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HYDROGEN AS AN ALBERTA EXPORT OPPORTUNITY: GAP ANALYSIS

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 ALBERTA INNOVATES

EMISSIONS
REDUCTION
ALBERTA 

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ABOUT EMISSIONS REDUCTION ALBERTA (ERA)

ERA was created in 2009 to help deliver on the province's environmental and economic goals. Since 2009, ERA has been investing revenues from the carbon price paid by large emitters to accelerate the development and adoption of innovative clean technology solutions. These technologies will lower costs, improve competitiveness, and accelerate Alberta's transformation to a low emissions economy.

ABOUT ALBERTA INNOVATES

Alberta Innovates is the province's largest and Canada's first provincial research and innovation agency. For a century we have worked closely with researchers, companies, and entrepreneurs – trailblazers who built industries and strengthened communities. Today we are pivoting to the next frontier of opportunity in Alberta and worldwide by driving emerging technologies across sectors. We are a provincial corporation delivering seed funding, business advice, applied research and technical services, and avenues for partnership and collaboration.

1.0 EXECUTIVE SUMMARY

Hydrogen and carrier molecules such as ammonia are being explored as low carbon fuel commodities for a variety of novel end-uses to replace fossil fuels. Currently, in Alberta and elsewhere, hydrogen is traded mainly as compressed gas over land for traditional industrial applications, such as oil and gas refining, chemicals, and fertilizer production. To establish hydrogen and its carriers as global clean energy commodities will require overseas transport, and thus significant infrastructure that does not currently exist at scale. This paper explores opportunities and challenges for export of hydrogen and its carriers as global commodities, targeting transportation and power end-uses in the Asia-Pacific region, with a particular focus on informing Alberta's investment landscape over the next decade. Ultimately, the aim of this assessment is to demonstrate the trade-offs that must be considered between lifecycle carbon intensity, energy delivery efficiency, and cost, all in the quest to meet net zero goals.

In this paper, we examined a series of cases pertinent to Alberta, within two high level boundary cases: (1) export of product produced in Alberta for end use in Asia-Pacific transportation applications, or "well to tank"; and (2) export of product produced in Alberta for transportation applications in Asia-Pacific, or "well to plant". We analyzed liquified natural gas (LNG), pure hydrogen, and ammonia as the export products in question, with nominal consideration given to alternatives such as methanol and liquid organic hydrogen carriers (LOHCs). Based on technological readiness and anticipated market demand, we assumed that ammonia may not be used directly for transportation applications but can be used directly for power. LNG and hydrogen may be used as a fuel for both transportation and power.

We completed a basic comparison of LNG, hydrogen and hydrogen carriers in terms of energy density, safety and toxicity, by-products of combustion, by-products of end-use, and logistics of transportation. We then calculated and provided a case-by-case, well-to-tank and/or well-to-plant analysis of key metrics, including lifecycle carbon

intensity and ultimate energy delivery efficiency, or the amount of energy delivered at point of use divided by the total input energy of production. For our analysis we did not derive our own lifecycle costs, but instead use our results to provide context and discuss costs taken from existing literature, particularly the work of Dr. Amit Kumar of the University of Alberta [Okunlola et al, 2022].

For the well-to-tank case, we determined that LNG ultimate energy delivery efficiency is the highest at 66%; followed by pure hydrogen at a much lower 31%, and ammonia even lower, at 26%. In terms of lifecycle emissions, including end-use, we determined LNG was highest at 89.1 kg CO_{2e}/GJ delivered; followed by ammonia at 40.9 kg CO_{2e}/GJ delivered; and pure hydrogen at the lowest of 35.6 kg CO_{2e}/GJ delivered. Therefore, more than twice the amount of input energy is required to deliver an equivalent amount of hydrogen transportation fuel compared to LNG, but lifecycle emissions are reduced by 60%. Almost three times as much input energy is required to export ammonia as it must be re-converted to hydrogen for transportation fuel, and lifecycle emissions are reduced by only 54%.

For the well-to-plant case, LNG ultimate energy delivery efficiency remains the same at 66%, followed by ammonia at 43%, greatly improved from the well-to-tank case since it is no longer being reconverted to hydrogen; and pure hydrogen the lowest, at 38%. In terms of lifecycle emissions, including end-use, we determined LNG was highest at 80.4 kg CO_{2e}/GJ delivered; followed by pure hydrogen at 28.9 kg CO_{2e}/GJ delivered; and ammonia at the lowest, with 25.1 kg CO_{2e}/GJ delivered. Therefore, 50% more energy is required to deliver ammonia for power generation with a 69% lifecycle emissions improvement compared to LNG, and 75% more energy is required to deliver hydrogen for power generation with a 64% emissions improvement.

Based on the outcomes of our analysis for energy penalty and emissions reduction, pure hydrogen is a superior export product compared to ammonia for the well-to-tank case, and ammonia is a superior export product compared to pure hydrogen for well-to-plant. The case to fuel-switch away from LNG for both hydrogen and ammonia is stronger overall for the well-to-plant than it is for well-to-tank, both in terms of energy losses and emissions reductions. Overall, the strongest case to fuel switch away from LNG is ammonia for power end-uses.

We further used our analysis to identify gaps in technology and data availability. From an emissions perspective, first and foremost, upstream processing and transport emissions of feedstock natural gas must be addressed to reduce lifecycle emissions across all pathways. In all cases, this was the greatest contributor to lifecycle emissions. We also did not consider fugitive methane emissions for end use of LNG for transport, for which data is limited and unreliable. Additionally, this analysis did not consider NO_x emissions from combustion of hydrogen and ammonia for power end-use, or other environmental impacts.

From an energy delivery efficiency perspective, the greatest energy losses occur during the conversion from LNG to hydrogen and/or ammonia, however, there are basic physical limits in how much this can be improved, so some energy losses will always be present. To further optimize energy delivery efficiency, conversion steps near the point of end use must be minimized. For example, currently, direct use cases for ammonia in transportation applications are at a very low level of technology readiness. Should these be advanced, this would greatly improve the case for switching from LNG to ammonia for the well-to-tank case, since it would save an energy-intensive reconversion step.

We expect this analysis could lead to multiple avenues of follow on work. Some recommended further analyses include: (1) expansion of the analysis to include environmental impacts that were ignored, such as NO_x emissions; (2) derivation of costs for delivery of LNG vs pure hydrogen vs ammonia to Asia-Pacific and comparing them to their relative lifecycle emissions benefits; (3) comparison of alternative upstream production methods for hydrogen relevant to Alberta, including decarbonization of natural gas feedstock production; (4) exploring the benefits of exporting LNG product to convert to clean burning fuels at point of use, such as via methane pyrolysis; and (5) in-depth comparison of how Alberta exports compare to other

jurisdictions and supply chains, such as those that plan to use electrolysis for hydrogen production.

Additionally, for Alberta to become a successful exporter of any of these fuels will require both improvements to technology readiness across the value chain and, importantly, successful deployment of infrastructure to reach the BC coast and to export product across the Pacific Ocean. Neither of these gaps were considered in-depth by this study.

In conclusion, hydrogen and ammonia may still be promising opportunities for Alberta export, but the tradeoff between energy delivery efficiency, lifecycle emissions reduction, and cost must be carefully considered for each specific case. Near term investments should focus on export of ammonia with minimal conversion steps near point of use. Further efforts are required to reduce lifecycle emissions for both hydrogen and ammonia produced in Alberta, as well as to engage stakeholders and develop the relevant export infrastructure.

2.0 INTRODUCTION

In the future, to achieve emissions targets while maintaining global economic growth, there will be increasing demand for portable, energy-dense, and carbon-free fuels. The challenge is to find a replacement to fossil fuels that reduces emissions across its lifecycle, while delivering sufficient total energy to meet demand, and to do this all at a reasonable cost that is acceptable to end users.

Hydrogen is being considered as a global replacement to fossil fuels for transportation, power, and heat applications. Similar to fossil fuels, hydrogen is both energy dense and can be stored for long periods of time; but unlike fossil fuels, does not release carbon emissions when combusted. Hydrogen has shown to be technically capable of replacing fossil fuels for both transportation as well as heat and power applications. Transportation replacements include fuel cell electric vehicles or direct combustion of hydrogen as fuel. For heat and power, hydrogen can be blended with or even replace natural gas, then combusted.

Due to challenges in transporting hydrogen that we discuss in the following section, “hydrogen carriers” such as ammonia, methanol, and LOHCs are also being explored alongside pure hydrogen. All of these chemicals “carry” hydrogen and thus share some of its advantages. They may offer logistical advantages compared to transporting hydrogen in its pure form. They also, however, involve disadvantages that must be considered, such as low technology readiness for end-use and/or additional conversion steps that increase costs, energy penalties, and emissions. All these trade-offs must be considered when assessing their potential to become global replacement commodities for fossil fuels.

For the purposes of this paper, the main incumbent we considered as a baseline for comparison is LNG converted to its gaseous form for heat and power production via combustion.

CURRENT USES FOR HYDROGEN:

- + Oil refining and industrial chemicals
- + Pre-cursor to fertilizer product

While LNG usage is not yet as widespread as crude oil, it has well established distribution networks for industrial and residential use and global infrastructure for ocean transport is expanding rapidly. Technology is established for use of compressed natural gas for road transport and for shipping. LNG has a significantly lower lifecycle greenhouse gas footprint than both coal and crude oil converted to gasoline or diesel, and technology exists for LNG to overtake almost all the same end-use applications.

LNG is nonetheless a fossil fuel that results in material greenhouse gas emissions when combusted for end-use. In an increasingly net zero world, LNG may face competition from newcomer fuels with an even lower carbon footprint, which is what this paper seeks to assess from the perspective of ultimate energy delivery efficiency and lifecycle GHG emissions. The following alternatives will be discussed as potential replacements for LNG for transportation, heat, and power applications:

- + Pure hydrogen – liquefied for overseas transport then re-gasified for end-use
- + Hydrogen carriers, including:
 - + Liquid ammonia (NH₃) – used directly, or “cracked” into gaseous hydrogen
 - + Other hydrogen carriers, to be considered in less detail: methanol and LOHCs.

Given these carriers’ relative technological and commercial maturity, this paper will focus mainly on pure hydrogen and liquid ammonia, with less detailed consideration given to methanol and LOHCs.

USES FOR HYDROGEN AS A CLEAN FUEL:



Fuel cell electric vehicles



Heat and power



Dual fuel diesel-hydrogen vehicles

3.0 BACKGROUND

In the following background section, we provide global and Alberta-specific context for potential growth in hydrogen demand, as well as current status and technological gaps for LNG, hydrogen, and its carriers including ammonia, methanol, and LOHCs. We then provide a comparison of physical properties, including safety considerations, for each fuel/carrier.

3.1 GLOBAL CONTEXT

Below we discuss potential for growth, current status, and gaps from a global perspective.

3.1.1 POTENTIAL FOR GROWTH

Based on announced pledges to develop hydrogen as a carbon-free fuel from countries around the world to date, demand for hydrogen, including its potential carrier fuels, is expected to grow to 250 Mt/year by 2050 from approximately 90 Mt/year currently (IEA, 2022). To meet global net zero goals, over 500 Mt/year of hydrogen for energy end-uses will be required by 2050 (IEA, 2021). Hydrogen as a net zero opportunity is gaining traction worldwide, and nine countries have announced hydrogen strategies within the past two years (IEA, 2022).

Of particular interest for this study is hydrogen demand growth in Asia-Pacific. Japan currently has hydrogen demand of 2 Mt/year and anticipates increasing to 20 Mt/year by 2050. Japan's ammonia demand is projected to be 3 Mt/year by 2030 and 30 Mt/year by 2050 (METI, 2021). Japan is considering both transportation as well as heat and power applications for hydrogen and ammonia direct use. South Korea's current hydrogen demand is more modest at 130 kt/year with a goal to increase this to 5.3 Mt/year by 2050 (CSIS, 2021). Both of these countries are focused on being end-users of hydrogen, not producers, and are thus seeking sources of international supply. Of note, China is also a major source of future demand, but can be expected to focus on meeting its needs via domestic production.

Here in Canada, hydrogen is also considered a promising net zero opportunity. A [federal hydrogen strategy](#) is in place, and [Ontario](#), [Alberta](#), [BC](#) and [Quebec](#) have also developed hydrogen strategies and roadmaps of their own. Additional provinces have acknowledged the importance of hydrogen and are advancing related initiatives. There have also been several discussions and agreements with international partners to advance hydrogen supply, including a memorandum of understanding between Canada and the Netherlands on hydrogen collaboration (Natural Resources Canada, 2021), a Joint Declaration of Intent between Canada and Germany (Natural Resources Canada, 2022), several trade missions to Japan and South Korea (Government of Alberta, 2023), and a Memorandum of Understanding

EXAMPLES OF MAJOR INTERNATIONAL EXPORT PROJECTS



1.0 NEOM Green Hydrogen Complex

Air Products announced a \$5B project in Saudi Arabia to produce up to 600 tons of hydrogen per day from renewable energy, targeting operations by 2026 (Air Products, 2023). Image source: Arab News, 2022.



2.0 Louisiana Clean Energy Complex

This is a \$4.5B project led by Air Products to produce hydrogen and ammonia in the Gulf Coast region from natural gas with 95% carbon capture, targeting operations by 2026 (Air Products, 2023). Image source: Haldor Topsoe, 2023.

between Alberta and the Japan Organization for Metals and Energy Security (JOGMEC, 2021). All these initiatives require the safe, cost-effective and efficient transportation of hydrogen and/or its carriers from Canada to other jurisdictions.

3.1.2 CURRENT STATUS, GAPS, AND RISKS

Despite optimism around the role hydrogen and its carriers can play in a global low-carbon economy, significant gaps and risks remain to achieving widespread usage of hydrogen, ammonia, or other low-carbon fuels as global commodities in the same way we currently use fossil fuels. These challenges are different for each hydrogen carrier and are discussed in further detail below.

As a baseline for comparison, in 2022, global demand for crude oil was 2.1 million barrels per day or 5,600 Mt/year (IEA). Global LNG trade is less mature, but rapidly growing. In 2021, global LNG trade was 380 Mt (IGU World LNG report). Both crude oil and LNG are transported by pipeline, truck, rail, and ship worldwide.

Below we discuss the current status and logistical gaps and risks for establishing global trade of hydrogen, ammonia, and other carriers.

3.1.2.1 HYDROGEN

Hydrogen is not currently used as a source of clean energy, but rather primarily for industrial uses, such as refining in the oil and gas industry, and as an ingredient in the production of fertilizer. Virtually all hydrogen transport occurs via pipeline over short distances, meaning international trade is limited to land transport between neighbouring countries. For instance, there is some pipeline transport between various U.S. states and between Belgium, France, and the Netherlands; but no overseas export at scale anywhere in the world.

Land transport options for hydrogen pipelines containing pure hydrogen, or hydrogen blended with natural gas, truck, or rail. In a pipeline, hydrogen must be transported in its gaseous form, and for truck or rail, it may be either gas or liquid. Both pure and blended hydrogen pipelines exist at small, local scales, but generally not at large, international scales. Truck and rail

EXAMPLES OF INTERNATIONAL EXPORT PROJECTS IN CANADA



3.0 Everwind Project

Everwind received permitting to pursue a \$6B project in Nova Scotia, Canada planning to produce 1.1 Mt hydrogen and ammonia per year from electrolysis using a combination of power purchase agreements and future wind power, targeting operations by 2026 (Everwind, 2023).



4.0 Petronas-Itochu Blue Ammonia Plant

Inter Pipeline Ltd. has announced a partnership with Itochu Corporation and Petronas Energy Canada Ltd. to evaluate the development of a large-scale blue ammonia plant in Alberta, using autothermal reforming plus carbon capture. Expected in-service date is 2027 (Inter Pipeline, 2022).

Image source: Invest Alberta.

transport are in their infancy. Overseas export would require liquefied transport by ship, also an emerging technology. For most applications, exported liquid hydrogen must be re-gasified at the point of end use, requiring additional infrastructure and demanding energy, cost, and emissions penalties.

Another important gap for future low-carbon global hydrogen trade lies in how it is produced. The vast majority of hydrogen today is produced from fossil fuels, with 75% of production coming from steam methane reforming (SMR) of natural gas, without carbon capture. Emissions result from both natural gas extraction, processing, and the reforming process. Globally, current hydrogen production emits 900 MtCO₂/year (IEA, 2022).

Future low or zero-emissions pathways for hydrogen production are making progress, with multiple word-scale facilities expected to come online within the next decade. Low carbon alternative production methods include: SMR with carbon capture and storage (CCS); auto-thermal reforming (ATR) with CCS; methane pyrolysis; in-situ production from fossil fuels; and electrolysis sourced from low carbon electricity. All of these alternatives add production costs and may have environmental impacts of their own, but these vary greatly by regional factors such as access to natural gas feedstock supply and grid intensity. For example, electrolysis requires

significant freshwater usage, and makes little sense in jurisdictions with carbon-intensive grids. All the above production methods have the potential to be net zero, with varying degrees of difficulty. On average, hydrogen production from fossil fuels, even with carbon capture, tends to be significantly cheaper than the alternatives, such as electrolysis (Transition Accelerator, 2022).

3.1.2.2 AMMONIA

Ammonia is a “carrier” of hydrogen, with the chemical form NH₃. In contrast to hydrogen, ammonia is already a global commodity with established overseas trade routes. Ammonia has global trade of \$6.9B USD at a scale of around 230 Mt/year (D. R. MacFarlane et al, 2020), making it the second most highly traded chemical worldwide. More widespread adoption of ammonia transport by ships may begin in the late 2020s, reaching 25% by 2050. This is one of the main reasons why it is considered a promising hydrogen carrier (Nutrien, 2022).

Today, ammonia is used mainly for fertilizer, both as pure ammonia and in other composite forms, such as urea. Ammonia is also used in other applications such as cleaning products and explosives. It can be found widely in nature as a waste product of biological processes. Ammonia is not currently used for transportation or heat

EXAMPLES OF NEW HYDROGEN SHIPPING & PRODUCTION



5.0 World's first shipment of liquid hydrogen completed between Australia and Japan

The world's first liquid hydrogen tanker, the Suiso Frontier built by Kawasaki Heavy Industries, successfully delivered liquid hydrogen from Australia to Japan in February 2022 as part of the Hydrogen Energy Supply Chain Project (HESC, 2023).

Image source: Asahi Shimbun, 2021.



6.0 Hydrogen production from nuclear energy

Alternative methods of hydrogen production are being explored, such as from nuclear energy. A demonstration began in early 2023 to produce hydrogen from the Nine Mile Point Nuclear Station in Oswego, New York using low-temperature electrolysis (U.S. Department of Energy, 2023).

Image source: Constellation Energy, 2023

and power applications, but these are also being explored.

While much further advanced than hydrogen, more widespread use of ammonia will still require engine modifications, increased fuel storage capacity, and managing of NO_x emissions, as well as adapting bunker infrastructure to accommodate ammonia's low energy density compared to diesel (Nutrien, 2022) (Global Maritime Forum, 2020).

Furthermore, whereas pure hydrogen end-use applications are approaching commercial readiness, ammonia end-use applications have more significant technology gaps. For end-use, ammonia may be cracked into its hydrogen and nitrogen components and then used the same way as pure hydrogen; or used directly as ammonia. Cracking is a high-temperature, high-energy process (10 MWh/t hydrogen) that releases hydrogen and nitrogen (U.S. Department of Energy, 2006), and exists at low technology readiness at a scale of 1-2 t/day (Siemens et al, 2020). If ammonia is used directly, in theory it can be converted to electricity or combusted, just like hydrogen; but both applications are much less technologically evolved. Direct use of ammonia in fuel cells is still early stage due to its tendency to poison catalysts (U.S. Department of Energy, 2022).

Similar to hydrogen, the GHG footprint of ammonia production must be addressed if it is to displace fossil fuels as a low-carbon alternative. Approximately 180 Mt of global ammonia production occurs via hydrocarbon reforming without CCS to produce hydrogen precursor, followed by industrial ammonia synthesis via the Haber-Bosch process (D. R. MacFarlane, 2022) (IEA, 2022). The whole process requires 8-12 MWh/t ammonia produced, consumes 1-2% of global energy, and is responsible for 1-1.5% global emissions (ACS, 2021) (U.S. Department of Energy, 2022). Most of this comes from production of the hydrogen precursor. Thus, decarbonization pathways for production of ammonia are very similar to those of hydrogen.

3.1.2.3 OTHER CARRIERS

Apart from ammonia, there are other hydrogen-containing chemicals being considered as "carriers" for the purpose of global trade. All of these are niche chemicals and not currently traded at any significant global scale, or even at a local scale. The requirements for their global trade are not yet well understood, and will require

additional scientific study and infrastructure investments, well beyond what will be required for hydrogen and ammonia.

One example of an alternate hydrogen carrier is methanol. Methanol is an alcohol that is used industrially as a solvent, pesticide, and alternative fuel source. It also occurs naturally in humans, animals, and plants. Importantly, however, not only is it at a low state of readiness for global export, but unlike hydrogen and ammonia, methanol is a carbon-containing chemical that releases CO₂ when combusted.

Liquid organic hydrogen carriers (LOHCs) are a potential hydrogen transport method that include a suite of organic compounds that can reversibly incorporate and release hydrogen gas through chemical reactions. An example is methylcyclohexane (MCH), a solvent and precursor to manufacture other chemicals. A catalytic conversion cycle between MCH and toluene can carry hydrogen as part of a liquid compound, then release it as pure hydrogen gas. LOHCs are at very low technology readiness worldwide in terms of production, logistics of transportation, and end-use (Meille and Pitault, 2021).

AMMONIA FOR SHIPPING



7.0 Ammonia ships near commercial-readiness

Ammonia is already exported on ships around the world, but because ammonia has lower energy density than traditional fossil fuels, ships will need to be modified to use ammonia as fuel. There are multiple projects worldwide to retrofit ships and/or design new builds capable of being powered by ammonia, including the supply vessel Viking Energy (IEEE, 2021) (Offshore Energy, 2022 & 2023).

Image source: Eidesvik, 2021.

3.2 ALBERTA'S LANDSCAPE

In this section, we expand on the opportunities and gaps for hydrogen and its carriers by focusing on the Alberta-specific context relevant to this analysis.

Alberta is already a leading low-cost producer of both hydrogen and ammonia, and is thus well positioned to participate in a future global hydrogen economy for these chemicals used as fuels. For this reason, both hydrogen and ammonia export are being considered as future opportunities for Alberta to participate in a global low carbon economy, with some companies also exploring alternatives like methanol and LOHCs.

Alberta currently produces 2.4 MT/year of hydrogen, primarily for oil refining, chemical production, and ammonia (Invest in Canada, 2022). Production occurs via the carbon-intensive SMR process, although Alberta has two plants that operate with partial carbon dioxide capture and sequestration. Ammonia production is 3.5 Mt/year for fertilizer via the Haber-Bosch processes (Invest in Canada, 2022). Alberta has made promising headway in novel end-use applications for hydrogen including heavy duty rail, trucking, bus transit, and residential and commercial heating. Additionally, Alberta is rapidly making advances towards low carbon intensity ammonia and hydrogen production by adding CCS to existing SMR production and/or displacing these with emerging technologies like ATR, with several operating and planned word-scale facilities.

Because of Alberta's easy access to a large supply of to low-cost natural gas feedstock, low-carbon production of hydrogen via SMR or ATR of natural gas with CCS is the most economic and practical near-term opportunity for Alberta hydrogen production at world scales. The Transition Accelerator estimates hydrogen from ATR plus CCS hydrogen can be produced in Alberta for as low as \$1.5-\$2/kg (2022). Cost estimates for electrolytically produced hydrogen in Alberta vary, and are generally estimated in the \$3-5/kg range, and present emissions challenges in Alberta due to our carbon-intensive grid (Transition Accelerator, 2022). Alberta does not have ready access to other means of clean hydrogen production, such as nuclear power.

For overseas export, Alberta faces many of the same challenges as other jurisdictions worldwide. Alberta currently supplies hydrogen locally in the Industrial Heartland region of Edmonton, but does not have any pure or blended hydrogen pipelines exporting product out of province. For ammonia, Alberta consumes much of what it produces, but has some exports by land to the U.S. Alberta does not have any infrastructure for either hydrogen or ammonia product to access tidewater at large scale, by either pipeline or train. Past experience shows significant stakeholder engagement and regulatory hurdles must be overcome to install this infrastructure, and these may be even more challenging for new products. Additionally, should hydrogen or ammonia product be able reach tidewater, additional infrastructure would be needed to export product overseas, such as specialized storage tanks, terminal, and loading infrastructure that does not currently exist on either of Canada's coasts.

Should these challenges be overcome, however, the U.S., Japan, and South Korea are key markets for Alberta hydrogen and ammonia. Some assessments have suggested these markets could double Alberta's current production to 4 Mt/year (Transition Accelerator, 2022). In an example relevant to this analysis, a cost-competitive opportunity may exist for Alberta to deliver hydrogen in the form of ammonia to Japan, given Japan's very high energy costs and dependence on imports (Okunlola et al, 2021). In the near term, Japan has indicated they are interested in the use of imported hydrogen and ammonia for power applications and are considering Alberta as a potential source of these fuels. Similarly, South Korea anticipates hydrogen imports to meet future growth will come in the form of liquefied hydrogen ammonia, LOHCs, and compressed gas, and will come from diverse sources, including Alberta (CSIS, 2021).

CURRENT ALBERTA LANDSCAPE FOR CLEAN HYDROGEN AND AMMONIA



8.0 Quest Carbon Capture and Storage Project

Located in Edmonton, Alberta, Shell Quest has captured and stored more than 6Mt of CO₂ since entering operations in 2015. The facility relies on steam methane reforming of hydrogen plus carbon capture and storage, with an overall maximum capture rate of 85% (Collodi et al., 2017).

Image source: Shell Scotford, 2015.



9.0 Nutrien Redwater

Nutrien's Redwater facility in Alberta produces ammonia for fertilizer from steam methane reforming and the Haber-Bosch process. CO₂ is captured and transported using the Alberta Carbon Trunk Line (ACTL) for permanent sequestration in central Alberta at a rate of approximately 500 tpd (Nutrien, 2020). The ACTL has been fully operational since 2020 (Enhance, 2023).

Image source: Nutrien, 2020.



10.0 Canada Net Zero Hydrogen Energy Complex

Air Products is constructing a \$1.6B facility in Edmonton, Alberta planning to produce hydrogen from autothermal reforming using biogenic feedstock with more than 95% carbon capture. The facility is planned to be in service in 2024. (Air Products, 2023).

Image Source: Air Products, 2023.



11.0 Hydrogen End Uses

Alberta is making rapid advancements in novel end-use applications for hydrogen. Several world-leading transportation pilots are underway, including hydrogen fuel-cell based freight rail with Canada Pacific, bus transit in the City of Edmonton and Strathcona County, and both fuel cell and hydrogen-diesel dual fuel truck trials across the province. ATCO is also delivering a 5% hydrogen blend to residential customers in Fort Saskatchewan with plans to increase this over time.

3.3 SUMMARY OF GAPS

Below is a table summarizing the key points regarding status and gaps for global export of hydrogen, ammonia, and other carriers in the global context and Alberta-specific case.

TABLE 1: GLOBAL STATUS & GAPS

PRODUCT	PRODUCTION	TRADE	CONVERSION FOR END USE
HYDROGEN	Currently produced at scale, with high GHG footprint. Low GHG alternatives exist at varying TRLs and cost.	Currently traded at-scale, but only over land. No overseas transport at scale.	Approaching high technology readiness for both fuel cells and direct combustion.
AMMONIA	Currently produced at scale, with high GHG footprint. Low GHG alternatives exist at varying TRLs and cost.	Currently traded at scale over land and overseas.	Low to mid technology readiness.
OTHER CARRIERS	Negligible, with gaps not fully understood.	Negligible, with gaps not fully understood.	Very low technology readiness.

TABLE 2: ALBERTA STATUS & GAPS

PRODUCT	PRODUCTION	LOCAL TRADE	INTERNATIONAL TRADE
HYDROGEN	Currently produced at scale, with high GHG footprint via SMR + CCS, but multiple low-carbon world-scale projects will become operational within 1-5 years, using SMR/ATR + CCS. Other production methods, like electrolysis, not readily available at cost, large scale, and low emissions.	Currently traded at-scale via pipeline in the local Alberta industrial heartland, with additional truck and train transport being added in the near term.	No international trade. No pipeline, truck, or train transport to tidewater. No infrastructure available for export.
AMMONIA	Currently produced at scale, with some CCS already in place and multiple world-scale low carbon projects entering operations within 5-10 years.	Currently used-at scale by local producers.	Limited trade to the US by land. No pipeline, truck, or train transport to tidewater. No infrastructure available for export.
OTHER CARRIERS	Negligible, some startups considering local applications	N/A	N/A

3.4 PHYSICAL PROPERTIES

In this section we explore some of the logistical challenges with hydrogen and its carriers in more depth by comparing their physical properties.

Key challenges to replacing global trade of fossil fuels with low carbon alternatives are due to their comparative physical properties that make transportation and storage far more complex than the incumbents. These challenges result in energy losses and cost increases that must be weighed against their improved carbon footprint. Below we explore a comparison of physical properties for hydrogen, ammonia, and other carriers, in relation to LNG.

3.4.1 LNG BASE CASE

LNG is natural gas that has been cooled to -160°C to form a liquid state at atmospheric pressure, where it can be stored at 1/600th its volume when at ambient temperature (NRCan, 2013). As a liquid it is neither flammable nor explosive, but it will freeze anything that it contacts, so must be stored in highly insulated vessels. When it re-gasified it has the potential to become flammable or explosive if it reaches a lower explosive limit (LEL) of approximately 4.4% in air (Engineering ToolBox, no date). Natural gas is comprised of up to 95% methane, with the balance comprised of ethane, propane, butane and trace amounts of nitrogen (US Department of Energy, 2005). There are rigorous controls in place to manage natural gas and LNG safety at all stages of production, transportation and end use.

The ability to dramatically increase the density of natural gas enables large volumes to be shipped cost-effectively by ocean vessel. Over the course of shipping, approximately 0.15% of the LNG per day re-gasifies (boils-off) and is captured by the ships and used as supplemental fuel for power (US Department of Energy, 2005). As of 2022, there were 641 active LNG vessels delivering up to 372 Mt of LNG (2021) with 460 Mt/year in global liquefaction plant capacity as of 2021 and up to 1034 Mt/year in capacity projected based on all projects planned (pre-FID or later) (International Gas Union, 2022).

3.4.2 HYDROGEN

Hydrogen is the lightest element on the periodic table and the most prevalent in the universe. The vast majority of hydrogen in nature exists in the form of other molecules, like water. Pure hydrogen has very high energy density by mass,

but lower density by volume in its gaseous form. Hydrogen is non-toxic and when combusted, does not emit CO_2 . When used in a fuel cell to generate electricity, there are no resulting emissions, only water vapor.

Hydrogen is similar to natural gas from a safety perspective, but does require some additional considerations (Engineering ToolBox, 2023). In its pure form, hydrogen reacts when small amounts are in contact with oxygen. Hydrogen burns with a transparent flame, making fires more difficult to detect. While there is considerable overlap with natural gas in terms of handling expertise required, there are regulatory gaps for widespread use of hydrogen and these must be overcome alongside technological challenges.

Due to its physical properties, hydrogen is also challenging to transport and store, and this is one of the major reasons why the infrastructure to do this at scale around the globe does not exist. In its pure form, hydrogen must be stored as a highly compressed gas at very high pressures, 70 MPa; or else as a cryogenic liquid, at -253°C , much lower even than natural gas. High pressures introduce safety risks, and such a low boiling point means that hydrogen can easily boil off, resulting in significant energy losses during transportation.

3.4.3 AMMONIA

In contrast to hydrogen, ammonia can be easily liquefied at room temperature or at -33°C at atmospheric pressure (ACS, 2021). Cracking of ammonia, or reconstitution into pure hydrogen, only releases nitrogen, a harmless greenhouse gas. Direct combustion of ammonia does not result in CO_2 emissions, but does result in NO_x emissions.

While not as explosive as hydrogen, ammonia is a toxic and noxious gas.

3.4.4 OTHER CARRIERS

Methanol is chemically similar to methane, with the substitution of one hydrogen for an alcohol functional group (OH-). It has a higher heating value of 23 MJ/kg, versus methane at 55.5 MJ/kg and hydrogen at 141.7 MJ/kg (Engineering ToolBox, 2023). Methanol is a commonly used industrial chemical and is the basis for producing acetic acid, formaldehyde, methyl methacrylate and methyl tertiary-butyl ether (MTBE) (NETL, no date). It can be made from syngas (hydrogen + carbon monoxide) through a water-gas shift

reaction using natural gas, coal, or biomass as the feedstock (NETL, no date).

Methanol is also being marketed as a fuel, either for blending with hydrocarbons or as a direct fuel for some fuel cell electric vehicles (direct methanol fuel cells), or even as a feedstock for synthesizing diesel. On its own it is not effective in diesel engines but has a high-octane value when used in gasoline engines (IEA, no date). Methanol evaporates at 11° C, so can be easily stored as a liquid for low-cost shipping. When using biomass or renewable natural gas as a production feedstock, methanol can have a very low carbon footprint; but sufficient volumes of renewable feedstock may not be available to meet demand.

Liquid organic hydrogen carriers (LOHCs) are a class of compounds that form bonds (covalent bonds or weak interactions) with hydrogen and are liquids at ambient temperature and pressure. These compounds bond with hydrogen (hydrogenation) and release hydrogen (dehydrogenation) in controlled conditions. Heat is usually involved with one or both steps and

therefore has an energy footprint associated with it. There are many proposed LOHC cycles, including toluene/methyl cyclohexane, dibenzyl toluene/perhydro dibenzyltoluene, and others (Valentini et. al., 2022).

The ability of LOHCs to store hydrogen at ambient temperatures and pressures could facilitate hydrogen shipment, reducing the energy penalties associated with hydrogen pressurization or liquefaction. However, the LOHCs must return to the source of hydrogen production when dehydrogenated to be used again to capture more hydrogen from the source. This return to base results in incremental costs and energy use that need to be weighed against the logistical benefits.

3.4.5 SUMMARY OF PHYSICAL PROPERTIES

The following figures summarize the key physical properties for each fuel/carrier.

Figure 1. Fuel Comparison - GHG Footprint vs Energy Content

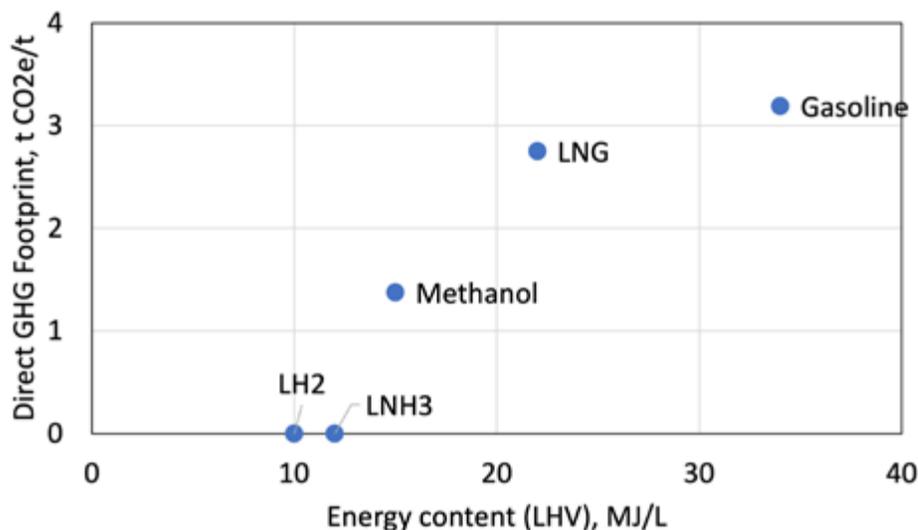


TABLE 3. FUEL COMPARISON – STORAGE REQUIREMENTS & SAFETY ISSUES

FUEL TYPE	STORAGE REQUIREMENTS	SAFETY ISSUES
GASOLINE	Liquid at atm	Toxic, flammable
NATURAL GAS	Liquid at -163 C or gas at 200 bar	Flammable
HYDROGEN	Liquid at -252 C or gas at 300 bar	Explosive
AMMONIA	Liquid at -252 C or gas at 300 bar	Explosive
METHANOL	Liquefied at -33 C	Toxic

4.0 EXISTING LITERATURE & GAPS

Beyond the authors of this paper, others have identified the Alberta export opportunity for hydrogen and its carriers, and some work has been completed to date. The most prominent example of existing literature is found in the work of Dr. Amit Kumar from the University of Alberta (Okunlola et al, 2022), which focuses on costs specific to the Alberta to Asia-Pacific export case. More limited work has also been performed on energy delivery efficiency for general cases. Both are discussed below.

4.1 EXPORT OF PRODUCT FROM ALBERTA TO ASIA-PACIFIC – TECHNOECONOMIC ANALYSIS

Dr. Kumar’s group has extensively studied potential costs of different modes of transporting hydrogen and its carriers from production facilities in Alberta to end-uses in the Asia-Pacific in Okunlola et al. (2022). For the Asia-Pacific case assessed in his report, Dr. Kumar considered the lifecycle of hydrogen produced via SMR + CCS, compression and transportation by pipeline to the BC coast, and transport by ship to Asia-Pacific, both for hydrogen and ammonia. They found it to be a cost-competitive opportunity for Alberta, with LNG being the lowest-cost, followed by ammonia, then pure hydrogen.

They did not assess ATR+CCS or consider the GHG impact of the end-use of hydrogen or ammonia or the impact on energy delivery efficiency.

4.2 ENERGY DELIVERY EFFICIENCY

As noted, due to their physical properties, hydrogen, ammonia, and carriers all require numerous conversion steps from the point of production to end-use, all of which result in energy losses. Like cost, these energy losses must be weighed against the emissions benefits of displacing carbon-emitting fuels.

Energy delivery efficiency is defined as the amount of energy delivered at point of use divided by the total input energy of production and transportation. In general, existing literature is very limited around energy delivery efficiency of hydrogen, ammonia, or its carriers.

Chatterjee et al. (2021) compared the energy delivery efficiency of pure hydrogen and ammonia derived from renewable electricity. Their analysis estimates the relative energy losses in each step of the hydrogen and/or ammonia supply chain from production to delivery, including overseas transport. Their analysis was not specific to Alberta, nor did it consider the lifecycle GHG impact for hydrogen and ammonia derived from natural gas with carbon capture and storage.

To our knowledge, no other studies exist on the energy delivery efficiency for hydrogen and ammonia as overseas export products. Information around energy delivery efficiencies for hydrogen and its carriers is thus limited and specific case studies do not yet exist for Alberta.

4.3 GAPS TO BE RESOLVED

This paper resolves the abovementioned gaps by analyzing energy delivery efficiency and lifecycle greenhouse gas footprint for two cases relevant to Alberta: (1) export of product produced in Alberta for end use in transportation applications in Asia-Pacific, or “well to tank”; and (2) export of product produced in Alberta for power generation applications in Asia-Pacific, or “well to plant”. We assessed energy delivery efficiency compared against GHG impact from the point of production to end-use, specific to the Alberta export to Asia-Pacific case. For our analysis we did not derive our own lifecycle costs, but instead use our results to provide context and discuss costs taken from existing literature, particularly the work of Dr. Kumar’s group mentioned previously.

For the purpose of this analysis, we considered only LNG, hydrogen and ammonia as potential export products. Methanol was not considered because it is a carbon-emitting fuel with a material greenhouse gas footprint from combustion, and thus brings many new logistical challenges without the benefits of being a net-zero compatible fuel. Similarly, LOHCs were not considered in depth because they are very much in their infancy and we do not consider them sufficiently progressed to be used at a material scale for export in the next decade.

5.0 CASE ANALYSIS & RESULTS

This following analysis considers “well to tank” and “well to plant” energy delivery efficiencies and lifecycle GHG analysis for export of LNG, hydrogen, and ammonia from Alberta to potential markets in Asia-Pacific. Below we discuss assumptions, boundaries, and key results for each case.

5.1 ASSUMPTIONS

Our analysis includes the following assumptions:

5.1.1 PRODUCTION

We assume all hydrogen, including as an ammonia precursor, is produced via ATR + CCS, due to near term world scale projects planning to use these technologies in Alberta.

We assume natural gas feedstock is produced by conventional means in Alberta with processing at distributed facilities to remove liquid components, hydrogen sulfide, and carbon dioxide. The gas is transported by pipeline to a central hub for either long-distance transport by pipeline, or for conversion to hydrogen or ammonia. Energy consumption and GHG emissions for natural gas upstream production, processing and transport are from ECCO (2022) and Oni et al. (2022). Energy for transport and liquefaction as liquefied natural gas (LNG) is given in Section 9, Appendix.

Hydrogen is produced from natural gas by ATR + CCS, such as from one of the facilities planned to become available in the timeframe of this assessment. The efficiency of carbon capture from the ATR plant is 95%, with sequestration in oilfields and deep aquifers (Section 9, Appendix).

Ammonia is produced using the Haber-Bosch process, using hydrogen from an adjacent ATR plant with CCS and nitrogen gas from the air separation unit of the ATR plant (Section 9, Appendix).

Hydrogen is used to generate electric power to drive the ATR plant, the air separation unit, and the ammonia plant, and for process heat as required.

5.1.2 PROCESSING & TRANSPORTATION

We assume energy for processing and transportation uses a portion of the energy stream as fuel. For example, we assume natural gas compression is powered by natural gas; and hydrogen liquefaction is powered by hydrogen. Other assumptions related to energy usage include:

- + High-temperature furnaces for processing are self-powered by hydrogen or ammonia
- + Generation of electric power by combined cycle occurs at 60% efficiency
- + Compressors for pipeline transportation use electric drive or are direct fueled at 45% efficiency
- + Refrigeration for liquefaction and fuel for ships is powered by hydrogen or ammonia, depending on the case.

Calculation factors are given in Section 9, Appendix.

5.1.3 END USE

In this analysis, we considered both transportation and power end-uses. Based on technological ability and anticipated market demand, we assume that ammonia may not be used directly for transportation applications in the “well-to-tank” case but can be used directly for power in the “well-to-plant” case. LNG and hydrogen may both be used directly in both cases. In both cases we did not calculate energy consumption of the actual usage, given the number of variables that would distort the analysis. We did, however, consider the GHG impact of the end-use cases.

5.2 CASE #1: WELL TO TANK

This first case involves export of product produced in Alberta for end use in transportation applications in Asia-Pacific for LNG, pure hydrogen, and ammonia.

In terms of the boundaries of this analysis, for the metric of energy delivery efficiency, the starting point input is natural gas produced by conventional means in Alberta. The output or end point of the analysis is a compressed transportation fuel at a fuelling terminal in Asia Pacific, that in this case will take the form of either natural gas or gaseous hydrogen.

5.2.1 PATHWAYS

The following pathways were assessed for LNG, hydrogen, and ammonia for the well-to-tank case:

- + **LNG:** Natural gas is produced, processed, transported by pipeline to the BC coast, liquefied, transported to Asia-Pacific as a liquid, re-gasified, then transported to a terminal where it can be used for transportation applications.
- + **Hydrogen:** Natural gas is produced, processed, converted to hydrogen via ATR + CCS, transported by pipeline to the BC coast, liquefied, transported to Asia-Pacific as a liquid, re-gasified, then

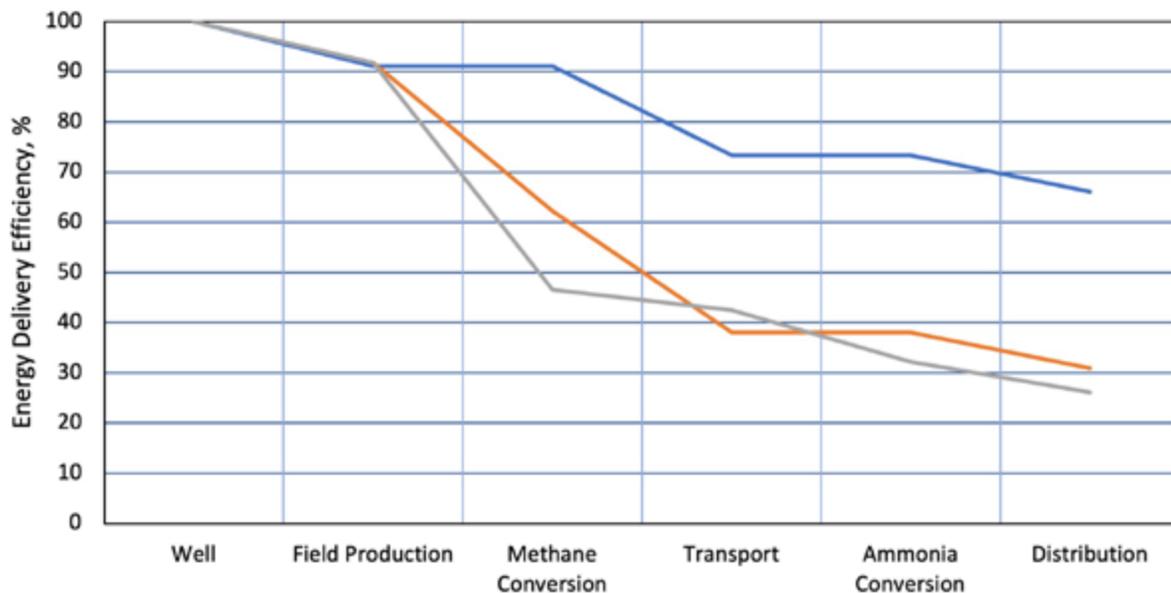
transported to a terminal where it can be used for transportation applications.

- + **Ammonia:** Natural gas is produced, processed, converted to hydrogen via ATR + CCS, converted to liquid ammonia by Haber-Bosch, transported by pipeline to the BC coast, transported to Asia-Pacific, converted back to hydrogen via cracking, then compressed and transported to a terminal where it can be used for transportation applications.

5.2.2 RESULTS – ENERGY DELIVERY EFFICIENCY

The data of Figure 2 show that LNG gives the highest energy delivery efficiency of 66%, with the major consumption for pipeline transport, liquefaction, and ship delivery to Asia-Pacific. Hydrogen delivery efficiency is significantly lower at 31%, due to the energy consumed for carbon capture, conversion of methane to hydrogen, and liquefaction for transport as a very low-temperature cryogenic liquid. Ammonia gives the lowest delivery efficiency at 26%. Although ammonia is easier to transport by long distances than hydrogen or LNG, the additional chemical steps of ammonia synthesis and ammonia cracking to produce hydrogen for end use greatly reduce the efficiency of delivery.

Figure 2. Well to Tank - Energy Delivery Efficiency



5.2.3 RESULTS – LIFECYCLE EMISSIONS INTENSITY

To assess the lifecycle GHG footprint, end-fuel combustion or usage was included, but fugitive emissions from end-use were ignored. The data of Figure 3 show that the GHG emissions from LNG were the highest at circa 90 kg CO₂e/GJ delivered because none of the emissions from the source methane was captured through the steps of the supply chain or in end use for road transport. The emissions from hydrogen and ammonia were significantly lower because 95% of the CO₂ from the synthesis step in Alberta was captured and sequestered.

As illustrated in Figure 4, the majority of the GHG emissions for the hydrogen case were due to upstream production of natural gas, both for the energy for collection and processing of the raw gas giving carbon dioxide emissions, and venting and fugitive releases of methane in well, pipeline and plant operations. The uncertainty in the methane emissions is significant, and Environment and Climate Change Canada has acknowledged that these sources are substantially underestimated in the national inventory (ECCC, 2022). GHG emissions associated with upstream natural gas production are expected to decrease in the future due to more rigorous control of venting, flaring and fugitive emissions, as well as implementation of carbon capture and sequestration in natural gas processing plants.

Figure 3. Lifecycle GHG footprint for well to tank case

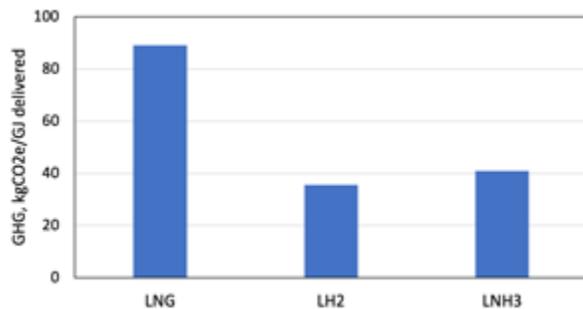
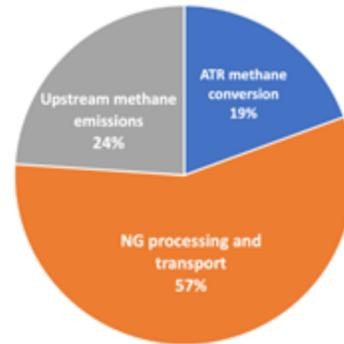


Figure 4. Contribution to GHG emissions for hydrogen in the well to tank case



*Total upstream emissions from Oni et al., 2022.
Fraction of methane emitted from ECCC, 2022.*

5.3 WELL TO PLANT

This case involves export of product produced in Alberta for end use in power applications in Asia-Pacific for LNG, pure hydrogen, and ammonia. In terms of the boundaries of this analysis of delivered energy efficiency, the starting point input will be natural gas produced by conventional means in Alberta. The output or end point of the analysis is fuel for a power plant in Asia Pacific, that in this case will take the form of natural gas, gaseous hydrogen, or ammonia. LNG, hydrogen, and ammonia are assumed to be used directly at facilities proximate to port facilities, with minimal requirement for transport and no need for significant compression.

5.3.1 PATHWAYS

The following pathways were assessed for LNG, hydrogen, and ammonia for the well-to-plant case:

- + **LNG:** Natural gas is produced, processed, transported by pipeline to the BC coast, liquefied, transported to Asia-Pacific as a liquid, re-gasified and used in a coastal power plant.
- + **Hydrogen:** Natural gas is produced, processed, converted to hydrogen via ATR + CCS, transported by pipeline to the BC coast, liquefied, transported to

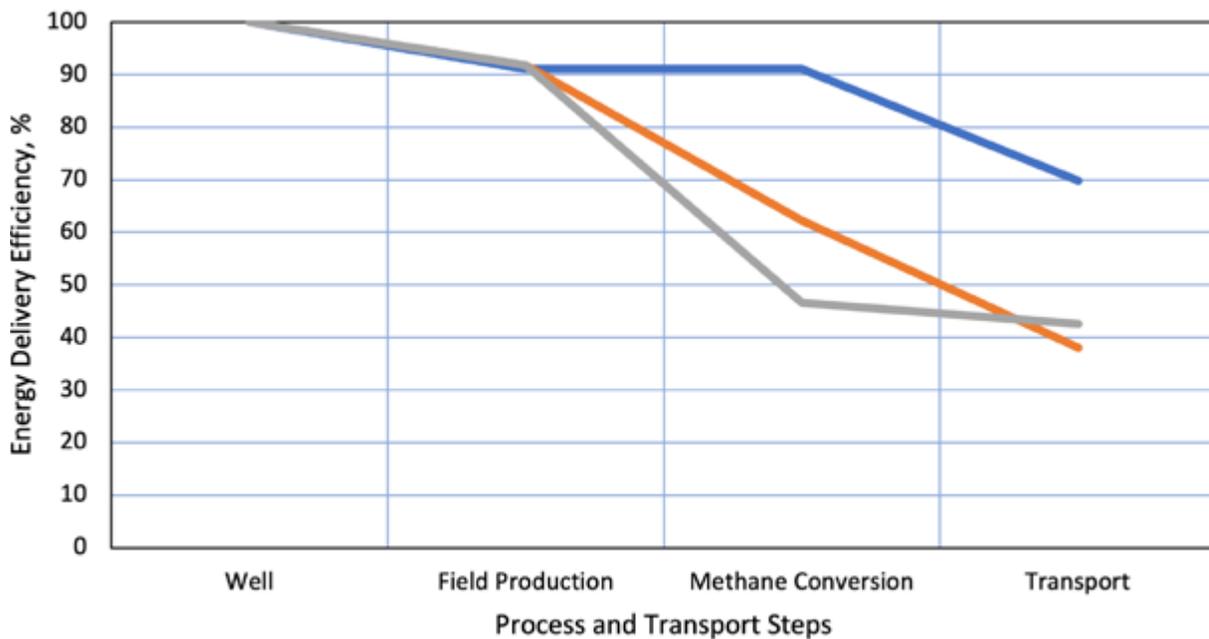
Asia-Pacific as a liquid, re-gasified, and used directly in a coastal power plant.

- + **Ammonia:** Natural gas is produced, processed, converted to hydrogen via ATR + CCS, converted to liquid ammonia by Haber-Bosch, transported by pipeline to the BC coast, transported to Asia-Pacific, re-gasified, and used directly in a coastal power plant.

5.3.2 RESULTS – ENERGY DELIVERY EFFICIENCY

Energy consumption and GHG emissions for the well-to-plant case are identical to the well-to-tank case, for all steps except for the final delivery from port facilities in Asia Pacific. The biggest difference is for ammonia, where direct use of ammonia as a fuel for boilers or other high-temperature furnaces would eliminate the need for cracking into hydrogen. The energy delivery efficiency of ammonia is improved the most in the well-to-plant case, to 43%, better than hydrogen, at 38%. LNG efficiency is slightly improved because compression for road transport is not required.

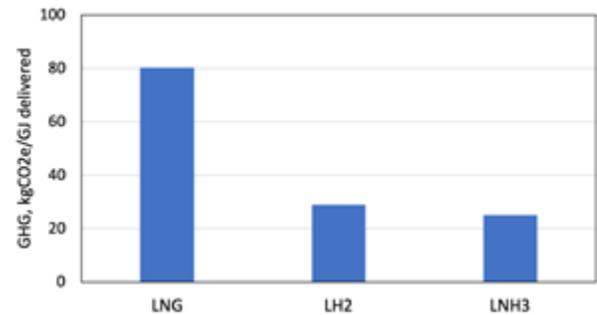
Figure 5. Well to Plant - Energy Delivery Efficiency



5.3.3 LIFECYCLE EMISSIONS INTENSITY

The higher energy efficiency of the supply chains in this case also reduces the GHG footprint of the delivered energy, as indicated in Figure 6. Both the hydrogen and ammonia cases have footprints below 30 kg CO_{2e}/GJ, with potential for further reductions with improved upstream operations for natural gas production in Alberta.

Figure 6. Lifecycle GHG footprint for well to plant case

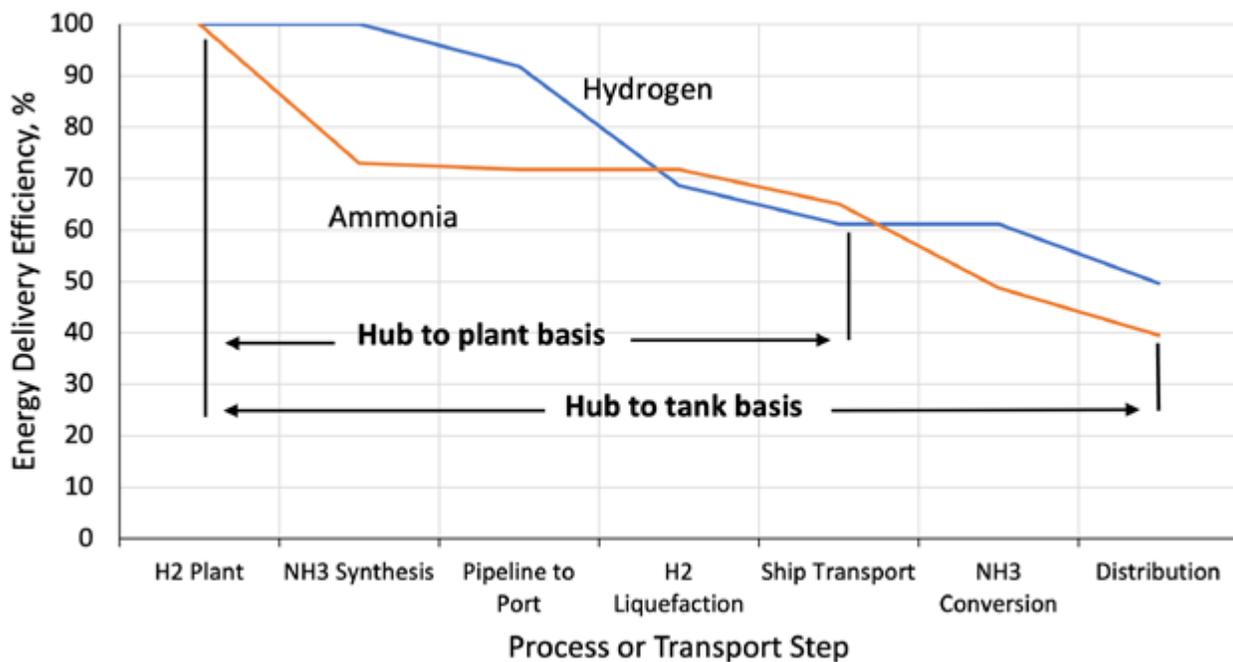


5.4 COMPARISON ON A HYDROGEN BASIS

An alternative comparison between hydrogen and ammonia is to consider the input boundary as hydrogen produced at a hub facility in Alberta, with transport to Asia-Pacific for use in transport or industrial plant facilities. The data of Figure 7 restates the results of sections 5.2 and 5.3 on this basis.

This comparison highlights the energy penalties for each of the two cases; for hydrogen the liquefaction step is very energy intensive, and long-distance transport requires more energy per GJ delivered. The penalties for ammonia are for its initial synthesis, and for conversion to hydrogen in the Hub-to-Tank case. The efficiencies are higher than in Figures 2 and 5 because energy for upstream processing and methane conversion to hydrogen are not included.

Figure 7. Energy delivery efficiency for Alberta hydrogen hub via hydrogen & ammonia



6.0 DISCUSSION

Based on our analysis of the Alberta export opportunity to Asia-Pacific, the strongest case to fuel switch away from LNG is ammonia for power-end uses. The following points summarize the key trade-offs between energy delivery efficiency and lifecycle GHG emissions for each case:

1. Well to plant – ammonia: 50% more input energy is required, and lifecycle emissions are reduced by 70%.
2. Well to plant - hydrogen: 75% more input energy is required, but lifecycle emissions are reduced by 64%.
3. Well to tank - hydrogen: >2x input energy is required, but lifecycle emissions are reduced by 60%.
4. Well to tank – ammonia: Almost 3x as much input energy is required, and lifecycle emissions are reduced by only 54%.

Therefore, based on the outcomes of our analysis for energy penalty and emissions reduction, pure hydrogen is a superior export product compared to ammonia for transportation end-use, and ammonia is a superior export product compared to pure hydrogen for power end use. The case to fuel-switch away from LNG for both hydrogen and ammonia is stronger overall for the well-to-plant than it is for well-to-tank, both in terms of energy losses and emissions reductions.

The data of Table 4 compares the results for energy delivery efficiency, lifecycle GHG emissions, and cost per unit delivery as determined by the Kumar group at University of Alberta, which are most relevant to the well-to-plant case. Although liquid hydrogen shipment is competitive with ammonia in terms of energy delivery efficiency and lifecycle GHG emissions, the well-to-plant cost of delivered energy is 1.7x higher than the ammonia case. This difference is largely driven by the high capital cost of facilities for liquefying, storing, and shipping liquid hydrogen at -252°C , well below LNG conditions.

COMPARISON TO RENEWABLE ELECTRICITY INPUT

Apart from the work of Okunlola et al. (2022) focusing on the cost of ammonia and hydrogen supply to Asia Pacific from Alberta, other recent studies of ammonia as an energy carrier have considered renewable electricity as the input boundary. The largest energy cost for both hydrogen and ammonia is the production of hydrogen, whether from methane or electricity. Production of ammonia requires additional energy for compression of the feed gases and for air separation for the feed nitrogen.

The current best actual performance in Canada for ammonia production by steam-methane reforming is 29.7 GJ/t ammonia (Natural Resources Canada, 2008). The upstream natural gas processing and transport add approximately 3.3 GJ/t (Okunlola et al., 2022), for a total of 33 GJ/t. Using ATR technology to produce hydrogen with minimal GHG emissions, and using hydrogen to provide electric power for the hydrogen and ammonia production would require 39 GJ/t ammonia, giving an energy delivery efficiency of 47% (Figure 2 and 5).

By comparison, using renewable electricity as an input, Giddey et al. (2017) estimated an energy input of 36–42 GJ/t ammonia, while Chatterjee et al. (2021) suggested a range of 33–38 GJ/t ammonia. Based on this comparison, the Canadian operating plant data for production of ammonia using SMR falls in the lower range of these electrified production estimates, while our estimate for production using ATR + CCS to produce “blue hydrogen” for ammonia is at the upper range. In both the work of Giddey et al. and Chatterjee et al., however, the underlying uncertainty in the electrolysis efficiency is significant. Neither study considers the energy efficiency cost or capital cost of using highly variable wind or solar power to feed a production process that requires stable operating conditions to achieve high efficiency. Moreover, electrolysis has not been commercially demonstrated at the scale discussed in our analysis.

TABLE 4: RESULTS COMPARISON: ENERGY DELIVERY EFFICIENCY, LIFECYCLE GHG EMISSIONS, AND COST*

Case	Energy delivery efficiency, GJ delivered/GJ input	Lifecycle GHG Emissions, kg CO ₂ e/GJ delivered	Cost, CAD\$/GJ delivered	Reference for cost data
Liquefied Natural Gas (LNG)	66	89		
Hydrogen (LH ₂ shipment)	31	36		
Ammonia (LNH ₃ shipment)	26	41		
Well-to-Plant Cases (Delivery to plant proximate to port)				
Liquefied Natural Gas (LNG)	70	80	13	Sapkota et al., 2018
Hydrogen (LH ₂ shipment)	38	29	55	Okunlola et al., 2022
Ammonia (LNH ₃ shipment)	43	25	32*	From Okunlola et al., 2022

*from literature

AMMONIA CRACKING

A major uncertainty our estimates for the ammonia well-to-tank case was the cracking step to produce hydrogen near point of end-use, because this technology is also not yet in commercial use at scale. Giddey et al. (2017) proposed a pathway based on a hypothetical palladium membrane reactor followed by purification with an efficiency of 86% (calculated as energy content of hydrogen product divided by the energy content of the ammonia feed). Kim et al. (2022) estimated 94% for efficiency of ammonia cracking to hydrogen, which is inconsistent with all previous analyses. We used the results from Nielsen (2021) who reported 75% efficiency on a pilot-plant operation using conventional catalysts at high temperature, followed by hydrogen purification. Chatterjee et al. (2021) also estimated the efficiency of ammonia cracking and purification of hydrogen at 75%.

OVERALL COMPARISON

Overall, the analysis of Chatterjee et al. (2021) is the most consistent for comparing renewable electricity to our methane-based analysis to produce ammonia or hydrogen for overseas delivery. Chatterjee et al. (2021) estimated energy delivery efficiencies of 30.6 to 39.6% for the sequence renewable electricity to ammonia to compressed purified hydrogen, including provision for ocean transport, compared to our estimate of 26% (Figure 2).

The Chatterjee et al. (2021) analysis of the hydrogen pathway from renewable energy gave an energy delivery efficiency of 41-49% for compressed purified hydrogen, compared to our well-to-tank estimate of 31%. Our well-to-tank case included additional compression and transport to ship hydrogen by pipeline from Alberta to port, whereas the Chatterjee analysis did not, as it assumes the hydrogen is already located at a port. A further source of uncertainty in all the hydrogen cases is the amount of boiloff during shipment that requires re-liquefaction, given the lack of data on such low-temperature cryogenic cargos at scale.

OTHER UNCERTAINTIES

Finally, one of the important assumptions of the results of this study was that the respective energy carriers (LNG, liquid hydrogen, and ammonia) were used to provide power and energy along the supply chain, from the Alberta production hub to the end boundary of either compressed hydrogen for transport or gaseous fuel for plant use. The use of methane for power generation and running turbines and engines is fully established. The technology for hydrogen is developing rapidly, with potential concerns of safety due to wide limits on flammable concentration and nitrous oxide emissions from high-temperature combustion. The technology for use of ammonia as an engine fuel is much less developed, and Chatterjee et al. (2021) listed potential problems in engines with difficult ignition, low flame speed, higher compression, and potential NO_x emissions from combustion of pure ammonia or ammonia-fuel blends. Our analysis did not consider ammonia as a fuel for end use in engines, but it was assumed to supply power for the transport engines, pipeline, and refrigeration compressors, and electric power generation for long distance transport and storage.

7.0 FUTURE WORK

We expect this analysis could lead to multiple avenues of follow on work. Some recommended further analyses are discussed below.

1. IN-DEPTH COMPARISON OF HOW ALBERTA EXPORTS COMPARE TO OTHER JURISDICTIONS AND SUPPLY CHAINS, SUCH AS THOSE THAT PLAN TO USE ELECTROLYSIS FOR HYDROGEN PRODUCTION.

A more in-depth analysis of exporting hydrogen, ammonia or other energy products to other regions should be compared in the context of the supply chains and available energy sources in those regions. For example, the production of hydrogen through electrolysis in sunny regions and ample supplies of fresh water may be competitive compared to Alberta, but transportation and storage will levelize these costs over certain distances and volumes of transport. Where these costs are at equilibrium will dictate the potential market reach for each of these jurisdictions.

2. EXPLORING THE BENEFITS OF EXPORTING LNG PRODUCT TO CONVERT TO CLEAN BURNING FUELS AT POINT OF USE, SUCH AS VIA METHANE PYROLYSIS.

Exporting LNG to convert to hydrogen at end use using pyrolysis-based solutions could be a practical way to avoid the energy penalties associated with hydrogen shipment as a compressed gas or liquid, or as a LOHC. The pyrolysis process would avoid the production of CO₂, thereby avoiding the costs and challenges of capture, compression, and sequestration. This may be a viable option for countries that do not have access to subsurface geology suitable for CO₂ sequestration. However, pyrolysis technologies are early in development and are currently at the scale. In addition, finding economic uses and/or storage for the large volumes of carbon black that will be produced from commercial-scale pyrolysis operations will be challenging.

3. COMPARISON OF ALTERNATIVE UPSTREAM PRODUCTION METHODS FOR HYDROGEN RELEVANT TO ALBERTA, INCLUDING DECARBONIZATION OF NATURAL GAS FEEDSTOCK PRODUCTION.

Based on our analysis, it is clear that from an emissions perspective, first and foremost, upstream processing and transport emissions of feedstock natural gas must be addressed to reduce lifecycle emissions for hydrogen and ammonia export product. Reducing these emissions would greatly improve the case for blue hydrogen and ammonia products to be considered “net zero”.

Switching to alternate methods of hydrogen production, such as electrolysis, would eliminate the upstream emissions from natural gas; but other environmental considerations should not be ignored. For example, electrolysis uses large quantities of fresh water that cannot be recycled in the process. It also has significantly higher energy penalties than ATR + CCS in part due to the water purification step but largely due to the energy required to split water versus the energy required to split methane.

Identifying the most compelling production pathway from an energy delivery efficiency, emissions, and cost perspective is thus a nuanced discussion that varies by regional factors and merits further study.

4. DERIVATION OF COSTS FOR DELIVERY OF LNG VS PURE HYDROGEN VS AMMONIA TO ASIA-PACIFIC AND COMPARING THEM TO THEIR RELATIVE LIFECYCLE EMISSIONS BENEFITS.

Further analysis is required to fully understand the trade-offs between energy delivery efficiency, lifecycle emissions, and cost for different use-cases of LNG, hydrogen, and ammonia. As discussed, Dr. Kumar’s group has completed cost work relevant to the Alberta to Asia-Pacific well-to-plant case. Future work could include validation of these costs and additional work relevant to the well-to-tank case.

5. EXPANSION OF THE ANALYSIS TO INCLUDE ENVIRONMENTAL IMPACTS THAT WERE IGNORED, SUCH AS NO_x EMISSIONS.

NO_x emissions resulting from combustion of both hydrogen and ammonia is an area of emerging work. Current research indicates these emissions are much improved compared to fossil fuel alternatives, such as diesel. In the quest for net zero fuels, it will be important to understand and quantify the relative GHG impacts of NO_x emissions.

OTHER MAJOR RISKS AND GAPS:

- + In-depth assessments of technology readiness of the respective LNG, hydrogen, and ammonia value chains, both within the assumptions considered in this assessment and with consideration given to future technologies, including alternative carriers like methanol and LOHCs.
- + Risks and opportunities for Alberta to get new energy products to tidewater.

8.0

CONCLUSION

Hydrogen and ammonia are both likely to offer lifecycle emissions benefits relative to LNG but these must be weighed against the energy losses that occur. The fewer conversion steps, the fewer energy losses. For some end-uses, such as transportation, LNG remains a more practical and promising approach to reduce GHG emissions in the near term until the energy losses of conversion to hydrogen and ammonia in particular can be addressed. For power end-use applications, the case to fuel switch to hydrogen or ammonia is stronger and this should be the focus major investments targeting exports of these fuels in the next five to ten years. Further analysis is required to fully understand the cost trade-offs with LNG, and between low carbon alternatives, and to fully eliminate emissions across the lifecycle of these fuels. Additionally, gaps beyond the scope of this study must be resolved to ensure hydrogen and ammonia exports at-scale can occur in a safe, efficient, and economic manner with sufficient stakeholder engagement and trust.

9.0 APPENDIX

TABLE A1. ENERGY CONSUMPTION AND GHG EMISSIONS FOR LIQUEFIED NATURAL GAS

Step	Energy consumed	GHG emissions	References
Production, processing, and transport of NG to hub	0.09 GJ/GJ NG	8.9 kg CO _{2e} /GJ natural gas	{ECCC 2022}; {Oni, Anaya et al. 2022}
Pipeline transport 1200 km to port	0.027 GJ/GJ NG	1.5 kg CO _{2e} /GJ NG	{Raj, Suman et al. 2016}
Liquefaction	0.162 GJ/GJ LNG	8.9 kg CO _{2e} /GJ LNG	{Raj, Suman et al. 2016}
Ship transport	0.076 GJ/GJ LNG	4.2 kg CO _{2e} /GJ LNG	{Raj, Suman et al. 2016}
Regasification	0.052 GJ/GJ LNG	2.8 kg CO _{2e} /GJ LNG	{Raj, Suman et al. 2016}
Transport to terminal	0.058 GJ/GJ CNG	3.12 kg CO _{2e} /GJ CNG	Compression to 250 bar

TABLE A2. ENERGY CONSUMPTION AND GHG EMISSIONS FOR HYDROGEN

Step	Energy consumed	GHG emissions	References
Production, processing, and transport of NG to hub	0.09 GJ/GJ NG	8.9 kg CO _{2e} /GJ natural gas	{ECCC 2022}; {Oni, Anaya et al. 2022}
ATR conversion to H₂ with CCS and 12.92 GJ el/t H₂ onsite power from H₂	56.9 GJ/t H ₂	412.5 kg CO _{2e} /t H ₂ (95% capture)	{Oni, Anaya et al. 2022}, adjusted for power generation
Pipeline transport 1200 km to port	10.7 GJ/t H ₂	-	{Okunlola, Giwa et al. 2022}
Liquefaction with onsite power from H₂	40.4 GJ/t H ₂	-	{Okunlola, Giwa et al. 2022}
Ship transport with onboard re-liquefaction of excess boiloff	14.7 GJ/t H ₂	-	{Al-Breiki and Bicer 2021} for boiloff, {Okunlola, Giwa et al. 2022} for liquefaction
Compression and tube truck transport to terminal	27.8 GJ/t H ₂	-	Gardiner, USDOE, 2009

TABLE A3. ENERGY CONSUMPTION AND GHG EMISSIONS FOR AMMONIA

Step	Energy consumed	GHG emissions	References
Production, processing, and transport of NG to hub	0.09 GJ/GJ NG	8.9 kg CO _{2e} /GJ natural gas	(ECCC 2022); (Oni, Anaya et al. 2022)
ATR conversion to H₂ with CCS, Ammonia synthesis and 4.9 GJ el/t NH₃ onsite power from H₂	31.3 GJ/t NH ₃	100 kg CO _{2e} /t NH ₃ (95% capture)	(Grundt and Christiansen 1982); (Oni, Anaya et al. 2022) adjusted for power generation
Pipeline transport 1200 km to port	0.06 GJ/t NH ₃	-	(Okunlola, Giwa et al. 2022)
Storage of LN₂ and ship transport	1.76 GJ/t NH ₃	-	(Kim, Huh et al. 2022)
Ammonia conversion to H₂ at 75% energy efficiency	4.9 GJ/t NH ₃	-	(Nielsen 2021)
H₂ Compression and tube truck transport to terminal	27.8 GJ/t H ₂	-	(Gardiner 2009)

TABLE A4. EFFICIENCIES FOR USE OF HYDROGEN AND AMMONIA AS FUEL

Step	Energy consumed	References
Electric power generation by combined cycle	60%	(Goldmeer 2019)
Large reciprocating engines for compression and power generation	45%	(Haga 2011)
Ship engines for ocean transport	57%	(Okunlola, Giwa et al. 2022)

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