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Final Report

Technology Gap Analysis for Alberta's Emerging Hydrogen Economy

Confidential to
Alberta Innovates

Prepared by
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Reviewed by
Brian Wagg, MSc, PEng

April 2021
E001

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Permit Signatory, Designation

Date ______________________

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TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

Figures

Tables

EXECUTIVE SUMMARY

Hydrogen presents Alberta with an opportunity for economic diversification and a move toward net-zero carbon emissions. Furthermore, there has been considerable press and multiple announcements from industry and governments recently sharing grand visions about the benefits of moving toward hydrogen; however, transitioning to a reality where hydrogen is both a major commodity and fuel source in Alberta means addressing the many challenges associated with this multi-directional effort and identifying the technologies and innovations required to overcome these challenges.

Alberta Innovates recognized this set of challenges and requested C-FER Technologies (1999) Inc. ("C-FER") prepare a technical gap analysis (hereinafter referred to as "gap analysis") for Alberta's emerging hydrogen economy. The intent of this gap analysis is to identify the potential major technical challenges and innovation gaps that Alberta hydrogen industry stakeholders across the entire value chain may face in the early stages (i.e. next three years) of the transition to hydrogen. Eventually, developing decarbonized hydrogen production in Alberta will be tied to a broader effort to decarbonize the economy through emissions reductions and improved process efficiency in Alberta's industrial sectors, as well as commercial and residential settings.

Currently, Alberta produces approximately 2 million tonnes (Mt) per year of hydrogen with most production located in either the Alberta Industrial Heartland (around Edmonton), or in the Fort McMurray region. Of this annual production, approximately 0.33 Mt is produced by way of steam-methane reforming (SMR) in combination with carbon dioxide (CO_2) capture systems and underground storage. This is often referred to as "Blue Hydrogen". The balance of hydrogen production is SMR-based production without CO_2 capture processes in place, commonly referred to as "Grey Hydrogen".

The hydrogen that is produced in Alberta is used almost exclusively for either hydrocarbon upgrading and refining, or industrial processes (e.g. ammonia and fertilizer production). Furthermore, this produced hydrogen is not transported long distances; with most hydrogen produced within the same industrial complex, or nearby facilities, where it is used. In these cases, purpose-built hydrogen pipelines are used to move the hydrogen within and between facilities.

Major changes and developments across the entire hydrogen value chain will likely be required for hydrogen to evolve from feedstock for industrial purposes to broad-spectrum means of both energy storage and low-emission heating fuel. Alberta and Canada have set ambitious long-range targets for hydrogen production, use and export; however, short-range targets and milestones must be accomplished to lay the foundation for success toward these end goals.

To this end, the focus of this gap analysis was to identify the challenges and gaps that the hydrogen economy faces in the next three years (i.e. by 2024). It was established at the onset of this gap analysis that it will take much longer than three years to grow the hydrogen industry in

Alberta from where it is today to what is envisioned; however, aggressive, yet achievable, milestones were set by the project team for various aspects of the hydrogen value chain. These milestones were based on direct consultation with industry stakeholders; as well as, comparisons with other jurisdictions that are also in the process of developing or deploying hydrogen road maps and strategies. The hydrogen value chain that was assessed in this gap analysis was divided into five main parts:

1. ***Decarbonized Hydrogen Production*** – Low-emission hydrogen production from natural gas likely by way of SMR with carbon capture processes or other means of low-carbon hydrogen production.

2. ***Hydrogen Transmission*** – Hydrogen that is produced in Alberta will need to move beyond local use to applications located throughout the province.

3. ***Hydrogen Storage*** – Storage is critical to act as a buffer on the transportation system to manage variability in hydrogen supply and demand.

4. ***Hydrogen End-Use*** – Industrial processes, transportation systems and commercial and residential appliances will have to be converted from other fuel sources to hydrogen on a large-scale to ensure a market for hydrogen.

5. ***Export Market Potential*** – Exporting hydrogen as a commodity to foreign markets will bolster Alberta's economy and is a pillar of the provincial government's vision for hydrogen in the future.

Based on this analysis, the following sequence of events are recommended to start the transition to a hydrogen economy:

1. Implement carbon capture with existing hydrogen production and improve capture efficiency.

2. Build CO_2 transport and sequestration infrastructure.

3. Evaluate where methane pyrolysis could be used in place of SMR.

4. Determine H_2 blend limits for the legacy natural gas pipeline system in Alberta.

5. Focus on converting industrial users to hydrogen and CCUS.

6. Explore North America focused export strategies.

Expand and Improve Decarbonized Hydrogen Production

Current production of hydrogen in Alberta is very emissions-intensive; as such, the first step in transitioning to decarbonized hydrogen production will likely be to capture as much CO_2 from existing hydrogen production as possible before expanding production to meet future targets. Brownfield carbon capture construction has been successfully demonstrated through the Shell

Scotford upgrader complex retrofit as part of the Shell Quest Carbon Capture and Sequestration (CCS) program. Multiple similar projects will need to be undertaken by Alberta's remaining emissions-heavy hydrogen producers. New technologies will help improve the efficiency of the carbon capture processes from current benchmarks of around 80 percent CO_2 capture rate. Given the amount of CO_2 that is produced per unit mass of hydrogen, even a few percentage points gained in capture efficiency will prevent a large amount of CO_2 from being vented to the atmosphere. Where retrofitting carbon capture is not practical, hydrogen producers may need to offset their emissions through other process efficiencies in their operations or invest in new technologies that can extract the CO_2 further downstream.

Expand CO_2 Transportation and Sequestration

Ultimately, SMR in combination with enhanced carbon capture technologies will likely be the main means of expanded decarbonized hydrogen production in Alberta. In anticipation of this, steps should be taken to ensure that there is sufficient access to carbon storage capacity in the province. The combined capacity of Shell Quest and the Alberta Carbon Trunk Line (ACTL) system is approximately 16 Mt of CO_2 per year. Factoring in current carbon capture efficiency, the ACTL has the capacity to manage the CO_2 from a total of about 2.2 Mt of hydrogen production per year. This is only a 10% increase from current total hydrogen production in Alberta, suggesting that additional CO_2 transportation systems will be required if there is to be any substantial increase in hydrogen production. Based on current projections for future decarbonized hydrogen production, many more CO_2 sequestration operations across the province will be required. While there is a tremendous amount of geological pore space available in the province to store CO_2, risks associated with caprock and well integrity (both injection and local abandoned/shut-in wells) need to be evaluated and understood to ensure the long-term security of these storage operations.

Evaluate Opportunities for Methane Pyrolysis

Expansion of Alberta's decarbonized hydrogen production could also be assisted by processes such as methane pyrolysis. Unlike SMR this process does not result in large amounts of CO_2 and does not use water. The process instead produces hydrogen and solid carbon. As a result, pyrolysis facilities do not require tie-in to a network of CO_2 pipelines leading to a carbon sequestration site. Pyrolysis-based hydrogen hubs could be established in regions across the province beyond the reach of a CO_2 pipeline network, providing hydrogen for local use (e.g. fueling stations for hydrogen fuel cell vehicles).

Evaluate Hydrogen Compatibility with Legacy Pipeline System

Once hydrogen has been produced it needs to get to where it is either used or turned into another product. Alberta has an extensive network of transmission and distribution pipelines for natural gas and some proponents of hydrogen have suggested that this network could be converted to transport hydrogen in the same way. While this would be advantageous from a logistical and cost perspective, the materials and equipment used in natural gas pipelines and the end use appliances such as stoves and furnaces will likely limit the hydrogen concentration in blends with natural gas to less than 20% to ensure the safe and reliable operation of all components of this system. Even within the legacy pipeline network in Alberta, individual lines must be evaluated and rated separately for hydrogen service considering factors such as metallurgy, construction, age, and service condition. Hydrogen can cause or accelerate damage mechanisms in some pipeline steel alloys and welds so purpose-built pipelines will be necessary for operations moving higher-ratio hydrogen blends or pure hydrogen.

Convert Industrial Users

A successful transition to a hydrogen-based economy in Alberta will ultimately rely on end-user acceptance and conversion to hydrogen. While there is an opportunity to use hydrogen in fuel cell powered vehicles, the larger market for hydrogen will likely be in replacement of thermal fossil fuels such as natural gas and coal. Heavy industry consumes over 80% of the natural gas in Alberta, so if conversion from natural gas to hydrogen blends or pure hydrogen is to proceed, this will require major investment from industry. Initial feedback is that some stakeholders are weighing the options of converting their systems to burn hydrogen or to continue to burn natural gas and pursue post-combustion carbon capture as their means for emissions reduction. Furthermore, conversion of natural gas burning systems will depend on increasing hydrogen production to ensure a reliable supply. On the residential and commercial front, consumers will be faced with a requirement to update their gas-burning systems (stoves, furnaces, water heaters, etc.) as research has shown that current designs do not reliably perform using pure hydrogen as a fuel source.

Explore Export Strategies

Lastly, there is a global need for hydrogen and Alberta is well-positioned to supply decarbonized hydrogen to the United States in the near-term. Time is of the essence since other countries are looking to export hydrogen, with some trials already underway. However, the same challenges and limitations to domestic networks of steel transmission pipelines apply to export pipelines, so large-scale export of hydrogen will likely only be effective through dedicated pipelines specifically designed for hydrogen service. Accelerated and coordinated efforts to develop effective regulatory guidelines for hydrogen export across provincial and national borders via purpose-built hydrogen pipelines and new technology development for hydrogen leak detection and mitigation will be required to enable an export market. Export opportunities to offshore nations such as South Korea, Germany and Japan are many years away, as they face additional challenges of cryogenic transport at temperatures significantly lower than LNG.

ACKNOWLEDGEMENTS

C-FER Technologies (1999) Inc. ("C-FER") would like to acknowledge the contributions of all stakeholders, across the hydrogen economy value chain of Alberta, in the development of this technology gap analysis.

C-FER would also like to acknowledge the funding and support provided by Alberta Innovates.

1. INTRODUCTION

Alberta has an opportunity to diversify its economy by developing its hydrogen industry and move toward net-zero carbon emissions through decarbonized hydrogen production. Furthermore, there has been considerable press and multiple announcements from industry and governments recently sharing grand visions about the benefits of moving toward hydrogen; however, transitioning to a reality where hydrogen is both a major commodity and fuel source in Alberta means addressing the myriad of challenges associated with this task and identifying the technologies and innovations required to overcome these challenges.

Alberta Innovates recognizes these challenges and has requested C-FER Technologies (1999) Inc. ("C-FER") prepare a technical gap analysis (hereinafter referred to as "gap analysis") for Alberta's hydrogen economy. The intent of this gap analysis is to identify the potential major technical challenges and innovation gaps that Alberta hydrogen industry stakeholders across the entire value chain may face in the early stages (i.e. next three years) of the transition to hydrogen. Eventually, hydrogen is expected to become broadly used as part of a greater effort to decarbonize and diversify Alberta's economy.

Information presented in this gap analysis was gathered through a comprehensive review of the literature (e.g. published technical papers, industry white papers, corporate information, regulator policy, international standards, and government strategy documents), comparisons with other hydrogen-producing jurisdictions, and direct industry consultations. Furthermore, a comprehensive bibliography of over one hundred references has been generated (refer to Section 8) to capture these sources; however, feedback and commentary from industry stakeholders has been kept anonymous.

This gap analysis report has been structured into six sections:

1. ***Review of Current Hydrogen Roadmaps and Strategies*** – Understanding the starting position of Alberta in context with Canada's national hydrogen strategy and relative to a collection of other major hydrogen-producing and/or consuming regions.

2. ***Assessing Technology Gaps in Alberta on a 3-Year Horizon*** – Context and targets based on industry feedback of what could reasonably be expected in terms of progress in the transition toward the long-term vision for hydrogen in the province.

3. ***Technology Gaps and Challenges*** – An in-depth gap analysis of each aspect of Alberta's hydrogen value chain, from producer to end user, and export potential. Specific technology gaps and challenges are highlighted in each section.

4. ***Summary of Technology Gaps and Challenges*** – The specific technology gaps and challenges highlighted are collected and summarized under higher-level technical themes or challenges that may be considered in developing Alberta's research priorities in this area.

5. ***External Factors – Challenges for Alberta's Hydrogen Economy*** – A discussion about potential external conditions that are not directly technical; although, could create conditions that result in technical challenges for stakeholders in the hydrogen value chain.

6. ***Conclusions and Recommendations*** – The final section of the report groups the gaps into main themes and provides focus area recommendations for Alberta's hydrogen economy stakeholders to build momentum towards a successful transition.

The purpose of this gap analysis is to focus exclusively on the technical challenges associated with the transition to hydrogen; commercial and economic challenges have been excluded from this study. Furthermore, as this is a gap analysis, a thorough assessment of how to overcome challenges and fill gaps has not been included; innovation and technology development will be driven by industry stakeholders, with support from the Alberta government, through policy and legislative processes.

This technology gap analysis builds off of existing work conducted in and outside of Alberta that is assessing various aspects of the hydrogen value chain, and is intended to provide Alberta Innovates with additional information to support research and development (R&D) initiatives that will accelerate the province toward a robust hydrogen-based economy.

2. REVIEW OF CURRENT HYDROGEN ROAD MAPS AND STRATEGIES

2.1 Alberta's Current Position on Hydrogen

Alberta issued a *Natural Gas Vision and Strategy* roadmap in October 2020 [1]. This plan included a brief description of the government's initial plans to develop hydrogen from industrial feedstocks to a broad-use commodity to assist in the decarbonization of the economy.

Subsequent to the release of Alberta's natural gas strategy [1], Alberta Innovates contracted C-FER to perform this gap analysis as part of a more detailed effort by Alberta Innovates to pinpoint technology innovation needs for decarbonizing Alberta's economy; including a successful transition to the use of hydrogen on a broad scale.

2.2 Canada's Hydrogen Strategy

The *Hydrogen Strategy for Canada* was released in December 2020 [2] and is a framework for actions to build hydrogen use into Canada's long-term goal of net-zero emissions by 2050. The document paints a vision of how a hydrogen economy in Canada could work by utilizing existing infrastructure, resources, and technology that exist in the country today to modernize Canada's energy systems.

The national hydrogen strategy is divided into three horizons:

1. ***2020-2025*** – Encourage early deployment hubs with mature hydrogen production (such as the Alberta Industrial Heartland), use regulation to drive investment, and frame new policy and regulatory measures to achieve long-term goals.
2. ***2025-2030*** – Growth and diversification of Canada's hydrogen industry.
3. ***2030-2050*** – Position Canada to be a world-leading supplier of hydrogen technology, generate economic recovery and growth (including large-scale employment opportunities), and use hydrogen as a key aspect of the net-zero emissions goal by 2050.

Furthermore, this document highlights the strategy's proposed recommendations through a series of eight pillars, as shown in Table 2.1.

Pillar	Pillar Name	Recommendation
1	Strategic Partnerships	Strategically use existing and new partnerships to collaborate and map out the future of hydrogen in Canada.
2	De-risking of Investments	Establish funding programs, long-term policies, and business models to encourage industry and governments to invest in growing the hydrogen economy.
3	Innovation	Take action to support further R&D, develop research priorities, and foster collaboration between stakeholders to ensure Canada maintains its competitive edge and global partnership in hydrogen and fuel cell technologies.
4	Codes and Standards	Modernize existing and develop new codes and standards to keep pace with this rapidly changing industry and remove barriers to deployment, domestically and internationally.
5	Enable Policies and Regulation	Ensure hydrogen is integrated into clean energy roadmaps and strategies at all levels of government and incentivize its application.
6	Awareness	Lead at the national level to ensure individuals and communities are aware of hydrogen's safety, uses, and benefits during a time of rapidly developing technologies.
7	Regional Blueprints	Implement a multi-level, collaborative government effort to facilitate the development of regional hydrogen blueprints to identify specific opportunities and plans for hydrogen production and end use.
8	International Markets	Work with our international partners to ensure the global push for clean fuels includes hydrogen so Canadian industries thrive at home and abroad.

Table 2.1 Canada's Hydrogen Strategy – Proposed Recommendations [2]

Canada's hydrogen strategy does not go into technical detail about every aspect of the national hydrogen value chain; however, it does provide a good backdrop and guidance for what stakeholders can expect from the federal government's perspective with respect to how the hydrogen industry can succeed. Gap analyses, such as the one being performed by Alberta Innovates' project team, provide an opportunity to take a closer look at what is needed for the transition to occur.

2.3 Brief Summary of International Hydrogen Development

2.3.1 United States Hydrogen Development

Understanding American hydrogen strategy and industry development will be critical to technology development and export opportunities for Alberta. In 2020, the U.S. Department of Energy ("US DOE") issued their Hydrogen Program Plan [3], a roadmap for the United States hydrogen industry to follow, in order to meet projected energy demands while reducing emissions. The US DOE's hydrogen plan assesses the current use of hydrogen in the United States energy system, as well as identifies short- and long-term needs and challenges that the entire hydrogen value chain may face during this period of growth.

Current United States hydrogen production is approximately 10 million tonnes per year; mainly servicing the needs of the energy and petrochemical industries. While industrial demand is projected to increase, the bulk of future demand in the US is expected to be from fuel-cell electric vehicles and other means to decarbonize the economy. Based on the US DOE's hydrogen plan, hydrogen demand is projected to increase to between 20 and 60 million tonnes by 2050.

Many of the challenges that are raised by the US DOE are also identified as challenges for Alberta-based hydrogen stakeholders. Furthermore, while there is no specific discussion about an American need to import hydrogen to meet their decarbonization efforts, it appears as though there is an opportunity for a significant amount of hydrogen to be supplied by Alberta to supplement American domestic production.

2.3.2 Overseas Hydrogen Development

Globally, there is a push to expand the use of hydrogen from industrial feedstock to a fuel that can help nations meet emissions targets set by The Paris Agreement [4]. In the United Kingdom, there is the belief that hydrogen can complement broad electrification of domestic energy systems and there is also a sense that domestic hydrogen production from renewable power may help reduce reliance on imports for energy production [5]. Germany has plans to become a zero-carbon producer of hydrogen [6] and ramp up the use of hydrogen through small, localized user hubs and build out infrastructure from there. The Asia-Pacific Energy Research Company sees growing interest from Asian countries to source low-cost hydrogen from jurisdictions like Canada [7]. Japan, an early adopter of hydrogen (having published its strategy in 2017), is moving more toward hydrogen for similar reasons as their European counterparts to decarbonize the Japanese economy and the national hydrogen strategy calls for a three-phase approach [8]: (1) a dramatic increase in the use of hydrogen across all aspects of the economy; (2) domestic hydrogen power generation by 2025-2030; and, (3) establishment of CO_2-free hydrogen supply system on a total basis by 2040 (note that fossil fuel-derived hydrogen coupled with carbon capture meets this criterion).

China [9] (currently the largest producer of hydrogen in the world, at 20 million tonnes per year) is strongly considering moving to cleaner hydrogen production and reduced reliance on coal for power and thermal industrial processes. South Korea embraced the hydrogen opportunity several years ago and is a global-leader in fuel-cell electric vehicles (with the Hyundai Motor Company ("Hyundai") producing several thousand per year) and industrial-scale fuel cell manufacturing [10]. Interestingly, South Korea is not pursuing hydrogen to decarbonize its economy but rather for industrial competitiveness and economic growth. This stands in contrast to virtually every other jurisdiction examined in this analysis.

Australia has been developing its hydrogen industry for several years and as of late 2020 was already exporting hydrogen produced from coal (without carbon capture) to Asian markets in specially-designed hydrogen carrying ships [11]; however, the national strategy [12] seeks to move toward decarbonized production, use, and export in a way that parallels Canada’s strategy; including Australia becoming a significant hydrogen producer and exporter by 2030.

3. ASSESSING THE TECHNOLOGY GAPS IN ALBERTA ON A 3-YEAR HORIZON

Currently, Alberta produces 5.4 thousand tonnes (kt) of hydrogen a day [13] or 1.97 million tonnes (Mt) per year with most production located in either the Alberta Industrial Heartland (around Edmonton, Alberta), or in Fort McMurray, Alberta. In relation to this production, approximately 0.9 kt per day (0.33 Mt/year) is blue hydrogen (i.e. by way of steam-methane reforming (SMR) in combination with carbon dioxide (CO_2) capture systems and underground storage) and the balance is grey hydrogen production (i.e. where no CO_2 capture mechanism is in place).

The hydrogen that is produced in Alberta is used almost exclusively for either hydrocarbon upgrading and refining, or industrial processes (e.g. ammonia and fertilizer production). Furthermore, this produced hydrogen is not transported long distances; with most hydrogen produced within the same industrial complex, or in close proximity to nearby facilities where it is used. In these cases, purpose-built hydrogen pipelines are used to move the hydrogen within and between facilities.

The hydrogen value chain that was assessed for this project can be divided into five main parts:

1. ***Decarbonized Hydrogen Production*** – zero- or low-emission hydrogen production from natural gas by way of steam-methane reforming or partial oxidation production processes.

2. ***Hydrogen Transmission and Production*** – hydrogen that is produced in Alberta will need to move beyond local use to applications located throughout the province.

3. ***Hydrogen Storage*** – Storage is critical to act as a buffer for variability in hydrogen supply and demand.

4. ***Hydrogen End-Use*** – Hydrogen has the potential to replace various emissions-intensive processes in use; however, this will require large-scale conversion and adoption.

5. ***Export Market Potential*** – Exporting hydrogen as a commodity to foreign markets will bolster Alberta's economy and is a pillar of the provincial government's vision for hydrogen in the future.

Major changes and developments across the entire hydrogen value chain are required for hydrogen to evolve from feedstock for industrial purposes to broad-spectrum means of both energy storage and low-emission heating fuel. Alberta and Canada have set ambitious long-range targets for hydrogen production, and its use and export; however, short-range targets and milestones must be accomplished to lay the foundation for success toward these end goals.

To this end, the focus of this gap analysis was to identify the challenges and gaps that the hydrogen economy faces in the next three years (i.e. by 2024). It was established at the onset of this study that it will take much longer than three years to grow the hydrogen industry in Alberta from where it is today to what is envisioned; however, aggressive, yet achievable, milestones were set by the project team for various aspects of the hydrogen value chain. These milestones were based on direct consultation with industry stakeholders; as well as, comparisons with other jurisdictions that are also in the process of developing or deploying hydrogen road maps and strategies.

3.1 Decarbonized Hydrogen Production

Most of Alberta's hydrogen production is carbon-intensive (e.g. 1 tonne of hydrogen produced by way of steam-methane reforming results in approximately 9 tonnes of CO_2). For Alberta to achieve a vision of decarbonized hydrogen production, it will be necessary to add CO_2 capture and storage to hydrogen production; however, given the magnitude of investment and resources required to achieve this goal, it may not be possible that processes to capture CO_2 generated from hydrogen production will be in place in all existing hydrogen production facilities within the 3-year time frame. Instead, the assumed target is a conversion process underway with a parallel focus on increasing the efficiency of the hydrogen production processes used in Alberta. Given the timeline required to build facilities to support large-scale hydrogen production, significantly expanded decarbonized hydrogen production by 2024, through new production facilities, was not considered a target for this gap analysis.

3.2 Hydrogen Transmission and Distribution

Moving hydrogen around the province to an expanding base of end users will require the use of pipelines, both at the transmission and distribution level. However, hydrogen is known to be potentially damaging to steel under some circumstances. Industry experts suggest that hydrogen could be shipped via existing pipelines at no more than 20% hydrogen in the blend. Given the limited available hydrogen production capacity that will exist in three years (based on Section 3.1), it will be difficult to achieve even a 10% blend ratio of hydrogen to natural gas across the entire natural gas supply system; although, these levels could be achieved in local areas. As such, it was decided that 10% hydrogen blend is the maximum achievable ratio in the next three years. Furthermore, new dedicated hydrogen transmission pipelines may not be commissioned in Alberta before 2024.

3.3 Hydrogen Storage

Targets for new hydrogen storage in the next three years were not considered due to the low blend of hydrogen in select pipelines across the province. Blends of hydrogen and natural gas may end up in existing salt cavern natural gas storage sites; however, at relatively low quantities.

3.4 Hydrogen End Use

A viable hydrogen economy will require a wide range of end uses and conversions from existing fuels and energy systems that hydrogen is targeting to replace. Given the relatively small-scale increase of hydrogen production forecasted in this 3-year horizon, it is likely that the only significant change to hydrogen use (i.e. beyond what is currently in place) will be several pilot projects located at hydrogen 'hubs' around the province, demonstrating the effectiveness of hydrogen as a replacement fuel for home heating and possibly vehicle use. In this sense, there will be matching use and demand for the supply that is envisaged in 2024.

3.5 Export Market Potential

The export market for Alberta's hydrogen in 2024 is not clear at this time, but will be developed through international efforts such as the Clean Energy Ministerial Hydrogen Initiative [14]. However, plans to coordinate blend standards and other key technical requirements for smooth transfer of hydrogen-based shipments will be determined between jurisdictions; whether in Canada or to the United States. Trade missions to Asia and Europe will showcase pilot projects in Alberta to demonstrate Alberta's hydrogen industry successes.

4. TECHNOLOGY GAPS AND CHALLENGES

Alberta Innovates tasked the project team to identify the major technical gaps and challenges that Alberta will face in developing a large-scale hydrogen economy. There are many challenges that hydrogen industries around the world face as they grow and many of those challenges will also be applicable to Alberta; however, the focus of this gap analysis was to examine the specific technology hurdles that could challenge Alberta's hydrogen economy stakeholders over the next three years, as momentum builds in this industry.

The research that was put into the gap analysis consisted of several interviews and discussions with stakeholders from across the hydrogen value chain including:

- Decarbonized hydrogen production;
- Carbon Capture Utilization and Storage (CCUS) operators;
- CO_2 Enhanced Oil Recovery (EOR) operators;
- Natural gas transmission pipeline operators;
- Steel and cement manufacturers;
- In-line inspection equipment suppliers;
- Engineering, Procurement and Construction (EPC) companies;
- In-situ oil sands operators;
- Federal and provincial regulators;
- Academia;
- Consultants;
- Research institutions; and
- Industry consortia and organizations.

4.1 Decarbonized Hydrogen Production

Alberta produces approximately two million tonnes (Mt) of hydrogen per year, which is approximately 3% of global hydrogen production [15]. This is achieved largely through steam-methane reforming at a handful of large industrial sites near Edmonton and Fort McMurray. Steam-methane reforming is a cost-effective and proven way to produce hydrogen in a two-stage process [16]:

Steam-methane reforming reaction

$$CH_4 + H_2O \text{ (+ heat)} \rightarrow CO + 3H_2$$

Water-gas shift reaction

$$CO + H_2O \rightarrow CO_2 + H_2 \text{ (+ small amount of heat)}$$

As effective as this process is, it is also very greenhouse gas (GHG) intensive. This process creates approximately nine units of CO_2 for each unit of hydrogen on a mass basis, despite the volumetric ratio being much closer due to the difference in molecular weight between hydrogen and CO_2. Most of the hydrogen produced in Alberta does not include any carbon capture process, resulting in approximately 18 Mt of CO_2 being released to the atmosphere per year [13].

The CO_2 emissions from Alberta's hydrogen industry is equal to approximately 17% of the 2030 emissions reduction target [17] of 105 Mt CO_2 per year set by the Government of Canada 2020 Strengthened Climate Plan (note that the federal government announced a more ambitious emissions reduction target on April 22, 2021; however, this target has not been made official as of this report's publication date). Therefore, adding CO_2 capture to the remaining hydrogen production would make a significant contribution to Alberta and Canada's goals of achieving long-term success in meeting emissions reduction targets.

Approximately 342 kt of decarbonized hydrogen is produced per year in the Alberta Industrial Heartland northeast of Edmonton via processes involving carbon capture. At Shell Canada Energy's ("Shell") Scotford upgrader complex [18], hydrogen is produced through a combination of SMR with a proprietary system to capture the process CO_2 (i.e. ADIP-X). At Nutrien Ltd.'s (Nutrien) fertilizer plant, hydrogen is produced through dehydration of industrial process CO_2 gas and the Northwest Redwater Sturgeon Refinery (NWR Refinery) uses the Rectisol® acid gas removal process to produce a small amount of decarbonized hydrogen [13].

To achieve decarbonized hydrogen production in the province, large-scale conversion of existing SMR hydrogen production toward reduced-emissions processes will be required in parallel with any expansion of hydrogen production to meet future demand. Both the conversion of existing hydrogen production facilities and the increase in hydrogen production capacity face multiple technical challenges. Solutions to these challenges may not be feasible in certain situations; however, these challenges must be addressed to achieve the long-term goal of decarbonized hydrogen production.

4.1.1 Steam-Methane Reforming Hydrogen Production

The 3-year target for decarbonized hydrogen production is based on adding CO_2 capture to all hydrogen production processes; however, currently there are limitations to how much CO_2 can be captured during hydrogen production via SMR. For example, during the first five years of Shell's Quest project, the carbon capture process efficiency was between 77.4% and 83.0%, as shown in

Figure 4.1, taken from Shell's, *Quest Carbon Capture and Storage Project - 2019 Annual Summary Report* [19], to the Government of Alberta.

The CO_2 is removed from the production stream via amine scrubbing, an energy-intensive process. This process is used extensively for a wide range of industrial applications and can remove up to 90% of CO_2 from a fluid stream [20] under ideal circumstances; however, recoveries between 75% and 85% are more common.

Quest Operating Summary	2015 Summary	2016 Summary	2017 Summary	2018 Summary	2019 Summary	Units
Total CO_2 Injected	0.371	1.11	1.138	1.066	1.128	Mt CO_2
CO_2 Capture Ratio[4]	77.4	83.0	82.6	79.1	78.8	%
CO_2 Emissions from Capture, Transport and Storage	0.080[3]	0.238[3]	0.241[3]	0.241[5]	0.237[5]	Mt CO_2
Net Amount (CO_2 Avoided)	0.291[3]	0.870[3]	0.897[3]	0.826[1,2,3]	0.891[1,2]	Mt CO_2
Waste Heat Credits	0.022[1]	0.062[1]	0.051[1]	0.044[1]	0.044[1]	Mt CO_2

1. Under SGER, waste heat credits were claimed from 2015-2017. As of Jan 1, 2018, under CCIR, waste heat was claimed under the Scotford Upgrader. Quest is an integrated operation within the Scotford Upgrader Complex, therefore, in 2018 and 2019 the Net CO_2 Avoided includes 0.044 Mt CO_2.
2. Under SGER, the reported indirect GHG emissions from imported steam for Quest was reduced by the Target (e.g. 20%), which is the required reduction in GHG intensity for large final emitters such as the Upgrader. Under CCIR, there is no target specified. As a result, the Target is set to 0% under CCIR.
3. 2015-2018 CO_2 emissions have been updated based on AEP's audit close out on waste heat methodology. The revised emissions now include the addition of 3rd party verified waste heat claims.
4. The CO_2 capture ratio refers to the percentage of CO_2 captured from the syngas (raw hydrogen) feed stream to the absorbers.
5. Indirect GHG emission from imported electricity now capturing electricity usage from both the Upgrader Cogen (0.37 tCO_2/MWh) and the grid (0.64 tCO_2/MWh).

Table 4.1 Summary of Shell Quest CO_2 Capture Rates 2015-2019 [19]

Technologies are being developed to improve the effectiveness of capturing the CO_2 produced during SMR; however, to-date, there is no indication that any of these methods will achieve 100% capture efficiency [21] on an industrial scale. One technology in particular that is being examined is autothermal reforming (ATR), a modification of the SMR process using pure oxygen, which nets higher carbon capture (upward of 95%) compared to traditional SMR; however, it is not used in Alberta, but is being considered elsewhere on a limited trial basis [13].

To this end, zero-carbon hydrogen production is not expected to be achievable using natural gas as the feedstock using existing SMR technology. This may be an important challenge to overcome in establishing international market share in competition with hydrogen production from renewable energy powered electrolysis (i.e. green hydrogen).

Gap: Typical SMR carbon capture processes cannot remove 100% of CO_2 formed during hydrogen production due to the process pulling CO_2 from the production stream. New technologies need to be developed to be installed inline with or in replacement of existing carbon capture technologies if 100% capture is to be achieved for hydrogen production via SMR.

4.1.2 Alternative Decarbonized Hydrogen Production Technologies

Although SMR (with or without carbon capture) is the most common means of hydrogen production in Alberta, there are other technologies that are being evaluated to produce decarbonized hydrogen. These technologies are further outlined in the following subsections.

4.1.2.1 Methane Pyrolysis

Methane pyrolysis is a process for hydrogen production from methane that does not produce carbon dioxide in the process, but rather solid carbon (i.e. carbon black) [22]. This one-step process produces hydrogen in high volume and at low cost with no CO_2 emissions. The industrial quality carbon can then be sold or landfilled and is prevented from being released into the atmosphere. Electricity consumption for this process is a fraction of the amount of what is consumed in the water electrolysis method for producing hydrogen.

Methane pyrolysis is being investigated by Ekona Power Inc. ("Ekona") for Alberta's hydrogen economy through an Emissions Reduction Alberta ("ERA") funded project, *Development and Field Testing of a Tri-generation Pyrolysis (TGP) System for Low-cost, Clean Hydrogen Production*, in partnership with Suncor Energy Inc. ("Suncor") and Cenovus Energy Inc. ("Cenovus"). The project [23] will develop and demonstrate a pulse methane pyrolysis (PMP) system for industrial-scale hydrogen production. The project will also demonstrate a direct carbon fuel cell (DCFC), which converts the solid by-product carbon from the PMP process to electrical power and enhances the economics of hydrogen production. According to Ekona, the resulting TGP platform produces clean hydrogen at costs lower than conventional SMR, incorporating CCUS with up to 90% lower GHG emissions. The 3-year ERA program will result in a field trial unit that will produce 200 kg/day of hydrogen, with plans to scale up production pending industry interest.

As an emerging technology, methane pyrolysis shows significant promise to produce large-scale hydrogen without GHG emissions. Furthermore, as methane pyrolysis only produces solid carbon, it does not require CCUS capacity; thus, a methane pyrolysis hydrogen production facility can be placed away from a network of pipelines feeding into a carbon sequestration operation. However, a market for the solid carbon black that is produced in the methane pyrolysis process will likely be required for it to be an attractive investment option (note that additional pyrolysis technologies, such as molten metal reactors, microwave dissociation of methane, and rapid pressurization and depressurization to dissociate hydrogen from the carbon in methane, are also being tested in Alberta through projects funded by Emissions Reduction Alberta ("ERA") and Alberta Innovates).

Considering the status of Ekona's trial project with ERA, it is unlikely that parallel large-scale methane pyrolysis will be pursued in the next three years; however, this will be driven more by economics than technical challenges. That said, given the costs associated with building new SMR with CCUS capacity in the province, as well as the limitations of how much CO_2 can be removed from SMR-generated hydrogen, methane pyrolysis should be closely examined because it will not put a strain on the CCUS network like other means of decarbonized hydrogen production (further discussed in Section 6.1)

4.1.2.2 Electrolysis

Electrolysis powered by renewable electricity is the basis of green hydrogen production. As a well-established method to produce hydrogen, electrolysis is also very energy intensive – far more than SMR and methane pyrolysis, requiring approximately 39 MWh of power to produce 1.1 tonnes of hydrogen by electrolysis, compared to between 5.7 and 5.2 MWh for SMR and methane pyrolysis [24], respectively.

Alberta's electrical grid is not carbon neutral; therefore, while the electrolysis process itself does not produce GHG emissions, electrolysis performed in Alberta would have significant associated emissions and thus, would not be considered decarbonized hydrogen. Furthermore, the cost of electricity in Alberta makes electrolysis uneconomic and impractical.

Gap: Alberta does not have large-scale, low-cost low-carbon intensity electricity to make electrolysis a practical means of hydrogen production at large-scale.

4.1.3 Increasing CO_2 Capture in Brownfield Hydrogen Production

Hydrogen is an important feedstock for many petrochemical and agricultural products as well as in the treatment and upgrading of Alberta's bitumen [25]. Some industrial facilities in Alberta produce their own hydrogen; whereas, others buy it from producers. These industrial facilities are an intricate network of modules and subsystems interconnected to each other via thousands of kilometers of piping and pressure lines. To note, systems that may be totally separate from each other on a process diagram may be physically intertwined, as shown in Figure 4.1. Sometimes these designs incorporate space for future expansion or additional facility capabilities; however, this is not always the case.

Figure 4.1 Shell Scotford Upgrader in Fort Saskatchewan, Alberta, Canada (Source: Shell Canada Limited) [26]

In the context of this report, this is important because the SMRs used in hydrogen manufacturing units are closely integrated with other systems; leaving little room to install carbon capture systems; but it is possible. Shell's Scotford upgrader complex was originally designed with a hydrogen manufacturing unit using SMR without CCUS capability. The decision to incorporate CCUS capability with Shell's proprietary ADIP-X carbon capture system came years after the upgrader first started operations and was made in conjunction with a substantial investment from government in Shell's Quest carbon capture and storage (CCS) project (i.e. CAD$870M in combined capital and operational funding to-date, plus future operating subsidies). Decarbonized hydrogen production at Shell Scotford eventually came online in 2015 once Quest was operational [18].

Shell's Quest CCS project plans to store approximately 27 Mt of CO_2 over a 25-year service life (note that this is well below the total storage capacity of the Basal Cambrian Sand formation that is being injected into). The publicly available literature states that the total cost (i.e. capital and operating expenses) of the project is approximately CAD$1.35B, which equates to approximately $50/t CO_2 sequestered. Furthermore, Shell stated in 2020 that they estimate that costs would be approximately 30 percent less if the project was started using current costs for labour and equipment [27], bringing the total cost for an equivalent facility based on this projection to $35/t CO_2

The Transition Accelerator estimates that the total cost of greenfield (i.e. new) SMR with CCUS hydrogen production is approximately $80/t CO_2 [13]. Comparing this with the known costs retrofitting the Shell Scotford upgrader, it shows that retrofitting existing systems could make more economical sense, rather than building new SMR with CCUS facilities in the broader effort to increase the ratio of decarbonized hydrogen production in Alberta.

However, some SMR facilities may not be well-suited for CCUS retrofitting. While it might be possible to divert SMR process flowlines to a carbon capture system distal to the SMR facility and then back into the original flow path; this may result in significant flow losses and corresponding increased energy requirements to complete the process and drive costs up. Furthermore, some facilities may be nearing the end of their service life thus making retrofits of new carbon capture systems uneconomic.

Gap: There may be some current hydrogen production facilities that cannot be retrofitted with conventional CCUS capability due to either plant layout or age. Depending on the number of these facilities, this may pose a significant challenge to decarbonization efforts in Alberta. Technology may need to be developed to find alternative ways to capture CO_2 further downstream or offset these emissions through capture elsewhere in the facility.

4.1.4 Moving, Using and Storing Captured CO_2

Carbon capture is only one part of the CCUS process; the CO_2 needs to be moved from where it is captured to where it can either be used by some other process or permanently stored. Currently, there are two fully operational, large-scale CCUS projects in Alberta [27]: 1) the previously discussed, Shell Quest project; and, 2) the Alberta Carbon Trunk Line (ACTL) system [28], that transports CO_2 from the NWR Sturgeon Refinery and Nutrien fertilizer plant in the Alberta Industrial Heartland to injection sites near Clive, Alberta – where it is used for Enhance Energy's CO_2 miscible flooding enhanced oil recovery (EOR) operations - to revitalize production from a depleted conventional oil reservoir.

These CCUS projects are world-class in both scope and scale and have garnered international attention for their effectiveness. The Shell Quest project has sequestered over 5 Mt of CO_2 since operation began in 2015 for an average of approximately 1 million tonnes per year. The ACTL system has been in operation since May 2020 and has already transported 1 Mt of CO_2 sequestered in Enhance Energy's operations. The ACTL system has the capacity to move almost

15 Mt of CO_2 per year and Shell Quest can handle up to 2 Mt of CO_2 per year; as such, there is surplus capacity of over 15 Mt per year available in these projects to move CO_2 from the Alberta Industrial Heartland to established CO_2 injection facilities.

Despite the ACTL system's capacity to supply EOR projects such as Enhance Energy, it is not as straightforward as filling the pipeline to capacity and increasing the amount of CO_2 that goes into the depleted oil reservoir. The amount of CO_2 that can be used by an EOR project is directly tied to the reservoir injectivity, CO_2 capacity, and the number of wells. To fully utilize the capacity of the ACTL system, additional sequestration wells must be developed at the injection site to expand the EOR process.

Gap: There is no feeder pipeline network to move CO_2 to Shell Quest or the ACTL from new large-scale carbon capture facilities in locations beyond the Alberta Industrial Heartland. If current SMR hydrogen production is to be converted to SMR with CCUS, new dedicated CO_2 pipelines and associated supporting infrastructure from Fort McMurray and other regions will need to tie into Shell Quest or the ACTL system, or new pipelines as part of local CO_2 storage capacities will need to be developed.

In the short-term, there should be sufficient capacity in the ACTL and at Shell Quest project to handle additional CO_2; assuming feeder lines are tied in from other CO_2 sources. Long-term, an expansion of injection capacity will need to occur in conjunction with expanded means to move CO_2 between capture and injection sites. Fortunately, Alberta is situated on a vast expanse of saline aquifers located deep within the Western Canadian Sedimentary Basin (WCSB) to expand CO_2 storage capacity. Furthermore, hydrogen production will compete with other industrial processes for access to CO_2 injection sites. Therefore, a substantial increase in CO_2 storage capacity will be required.

As an example, Canada's hydrogen strategy [2] projects a goal of 40 Mt of hydrogen production per year in 2050 (i.e. including production for domestic use and export). Assuming that this will be accomplished by a combination of hydrogen produced from hydrocarbons via SMR with CCUS and hydrogen produced through electrolysis using renewables at a 50/50 split; this results in 20 Mt per year of hydrogen production from SMR with CCUS. As noted previously, 9 tonnes of CO_2 are produced for every tonne of hydrogen produced by SMR; as such, this will result in 180 Mt of CO_2 produced and 144 Mt of CO_2 captured that will require storage per year (factoring in an 80% capture efficiency). This is a 72-fold increase over the current 2 Mt CO_2 that is being sequestered by Shell's Quest project and the ACTL combined.

Gap: While this is primarily an infrastructure gap, the sheer scale of this undertaking may require new technologies and innovation to improve large-scale efficiency and performance of a potentially large network of CCUS facilities and pipelines.

Note that it is assumed that carbon storage will be the primary end point for CO_2 in the near-term, as carbon utilization processes are not expected to be at a scale to divert a significant quantity of CO_2 in the province.

Gap: CO_2 sequestration capacity must lead hydrogen production. As hydrogen production increases, CO_2 sequestration capacity must increase at a rate commensurate with the amount of CO_2 produced in the process. Given the time to evaluate, obtain regulatory approval and complete infrastructure construction of a CO_2 transportation network and sequestration site, this could constrain the expansion of hydrogen production in the province if CO_2 sequestration capacity lags the demand created by decarbonized production.

While the Global CCS Institute ("Global CCS") estimates that there is saline aquifer pore space available for approximately 200 to 430 billion tonnes of CO_2 injection [29] in Canada (with much of it being located in Alberta), and CO_2 injection technology is relatively well-established, there are risks and challenges that must be understood and addressed if the scale of CCUS capacity is to match the forecasted demand. Alberta is home to thousands of abandoned and shut-in wells [30], many of which penetrate the cap rock of reservoirs that may otherwise be ideal for CO_2 sequestration. It will be critical to locate these abandoned or shut-in wells and assess the risk of these wells creating leak paths through the cap rock; potentially enabling injected CO_2 to enter potable water aquifers or reach surface.

Gap: Abandoned and shut-in oil and gas wells may compromise cap rock integrity in reservoirs chosen for CO_2 sequestration. It will be critical to ensure that all potential leak paths are identified, and risk-mitigation measures are taken to ensure that the danger of CO_2 breaching the cap rock is avoided or minimized to an acceptable level.

Although estimates have been made on total capacity, a detailed inventory of ultimate storage capacity in the major saline aquifers and injectivity rates for these reservoirs will be required to determine the investment required to expand CO_2 storage capacity. Moreover, while current rates of CO_2 injection appear to not have a significant impact on the broad network of saline aquifers, the massive amounts of CO_2 that will be injected in the future may result in CO_2 migrating from injection sites to other areas of the aquifer network, where the cap rock integrity is less well-documented. Basin-scale planning is required for future CCUS injection locations that will consider regional geology and potential interactions among multiple injection sites.

Gap: It remains unknown what the impact of injecting upwards of 180 Mt of CO_2 per year into deep aquifers will do to regional subsurface reservoir pressures and how this pressure could affect cap rock integrity.

4.1.5 Water Consumption in Decarbonized Hydrogen Production

Another aspect of decarbonized hydrogen production that must be addressed is the amount of water required. According to a study [31] by WaterSMART Solutions Ltd. ("WaterSMART Solutions") on the impact of increased hydrogen production on water usage in the province, SMR can require between 5.8 and 13.2 L of freshwater for every kilogram of hydrogen produced. This water consumption is based on stoichiometric requirements of SMR as well as cooling and steam demand in large-scale hydrogen production. Scaling up hydrogen production will put a significant strain on water resources in the province. As such, transitioning to a hydrogen economy may be limited by the amount of water available in the province, factoring in allocations for municipal, agricultural and industrial use that already exist. This limitation will vary based on location in the province (e.g. the south has more water allocated than the north); however, it will be critical for the Government of Alberta to develop water management strategies.

Gap: The impact of large-scale hydrogen production on provincial water resources is not widely understood. Given the critical nature of water resources to Albertans, technology will need to be developed and deployed to reduce the amount of water required per unit of hydrogen production.

In-situ oil sands operators are proficient at industrial-scale water treatment for steam injection processes used in steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) operations. These facilities have become very effective, to the extent that up to 98% of the water used in the process is recycled (i.e. the remaining water is retained in the reservoir). The technologies used in these facilities may be suitable for providing water to the hydrogen industry from brackish or saline aquifers where freshwater supply is restricted.

Gap: Water treatment and re-use technologies similar to those used for SAGD and CSS operations need to be developed to minimize freshwater use in SMR production of hydrogen.

4.2 Hydrogen Transmission and Distribution

Hydrogen can be transported through pipelines in a pure state or mixed with natural gas. At present, pure hydrogen pipelines are typically operated as direct links between a hydrogen producer and an industrial end user such as a refinery or ammonia plant. These pipelines use metallic alloys that have low susceptibility to damage caused by hydrogen, including embrittlement and cracking. However, these alloys are not typically used in pipeline systems designed for transmission of natural gas. Alternatively, diluting hydrogen by blending it with natural gas could make it possible to transport hydrogen safely in systems originally designed to transport natural gas over long distances.

Natural gas distribution systems that carry gas at low pressure throughout urban areas are generally constructed of non-metallic materials such as high-density polyethylene (HDPE). While these systems are not impermeable to hydrogen, hydrogen does not degrade the mechanical properties of these materials the way it can in some metallic alloys.

4.2.1 Blending Hydrogen in Existing Transmission Pipelines

The National Renewable Energy Laboratory ("NREL") suggests that between 5% and 15% hydrogen could be blended into the current natural gas transmission network without significantly impacting safety, the durability of the pipeline network or the performance of end use appliances [32]. However, the report cautions that even at low hydrogen blends, “extensive study” on a case-by-case basis is required to determine what volumetric ratio of hydrogen is safe for each pipeline. Furthermore, the report notes that hydrogen blends above 50% face additional challenges across multiple areas, including pipeline materials and safety.

It appears that the International Renewable Energy Agency ("IRENA") and NREL share in the opinion that most existing transmission pipeline networks, and parts of their distribution systems in place for natural gas handling, will require substantial retrofitting and modifications to accommodate the safe transport and handling of hydrogen blends up to 100% [33].

In contrast, a consortium of 11 gas utilities from nine European Union ("EU") states, launched as the European Hydrogen Backbone plan, have proposed the development of a dedicated hydrogen transport infrastructure expected to reach 6,800 km by 2030 and 23,000 km by 2040 [34]. Approximately 75% of the proposed hydrogen network would consist of converted natural gas pipelines, while 25% of the infrastructure would account for newly built pipeline. The consortium maintains that little modification is required for natural gas pipelines to carry pure hydrogen; however, they concede that due to the low volumetric weight of hydrogen, compression stations will require major modification.

The position of the consortium contrasts with the opinions expressed by NREL or IRENA; demonstrating that North American pipeline operators appear to be less optimistic about the ability to use existing natural gas transmission networks for hydrogen than their European counterparts.

Figure 4.2 shows a plot published by the International Energy Agency ("IEA") illustrating how various jurisdictions have set limits, as of March 2020, on the proportion of hydrogen that can be blended in their respective natural gas networks. Jurisdictions, such as the United Kingdom, have low allowable hydrogen blending limits as a carry over from legislation adopted from oil and gas operations, where hydrogen content is generally negligible. As jurisdictions transition to hydrogen, these allowable levels are continually updated to reflect the level of confidence in the ability of the network to operate safely.

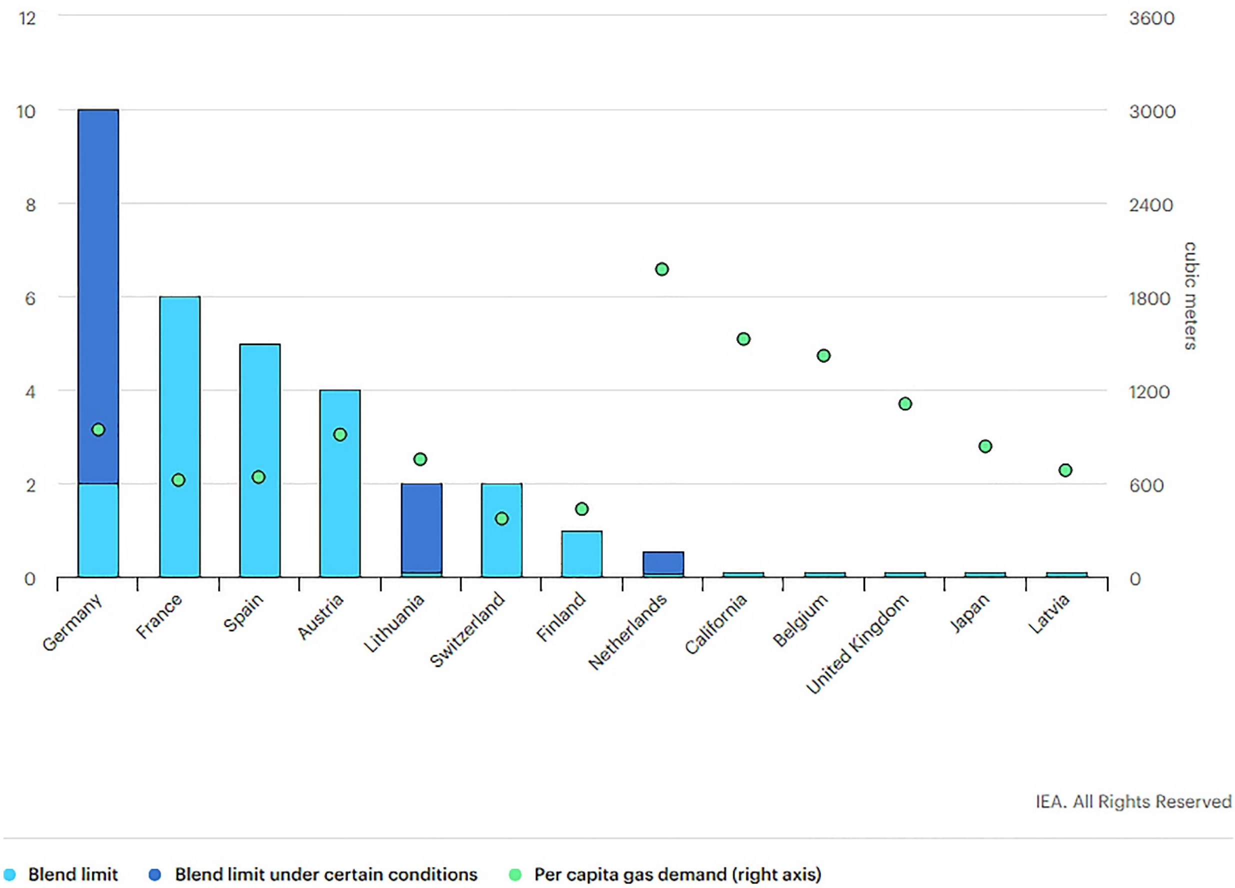

Figure 4.2 Percent Hydrogen Blend Limits in Various Global Natural Gas Networks [35]

Perhaps the longest running pipeline system where hydrogen is blended with natural gas is in the Hawai'i Gas network [36]. Since 1970, residual naphtha from the crude oil refining process has been used to manufacture Synthetic Natural Gas (SNG). A portion of the SNG is then converted to hydrogen using SMR. This results in a mix of SNG with approximately 12% hydrogen that is delivered to customers. The gas distribution pipeline is limited to the island of Oahu and consists of only 35 km of transmission line.

Several limited hydrogen blending projects have been conducted around the world, with most adding hydrogen to isolated sections of gas distribution networks or confined to off-grid research projects; these trials are summarized in Table 4.2.

Project	Location	Timeline	Hydrogen Blend (%)	Description
GRHYD [37]	France	2020-2021	20	Hydrogen blend to 100 homes.
SNAMTEC [38]	Italy	2019 (1 Mo.)	5	One-month trial to two industrial customers.
HYDEPLOY [39]	UK	2019 - Present	20	Experiment at Keele University to small-scale commercial boilers.
ATCO [40]	Australia	2019 - Present	Not Available	Demonstration project, hydrogen-powered experimental home.
H2RES [41]	Denmark	2021 Start	Not Available	Wind generated hydrogen for vehicle fuels.
Ameland [42]	Netherlands	2007-2011	20	14 homes supplied with hydrogen for four years.
H100 [43]	Scotland	2022 Start	100	100% hydrogen to 100 homes in Fife, Scotland.

Table 4.2 Summary of International Hydrogen Blending Trials and Projects

These hydrogen blend trials were of limited duration and were conducted under tightly controlled conditions, with very few customers, in limited areas. The size of each project was likely limited by the capacity to generate hydrogen by electrolysis. Most have occurred in the last two years or have yet to begin. Consequently, there is very little information available on the performance of transmission or even distribution pipeline systems with hydrogen over the long-term.

In addition to the projects outlined in Table 4.2, hydrogen blending trials are also underway in Canadian public gas distribution networks, as summarized in Table 4.3.

Project	Location	Timeline	Hydrogen Blend (%)	Description
Enbridge [44]	Ontario	Q3 2021	2	Blended hydrogen storage and delivery to an established neighbourhood of 3,600 homes in Markham region.
Enbridge [45]	Quebec	Announced Q1 2021	Not Available	A hydroelectric electrolyzer will generate hydrogen to inject into a natural gas distribution network.
ATCO [46]	Alberta	Q1 2021	5	Blended hydrogen delivery to 5,000 homes in Fort Saskatchewan, Alberta.

Table 4.3 Summary of Canadian Hydrogen Blending Projects

Once operating, the Canadian hydrogen blending projects will each be significantly larger than any previous hydrogen blending projects to-date in Canada and elsewhere. Furthermore, these trials will differ from most other trials, as they will be operating in established, public natural gas networks. Moreover, these Canadian projects will provide key insights into operating a complex distribution system and how hydrogen blending might affect the distribution system and end use appliances.

4.2.2 Transporting Hydrogen in Legacy Pipelines

The key challenges related to transporting hydrogen blends in legacy pipeline systems fall into seven categories:

1. Line Pipe Materials.
2. Compressors Stations.
3. Metering and Gas Quality.
4. Inspection.
5. Leak Monitoring.
6. Maintenance.
7. Risk Management.

The following subsections discuss each of these identified categories in further detail.

4.2.2.1 Line Pipe Materials

Natural gas pipeline systems generally consist of long-distance transmission pipelines constructed of steel to transport gas at high pressure from the source of the gas to a "city gate" where the gas pressure is reduced. From there, it moves into the distribution system that is largely constructed of plastic pipe such as polyethylene (PE). Both steel and plastic pipe have unique challenges when considering hydrogen transportation.

4.2.2.1.1 Steel Line Pipe

Hydrogen can cause damage to many steel alloys by either embrittling the material or contributing to cracking [47]. Embrittlement reduces the ability of the steel to withstand damage caused by external factors such as ground movement and impact from equipment like excavators or farm equipment. The effects of hydrogen can also make the pipe more susceptible to fatigue cracking caused by fluctuations in the pipeline operating pressure.

Standards for designing pipelines to carry hydrogen have been established in several jurisdictions by industry associations, including:

- The European Industrial Gases Association ("EIGA") – *Hydrogen Pipeline Systems* [48];
- The American Society of Mechanical Engineers ("ASME") – *Hydrogen Piping and Pipelines* [49]; and
- The CSA Group ("CSA")– *CSA Z662:19 Oil and Gas Pipeline Systems* (Note: Canada's pipeline systems are designed according to this standard) [50] .

Currently, the Canadian standard does not address pipelines carrying hydrogen; however, CSA's Technical Committees have identified the need to amend the existing standard to include the impacts of hydrogen blending with natural gas and to add a clause, or a supplemental standard, to address pipelines dedicated to hydrogen transportation.

Gap: Canadian pipeline standards do not currently address requirements for pipelines carrying pure hydrogen or hydrogen and natural gas blends.

Generally, lower strength metal alloys are less susceptible to hydrogen damage mechanisms than higher strength materials [51]. Older pipeline systems were generally constructed of lower strength material that might be suitable for operation with low concentrations of hydrogen. However, details of the manufacturing processes for these older lines might not be available to verify suitability for exposure to hydrogen. Different manufacturing processes can result in different metal microstructures that have different susceptibilities to degradation in the presence of hydrogen. Consequently, two pieces of pipe that meet the specifications for a particular material grade might have different susceptibilities to hydrogen-related damage due to different microstructures [51].

Gap: Joint-by-joint details of the material properties, including micro-structure, of legacy pipelines are generally not available to assess compatibility with hydrogen.

Over time, pipeline designers have moved towards using higher strength materials to reduce the required pipe wall thickness which minimizes material costs, transportation costs and welding time; these materials are generally higher quality compared to the materials used for older pipelines due to higher manufacturing standards. However, the higher strength could make them more susceptible to the effects of hydrogen. Recent work has also shown that modern manufacturing processes may induce Local Hard Zones on the surface of the material [52]. This can make lower strength materials susceptible to cracking, which are commonly used where hydrogen-related material degradation is expected.

Nevertheless, newer pipe is not necessarily a better option. Recent work presented at the 2021 Pipeline Research Council International ("PRCI") Research Exchange (VREX2021) indicated that legacy pipe materials showed greater resistance to fatigue crack growth in the presence of hydrogen than new pipe materials of the same grade (e.g. X52) [53].

Gap: Performance of modern steel grades, including high-strength materials and materials that may include Local Hard Zones, are not well understood in the presence of hydrogen.

Hydrogen compatibility tests on a pipeline material commonly used in legacy systems (e.g. X52) concluded that exposure to hydrogen did not influence the burst pressure of a pipe [54]. These tests only exposed the steel to low pressure hydrogen for 20 hours, then removed the specimens from the hydrogen environment to conduct the burst test. The research also confirmed that the rate of hydrogen penetration into the steel increases dramatically (i.e., as much as five times) if the pipe is under stress while exposed to hydrogen. Furthermore, it appears that these tests did not reproduce the conditions that would occur in a pipeline carrying hydrogen; where the exposure to hydrogen is constant and at higher pressure, and where the steel is also under constant stress, which would increase the hydrogen permeation. Likewise, conducting the burst tests without continuous hydrogen exposure would reduce the hydrogen permeation at the time when the stress is highest, as the pipe approaches failure.

In addition, recent work for PRCI by C-FER has shown that standard burst testing procedures specified by the American Petroleum Institute ("API") can sometimes over-estimate the burst resistance of pipe with corrosion defects. This effect could be more pronounced when combined with time dependent environmental effects like hydrogen permeation that play a role in crack growth and changes in material properties.

Gap: Current test methods used to assess pipeline performance in the presence of hydrogen may not fully represent actual pipeline service conditions.

GRTGaz and CATALYSE in France are developing a coating to protect pipelines from the effects of hydrogen [55]. If a coating can be developed and applied efficiently, it could make it possible to re-use more of the current natural gas pipeline system for hydrogen blends. Expected challenges associated with the use of such a coating include:

- Cleaning the pipeline sufficiently to ensure proper bond with the coating;
- Ensuring consistent coating along great lengths of pipe, with limited access;
- Accommodating imperfect pipe geometry due to dents and ovalization;
- Accommodating ancillary pipeline equipment, such as valves and pig traps;
- Ability to inspect the condition of the coating;
- Ability to repair coating damaged by pipeline operation and repair activities; and
- Ensuring the coating does not affect the ability to inspect the condition of the base pipe using in-line inspection tools or in-ditch measurement techniques.

Gap: Feasibility and efficacy of internal pipeline coatings to increase hydrogen resistance are not well understood.

4.2.2.1.2 Welding

Welding processes used during steel pipeline construction and/or repair can increase the hardness of the material in the heat affected zone around the weld, making the material more susceptible to the effects of hydrogen [56]. Welding requirements in the current Canadian pipeline standard [50] are designed to minimize hydrogen-induced cracking.

Records from the construction of legacy pipelines may not include sufficient information on the welding procedure and weld filler materials to determine if the welds are compatible with hydrogen service. Weld inspections typically include X-ray imaging to identify defects in the weld and cracks that occurred as the weld cooled. Pipeline construction standards include specifications for the size and number of defects that are allowable in a weld. Since hydrogen has the potential to influence crack growth during pipeline operation, adding hydrogen to natural gas might change what defects and crack sizes are deemed acceptable to ensure reasonable operating life of the pipeline.

Gap: Acceptable weld defect and crack criteria do not exist for legacy and new pipeline materials in hydrogen service.

Special attention is required for in-service welding, where welds are applied to the exterior of the pipe while the pipeline continues to flow product. In-service welding is required in instances such as some repair operations as well as when branch lines are added to expand a pipeline system. The flowing gas or liquid in the pipeline tends to cool the weld faster than if there was no flow, or the pipeline is empty as it is during initial construction [57]. The faster cooling can cause hydrogen to become trapped in the weld zone and cause stress concentrations around the weld that can lead to cracking. When the flowing product contains hydrogen, there might be a higher potential to trap more hydrogen in the weld area, increasing the chance of cracking.

Gap: In-service welding procedures for pipelines carrying products that contain hydrogen have not been established.

4.2.2.1.3 Plastic Line Pipe

Plastic pipe used in distribution networks is typically medium-density polyethylene (MDPE) or high-density polyethylene (HDPE). Field tests in Denmark on various grades of new and used pipe were subjected to pure hydrogen for four years to determine if the material properties degraded with exposure to hydrogen [58]. The tests showed that these materials are not degraded by the presence of hydrogen, but are somewhat permeable to hydrogen; resulting in slightly higher leakage rates of hydrogen compared to steel pipe [59]. However, because of the lower energy density of hydrogen compared to natural gas, the amount of energy loss is 30% lower for hydrogen. This leakage rate is economically negligible and not, generally, a safety concern unless the leaked gas is confined by a building or other structure.

Other materials, such as polyamides [60] and fibre reinforced pipe (FRP) [61], exhibit greater resistance to hydrogen permeation and show no signs of degradation in the presence of hydrogen; however, they do not appear to be widely used.

4.2.2.2 Compressor Stations

Gas pipeline systems require a series of compressor stations distributed throughout the network to maintain pressure in the system. Compressor stations typically include multiple compressors for redundancy and to meet peak demand flow requirements. Each compressor is driven by an internal combustion engine or a gas turbine that consumes some of the gas from the pipeline. The compressors themselves may be positive displacement piston type or multi-stage turbine type.

Blending hydrogen (i.e. with natural gas) affects the compressor capacity required to move the gas blend through the pipeline network. Because hydrogen has only about 31% of the heating value per unit volume compared to natural gas, more hydrogen blend must be transported to deliver the same amount of energy to the customer. However, because hydrogen's density and viscosity are also lower, a larger volume of gas can be transported through the system at the same pressure.

One way to evaluate compression requirements with different gas blends is to consider the amount of energy that is delivered to the customer. Simulations of the power requirements for transporting different blends of hydrogen and natural gas [62] show that, to maintain equivalent energy delivery, the compressor power requirement increases 1.7 times at 20% hydrogen and almost 10 times for pure hydrogen compared to transporting natural gas. Since the compressors typically use the product in the pipeline as the fuel supply, the higher power requirement consumes more gas.

Another way to look at the impact of hydrogen blends on pipeline efficiency is to determine how much energy could be delivered if the existing compression systems are not upgraded. Simulations of existing pipeline systems show that if the compression capacity is not increased, the system capacity to deliver energy with a 20% hydrogen blend is reduced to 85% of the energy that can be transported with natural gas. This transportation efficiency declines significantly as more hydrogen is added [63].

Therefore, to maintain the rate of energy delivery to customers using hydrogen blends through the existing pipeline system, additional compressor capacity will be required.

In addition, hydrogen blends are expected to have the following impacts in the design and operation of compressor stations:

- Increases the combustion temperature in the drive unit, which can increase nitrogen oxide (NOx) emissions;
- Increases the flame speed so that flashback can occur inside the fuel injectors, causing damage to the drive unit;
- Reduces the Lower Explosive Limit (LEL) of the gas mixture which could result in combustible gas mixtures in the turbine exhaust during system faults such as failure to ignite. Ignition of this mix would result in overpressure in the exhaust system;
- Lowers the gas viscosity resulting in higher leakage rate through seals and connections;
- Reduces LEL which increases the probability of ignition of leaks from the compressor system, potentially requiring the reclassification of electrical equipment in the compressor station to meet local electrical codes for equipment in explosive environments;
- Changes the flame colour, with pure hydrogen burning with an invisible flame, so that current flame detection systems may be unreliable;

- Changes the gas density and composition which will affect leak detection systems that are calibrated for methane;
- Increases the potential for hydrogen-related embrittlement damage of metallic parts of the compressor system, including the drive unit, instrumentation, control and safety systems; and
- Increases the potential to damage non-metallic components such as seals, membranes and o-rings that might be susceptible to softening, embrittlement or explosive decompression.

Industry consensus is that most of the compression equipment currently installed on pipeline systems are likely compatible with gas blends up to about 20% hydrogen. However, some legacy reciprocating engine drive systems may not be compatible with over 5% hydrogen blends. Therefore, significant changes to compression technologies are not expected in the near-term, when hydrogen concentrations are not likely to exceed 20%; however, without adding additional compression capacity, the energy deliverability for a pipelines system would reduce to about 85% of its design capacity.

Gap: It is unclear to what degree current compressor stations are compatible with different hydrogen blends. Furthermore, the trade-off between the cost of increasing compression capacity and the customer impact of reduced energy delivery is unknown.

4.2.2.3 Metering and Gas Quality

The composition of blends of natural gas and hydrogen must be monitored in a pipeline network to confirm the transaction value of the gas, and that it meets quality standards for heating value, composition, and impurities. Metering is also critical for plant processes requiring specific combustion mixtures for optimal efficiency.

Most current methods of metering and quality monitoring use a combination of an ultrasonic flow meter to determine flow velocity and a gas chromatograph (GC) to determine the composition of the gas that can be used to calculate the Gross Calorific Value (GCV) or heating value of the gas. The GC units used on pipelines are not designed to analyse gas mixtures containing hydrogen.

Some researchers are developing systems to measure gas density that can be used to infer the heating value of the gas mixture [64]. These systems would not be capable of measuring trace impurities in the gas. This is important because trace impurities can have a significant impact on the effects of hydrogen on materials. For instance, only 100 ppm oxygen in the gas can reduce the effect of increased fatigue crack growth rate caused by hydrogen. This has prompted the suggestion that a minimum oxygen content could be specified for gas containing hydrogen [65].

Gap: A proven method to continuously monitor the composition of natural gas containing hydrogen is required to replace current GC methods.

4.2.2.4 Inspection

Transmission pipelines are inspected regularly to identify defects such as corrosion, cracks, and dents. Sophisticated in-line inspection (ILI) tools use a variety of devices based on magnetic, ultrasonic, and physical measurements to locate and size the defects. Since hydrogen can accelerate the growth of fatigue cracks, detecting cracks will become more important when transporting hydrogen blends. ILI tool service companies are continuously improving the performance of their tools to provide more reliable detection of small defects (fewer missed defects), more precise measurements of the size of the defect (usually length, width and depth) and more reliable identification of the defect as either corrosion wall loss or a crack.

The results of the ILI survey must be able to identify any defects that could grow to a critical size, and result in a failure of the pipeline before the next scheduled inspection. Since hydrogen could increase the rate of crack growth, ILI tools run in pipelines carrying hydrogen blends may need to either detect smaller cracks than required for natural gas pipelines or the tools will have to be run more frequently to reduce the time available for the cracks to grow.

Limited field trials of ILI tools have been run in pipelines carrying hydrogen [66]. Extended exposure to hydrogen could cause degradation of some metallic components of the tools or could impregnate seals and other non-metallic components to degrade the tool performance or service life.

Gap: ILI tools need to demonstrate the ability to operate in a hydrogen-rich environment and to detect smaller crack-like defects than what is currently possible in natural gas pipelines.

New ILI methods have been developed to determine the grade of the pipeline material. These tools could be used in legacy pipelines to record the type of steel used where construction records are incomplete. This information would help operators determine if a legacy pipeline is suitable for transporting hydrogen blends. These new ILI methods also detect local hard zones in the pipe material that are prone to cracking in the presence of hydrogen.

The data from these new ILI tools do not appear to provide sufficient information to evaluate the micro-structure of the steel, which can influence material behaviour when exposed to hydrogen [67]. Likewise, the tools do not appear to resolve material properties in pipe girth welds to determine if they are suitable for exposure to hydrogen.

Gap: Advanced inspection methods are required to provide detailed information on material and weld properties to verify suitability for hydrogen exposure.

Other advanced ILI tools now measure the axial and bending strain in the pipe. High strain indicates that the pipe is subjected to high stress which could make the pipe more susceptible to hydrogen impregnation and cracking. This information is important for legacy pipelines where ground movement or heavy traffic at crossings could have imposed unexpected loads on the pipe over time [68]. Areas with higher than expected stresses in a legacy pipeline system could be identified and subjected to further inspection to determine if the pipe is suitable for exposure to hydrogen.

Critical defects identified with ILI tools are inspected further by excavating the pipe and using non-destructive testing (NDT) techniques "in-ditch" to verify the ILI readings and gather more detailed information on the defect. Because hydrogen contributes to crack growth, more precise and reliable in-ditch measurement techniques are required to identify and characterize cracks [69].

Gap: Advanced in-ditch pipe inspection methods need to be verified to ensure accurate and reliable characterization of crack-like defects.

Inspection of plastic pipe in gas distribution systems is not expected to be affected by hydrogen blends since no additional damage mechanisms have been identified.

4.2.2.5 Leak Monitoring

Leak monitoring systems will need to be upgraded for both transmission and distribution systems, as most systems were designed for hydrocarbon products. Furthermore, since natural gas is odourless, specialized odourants are added to give the gas the "rotten egg" smell so that even small leaks can be smelled by people in the area. As hydrogen is also odourless, a similar approach is prudent. There is some uncertainty regarding how odourants designed for hydrocarbon gases will behave with hydrogen. If, during a gas leak, the hydrogen and natural gas remain mixed, the odourant in the natural gas should serve as an indicator of the presence of hydrogen as well. However, if the hydrogen and natural gas separate due to the difference in density and the much faster diffusion rate of hydrogen, it is not clear if the odourant will remain in high enough concentrations in the hydrogen to be easily smelled. Likewise, alternate odourants suitable for hydrogen have been identified; however, their impact on end use devices such as fuel cells that require high purity hydrogen, must be verified.

Gap: Odourants may have a negative impact on the performance of hydrogen end-use appliances equipment. This impact needs to be evaluated and should be mitigated to improve overall operability and reliability of these systems.

While odourants are effective at detecting if a leak is occurring, portable electronic sensors are used by emergency response and repair crews to locate the source of the leak. Various hydrogen leak detection technologies are available; although, may need to be verified for field and facility use with mixtures of hydrogen and natural gas [70].

Flame detection may be more difficult with pure hydrogen since it has a colourless flame, but hydrogen blends with natural gas will have a similar appearance to a natural gas flame. Even with pure hydrogen, studies have shown that larger flames are generally visible. While small flames may not be easily visible in some circumstance, they only pose a minor safety hazard [71]. Nonetheless, the performance of flame detection systems in facilities handling gas blends will need to be verified to ensure safe operations.

Gap: Methods to detect hydrogen, including odourants, leak detectors and flame detectors need to be certified for various hydrogen blends.

4.2.2.6 Maintenance

External repair sleeves can be installed on pipelines to repair sections with corrosion or crack-like defects. Repair methods include welded steel sleeves and non-welded sleeves that are either steel or composite material that are bonded to the pipeline using epoxy or other adhesives. Over time, hydrogen will permeate through the pipeline wall and will interact with the external sleeve. If the sleeve has a low permeability to hydrogen, hydrogen could accumulate between the pipeline and the sleeve and eventually cause the pipe to collapse. The sleeve material could also be damaged by exposure to hydrogen, reducing its strength or the bond with the pipeline.

Low pressure pipelines in distribution systems can be repaired from the inside using a cured-in-place pipe (CIPP). This commonly consists of an epoxy impregnated material that is inserted into a damaged pipe, expanded against the inner wall of the pipe, then cured with either heat or an ultraviolet (UV) light. While this technique is well established for repairing natural gas pipelines, the impacts of long-term exposure to hydrogen is unknown. Hydrogen that permeates through the liner could degrade the epoxy bond to the original pipe. Hydrogen could also be trapped between the liner and the original steel pipe, potentially causing the liner to collapse if the pressure inside the liner is decreased. The compatibility of liner materials with hydrogen is being tested by the Gas Technology Institute ("GTI") in Des Plaines, Illinois, United States; however, the full-scale performance of the liners when exposed to hydrogen is beyond the work scope of the current project.

Gap: Performance of cured-in-place pipe liners and external repair sleeves when exposed to hydrogen is unknown.

A key aspect of pipeline welding procedures is to minimize exposing the weld to hydrogen, as hydrogen can lead to cracking as the weld area cools. Low-hydrogen welding materials are selected for pipeline repairs and heat treatment protocols are used to ensure hydrogen that is in the weld can migrate out of the weld before it cools.

In some cases, such as repairing a pipeline by installing an external sleeve or when a new branch is added to an existing pipeline, welding might occur while the pipeline remains in service. For a pipeline carrying hydrogen or hydrogen blends, hydrogen will be continuously permeating through the steel in the weld region, potentially making it difficult to achieve a "low-hydrogen" weld. Current procedures for in-service welding in the presence of hydrogen sulfide (sour service) might provide guidance to developing procedures for in-service welding on pipelines with hydrogen. The procedures will likely need to be modified for legacy pipeline materials that are not commonly used in sour service applications. Welders will need to be trained and certified in these new procedures.

Gap: In-service welding procedures, training and certification need to be developed for pipelines carrying hydrogen.

4.2.3 Risk Management

The first step in risk management for pipelines consists of considering a broad range of threats to the pipeline to estimate the probability of failure. Adding hydrogen to a natural gas pipeline could accelerate fatigue crack growth rate compared to a pipeline with no hydrogen. The amount that hydrogen affects the fatigue crack growth rate depends on the material toughness as well as the stress in the pipe [65]. Stress in the pipe is a function of the operating pressure as well as any post-construction loading caused by geohazards such as frost heave, erosion or slope instability. Dents and gouges caused by mechanical damage can also increase the local stresses and thus the hydrogen permeation rate and cracking potential. At the same time, small amounts of oxygen in the gas can counteract the effects of hydrogen by passivation, where the oxygen preferentially adheres to the steel where the hydrogen would normally cause damage.

Gap: The effects of hydrogen gas blends on crack initiation and growth in pipeline steels must be refined to estimate how this could affect the probability of pipeline failure.

To estimate the risk associated with a pipeline, the probability of failure must be multiplied by the consequences of the failure. Typically, a consequence analysis will consider the negative impacts on the:

- ***Environment*** - damage due to liquid hydrocarbon spills and greenhouse gas releases;
- ***Life Safety*** – estimating fatalities based on population density and land use; and
- ***Economics*** – fire damage, service interruption and product loss.

For natural gas lines carrying hydrogen blends, ignited releases pose the greatest threat of life safety and fire damage. A release can ignite immediately, in which case it forms a jet fire where the radiative heat is the primary threat. Ignition can also be delayed, resulting in an explosion where over pressure is the primary threat. Current models of natural gas jet fires and explosions might not be applicable to hydrogen blends due to the flow behaviour and low density of hydrogen. The probability of ignition of a hydrogen blend release might also differ from natural gas due to the broader flammability range (i.e. 4% to 75% for hydrogen versus 5% to15% for methane).

Gap: Models of the hazard zone around a hydrogen blend jet fire and explosion are not publicly available.

The risk at pipeline facilities such as compressor and metering stations could also be affected by hydrogen blends. Flame visibility might be reduced in certain lighting conditions, making flame detection more difficult and requiring modified emergency response procedures to protect first responders from inadvertently contacting low visibility flames. The broader flammability limits of hydrogen blends might also change the electrical code classification for facility equipment. The lower density and viscosity of hydrogen blends could impact the performance of pressure relief safety systems on pressure piping.

Gap: The impact of hydrogen blends on facility risk needs to be determined.

4.2.3.1 Alternate Hydrogen Carriers

Hydrogen could also be transported through pipelines, and by other means, as other products. While these products might reduce or eliminate issues related to the hydrogen interacting with the legacy pipeline system, each product introduces other challenges, as discussed below.

Liquid Organic Hydrogen Carriers (LOHC)

Hydrogen can be reacted with liquid organic hydrogen carriers (LOHC) such as toluene, dibenzyltoluene or methylcyclohexane in a hydrogenation process that requires heat, pressure, and a catalyst. The resulting liquid is stable at ambient temperature and pressure, allowing existing liquid transport systems like ships and pipeline systems to transport hydrogen. The LOHC process has been implemented at a large-scale in Japan to transport hydrogen from Brunei [72].

A key drawback of using LOHC is that reaction temperatures on the order of 200°C (392°F) to 300°C (572°F) are required to liberate the hydrogen from the LOHC once it reaches its destination. Research is underway to use other processes to reduce this reaction temperature and make the process more efficient [73].

In the process the LOHC is shipped back to the place of origin where it can be re-hydrogenated to transport more hydrogen. If transporting by ship, the same ship could be used to return the LOHC, but for pipelines, a separate pipeline system would be required to return the LOHC. In either case, the return trip of the fluid increases the process cost and increases the risk of releases of the LOHC.

The toxicity of the LOHC can vary depending on the compound used [74]. Some processes use a LOHC that are claimed to be non-toxic [75]. The manufacture of the catalysts used in the hydrogenation and dehydrogenation process and their disposal once the catalyst is spent could also create a secondary waste stream that must be considered in using LOHC to store and transport hydrogen.

Gap: The full life-cycle cost and environmental risk of the LOHC process must consider producing the LOHC and catalyst, the useful life and disposal of these products, the energy cost of hydrogenation and dehydrogenation and return transport.

Anhydrous Ammonia

Hydrogen can be combined with nitrogen to form anhydrous ammonia that can be stored and transported in liquid form at moderate pressure and ambient temperature or chilled to -33 °C (-27.4°F) and stored at ambient pressure [76]. The energy density of liquid ammonia is about 38% higher than liquified hydrogen on a volume basis [77], making it efficient to transport by ground, rail or pipeline. An extensive ammonia pipeline system is already in operation in the USA, stretching from Louisiana to Minnesota. United States pipeline regulations [49] include specifications for ammonia pipelines; however, the Canadian pipeline code [50] does not.

Gap: Canadian pipeline codes do not address long distance transport of ammonia.

An ammonia pipeline can carry approximately twice as much energy as a hydrogen pipeline. Because the ammonia is transported as a liquid, it can be pumped, which requires about one tenth the energy to transport hydrogen as a gas pipeline due to the higher energy requirements of compression. However, if the ammonia needs to be reformed into hydrogen for the end user, it is more energy efficient to simply transport hydrogen.

Ammonia releases form visible clouds that are heavier than air, causing the cloud to travel along the ground rather than immediately dissipating [77]. At low concentrations ammonia has a strong odour and causes severe irritation to the respiratory system [79]. At higher concentrations it is toxic. Ammonia has a narrow flammability range (i.e. 16% to 25%) reducing the likelihood that releases are ignited compared to hydrogen (i.e. 4% to 75%).

Gap: Risk assessments for ammonia pipelines through non-industrial areas have not been completed in Canada.

The prevalence of ammonia as a feedstock in fertilizer production and as an industrial refrigerant has resulted in well established procedures for safe production, transport and use. Pumping ammonia through pipelines to transport hydrogen over great distances, such as for export, could be more economical than compressing hydrogen as a gas or liquid due to the substantial energy savings and simplified infrastructure. For local markets, ammonia may be suitable for applications such as fuel cells, where it can be used directly. Ammonia might also be used directly as a combustible fuel in more conventional applications such as industrial burners or internal combustion engines; however, significant challenges remain including higher NOx production [80]. Ammonia does not appear to be practical as a hydrogen transportation method for local markets where the end use requires hydrogen, such as in residential use, because of the energy required to dehydrogenate the ammonia to form hydrogen. Broad domestic adoption of direct end uses of ammonia as a fuel would be required before local distribution systems would be practical.

Gap: Direct uses of ammonia as a fuel, including fuel cells and combustion applications, must be developed before ammonia could be used to transport hydrogen for domestic markets.

Methanol

Methanol can also be used as a hydrogen carrier; however, CO_2 is released when the hydrogen is reformed for use or the methanol is burned. Methanol can be manufactured from natural gas where SMR creates hydrogen and CO_2, which are then recombined to form methanol. This process requires energy input and the CO_2 is ultimately emitted when the methanol is used, so there are no emissions reduction benefits. A carbon-neutral methanol process is possible if zero-emission electricity is used to create hydrogen, and CO_2 is captured from other processes. Again, this is only practical as a way to store electricity, not as a clean energy source since the CO_2 emissions still occur upon use of the methanol.

Methanol is already being used as a fuel in vehicles where it can be blended with gasoline, in flex-fuel systems, dedicated methanol systems or in fuel cells [81]. Transportation and storage of methanol is at ambient temperature and pressure, similar to gasoline, so that infrastructure costs and energy required for transport is minimal.

While methanol allows easy handling and can be used in vehicles with current technologies, manufacturing hydrogen from natural gas, then converting that to methanol only adds to the emissions that would have been generated if the natural gas had simply been burned with conventional systems. Since Alberta is likely to rely on generating hydrogen from natural gas in the near-term, methanol does not appear to be a practical solution for transporting hydrogen.

4.3 Hydrogen Storage in Alberta

Having effective hydrogen storage capacity in Alberta will be part of the large-scale hydrogen supply chain to provide energy for many different applications. The stored hydrogen can be used on a seasonal or continual basis, during peak hours, and as system backup; as well as for portable, transportation, or industrial applications. The goal of stationary storage is to minimize the cost and logistical challenges of transporting hydrogen long distances through the balancing of supply and demand.

There are several hydrogen storage options that have been used and investigated to varying degrees. The two main categories are generally grouped as: 1) Physical-based storage; or, 2) Material- (or Chemical-) based storage. For physical-based storage, the hydrogen may be stored in its pure molecular form as a compressed gas or as a liquid. For material-based storage, the hydrogen may be adsorbed into a material, or chemically bonded to another material such as a metal atom, ion, or chemical element. The general classifications of hydrogen storage are illustrated in Figure 4.3.

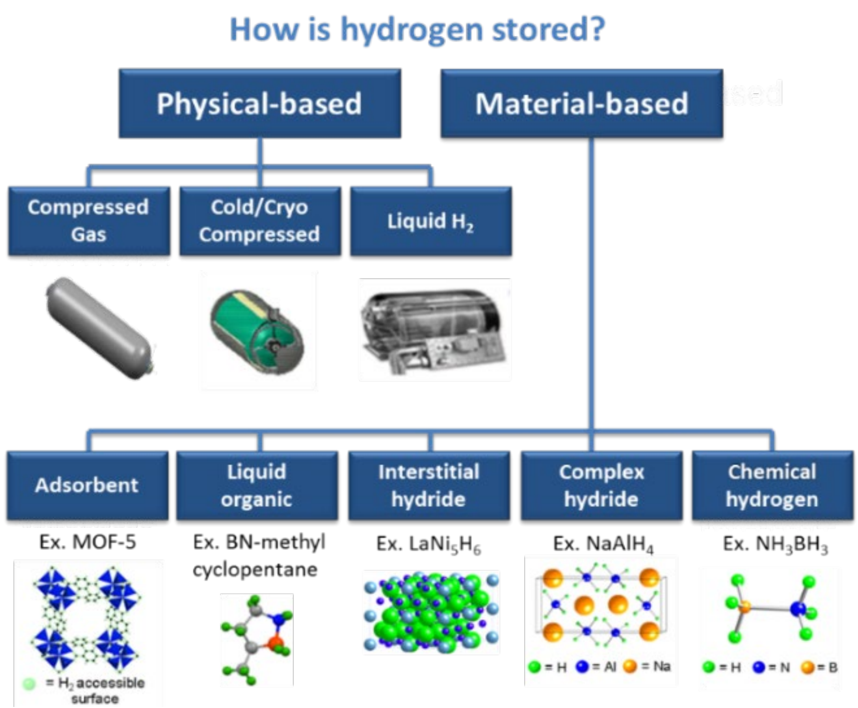

Figure 4.3 Options for Storing Hydrogen [82]

For the purposes of this section, it was assumed that enough hydrogen storage would be required to allow for a 10% hydrogen blend (as per the 3-year horizon target for hydrogen blending in the natural gas network) for the entire natural gas storage system in Alberta. Alberta currently has over 10 commercial natural gas storage pools, with a total working gas capacity of approximately 1.51 E+10^{10} m^3, as shown in Figure 4.4.

Given a total natural gas stored volume of approximately 1.51 E+10^{10} m^3, and a caloric ratio of 3.2 by volume of natural gas versus hydrogen, the total storage system must be increased by roughly

7% to maintain a similar amount of energy in storage. This equates to roughly 1.61E+9 m^3 of total hydrogen in the system, or 132,000 tonnes.

Table S5.4 Alberta commercial natural gas storage pools as of December 31, 2019

Field	Pool	Operator	Working gas capacity (10^6 m^3)	Working gas capacity (Bcf)	Injection volumes (10^6 m^3)	Withdrawal volumes (10^6 m^3)
Brazeau River	Nisku E	Tidewater Midstream and Infrastructure	1,100	39	0	0
Carrot Creek	Cardium CCC	Iberdrola Canada Energy Services Ltd.	986	35	149	189
Countess	Bow Island N & Upper Mannville M5M	Rockpoint Gas Storage	1,986	70	637	956
Crossfield East	Elkton A & D	TC Energy	1,916	68	321	523
Dimsdale	Paddy A	Tidewater Midstream and Infrastructure	2,958	105	319	66
Edson	Viking D	TC Energy	1,409	50	173	502
Hussar	Glauconitic R	Husky Oil Operations Ltd	423	15	238	267
McLeod	Cardium D	Iberdrola Canada Energy Services Ltd.	282	10	20	92
Suffield	Upper Mannville I & K, and Bow Island N & BB & GGG	Rockpoint Gas Storage	2,353	84	660	1,281
Warwick	Glauconitic-Nisku A	Rockpoint Gas Storage	606	22	220	247
Wayne-Rosedale	Glauconitic-M5M	ATCO Midstream	1,127	40	410	631
Total			**15,146**	**537.6**	**3,147**	**4,753**

Note: Working gas capacities are from the company.

Figure 4.4 Alberta Commercial Natural Gas Storage Pools [83]

As noted in Canada's federal hydrogen strategy [2], it will also be challenging to build out supply and distribution infrastructure concurrently with growth in demand. This will have an impact on how and where hydrogen is stored in the province. Both the Government of Canada and the Transition Accelerator are proponents of regionally based hydrogen hubs initially; eventually being interconnected through pipeline networks and other transportation options to allow for greater volume and improved balancing of supply and demand on a provincial or inter-provincial scale.

4.3.1 Subsurface Storage

Given Alberta's experience with subsurface natural gas storage, subsurface storage of hydrogen in salt caverns, depleted hydrocarbon reservoir and/or deep saline aquifers may provide the best solution. A key geological requirement is an impermeable cap rock to prevent leakage of hydrogen to the surface. A detailed geological survey is required as part of the design process to locate any faults, abandoned wells, or other features that could allow the gas to escape from storage.

CSA Z341 Series-18, *Storage of hydrocarbons in underground formations*, is the governing document for Canadian underground hydrocarbon storage [84]. Section 5.4 of the standard states that the fluid being stored in the underground formation must be evaluated for its compatibility with the confining structure (e.g. cavern, reservoir), downhole fluids, and operating pressures of the underground storage formation. Before hydrogen blends are injected into the current inventory of natural gas storage formations in Alberta, the injection reservoir or cavern should be carefully assessed for hydrogen suitability.

Gap: Assessments need to be performed on various underground formations to determine efficacy of hydrogen and hydrogen blend containment by that specific formation and caprock.

Gap: CSA Z341 Series-18 does not specifically include hydrogen as a potential fluid stored in the reservoirs (as it is not technically a hydrocarbon). This may result in assumptions that their exclusion from being mentioned is equivalent to underground hydrogen storage being acceptable without modifications to the storage wells and/or supplemental evaluation of the subsurface geology given hydrogen's unique nature compared to other injected fluids.

4.3.1.1 Salt Caverns

While Alberta has not yet gained experience with subsurface hydrogen storage, salt caverns are frequently used to store natural gas, both in Canada and the United States. Additionally, hydrogen storage has been commercially implemented by the petrochemical industry for over 30 years in the United Kingdom [85] and, more recently, the Air Liquide Group's ("Air Liquide") Spindletop hydrogen storage caverns [86] near Beaumont, Texas, United States, to name a few prominent operations.

Salt cavern storage is well suited to varying energy demand, as they allow for higher injection and production rates than storage in aquifers or depleted gas reservoirs. Salt caverns also typically have low construction costs, low leakage rates, and minimal risks of hydrogen contamination due to the inert chemical nature of salt. The main constraint is the physical location of salt caverns with suitable volume compared to transportation and process hubs.

While Alberta has liquid storage salt caverns located at Fort Saskatchewan, Alberta (i.e. ATCO Energy ("ATCO") and Keyera Corp. ("Keyera")) and Hardisty (i.e. Enbridge Inc. ("Enbridge")), there are presently no gas storage caverns in the province, only gas stored in depleted fields (as illustrated in Figure 4.4).

Gap: Salt caverns have been proven globally as effective means to store hydrogen underground, but Alberta does not currently have any salt cavern gas storage capacity.

4.3.1.2 Hydrocarbon Reservoirs

For Alberta, another potentially viable option for hydrogen storage is the use of depleted hydrocarbon reservoirs, similar to those already used for commercial natural gas storage. These depleted reservoirs offer greater storage capacity than salt caverns and are more widely distributed across the province. An advantage of using a depleted reservoir, such as a gas field, is that the geology of the target formations, is generally well-known through years of operation; however, it is necessary that the reservoir be tested and monitored to ensure that the hydrogen is prevented from escaping.

There may also be synergies with underground storage that will be utilized for CO_2 sequestration. Both operations will require similar geological formations, and procedures for measuring and monitoring the stored material.

Hydrocarbon reservoir storage sites must be designed to guarantee secure hydrogen injection and production. Additionally, it will be crucial to install measurement and monitoring systems to ensure rapid detection of any potential loss of containment from the reservoir. While these design, operational, and monitoring criteria are crucial for hydrogen storage; currently, it appears standardized selection procedures have not been established.

Before hydrogen storage in hydrocarbon reservoirs is implemented, further considerations must be studied, as hydrogen has different physical and chemical properties compared to other fluids stored in underground formations such as natural gas and CO_2 [87]:

- Hydrogen may react with the formation minerals and fluids, affecting storage injection and retrieval operations;
- Hydrogen may cause the growth of hydrogen consuming microbes in the reservoir, which may generate hydrogen sulfide (H_2S), causing embrittlement of well equipment and contamination of the hydrogen gas; and
- The stress regime in the reservoir will vary during the repeated injection-production cycles; therefore, a risk assessment related to cavern leaks should be conducted.

Gap: Although there are numerous underground storage sites for natural gas in Alberta, it is currently unknown how storing hydrogen at elevated pressures will affect the reservoir or caprock integrity. Furthermore, hydrogen may cause adverse reactions with either formation minerals/fluids, or microbes resulting in corrosive by-products such as H_2S, that could negatively impact injection well and reservoir integrity and possibly contaminate the stored hydrogen.

When hydrogen is injected into a reservoir, it will displace and mix with fluids in the formation. It is also possible that a cushion gas (likely natural gas) will be used to maintain operational pressure.

While the properties of each are known, the behaviour of multiphase mixtures of hydrogen, methane, and other formation fluids are less certain. The mixture behaviour including viscosity, buoyancy, and stratification should be understood, as this could lead to contamination of the hydrogen and affect storage operating procedures.

Gap: Buoyancy effects and fluid stratification in underground storage reservoirs must be better understood to ensure that hydrogen can be withdrawn from storage consistently.

4.3.1.3 Storage Well Integrity

The wells that inject the hydrogen (or hydrogen and natural gas blend) into the underground storage cavern or reservoir can become effective leak paths for the injected fluid if they are not properly designed, built and maintained. As per Alberta Energy Regulator ("AER") Directive 051 [85], *Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements,* injection wells for gaseous hydrocarbons are known as Class III wells, which come with a more stringent set of requirements for completion design and testing compared to injection and disposal wells for liquid service; however, this directive does not mention hydrogen specifically, as the directive was last published in 1994.

Wells that are selected for hydrogen injection service should have all components of the well design that are considered containment barriers evaluated for sealability with hydrogen. This means the tubing and casing strings, packer seals, and cement sheath should be evaluated to ensure that they can prevent significant losses of hydrogen that could increase life safety risk or affect the economics of the hydrogen storage operation. CSA has two standards that pertain to well design and integrity:

- ***CSA Z624:20*** - *Well integrity management for petroleum and natural gas industry systems* [89]; and
- ***CSA Z625:16*** - *Well design for petroleum and natural gas industry systems* [90].

Respectively, both CSA standards are currently being reviewed to address potential hydrogen service considerations. That said, even if standards are put in place to address injection and storage wells for hydrogen service, the equipment used to build the wells may not be rated for that service. Premium connection designs used for tubing and casing connections rated for high-pressure gas service are tested using nitrogen as the pressure media. Connection designers have acknowledged that hydrogen service could result in leakage rates that exceed current criteria and are working to design new connections for the smaller hydrogen molecule. Other components of the well will need to undergo similar design modifications to address the tighter seal requirements posed by hydrogen service.

Gap: Wellbore equipment designs have not considered hydrogen until very recently. Design modifications to equipment such as premium connection design, packer seal systems, and even cement blending may be required to ensure suitability for hydrogen service in future injection wells.

4.3.2 Physical-Based Storage

Hydrogen can be stored physically as either a gas or a liquid [91]. Storage of hydrogen as a gas typically requires high-pressure tanks of 5,000 to 10,000 psi (34.5 MPa to 68.9 MPa). Storage of hydrogen as a liquid requires cryogenic temperatures because the boiling point of hydrogen at atmospheric pressure is −252.8°C (-423.8°F).

Given the low volumetric density of hydrogen, in addition to underground storage in salt or hydrocarbon formations, another large-scale option is surface storage in spherical or cylindrical steel tanks, or possibly buried pipes.

4.3.2.1 Surface Compressed Gas Storage

One potential solution is to store hydrogen gas in a metal pressure vessel, which ensures the stability of the storage, the purity of stored hydrogen, and allows for many physical storage locations. While the vessel material provides structural and pressure integrity for the storage, the vessels may be buried below ground to reduce surface footprint, provide protection against impact and weather, and supply an extra layer of insulation. With this location however, external corrosion protection and inspection methods must be implemented.

Compressed gas storage is likely only a solution for relatively small storage applications. This is due to the low energy density associated with hydrogen stored this way. While the energy density can be increased by high pressures, surface hydrogen storage tanks have limited storage and discharge capacity. They may be feasible for storage in the distribution system for residential use but are unlikely to provide a meaningful level of storage for large-scale distribution of hydrogen or blended hydrogen. For context, the Transition Accelerator notes that an economically viable fueling station in Alberta may deliver 2 tonnes of hydrogen per day [92].

4.3.2.2 Cryogenic-Compressed Hydrogen Storage

In addition to compression, the density of hydrogen may also be increased by condensing it to liquid hydrogen. This allows for hydrogen to be stored at higher densities while at much lower pressures than conventional surface compressed storage systems. For example, the density of saturated liquid hydrogen at 1 bar is 70 kg/m^3. Canada has hydrogen liquefaction assets in both Quebec and Ontario, owned and operated by large industrial gas companies.

One concern for this type of storage is that liquifying hydrogen is very energy-intensive since the boiling point of hydrogen is extremely low at −252.8°C (-423.8°F). The energy required for hydrogen liquefaction is equal to about 30% of the heating value of hydrogen being liquefied.

Another concern is that after the hydrogen has been liquefied, it must be immediately stored and maintained at very low temperatures to minimize evaporation considering any evaporated gas must be vented to prevent pressure build-up inside the vessel.

One complexity with physical-based liquid hydrogen storage is that hydrogen molecules can exist in two different arrangements: para hydrogen and ortho hydrogen [93]. The relative amounts of each form are in dynamic equilibrium, determined solely by temperature. The equilibrium fraction of para-hydrogen is only about 25% at room temperature but grows to 99% at a very low temperature of -253°C (-423.4°F). Spontaneous conversion of ortho-hydrogen to para-hydrogen form at low temperatures releases enough thermal energy (i.e. approximately 500 kJ/kg of hydrogen) to vaporize up to 50% of the hydrogen within one week. The heat released during conversion is usually removed by cooling with liquid nitrogen, then further cooling with liquid hydrogen.

Even after conversion, boil-off is still a concern for liquid storage since it is stored as a cryogenic fluid at its boiling point; therefore, any heat transfer through the vessel or heat introduced by mixing or pumping equipment causes some hydrogen to evaporate. To prevent evaporation, the vessels typically have advanced insulation to minimize heat transfer through the tank walls. Most liquid hydrogen tanks are spherical, which minimizes the heat transfer surface area per unit of storage volume. Additionally, it is common for the vessels to be double-walled with a vacuum applied between the walls to minimize heat transfer, such as the vessels the National Aeronautics and Space Administration ("NASA") operates for liquid hydrogen at Cape Canaveral, Florida; the amount of hydrogen stored in each of these vessels is between 230 and 270 tonnes.

Building these facilities in Alberta is certainly possible; however, they are complex and expensive. Timelines to facilitate the commissioning of these facilities for hydrogen service may be outside the 3-year window set for this gap analysis, and it will be up to the prospective facility operator to determine their economic practicality. Furthermore, given that the largest cryogenic hydrogen vessels identified may store approximately 10,000 m^3 of hydrogen [94], the number of vessels required to provide enough storage supply for even Alberta's domestic use will likely be in the 100 to 200 range (i.e., assuming underground storage of hydrogen is not possible) spread through the province near major use locations.

Gap: Surface hydrogen storage vessels and infrastructure does not exist in Alberta at the scale required to maintain the stored energy currently available with natural gas. Construction of storage facilities will be costly and take time that may delay the ramping up of hydrogen blending and availability throughout the province if underground hydrogen storage is not possible.

4.3.2.3 Material-Based Storage

In addition to physical hydrogen storage methods, there is also research and development being completed on materials-based hydrogen storage technologies, including sorbents, metal hydrides, and chemical hydrogen storage materials. The goal of these methods is to convert hydrogen to a higher density liquid that is easier to store and distribute compared to pure hydrogen.

Adsorption

The storage of hydrogen via adsorption utilizes bonding between molecular hydrogen and a material with a large specific surface by applying low temperatures and elevated pressures [95]. The most common material used for hydrogen adsorption is liquid nitrogen, with a boiling point of -196°C (-320.8F°). However, there is relatively little experience with the application of adsorbent based hydrogen storage past the laboratory scale.

Metal Hydrides

With this storage method, hydrogen is chemically bonded into metal hydrides [96]. These bonds are much stronger than the physical bonds involved in the adsorption of hydrogen, and thus allows hydrogen to be stored at high density even at ambient conditions.

The subsequent hydrogen release from metal hydrides can be achieved either by heating or reaction with water. With heating (thermolysis), the process requires elevated temperatures, while with a water solution (hydrolysis), the process may be spontaneous at room temperature. The most promising metal hydride for hydrolysis is sodium borohydride ($NaBH_4$) [87]. Metal hydrides do not appear to be a practical means of large-scale hydrogen storage in Alberta (or elsewhere), but rather smaller local storage for decentralized power or heat production (e.g. off-grid hydrogen supply to a boiler).

While showing promise, there are substantial advances still to be made in metal hydride hydrogen storage. As such, commercial application of these methods is very likely outside of the 3-year timeframe considered for this project.

Gap: Metal hydrides may eventually be useful for localized or mobile storage; however, they require further use and development before large-scale application is possible.

Chemical Hydrides

Like the metal hydrides, chemical hydrides bond to hydrogen; however, one significant difference is that chemical hydrides are generally liquids at operating conditions, which simplifies their transport and storage [97]. Some chemical hydrides considered for hydrogen storage include methanol, ammonia, and formic acid. These chemicals are commonly synthesized from natural gas and are widely produced.

The challenge with using chemical hydrides as a means of storage for hydrogen is that they come with their own set of risks, whether toxicity, flammability or other undesirable traits that may make handling and storage costly, despite any advantages in terms of chemical stability and transportability that they may have over pure hydrogen (see Section 4.2) .

Gap: Chemical hydrides, while an effective way to improve the stability of hydrogen, present their own set of challenges in terms of handling and impact on the environment. In order for chemical hydrides to be adopted as a means of hydrogen storage on a large scale in Alberta, technologies must be developed to mitigate these challenges.

4.4 Hydrogen End Use

Increased production of hydrogen only makes sense if there is an end use for it. As noted previously, virtually all of the hydrogen produced in Alberta is used for industrial processes; however, for it to have a meaningful impact on decarbonizing energy utilization in Alberta, it must be used in a broader range of industrial, commercial, residential and transportation applications.

4.4.1 Industrial End Use

Industries currently using natural gas for heating in Alberta that could transition to hydrogen use include petrochemical plants, refineries, in-situ oil sands, oil sands mines, pulp and paper and cement manufacturing. Studies have shown that up to 50% blends of hydrogen with natural gas can be accommodated in industrial applications by adjusting burner settings [98].

Transition to hydrogen use in electricity generation could take different paths in Alberta. In some cases, coal fired boilers could be refit with burners that can burn blends of hydrogen and natural gas. Where it is not practical to refit the coal-fired boiler, the boiler could be replaced by a direct-fire gas turbine as the primary electricity generator. The exhaust from the gas turbine can be passed through a heat recovery steam generator (HRSG) and the steam used to drive the existing steam turbine to maximize electricity production from the facility. Turbine manufacturers report that fuel sources with hydrogen concentrations from 5% to 100% can be used in different turbine models [99]. Electricity generation utilities in Alberta are assessing the best way to update, and in some cases, repower their facilities to accommodate blends of hydrogen in the natural gas supply.

Since SMR is likely to be the primary source of hydrogen in Alberta in the near-term, large industrial consumers of natural gas have a choice of capturing the carbon emission pre- or post-combustion. In the pre-combustion option, CO_2 is captured from the SMR process. This could include installing a hydrogen generation system adjacent to an existing natural gas burning facility so that the operator is not dependent on hydrogen supplied by others. In the post-combustion scenario, CO_2 is captured after the natural gas is burned in a conventional boiler, turbine, or furnace. While the pre-combustion scenario has the added energy requirement and facility cost to manufacture hydrogen, carbon capture from the SMR process is likely lower cost and requires less energy than carbon capture post-combustion. This is because the SMR process provides a CO_2 stream that is more concentrated and at a higher pressure than combustion processes, thus reducing separation and compression costs to dispose of or transport the captured CO_2. Industrial natural gas users are still uncertain which process is most advantageous.

If Alberta industry determines that post-combustion carbon capture (i.e. burning natural gas) is the best way to decarbonize their operations, it would eliminate a large portion of the market for hydrogen production for stationary, centralized applications such as electric power generation.

Gap: It is unknown how much of industrial natural gas use will be decarbonized by post-combustion carbon capture, and how much will be decarbonized by pre-combustion carbon capture through hydrogen production.

Some industrial processes that currently use natural gas firing that directly contacts the product could be affected by the addition of hydrogen. For example, in cement kilns, the higher flame temperature of hydrogen could affect the temperature distribution in the kiln and could impact the formation of the clinker [100]. In other instances, cement plant operators are investigating if hydrogen can be added to the CO_2 captured from the kiln to form other end use products.

Tests to evaluate how hydrogen can be used in steel making first verified that hydrogen could be used to minimize the use of coke in the reduction of iron ore in a blast furnace [101]. The second phase of the project will evaluate how the hydrogen impacts the metallurgical processes in the furnace and how this might affect the steel quality.

Gap: It is uncertain how hydrogen addition to industrial manufacturing processes could affect the manufactured product when that product is directly contacted by hydrogen.

4.4.2 Commercial and Residential End Use

Residential and commercial use of hydrogen will focus on heating needs in various appliances including furnaces, boilers, radiant heaters, water heaters, gas fireplaces, stoves, clothes dryers, fire pits and grills. The Bureau de Normalisation du Québec ("BNQ") updated the *Canadian Hydrogen Installation Code* [102] in 2008 for hydrogen generating equipment, hydrogen utilizing equipment, hydrogen dispensing equipment, hydrogen storage containers, hydrogen piping systems and their related accessories.

Testing of various appliances has shown that hydrogen blends over 18% may affect the function of some domestic gas appliances [103]. The tests were conducted on new appliances and noted that proper appliance maintenance is critical, suggesting that older appliances might not be able to accommodate this level of hydrogen blending. Utility companies will likely have to check the compatibility of all appliances in areas where hydrogen is being blended, even in near-term pilots where hydrogen concentrations will be very low. The consistency in hydrogen blends will also be important since most commercial and residential appliances will not have real-time monitoring of gas composition or automated systems to adjust for proper operation with varying gas blends.

In the long-term, to accommodate hydrogen blends over 20%, all appliances will require retrofit kits or new appliances must be purchased. The public will likely be resistant to paying for retrofitting and replacing their appliances; therefore, mandatory replacements, funded by government programs will be required. It is likely that once the hydrogen supply can exceed 20%, the supply can be transitioned to 100% hydrogen since any system upgrades required to exceed 20% will likely be suitable for 100% hydrogen. The logistics of transitioning sections of the distribution grid to pure hydrogen, while ensuring that all appliances are upgraded, is daunting.

Pure hydrogen gas supplies will also affect the appearance of flames as hydrogen burns with a colourless flame. This could introduce safety hazards where people could contact open flames before seeing them on appliances like stoves and fire pits. The colourless flame will also affect the aesthetics of gas burning fireplaces and firepits, reducing the perceived value to homeowners.

Gap: Current testing shows that natural gas burning appliances do not perform reliably at hydrogen blend ratios above 18%. While this may be acceptable for short-term targets of the hydrogen transition in Alberta, replacement of these appliances will eventually become necessary. For end-use of hydrogen to be adopted successfully in the long-term, new gas burning appliances will need to operate with up to 20% hydrogen and should be easily convertible to 100% hydrogen.

4.4.3 Transportation End Use

An international effort for standardization through *ISO Technical Committee 197 (ISO/TC 197) - Hydrogen Technologies* is developing standards for technologies required to support the widespread use of hydrogen including: fueling stations, storage tanks, and fuel quality [104].

The SAE International ("SAE") has developed international standards for refueling stations and vehicle storage tanks operating at 35 MPa or 70 MPa [105]. For comparison, compressed natural gas is stored at about 25 MPa in vehicles. Operating at the elevated pressures for hydrogen approximately replicates the end user experience of fill times and driving range for gasoline powered cars.

Long-haul trucking of commercial goods on heavy-duty vehicles is focusing on converting to hydrogen fuel cell electric (HFCE) vehicles. The fuel cell approach offers faster refueling (i.e. 20 minutes, compared to eight hours) and greater range between refueling (i.e. 1200 km, compared to 800 km) compared to battery electric (BE) vehicles [106]. The Alberta Zero Emissions Truck Electrification Collaboration (AZETEC) [107] identifies the need for improved supply of fuel grade hydrogen and a network of refuelling stations. In addition, due to the low energy density of hydrogen, large, pressurized fuel tanks are required to enable operating ranges on par with current diesel engines. Fuel tank size could be reduced by increasing the pressure capacity using advanced manufacturing methods such as composites, additive manufacturing and advanced design concepts such as tanks with internal support structures [108].

Gap: Technologies that meet ISO and SAE standards for hydrogen vehicles and refueling stations must be developed for use in Alberta.

The aviation industry is also planning hydrogen-powered commercial aircraft with programs like ZEROe [109] at Airbus S.A.S. ("Airbus"); aiming at hydrogen-powered aircraft by 2035. The Boeing Company ("Boeing"), on the other hand, does not expect hydrogen to be a significant fuel source for commercial aircraft until 2050, with their focus on using sustainable fuel [110]. The key challenge in implementing hydrogen as an aviation fuel, cited by Airbus, is the complexity and weight requirements of storing liquefied hydrogen onboard the aircraft. While the energy content per kilogram of liquid hydrogen is three times higher than conventional jet fuel, it also requires four times the volume to store the same amount of energy at safe pressures. This allows an aircraft to have a lighter fuel payload for the same operating range; however, requires a larger, heavier aircraft to accommodate a much larger and complex fuel storage system. Hydrogen supply and storage at airports is also identified as an issue; although, this is the same for all other aspects of the transition to a hydrogen-based energy system. These challenges are likely to be encountered well beyond the near-term focus of this review.

4.5 Export Market Potential

The Transition Accelerator suggests that for Canada to match hydrogen supply and demand needs and create a thriving hydrogen economy, “hydrogen nodes” must be established. These would be located in regions of the country where a low-cost, low-carbon hydrogen source is available, there are fuel or industrial feedstock markets nearby, and pipelines to connect the supply to demand. One promising region they identified was Alberta’s Industrial Heartland region, adjacent to northeast Edmonton [92].

In the 3-year horizon for this report, setting up one or more self-sustained nodes in Alberta will be an ambitious scope for Alberta’s hydrogen industry to pursue; however, more and more hubs will develop as infrastructure, technology and policy can match sustained demand. Then, over a longer timeframe these could be further interconnected to unify a multi-province strategy by utilizing an energy corridor through a system of existing and potentially new transmission and distribution pipelines. Furthermore, this could also be supported by road or rail transport to specific communities and industry if pipelines are not practical, or as an intermediate step as the framework is built.

Gap: Presently, there is not a comprehensive transportation or distribution network for hydrogen.

One gap acknowledged in Canada's national hydrogen strategy is that the country currently lacks a comprehensive and long-term policy and regulatory framework that includes hydrogen. While policies are in place, they are inconsistent across regions, resulting in a 'patch-work' approach that slows adoption. The strategy also acknowledges that there are gaps in existing codes and standards that must be addressed to enable adoption. Harmonizing codes and standards across jurisdictions will ensure that best practices are applied across the global hydrogen economy to facilitate the growth of trade and export markets [2].

Gap: Canada currently lacks a comprehensive policy and regulatory framework for hydrogen. Where policies are in place, they are inconsistent across regions, resulting in a 'patch-work' approach that slows adoption.

Gap: There are gaps in existing codes and standards that must be addressed to enable adoption. Harmonizing codes and standards across jurisdictions will ensure that best practices are applied across the global hydrogen economy to facilitate the growth of trade and export markets.

4.5.1 Exporting to Markets in the United States of America

The main American-based export market for Alberta hydrogen is expected to be California although this is expected to be a slow transition over the next 20 years, corresponding to the timeline for California to phase out natural gas. The Transition Accelerator estimates that the potential Californian hydrogen demand for heavy duty vehicles (HDV) alone may be 10 kT H_2/day [111] (i.e. nearly double Alberta's current production); as such, the potential market for Alberta is significant. There is a natural gas pipeline between Alberta and California that may be able to move low-ratio blends of hydrogen; however, as with any existing pipeline, it will need to be assessed for suitability. Furthermore, there may be requirements from the various jurisdictions that the pipeline crosses for specific limits in hydrogen content due to their own regulations about legacy pipeline use for hydrogen.

Gap: Hydrogen export to markets in the United States in the volumes forecasted will require dedicated pipelines due to limitations in materials and components in legacy pipelines operating in a high-ratio hydrogen blend or pure hydrogen gas stream.

4.5.2 Exporting to Offshore Markets

There are also significant emerging export opportunities for Alberta to overseas markets in both Asia and Europe.

Asia, Japan, South Korea, and China have ambitious hydrogen strategies. Japan and South Korea will need to rely on imports to meet the bulk of their demand, with Australia being one of Canada's main competitors to supply their market. British Columbia would be the logical export hub for Canadian hydrogen to Asia. While British Columbia will likely develop regional hydrogen production hubs, there may be potential for existing transportation infrastructure to allow Alberta low-ratio hydrogen natural gas blends to be shipped overseas in a regional partnership. Higher ratio hydrogen blends or pure hydrogen will require dedicated hydrogen pipelines.

Europe, Germany and other European Union countries are developing hydrogen strategies, mainly based on renewable energy and electrolysis; however, they will also likely rely on imports of hydrogen to complement domestic production. Atlantic Canada would be a logical export hub for the European market.

Transporting to overseas markets adds a logistical challenge for Alberta, since the hydrogen must be transported to tidewater, converted to liquid hydrogen, and stored in cryogenic vessels for marine transport. Hydrogen liquefaction facilities would need to be fabricated on-site at tidewater as well. The receiving country would also need to have very similar facilities to accept the cryogenic vessels and introduce the hydrogen into their hydrogen storage, transportation, and distribution network.

Offshore export is presently being developed between Australia and Japan. A Pilot project named, the Hydrogen Energy Supply Chain ("HESC") [112], is working to:

- create hydrogen gas in the Victoria State of Australia by gasifying coal;
- transport the hydrogen gas to the Port of Hastings;
- liquify the gas at the port and store in cryogenic vessels; and
- oceanic transport to Japan.

The HESC pilot is made up of a consortium of companies including: Kawasaki Heavy Industries, Ltd. ("KHI"); Electric Power Development Co., Ltd. ("J-POWER"), Iwatani Corporation ("Iwatani"), Marubeni Corporation ("Marubeni"), AGL Energy ("AGL") and Sumitomo Corporation ("Sumitomo"). The consortium is further being supported by the Australian and Japanese federal governments and the Victorian provincial government.

In March 2021, HESC announced that operations had started at their gasification and gas refining facilities in Victoria state for this pilot project. According to the same press release [112], the first shipment of hydrogen from Australia to Japan is expected in 2021, utilizing a purpose-built liquified hydrogen carrier named the Suiso Frontier. For the 3-year timeframe outlined in this report, it is impractical for Alberta to establish export capabilities. However, initial research and communications with the HESC companies and respective governments may yield very useful information and shape infrastructure and procedures for Alberta with an eventual line-of-sight to an overseas supply chain.

Gap: Hydrogen transported to overseas markets requires a transportation network to a Canadian coastline, liquification facilities, as well as cryogenic and marine storage. This will require technical innovation to develop world-class facilities in terms of efficiency, safety and performance supported by federal and inter-provincial cooperation, along with a robust regulatory framework.

4.6 Standardization

Several Canadian and International standards on hydrogen technologies and the adjacent infrastructure required to move and store the chemical substance are referenced in this report. These standards and protocols must be continuously developed in coordination with technology and policies; especially given how rapid the projected transition to a global hydrogen economy will be. As the global hydrogen industry grows, so too will the standards and protocols that guide its consistent and safe development.

It will be essential for Alberta-based hydrogen stakeholders to be involved in international standardization to ensure perspective from a relatively large player in the global hydrogen industry; especially considering the tie-ins to foreign markets in the United States and overseas.

5. SUMMARY OF TECHNOLOGY GAPS AND CHALLENGES

The following sub-sections summarize the gaps identified in Section 4 of this report.

5.1 Decarbonized Hydrogen Production

Conventional hydrogen production in Alberta has limitations with respect to how decarbonized it can become if SMR remains the main process for generating hydrogen.

- Typical SMR carbon capture processes cannot remove 100% of CO_2 formed during hydrogen production due to the process pulling CO_2 from the production stream. New technologies need to be developed to be installed inline with or in replacement of existing carbon capture technologies if 100% capture is to be achieved for hydrogen production via SMR.

There are other means to produce decarbonized hydrogen, methane pyrolysis in particular, may play a role in 'decentralized' hydrogen production in locations away from the ACTL system or another carbon dioxide transmission pipeline. Other means of hydrogen production such as electrolysis are not practical given Alberta's natural resource and electricity mix.

- Alberta does not have large-scale, low-cost low-carbon intensity electricity to make electrolysis a practical means of hydrogen production at large scale.

One of the goals of decarbonizing hydrogen production in Alberta is to reduce the CO_2 emissions from existing production. Most of the 'grey' hydrogen production in the province is done by SMR without CCUS capacity, so this will require retrofitting these facilities with systems that can capture the CO_2 from the process stream. This has been demonstrated at Shell Scotford's upgrader complex; however, there was a substantial government investment in the project. Future retrofitting programs may not benefit from as much external funding given how much other hydrogen economy infrastructure needs to be simultaneously developed.

- There may be some current hydrogen production facilities that cannot be retrofitted with conventional CCUS capability due to either plant layout or age. Depending on the number of these facilities, this may pose a significant challenge to decarbonization efforts in Alberta. Technology may need to be developed to find alternative ways to capture CO_2 further downstream or offset these emissions through capture elsewhere in the facility.

Carbon sequestration is fundamental to the success of decarbonized hydrogen production in Alberta, and to achieve this success will require an extensive network of CO_2 pipelines and numerous safe sequestration locations.

- There is no feeder pipeline network to move CO_2 to Shell Quest or the ACTL system from new large-scale carbon capture facilities in locations beyond the Alberta Industrial Heartland.

If current SMR hydrogen production is to be converted to SMR with CCUS, new dedicated CO_2 pipelines and associated supporting infrastructure from Fort McMurray and other regions will need to tie into Shell Quest or the ACTL system, or new pipelines as part of local CO_2 storage capacities will need to be developed.

- While this is primarily an infrastructure gap, the sheer scale of this undertaking may require new technologies and innovation to improve large-scale efficiency and performance of a potentially large network of CCUS facilities and pipelines.
- CO_2 sequestration capacity needs to lead hydrogen production. As hydrogen production increases, CO_2 sequestration capacity needs to increase at rate commensurate with the amount of CO_2 produced in the process. Given the time to evaluate, get regulatory approval, and complete infrastructure construction this will have a significant impact on how quickly hydrogen production can ramp up in the province if CO_2 sequestration capacity lags the demand created by decarbonized production.

While Alberta is home to a vast network of saline aquifers and reservoirs ideal for permanently sequestering CO_2, there are risks and challenges posed by both the existing infrastructure scattered around the province as well as the substantial amount of CO_2 projected to be injected into the ground by large-scale hydrogen production.

- Abandoned and shut-in oil and gas wells may compromise cap rock integrity in reservoirs chosen for CO_2 sequestration. It will be critical to ensure that all potential leak paths are identified, and risk-mitigation measures are taken to ensure that the danger of CO_2 breaching the cap rock is avoided or minimized to an acceptable level.
- It remains unknown what the impact of injecting upwards of 180 Mt of CO_2 per year into deep aquifers will do to regional subsurface reservoir pressures and how this pressure could affect cap rock integrity.

While methane has been the focus for hydrogen producers, the other component needed in SMR is freshwater. Based on current water allocations in the province, water supply may be the limiting factor in how much hydrogen can be produced in Alberta.

- The impact of large-scale hydrogen production on provincial water resources is not widely understood. Given the critical nature of water resources to Albertans, technology will need to be developed and deployed to reduce the amount of water required per unit of hydrogen production.
- Water treatment and re-use technologies similar to those used for SAGD and CSS operations need to be developed to minimize freshwater use in SMR production of hydrogen

5.2 Hydrogen Transmission and Distribution

Some hydrogen advocates point to an opportunity to re-use existing legacy pipelines originally designed for natural gas to move blended or pure hydrogen around Alberta and into other jurisdictions. The broad consensus from North American pipeline stakeholders is that there should be no more than 20% hydrogen in a blend with natural gas in any legacy pipeline. Furthermore, the pipeline operators that were interviewed for this report were consistent in each stating that every pipeline (and even within a line, specific sections) needs to be evaluated for suitability on a case-by-case basis.

- Canadian pipeline standards do not currently address requirements for pipelines carrying pure hydrogen or hydrogen and natural gas blends.
- Joint-by-joint details of the material properties, including micro-structure, of legacy pipelines are generally not available to assess compatibility with hydrogen.
- Performance of modern steel grades, including high strength materials and materials that may include Local Hard Zones, are not well understood in the presence of hydrogen.
- Current test methods used to assess pipeline performance in the presence of hydrogen may not fully represent actual pipeline service conditions.
- Feasibility and efficacy of internal pipeline coatings to increase hydrogen resistance are not well understood.

Pipe joints in transmission pipelines are welded together, with tens of thousands of joint welds in each pipeline; as well as, tees, elbows, and branches to auxiliary lines. Welding pipeline joints together is a well-established technology; however, welding on pipelines designed for hydrogen use requires additional care and precautions.

- Acceptable weld defect and crack criteria do not exist for legacy and new pipeline materials in hydrogen service.
- In-service welding procedures for pipelines carrying products that contain hydrogen have not been established.

Hydrogen poses a challenge to compressors commonly used in natural gas transmission pipelines because of its low density, unique flow characteristics and potential to cause embrittlement and cracking in metal components. Blending hydrogen with natural gas may negatively impact compressor performance and reduce efficiency. Additionally, monitoring technologies to determine real-time composition and heating value of natural gas and hydrogen have not been developed. These will be key to ensuring that end users are receiving the ratio of hydrogen to natural gas that they are being told is sent to them.

- It is unclear to what degree current compressor stations are compatible with different hydrogen blends. Furthermore, the trade off between the cost of increasing compression capacity and the customer impact of reduced energy delivery is unclear.

- A proven method to continuously monitor the composition of natural gas containing hydrogen is required to replace current GC methods.

Hydrogen also poses new challenges when it comes to inspection; to-date, it is not known whether minimum crack sizes for remediation and repair need to be re-evaluated in the presence of hydrogen. Moreover, if this is the case, it is not yet known if current technologies can reliably detect material defects and cracks at the resolution required for hydrogen service.

- ILI tools need to demonstrate the ability to operate in a hydrogen-rich environment and to detect smaller crack-like defects than what is currently possible in natural gas pipelines.

- Advanced inspection methods are required to provide detailed information on material and weld properties to verify suitability for hydrogen exposure.

- Advanced in-ditch pipe inspection methods need to be verified to ensure accurate and reliable characterization of crack-like defects.

Leaks of hydrogen blends with natural gas could behave quite differently from leaks of natural gas alone. Due to density and viscosity differences, natural gas and hydrogen may separate once released from a pipeline. This could impact the performance of leak detection systems.

- Odourants may have a negative impact on the performance of hydrogen end-use appliances equipment. This impact must be evaluated and should be mitigated to improve overall operability and reliability of these systems.

- Methods to detect hydrogen, including odourants, leak detectors and flame detectors need to be certified for various hydrogen blends.

Pipeline repair and maintenance activities may need to be adapted for pipelines carrying hydrogen blends to ensure reliable repairs that are not degraded by hydrogen and procedures, such as in-service welding, can be performed safely.

- Performance of cured-in-place pipe liners and external repair sleeves when exposed to hydrogen is unknown.

- In-service welding procedures, training and certification need to be developed for pipelines carrying hydrogen.

Pipeline and facility operators are constantly evaluating and managing risk as the pipelines age and service conditions change (e.g. encroachment on pipeline rights-of-way, geohazards, corrosion). Powerful software programs are used to provide detailed feedback to operators on the changing risk conditions of their operations. These programs rely on accurate input data as well as models that simulate real-world conditions, which will need to be updated to include the effects of hydrogen on pipeline performance and risk.

- The effects of hydrogen gas blends on crack initiation and growth in pipeline steels must be refined to estimate how this could affect the probability of pipeline failure.
- Models of the hazard zone around a hydrogen blend jet fire and explosion are not publicly available.
- The impact of hydrogen blends on facility risk needs to be determined.

Alternative hydrogen carriers offer a means to improve the stability of hydrogen during transport; however, they come with their own set of challenges that may or may not be acceptable to pipeline operators, regulators, and the public.

- The full life-cycle cost and environmental risk of the LOHC process must consider producing the LOHC and catalyst, the useful life and disposal of these products, the energy cost of hydrogenation and dehydrogenation and return transport.
- Canadian pipeline codes do not address long distance transport of ammonia.
- Risk assessments for ammonia pipelines through non-industrial areas have not been completed in Canada.
- Direct uses of ammonia as a fuel, including fuel cells and combustion applications, would need to be developed before ammonia could be used to transport ammonia for local markets.

5.3 Hydrogen Storage

If hydrogen is introduced as a blend with natural gas, it is highly probable that the existing network of natural gas storage sites in the province will be filled with these blended gases. Given its small molecular size, hydrogen will be more prone to migration out of the storage reservoir or cavern than natural gas. As such, it will be critical to understand reservoir caprock integrity and how localized intrusions or breaches (i.e. injection wells and legacy oil and gas wells) could affect the ability to contain the gas blend.

- Assessments must be performed on various underground formations to determine efficacy of hydrogen and hydrogen blend containment by that specific formation and caprock.
- CSA Z341 Series-18 does not specifically include hydrogen as a potential fluid stored in the reservoirs (as it is not technically a hydrocarbon). This may result in assumptions that their exclusion from being mentioned is equivalent to underground hydrogen storage being

acceptable without modifications to the storage wells and/or supplemental evaluation of the subsurface geology given hydrogen's unique nature compared to other injected fluids.

- Salt caverns have been proven globally as effective means to store hydrogen underground; however, Alberta does not currently have any salt cavern gas storage capacity.

- Although there are numerous underground storage sites for natural gas in Alberta, it is currently unknown how storing hydrogen at elevated pressures will affect the reservoir or caprock integrity. Furthermore, hydrogen may cause adverse reactions with either formation minerals/fluids, or microbes resulting in corrosive by-products such as H_2S, that could negatively impact injection well and reservoir integrity and possibly contaminate the stored hydrogen.

- Buoyancy effects and fluid stratification in underground storage reservoirs must be better understood to ensure that hydrogen can be withdrawn from storage consistently.

It is not just the caprock, cavern or reservoir integrity that must be better understood; similarly, well integrity in a hydrogen environment must be assessed as well. It may be necessary to establish new sealability requirements for injection well components to prevent hydrogen from seeping past seals that were originally designed for either liquid or larger natural gas molecules.

- Wellbore equipment designs have not considered hydrogen until very recently. Design modifications to equipment such as premium connection design, packer seal systems, and even cement blending may be required to ensure suitability for hydrogen service in future injection wells.

Ultimately, if modeling and real-world evaluations determine that cavern storage is not feasible, then surface storage will be necessary. This would require ramping up construction of many very complex facilities to establish enough storage capacity to stay ahead of increasing demand.

- Surface hydrogen storage vessels and infrastructure does not exist in Alberta at the scale required to maintain the stored energy currently available with natural gas. Construction of these facilities will be costly and take time that may delay the ramping up of hydrogen blending and availability throughout the province if underground hydrogen storage is not possible.

Hydrides are another means of hydrogen storage; however, the benefits they may provide in stabilizing hydrogen may be offset by other challenges. Metal hydrides may make sense for small (e.g. residential-scale) storage systems, but not for widespread industry. Chemical hydrides come with their own risks and hazards that may outweigh those posed by other means of hydrogen storage.

- Metal hydrides may eventually be useful for localized or mobile storage; however, they require further use and development before large-scale application is possible.

- Chemical hydrides, while an effective way to improve the stability of hydrogen, present their own set of challenges in terms of handling and impact on the environment. In order for chemical hydrides to be adopted as a means of hydrogen storage on a large scale in Alberta, technologies must be developed to mitigate these challenges.

5.4 Hydrogen End Use

Most of Alberta's natural gas is used by heavy-industry: oil sands operators, petrochemical facilities, and power generation. The facilities for these industries are large, complex, and costly; where capital investments are made on a long-term basis. There is considerable uncertainty as to how converting to hydrogen will impact the economics of these operations. While all end users accept that increased decarbonization is a requirement, there are some large-scale end users weighing capturing CO_2 emissions after natural gas is burned at their facilities over retrofitting their systems to burn blended or pure hydrogen. Each of these options carries risk and substantial cost, but it demonstrates that a move to hydrogen is not going to be an obvious choice for some industrial users.

- It is unknown how much of industrial natural gas use will be decarbonized by post-combustion carbon capture, and how much will be decarbonized by pre-combustion carbon capture through hydrogen production.

The use of hydrogen in industrial thermal processes (e.g. steel furnaces and cement kilns) has been investigated by a handful of companies around the world. There is uncertainty in how introducing hydrogen into traditional thermal processes will impact the finished products due to the different flame temperatures, energy levels produced during combustion as well as combustion products.

- It is uncertain how hydrogen addition to industrial manufacturing processes could affect the manufactured product when that product is directly contacted by hydrogen.

From a domestic and commercial use perspective, the reliability of gas-powered equipment and appliances needs to be resolved. If current generations of gas heating equipment can only work with low-ratio hydrogen blends, then these appliances must be replaced with those that can use higher-ratio blends or pure hydrogen. This replacement will need to precede the move to higher-ratio blends of hydrogen in the gas distribution network.

- Current testing shows that natural gas burning appliances do not perform reliably at hydrogen blend ratios above 18%. While this may be acceptable for short-term targets of the hydrogen transition in Alberta, replacement of these appliances will eventually become necessary. For end-use of hydrogen to be adopted successfully in the long-term, new gas burning appliances will need to operate with up to 20% hydrogen and should be easily convertible to 100% hydrogen.

In terms of vehicular use of hydrogen, the infrastructure needs to be put in place to make sure that hydrogen-powered vehicles can be refueled along the routes that they are commonly used. This will be more easily achieved through the growth of hydrogen nodes or hubs wherein hydrogen-powered vehicles can operate and building out infrastructure from there to expand their range.

- Technologies that meet ISO and SAE standards for hydrogen vehicles and refueling stations need to be developed for use in Alberta.

5.5 Export Market Potential

Exporting hydrogen will require a dedicated hydrogen transmission pipeline network; however, before dedicated hydrogen pipelines are built, it is likely that hydrogen blends will be exported first to pipeline connected end users. It will take some time to re-certify a network of legacy natural gas pipelines for hydrogen blend service. Until this is accomplished, there will not be a practical way of exporting Alberta-produced hydrogen.

- Presently, there is not a comprehensive transportation or distribution network for hydrogen.

Moving hydrogen from source to end users will require harmonization of codes and practices for hydrogen blending and transmission. As the industry grows, it will be important that this growth remains interconnected with other markets and stakeholders in the national and global hydrogen industry. Due to its share of the existing market and forecast production targets, Alberta-based hydrogen industry stakeholders and policy makers will need to be active at multiple levels to ensure that the work done to grow the domestic hydrogen industry is done to standards that meet or exceed those set by governments and regulators in the target markets.

- Canada currently lacks a comprehensive policy and regulatory framework for hydrogen. Where policies are in place, they are not consistent across regions resulting in a ‘patch-work’ approach that slows adoption.
- There are gaps in existing codes and standards that need to be addressed to enable adoption. Harmonizing codes and standards across jurisdictions will ensure that best practices are applied across the global hydrogen economy to facilitate the growth of trade and export markets.

One of the main challenges for Alberta exporting hydrogen is the lack of export infrastructure for hydrogen. While some pipelines may be able to move low-ratio blends of hydrogen with existing natural gas exports, this will not be sufficient to meet export projections and needs of those export markets. Furthermore, overseas exports will require substantial infrastructure and dedicated hydrogen carrying ocean tankers, and this will require unified national and inter-provincial strategies.

- Hydrogen export to markets in the United States in the volumes forecast will require dedicated pipelines due to limitations in materials and components in legacy pipelines operating in a high-ratio hydrogen blend or pure hydrogen gas stream.
- Hydrogen transported to overseas markets requires a transportation network to a Canadian coastline, liquification facilities, as well as cryogenic and marine storage. This will require technical innovation to develop world-class facilities in terms of efficiency, safety and performance supported by federal and inter-provincial cooperation along with a robust regulatory framework

6. EXTERNAL CHALLENGES FOR ALBERTA'S HYDROGEN ECONOMY

6.1 Decarbonized Hydrogen Production

Green hydrogen production costs are declining. The IEA forecasts that green hydrogen production costs will decline by 30% to 50% [15] by 2030 and this will put them in line with blue hydrogen costs. There are major implications for producing hydrogen via electrolysis, in particular the amount of fresh water and power this process will consume; however, from an emissions perspective, green hydrogen production will have lower GHG emissions than any hydrogen produced by fossil fuels.

This could be challenging for long-term investment in Alberta's hydrogen industry given the cost to build up production capacity at the scale envisioned by government strategies. This is not because there will be local green hydrogen production, but rather export jurisdictions may start to be selective about where they source their hydrogen based on the carbon intensity of the production process (carbon intensity of all midstream and downstream processes are negated in this analysis because both sources of hydrogen need to be transported and stored). This has already been floated by countries in Europe such as Germany [113] where there is already a strong preference for green hydrogen and more subsidies and investment protection for these projects over other means of hydrogen production.

At the same time, water use limits and zero-emission electricity production could limit the volume of green hydrogen that can be produced by electrolysis. If these limitations occur, hydrogen production from natural gas could remain competitive.

6.2 Hydrogen Transmission and Distribution

The most cost-effective way to move large amounts of hydrogen will be through dedicated pipelines specifically designed for hydrogen service. These pipelines are significant investments for operating companies and require extensive regulatory review and multiple stakeholder acceptance before construction can even begin. Despite the technical rigor dedicated to hydrogen pipeline design, there may be continued social resistance to building new pipelines in Canada. It will be imperative for pipeline operators to continue the safe building and operation practices for hydrogen pipelines as they do for commodities such as natural gas and oil.

6.3 Hydrogen Storage

The short-term external challenges and risks for storing hydrogen in Alberta will be based on the rate of hydrogen consumption and the ability to move hydrogen or hydrogen blends around the province to end users. Further storage challenges will be tied to how fluctuations in exports of hydrogen are managed.

6.4 Hydrogen End Use

Industrial users of natural gas face a complex decision for decarbonizing their operations. The Canadian federal cost of carbon is forecast to increase to \$170/tonne CO_2 by 2030 which will make heavy-emitting operations very expensive without some sort of carbon capture or other emissions intervention strategy. There is a break-even point for these users to decarbonize their operations; however, they may decide to pursue post-combustion or direct air capture of CO_2 emissions rather than convert their operations to use hydrogen. If enough heavy industry fossil fuel (i.e., coal, natural gas) users decide to pursue post-combustion CO_2 capture, this will likely significantly reduce overall domestic demand for hydrogen and thereby correspondingly slow the growth of the hydrogen industry in Alberta.

Converting appliances and equipment that use natural gas today to use high-ratio blends or pure hydrogen will be expensive for the consumer. There are currently no incentive programs from government to make the investment attractive for consumers and industry. The transition to widespread adoption of hydrogen as a replacement for natural gas and other CO_2 emitting fuels (e.g. gasoline, coal) will need to be supported by government rebates and incentives to overcome social skepticism and reluctance to pay for costly upgrades that do not create immediate benefit for the end user. If the transition to hydrogen remains complex and expensive for consumers, there is a chance that hydrogen energy adoption will face competition from other sources of decarbonized energy such as solar and wind as well as potential renewable heat sources such as geothermal heat pumps.

6.5 Export Market Potential

The major external challenge for Alberta's export market access could be inter-provincial competition. Canada's hydrogen strategy acknowledges that hydrogen production will need to come from a mix of low-carbon (blue) hydrogen produced from hydrocarbons sourced in the Western Canadian Sedimentary Basin and zero-carbon (green) hydrogen produced from electrolysis powered by hydro-electric power in Eastern Canada and British Columbia. Policies at federal and provincial levels could penalize Alberta's hydrogen production in favour of other producers. For decarbonized hydrogen from natural gas to be successfully exported, innovation and technology development that will eliminate close to all of the emissions created during hydrogen production from natural gas will be necessary to ensure that Alberta hydrogen production remains viable and competitive in the global market.

7. CONCLUSIONS AND RECOMMENDATIONS

Alberta has a real opportunity to simultaneously diversify the economy and reduce carbon dioxide emissions with careful and targeted expansion of the hydrogen industry from current production serving various industrial applications to a broadly-used commodity replacing fossil fuels such as coal and natural gas in a variety of applications. Fundamentally, developing decarbonized hydrogen production in Alberta is tied to a broader effort to decarbonize the economy through actual emissions reductions and improved process efficiency in Alberta's industrial sector, as well as commercial and residential settings.

This opportunity is coupled with many technical challenges across the entire value chain of the hydrogen industry, but the key in addressing these challenges is to acknowledge that hydrogen itself will likely not be a replacement for every type of energy source (non-renewable or otherwise) in Alberta, and successful growth of this industry will be better achieved through careful, sequenced technology development and innovation in key aspects of the hydrogen value chain in parallel with timely regulation and policy development and focusing on where hydrogen can be most effectively deployed among other energy sources of the future in Alberta.

Current production of hydrogen in Alberta is very emissions-intensive, so the first step in transitioning to decarbonized hydrogen production will likely be to capture as much CO_2 from existing hydrogen production as possible before expanding production to meet future targets. Brownfield carbon capture construction has been successfully demonstrated through the Shell Scotford upgrader complex retrofit as part of the Shell Quest CCS program. Similar projects will need to be undertaken by Alberta's remaining emissions-heavy hydrogen producers, but perhaps with new technologies that can improve the efficiency of the carbon capture processes from current benchmarks. Given the amount of CO_2 that is produced per unit mass of hydrogen, even a few percentage points gained in capture efficiency will prevent a large amount of CO_2 from being vented to the atmosphere. Where retrofitting carbon capture is not practical, hydrogen producers may need to offset their emissions through other process efficiencies in their operations or invest in new technologies that can extract the CO_2 further downstream.

Expansion of Alberta's decarbonized hydrogen production could be assisted by processes such as methane pyrolysis. Unlike SMR this process does not result in large amounts of CO_2 and does not use water. In addition, pyrolysis facilities do not require tie-in to a network of CO_2 pipelines leading to a carbon sequestration site. Pyrolysis-based hydrogen hubs or nodes could be established in regions across the province beyond the reach of a CO_2 pipeline network, providing hydrogen for local use (e.g. fueling stations for hydrogen fuel cell vehicles).

Ultimately, SMR in combination with enhanced carbon capture technologies will likely be the main means of expanded decarbonized hydrogen production in Alberta. In anticipation of this, steps should be taken to ensure that there is sufficient access to carbon storage capacity in the province. The combined capacity of Shell Quest and the ACTL system is approximately 16 Mt of CO_2 per year. Factoring in current carbon capture efficiency (80%), this translates to about 2.2 Mt of hydrogen production per year, which is only a marginal (10%) increase from current total hydrogen production in Alberta. Shell Quest and the ACTL system both took several years to design and build; if new SMR with carbon capture capacity is on Alberta's horizon, this should be done in coordination with increased CO_2 pipeline access to existing storage sites. Based on current projections for future decarbonized hydrogen production, many more CO_2 sequestration operations across the province will be required. While there is a tremendous amount of geological pore space to store CO_2 available in the province, risks associated with caprock and well integrity (both injection and local abandoned/shut-in wells) needs to be evaluated and understood to ensure the long-term security of these storage operations.

Once hydrogen has been produced it needs to get to where it is either used or turned into another product. Alberta has an extensive network of transmission and distribution pipelines for natural gas and some proponents of hydrogen have suggested that this network could easily be converted to transport hydrogen in the same way. While this would be advantageous from a logistical and cost perspective, the materials and equipment used in natural gas pipelines and the end use appliances such as stoves and furnaces will likely limit the hydrogen concentration in blends with natural gas to less than 20% to ensure the safe and reliable operation of all components of this system. Even within the legacy pipeline network in Alberta, individual lines must be evaluated and rated separately for hydrogen service considering factors such as metallurgy, construction, age, and service condition. Hydrogen can cause or accelerate damage mechanisms in some pipeline steel alloys and welds so purpose-built pipelines will be necessary for operations moving higher-ratio hydrogen blends or pure hydrogen.

A successful transition to a hydrogen-based economy in Alberta will ultimately rely on end-user acceptance and conversion to hydrogen. While there is an opportunity to use hydrogen in fuel cell powered vehicles, the larger market for hydrogen will be in replacement of thermal fossil fuels such as natural gas and coal. Heavy industry consumes over 80% of the natural gas in Alberta, so if conversion from natural gas to hydrogen blends or pure hydrogen is to proceed, this will require major investment from industry. Initial feedback is that some stakeholders are weighing the options of converting their systems to burn hydrogen or to continue to burn natural gas and pursue post-combustion carbon capture as their means for emissions reduction. Furthermore, conversion of natural gas burning systems will depend on increasing hydrogen production to ensure a reliable supply. On the residential and commercial front, consumers will be faced with a requirement to update their gas-burning systems (stoves, furnaces, water heaters, etc.) as research has shown that current designs do not reliably perform using pure hydrogen as a fuel source.

Lastly, there is a global need for hydrogen and Alberta is well-positioned to supply decarbonized hydrogen to the United States in the near-term. Time is of the essence since other countries are looking to export hydrogen, with some trials already underway. However, the same challenges and limitations to domestic networks of steel transmission pipelines apply to export pipelines, so large-scale export of hydrogen will only be effective through dedicated pipelines specifically designed for hydrogen service. Accelerated and coordinated efforts to develop effective regulatory guidelines for hydrogen export across provincial and national borders via purpose-built hydrogen pipelines and new technology development for hydrogen leak detection and mitigation will be required to enable an export market. Export to offshore nations like South Korea, Germany and Japan are many years away as they face additional challenges of cryogenic transport at temperatures significantly lower than LNG.

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