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THE ROLE OF HYDROGEN IN CANADA'S TRANSITION TO NET-ZERO EMISSIONS

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SUMMARY

Electrifying as many end-uses as technically and economically feasible is a key strategy for achieving net-zero greenhouse gas (GHG) emissions. However, "electrifying everything" is not currently a practical or economical option for everything. In many of these hard-to-decarbonize sectors, hydrogen has a role to play.

Hydrogen and hydrogen derivatives can play a key role in certain emission-intensive sectors that are important to Canada's economy, including steel, chemical and clean fuel production, and possibly heavy freight, long distance rail, and other off-grid end-uses that currently depend on diesel motors. In a companion piece, we discuss the role for hydrogen in electricity systems.

Unlike oil and gas, whose resources are isolated to only some parts of the country, hydrogen has the potential for broad participation across Canada due to the ability to produce it from hydrocarbons and clean electricity. The former is likely to dominate in the near term, whereas declining costs for hydrogen from electricity should tilt the economics in that direction in the longer run. In all cases, however, regulators and policy makers should be focused on life-cycle emissions from the production process rather than arbitrary colour classification schemes.

Canada's natural advantages in producing clean hydrogen also puts it in a position to capitalize on new export opportunities from hydrogen-derived products. It already has one of the cleanest steel-production facilities in the world in Québec, a technology that can be adapted to operate on 100%

hydrogen. Opportunities exist for Canada to become a green iron or steel exporter, from Québec or even possibly Alberta with its unused iron ore deposits and abundance of hydrogen potential.

For hydrogen to reach its potential, there are some key areas where government policy and support will be needed. From helping to establish clean hydrogen industrial clusters, where firms share production and storage infrastructure, to ensuring hydrogen refueling networks for transport are established with sufficient breadth needed for heavy freight transport, government has a role to play in setting up the landscape for innovators to thrive.

Ultimately, hydrogen will not solve every decarbonization challenge Canada faces, but it will have a critical role to play as a complement to a variety of strategies aimed at reaching net-zero emissions. Hydrogen has had many “hype cycles” before, and while it is no panacea for decarbonization, it is now genuinely poised to help Canada achieve its net-zero goals.

1. INTRODUCTION

The universe's smallest element has been making big news of late, and for good reason. The use of hydrogen stands to be a key strategy to decarbonize our energy systems and economy in the push to get to net-zero carbon dioxide emissions and eventually net-zero for all greenhouse-gas (GHG) emissions.

This School of Public Policy Research Paper is intended to provide policy-makers, industry participants, and the interested public an overview of:

1. **supply** options for hydrogen across Canada; and
2. end-use opportunities for hydrogen **demand**.

Hydrogen presents a significant opportunity for Canada, given our abundance of low-cost electricity and natural gas, the key precursors for making low-GHG hydrogen. Estimates of Canada's export potential as a low-cost producer are upwards of $100 billion per year (Layzell et al. 2020). The recently announced federal climate policy, with a carbon price reaching $170-per-tonne carbon dioxide by 2030, will also provide further incentive to produce and use low-GHG hydrogen (Government of Canada (GOC), 2020a). While hydrogen remains a small part of the broader economy today, Canada has already laid some of the foundation for a more prominent future role for hydrogen with the recently released Federal Hydrogen Strategy for Canada (Government of Canada (GOC), 2020c).

Unlike oil and gas, where regional endowments vary considerably, hydrogen has potential for broad participation across the country. This stems from the various ways in which hydrogen can be produced. Today, hydrogen is predominantly made by reforming a fossil fuel, usually methane in North America but often coal in Asia, to separate its elemental hydrogen from the carbon, which is currently released to the atmosphere as carbon dioxide. If this carbon dioxide were immediately returned to the ground (i.e., "carbon capture and storage," aka CCS), for which there is ample appropriate geology under most of Alberta and Saskatchewan, as well as in northeast B.C. (i.e., the Western Canadian Sedimentary Basin), these regions could produce large quantities of low-GHG hydrogen.

Hydrogen can also be made by splitting water into its constituent elemental parts, hydrogen and oxygen, either thermally or with electricity using electrolysis. This method has strong potential in provinces with abundant hydroelectric, wind or solar resources in the case of electrolysis (B.C., Québec, Manitoba, Newfoundland and Labrador for hydroelectricity; wind power in the Atlantic provinces). In Ontario's case, there exists the potential to do it thermally, using the heat from nuclear power.

On the demand side, the excitement around hydrogen stems from its ability to decarbonize sectors that are deemed otherwise difficult to decarbonize. While clean electrification is a core net-zero strategy, in some sectors this simply is not feasible nor desirable. Instead, hydrogen can be used in sectors where electrification may be either too costly or practically too challenging, such as fertilizer production, iron and steel, aviation and shipping, long-haul road and rail heavy freight, or where clean hydrogen can be used as a building block for net-zero emissions chemicals and fuels.

Hydrogen can also help with decarbonization efforts in electricity systems, a topic we go into further detail in a separate School of Public Policy Research Paper (Neff et al. 2021). The pathway for clean hydrogen is likely to begin in markets where it has the highest value (i.e., where decarbonization alternatives are costly) and in areas of least resistance, such as where existing energy supplies, infrastructure and end-uses can be most easily repurposed for hydrogen use.

In this report, while we acknowledge (and use) the naming convention based on colours that has developed to describe different hydrogen production methods, we discourage its blanket use in assessing the relative merits of different processes. Instead, we encourage more detailed and continuous metrics of lifecycle costs and emissions profiles.

Ultimately, we recognize the potential for hydrogen in many end-use sectors of Canada's economy, especially in sectors with limited alternatives to electrify. Hydrogen will not be a panacea for decarbonization, but it stands to be a useful tool in our path to net-zero, given Canada's resource endowments and potential end-uses.

2. HYDROGEN SUPPLY

A convention has formed to categorize hydrogen based on how it is produced, using a nomenclature of colours: black and grey hydrogen from coal and fossil methane, blue from fossil fuels with carbon capture and storage, and green where the hydrogen is made from water using electrolysis and low-carbon electricity.

Regarding this colour-based naming convention, we acknowledge its usefulness as a pervasive and simple way of distinguishing between production processes. Case in point, we use the convention in this paper. However, we have concerns over its use as a way to assess the merits of different ways in which hydrogen can be produced. The discrete categories do not sufficiently distinguish differences within the production processes.

First, while colour categories are often used to compare environmental attributes across production processes, the reality is far more nuanced than that. ***Blue hydrogen*** can come in many forms, with very different emission intensities. Similarly, ***green hydrogen*** emission intensities are a function of the carbon intensity of the generation sources supplying the electricity.

Second, the use of these discrete labels can create blanket stances contrary to the ultimate goal: low-cost and low-emission sources of hydrogen. For example, in Germany's national plan, ***green hydrogen*** is restricted to production powered solely by variable renewable energy, such as wind and solar, yet excludes other forms of zero-emission power, such as large hydroelectric and nuclear. If the goal is lowering carbon emissions, carbon intensity should be the metric upon which production processes are judged. Policy-makers should avoid the use of rigid, discrete, and often arbitrary classifications.

Box 1. The "colours" of hydrogen

Black or grey hydrogen is how most hydrogen is produced today. Fossil fuels, mainly methane (for "grey hydrogen"), but sometimes coal (for "black hydrogen") where methane is expensive (e.g., in Asia), are mined for their hydrogen using a paired set of steam-methane-reforming and water-gas-shift reactions (SMR-WGS). While dominant today, this is not viewed as the method of the future, as it emits significant quantities of CO_2.

Blue hydrogen is similarly derived from fossil fuels, but with **carbon capture and sequestration** applied for the waste CO_2 that emerges from the steam-reforming and water-gas-shift reactions. The SMR-WGS reaction can be designed in different ways, delivering more or less concentrated CO_2. Sequestration of highly concentrated CO_2 is an already commercialized oil and gas technology, based on mandatory acid-gas reinjection and enhanced oil-recovery techniques. The whole process requires heat, however, and the source for this, usually natural gas, must also have its waste products sequestered. Post-combustion CO_2 sequestration is at a much lower state of development, making 90%+ capture of all process and heat emissions difficult with some SMR designs. Another closely related fossil-fuel-based hydrogen production technology, **autothermal reforming (ATR)**, while slightly less efficient, allows for the necessary heat to be generated in the main reaction, with concentrated CO_2 produced, allowing for cheaper sequestration, and has already been commercialized. ATR is likely to be the production mode of choice for purpose-built blue hydrogen production.

Green hydrogen uses low-carbon electricity to split water (H_2O) into its constituent parts — hydrogen and oxygen — through the process of electrolysis. The oxygen also has value as a salable commodity for many different industrial uses. This includes possible oxycombustion with fossil fuels, which produces a highly sequesterable concentrated waste stream of CO_2 because no nitrogen is present.

Accordingly, we propose hydrogen processes be measured based on their full lifecycle emissions. This allows for more clarity between different types of ***blue hydrogen*** methods, the inclusion of some methods that do not currently fit within the taxonomy of current colour schemes, and an impartial view towards emissions from different electricity sources. The analysis should also include upstream emissions, to acknowledge emissions prior to the hydrogen production process, such as well-venting, flaring, pipeline leakages, formation-gas CO_2-venting, and producer self-consumption during natural gas production and transmission, to encourage a cleaner upstream sector. Fugitive emissions are already officially approximately eight per cent of Canadian energy-system GHG emissions , and recent studies provide evidence that these emissions may be 50-100% more than the currently officially reported level (Chan et al. 2020; MacKay et al. 2021; Tyner and Johnson 2021).

In the sections that follow, we discuss these various processes in more detail, as well as storage and transportation issues that need to be addressed to supply hydrogen.

2.1 HYDROGEN FROM FOSSIL FUELS WITH CARBON CAPTURE AND SEQUESTRATION

Hydrogen gas can be produced from practically any fossil fuel. There are several methods to extract the hydrogen from hydrocarbons such as methane and coal. Most involve some version of a process to reform the starting fuel into carbon monoxide and hydrogen gas, where the carbon monoxide is further reacted into carbon dioxide by a water-gas-shift reaction, releasing yet more hydrogen (International Energy Agency (IEA), 2019b). Such processes are the dominant method of hydrogen production today, accounting for the vast majority of current hydrogen production worldwide. Some use heat sources outside the reaction process (newer steam-methane-reforming units, aka SMR) and produce a mix of post-combustion CO_2 diluted in atmospheric nitrogen and concentrated-process CO_2, and some generate the necessary heat within (older SMR and autothermal reforming, aka ATR), generating only concentrated CO_2. In the context of making blue hydrogen, processes that produce concentrated CO_2, such as ATR, while slightly less efficient, can take advantage of already-commercialized CCS technology, derived from acid-gas injection in the oil and gas sector, to achieve high (90–95-percent) levels of capture relatively cheaply ($20–40 per tonne sequestered) (Leeson et al. 2017). A "greenfield" or purpose-built blue hydrogen production system would most likely go straight to ATR, instead of the currently more common SMR, as is being done in the northern U.K. for the H21 building heating project (www.h21.green).

There are other innovative hydrogen extraction methods that are starting to gain traction that offer potential cost reductions to the above methods while attempting to take carbon dioxide out of the equation. One commonly explored method is pyrolysis, where a hydrocarbon, usually methane, is separated into hydrogen gas and solid carbon in the absence of oxygen using heat, often using a catalyst to improve efficiency. Another newer method involves in-situ hydrogen extraction.[1] In this process, hydrogen is directly produced from exhausted oil and gas wells via direct injection of oxygen. The oxygen reacts with well hydrocarbons, producing heat, with the lightest products (including hydrogen) rising to the top of the well, where they can be selectively extracted using a proprietary method.

2.2 HYDROGEN THROUGH ELECTROLYSIS

Producing hydrogen through electrolysis using an electrolyzer has become the gold standard for advocates against climate change, partly because of the ease of monitoring emissions intensity. Electrolysis relies on water as the hydrogen input and utilizes an electric current to split it into hydrogen and oxygen gas. The addition of waste heat from other processes can reduce the need for electricity as well; almost purely thermochemical splitting can be done at 500°C to 2,000°C, depending on the process (for instance, using nuclear heat). This has been done commercially in the past at large nuclear plants; it is also a potentially dangerous reaction in water-cooled plants that must be controlled and monitored carefully, and was part of the reason for the damage done by the Chernobyl meltdown.

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1 Disclosure: Shaffer is an investor in Proton Technologies Inc.

The GHG intensity of purely electrolytic hydrogen production depends on how the electricity is produced. To maximize emissions reduction, the electricity should come from a non-emitting source, such as hydropower, nuclear, wind, solar, geothermal or even fossil fuels with over 90 per cent carbon capture and storage rates. As mentioned previously, in some classification schemes, only hydrogen produced from renewable sources is designated “green.” A focus on lifecycle-embodied emissions schemes, rather than arbitrary classifications, can improve policy efficiency by ensuring emissions reductions are treated equally.

Box 2. Electrolysis

Electrolysis can further be split into several different technologies that achieve the same goal but approach it with different methods and materials. The dominant technologies are, in their respective orders of maturity, alkaline, polymer-electrolyte membrane (PEM), and solid-oxide-electrolyzer fuel cells (SOEC), and each of them have qualities that will make them more appealing for particular applications. For example, SOECs require operating temperatures of 600°C to over 1,000°C, and so could benefit from a common heat source such as a waste-heat recovery system or from even being tied to an industrial process (IEA 2019b, 44). SOECS are also, in theory, fully reversible. On the other hand, PEM electrolyzers require much lower temperatures at around 60 to 80°C, and therefore could be used for smaller-scale production in urban or rural areas. The efficiency of these electrolysis methods is improving and efficiencies are targeted to reach up to 90 per cent in the long term, up from the 56-to-81 per cent that is currently observed (IEA 2019b, 44).

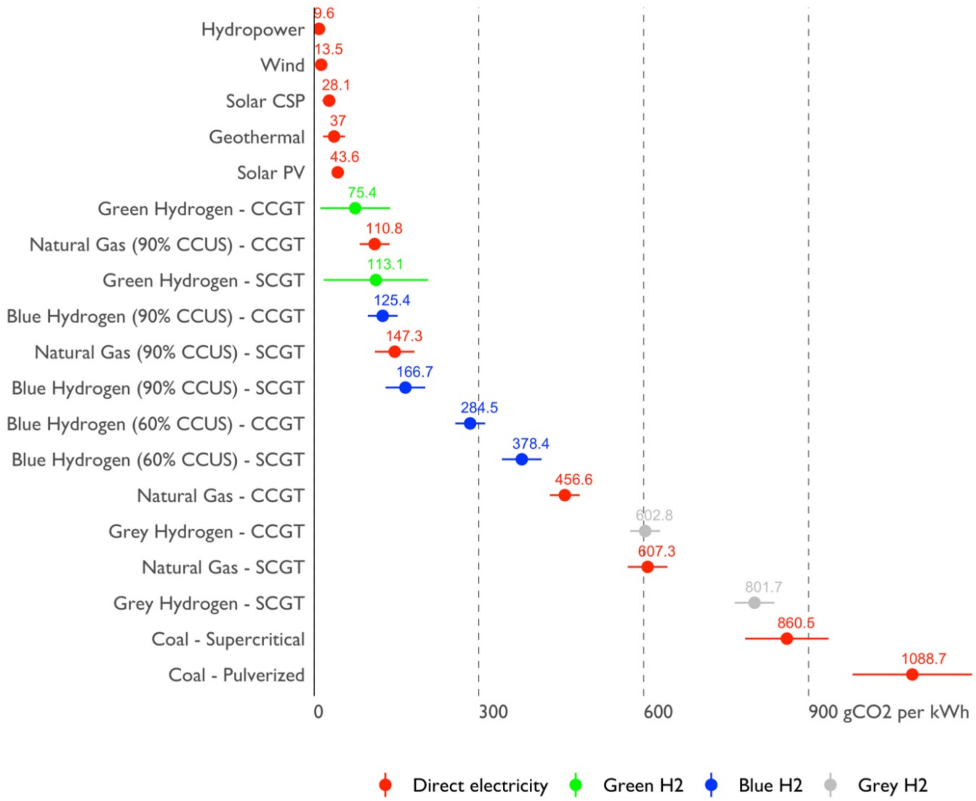
The comparative downside to electrolysis is the upfront capital costs and the current costs of low-GHG electricity. While falling rapidly with economies of scale, today alkaline electrolyzers cost roughly between US$500 and US$1,400 per kilowatt, and PEMs cost roughly between US$1,400 and US$2,300 per kilowatt (IEA 2019b). Even with low-cost, low-GHG electricity, electrolyzer costs would need to fall to roughly $500 per kilowatt or less to be competitive with fossil-fuel reformers with CCS. Recent announcements in Europe, China, India and elsewhere for projects coming online between 2022 and 2030 will add large, but as yet unknown, economies of production scale and innovation.

Finally, the residual oxygen from electrolysis also has a value in the chemical industry and for other purposes, e.g. oxycombustion electricity plants producing a concentrated flow of CO_2 for CCS, such as the Netpower Allam cycle supercritical CO_2 technology.

2.3 LIFECYCLE EMISSIONS OF HYDROGEN PRODUCTION

In Figure 1, we estimate the lifecycle carbon emissions per fuel source, based on the ultimate production of electricity for end-use purposes. The figure highlights three broad tranches of emissions profiles.

Figure 1. Lifecycle carbon emissions per fuel source (gCO_2/kWh)



Notes: Solar CSP refers to concentrated solar power; solar PV refers to solar photovoltaic; SCGT refers to a simple-cycle gas turbine; CCGT refers to a combined-cycle gas turbine; CCUS refers to carbon capture, utilization and storage. Data sources: (Environment and Climate Change Canada (ECCC), 2017; Ewing, 2020; Open Energy Information, 2020)

In the lowest tranche, the emissions profile of renewable electricity (hydropower, wind, solar photovoltaics, concentrated solar power, and geothermal) all have, predictably, negligible CO_2 emissions. Green hydrogen used in a simple-cycle gas turbine (SCGT), combined-cycle gas turbine (CCGT), or fuel cell (FC) has similar intensities to renewables generating electricity directly. The hydrogen systems, however, can also provide firm capacity that can complement the variability in direct wind and solar generation.

The second tranche of emissions intensities involve the use of either blue hydrogen using sequestration of the process $CO_{2,}$ or natural gas run through a combined-cycle gas turbine or simple-cycle gas turbine with post-combustion sequestration. Each method of hydrogen production from hydrocarbons emits significant amounts of CO_2 as a chemical and energy by-product, and so carbon capture is an important element in reducing overall emissions. Emissions intensities from these processes range from roughly 100 to 250 grams of CO_2 per kilowatt-hour.

Of note, the ultimate emission intensity of using natural gas with post-combustion sequestration at the power plant can be slightly better than first reforming natural gas to blue hydrogen. This is because energy losses in converting fossil fuels to hydrogen can result in substantially higher emissions than just using the fossil fuels as is. Depending on the efficiency of the conversion setup, losses can be significant (23- to 28-per-cent losses on a usable unit energy basis). However, installing a CCS unit on each and every existing and new combustion turbine is more expensive than a centralized carbon-capture facility that can benefit from economies of scale. In addition, any hydrogen produced could be distributed for other uses that are too small or where it is not cost-effective enough to install a CCS unit while still benefiting from lower carbon emissions. In essence, CCS can be applied at the hydrogen production site, and then used as a distribution hub to feed other hydrogen systems. Furthermore, concentrated CO_2 produced from an SMR reformer unit, or especially from an ATR reformer where heat production is internal, is easier and cheaper to dispose of than post-combustion flue gas from a natural gas turbine, diluted in nitrogen and contaminated with trace air pollutants.

The third tranche involves unsequestered natural gas (and coal) power generation, as well as the use of grey hydrogen, which actually results in a higher emission intensity than just using the fossil fuel directly, due to the energy-conversion losses in the grey hydrogen process. Of note, 60-per-cent sequestered blue hydrogen run through a combustion turbine to produce power delivers only half the benefit as going to 90-per-cent sequestration. For this reason, we argue that minimum acceptable levels of sequestration should target 90 per cent.

Lastly, when comparing the lifecycle emissions in Figure 1, it is easy to assume that CCGTs should be used instead of SCGTs, because they are more efficient. However, SCGTs are much more agile, both in ramp rate and startup time, providing fast response to demand changes, supply inconsistencies and grid disturbances. Having a highly flexible and agile system over several time scales (i.e., milliseconds, seconds, minutes, hours, days, and seasons) is needed to complement and backstop renewable variability on the system. While batteries will likely dominate on the seconds-to-hours timescale in the future, other grid-flexibility mechanisms will be needed for longer-duration supply and demand matching.

A key takeaway is that there is no point to using hydrogen where the production CO_2 isn't sequestered. Whereas the production of electricity from unsequestered (i.e., black or grey) hydrogen through an efficient combined-cycle unit does emit less CO_2 directly than coal power, it still emits more than using natural gas directly for power generation. Indeed, to substantially reduce emissions in the electricity sector, blue hydrogen must at a minimum come with a high percentage of carbon capture and sequestration (e.g., 90 per cent or more). If grey unsequestered hydrogen is to be used at all, it should only be a transitory mechanism to ensure that technologies are able to adapt from natural gas to hydrogen while CCS is installed on the hydrogen production equipment.

One of the fundamental long-term limitations to using methane to make blue hydrogen, from a climate point of view, will not be the cost of over-90-per-cent CCS if ATR is used, but the upstream fugitives associated with the extraction, processing and transportation of the methane to the hydrogen production site. Recent studies have shown the magnitude of upstream methane emissions may be 50 to 100% more than national inventory estimates (Chan et al., 2020; MacKay et al., 2021; Tyner & Johnson, 2021). At minimum, well-head venting and line fugitives must be minimized (reducing well-head venting involves flaring or piping into the gas network), and CCS will be required for the raw formation-gas CO_2, as has been done by Equinor at the Sleipner gas platform since 1996. All these elements will add to methane-supply costs in a lower-carbon economy, and not just for making hydrogen.

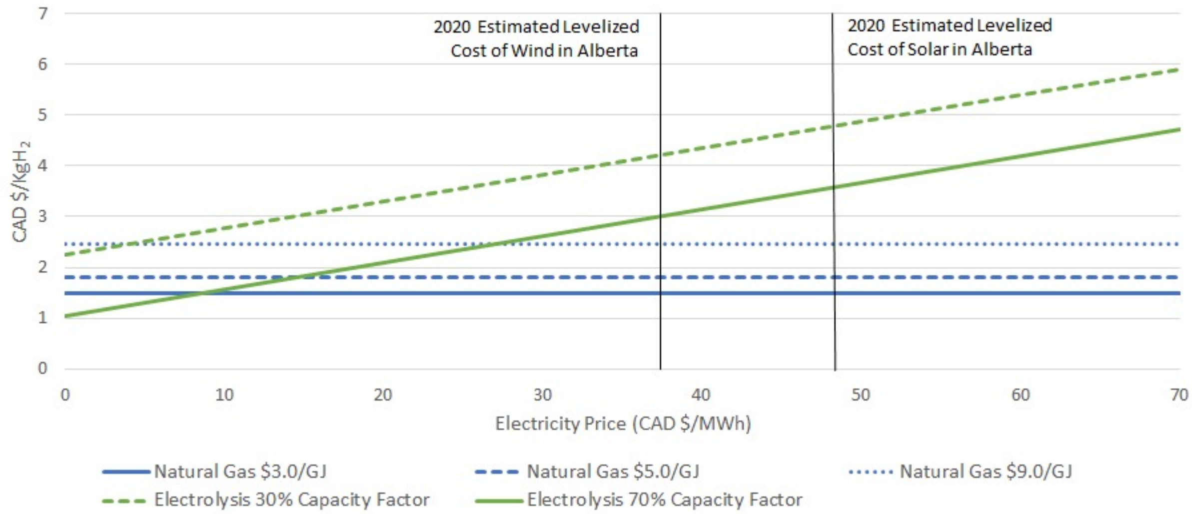
2.4 THE RELATIVE ECONOMICS OF HYDROGEN PRODUCTION PROCESSES

The relative economics of producing hydrogen through electrolysis versus producing it from methane with CCS depend on many factors, including the capital cost and capacity factor of the electrolyzers (the latter a measure of how much the electrolyzer gets used), the relative price of electricity compared to that of natural gas, and the cost and availability of carbon capture and sequestration.

At current electrolyzer capital costs and a 70-per-cent capacity factor of their use, Figure 2 shows that electrolysis requires electricity costs under $10 per megawatt-hour to compete with current SMR hydrogen production using natural gas. Such low prices are seldom realized in electricity markets, perhaps only captured where the electricity would otherwise be spilled due to variable renewable-energy management or electricity-grid constraints.

However, if the economics are based around using extremely cheap electricity when excess renewables would be otherwise spilled, it is unlikely the electrolyzer would achieve a 70-per-cent capacity factor of usage. At lower capacity factors, the electricity price needs to be even cheaper. The break-even value for a 30-per-cent capacity factor to choose green over blue hydrogen is essentially free electricity to compete with $7 per gigajoule natural gas. At a 70-per-cent capacity factor and $5 gas, green hydrogen competes with electricity prices under $15 per megawatt-hour. At $3 gas, the break-even electricity price is less than $9. Similar findings are repeated in the IEA's 2019 Future of Hydrogen report.

Figure 2. Relative production costs of blue hydrogen with 90-per-cent carbon capture, utilization and storage versus green hydrogen with a $1170 per kW capital expenditure and a $50 carbon price



Data sources: (International Energy Agency (IEA), 2019b; National Renewable Energy Laboratory, 2018).

The last component of comparing the incentives between methane reforming and electrolysis is the carbon capture rate. At a high 90-per-cent capture rate, raising the carbon price from $50 to $170 per tonne CO_2-equivelant will increase costs by approximately $0.11 per kilogram of hydrogen. For a moderate 60-per-cent capture rate, the carbon price will raise costs by approximately $0.44 per kilogram of hydrogen.

Given the current relative production costs, these findings indicate the following key elements:

1. At current electrolyzer costs, if CCS is available and natural gas costs less than $12 per gigajoule, methane reforming will be the cheaper alternative. CCS is widely available in Western Canada but not in Eastern Canada, with the notable exception of the Utica basin, or if the CO_2 were shipped over the border into Pennsylvania or Ohio for storage in depleted oil and gas wells.
2. Fundamentally, for electrolyzers to be successful, the process requires cheap low-GHG input electricity. Areas of abundant solar and wind energy and land or water to place generation units will be best positioned for this opportunity.
3. Relying on extremely low-cost or essentially free electricity, based on periods of otherwise curtailed renewables, will result in low-capacity factors for the electrolyzers, impairing their economics.

This combination of key elements effectively means that, for the foreseeable future, inexpensive blue hydrogen (i.e., $1.50 per kilogram) is likely to dominate in Western Canada where carbon capture and sequestration is available, while the cost of hydrogen production in Eastern Canada, where natural gas prices are higher and CCS geology is scarce, will be set by the cost of clean electricity, for example $2 to $5 per kilogram depending on prevailing power costs and electrolyzer capital costs. **In the longer run, however, declining electrolyzer costs coupled with continued declines in renewables costs are likely to tilt the economics towards green hydrogen**.

2.5 HYDROGEN STORAGE AND TRANSPORTATION

The last stage to deal with in the production process is getting it to market. Once produced, hydrogen faces challenges — some unique, some shared by other energy carriers — in storage and transportation.

Hydrogen is not as easy to store as natural gas, which is held easily in steel pressure vessels. And, as a smaller molecule, hydrogen leaks more easily. There are two main methods of hydrogen storage: in geological cavities (e.g., salt caverns or depleted oil & gas reservoirs) or specially lined pressure vessels, for example with acrylonitrile butadiene styrene (ABS) plastic. Most current industrial hydrogen, which is made and used on a daily basis, is stored in either above- or below-ground pressure vessels. Lifecycle costs are in the range of $0.15 to $0.25 per kilogram for high-usage (daily fill and empty) pressure vessels, including compression (Mallapragada et al. 2020), with near-zero life-cycle carbon emissions. Here, we assess the levelized cost of continuous hydrogen supply (95% availability. For larger amounts, or over longer periods of time, hydrogen (and natural gas) storage requires salt caverns or other suitable geological storage. The technology to do this is well-understood and will benefit from economies of scale. Capital costs to prepare a cavern are estimated to range from $3 to $33 per kilogram, but the operating costs are less than one per cent of this, with functionally unrestricted volume.

There is much debate about the capacity to transport hydrogen using natural gas pipelines, which could also serve as temporary storage. There are several significant issues of concern. The first is that, at a given pressure, a unit of hydrogen has roughly one-third the energy of a unit of natural gas - to maintain the energy delivery rate, the flow rate would have to be tripled. It is for this reason — and not corrosion, as is commonly discussed — that only up to 20-per-cent replacement in a standard gas line is usually considered. Anything greater than 20 per cent would cause difficulties at the point of delivery. Dedicated hydrogen pipelines operate at higher pressures to compensate.

The second issue is that hydrogen is highly reactive, making it corrosive to many potential storage and transport materials, for example, it eats away at the carbon in most grades of steel. Plastic liners or coatings are one way to address this problem. The U.K. had been using coal-derived "town gas" in iron pipe from the 1800s; when replacing them in the 1970s and 1980s, the retail gas pipes were replaced with plastic, partly for cost reasons, but also partly anticipating a potential switch to hydrogen. A dedicated hydrogen grid would likely be fully plastic at the retail end, with plastic-lined steel or some other material for bulk, high-volume transmission.

Because a broad, dedicated hydrogen grid does not yet exist (there are hydrogen pipelines for chemical industry purposes), nor is one likely to be built quickly (barring developments, such as easy-to-lay mixed plastic and carbon-fibre pipelines, which would still require rights of way), early uses of hydrogen will likely be co-located with their supply and storage in "hydrogen-use hubs," aka industrial clusters.[2] For blue hydrogen, this will mean confinement to areas with CCS geology.

There is also considerable debate about how hydrogen might be shipped overseas. Gaseous hydrogen would require huge tanks, so it is likely that it would be at least cooled and compressed as liquid hydrogen, much like liquid natural gas (LNG) is. However, as compared to LNG, which is liquified at –160°C, hydrogen requires temperatures below –250°C (not far from absolute zero) to become a liquid. Low-GHG liquid hydrogen, while likely to have high chemical feedstock value, will have a low relative value in terms of energy compared to LNG, unless carbon prices are very high globally. To be economical to move on an energy basis, it is likely to be transformed to ammonia (NH_3), which is valuable unto itself and for which safety and handling protocols are well-known. Other alternatives include net-zero methane (CH_4) or methanol (CH_3OH), where the carbon source would gradually evolve closer to net-zero through time, being sourced first from CCS and biomass, and eventually directly from the air (Bataille et al. 2018).

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2 See Layzell et al. (2020) report: "Building a Transition Pathway to a Vibrant Hydrogen Economy in the Alberta Industrial Heartland."

Lastly, hydrogen burns relatively rapidly, invisibly and potentially explosively, causing handling challenges. Good venting and design to allow for the dispersal of the energy from any explosions would be required (meaning no people, critical infrastructure or mechanicals would be positioned above hydrogen storage). Almost all energy carriers, however, have handling challenges to some degree. For example, mercaptan is added to natural gas so people can smell leaks, and ammonia (NH_3), which is poisonous, is regularly produced, stored and transported within a careful, globally used regulatory regime.

3. END-USE DEMAND OPPORTUNITIES FOR HYDROGEN

The process for making hydrogen from fossil fuels and electricity has been well-known since the early 1800s. Hydrogen was a large component of "town gas" made from coal from the mid-1800s through the early 20th century in some places, which was what gave the Hollywood "Gaslight" era its name. The first fuel cell that utilized hydrogen to make electric power was invented in 1838, and NASA has regularly used them for generating power in spacecraft since the 1960s, due to their high energy storage-to-weight characteristics. Hydrogen has also been a key feedstock in the chemical industry for over a hundred years; arguably, more than half the people alive today owe their lives to nitrogen fertilizers made from fossil-fuel-derived hydrogen (it is made into ammonia, then urea). The end-use gasoline and diesel potential of crude oil is also normally boosted by adding hydrogen in refineries, where most hydrogen is used today; it is also used to remove sulfur in refined fuels. In fact, one of the first applications of blue hydrogen in the world was at the Quest upgrader near Edmonton. Hydrogen is a well-known element, with its combustion and chemical-reactivity potential very well-understood.

Beyond hydrogen's standard uses in refining and chemicals production, it has already gone through several climate-related "hype cycles," when it seemed that fuel-cell-driven cars and other vehicles seemed imminent (Melton, Axsen, and Sperling 2016). Absent sufficiently stringent policies, these hype cycles ended, leaving lingering suspicion. What is different now?

The Paris Agreement, and its requirement of global net-zero CO_2 emissions by 2070 to limit warming to 2°C, and by 2050 to limit it to 1.5°C, followed by significant levels of net-negative emissions, has fundamentally changed the level of climate policy ambition for several sectors that were otherwise previously given a light touch. Steel, cement, chemicals, and other heavy industry used to fall under the –50- to –80-per-cent targets discussed previously, allowing them to focus solely on energy-efficiency improvements, with some minor electrification, bioenergy and CCS in the longer run (Bataille, Nilsson, & Jotzo, 2021). Because of the long life of facilities in these sectors, usually 25 or more years, the new net-zero targets forced a discussion about transformative change in these sectors for all new stock and retrofits starting in the 2030s onward (Bataille et al. 2018). Along with a revisiting of demand-side material efficiency and circularity measures (International Energy Agency (IEA), this brought several existing but obscure potential technologies to the fore, based on direct electrification, alternative heat sources, various methods of CCS, and hydrogen. Many industries depend on coal or fossil methane for high process heat and reactivity with oxygen (e.g., the removal of oxygen from iron ore to leave pure iron for smelting), and hydrogen does both.

While hydrogen can do many things, its highest value will be found in areas where it is really the only option for decarbonization. Those exist primarily in heavy industry. We outline several such applications below.

3.1 STEEL-MAKING

One of the key applications for hydrogen will be in the upfront "reduction" process, where oxygen is removed from iron ore (e.g., Fe_3O_4 & Fe_2O_3) so the iron can be melted and mixed ("smelted") with other elements to make steel. Most new, as opposed to recycled, steel is reduced using coking coal in blast furnaces, and is then smelted in basic oxygen furnaces, with coal providing the heat. An already existing commercial alternative is MIDREX Technologies Inc.'s direct-reduced iron technology, where prepared iron ore pellets are subjected to a hydrogen and carbon-monoxide synthetic gas typically made from methane, then melted and smelted in an electric arc furnace (the normal technology for recycling iron products). A MIDREX-like plant is already operating at Contrecoeur, Que., and because the electric arc furnace runs on Québec's hydroelectricity, it is one of the cleanest steel plants in the world, at 0.7 tonnes CO_2 emitted per tonne of steel (Bataille and Stiebert 2018), compared to approximately 2.2 tonnes for a modern blast/basic-oxygen furnace plant, and 1.83 tonnes for all steel production globally (World Steel Association 2020). A variant of MIDREX, using a syngas of hydrogen gas and carbon monoxide with carbon capture and use/storage is already operating at Al Reyadh in Abu Dhabi, with the CO_2 injected underground for enhanced oil recovery. A green hydrogen variant, which will be the first practical near-zero emissions steel mill, is being piloted in Lulea, Sweden, with commercial operation planned for 2026.[3] Hydrogen can also be used to partially retrofit existing steel blast furnaces. ThyssenKrupp AG is experimenting with ways to co-fire blast furnaces with up to 40-per-cent hydrogen as an energy source and reductant, but coke will continue to be needed to hold up the physical stack of iron ore as it is reduced.

If the social value-added of low-emission steel (i.e., the reduced GHGs and local air and water pollutant reductions) can be recognized — that is, if a premium price can be captured for it — Canada, and especially Québec with its cheap hydro and iron ore, has a pole position for making premium clean iron and steel for a global low-carbon economy. In addition to Canadian and U.S. steel needs, green iron could become an export opportunity for regions with electric arc furnaces but without relatively cheap iron ore and the means to make hydrogen for reduction (Bataille et al. 2021; Trollip et al. 2021).

3.2 AMMONIA FOR FERTILIZER AND CHEMICALS IN GENERAL

Lower- and zero-GHG hydrogen could also allow the chemicals industry to dramatically reduce its GHG footprint, given its need for 400–1,000°C heat and hydrogen as a physical feedstock. The key first applications will likely be replacing black and grey hydrogen production for refining to meet low-carbon fuel-standard

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3 See Hybrit Development: https://www.hybritdevelopment.se/en/.

requirements and for chemical feedstocks for making ammonia, urea fertilizer, methanol and other chemicals.

The Canadian chemicals industry could benefit from transitioning from mainly natural gas as a feedstock to clean hydrogen and lower-net-emissions sources of carbon (which provides most organic chemicals with their structure), such as waste CO_2, gasified biomass, or potentially capturing carbon directly from the air. These emissions reductions are not sufficiently quantifiable at this time, and Canada's chemical companies, which use methane, ethane and natural gas liquids for chemical production directly, instead of crude oil and coal, are already some of the world's cleanest producers.

3.3 CEMENT

Cement and concrete production has also been mentioned as a target market for hydrogen. Most emissions in this sector (approximately 60 per cent), however, are process emissions from when CO_2 is liberated from limestone to make calcium oxide, or "quicklime," the key ingredient for making clinker. Clinker is used in various concentrations with other cementitious materials to make Portland cement, the "glue" in concrete that holds the sand, gravel and stones together. Hydrogen could be partly used for heat for the calcination reaction (850°C), or the clinker cooking (1,450°C), but its "over-reactive" flammability means it would likely need to be mixed with other fuels to provide precise process temperature control. Hydrogen will not likely be the primary means of reducing cement-production emissions (Bataille 2019; Habert et al. 2020).

3.4 LONG-HAUL TRANSPORT

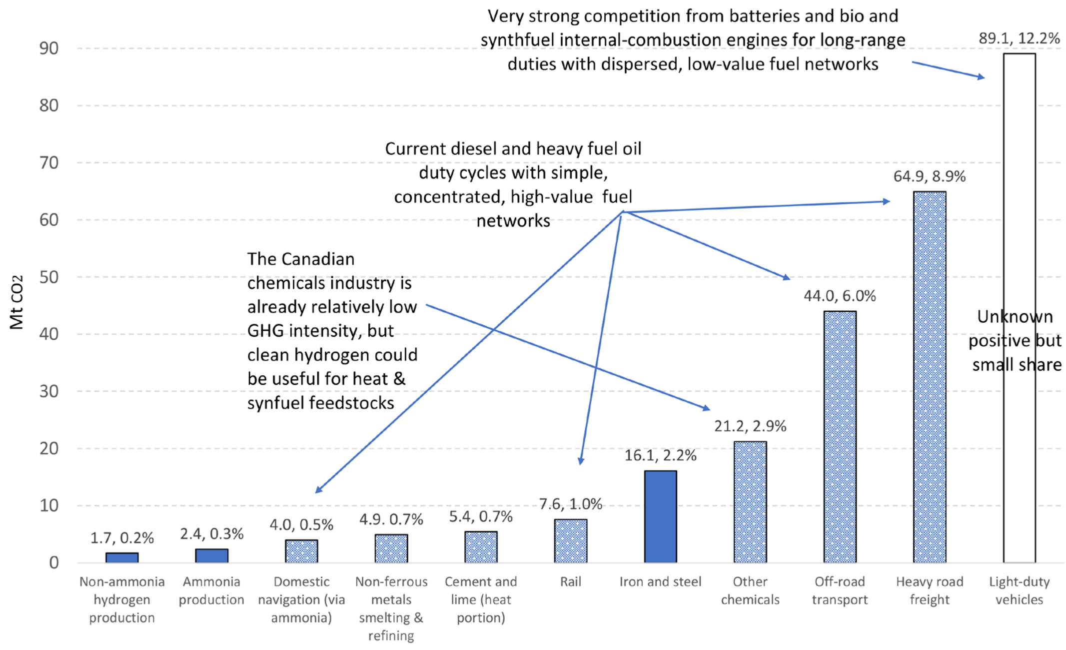
Compared to batteries, hydrogen fuel cells and their fuel-storage systems have a much higher potential power and energy density for a given weight. Hydrogen gas or liquid fuel tanks are also currently much more speedily filled than charging batteries, although solid-state or hybrid chemical and supercapacitor batteries under development may change this. Fuel cells are potentially ideal candidates for eliminating emissions from off-transmission-grid end-uses, where lots of power and energy are required and large but light storage tanks are not an issue. These end-uses potentially include heavy road freight, diesel trains, small stationary power stations, and other applications where diesel motors are used and storage can be carried or trailered. For this to happen, though, fuel-cell prices need to fall, and the hydrogen needs to be produced at a reasonable price compared to other low-emissions options. The International Energy Agency's latest Energy Technology Perspective report for 2020 indicates that, from now through 2050, battery-electric trucks will dominate on a cost-per-tonne-kilometre basis for light and medium freight, especially in a daily "return to base mode"; however, beyond 400 kilometres, fuel-cell electric vehicles have a decided energy-density cost advantage (International Energy Agency (IEA), 2020). Given all the above, it is arguable that the competition between pure battery versus fuel-cell trucks in many duty cycles will depend on which widespread refueling/recharging network is rolled out first.

Hydrogen may also have an edge in low-carbon shipping fuels (International Energy Agency (IEA), 2020). Ships would likely operate not on compressed or liquid hydrogen, but ammonia run either through a fuel-cell or internal-combustion motor. Methanol made with clean hydrogen is also an option. Several shipping companies are piloting ammonia- and methanol-driven vessels, with Maersk having recently ordered five ships to run on net-zero methanol.

3.5 THE SIZE OF THE PRIZE

Figure 3 shows the potential end-users of hydrogen in terms of sector total and share of total Canadian emissions in 2018 (728 megatonnes CO_2e), based on the 2021 National Inventory report. Sectors where clean hydrogen will be critical, technologies are well-developed or near commercial, and production and use will be located together (eliminating the need for hydrogen transport), are shown in dark shading (i.e., refining, ammonia production, and iron and steel). These are the sectors with the highest likelihood of hydrogen being ready to displace current emissions. These dark bars in Figure 3 shows that hydrogen is really only a “near sure thing” for just 20.2 megatonnes or 2.8 per cent of Canada’s 2018 emissions. It should be kept in mind that Figure 3 only represents current emissions, and underplays the potential for growth in green iron and steel and hydrogen products for export, which could grow rapidly in Canada, given our iron ore resources and clean hydrogen-making capability.

Figure 3. Emissions-reduction opportunities for hydrogen: Potential end-users of hydrogen in terms of sector total and share of total Canadian CO_2 emissions in 2018 (Mt CO_2, per cent of 2018 Canadian total)



Data sources:(Government of Canada (GOC), 2020b); and authors’ calculations.

Shown in a lighter shade are sectors where hydrogen could be transformative for high process heat, feedstocks, or fuel-cell-motive power, but technologies are less well-developed; the economics are uncertain; partner technologies are needed (e.g., net-zero carbon in chemicals); and/or production and use will be separated, requiring a fueling or transport network. These lighter-shaded bars include cement and lime production, non-ferrous metals processing, and other chemicals; these add to 31.5 megatonnes, or 4.3 per cent of 2018 emissions). Most significantly would be if hydrogen fuel cells were to displace the work by large mobile diesel motors today: long-haul on-road heavy freight; heavy rail; domestic navigation; and off-road (120.5 megatonnes). This would represent 16.6 per cent of Canadian emissions in a sector that is considered difficult to electrify. The total for all the more challenging, lighter-shaded sectors is 20.9 per cent of 2018 emissions.

Light-duty vehicles (LDVs) are also shown in the rightmost bar at 12.2 percent of current emissions, but with no shading to represent their highly uncertain market share, due to stiff competition from electrification for urban transport and "daily return to base" light and medium freight, and alternative long-range motor options for light-duty fuel cells (e.g., bio or synthetic fuel internal-combustion motors). We have chosen not to include mixing of building and industrial methane heating use due to the incompatibility of hydrogen with our current methane network and hydrogen's reduced (–66-per-cent) energy content at standard gas-network pressure, making it unsuitable for most industrial uses while only improving gas utility intensity marginally.

Figure 3 presents us with a challenging reality: while hydrogen production will be key to decarbonizing much of industry, and could be a growth industry, its use outside industry hinges on commercialization of vehicle fuel cells, a widespread refueling network, and widely available clean hydrogen, all serious lifts for technology, investment and policy.

Much less certainly — and also therefore not included in Figure 3 — but something that could someday have a very high impact is that low-emissions hydrogen might be able to help dramatically increase the potential supply of renewable biomethane (RNG). A large portion of Canada's industry, buildings and residences are fueled and heated by fossil methane, and due to slow stock turnover and the cost of retrofitting or replacing the gas network with dedicated hydrogen piping, it will take time for new non-methane-based (i.e., electric or hydrogen) technologies to capture market share. "Drop-in" replacement biogas and bioliquid replacements would allow the GHG intensity of the existing long-lived industrial processes, buildings and home heating to fall. While not yet fully commercialized (pilots are underway in Canada), gasification of woody biomass, such as forestry or agricultural residue, produces a string of valuable chemicals (e.g., carbon solids, H_2, CO, CO_2, CH_4, C_2H_6). They tend to be "carbon-heavy," however, with lots of carbon compared to hydrogen. The addition of hydrogen would allow more biomethane, biomethanol, bioethanol, and bioethylene to be produced (Bataille et al. 2018). There are fundamental economic and technical challenges to widespread commercialization of this "hydrogen-boosted" bio-hydrocarbon pathway, however. The key economic challenges are relatively cheap fossil-fuel methane, which prevents biomethane from gathering market share unless it is mandated, and the cost of gathering sufficient biomass. The technical challenges are associated with "bottoms-fouling," or "gumming up" of chemical-transformation catalysts with bio-hydrocarbon coke and resins. If these economic and technical challenges could be addressed, however, Canada would be well-positioned to take advantage of this pathway.

Fuel cells and hydrogen have another potential key application: making electricity to provide firm power support for variable renewable energy sources, such as wind and solar photovoltaics. We discuss this role for hydrogen in greater depth in a separate SPP Research Paper (Neff et al. 2021).

4. CONCLUSION

While hydrogen can do many things, its highest value will be found in areas where it is the cheapest or only option for decarbonization. Hydrogen has a critical role to play in a few industrial sectors (e.g., steel and chemicals production), and could also be very important for rail, heavy freight, off-road diesel uses, and reliable electric-power generation.

Low-GHG hydrogen can currently be produced at least two ways: from methane with 90–95-per-cent capture CCS (blue hydrogen), or from electrolysis with low-GHG electricity (green hydrogen). Blue will likely be the method of choice for some time in Western Canada, while green will likely take off in Québec, spreading to other provinces as clean renewable-power costs fall.

Lifecycle-GHG intensity needs to be the metric for hydrogen production and will be required for accurate carbon pricing; in many cases clear "rules of thumb" will be required to determine what qualifies as blue or green hydrogen. Blue hydrogen, made from fossil fuels with CCS (including their upstream GHG emissions), and the electricity used to make green hydrogen via electrolysis, must both be viewed through this lens. In both cases, hydrogen lifecycle-production emissions should be based on 90-per-cent CCS or 150 grams per kilowatt-hour. At one-third use in a 66-per-cent variable renewable and 33-per-cent hydrogen-combustion or fuel-cell system, this would be 50 grams per kilowatt-hour electricity-emissions intensity — the conventional maximum threshold for deep decarbonization of the electricity system.

If grey unsequestered hydrogen is to be used at all, it should only be a transitory mechanism to ensure that technologies are able to adapt from natural gas to hydrogen while CCS is installed on the hydrogen production equipment.

Given that Canada's upstream fugitives could be higher than currently reported by about 50-100 per cent or more (Chan et al., 2020; MacKay et al., 2021), even with the 2016 effort to lower them by 45 per cent, our current control regime is too weak to allow a broad blue-hydrogen strategy. The Liberal Party commitment during the 2021 election to a reduction of 75% by 2030 was an excellent step. Eventually a much tighter target should be aimed at, perhaps reductions of 80–90 per cent by 2030, which would only allow emergency flaring and minimal leakage. This will constrain the oil and gas industry from developing some low gas-to-liquid wells, as it will cost too much to pipe the gas away instead of flaring it. This should be expected and planned for.

For hydrogen to play a big role in freight, once fuel-cell trucks are readily available, there is the regular chicken-and-egg problem of whether trucks will be bought before a fueling network is put in, and vice versa. A role for fuel-infrastructure policy is likely required. There are many models for this to follow: full public, full private, and as a private-public partnership. But the presence of a refueling network on main transportation highways will be absolutely necessary for uptake.

Hydrogen could be the means to new export industries, including green primary iron made using hydrogen direct reduced iron metallurgy and hydrogen based chemical feedstocks like ammonia. If the value-added of these products can be monetized, through public and private lead markets, carbon pricing and eventually border carbon adjustments amongst our trading partners, Canada is in an excellent position to be a low cost supplier of green and blue hydrogen based products. For example we could export green iron reduced with hydrogen based on Québec's hydroelectricity and Alberta's methane and CCS potential.

Ultimately, one of the most valuable roles for hydrogen will be in assisting the decarbonization of the power sector. As the share of renewable power in the grid increases, hydrogen can play an essential role in both absorbing excess generation during periods of wind and solar abundance for electrolysis, and generating firm, reliable power in hydrogen-capable gas turbines. The combination of larger shares of renewables supported by complementary hydrogen infrastructure offers a pathway to decarbonize power grids, such as those in Alberta, Saskatchewan, and parts of the Maritimes, which have historically been high-emission. We discuss this role for hydrogen in more detail in a separate SPP Research Paper (Neff et al. 2021).

In sum, hydrogen will likely have a critical role in a net-zero-emissions future in Canada, not as a silver bullet, but as a complement to a variety of other strategies.

APPENDIX

Key Assumptions for Figure 1 Model	Value	Units
Natural Gas Upstream Emissions Low	6.58	gCO_2e/MJ
Natural Gas Upstream Emissions Mid	10.53	gCO_2e/MJ
Natural Gas Upstream Emissions High	14.48	gCO_2e/MJ
Natural Gas Emissions	56	gCO_2e/MJ
SMR Emissions for H_2	77.3	gCO_2e/MJ
CCGT Heat Rate (Lower Heating Value)	6.863	MJ/kWh
SCGT Heat Rate (Lower Heating Value)	9.127	MJ/kWh
Electrolysis Efficiency	60%	
Combustion Efficiency — SCCT	40%	
Combustion Efficiency — CCGT	60%	

Key Assumptions for Figure 2 Model	Value	Units
Natural Gas Emissions	56	gCO_2e/MJ
SMR Emissions for H_2	77.3	gCO_2e/MJ
SCGT Heat Rate	9.127	MJ/kWh
TIER Carbon Allocation — Electricity	0	tCO_2e/MWh
TIER Carbon Allocation — Hydrogen	0	tCO_2e/kgH_2
SMR Base Production Cost	0.457	$\$/kgH_2$
SMR 90% CCS Cost	0.485	$\$/kgH_2$
SMR Natural Gas Usage	0.165	GJ NG/kgH_2
SMR Emissions for H_2	77.3	gCO_2e/MJ
Carbon Price	50	$\$/tCO_2e$
Electrolysis Electricity Usage	0.0486	MWh/kgH_2

Note: TIER refers to Alberta's Technology Innovation and Emissions Reduction Regulation, an output-based carbon-allocation program.

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