending - Green H2	1,913	(147.76)	-7.2%
NG + 50% RNG Blending - RNG from LFG/WWTP	1,486	(574.40)	-27.9%
NG + 50% RNG Blending - RNG from Dairy Manure	(2,881)	(4,941.00)	-239.8%

As can be seen in the results, hydrogen blending only provides emissions reductions if low-carbon hydrogen, preferably green hydrogen with a carbon intensity of 0 gCO_2e/MJ, is secured. An on-site electrolyzer can be power by renewable energy, or perhaps connected to the Keene electric grid with a control system in place to optimize power consumption for periods of high nuclear and renewables generation. Producing hydrogen from electrolysis of electricity provided from natural gas firing is highly inefficient and significantly impacts the resulting CI of the produced hydrogen. Liberty should aim to avoid producing hydrogen from power during periods of high gas generation for this reason.

RNG blending presents a significant opportunity for emissions reductions, especially if low carbon intensity RNG can be secured. RNG blending is less technically challenging than hydrogen blending due to similar gas properties with natural gas, and can be initiated today without introducing additional safety or network integrity concerns.

Hydrogen blending on the other hand, is technically challenging with increased risk for pipeline and valve integrity, safety, network management, and end-use customers that must be evaluated and managed. This is discussed further in Section 5.

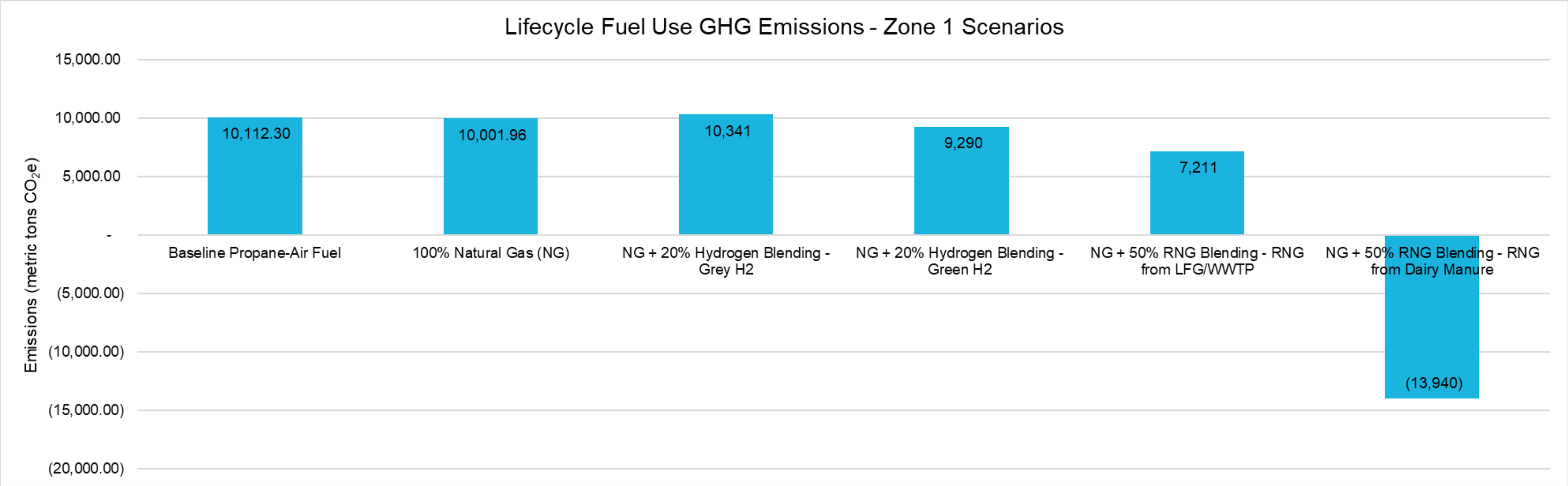

Figure 4.1 Emissions from Fuel Use for Select Zone 1 Scenarios

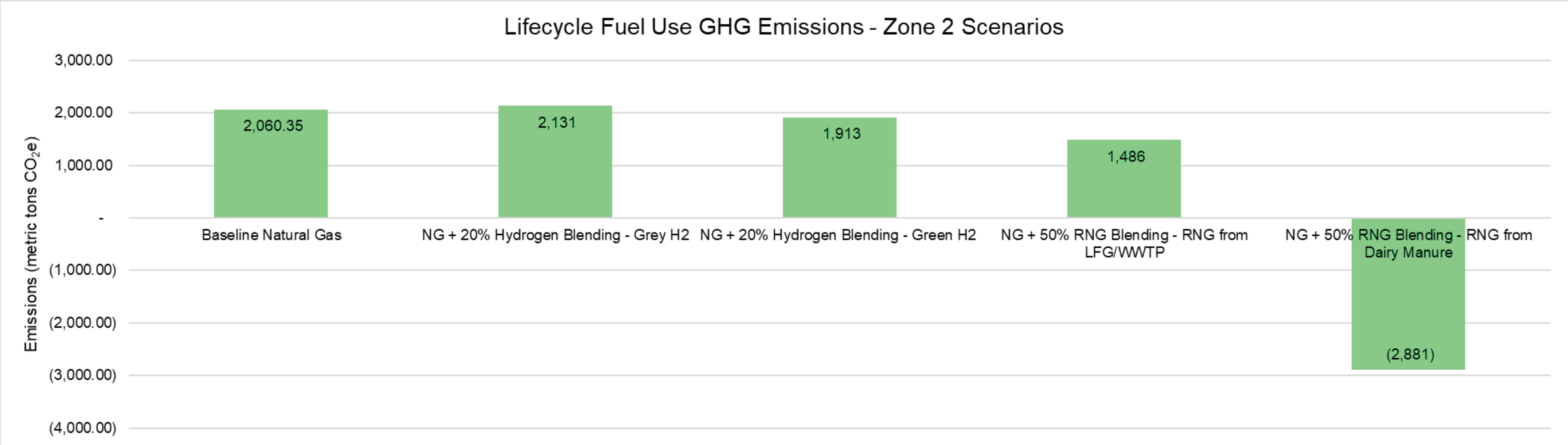

Figure 1.2 Emissions from Fuel Use for Select Zone 2 Scenarios

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5. Technical Gas Blending Considerations

As of today, hydrogen blending in natural gas systems has been demonstrated successfully through several projects around the world. However, there is a notable lack of data and standards for blending, and remaining gaps in knowledge in key applications, that need to be addressed for blending to be implemented on a larger scale. This section discusses, at a high level, the technical considerations of hydrogen blending in natural gas and compatibility with Keene's gas supply infrastructure.

Notable hydrogen blending demonstration projects include:

– HyDeploy Keele Pilot, United Kingdom – Successfully demonstrated blends of up to 20% hydrogen by volume to date at the Keele University campus, supplying 100 residential homes and 30 faculty buildings. Phase 2 of HyDeploy will replicate this demonstration into a gas supply network in Northeast UK, feeding approximately 670 customers.
– Hawaii Gas Town Gas, US – Hawaii Gas has been delivering a town gas blend comprising approximately 12% hydrogen by volume to customers on the island of Oahu since the 1970s.
– University of California, Irvine (UCI), US – UCI has been blending and testing hydrogen in the campus' isolated gas distribution network since 2016, recognized as the first power-to-gas hydrogen blending pilot in mainland US. Blending up to 3.8% has been demonstrated.
– GRHYD, France – Led by ENGIE and involving a consortium of members, this is a power-to-hydrogen demonstration project in a small, isolated, low pressure gas distribution grid in France. Blending was successfully demonstrated for up to 20% hydrogen by volume.
– Power-to-Gas Ameland, Netherlands – Successful demonstration of up to 20% hydrogen blending in the Ameland islanded natural gas distribution network with a variety of customers. Prior to the demonstration, laboratory testing of end-use equipment up to 30% hydrogen was completed with no issues identified.
– ATCO residential appliance testing – ATCO has tested typical and vintage residential home appliances in Alberta, Canada, for up to 40% hydrogen by volume successfully.
– Testing Hydrogen Admixture for Gas Application (THyGA), Belgium – Testing and demonstration of hydrogen blending in various end-use equipment including residential/commercial gas appliances. A recent publication summarized the results to date in residential and commercial gas appliances, and is available open-source online[6].

5.1 Note on Percent Blend of Hydrogen

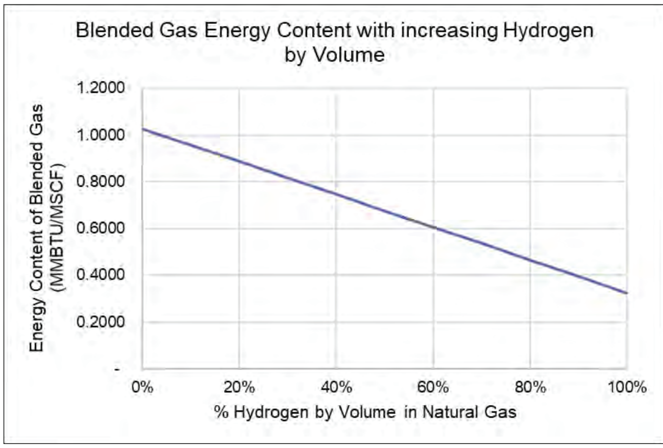
For the majority of this report, hydrogen blending levels in natural gas are discussed as a percent *by volume*. While discussing blend level on a percent by volume basis allows for consistent discussion and assessment across applications, it is important to understand that in many cases the impact of hydrogen admixing is heavily driven by the *partial pressure* of hydrogen in the mixture.

The partial pressure of hydrogen in a natural gas-hydrogen blend is the pressure exerted by the hydrogen component. The percent hydrogen blend is equivalent to the contribution of the partial pressure of hydrogen to the total gas mixture pressure. For example, in a 200 psi distribution pipeline, a 5% hydrogen blend by volume translates to 10 psi partial pressure of the hydrogen component. In a 1,200 psi transmission pipeline, a 5% hydrogen blend by volume translates to 60 psi hydrogen partial pressure. In a 5,000 psi underground storage site, a 5% hydrogen blend level corresponds to partial pressure of 250 psi.

[6] Leicher, J., *et al.,* (2022) *The Impact of Hydrogen Admixture into Natural Gas on Residential and Commercial Gas Appliances*, in Energies (2022) 15(3), 777. Available online at https://www.mdpi.com/1996-1073/15/3/777

The partial pressure of hydrogen in the mixture is important to consider as it is often the governing factor on whether or not hydrogen has an effect on mechanisms such as diffusion or embrittlement of steel grades. The solubility of gases correlates with their partial pressure in the gaseous phase. Higher partial pressure corresponds to great risk of embrittlement and diffusion.

Further, due to the significantly lower energy content of hydrogen, percent blend by volume is significantly different than the percent blend by energy. Emissions reductions are correlated with the percent blend by energy rather than the percent blend by volume. Figure 5.1 below indicates the relationships between (a) blended gas energy content and hydrogen blend percent by volume, and (b) percent of hydrogen content by energy versus by volume.



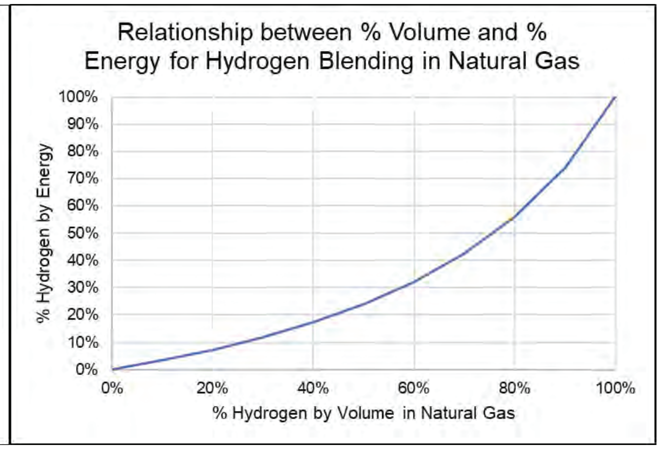


Figure 2.1 *Relationships between (a, left) blended gas energy content and hydrogen blend percent by volume, and (b, right) percent of hydrogen content by energy versus by volume*

5.2 Technical Considerations and Risks with Hydrogen Blending

Hydrogen is a substantially different molecule than methane – lighter, faster, and with a wider explosivity range. Hydrogen has been used in various industries for decades with established safety cases, codes, and standards. Hydrogen has a low energy density by volume (approximately ¼ that of gasoline, ⅓ of natural gas) but a high energy density by mass (approximately 3-times that of gasoline). Hydrogen burns fast, has a wide flammable region, high diffusivity, and low ignition energy when compared to natural gas. Admixing hydrogen in natural gas will impact various properties of the fuel, such as explosivity, dispersion, ignition, and flammability. This section discusses the technical considerations for hydrogen blending in a low pressure gas distribution system such as Keene's. Four key information sources are recommended for further details on the challenges briefly discussed here:

– Pipeline Research Council International's (PRCI's) 2020 *Emerging Fuels – Hydrogen: State-of-the-Art, Gap Analysis, and Future Project Roadmap,* prepared by GHD with input from subject matter experts from over 20 organizations
– The National Renewable Energy Laboratory's (NREL's) 2013 *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, which is currently being updated through the DOE initiative *HyBlend* (no published results as of yet)
– The European Gas Research Group's (GERG's) 2019 *Admissible Hydrogen Concentrations in Natural Gas Systems*
– The ThyGA research project's 2022 report The Impact of Hydrogen Admixture into Natural Gas on Residential and Commercial Gas Appliances

The key technical challenges for hydrogen blending can be summarize into the following topics:

- Pipeline and materials integrity
- Safety and risk
- Gas quality, metering and measurement
- End-use equipment compatibility

A brief overview of these challenges and importance to Liberty's Keene gas supply grid is discussed below, followed by a compatibility evaluation with Keene's existing gas infrastructure. The information discussed and conclusions drawn are based on desktop literature review of state-of-the-art hydrogen blending challenges and solutions, including experimental and field pilot results, and are meant to provide indicative information at this early stage of project planning. GHD recommends that, prior to initiating a hydrogen blending pilot, Liberty conduct a detailed hydrogen blending feasibility study including survey of statistically significant infrastructure and end-use equipment followed by engineering critical assessment, and quantitative risk assessment and/or hazards and opportunities study. An implementation and testing/monitoring plan can then be developed to ensure public safety and acceptance as the pilot begins.

5.2.1 Pipeline and Materials Integrity

Hydrogen does not cause degradation of polyethylene pipe. Rather, the primary concern is with permeation of hydrogen through the pipe leading to losses and impact to the blended gas ratio. Hydrogen has a significantly higher permeation rate than natural gas. Compared to methane, hydrogen permeation rates are 4 to 5 times higher through typical polymer pipes used in the U.S. natural gas distribution system [1]. Generally, plastic piping is preferred for hydrogen blending projects as hydrogen does not cause embrittlement and subsequent failure concerns for plastic pipe.

Hydrogen has an active electron which can easily migrate into the crystal structure of most metals, causing embrittlement and accelerated cracking and failure. High-strength steels are particularly susceptible, and the effect is drive by the partial pressure of hydrogen putting transmission systems at significantly higher risk than low pressure distribution systems. Steel pipes – and particularly the steel welds – used for pipeline infrastructure can suffer from hydrogen embrittlement and accelerated growth of cracking after continuous exposure to hydrogen. However, steel pipes in U.S. low-pressure distribution systems are primarily made of low-strength steel, typically API 5L A, B, X42, and X46, and these are generally not susceptible to hydrogen-induced embrittlement under normal operating conditions [1]. At the pressures and stress levels occurring in the natural gas distribution system, hydrogen induced failures are not major integrity concerns for steel pipes. For the other metallic pipes— including ductile iron, cast and wrought iron, and copper pipes—there is no concern of hydrogen damage under general operating conditions in natural gas distribution systems.

For valves and threaded or flanged connections, a higher leak rate by volume should be anticipated with hydrogen blending, but in general the amount of energy leaking is not expected to be higher as with natural gas. Threaded connections are widely used for steel distribution piping, especially on meter set assemblies, and a variety of thread sealants have been used. Threaded connections are common leak sources, even with 100% natural gas. It seems likely that the addition of hydrogen would increase leak rates, but additional data is needed to understand the magnitude of the impact.

Hydrogen permeates almost all materials and has the potential to diffuse into sealing materials causing damage. Specific design parameters regarding seal compression and base materials for the seals should be considered. Incompletely cured sealing materials (i.e. non-cross linked polymers) may cause the seal to appear greasy, with the liquid polymer coming out of the seal. The resulting loss in seal volume can cause the seal to no longer function properly (i.e. loss of compression). Some seal materials can become embrittled and/or have voids trapped inside of the material, which, when subjected to a rapid depressurization, could lead to total seal failure.

For the reasons discussed above, a hydrogen blending pilot project should be accompanied by a robust inspection and maintenance program to monitor system integrity.

5.2.2 Safety and Risk

Hydrogen blending impacts to key safety-related properties are summarized below.

– **Explosivity:** Studies have shown that there are virtually no changes to the lower explosivity limit (LEL) for hydrogen blending up to 10%, with only minor changes for higher blends to 100%. The upper explosivity limit (UEL) of the blended gas increases exponentially with increasing hydrogen addition, although the impact is negligible for blends to 10% hydrogen and minimal for blends up to 25% hydrogen. At blending levels of 50% or greater, there is a significant increase in explosivity severity. Table 5.1 and Figure 5.2 below provide a summary of theoretical and experimental data for explosivity risk impacts from hydrogen blending in methane and natural gas.

Table 5.1 – Explosion limits of methane/hydrogen and natural gas/hydrogen mixtures [2]

hydrogen fraction in fuel gas blend	Methane/hydrogen			natural gas/hydrogen		
	LEL	UEL	LOC	LEL	UEL	LOC
0 mole%	4.2	16.6	10.1	3.8	16.2	9.7
5 mole%	4.2	17.4	9.8	3.8	17.2	9.7
10 mole%	4.2	18.2	9.6	3.8	17.8	9.4
25 mole%	4.2	21.2	9.1	4.0	21.0	8.9
50 mole%	4.0	29.0	7.9	3.8	28.4	7.6
100 mole%	4.1	75.6	4.3	4.1	75.6	4.3

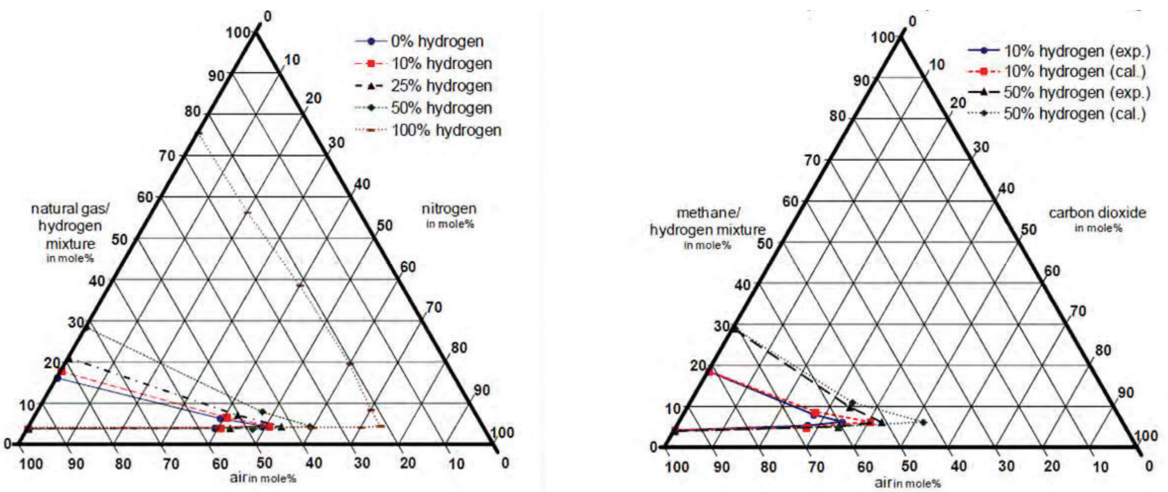


Figure 5.2 Explosive regions for: (Left) natural gas-hydrogen blends in nitrogen and air and (Right) methane-hydrogen blends in carbon dioxide and air [2]

– **Gas build-up and dispersion:** Hydrogen is a lighter and faster molecule that methane with higher diffusivity (approximately 4 times) and dispersion speed and lower density. Experimental research has shown gas flow rate increases for leaks as hydrogen concentration increases, thus causing an increased leak risk for hydrogen blending projects. However, this effect is minimal for low blend levels, becoming significant for blends of greater than 50% hydrogen by volume. The percent hydrogen in the gas mixture, height of the release point from the ground, wind conditions, flow rate of the leak, air/gas mixture and venting in the enclosure, and direction of the gas being released will influence the potential gas accumulation in an enclosure following a leak. There has been extensive experimental research in this area to prove the safety case for hydrogen blending, which has generally concluded that hydrogen and natural gas do not separate for leaks in ventilated, enclosed spaces, meaning that the natural gas odorant and other detection methods can generally be used for low blend levels.

– **Ignition:** Generally, minimum ignition energy decreases as the hydrogen content increases. There is sufficient experimental data on minimum ignition current (MIC) and maximum experimental safe gap (MESG) for methane-hydrogen blends with up to 20% hydrogen. The MIC of a gas can determine its sensitivity to electric or electrostatic sources. Methane-hydrogen blends containing less than or equal to 6% hydrogen have MIC ratios greater than 0.9; blends containing 8 to 14% hydrogen have MIC ratios between 0.8 and 0.9, and blends containing 16 to 20% hydrogen have MIC ratios less than 0.8 [3] [4] [5].

– **Flammability:** Hydrogen is highly flammable and has wider flammability limits than natural gas at ambient temperature and pressure. This relates to a flammability range in % by volume of 4.4–17% for pure natural gas and 4.0–75% for pure hydrogen. This wider flammability range of hydrogen needs to be considered in detailed risk assessment and safety review. Flammable limits and limiting oxygen for combustion for hydrogen-methane blends can be calculated using Le Chatelier's rule.

– **Safety Zones:** Safety zones are well defined for natural gas networks and equipment, typically governed by codes and standards applicable to each region. North America and Europe have their own hazardous location classification system (NFPA code in North America, ATEX directives in Europe). Area classifications are based on Classes, Divisions and Zones that together define hazardous conditions of a specific area. As discussed above, the introduction of hydrogen into natural gas networks impacts key safety characteristics such as flammability, explosivity, ignition and dispersion. Therefore, safety zone distances will need to be adjusted as a function of hydrogen blending percentage. There are no known resources addressing safety zone calculations for natural gas pipelines and equipment under hydrogen blending. This presents a notable gap that will need to be addressed for regulators to confidently adjust safety zones based on increasing hydrogen blending in distribution grids.

– **Flame Visibility:** Hydrogen burns hot and clean with a pale blue flame that is almost invisible during daylight hours and produces low radiant heat. A pure hydrogen fire is almost impossible to see with the naked eye, will not produce any smoke, and a person may not realize a fire is present until they are very close to the flame. Standard infrared flame (IR) detection is ineffective for hydrogen flames due to reduced flame luminosity, and therefore ultraviolet (UV) detection is required. For hydrogen blending in natural gas, increasing hydrogen content results in reduced flame visibility. Portable and stationary flame detectors may need to be replaced with units capable of UV flame detection as hydrogen blending increases. The figures below indicate the impact of hydrogen on flame visibility for low blend percentages, produced by Enbridge for the company's 2% hydrogen blending pilot in Markham, Ontario.

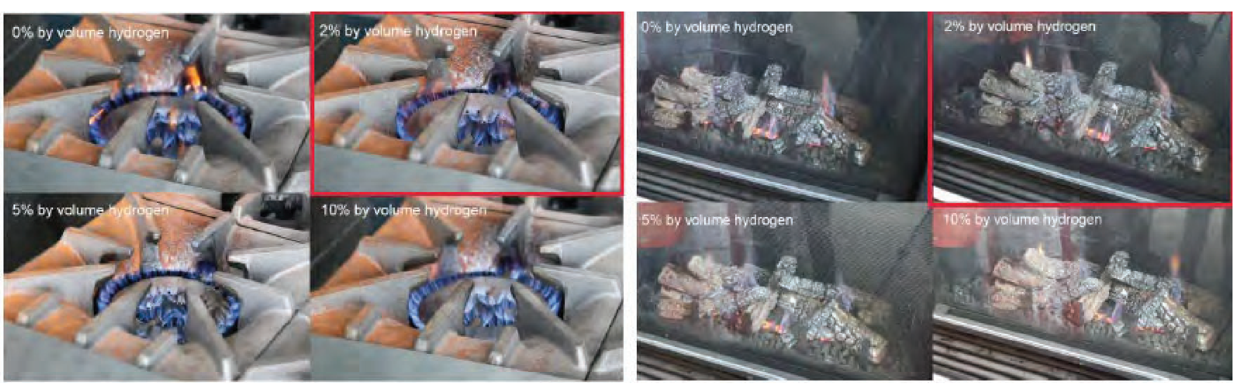


***Figure 5.3** Stove (left) and fireplace (right) images of natural gas-hydrogen blends from 0% to 10% hydrogen by volume, sourced from Enbridge [6]*

5.2.3 Gas Quality, Metering and Measurement

As discussed previously, hydrogen has a significantly lower calorific value by volume than natural gas and the introduction of hydrogen into a natural gas system will therefore reduce the energy content of delivered, blended gas. Accurate measurement and knowledge of the calorific value of delivered gas is important for a number of reasons. These include determining the transaction value of natural gas, quality control based on heating value standards, controlling plant combustion equipment for stable operation, and controlling air-fuel ratios for gas turbine generators that require precise combustion control.

Since the addition of hydrogen into natural gas changes the properties of the gas, accuracy and compatibility of existing metering equipment with the presence of hydrogen needs to be understood. Billing credits may be deemed necessary to ensure accurate billing for customers on an energy-content basis.

There are challenges with typical gas chromatography once hydrogen is introduced. Typical hydrocarbon gas chromatographs (GCs) existing in the gas network use helium as the gas carrier, which cannot carry and therefore cannot detect hydrogen content. Hydrogen impact on heating value measurements are related to the low sensitivity of currently employed GC thermal conductivity detectors (TCDs). Heating value measurement uncertainty increases with the amount of hydrogen added.

New GCs are being developed that may be compatible with up to 20% hydrogen by volume, where an argon carrier single column set or a dual-column with two carrier gases is used. Further testing is required to prove the accuracy of these solutions.

Alternatively, meters using sound and light measurements (i.e. RIKEN OPT-SONIC™) may be viable alternatives for accurately measuring hydrogen concentrations up to 10% by volume, although this technique is still under research and development.

Figure 5.4 H2Scan's HY-OPTIMA 2700 Series analyzer outputs hydrogen concentration in real time

There are commercial meter options for specifically measuring the hydrogen content in a mixed gas, which are not cross-sensitive to other gases. For example, the HY-OPTIMA™ 2700 Series Explosion-Proof In-Line Hydrogen Process Analyzer by H2Scan is a relatively newly commercialized solution specifically meant for hydrogen blending applications. This meter measures partial pressure of hydrogen in the process stream in real time, with one model (model 2710) validated for blends of 0.1% to 10% hydrogen and at least two others for 0.5% to 100%. The HY-OPTIMA™ 2700 Series uses a solid-state, non-consumable sensor that is configured to operate in process gas streams. The H2Scan thin film technology provides a direct hydrogen measurement that is not cross-sensitive to other gases.

Gas volume measurement can also be a challenge with hydrogen admixing, depending on the meter type. Hydrogen is considered a difficult industrial gas to measure, due to its low molecular weight and therefore low operating density. Traditional technologies such as differential pressure, vortex, or thermal mass experience difficulties measuring pure hydrogen flow. For hydrogen blending, inferential measurement meters such as orifice meters, ultrasonic meters and turbine meters may be less accurate with increasing hydrogen content, especially above 10%, while direct measurement meters (or positive displacement meters) such as diaphragm meters and rotary meters are expected to be less impacted by hydrogen addition.

5.2.4 End-Use Equipment Compatibility

Hydrogen blending impacts gas quality criteria such as relative densities, calorific values and Wobbe Indices of the fuel, as well as other key combustion parameters such as adiabatic combustion temperatures, flame shape and positioning, and laminar combustion velocities.

For residential and commercial end-use, natural gas is exclusively used as a fuel to provide low-temperature heat for space heating, cooking, or to heat water, to name the most common applications. Testing completed through a number of demonstration and experimental project (see the list of relevant projects at the beginning of Section 5 of this report) has shown that generally, hydrogen is expected to be acceptable in residential and commercial gas equipment for blends at least up to 20% by volume. However, a survey of end-use equipment in the network should be completed (to a statistically significant level) and evaluated against published experimental data for any gaps in confidence. As most gas appliances in operation today were not designed with hydrogen blending in mind, it is important to assess hydrogen acceptability on a case-by-case basis.

5.3 Hydrogen Blending Compatibility with Keene's Gas Supply Infrastructure

Using the information discussed in Section 5.2 above and particularly relying on the conclusions published by PRCI, NREL, and GERG, Table 5.2 below presents the compatibility of Keene's existing gas supply infrastructure with increasing hydrogen blending content by volume in natural gas operated at a maximum pressure of 60 psig.

Table 5.2 - Hydrogen Blending Compatibility with Keene's Gas Supply Infrastructure

Legend
No modifications required
Potential modification/replacement required, further investigation and data needed
Replacement needed with compatible alternative

Maximum operating pressure: 60 psig

	Compatibility with Hydrogen Blending at % H2 by volume in NG							
	2%	5%	10%	20%	30%	40%	50%	100%
System piping at 60 psi								
Plastic pipeline[1]								
Steel pipeline (cathodically protected)[2]								
Cast/wrought iron pipeline[3]								
System meters and valves								
Diaphragm flow meteres[4]								
Rotary flow meters[4]								
PE ball valves[5]								
Steel multi-turn gas valves[6]								
Customers and End-Use								
Residential/Commercial - building heating, stoves, fireplaces[7]								
Industrial[8]								

Notes:

1. PE piping is generally expected to accept hydrogen blending without material integrity issues. Little or no interaction between hydrogen gas (or any non-polar gas) and polyethylene should be expected. Green lighted to 30% blend by volume given successful demonstrations globally. Orange for 50% and above due to lack of experimental data and demonstration.

2. H2 blending poses embrittlement and subsequent fracture concerns for high strength steels in high pressure systems. The steel grades (API 5L A, B, X42 and X46) used in natural gas distribution pipeline are relatively low strength steels, and 60 psi operating pressure is relatively low pressure compared to transmission systems. The predominant concern for low strength steels is loss of tensile ductility or blistering, and with hydrogen, they usually fail in a ductile mode instead of catastrophic brittle fracture. Fatigue cracking could become an issue with frequent pressure cycling. Blends above 5% should be initiated carefully with increased monitoring and inspections to evaluate system integrity.
3. Many cast iron systems in the US were installed over 50 years ago and originally used to transport town gas, which contained as much as 10-30% hydrogen. However, given the age of these assets, Liberty may wish to err on the side of caution by replacing iron pipe sections with plastic ahead of hydrogen introduction.
4. Direct measurement meters (or positive displacement meters) such as diaphragm meters and rotary meters have been found to be less impacted by hydrogen addition than inferential meters such as ultrasonic and orifice meters. It is unclear whether these meter types will be fully compatible with 100% hydrogen gas flows. Accuracy and safety (through increased hydrogen leakage) will possibly decrease as more hydrogen is blended into the mix but the practical upper limit is not yet known and may vary from model to model.
5. The main concern with valves in the low-pressure distribution system is higher leakage due to hydrogen's high diffusivity and low density. The NaturalHy project found that blends of up to 30% hydrogen by volume do not significantly increase leak risk.
6. Steel valves may be susceptible to fatigue cracking under hydrogen service. Increased monitoring and inspection recommended for any percent hydrogen blend, or full replacement with PE valves ahead of hydrogen introduction.
7. Multiple assessments of typically residential/commercial natural gas equipment have been completed for blending demonstration projects. Blending of up to 20% does not require modifications, and some evaluations have shown no issues with blending up to 40% (ex. ATCO). However, some modification may be required for higher blends (ex. replacing burner tips), which should be assessed.
8. Generally, gas engines, turbines, and boilers can accept up to 5% hydrogen without modifications due to designed gas quality limits. Higher blends need to be evaluated on case by case basis, and the OEM should be contacted for hydrogen compatibility limits. Some boilers may be able to handle up to 30%, and many new turbines and engines are being designed to handle 30%+ hydrogen blending. Older equipment is of higher concern and will likely require replacement for blends above 5%. Any customers using direct-fired equipment (i.e. kilns) may need to be isolated from hydrogen as the hydrogen can impact product quality even at low blends of 2%.

6. Recommendations

Based on Liberty’s proposed plan to convert Zone 1 from a propane-air system to LNG/CNG, the overall carbon intensity for both supply options are similar, however the opportunity to blend renewable natural gas (RNG) into the CNG/LNG supply mix provides a significant reduction in carbon intensity as shown in Table 3.2.

Development of a hydrogen blending demonstration program provides a pathway to improve decarbonization options over time and creates the ability to define infrastructure modifications, hydrogen production options and an opportunity to expand Liberty’s customer base in Keene

Below is a recommended implementation schedule.

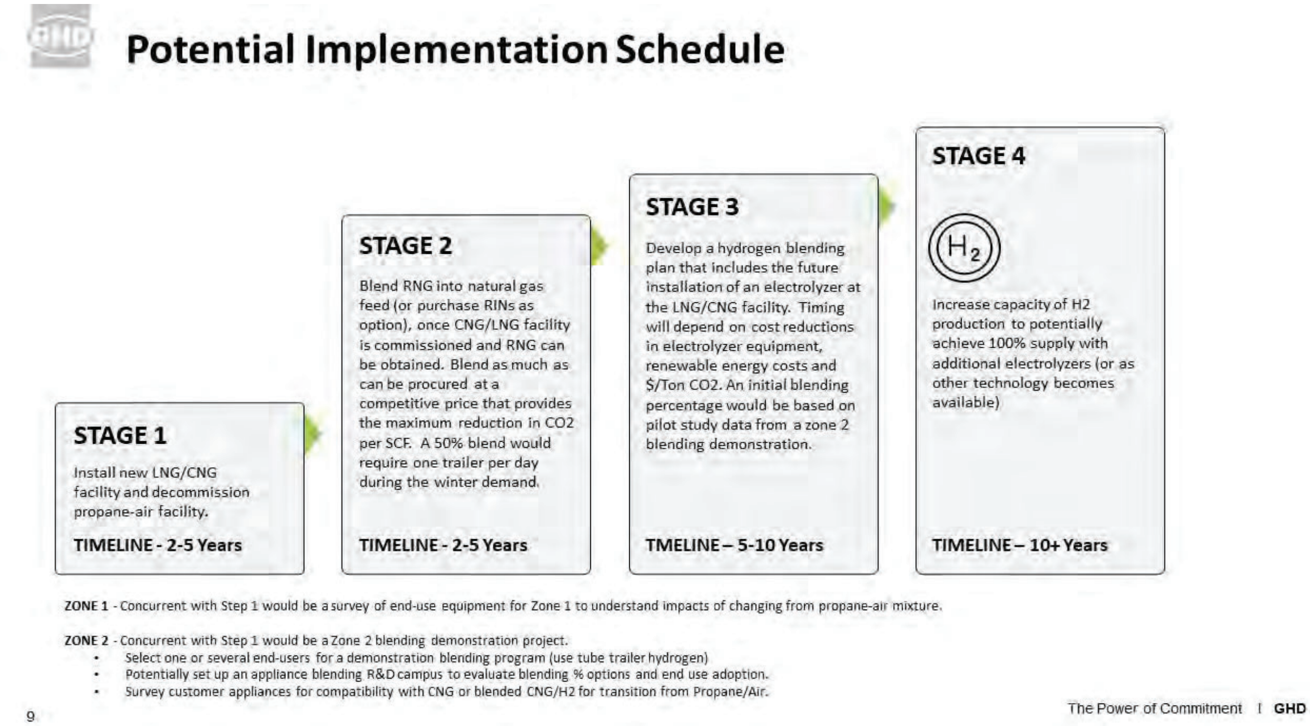


Figure 5.5 Potential Implementation Schedule

Stage 1: Install new LNG/CNG facility and decommission propane-air facility.
Short-Term (2-5 years).

Stage 2: Blend RNG into natural gas feed, once CNG/LNG facility is commissioned and RNG can be obtained. Blend as much as can be procured at a competitive price that provides the maximum reduction in CO_2 per SCF. A 50% blend would require one trailer per day during the winter demand.
Short-Term (2-5 years)

Stage 3: Develop a hydrogen production and blending plan that includes the future installation of an electrolyzer at the LNG/CNG facility: Timing will depend on anticipated cost reductions in electrolyzer equipment and renewable energy costs as well as any market-based costs per ton of CO_2. An initial blending percentage would be based on pilot study data from a zone 2 blending demonstration.
Mid-Term (5-10 years).

Stage 4: Increase capacity of H_2 production to potentially achieve 100% supply with additional electrolyzers (or as other technology that becomes available)
Long-Term (10+ years)

Concurrent with Step 1 would be a survey of end-use equipment for Zone 1 to understand impacts of changing from propane-air mixture.

The implementation of the pilot program for Zone 2 would provide the following:

– Early adoption of H2 at a minimized overall project cost and to demonstrate safe and reliable use.
– Higher probability of receiving either state or federal funding.
– Provides a well-defined community, and fire marshal engagement plan based on a smaller scale (reduced overall safety and risk issues).
– Allows for further piping and component and end user survey and analysis prior to additional blending or customer system upgrades.
– Allows for future expansion as piping systems improve and customer base increases.
– Allows for further procurement options for renewable power sources for the electrolyzer.

Additional Value-added opportunities:

Since the energy demand in Keene is seasonal, any capex invested for hydrogen supply will not be fully utilized during low demand months.

1. Consider producing hydrogen (if via electrolysis) for other potential applications such as fuel cell vehicle H2 fueling program, EV fast charging and back-up power for critical facilities (police, fire, first responders, etc). Additional funding would be required. This improves the overall economics and capacity factor of the electrolyzer unit.
2. Consider utilizing the heat given off from the electrolyzer (up to 50% of the total energy input) to pre-heat any of the high pressure CNG prior to let-down. This could improve the overall economics and efficiency of the electrolyzer system.
3. Investigate tax credit and other funding opportunities for renewable H2 production, grants and NH-based appliance incentive programs for eventual transition to CNG.
4. Consider development of an Advanced Fuel Lab concept in NYS. The concept consists of building a series of small sheds (buildings) that can be strategically placed to simulate a typical “community” setting. Each shed could house different NG appliances such as furnaces, heaters, hot water tanks, stoves, cooktops, etc. Each shed would be supplied NG via conventional residential delivery (plastic pipe, regulators, meters).

   Hydrogen would be supplied via cylinders such that the overall onsite storage capacity of hydrogen was minimized. GHD or others can design a hydrogen blending system that would include mass flow controllers/meters, tubing, instrumentation and controls, safety features, etc, that could test various blending percentages of hydrogen. Small flowrates (500 SCFH Max) would suffice for appliance testing and the blending site could be set up at a Liberty or Algonquin training or testing facility that already has access to land and NG supply. This creates a low cost, highly effective means to engage Liberty and Algonquin staff, local permitting entities, local fire marshals and local stakeholders prior to expanding to a full-scale blending demonstration.

   The lab also provides media, PR thought leadership and training value to the Liberty and Algonquin brands.

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Appendix A

Detailed Results from GHG Assessment of Gas Supply Options

Zone 1 - Propane/Air Fuel Mix in Baseline, Pure NG, NG + H2, and NG + RNG in Project

GHD, January 2022

Assumptions and Unit Conversions

Propane		
Propane-Air Mix Heating value	0.748	MMBTU/MCF
Lifecycle CI of LPG	83.19	gCO2e/MJ Propane
LPG density	1.885	kg/gallon
LPG energy density	49.3	MJ/kg

Hydrogen		
Heating value	325	BTU/SCF
	0.325	MMBTU/MSCF
Density	2.362	kg/1000SCF
Lifecycle carbon intensities		
Grey - trucked	117	gCO2e/MJ
Keene Grid - on-site	73	gCO2e/MJ
100% Solar/Wind avg	0	gCO2e/MJ
Energy density (HHV)	142	MJ/kg

Natural Gas		
Heating value	1027	BTU/SCF
	1.027	MMBTU/MSCF
Lifecycle CI	79.21	gCO2e/MJ

Renewable Natural Gas (RNG)		
Heating value	Assumed same as NG for simplicity.	
Lifecycle carbon intensities		
RNG from manure	-300	gCO2e/MJ
RNG from SSO AD	-40	gCO2e/MJ
RNG from WWTP/LFG	35	gCO2e/MJ

Conversions		
1 MMBTU =	1055	MJ

Replacing Propane-Air Fuel with Natural Gas

	Baseline (2021 Data)					Natural Gas Equivalent for same MMBTU			
	LPG Use	**Propane/Air Fuel Mix**			**Fuel Use Emissions**	**Natural Gas Use**		**Fuel Use Emissions**	**Change in Emissions**
Month	Gallons	MCF	MMBTU	BTU/SCF	tonnes CO2e	MCF	MMBTU	tonnes CO2e	tonnes CO2e
January	227,988	28,010	20,861	745	1,762.55	20,312.91	20,861.36	1,743.31	(19.24)
February	216,424	26,581	19,803	745	1,673.15	19,282.60	19,803.23	1,654.89	(18.26)
March	164,196	20,156	15,024	745	1,269.38	14,629.27	15,024.26	1,255.53	(13.86)
April	99,652	12,234	9,118	745	770.40	8,878.63	9,118.36	761.99	(8.41)
May	59,861	7,330	5,477	747	462.78	5,333.40	5,477.40	457.73	(5.05)
June	40,917	5,002	3,744	749	316.32	3,645.56	3,743.99	312.87	(3.45)
July	38,250	4,672	3,500	749	295.71	3,407.94	3,499.95	292.48	(3.23)
August	38,209	4,614	3,496	758	295.39	3,404.28	3,496.20	292.17	(3.22)
September	42,237	5,139	3,865	752	326.53	3,763.16	3,864.77	322.97	(3.56)
October	59,879	7,324	5,479	748	462.92	5,335.00	5,479.05	457.87	(5.05)
November	142,849	17,508	13,071	747	1,104.35	12,727.33	13,070.97	1,092.30	(12.05)
December*	177,577	21,788	16,249	746	1,372.83	15,821.81	16,249.00	1,357.87	(14.96)
Totals	1,308,039	160,358	119,689	748	10,112.30	116541.9026	119688.5339	10001.95785	(110.35)

* Assumed totals via averages for first 7 days of the month

Hydrogen Blending in Natural Gas Scenarios - Quantities & Emissions Offsets

Hydrogen blending quantities for 2, 5, 10, 15, and 20% hydrogen

				2% by volume	0.62% by energy			**5%** by volume	1.59% by energy		
	100% Natural Gas			2% Hydrogen Blend				5% Hydrogen Blend			
MMBtu/MCF	1.0270 MMBTU/MCF			1.02178 MMBTU/MCF				1.0005 MMBTU/MCF			
Month	NG MCF	MMBTU	NG MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	20,312.91	20,861.36	22,008,733	20,417	964	21,871,776	136,956.7	20,852	2463	21,659,041	349,691.8
February	19,282.60	19,803.23	20,892,406	19,381	916	20,762,396	130,010.0	19,794	2338	20,560,452	331,954.7
March	14,629.27	15,024.26	15,850,597	14,704	695	15,751,961	98,635.7	15,018	1774	15,598,750	251,846.6
April	8,878.63	9,118.36	9,619,867	8,924	422	9,560,004	59,862.9	9,114	1076	9,467,019	152,847.9
May	5,333.40	5,477.40	5,778,658	5,361	253	5,742,699	35,959.6	5,475	647	5,686,842	91,815.8
June	3,645.56	3,743.99	3,949,907	3,664	173	3,925,327	24,579.6	3,742	442	3,887,147	62,759.2
July	3,407.94	3,499.95	3,692,449	3,425	162	3,669,471	22,977.5	3,498	413	3,633,780	58,668.5
August	3,404.28	3,496.20	3,688,491	3,422	162	3,665,538	22,952.9	3,495	413	3,629,885	58,605.6
September	3,763.16	3,864.77	4,077,332	3,782	179	4,051,960	25,372.6	3,863	456	4,012,549	64,783.8
October	5,335.00	5,479.05	5,780,396	5,362	253	5,744,425	35,970.5	5,477	647	5,688,553	91,843.4
November	12,727.33	13,070.97	13,789,873	12,792	604	13,704,060	85,812.1	13,065	1543	13,570,768	219,104.2
December	15,821.81	16,249.00	17,142,695	15,903	751	17,036,019	106,676.2	16,242	1918	16,870,319	272,376.4
Totals	116,541.9	119,688.5	126,271,403	117,137.3	5,533.6	125,485,637	785,766.3	119,634.7	14,128.9	124,265,105	2,006,297.8

	10% by volume	3.29% by energy			**15%** by volume	5.13% by energy			**20%** by volume	7.11% by energy		
	10% Hydrogen Blend				15% Hydrogen Blend				20% Hydrogen Blend			
MMBtu/MCF	0.9649 MMBTU/MCF				0.9294 MMBTU/MCF				0.8938 MMBTU/MCF			
Month	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	21,620	5107	21,283,582	725,151.1	22,447	7953	20,879,398	1,129,335.0	23,340	11026	20,443,062	1,565,670.8
February	20,524	4848	20,204,036	688,370.0	21,309	7550	19,820,354	1,072,052.9	22,156	10467	19,406,150	1,486,256.9
March	15,571	3678	15,328,346	522,250.8	16,166	5728	15,037,255	813,342.3	16,809	7941	14,723,007	1,127,589.6
April	9,450	2232	9,302,908	316,958.6	9,812	3476	9,126,242	493,624.6	10,202	4819	8,935,523	684,344.0
May	5,677	1341	5,588,261	190,397.2	5,894	2088	5,482,138	296,520.5	6,128	2895	5,367,573	411,085.8
June	3,880	916	3,819,764	130,142.8	4,029	1427	3,747,225	202,681.7	4,189	1979	3,668,916	280,990.9
July	3,627	857	3,570,789	121,660.0	3,766	1334	3,502,978	189,470.8	3,916	1850	3,429,773	262,675.7
August	3,623	856	3,566,961	121,529.6	3,762	1333	3,499,223	189,267.7	3,912	1848	3,426,097	262,394.1
September	4,005	946	3,942,991	134,341.3	4,159	1473	3,868,112	209,220.3	4,324	2043	3,787,277	290,055.8
October	5,678	1341	5,589,941	190,454.4	5,896	2089	5,483,786	296,609.7	6,130	2896	5,369,187	411,209.4
November	13,546	3200	13,335,519	454,353.3	14,065	4983	13,082,272	707,600.3	14,624	6908	12,808,880	980,992.5
December	16,840	3978	16,577,872	564,823.3	17,484	6195	16,263,051	879,643.8	18,180	8588	15,923,187	1,219,507.6
Totals	124,042.4	29,298.8	122,110,971	4,160,432.5	128,787.4	45,629.4	119,792,034	6,479,369.4	133,909.7	63,259.0	117,288,630	8,982,773.1

GHG Emission & Reductions - Annual Totals

	Baseline - Propane	100% NG		2% Hydrogen Blend		5% Hydrogen Blend		10% Hydrogen Blend		15% Hydrogen Blend		20% Hydrogen Blend	
	Emissions from Fuel Use (Lifecycle)	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline	Emissions from Fuel Use (Lifecycle)	Change in Emissions from Baseline
	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e
Grey H2	10,112.30	10,001.96	(110.35)	10,031.65	(80.65)	10,077.78	(34.53)	10,159.18	46.88	10,246.81	134.51	10,341.42	229.11
Keene grid H2	10,112.30	10,001.96	(110.35)	9,997.08	(115.23)	9,989.50	(122.80)	9,976.12	(136.18)	9,961.72	(150.58)	9,946.17	(166.13)
Green H2	10,112.30	10,001.96	(110.35)	9,939.72	(172.59)	9,843.04	(269.26)	9,672.41	(439.89)	9,488.73	(623.58)	9,290.43	(821.87)

RNG Blending Scenarios - Quantities & Emissions Offsets

RNG Blending Quantities

				20%				50%				
	100% Natural Gas			20% RNG Blend by Volume				50% RNG Blend by Volume				
Month	NG MCF	MMBTU	NG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ
January	20,312.9	20,861.4	22,008,732.7	16,250.3	4,062.6	17,606,986.1	4,401,746.5	10,156.5	10,156.5	11,004,366.3	11,004,366.3
February	19,282.6	19,803.2	20,892,406.4	15,426.1	3,856.5	16,713,925.1	4,178,481.3	9,641.3	9,641.3	10,446,203.2	10,446,203.2
March	14,629.3	15,024.3	15,850,596.8	11,703.4	2,925.9	12,680,477.5	3,170,119.4	7,314.6	7,314.6	7,925,298.4	7,925,298.4
April	8,878.6	9,118.4	9,619,867.0	7,102.9	1,775.7	7,695,893.6	1,923,973.4	4,439.3	4,439.3	4,809,933.5	4,809,933.5
May	5,333.4	5,477.4	5,778,658.3	4,266.7	1,066.7	4,622,926.6	1,155,731.7	2,666.7	2,666.7	2,889,329.1	2,889,329.1
June	3,645.6	3,744.0	3,949,906.6	2,916.4	729.1	3,159,925.3	789,981.3	1,822.8	1,822.8	1,974,953.3	1,974,953.3
July	3,407.9	3,500.0	3,692,448.8	2,726.3	681.6	2,953,959.1	738,489.8	1,704.0	1,704.0	1,846,224.4	1,846,224.4
August	3,404.3	3,496.2	3,688,490.9	2,723.4	680.9	2,950,792.7	737,698.2	1,702.1	1,702.1	1,844,245.5	1,844,245.5
September	3,763.2	3,864.8	4,077,332.3	3,010.5	752.6	3,261,865.9	815,466.5	1,881.6	1,881.6	2,038,666.2	2,038,666.2
October	5,335.0	5,479.0	5,780,395.9	4,268.0	1,067.0	4,624,316.7	1,156,079.2	2,667.5	2,667.5	2,890,198.0	2,890,198.0
November	12,727.3	13,071.0	13,789,872.5	10,181.9	2,545.5	11,031,898.0	2,757,974.5	6,363.7	6,363.7	6,894,936.3	6,894,936.3
December	15,821.8	16,249.0	17,142,695.0	12,657.4	3,164.4	13,714,156.0	3,428,539.0	7,910.9	7,910.9	8,571,347.5	8,571,347.5
Totals	116,541.9	119,688.5	126,271,403	93,234	23,308	101,017,123	25,254,281	58,271	58,271	63,135,702	63,135,702

RNG Blending Emissions and Emissions Reductions from Baseline

	Baseline - Propane	100% NG		20% RNG Blend		50% RNG Blend	
	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions from Baseline tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e
RNG from manure	10,112.30	10,001.96	(110.35)	425.28	(9,687.02)	(13,939.73)	(24,052.03)
RNG from SSO AD	10,112.30	10,001.96	(110.35)	6,991.40	(3,120.91)	2,475.55	(7,636.75)
RNG from WWTP/LFG	10,112.30	10,001.96	(110.35)	8,885.47	(1,226.84)	7,210.73	(2,901.57)

Zone 2 - Natural Gas in Baseline, NG + H2 and NG + RNG in Project

Assumptions and Unit Conversions

Hydrogen		
Heating value	325	BTU/SCF
	0.325	MMBTU/MSCF
Density	2.362	kg/1000SCF
Lifecycle carbon intensities		
Grey - trucked	117	gCO2e/MJ
Keene Grid - on-site	73	gCO2e/MJ
100% Solar/Wind avg	0	gCO2e/MJ
Energy density (HHV)	142	MJ/kg

Natural Gas		
Heating value	1027	BTU/SCF
	1.027	MMBTU/MSCF
Lifecycle CI	79	gCO2e/MJ

Renewable Natural Gas (RNG		
Heating value	Assumed same as NG for simplicity.	
Lifecycle carbon intensities		
RNG from manure	-300	gCO2e/MJ
RNG from SSO AD	-40	gCO2e/MJ
RNG from WWTP/LFG	35	gCO2e/MJ

Conversions		
1 MMBTU =	1055	MJ

Hydrogen Blending Scenarios - Quantities & Emissions Offsets

Hydrogen blending quantities

				2%	by volume	0.63%	by energy	**5%**	by volume	1.60%	by energy
	Baseline - 0% H2			2% Hydrogen Blend				5% Hydrogen Blend			
MMBtu/MCF	1.0274 MMBTU/MCF			1.0130 MMBTU/MCF				0.9919 MMBTU/MCF			
Month	NG MCF	MMBTU	NG MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	3597.3	3690.9	3,893,900	3644	172	3,869,457	24,442.1	3721	439	3,831,497	62,402.6
February	3186.9	3271.7	3,451,644	3230	153	3,429,977	21,666.0	3298	390	3,396,328	55,315.1
March	2699.9	2772.9	2,925,410	2737	129	2,907,047	18,362.9	2796	330	2,878,528	46,881.8
April	1701.7	1745.8	1,841,819	1723	81	1,830,258	11,561.1	1760	208	1,812,303	29,516.5
May	1385	1420.2	1,498,311	1402	66	1,488,906	9,404.9	1432	169	1,474,299	24,011.5
June	1029.4	1059	1,117,245	1045	49	1,110,232	7,013.0	1068	126	1,099,340	17,904.7
July	1100.5	1129.4	1,191,517	1115	53	1,184,038	7,479.2	1139	134	1,172,422	19,094.9
August	949.6	971.2	1,024,616	959	45	1,018,184	6,431.5	979	116	1,008,196	16,420.2
September	1114.5	1144	1,206,920	1129	53	1,199,344	7,575.9	1153	136	1,187,578	19,341.8
October	1346.5	1386.2	1,462,441	1368	65	1,453,261	9,179.8	1398	165	1,439,004	23,436.7
November	2598.8	2686.2	2,833,941	2652	125	2,816,152	17,788.7	2708	320	2,788,525	45,416.0
December	3350.5	3443.2	3,632,576	3399	161	3,609,774	22,801.8	3471	410	3,574,361	58,214.7
Totals	24,060.6	24,720.7	26,080,338.5	24,404.4	1,152.9	25,916,632	163,706.8	24,922.6	2,943.4	25,662,382	417,956.5

	10% by volume		3.32% by energy		**15%** by volume		5.17% by energy		**20%** by volume		7.17% by energy	
	10% Hydrogen Blend				15% Hydrogen Blend				20% Hydrogen Blend			
MMBtu/MCF	0.9568 MMBTU/MCF				0.9217 MMBTU/MCF				0.8866 MMBTU/MCF			
Month	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ	MCF Mix	KG H2	NG MJ	H2 MJ
January	3858	911	3,764,516	129,383.6	4004	1419	3,692,433	201,466.2	4163	1967	3,614,643	279,256.2
February	3419	808	3,336,955	114,688.7	3550	1258	3,273,059	178,584.3	3690	1743	3,204,104	247,539.2
March	2898	685	2,828,206	97,203.4	3008	1066	2,774,052	151,357.6	3128	1477	2,715,610	209,799.6
April	1825	431	1,780,620	61,198.6	1894	671	1,746,525	95,293.7	1969	930	1,709,731	132,088.5
May	1484	351	1,448,526	49,784.8	1541	546	1,420,790	77,521.0	1602	757	1,390,858	107,453.4
June	1107	261	1,080,122	37,123.0	1149	407	1,059,440	57,805.1	1194	564	1,037,120	80,124.7
July	1180	279	1,151,926	39,590.9	1225	434	1,129,869	61,647.8	1274	602	1,106,066	85,451.2
August	1015	240	990,571	34,045.2	1054	373	971,603	53,012.5	1095	517	951,134	73,481.7
September	1196	282	1,166,817	40,102.7	1241	440	1,144,475	62,444.8	1290	610	1,120,364	86,555.9
October	1449	342	1,413,848	48,592.9	1504	533	1,386,776	75,665.1	1564	739	1,357,560	104,880.9
November	2807	663	2,739,777	94,164.1	2914	1033	2,687,316	146,625.1	3030	1431	2,630,701	203,239.8
December	3599	850	3,511,875	120,700.6	3736	1324	3,444,630	187,945.6	3884	1835	3,372,061	260,515.0
Totals	25,836.9	6,102.7	25,213,760	866,578.4	26,820.8	9,502.6	24,730,970	1,349,368.8	27,882.6	13,171.7	24,209,952	1,870,386.1

GHG Emission & Reductions - Annual Totals

	Baseline	**2% Hydrogen Blend**		**5% Hydrogen Blend**		**10% Hydrogen Blend**		**15% Hydrogen Blend**		**20% Hydrogen Blend**	
	Emissions from Fuel Use (Lifecycle)	Emissions from Fuel Use (Lifecycle)	Change in Emissions	Emissions from Fuel Use (Lifecycle)	Change in Emissions	Emissions from Fuel Use (Lifecycle)	Change in Emissions	Emissions from Fuel Use (Lifecycle)	Change in Emissions	Emissions from Fuel Use (Lifecycle)	Change in Emissions
	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e	tonnes CO2e
Grey H2	2,060.35	2,067	6	2,076	16	2,093	33	2,112	51	2,131	71
Keene grid H2	2,060.35	2,059	(1)	2,058	(3)	2,055	(5)	2,052	(8)	2,049	(11)
Green H2	2,060.35	2,047	(13)	2,027	(33)	1,992	(68)	1,954	(107)	1,913	(148)

RNG Blending Scenarios - Quantities & Emissions Offsets

RNG Blending Quantities

				20%				50%			
	Baseline - 0% RNG			20% RNG Blend by Volume				50% RNG Blend by Volume			
Month	NG MCF	MMBTU	NG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ	NG MCF	RNG MCF	NG MJ	RNG MJ
January	3597.3	3690.9	3,893,900	2877.84	719.46	3,118,096	779,524	1798.65	1798.65	1,948,810	1,948,810
February	3186.9	3271.7	3,451,644	2549.52	637.38	2,762,367	690,592	1593.45	1593.45	1,726,479	1,726,479
March	2699.9	2772.9	2,925,410	2159.92	539.98	2,340,241	585,060	1349.95	1349.95	1,462,651	1,462,651
April	1701.7	1745.8	1,841,819	1361.36	340.34	1,475,013	368,753	850.85	850.85	921,883	921,883
May	1385	1420.2	1,498,311	1108	277	1,200,501	300,125	692.5	692.5	750,313	750,313
June	1029.4	1059	1,117,245	823.52	205.88	892,272	223,068	514.7	514.7	557,670	557,670
July	1100.5	1129.4	1,191,517	880.4	220.1	953,900	238,475	550.25	550.25	596,188	596,188
August	949.6	971.2	1,024,616	759.68	189.92	823,102	205,775	474.8	474.8	514,439	514,439
September	1114.5	1144	1,206,920	891.6	222.9	966,035	241,509	557.25	557.25	603,772	603,772
October	1346.5	1386.2	1,462,441	1077.2	269.3	1,167,130	291,783	673.25	673.25	729,456	729,456
November	2598.8	2686.2	2,833,941	2079.04	519.76	2,252,609	563,152	1299.4	1299.4	1,407,880	1,407,880
December	3350.5	3443.2	3,632,576	2680.4	670.1	2,904,173	726,043	1675.25	1675.25	1,815,108	1,815,108
Totals	24,060.6	24,720.7	26,080,339	19,248	4,812	20,855,439	5,213,860	12,030	12,030	13,034,650	13,034,650

RNG Blending Emissions and Reductions

	Baseline	20% RNG Blend		50% RNG Blend	
	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e	Emissions from Fuel Use (Lifecycle) tonnes CO2e	Change in Emissions tonnes CO2e
RNG from manure	2,060.35	83	(1,977)	(2,881)	(4,941)
RNG from SSO AD	2,060.35	1,439	(621)	508	(1,552)
RNG from WWTP/LFG	2,060.35	1,830	(230)	1,486	(574)

Appendix B

Draft Liberty Utilities Regulatory Review Report

Regulatory Review

Keene, New Hampshire Project

Liberty Utilities

March 23, 2022

→ **The Power of Commitment**

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Printed date	2022-04-18 3:27:00 PM
Last saved date	April 18, 2022
File name	C:\Users\cbravo\Desktop\12569693-RPT-2-Liberty Utilities Regulatory Review - RD Edit - March 21 2022 (002).docx
Author	Fred Taylor
Project manager	Morgan MacGregor
Client name	Liberty Utilities
Project name	Liberty Keene Gas Supply Upgrade
Document title	Regulatory Review | Keene, New Hampshire Project
Revision version	Rev [00]
Project number	12569693-RPT-2

Document status

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S0	DRAFT	Fred Taylor	Rob Dysiewicz		Fred Taylor		

→ The Power of Commitment

Executive summary

This report is prepared for Liberty Utilities (Liberty) to provide key regulatory considerations for integrating hydrogen into Liberty's current or future assets and operations to support Liberty's Keene Gas Supply Upgrade Strategy and other U.S. projects, specific to hydrogen. These key considerations will need to be further tracked and evaluated by Liberty as policies and regulations develop further regarding the green and blue hydrogen economy. There are currently regulations that govern grey hydrogen production, storage, distribution and use but significant policies and regulatory changes are being developed to support green and blue hydrogen supply chains (e.g., blending with natural gas and carbon sequestration). It also is apparent that significant funding and incentives will continue to be put in place to support cleaner hydrogen use and this is important for industry until supply chain costs decrease to make acceptance more economically feasible. The faster international growth of cleaner hydrogen supply chains is also important to track to see how they have developed and the policies and regulatory changes that have been adopted to support this growth. There is a significant overlap with other considerations in the regulatory requirements for the design, permitting, installation and use of hydrogen in operations and as such and for completeness this report should be read in conjunction with the separate Fuel Source and System Review Report.

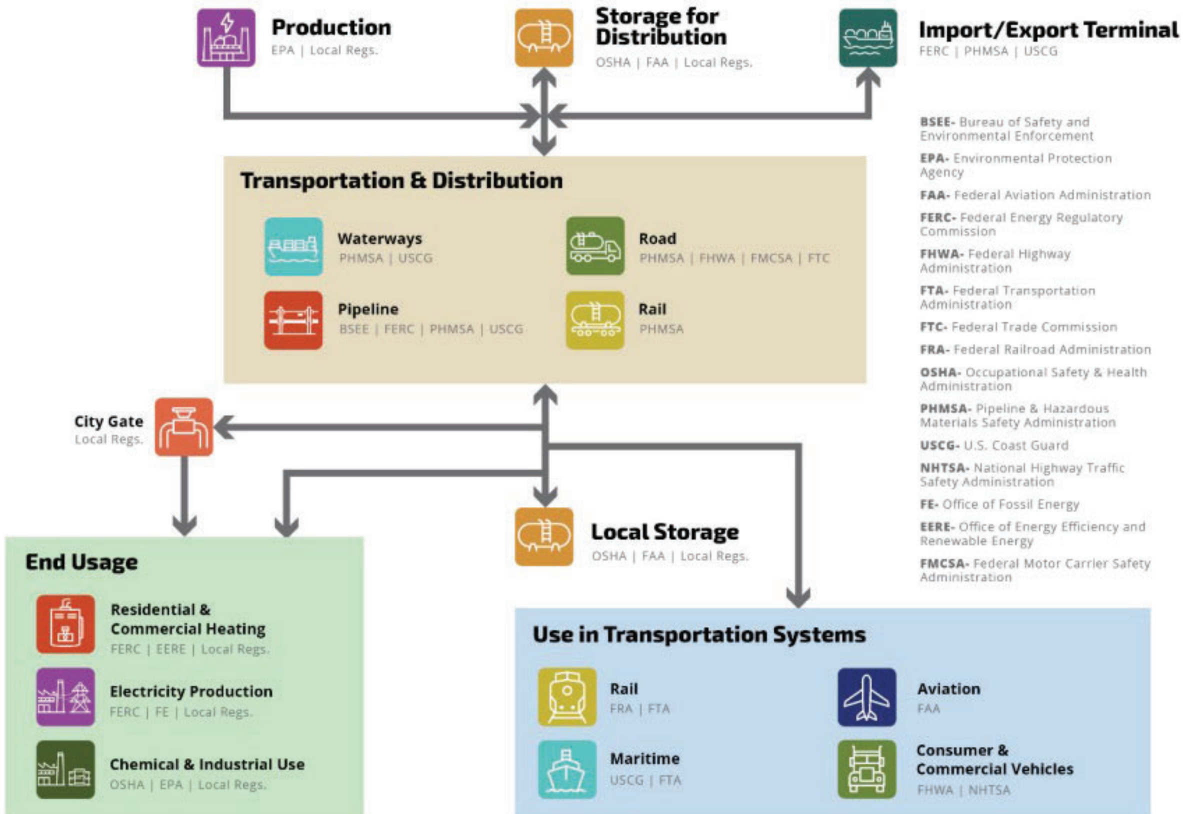
The confluence of several trends (e.g., environmental, social and governance (ESG), global decarbonization, and Federal clean energy/infrastructure initiatives) is supporting a cleaner hydrogen industry directed at decarbonization efforts. The acceptance and build-out of a hydrogen economy will require significant physical asset development but also substantial policy and regulatory changes. One of the largest global pure hydrogen infrastructure systems is in North America and several agencies have regulations addressing hydrogen which provides permitting and approvals for the design, construction and operation and maintenance of this infrastructure. There also are regulations which have permitted the widespread use of hydrogen in refineries, chemical manufacturing and other industrial operations for many decades. However, these regulations generally don't directly address the use of intentional hydrogen blends in natural gas infrastructure and carbon sequestration. Non-methane compounds are present in natural gas at low levels (e.g., 1 to 2 %) but are not specifically regulated other than indirectly by gas purity regulations and producers and distributors specifications. It also is important to note that historically hydrogen was a major component of town gas generated from coal (there were a substantial number of manufactured gas plants in the US northeast) that was widely used prior to the development of the natural gas industry. In some jurisdictions like Hawaii, 12 to 14% hydrogen has been present in the natural gas supply for over 30 years with no significant operational issues. Regulations are evolving for green hydrogen production from electrolysis, hydrogen fuelcells, and other industrial hydrogen applications, as well as more recent EPA regulations and procedures that provide for the permitting and approval of carbon sequestration by deep well injection to support carbon capture, utilization and storage (CCUS) projects or blue hydrogen production.

A hydrogen economy will require more comprehensive and deliberate regulation of hydrogen generation, storage, transportation and use as has been rapidly developing in other global regions (i.e., the United Kingdom, Europe and Australia). Of the agencies whose mandates include hydrogen, the most significant Federal regulatory actions are likely to come from FERC, DOE, EPA, OSHA and DOT/PHMSA. With respect to oil and gas infrastructure repurposed for hydrogen transmission, various State agencies also will play a role in regulating hydrogen in oil and gas infrastructure. Oil and gas entities and a number of national and state member associations lobby and influence policy and regulation on both Federal and State levels. There have been hydrogen associations and government agencies working to advance the field for a few decades. More recently the oil and gas and other industry associations and regulatory agencies have included hydrogen as a topic of interest to members and new organizations have formed such as local Hydrogen Councils to advance understanding and discussions around the use of hydrogen in oil and gas operations to reduce GHG emissions and provide cleaner energy to customers.

Section 1 provides the purpose of the report, the scope and limitations, and the assumptions that have been used in the development of the report.

Federal Regulatory Framework

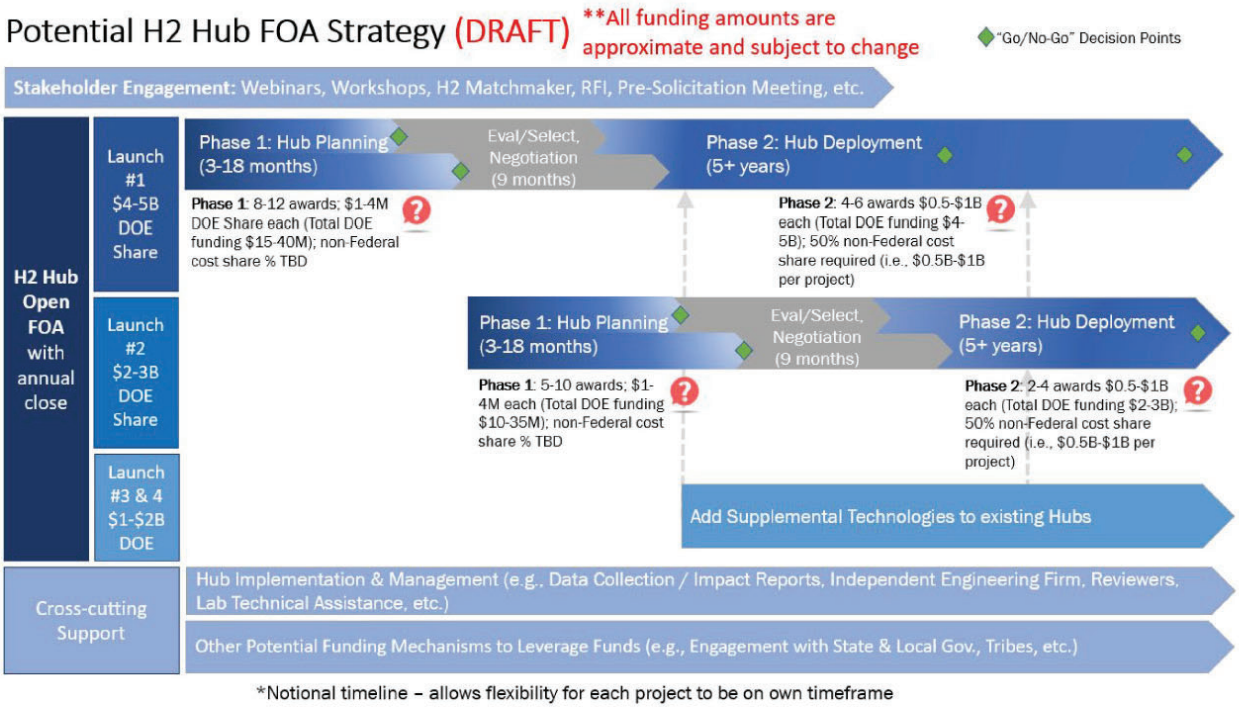
Section 2 details key Federal regulatory departments and agencies that are currently guiding policy and regulation development.



– Federal Energy Regulatory Commission (FERC) – As Liberty's gas supply system in Keene is islanded and not connected across state lines, FERC will not play a significant role for permitting and regulating any change of use with existing assets unless there is an addition of assets that would operate on an interstate basis. Current assets that are FERC regulated would require permit amendments to allow hydrogen use in those assets even if those assets to be converted to a hydrogen blend are only in one state.

– Department of Energy (DOE) – DOE has a long history of significant funding applied to hydrogen research and development and this is expected to increase at a more significant rate with substantially higher funding. DOE recently released a Hydrogen Program Plan outlining how the department plans to coordinate additional efforts to advance the affordable production, transport, storage, and use of hydrogen across different sectors of the economy. The Plan involves participation from the Offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy, Electricity, Science, and the Advanced Research Projects Agency–Energy. Significant DOE funding will continue to be available to support demonstration projects and Liberty should consider participating in DOE programs to help offset Hydrogen Strategy development costs.

  In February 2022, DOE launched a $8.5B initiative to support multi-year development of at least 4 large scale hydrogen Hubs across the U.S. A summary of the initiative is provided below. GHD has significant experience in Hub development in Australia and New Zealand and is participating in multiple potential hubs in the U.S. In March 2022, GHD also submitted a response to DOE's RFI to provide information based on our global experience on lessons learned and key considerations for Hub development. A copy of GHD's submittal is provided in Appendix A. GHD advises Liberty that the development of small and medium scale hubs also will occur and some ongoing review of activities would be prudent to identify jurisdictions that Liberty may want to have a role(s) in hub development.



– US Environmental Protection Agency (EPA) – EPA's most recent and relevant regulatory effort in the hydrogen space is the development of guidelines and application processes for deep well CO_2 injection for sequestrations projects (e.g., includes blue hydrogen). This program is a continuation of EPA's program for deep well injection permits and a new call of well (Class VI) has been developed specifically for sequestrationprojects. The technical process to apply for a permit is quite onerous as it must be demonstrated that the geological feature to be injected into is well understood, is amenable to long term, stable storage and sufficient measures can be put in place to provide adequate monitoring of long- term storage.

  EPA also regulates hazardous substances and in some cases (e.g., large volumes) hydrogen could be considered a hazardous substance. This determination is more of a safety issue though due to hydrogen's flammability and explosive properties which are somewhat increased over natural gas. The release of hydrogen to the environment is not as much of a concern as it vents and does not contribute to greenhousegases when combusted or released as pure hydrogen.

– Occupational Safety and Health Administration (OSHA) – OSHA requires owners or operators to develop a Process Safety Management (PSM) program (or modify the existing program to include the additional risk posed with the addition of hydrogen) for any interconnected process (i.e., in storage, process vessels, and piping) with a triggering threshold of 10,000 lbs of hydrogen under the control of a single entity.

– US Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) – PHMSA currently regulates approximately 1,600 miles of pure hydrogen pipelines and associated infrastructure operated by merchant hydrogen producers since this infrastructure began development in the mid-1900s. These regulations are primarily based on natural gas regulations, with the definition of gas being "flammable gas", which would include hydrogen. Since the primary focus of these regulations is natural gas, certain characteristics of hydrogen are not necessarily fully contemplated in some of the existing regulations' design requirements. PHMSA (and many other companies, research and other institutions) continues to conduct research regarding hydrogen's effects on steel pipelines and associated equipment and materials. There is a considerable body of technical information and experience regarding the use of hydrogen in pipelines and related infrastructure. This knowledge and experience is used by qualified professionals to design, construct, operate, and maintain pure hydrogen infrastructure, as well as infrastructure that is going tohave a change in use to hydrogen or blends of hydrogen in natural gas.

Currently the purity of natural gas is typically 70 to 90% in methane content. Other gases and non-fossil fuel contaminants (e.g., ethane, propane and carbon dioxide) are present due to the nature of natural gas production. Some natural gas also contains traces of hydrogen already and 1-2% of hydrogen present in natural gas would very generally be considered acceptable. Intentional blending at higher levels (e.g., 5 to 10% in a lower pressure distribution system) would not be considered an impurity and would require specific notification to PHMSA/State agencies and related approvals.

– On March 31, 2021, the Biden Administration unveiled the $2 trillion American Jobs Plan which requires congressional approval. The Plan includes a wide array of investment allocations for various infrastructure and industries, with the energy sector receiving about 25% of the total proposed funding spread out over grid modernization and clean energy incentives. Hydrogen is specifically called out within a $15 billion allocation to RD&D projects, with mention of 15 decarbonized hydrogen demonstration projects in distressed communities with a new production tax credit.

  Hydrogen projects and funding may also find relevance among $50 billion investment in the National Science Foundation (NSF), $35 billion investment in solutions needed to achieve technology breakthroughs that address the climate crisis, and $5 billion in funding for other climate-focused research. As of this report, the Plan has not been passed into law.

Section 3 considers the states in which Liberty is operating and highlights key trends on the local and regionalpolicies and regulations concerning hydrogen and other emerging fuels technologies. There are publicly available tools which can be used to track policy and regulation changes by State, and two of these tools are referenced. A number of electrolyzer and hydrogen blending demonstration projects are identified in various states and Liberty can learn from these projects regarding regulatory approaches and requirements. Details of these projects are provided in Appendix B.

Section 4 provides key insights into how regulations related to hydrogen have been developing internationally to provide some global perspective. Generally, initiatives and framing of regulation and policy is driven at the Federal level, with significant policy and regulation, codes and standards initiatives, capital investments and coordinated research, development & demonstration (RD&D) programs. Nations that have developed structured national hydrogen strategies with road maps include specific ramping up of production volumes, economic implications of transitioning away from traditional fuels, and considerations for the balancing of international trade supply and demand between now and beyond 2050. Countries with excess energy are making major plays into hydrogen export. These developments, while specific to each country, have been developed ahead of North American policies and regulatory changes and provide insights to how the process will develop and the key changes that are considered to more specifically adopt and account for hydrogen. While many international oil and gas codes and standards were developed based on American ones the faster growth of cleaner hydrogen use in other global regions has resulted in changes that can be learned from for American adoption.

Blending Injection Limits

Section 5 provides descriptions of hydrogen blending injection limits (volume %) in countries that have adopted or indicated adoption of blending is planned. This experience provides Liberty with a perspective on what blending limits have been approved in other gas networks.

Hydrogen Associations & Coalitions

Section 6 details key domestic and international associations pushing the development of the hydrogen economy. Generally, these associations include industry players that will have critical roles with existing assets that will be impacted by increased widespread hydrogen adoption. Associations collaboratively develop and advance member interests and help drive policy and regulation. Liberty could consider joining a number of organizations as a member, such as the Clean Hydrogen Future Coalition (CHFC), Zero Carbon Hydrogen Coalition and Pipeline Research Council International (PRCI), and support organizations such as the Gas Technology Institute (GTI).

Recommendations for Liberty

Throughout the regulatory review, a variety of initiatives and considerations are identified, which are summarized below. Liberty should consider pursuing some of these initiatives as part of their Hydrogen Strategy, including and beyond Keene. Liberty could position themselves to help guide policies, regulations, safety and technical aspects of hydrogen use in the industry, while remaining flexible to capture market growth and opportunistic investment opportunities.

1. NHPUC will largely govern approval of gas supply changes and upgrades.
2. Other select Federal, State, and local regulations, standards and by-laws will have applicability for the design, construction and safe operation of gas supply upgrades depending on the specific activities.
3. For hydrogen gas blending, Liberty can learn about specific regulatory requirements from other demonstration projects that are planned and/or in operation in various states such as NY, OH, NJ, AZ, NV, FL, in Canada and internationally. GHD is involved with a number of these projects and can provide more detailed information and/or support discussions with the utilities doing the projects.
4. GHD has significant activity in the RNG space in many jurisdictions and can provide more detailed information and/or support discussions with the utilities/parties doing the projects.
5. In February 2022, DOE launched a $8.5B initiative to support multi-year development of at least 4 large scale hydrogen Hubs across the U.S. The development of small and medium scale hubs also will occur and some ongoing review of activities would be prudent to identify jurisdictions that Liberty may want to have a role(s) in hub development.

More generally, GHD recommends that Liberty continue to consider pursuing/supporting the following activities:

1. Lobby for incentives (e.g., tax credits) for adoption of hydrogen in natural gas systems.
2. Promote clear definitions, classifications, and appropriate permitting and monitoring requirements for the intentional addition and use of hydrogen in natural gas networks, both high pressure transmission and low-pressure distribution networks.
3. Pursue DOE, other Federal and State funding for demonstration projects to offset initial costs for Liberty's HydrogenStrategy and gain experience with designing, constructing and operating and maintaining hydrogen, hydrogen/natural gas, and CCUS assets.
4. Continue considering joining additional associations and supporting groups that can advance Liberty's interests in hydrogen development.
5. Consider developing an internal cost of carbon to evaluate capital projects and strategic initiatives to incorporate a measure of economic and ESG impact consistent with the widespread external developmentand adoption of numerous carbon accounting, credit and other GHG type measures.
6. Lobby for clear definitions, industry standards, and classification of hydrogen 'colors', Carbon Intensities (CIs), Full Life Cycle Analyses (LCAs) and green certificates of origin etc.

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1. Introduction

1.1 Purpose of This Report

The report examines existing U.S. Federal and State-specific legislation (including regulations, policy, and reference standards) that pertain to the emergence of future fuels such as hydrogen, syngas, or biogas into existing natural gas infrastructure. The regulatory review includes standards across all aspects of the value chain (generation and manufacturing, storage, transmission, distribution, and use) relevant to introduction of fuels into existing gas infrastructure.

1.2 Scope and Limitations

The first stage of the regulatory review project comprised of document and desktop review of existing regulations, legislation, and policies covering all state and federal jurisdictions across gas network transmission supply chain, and relevant value chain components that would complement Liberty in their overall strategy of pursuing hydrogen market entry. The focus of this regulatory review is on capturing the breadth of regulation across sectors that influence existing gas network functioning including:

– Technical legislation
– Environmental and land use planning and development
– Economic legislation
– Other legislation that may be sensitive to the types of fuel used or contained within gas infrastructure

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GHD otherwise disclaims responsibility to any person other than Liberty arising in connection with this report. GHDalso excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report (refer to section 1.3 of this report). GHD disclaims liability arising from any of the assumptions being incorrect.

1.3 Assumptions

At the time of writing, hydrogen injection and blending into natural gas distribution and transmission networks is an emerging process for which the implications are not fully understood. Most countries do not yet have standards developed that govern the percent of hydrogen by volume that can be blended. Some jurisdictions, however, are ahead in this regard, with standards implemented to limit the hydrogen content for existing natural gas pipelines. With that in mind, this review will serve as a snapshot in time regarding regulation at the time of completion and will need to be complemented with the evolving regulatory advancements over time.

1.4 Foreword

Regulation and policy concerning hydrogen as an energy carrier is spread across a variety of industries, markets, and positions within value chains, with varying levels of respective detail and specificity. For potential market entrants, the ambiguity of prescriptive legislation and concrete frameworks do not allow for exploitation of new business models and emerging competitive landscapes. Further, Liberty's assets beyond Keene are located in a number of States and are thus subject to both State and Federal regulation which are not always congruent with one another. However, current regulation and policy frameworks of the emerging hydrogen economy provide a sound basis with technical limitations increasingly researched and refined. Several existing standards developed in the U.S. and international markets which allow for the safe use, distribution, and storage of pure hydrogen, with increasing comprehension of blended natural gas and hydrogen pipeline networks. These standards are primarily focused on the current hydrogen infrastructure, including building codes, fire codes, and items pertaining to technologies used to transport and store pure hydrogen.

Shipping hydrogen by dedicated pipeline is not new in the United States, but the existing hydrogen pipeline infrastructure (about 1,600 miles) is small compared to that of the nation's natural gas and oil pipeline systems (2 million miles of natural gas distribution mains and pipelines and 321,000 miles of gas transmission and gathering pipelines). The hydrogen pipeline network required to support a hydrogen-based U.S. energy strategy would need to be much larger and with much broader geographic reach than that in place today. Hydrogen also historically has been blended with natural gas in some U.S. natural gas pipelines, and currently is being shipped this way in significant volumes overseas, but there currently are barriers and limitations to the blending approach. Establishing a national network of dedicated hydrogen pipeline infrastructure, or reconfiguring existing natural gas systems to carry hydrogen, poses numerous challenges related to regulation.

Legislative frameworks have not always caught up with development ambitions of the developing hydrogen economy. As such, another key challenge that has emerged is the lack of a clear legal and regulatory framework for hydrogen as an energy carrier. Due to the different nature and use of hydrogen, existing gaseous energy carrier frameworks are not always appropriate and market players would benefit from the introduction of a clear regulatory framework to encourage the development of a hydrogen economy. Despite hydrogen's similarity to natural gas as an energy carrier, this emerging technology's unique characteristics need to be respected such that legal and regulatory frameworks, investment cases, financing structures, operational requirements, revenue stream arrangements, among other elements, are taken into consideration to formulate effective commercialization models.

Multiple agencies have authority that touch at least tangentially on hydrogen, but there is currently no comprehensive hydrogen regulatory regime for the United States. Agencies are often aware of their ability to regulate hydrogen, and recent developments - such as the Department of Energy's (DOE) newly revised Hydrogen Program Plan - indicate that they are starting to act. Currently, the main agencies with the ability to influence the development of hydrogen industry and infrastructure include: the DOE, the Federal Energy Regulatory Commission (FERC), the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Environmental Protection Agency (EPA). Hydrogen regulations are not a central part of these agencies' missions, but the agencies will continue to play an important role as hydrogen becomes more prevalent and technologies advance and change and are detailed below.

2. Federal Programs and Incentives

Despite the lack of a comprehensive regulatory scheme, the U.S. government has recognized hydrogen's potential as a fuel source. Thus far, the federal government's major initiative regarding hydrogen as a fuel source has been to incentivize research in the area, including by funds made available through programs in multiple agencies. One of the most important programs is DOE's $100 million pledge, which reflects DOE's intention to invest up to this amount in two new DOE National Laboratory-led consortia to advance hydrogen and fuel cells technology research, development, and demonstration (RD&D) over the next five years. One consortium will develop affordable, commercial scale electrolyzers, which use electricity to divide water into hydrogen and oxygen, and the other consortium will assist in accelerating the development of fuel cells for vehicles, specifically for long-haul trucks. DOE recently released its updated Hydrogen Program Plan, which underscores DOE's department-wide commitment to facilitating the growth of hydrogen as a source of energy and provides a "strategic framework for the Department's hydrogen RD&D activities."

As the hydrogen economy continues to develop and include more players across the energy sector, the U.S. federal government will need to incorporate hydrogen into its broader regulatory scheme for hydrogen to truly become part of the energy infrastructure in the U.S. Several federal agencies already address hydrogen in their regulations; however, they only address it incidentally, as one of the many substances regulated under their regimes. For example, most environmental regulations on hydrogen deal with hydrogen's properties, such as its flammability/explosivity (which often requires it to be regulated as a hazardous substance) as detailed in the Technical and Safety Review. These regulations are scattered throughout the Code of Federal Regulations (C.F.R.) and are not organized to address hydrogen in a cohesive manner. Instead, disparate regulations touch upon a portion of the hydrogen industry or issues related to the characteristics of hydrogen itself, but do not focus on regulation of the hydrogen industry as a whole and specific to how midstream gas players are to be regulated as they enter the hydrogen market.

2.1 Federal Energy Regulatory Commission (FERC)

Key highlights:

– FERC regulations involving hydrogen are currently tied to interstate natural gas pipeline measures and lack uniformity with state-based regulatory advancement.

– FERC issued a Notice of Proposed Rulemaking (October 2020) to amend PURPA definition of "useful thermal energy output" to include thermal energy produced via Solid Oxide Fuel Cells that then uses the thermal energy to reform methane and produce hydrogen for electricity production.

FERC could seek to establish regulatory provisions for the interstate transportation of hydrogen. Pursuant to the Natural Gas Act (NGA), FERC regulates the siting, construction, and operation of interstate natural gas pipelines and storage, and the rates and terms of service offered by these pipelines.[1] While FERC has not utilized this authority to regulate pipelines exclusively transporting hydrogen, and may not have jurisdiction to do so under the NGA or other existing statutes, it is possible that FERC could regulate the transportation of hydrogen if it is transported in a blended stream with natural gas. While gaseous hydrogen generally is currently transported through designated hydrogen- specific pipelines,[2] it also can be found alongside natural gas in natural gas transmission pipelines. Several groups have posited that one way to transport hydrogen and make the end-use of hydrogen cheaper could be to integrate thetransportation of gaseous hydrogen into existing natural gas pipelines in greater quantities, blending hydrogen with thenatural gas stream.[3] The transportation and construction of natural gas pipelines is squarely within FERC's authority under the NGA, and accordingly, transportation of hydrogen blended in these pipelines could subject hydrogen transportation to regulation by FERC.

FERC's regulations of natural gas pipelines extend beyond the regulation of construction of pipeline facilities and also apply to the terms and conditions of transportation services. FERC regulations require natural gas companies to file a tariff that sets forth the terms and conditions of service on the natural gas company's pipeline, including terms and conditions related to the quality of the gas being transported. Including greater quantities of hydrogen in the natural gas stream on FERC-regulated natural gas pipelines could require modification of existing gas quality provisions in a pipeline's tariff, and likely would require coordination with shippers and other pipelines in order to accommodate additional hydrogen content. This coordination and the balance of pipeline and shipper interests is familiar territory for FERC and its regulated natural gas companies, and the existing regulatory regime may have benefits if applied to the transportation of hydrogen.

Construction and operation of 100% dedicated hydrogen pipelines within existing FERC-regulated gas transmission easements may also trigger an additional FERC permit depending on the easement conditions with respect to the

[1] FERD. 2018. An Overview of the FERC and Federal Regulation of Public Utilities.
[2] https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed March 2021.
[3] https://www.energy.gov/eere/fuelcells/hydrogen-pipelines Access March 2021.

original FERC approval. It is typical that the pipeline system and lands (including easements) is part of the approval and placing another pipeline in the easement is generally subject to the original approval conditions. Additionally, it is common in many jurisdictions that there is a constraint on what other pipelines can be placed in an easement for a gas pipeline system. A hydrogen pipeline in a natural gas pipeline easement may also require a renegotiation of the easement with all the relevant landowners, as it may be outside the easement conditions.

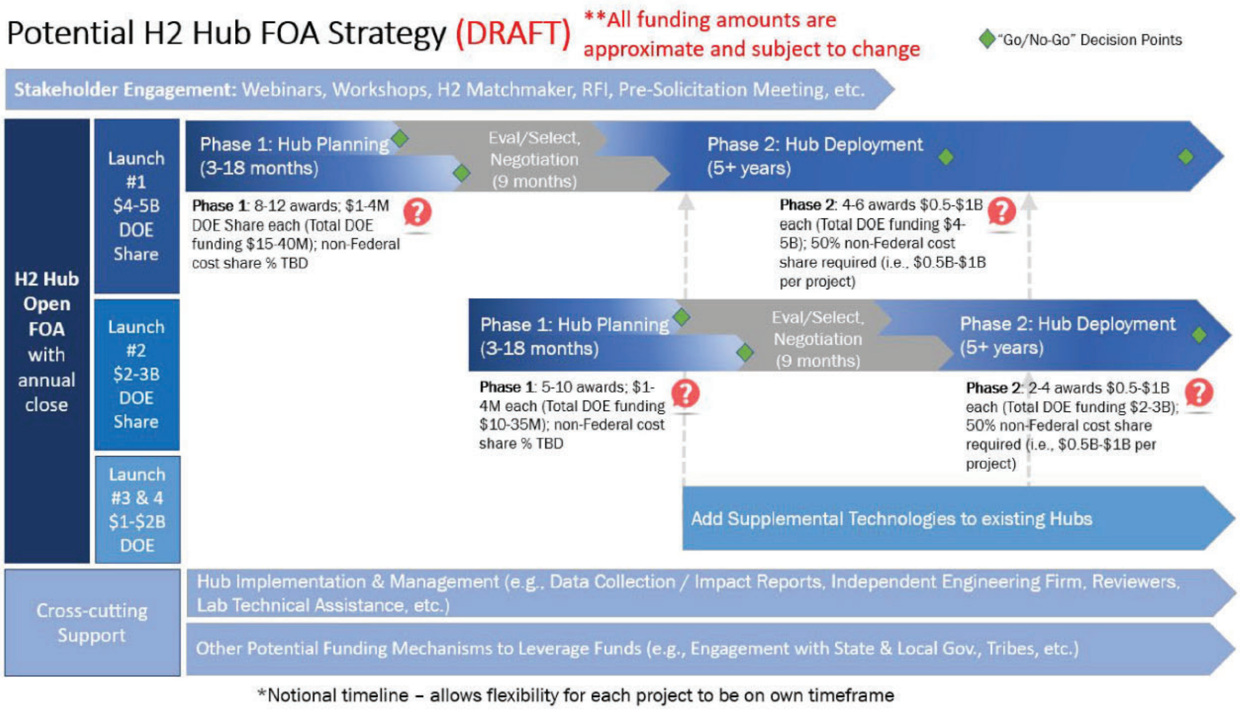
FERC may encourage hydrogen production by classifying it as a "useful thermal energy output" that would entitle some cogeneration facilities to beneficial regulatory treatment.[4] FERC is also responsible for implementing regulations under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA provides a number of benefits to certain qualifying electricity generating facilities, including the right to sell energy or capacity to certain utilities, the right to purchase certain services from utilities, and relief from certain regulatory burdens.[5] FERC has announced that it is considering whether to expand its PURPA regulations to allow a specific hydrogen-based technology, a solid oxide fuel cell system, "that then uses the thermal energy it produces to reform methane and produce hydrogen for electricity generation", to qualify for this beneficial regulatory treatment. FERC issued the Notice of Proposed Rulemaking on this issue on October 15, 2020, and comments were due to FERC on November 25, 2020. If the proposed rule is issued after FERC's review, the resulting Final Rule could open another avenue of support for hydrogen production through better rate and regulatory treatment.

2.2 Department of Energy (DOE)

<u>Key highlights:</u>

– DOE Hydrogen Program Plan released in 2020, outlines efforts to advance the affordable production,transport, storage, and use of hydrogen across different sectors of the economy.
– Since 2019, H2@Scale initiative has overseen funding initiatives worth over $100M for hydrogen-focused projects aimed to advance research, development, and demonstration projects across multiple energy sectors.The Consolidated Appropriations Act for Fiscal Year (FY) 2021 provided $150 million to HFTO which governs H2@Scale.
– In February 2022, DOE launched a $8.5B initiative to support multi-year development of at least 4 large scale hydrogen Hubs across the U.S. A summary of the initiative is provided below. GHD has significant experience in Hub development in Australia and New Zealand and is participating in multiple potential hubs in the U.S. In March 2022, GHD also submitted a response to DOE’s RFI to provide information on lessons learned and key considerations for Hub development. A copy of GHD’s submittal is provided in Appendix A. GHD advises Liberty that the development of small and medium scale hubs also will occur and some ongoing review of activities would be prudent to identify jurisdictions that Liberty may want to have a role(s) in hub development.

[4] A cogeneration facility is a facility that produces a useful thermal energy output and electricity. Fuel Cell Thermal Energy Output, 173 FERC 61,050 at PP 8-9 (2020) ("Notice of Proposed Rulemaking").
[5] 16 U.S.C. § 824a–3 (2018); PURPA Qualifying Facilities, Fed. Energy Reg. Comm'n, https://www.ferc.gov/qf.



The DOE will continue to play a significant role in the development and testing of new hydrogen technologies. The DOE recently issued its Hydrogen Program Plan which describes DOE's high-level, cross-agency strategy for fostering the hydrogen economy by funding research and development. The Hydrogen Program Plan analyzes potential uses of funding for hydrogen development, primarily focusing on hydrogen's role in power generation and transportation, sectors in which hydrogen could become more prevalent if technological advances made it financially accessible and environmentally sustainable. The Hydrogen Program Plan likewise discusses potential advances to bemade in chemical and industrial processes, where hydrogen traditionally has been used. DOE also envisions itself playing a role in incentivizing the use of hydrogen in fuel cells, especially for long-haul trucks.

In addition, DOE's Hydrogen Program Plan examines the production, storage, and transportation of hydrogen, specifically methods to make carbon-neutral or carbon-negative hydrogen an affordable reality. This means evaluating all possible methods of producing hydrogen – fossil fuels, renewable energy, nuclear energy, and methanol. DOE seeks to enable the hydrogen transition, primarily through research and development and funding, and appears to be preparing for a role as the thought leader on the integration of hydrogen into the broader energy scheme. While the Hydrogen Program Plan does not specifically seek to regulate hydrogen itself, the Plan lays out a comprehensive strategy to foster the development of hydrogen as a substantial component of the energy and transportation sectors.

2.2.1 Hydrogen Program Plan

The DOE Hydrogen Program is a coordinated Departmental effort to advance the affordable production, transport, storage, and use of hydrogen across different sectors of the economy. The Plan involves participation from the Offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy, Electricity, Science, and the Advanced Research Projects Agency–Energy.

	Transportation Applications	Chemicals and Industrial Applications	Stationary and Power Generation Applications	Integrated/Hybrid Energy Systems
Existing Growing Demands	• Material-Handling Equipment • Buses • Light-Duty Vehicles	• Oil Refining • Ammonia • Methanol	• Distrubuted Generation: Primary and Backup Power	• Renewable Grid Integration (with storage and other ancillary services)
Emerging Future Demands	• Medium-and Heavy-Duty Vehicles • Rail • Maritime • Aviation • Contruction Equipment	• Steel and Cement Manufacturing • Industrial Heat • Bio/Synthetic Fuels	• Reversible Fuel Cells • Hydrogen Combustion • Long-Duration Energy Storage	• Nuclear/Hydrogen Hybrids • Gas/Coal/Hydrogen Hybrids with CCUS • Hydrogen Blending

Figure 1 DOE Outline of Existing and Emerging Demands for Hydrogen
Source: DOE Hydrogen Program Plan, 2020

The DOE Hydrogen Program Plan provides a strategic view of how the Department conducts and coordinates hydrogen research, development, and demonstration (RD&D) activities under the DOE Hydrogen Program. With participation from the Offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy, Electricity, Science, and ARPA-E, the DOE Hydrogen Program is a coordinated Departmental effort to advance the affordable production, transport, storage, and use of carbon-neutral hydrogen across different sectors of the economy. This version of the Plan updates and expands upon previous versions, including the Hydrogen Posture Plan and the DOE Hydrogen and Fuel Cells Program Plan, and provides a coordinated high-level summary of hydrogen-related activities across DOE. Figure 2 provides an overview of DOE's organizational structure with respect to the Hydrogen Program Plan.

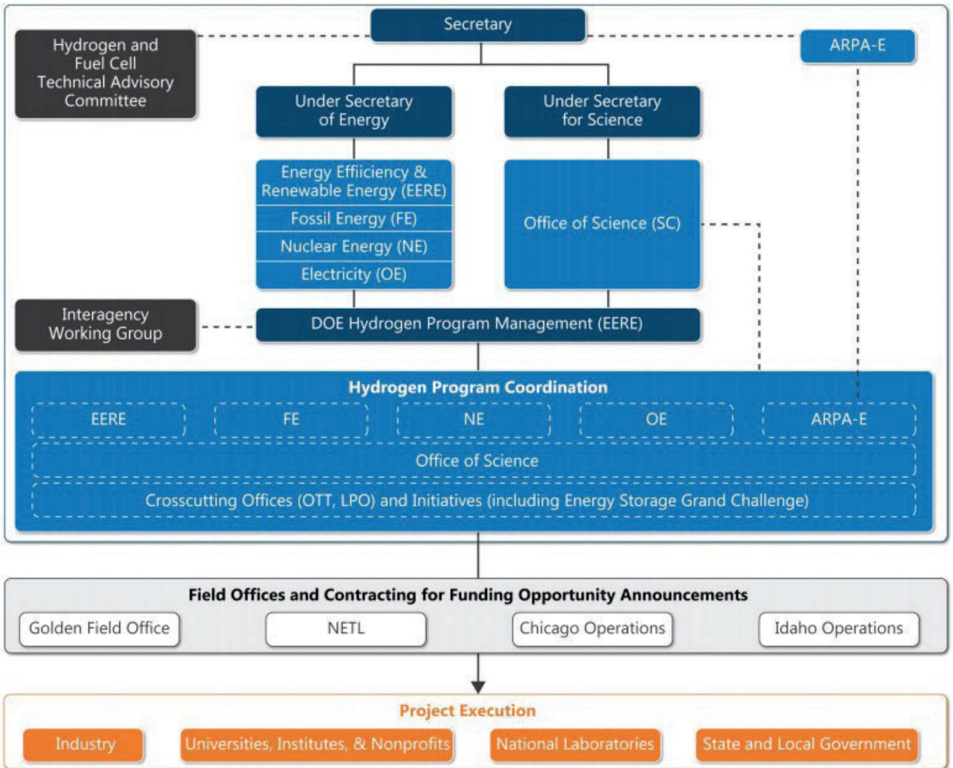


Figure 2 ***DOE Hydrogen Program Organization Structure***
Source: DOE Hydrogen Program Plan, 2020

2.2.2 Office of Energy Efficiency and Renewable Energy

The Office of Energy Efficiency and Renewable Energy (EERE) leads a comprehensive strategy focusing on RD&D and innovations across a broad portfolio of renewable energy technologies (solar, wind, biomass, geothermal, water power, and renewable hydrogen), energy efficiency in buildings and the industrial sector, transportation technologies across applications (vehicles, trucks, marine, rail, air), advanced manufacturing, and crosscutting activities (the Federal Energy Management, Weatherization, and Intergovernmental Programs).

2.2.3 Hydrogen and Fuel Cell Technologies Office

The Hydrogen and Fuel Cell Technologies Office (HFTO), leading DOE's Hydrogen Program including H2@Scale, supports RD&D and innovation to advance diverse technologies and infrastructure for hydrogen production, delivery, storage, and utilization. HFTO conducts RD&D at the materials-, component- and system-levels, to address the cost, performance, durability, and safety requirements for widespread adoption of hydrogen across the transportation, industrial, and stationary power sectors. RD&D focus areas include: electrolyzers and other advanced water-splitting approaches; advanced liquefaction and carriers for hydrogen delivery; advanced high-pressure tanks, liquid hydrogen storage, and material-based storage systems; and low- and medium-temperature fuel cells. HFTO coordinates with FE on various topics including reversible solid oxide fuel cells; with NE and OE, particularly on integrating renewables into the grid using hydrogen as an energy storage medium; and with SC and ARPA-E on basic science and next generation technologies.

Through this CRADA call, DOE's Hydrogen and Fuel Cell Technologies Office seeks to accelerate development of hydrogen fueling technologies for medium- and heavy-duty fuel cell vehicles, address priority R&D barriers to enabling hydrogen blending in natural gas pipelines at scale, and increase industrial and stakeholder engagement in H2@Scale through investment and active participation in the associated projects.

H2@Scale is a DOE initiative that supports innovations to produce, store, transport, and utilize hydrogen across multiple sectors. The intent of H2@Scale is for hydrogen to enable—rather than compete with—energy pathways across applications and sectors. Up to $24 million in DOE funding is available for collaborative projects at national laboratories in two priority areas of R&D:

– Hydrogen fueling technologies for medium- and heavy-duty fuel cell vehicles

  Areas of interest include, but are not limited to, compressors, dispensers, cryogenic pumps, analysis to inform fueling station design, and heavy-duty fueling methods that can inform standards development organizations leading fueling protocol development.

– Technical barriers to hydrogen blending in natural gas pipelines

  Specific R&D priorities include materials compatibility, pipeline compressors, hydrogen combustion in end uses, technologies for separating hydrogen from blends downstream of injection, compatibility of blends with underground reservoirs, and techno-economic and life cycle analysis.

Selected projects include one or more national laboratories and also include partners from one or more of the following: industry, universities, non-profits, institutes, codes and standards organizations, associations, or other relevant stakeholders. Support from the Hydrogen and Fuel Cell Technologies Office will fund the national laboratory services, staff time, and facilities necessary to support each selected project.

2.2.4 Office of Fossil Energy

The Office of Fossil Energy (FE) seeks to advance transformative science and innovative technologies that enable the reliable, efficient, affordable, and environmentally sound use of fossil fuels. The office conducts diverse RD&D efforts, including advanced power generation; power plant efficiency; water management; carbon capture, utilization, and storage (CCUS) technologies; executing natural gas regulatory responsibilities; and technological solutions for the prudent and sustainable development of unconventional oil and gas domestic resources. Two major FE programs are currently conducting fossil energy based hydrogen RD&D:

– The Office of Clean Coal and Carbon Management (CC&CM) is focused on advancing technologies for producing hydrogen from coal with CCUS, including through modular systems and co-gasification with biomass and waste plastics. Key priorities are hydrogen-combustion turbines and reversible solid-oxide fuel cell systems for large scale power generation as well as integration with gasification islands for large chemicalco-production (e.g., ammonia and polygeneration). Reversible solid oxide fuel cell R&D is conducted in coordination with EERE's HFTO to ensure there is no duplication of efforts. FE will also coordinate with EERE,NE, and other offices on hybrid energy systems where reversible SOFCs can be integrated. RD&D emphasis includes combustion and fuel science, catalysis, gasification, separations, as well as CCUS to enable the utilization of carbon-neutral (or even carbon-negative when co-firing biomass) hydrogen at scale. In addition, the office will evaluate the use of hydrogen in energy storage systems and technologies for storing large volumes (>100 tons) on site. Such volumes could be used for emergency supply (when there are fuel supply disruptions at gas turbine facilities such as seen during extreme weather events or other emergencies). Finally, carbon dioxide-utilization programs will require hydrogen for the manufacture of polymers, chemicals, and other products that will support both manufacturing and reduction of carbon dioxide emissions.

– The Office of Oil and Natural Gas (ONG) works to increase the energy and economic security of oil and natural gas supplies and typically focuses on early-stage research in natural gas infrastructure and gas hydrates. ONG leverages insight and expertise in oil and natural gas production, transport, storage, and distribution to support RD&D to enable the use of natural gas supply and storage infrastructure and the large-scale delivery and storage (e.g., geological storage) of hydrogen. Focus areas include RD&D to enable the transmission and storage of hydrogen and hydrogen blends in the existing national network of natural gas pipelines and underground reservoirs. Other RD&D areas include: hydrogen-based approaches for mitigating mid-stream emissions from natural gas infrastructure; technologies to convert flared or vented gas to hydrogen products; and technologies to convert natural gas to solid carbon products, hydrogen, and othervalue-added products.

– FE also leads DOE's CCUS efforts and collaborates with EERE on opportunities to co-locate hydrogen production with CCUS sites and large-scale hydrogen storage sites to enable the use of hydrogen and carbondioxide to produce synthetic chemicals and fuels.

2.2.5 DOE Office of Nuclear Energy

The Office of Nuclear Energy (NE) works to advance nuclear power to meet the nation's energy supply, environmental, and national security needs. RD&D objectives include enhancing the long-term viability and competitiveness of the existing U.S. reactor fleet and developing advanced nuclear reactor concepts. As part of these efforts, NE is working with partners in EERE and industry to conduct RD&D to enable commercial-scale hydrogen production using heat and electricity from nuclear energy systems. In addition to emissions-free electricity, nuclear reactors produce large amounts of heat, which can be used to improve the economics of hydrogen production. NE's efforts related to hydrogen production include:

– Demonstration of both high-temperature and low-temperature electrolysis systems at operating light water reactors that can provide the low-cost heat necessary for these processes to produce hydrogen economically.NE, in coordination with industry, utilities, and vendors, is also developing the necessary control systems to readily apportion energy and electricity based on market demands.
– Modeling, simulation, and experimentation to develop and advance concepts and technologies needed to integrate hydrogen production methods with existing and future reactors in ways that optimize the system-level economic, environmental, and safety performance as they operate in concert with other generation sources and end-use technologies.
– Development of advanced reactors that will operate at very high temperatures, making them well suited for promising new thermally driven hydrogen production processes. These advanced reactors are now being developed by NE through directed laboratory R&D, university programs, and partnerships with domestic nuclear industry vendors.
– NE and EERE have collaboratively initiated hydrogen production pilot projects to demonstrate the initialfeasibility of such systems at currently operating U.S. nuclear power plants.

2.2.6 Advanced Research Projects Agency – Energy

The Advanced Research Projects Agency-Energy (ARPA-E) catalyzes transformational energy technologies to enhance the economic and energy security of the United States. ARPA-E funds high-potential, high-impact projects that are too early for private sector investment but could disruptively advance the ways energy is generated, stored, distributed, and used. Some programs at ARPA-E have sought to develop technologies involving renewable energy and natural gas, with applications in the transportation, commercial, and industrial power sectors; in these areas, there are a number of efforts related to hydrogen. Focused R&D programs relevant to hydrogen or related technologies have included:

– Range Extenders for Electric Aviation with Low Carbon and High Efficiency (REEACH)
– Duration Addition to electricitY Storage (DAYS)
– Methane Pyrolysis Cohort
– Innovative Natural-Gas Technologies for Efficiency Gain in Reliable and Affordable Thermochemical Electricity-Generation (INTEGRATE)
– Integration and Optimization of Novel Ion-Conducting Solids (IONICS)
– Renewable Energy to Fuels through Utilization of Energy-dense Liquids (REFUEL)
– Reliable Electricity Based on ELectrochemical Systems (REBELS)

2.2.7 Unsolicited Proposals

An unsolicited proposal is an application for support of an idea, method, or approach, which is submitted by an individual, business, or organization based solely on the proposer's initiative rather than in response to a DOE solicitation. Funding of unsolicited proposals is considered a non-competitive action.

DOE's central point of receipt for all Unsolicited Proposals is the National Energy Technology Laboratory (NETL) as outlined in the link below which includes all DOE Program Research Areas. DOE encourages organizations and individuals to submit self-generated, unsolicited proposals that are relevant to DOE's research and development mission.

An unsolicited proposal is an application for support of an idea, method, or approach, which is submitted by an individual, business, or organization based solely on the proposer's initiative rather than in response to a DOE solicitation. Funding of unsolicited proposals is considered a non-competitive action.

The proposal document should persuade the staff of DOE and other qualified members of the scientific and engineering community who review the proposed work, that the project represents a worthwhile approach to the investigation of an important, timely problem. Each proposal should be self-contained and written with clarity and thoroughness.

The proposal must present:

– Objectives that show the pertinence of the proposed work to DOE
– Rationale of the approach
– Methods to be pursued
– Qualifications of the investigators and the institution (if applicable)
– Level of funding required to attain the objectives.

A number of regulations relate to criteria governing acceptance and funding of an unsolicited proposal:

– Title 48 Code of Federal Regulation (CFR), Chapter 1, The Federal Acquisition Regulation (FAR) Subpart 15.6 Unsolicited Proposals
– Title 48 CFR, Chapter 9, the Department of Energy Acquisition Regulation (DEAR) Subpart 915.6 Unsolicited Proposals; and 2 CFR, Part 200

DOE considers proposals in all areas of energy and energy-related research and development with emphasis on long-term, high-risk, high-payoff technologies. DOE may accept an unsolicited proposal if it:

– Demonstrates a unique and innovative concept or a unique capability of the submitter
– Offers a concept or service not otherwise available to the Federal government
– Does not resemble the substance of a recent, current or pending competitive solicitation

2.3 Environmental Protection Agency (EPA)

Key highlights:

– EPA’s current regulations suggests that they may be ill-fitting to a future where hydrogen has moved froma peripheral to a core focus for energy companies, but the EPA may develop new regulatory standards for hydrogen production that are distinct from fossil fuel processing.

The EPA regulates substances that have an impact on human health and the environment.[6] This mandate includes a broad array of substances, including hydrogen. The EPA's regulations on hydrogen are a prime example of the haphazard way in which hydrogen has been regulated by the U.S. federal government to date. Primary regulation of

6 https://www.epa.gov/aboutepa Accessed March 2021.

hydrogen by EPA is found under the Mandatory Greenhouse Gas Reporting Program (GHG Reporting), Effluent Standards under the Clean Water Act, and Chemical Accident Prevention program. In each instance, hydrogen is listed not due to any systematic consideration by EPA of regulations that may be needed for hydrogen under the agency's mandate, but instead because of hydrogen's relationship to that program.

Both the GHG Reporting and Effluent Standards regulate production of hydrogen as an offshoot of regulations on fossil fuel processing. The broader program for GHG Reporting, found in 40 C.F.R. Part 98, requires reporting of greenhouse gas data from large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the U.S.[7] 40 C.F.R. § 98.160 specifically imposes these reporting requirements onto hydrogen production from process units that produce hydrogen by transforming feedstocks (e.g., the methane steam reformation process used to produce grey hydrogen).[8] Any such hydrogen production source that emits 25,000 metric tons of CO_2 must comply with GHG reporting, as specified in 40 CFR § 98.160 et seq., which also includes monitoring requirements as well as quality assurance and quality control procedures. The Effluent Standards also derive from the regulation of hydrogen production from fossil fuel sources. Not only do the Effluent Standards apply to discharges of materials to water that result from the production of hydrogen as a refinery by-product, but the standards themselves ultimately refer back to those regulations in the petroleum refining part of the chapter.

Similarly, the EPA's Chemical Action Prevention scheme only regulates hydrogen tangentially. The regulations are found in 40 C.F.R. Part 68 and were created to implement part of the Clean Air Act. This scheme is not specifically focused on hydrogen but establishes requirements for chemical risk management applicable to facilities storing certain listed substances in quantities above a certain threshold.[9] These regulations require a risk management program complying with certain requirements (and including provisions for accident prevention and response) for facilities storing hydrogen in a quantity over a threshold amount of 10,000 pounds.[10]

While these regulations all address hydrogen, they suggest that hydrogen was not the focal point of the regulatory process establishing these regulations. If hydrogen (particularly green hydrogen) grows as a fuel source and becomes material to economic channels, then EPA will likely need to revisit its regulatory approach.

EPA may develop new regulatory standards for hydrogen production that are distinct from fossil fuel processing. EPA's regulatory mandate is wide, and there are multiple potential touchpoints as a hydrogen economy is developed. Many of these will depend on trends in the industry that will require some trial-and-error to establish, such as preferred distribution channels. EPA has not yet provided significant guidance on how it sees its role in a hydrogen economy; however, a survey of EPA's current regulations suggests that they may be ill-fitting to a future where hydrogen has moved from a peripheral to a core focus for energy companies. EPA may, therefore, decide it needs to expand its regulations within the hydrogen economy.

For example, effluent discharges from grey hydrogen production are currently only related to by-products of the petroleum refining process; however, if already processed fossil fuels are being directed specifically for hydrogen production, then it is less clear that EPA's current regulations would capture those discharges. Similarly, the EPA's GHG Reporting requirements for hydrogen production only apply to hydrogen produced from feedstocks, not electrolysis. If fossil fuels, or even renewables, are used for the electrolysis, then any environmental characteristics of that energy currently are not captured in the GHG Reporting requirements related to hydrogen production. While the EPA may not need to change its mechanism or standard of review under any of these statutory schemes in order to accommodate hydrogen, the EPA may need to expand its review of hydrogen with respect to impacts on human health and the environment, which may require the creation of more detailed and comprehensive hydrogen regulations. While many of these regulations would likely be created in dialogue with the development of the hydrogen industry, they provide several avenues for EPA to revise or expand upon current regulations for the new industry.

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7 https://www.epa.gov/ghgreporting Accessed March 2021.
8 40 C.F.R. § 98.160 (2020).
9 40 C.F.R. § 68.12(a).
10 40 C.F.R. § 68.130, Table A.

CO_2 Sequestration

EPA's most recent and relevant regulatory effort in the hydrogen space is the development of guidelines and application processes for deep well CO_2 injection for sequestrations projects (e.g., includes blue hydrogen). This program is a continuation of EPA's program for deep well injection permits and a new call of well (Class VI) has been developed specifically for sequestration projects. EPA has received applications from some proponents already. The technical process to apply for a permit is quite onerous as it must be demonstrated that the geological feature to be injected into is well understood, is amenable to long term, stable storage and sufficient measures can be put in placeto provide adequate monitoring of long- term storage.

Risk Management Plan (RMP)

USEPA requires owners or operators to develop a Risk Management Plan (RMP) for any interconnected process (i.e.,in storage, process vessels, and piping) with a triggering threshold of 10,000 lbs of hydrogen under the control of a single entity. RMPs are intended to enhance safety and emergency planning to protect the off-site public and potentialreceptors. See Technical and Safety Review for more details.

Low Carbon Fuel Standards Renewable Identification Numbers

One way to prove hydrogen carbon intensity is via a Guarantee of Origin system, similar to California's Low Carbon Fuel Standard program and how the EU tracks the source of electricity (see CertifHy program). This credit-based chain of custody would aim to provide transparent and credible information regarding trust and definitions of renewably sources carbon to those customers willing / required to pay more for low carbon fuels.

Decarbonization factor / Sustainability of hydrogen highly depends on the energy source it is obtained from. 95%+ hydrogen produced today is sources from fossil fuels, high intensity carbon sources such as gas, coal, and through processes such as steam methane reforming (SMR). Variable renewable energy systems such as wind power solar photovoltaics that can power electrolyzers that alone produce hydrogen and oxygen gases offer alternate means of hydrogen production. Ambiguity of sustainability and carbon content of hydrogen arises with energy source to produce hydrogen through gas grid with increasing blends of hydrogen injection as well as electricity with increasing penetrations of VRES systems specific to time of use:

– EPA currently oversees the RIN Market for biofuels and a similar system could be instated for hydrogen.
– Potential for parallel system of certifications for colored hydrogen, Guarantee of Origin (GOs).
– Chain of custody systems would trace hydrogen production and consider system boundaries where hydrogenis injected, with promotion of trade of GOs where systems are interlinked.

2.4 US Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)

Key highlights:

– Of the 1,600 total miles of dedicated hydrogen pipelines in the U.S., PHMSA currently regulates approximately 700 miles under their pipeline safety jurisdiction. These regulations are primarily based on existing natural gas regulations, but the definition of gas under this provision includes “flammable gas”, which brings hydrogen into play.
– Due to PHMSA’s goals and the intent of its regulations, PHMSA currently is conducting research regarding hydrogen’s effects on steel pipelines.

PHMSA's mission is to protect human health and the environment by promoting the safe transportation of energy and other hazardous materials by creating national policy, setting and enforcing industry standards, and conducting research.[11] PHMSA currently regulates approximately 700 of the 1,600 (44%) total U.S. miles of hydrogen pipelines

[11] https://www.phmsa.dot.gov/about-phmsa/phmsas-mission Accessed April 2021.

via 49 C.F.R. Part 192.[12] These regulations are primarily focused on natural gas, but the definition of gas under this provision includes "flammable gas", which brings hydrogen into play.[13] However, due to the fact that the primary focus of these regulations is natural gas, certain characteristics of hydrogen are not necessarily fully contemplated in some of the existing regulations' design requirements. Nonetheless, in light of PHMSA's goals and the intent of its regulations, PHMSA currently is conducting research regarding hydrogen's effects on steel pipelines.[14]

PHMSA does administer some regulations that more specifically focus on hydrogen. For example, 40 C.F.R. §§ 173.230, 173.301, and 173.302 regulate hydrogen in transportation. In addition, 40 C.F.R. § 173.230 imposes certain requirements for the design, filling, and marking of hydrogen fuel cells, and 40 C.F.R. §§ 173.301 and 173.302 impose general requirements on the transportation of compressed gases, including compressed hydrogen. These regulations provide some guidance on the use of hydrogen but fall short of creating a comprehensive regulatory regime that will guide the development of the entire industry.

PHMSA may introduce hydrogen-specific storage and transportation requirements. PHMSA has stated that it has a "need to focus on supporting activities to ensure that hydrogen is transported safely" and identified that it needs a "clear technical focus regarding safety implications of infrastructure materials, designs and systems; preparations to address any regulatory barriers towards a hydrogen economy; research in support of additional industry consensus standards; [and] efforts to educate and prepare emergency responders." As discussed above, PHMSA's regulations that govern hydrogen transported in pipelines were created to handle natural gas. However, given the molecular differences between the two substances, regulations focused on natural gas may not be enough to fully encompass the needs of a hydrogen pipeline system. For example, hydrogen can embrittle and accelerate the growth of cracks in pipelines, and can more easily permeate elastomer seals and plastic pipe than natural gas, all of which increase the risk of pipeline failure.[15] The existing safety regulations likely only contemplated small-scale usage of hydrogen,[16] and will need to be expanded to handle hydrogen transportation on a larger, commercial scale. Based on these industry- identified concerns, PHMSA determined several key research items that will lead to the development of specific standards and engineering designs and systems for the transport of hydrogen by pipeline:

– The correlations among pressure, temperature, and loss of mechanical properties for hydrogen pipelines,as more research and testing are needed to obtain definitive guidance for regulations and standards developers[17]
– The loss of fatigue resistance and impact strength in hydrogen pipelines
– Research to understand the entire pipeline system using high-strength steels to enhance performance of hydrogen pipelines
– Assessment to understand the effects of hydrogen on natural gas pipelines

PHMSA may need to create new regulations or expand the existing regulations based on the results of the research tasks described above in order to combat the risks associated with hydrogen transportation by pipeline.

2.5 Occupational Safety and Health Administration(OSHA)

OSHA requires owners or operators to develop a Process Safety Management (PSM) program (or modify they existing program to include the additional risk posed with the addition of hydrogen) for any interconnected process (i.e., in storage, process vessels, and piping) with a triggering threshold of 10,000 lbs of hydrogen under the control of a single entity.

2.6 Federal Legislation / American Jobs Plan

Early in 2021, the U.S. Senate introduced the Carbon Capture, Utilization, and Storage Tax Credit Amendments Act. This legislation would enable carbon capture, utilization, and storage (CCUS) and direct air capture (DAC) projects to

12 https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed April 2021.
13 49 C.F.R. § 192.3.
14 https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed April 2021.
15 Pacific Gas and Electric, White Paper – Pipeline Hydrogen, September 2018.
16 Alastair O'Dell, PE Live: Regulation Needs to Catch Up With Hydrogen Development, Petroleum Econ.
17 https://primis.phmsa.dot.gov/comm/hydrogen.htm Accessed April 2021.

access necessary federal incentives for reducing CO_2 emissions. The bill would enhance the 45Q tax credit for CCUS and DAC by extending the commence construction window by an additional five years, as well as increasing the credit value for DAC projects from $50 to $120 per metric ton of CO_2 captured and stored in saline formations, and from $35to $75 per ton for geological storage in oil and gas fields. It would also create a direct pay option for the 45Q and 48A tax credits and make several technical fixes to ensure that the tax credits are usable.

On March 31, 2021 the Biden Administration unveiled the $2 trillion American Jobs Plan which requires congressional approval. The Plan includes a wide array of investment allocations for various infrastructure and industries, with the energy sector receiving about 25% of the total proposed funding spread out over grid modernization and clean energy incentives. Hydrogen is specifically called out within a $15 billion allocation to RD&D projects, with mention of 15 decarbonized hydrogen demonstration projects in distressed communities with a new production tax credit.

Hydrogen projects and funding may also find relevance among $50 billion investment in the National Science Foundation (NSF), $35 billion investment in solutions needed to achieve technology breakthroughs that address the climate crisis, and $5 billion in funding for other climate-focused research.

As of this report, the Bipartisan Infrastructure Legislation (BIL) has not been passed into law. This legislation will provide generational impacts to by fostering infrastructure and clean energy projects across the country.

3. State Programs and Incentives

Liberty owns, operates, and maintains assets across a number of states; each state has a wide variance of state and local jurisdictional regulation, policy, and legal frameworks that all require deliberate and precise consideration for implementing projects within Liberty's business operations.Specific to hydrogen and its primitive state of regulation, that variance increases on which states address hydrogenwithin their respective regulatory frameworks.

There are two main sources of state policy and incentives are recommended to be utilized for staying current on the evolving regulatory landscape over the broad geographical spectrum of Liberty's assets:

– **Database of State Incentives for Renewables & Efficiency® - DSIRE (dsireusa.org)**

  DSIRE is a comprehensive source of information on incentives and policies that support renewable energy and energy efficiency in the United States. Established in 1995, DSIRE is operated by the N.C. Clean Energy Technology Center at N.C. State University. Since 2015, EERE of DOE has partnered with the N.C. State to expand and enhance the database's capabilities. The DSIRE database also includes a search tool that filters incentives and policies by type, state, technology, implementing sector, and eligible sector.

– **Alternative Fuels Data Center: All Laws and Incentives Sorted by Type (energy.gov)**

  The Alternative Fuels Data Center (AFDC) provides information, data, and tools to help fleets and other transportation decision makers find ways to reach their energy and economic goals through the use of alternative and renewable fuels, advanced vehicles, and other fuel-saving measures. The AFDC is a resourceof the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy's Vehicle TechnologiesOffice administered by the National Renewable Energy Laboratory.

3.1 Domestic Projects of Interest

There are a number of programs and projects of interest to Liberty where the results will help shape early decisions for policy and regulation.

UC Irvine and SoCalGas Advanced Power and Energy Program

The University of California, Irvine ("UCI"), in collaboration with SoCalGas, is running a demonstration project through its Advanced Power and Energy Program ("APEP") to utilise excess renewable power by converting it to hydrogen and blending it into the natural gas system. In 2016, UCI engineers successfully implemented the first power-to-gas hydrogen pipeline injection project in the US. SoCalGas is exploring ways that their existing infrastructure could be leveraged to enable other power-to-gas opportunities:

– $32M Estimate Budget.
– Project components: Literature review and laboratory research, Demonstration of injection into newer distribution system and collecting operational and performance data, Demonstration of injection into older distribution system and collecting operations and performance data, and Demonstration of injection into transmission system and collecting operational and performance data.
– Summary of pipeline fatigue and fracture behavior: Fatigue accelerated >10% and fracture resistance reduced by >50%, Welds of comparable strength have similar performance to base metals when residual stresses are accounted for, fatigue and fracture are affected by magnitude of pressure, and even small amounts of hydrogen have large effects.

Mitsubishi Power Americas Inc. in Northeast Hydrogen-powered Gas Turbines

The developers of three natural gas-fired generation projects in New York, Ohio and Virginia announced the selection of Mitsubishi Power Americas Inc. to supply hydrogen-compatible gas turbines, along with associated equipment for the generation and storage of hydrogen from renewable sources for the planned power stations. The projects, with a proposed aggregate capacity of 3,000 MW, are being developed by Danskammer Energy LLC, Balico LLC and EmberClear and scheduled to complete in 2022 and 2023. It is intended that all three projects (with an estimated aggregate value of US$3 billion) will, gradually, transition to 100 percent green hydrogen, while at the same time utilizing excess renewable energy to produce and store hydrogen on-site.

Other Electrolyzer and Blending Demonstration Projects

There are numerous hydrogen electrolyzers operating in the US and there are a number of planned or operating hydrogen natural gas blending demonstration projects. GHD has provided some detailed information on these facilities and projects in Appendix B. Liberty can obtain information and learn from these other projects in terms of approaches and requirements for regulatory approvals.

4. International Perspective

Key highlights:

– There is an increasing number of nations bullish with hydrogen strategies and investment road maps.
– National strategies often share regional goals of decarbonization, generation pathways, import/export schemes, and integration of renewables.

Hydrogen activities are well spread around the globe with major interests in Europe, Asia, and the Pacific region, as well as in the Americas. Most strategies have been developed and announced recently, i.e., in 2020 or in late 2019, (AU, NL, NO, DE, EU, ES) with three countries establishing their strategy prior to 2019 (JP, FR, KR). Figure 3 details which countries have addressed hydrogen from a national perspective and how advanced each strategy has developed to date.

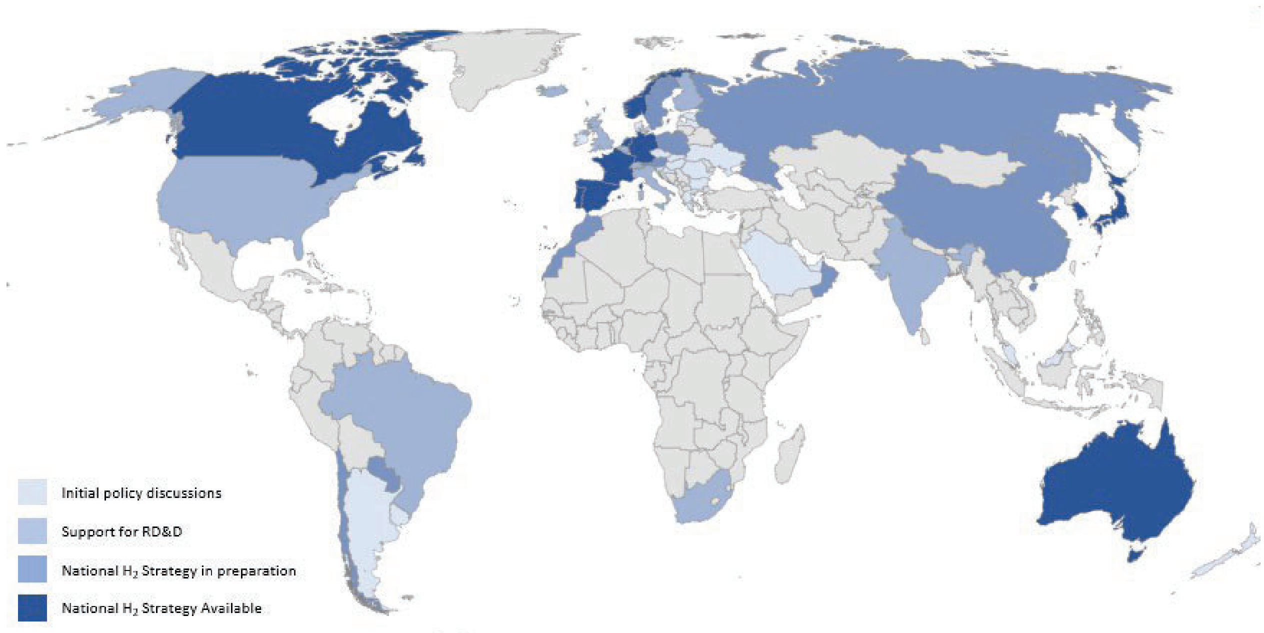

Figure 3 ***Current Status of International Hydrogen Strategies and Road Maps***
Source: Respective National Hydrogen Strategies, GHD Analysis

Main drivers for this development are GHG emission reduction goals, the integration of renewables, as well as the opportunity for economic growth. While national strategies differ in detail, reflecting particular country interests and industrial strengths, there is substantial international momentum behind the universal recognition of hydrogen playing an essential and indispensable role with decarbonized energy systems. Figure 4 highlights key motivators and strategic goals for selected nations.

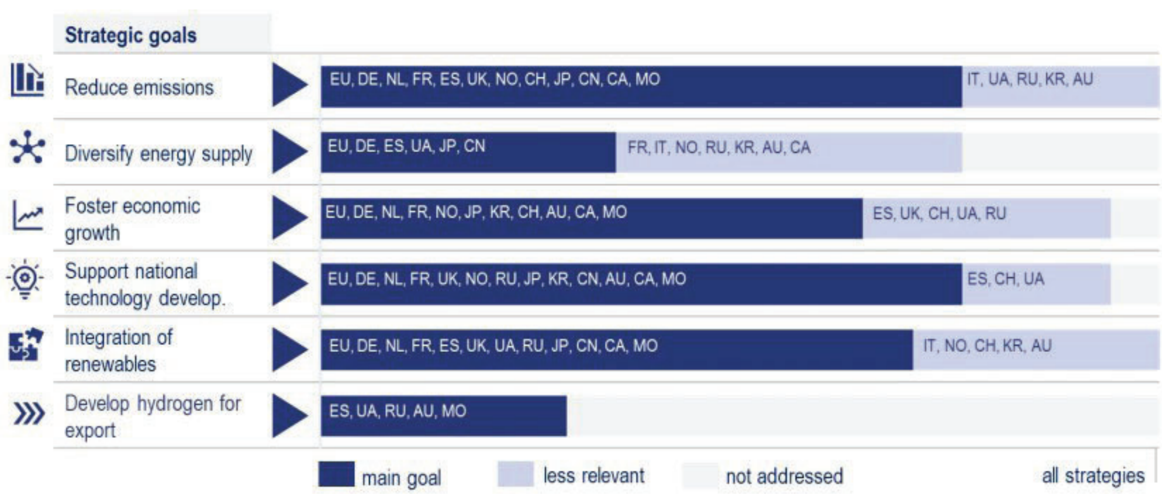

Figure 4 ***Strategic Goals for Selected Nations' Hydrogen Strategies and Road Maps***
World Energy Council

In this section, an overview of work being undertaken by nations at the forefront of developing their own respective hydrogen economies and status of regulatory frameworks.[18]

[18] World Energy Council, International Hydrogen Strategies, September 2020.

4.1 National Hydrogen Strategies

Generally, initiatives and framing of regulation and policy is driven at the Federal level, with significant capital investments and coordinated RD&D programs. Nations that have developed structured national hydrogen strategies or road maps include specific ramping up of production volumes, economic implications of transitioning away from traditional fuels, and considerations for the balancing of international trade supply and demand between now and beyond 2050. These developments, while specific to each nation, may serve as guidance and motivation for US regulatory and policy framing and are thus critical to follow moving forward:

- Strategies are largely congruent with one another: RD&D to frame regulation and policy.
- Each country's focus specific to existing strengths, potential for customers, and availability of resources toproduce hydrogen in near vs long term (Generation, transport / storage, off-takers).
- Following countries provide examples of significant investment, progress with strategy, and cohesionamong domestic priorities with of subtle differences between each other.
- End effect: strategy and RD&D will develop into concrete policy and regulation.

Canadian National Hydrogen Strategy

In December 2020, Canada released a National Hydrogen Strategy. Development of an at-scale, clean hydrogen economy is a strategic priority for Canada, needed to diversify the future energy mix, generate economic benefits and achieve net-zero greenhouse gas emissions by 2050. This will require a radical transformation of Canada's energy system. Canada has all the ingredients necessary to develop a competitive and sustainable hydrogen economy.

Canada's hydrogen strategy has been developed to reflect the input and views expressed in wide consultation with stakeholders and partners. The recommendations will inform the development of concrete actions by all players needed to lay the foundation for and support the growth of diversification and expansion of the hydrogen ecosystem in Canada. Recommendations have been proposed across 8 key pillars:

1. Strategic Partnerships - Use existing and new partnerships strategically to collaborate and map the futureof hydrogen in Canada.
2. De-risking of Investments - Establish funding programs, long-term policies, and business models toencourage industry and governments to invest in growing the hydrogen economy.
3. Innovation - Take action to support further R&D, develop research priorities, and foster collaborationbetween stakeholders.
4. Codes and Standards - Modernize existing codes and standards to keep pace with this rapidly changingindustry and remove barriers to deployment, domestically and internationally.
5. Enabling Policies and Regulations - Ensure hydrogen is integrated into clean energy road maps andstrategies at all levels of government to incentivize its application.
6. Awareness - Lead at the national level to ensure individuals and communities are aware of hydrogen'ssafety, uses, and benefits during a time of rapidly expanding technologies.
7. Regional Blueprints - Implement a multi-level, collaborative government effort to facilitate the developmentof regional hydrogen blueprints to identify specific opportunities and plans for hydrogen production and end use.
8. International Markers - Work with international partners to ensure the global push for clean fuels includes hydrogen.

German National Hydrogen Strategy

In June 2020, Germany rolled out a national hydrogen strategy that eyes a 200-fold increase in electrolyzer capacity—of up to 5 GW by 2030. This corresponds to 14 TWh of green hydrogen production and will require 20 TWh of renewables-based electricity. An additional 5 GW of capacity may be added by 2035 and no later.[19]

[19] BMWi, German National Hydrogen Strategy, 2020.

Within this context of extending the range of hydrogen as an energy source within Germany, the Federal Ministry of Economic Affairs and Energy (BMWi) in 2019 announced 20 federally funded projects intended to progress the implementation of large-scale projects intended to bolster its domestic hydrogen economy. These Reallabore, or Living Sandboxes, focus on the production, storage, and utilization of hydrogen within various real environments, and the results will help guide Germany's long-term strategy and roadmap concerning their hydrogen economy. They offer companies the opportunity to implement their technical and fundamental innovations and test them in a real environment in cooperation with researchers. Further, an immediate and large-scale application of relevant technologies can show where and how regulatory barriers can be overcome to accelerate the market establishment of hydrogen-based energy innovations.

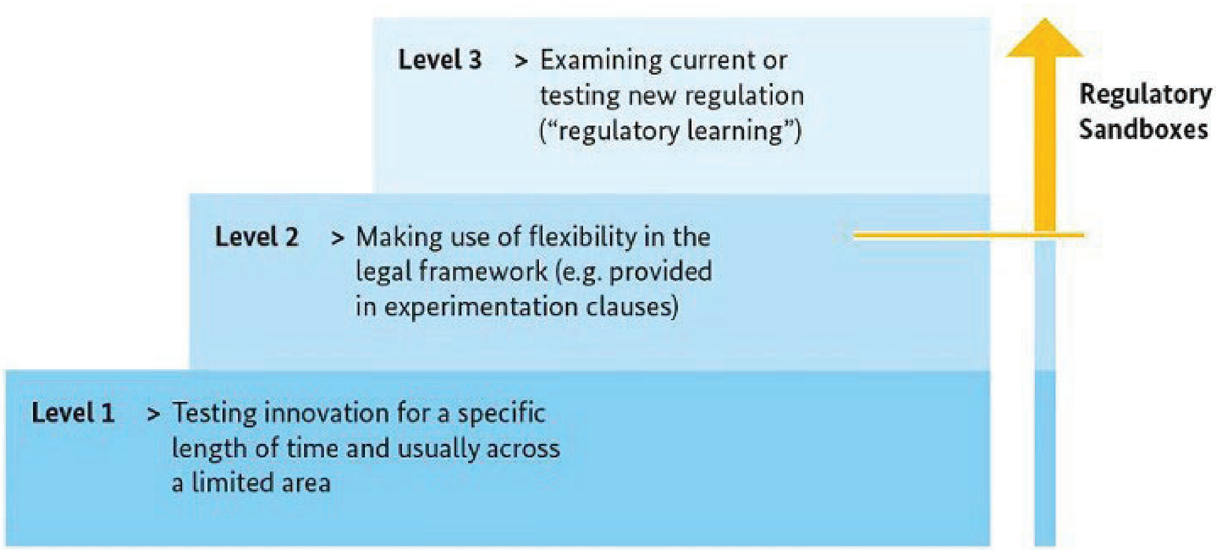

Figure 5 *Overview of German Pathway for Regulatory Sandboxes to Drive Regulation*
Source: BMWi, National Hydrogen Strategy, 2020

Australian National Hydrogen Strategy

Australia's National Hydrogen Strategy, developed in 2019[20], lays out an adaptive pathway to clean hydrogen growth:

– Support an adaptive approach to industry development that means Australia can be ready to move quicklyto scale up as signs of large-scale markets emerge. A 'review-revise-adapt' feedback loop will support andrefine actions as technology and markets change. This adaptive approach will focus on actions that remove market barriers, efficiently build supply and demand, and accelerate the global hydrogen cost- competitiveness of Australia's hydrogen industry.
– Support an approach guided by four underpinning principles, namely to:
  - Take an adaptive and nationally coordinated approach to support industry development, includingregulatory reviews
  - Prioritize regulatory consistency and a coordinated approach to project approvals
  - Support partnerships to activate the market
  - Put safety, environmental sustainability, and benefits to Australians at the forefront
– Support actions themed around seven areas: developing production capacity, supported by local demand; responsive regulation; international engagement; innovation and R&D; skills and workforce; community confidence; and national coordination.

[20] COAG Energy Council, Australia's National Hydrogen Strategy, 2019.

– Support a pathway for developing a local industry, initially by removing regulatory barriers to hydrogen use and encouraging it through policies to help early movers overcome investment barriers. Mandating use of hydrogen will require evidence that a net benefit to consumers will result, or there is a consumer willingness to pay where appropriate, and that industry can meet regulated requirements.

Japan's Strategic Roadmap for Hydrogen and Fuel Cells

In March 2019 the Government of Japan released its third Strategic Roadmap for Hydrogen and Fuel Cells. Japan considers its domestic uptake of hydrogen as a viable way to increase its energy self-sufficiency; decarbonize its economy; increase industrial competitiveness; and position Japan as a fuel cell technology exporter. At this stage, Japan is prioritizing the reduction of the production cost of hydrogen. The key consideration for large-scale uptake of hydrogen in Japan will be cost, and Japan is pursuing hydrogen produced using fossil fuels and utilizing CCUS technology which is currently more economically competitive. Japan is looking for international cooperation to build a hydrogen supply chain, increase the scale of production, and reduce costs. Japanese companies continue to actively seek engaged international partners to undertake demonstration projects that deliver tangible results which presents an opportunity for Australia and New Zealand with their renewable energy credentials, and both Government's strong support for hydrogen. Japan is interested in importing green hydrogen if the price is competitive, and two Japanese companies have invested in, or are looking to invest in, green hydrogen projects in both Australia and NewZealand. Initial proof of concept projects will likely produce hydrogen with either coal or carbon-based feedstocks.

The total government budgetary support for hydrogen for this financial year (ending March 2021) is 70 billion yen and includes:

– Subsidies for fuel cell vehicles
– Subsidies for hydrogen refueling stations
– Research and development on fuel cell technologies
– Hydrogen supply infrastructure
– International research collaboration projects for innovative technologies in clean energy (for exampleCCS)
– Pilot projects to develop the hydrogen supply chain
– Development to produce, store and utilize hydrogen

In January 2020 the Japan Bank for International Cooperation designated hydrogen as an "essential resource", unlocking more government funding for hydrogen projects (covering the entire supply chain including production, transportation, supply and utilization) to be undertaken in developed countries. Japan was planning to use the 2020 Olympic and Paralympic Games as a platform to promote it hydrogen technology by using fuel cell vehicles and buses, and powering the athletes' village with hydrogen. Japan may consider showcasing a scaled down version of its hydrogen technology at the Olympic and Paralympic Games postponed to 2021. Japan considers Expo 2025 in Osaka as another opportunity to showcase Japan's hydrogen technology and share its plans for a hydrogen economy.

Japan also considering ammonia as a potential fuel to decarbonize its economy. Japan is also actively considering ammonia as a viable fuel to:

– Decarbonize the maritime industry
– Transport hydrogen
– Store energy

An industry group called the Green Ammonia Consortium operates in Japan which is working to build an international supply chain for ammonia as a way to decarbonize economies.

The strategy notably seeks to achieve cost parity with competing fuels, such as liquefied natural gas for power generation. It has also set out concrete cost and efficiency targets per application, targeting electrolyzer costs of $475/kW, efficiency of 70% or 4.3 kWh/Nm^3, and a production cost of $3.30/kg by 2030. It also has multiple projects underway for international trade in hydrogen. The Hydrogen Energy Supply Chain, for example, is committed to delivering hydrogen converted from coal gasification from Victoria's Latrobe Valley in Australia. The first liquid hydrogen ship was delivered in December 2019, and the first blue ammonia (ammonia from gas reforming with carbon capture) shipment arrived in September 2020.

European Union

The aim of the EU Hydrogen Strategy is to decarbonize hydrogen production and expand its use in sectors where it can replace fossil fuels. Although the main focus lies on green hydrogen, the EU Hydrogen Strategy recognizes the role of other low-carbon hydrogen in the transition phase in the short to medium term.

The most relevant goal of the EU Hydrogen Strategy is the build-up of additional hydrogen production capacity (i.e., building electrolyzers). The EU Hydrogen Strategy provides targets of installing (i) in phase 1, at least 6 GW of renewable hydrogen electrolyzers in the EU by 2024 and (ii) in phase 2, 40 GW of renewable hydrogen electrolyzers in the EU, along with an additional 40 GW electrolyzer capacity target in the eastern and southern 'neighborhoods' of Europe, e.g., Ukraine, as the priority partners for cross-border trade in hydrogen.

The EU Hydrogen Strategy highlights that support schemes are likely to be required for some time to enable renewable hydrogen to become cost-effective on the scale envisaged. In this regard the EU Hydrogen Strategy considers an amendment of the EU Emission Trading System. In the next revision of the ETS, the Commission may consider how to incentivize the production or renewable and low-carbon hydrogen while considering the risk of carbon leakage. If differences in climate targets around the world continue, the Commission will propose a Carbon Border Adjustment Mechanism in 2021.

According to the EU Hydrogen Strategy, Carbon Contracts for Differences could be another valuable support mechanism. The Strategy Document envisages where the public counterpart would remunerate the investor by paying the difference between the carbon strike price and the actual strike price in the ETS.

5. Hydrogen Injection Blending Limits

Specific to blending limits on an international level, the following table provides an overview of the existing limits. Some demonstration projects, such as the HyDeploy project in the UK, have gained exemption to blend beyond the regulatory limits presented.

Table 5.1 Overview of Existing Blending Limits

Country	Standard/Regulation/Specification &Comments	Blend Limit	Limitation Includes
Austria	ÖVGW-RL 31	4%vol	Natural gas distribution and transmission
		2%vol	If a natural gas refueling station is downstream of injection point
France	Decree n°2004-555 describes requirements for non-natural gas injection into the grid (i.e., Wobbe index, density, etc.). GRTgaz published technical guidelines based on this Decree for hydrogen injection and blending, specifying the blend limit given.	6%vol	Natural gas distribution and transmission
Germany	DVGW Standard G 262	10%vol	Natural gas distribution system
		2%vol	If a natural gas refueling stationis downstream of injection point

Country	Standard/Regulation/Specification &Comments	Blend Limit	Limitation Includes
Italy	Snam Gas Grid Code – Snam is a large gas grid operator in Italy. There are no national- level regulations or standards in place. In 2019, Snam began injecting 5% hydrogen intoa local gas grid, announcing intentions to jumpto 10% in December 2019. Therefore it is likely Snam's Gas Grid Code referenced is superseded.	0.5-1%vol	Natural gas distribution system
Latvia	Overall legislation for mixture in gas networkbased on gas quality (not targeted for hydrogen injection and blending)	0.1%vol	Natural gas distribution and transmission
Netherlands	Dutch Gas Act	0.02%vol	High-pressured Dutchtransmission grid
		0.5%vol	Natural gas distribution andregional transport grids
Spain	Ministerio de Industria, Turisme y Comercio de España, Boletín Oficial del Estado n°238	5%vol	Uncertain
United Kingdom	Gas Safety Management Regulations 1996 – sets the UK gas quality specification and Wobbe Index range, including stated limit forhydrogen	0.1%vol	All natural gas

Source: PRCI report PR-720-20603-R01 Emerging Fuels - Hydrogen SOTA Gap Analysis and Future Project Roadmap.

6. Hydrogen Coalitions and Associations

International or regional platforms for stakeholders in the hydrogen industry may collectively facilitate and promote the best interests of the hydrogen sector from a regulatory perspective. Current coalitions and associations are scoped at both federal and state levels.

6.1 North America

Clean Hydrogen Future Coalition (CHFC)

The Clean Hydrogen Future Coalition (CHFC) was launched in March 2021 with over 20 organizations, including Liberty, to support federal clean hydrogen policies promoting clean hydrogen as a key pathway for US decarbonization and competitiveness. 'The coalition is identifying specific actions that the U.S. can undertake to scalethe full supply chain for clean hydrogen production, transport, storage, and use, as well as the technology development and infrastructure needs across multiple sectors.'[21]

[21] https://cleanh2.org/ Accessed April 2021.

Figure 6 *Clean Hydrogen Future Coalition (CHFC) Members*
Source: cleanh2.org

Zero Carbon Hydrogen Coalition

The Zero Carbon Hydrogen Coalition is a coalition of companies who are working together to persuade Congress to open the Innovation Tax Credit and Production Tax Credit to allow renewable natural gas (RNG) and renewable hydrogen (RH2) projects to qualify for the tax credit. The Coalition was just formed earlier this year and plans to run through 2021.

Hydrogen Forward

Hydrogen Forward is a coalition of 11 organizations formed in February 2021 to advance hydrogen development in the

U.S. The coalition aims to educate decisionmakers and stakeholders on the value hydrogen delivers today and the important role that it should play in the future. The consortium 'support the establishment of a national hydrogen that outlines a clear, comprehensive approach to hydrogen and related infrastructure development.'[22]

Members of the Hydrogen Forward coalition are making significant domestic investments and driving specific projects across the nation to bring these technologies to scale. From the manufacturing and sale of hydrogen fuel cell electric vehicles (FCEVs) to supporting the fueling stations that keep FCEVs moving, Hydrogen Forward members are on the leading edge of transportation innovation. Likewise, member company hydrogen storage solutions and partnerships with local utility companies are helping to harness renewable energy and decarbonize the power generation sector.[23]

22 https://www.hydrogenfwd.org/about/ Accessed April 2021.
23 Bloom Energy. 2021. Press Release on Hydrogen Forward Coalition.

Figure 7 ***Hydrogen Forward Founding Members***
Source: hydrogenfwd.org

Fuel Cell and Hydrogen Energy Association (FCHEA)

The Fuel Cell and Hydrogen Energy Association (FCHEA) represents more than 50 companies and organizations that are advancing innovative, clean, safe, and reliable energy technologies. FCHEA drives support and provides a consistent industry voice to regulators and policymakers on the environmental and economic benefits of fuel cell and hydrogen energy technologies. The mission of FCHEA is to advance the commercialization of and promote the markets for fuel cells and hydrogen energy.

FCHEA primary activities include:

– Leading national advocacy to encourage all levels of government to support fuel cell and hydrogentechnology research, development, and deployment.
– Providing the industry a voice in shaping regulations, codes, and standards to enable commercial growth,while ensuring the highest levels of consumer safety and satisfaction.
– Educating the public and key opinion and policy leaders on the economic and environmental benefits offuel cell and hydrogen technologies.

To achieve these goals, FCHEA operates a number of working groups and committees, collaborating with itsmembers on specific initiatives and technologies to help the industry thrive.

Pipeline Research Council International (PRCI)

Pipeline Research Council International (PRCI) is a not-for-profit corporation, comprising about 70 organizations from around the world, primarily energy pipeline companies, as well as equipment manufacturers and service providers.

PRCI membership consists of gas network operators and institutions globally, invested in the advancement of the industry with a particular focus on gas transmission pipelines. Liberty will want to continue leveraging the knowledge and partnership opportunities as hydrogen plays an increasing role within the community of PRCI members.

PRCI recognizes an increasing interest, particularly in Europe, North America, and Australia, in blending hydrogen into the natural gas network as both a way to decarbonize the natural gas grid and enable the transition to a hydrogen economy through existing pipeline transport. Due to this development, PRCI funded a research effort to address hydrogen blending in a report released to members in 2020.

The goal of the effort was to assess the key technical knowledge gaps associated with introducing hydrogen to natural gas systems and identify research priorities to ensure the safe, reliable and cost-effective injection and blending of hydrogen in existing pipelines. This state-of-the-art study provides PRCI members with valuable up-to-date information on the key technical challenges and ongoing research and project efforts, while advising PRCI with regards to future research needed to advance this industry.

American Gas Association (AGA)

The American Gas Association (AGA), founded in 1918, represents more than 200 local energy companies that deliver natural gas. AGA's core strengths include developing standards, advocating for natural gas industry issues, regulatory constructs and business models. AGA's new chair, David Anderson, President and CEO of Northwest Natural, recognizes the key roles of renewable natural gas and hydrogen in decarbonizing the US natural gas distribution system.

Gas Technology Institute (GTI)

GTI is a research, development and training organization addressing energy and environmental challenges. GTI has decades of experience with hydrogen research and technology development, including generation, storage & delivery, transportation and end uses.

6.2 State-level

A main emphasis of hydrogen and fuel cells initiatives in the U.S. is centered on the mobility sector with varying magnitudes of incentives dependent on State and/or municipality.

Clean Cities Coalition Network

A coordinated group of nearly 100 coalitions serve as the foundation of Clean Cities, working in communities across the country to help local decision makers and fleets understand and implement alternative and renewable fuels, idle- reduction measures, fuel economy improvements, new mobility choices, and emerging transportation technologies. The U.S. Department of Energy's (DOE) Vehicle Technologies Office (VTO) within the Office of Energy Efficiency andRenewable Energy facilitates national coordination of the coalitions through its Technology Integration Program.

Together, Clean Cities coalitions and VTO focus on advancing affordable, domestic transportation fuels, energy efficient mobility systems, and other fuel-saving technologies and practices.

Figure 8 *DOE Map of Clean Cities Coalition Network Participants*
Source: Clean Cities Coalition Network, 2020

As Liberty continues to build out their hydrogen strategy, including prospective mobility markets within the CleanCities Coalition Network serves as a valuable collaboration point for establishing potential hydrogen off-takers.

California Fuel Cell Partnership (CalFCP)

Founded in 1999, the California Fuel Cell Partnership (CalFCP) is an industry/government collaboration aimed at expanding the market for fuel cell electric vehicles powered by hydrogen to help create a cleaner, more energy- diverse future with no-compromises zero emission vehicles. Staff from member organizations participate on standingcommittees and project teams that help ensure that vehicles, stations, regulations and people are in step with each other as the market grows.[24]

Connecticut Hydrogen-Fuel Cell Coalition (CHFCC)

The Connecticut Hydrogen-Fuel Cell Coalition, administered by the Connecticut Center for Advanced Technology, is comprised of representatives from Connecticut's fuel cell and hydrogen industry, academia, government, and other stakeholders. CCAT and the Connecticut Hydrogen-Fuel Cell Coalition works to enhance economic growth in Connecticut through the development, manufacture, and deployment of fuel cell and hydrogen technologies and associated fueling systems.

The Connecticut Hydrogen-Fuel Cell Coalition is made up of companies and organizations that do business with each other and/or have common needs for talent, technology, and infrastructure. Connecticut companies now lead the world in the development of molten carbonate and phosphoric acid fuel cells and are among the leaders in proton

24 https://cafcp.org/about_us Accessed April 2021.

exchange membrane (PEM) and other electrochemical technology applications. Connecticut companies in hydrogen generation are leaders in both proton exchange membrane electrolysis systems and in converting natural gas or petroleum products to hydrogen through reforming processes.[25]

6.3 International Coalitions

Hydrogen Council

The Hydrogen Council is a global CEO-led initiative that brings together leading companies with a united vision and long-term ambition for hydrogen to foster the clean energy transition. Using its global reach to promote collaboration between governments, industry and investors, it provides guidance on accelerating the deployment of hydrogen solutions around the world.

The Hydrogen Council believes that hydrogen has a key role to play in the global energy transition by helping to diversify energy sources worldwide, foster business and technological innovation as drivers for long-term economic growth, and decarbonize hard-to-abate sectors.

Acting as a business marketplace, the Hydrogen Council brings together a diverse group of 109 companies based in 20+ countries and across the entire hydrogen value chain, including large multinationals, innovative SMEs, and investors. The Hydrogen Council serves as a resource for safety standards and an interlocutor for the investment community, while identifying opportunities for regulatory advocacy in key geographies.

The Hydrogen Council is currently composed of CEOs and chairpersons from the following companies:

– Steering members: 3M, Airbus, Air Liquide, Air Products, Alstom, Anglo American, Audi AG, BMW GROUP, BP, CF Industries, Chemours, Bosch, China Energy, CMA CGM, CNH Industrial (via IVECO), Cummins, Daimler, EDF, ENEOS Corporation, ENGIE, Equinor, Faurecia, General Motors, Great Wall Motor, Honda, Hyundai Motor, Iwatani, Johnson Matthey, Kawasaki, KOGAS, Linde, Michelin, Microsoft,MSC Group, Plastic Omnium, SABIC, Saudi Aramco (via the Aramco Overseas Company), Schaeffler Group, Shell, Siemens Energy, Sinopec, Solvay, thyssenkrupp, Total, Toyota, Uniper and Weichai.
– Supporting members: ACME, AFC Energy, AVL, Baker Hughes, Ballard Power Systems, Black & Veatch, Chart Industries, Chevron, Clariant, Delek US Holdings, ElringKlinger, Enbridge Gas, Faber Industries, First Element Fuel (True Zero), Fortescue Metals Group, Galp, W. L. Gore, Hexagon Composites, ILJIN Composites, ITOCHU Corporation, Liebherr, MAHLE, MANN+HUMMEL, Marubeni, McDermott, McPhy, Mitsubishi Corporation, Mitsubishi Heavy Industries Ltd., Mitsui & Co, Nel Hydrogen, NGK Spark Plug Co.,Nikola Motor, NYK Line, PETRONAS, Plug Power, Port of Rotterdam, Power Assets Holdings, Re-Fire Technology, Reliance Industries Limited, Sinocat, SinoHytec, Sinoma Science & Technology, Snam, Southern California Gas, Sumitomo Mitsui Banking Corporation, Sumitomo Corporation, Technip Energies, Tokyo Gas, Toyota Tsusho, Umicore, Vopak, and Woodside Energy.
– Investor Group: Antin Infrastructure Partners, BNP Paribas, Crédit Agricole, GIC, John Laing, Mubadala Investment Company, Natixis, Providence Asset Group and Société Générale.

Asia-Pacific Hydrogen Association

Established in December 2019, the Asia-Pacific Hydrogen Association is the leading industry association for the hydrogen sector in Asia-Pacific. The Asia-Pacific Hydrogen Association acts as the regional platform for all stakeholders in the hydrogen industry to collectively promote the best interests of the hydrogen sector. Members include utilities, power project developers, equipment manufacturers, technical consultants, financial institutions, regional associations and other institutions in the hydrogen sector.

25 http://chfcc.org/ Accessed March 2021.

Hydrogen Europe

Hydrogen Europe brings together diverse industry players, large companies and SMEs, who support the delivery of hydrogen and fuel cells technologies. Hydrogen Europe represents the European hydrogen and fuel cell sector with(as per April 2021) 260+ companies and 27 National Associations.

Hydrogen Europe Research (HER) is an international non–profit association composed of 91 universities and Research & Technology Organizations (RTO) from 26 countries all over Europe and beyond. Hydrogen Europe members are active within the European hydrogen and fuel cell sector.

HER is one of the three participants of the European Joint Undertaking (JU) on Hydrogen, alongside its industry counterpart Hydrogen Europe (HE) and the European Commission. From 2008 to 2020, the Fuel Cells and Hydrogen JUs (FCH JU & FCH 2 JU) have been unique public private partnerships supporting Research, Technological development and Demonstration (RTD) activities in fuel cell and hydrogen technologies in Europe. HER will continueto participate in the future Institutionalized European Partnership (IEP) on hydrogen, entitled Clean Hydrogen Joint Undertaking (CH JU), from 2021 to 2027.

HER's members contribute to the preparation of the Clean Hydrogen JU's Multi-Annual and Annual funding priorities. In cooperation with Industry, they have the unique possibility to shape the focus of the Program. Concretely, HER members participate in the different Technical Committees and roadmaps shared with HE where annual strategic priorities are discussed and topics for future Calls for proposals are drafted. The Technical Committees and roadmaps are included in the three pillars of the JU (Pillar 1: Hydrogen production; Pillar 2: Hydrogen storage, transport and distribution; Pillar 3, Hydrogen end-uses).[26]

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