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ATB Capital Markets

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Energy Services

Hydrogen to Play A Key Role in the Energy Transition

Companies Under ATB Coverage with Leverage to Hydrogen

	Ticker	Analyst	Rating	US$/C$	PT
CCUS for Blue Hydrogen					
TechnipFMC plc	FTI-N	Waqar Syed	OP	US$	$14.50
Baker Hughes Company	BKR-N	Waqar Syed	OP	US$	$24.50
Keyera Corp.	KEY-T	Nate Heywood	OP	C$	$28.00
Hydrogen Transmission					
Baker Hughes Company	BHI-N	Waqar Syed	OP	US$	$24.50
Hydrogen Production					
Schlumberger Ltd.	SLB-N	Waqar Syed	OP	US$	$27.00
Enerflex Ltd.	EFX-T	Tim Monachello	OP	C$	$9.00
Renewable Electricity					
Northland Power Inc.	NPI-T	Nate Heywood	OP	C$	$45.00
Capital Power Corporation	CPX-T	Nate Heywood	SP	C$	$36.00
TransAlta Corporation	TA-T	Nate Heywood	OP	C$	$11.00
E&C Services for New Hydrogen Facilities					
TechnipFMC plc	FTI-N	Waqar Syed	OP	US$	$14.50
Stantec Inc.	STN-T	Chris Murray	OP	C$	$49.00
SNC-Lavalin Inc.	SNC-T	Chris Murray	OP	C$	$41.00
WSP Global Inc.	WSP-T	Chris Murray	OP	C$	$125.00
Aecon Group Inc.	ARE-T	Chris Murray	OP	C$	$19.00
Gas Leveraged E&P					
Tourmaline Oil Corp.	TOU-T	Patrick O'Rourke	OP	C$	$25.00

Note: Links to the most recent report for each company in this table start on page 46.

Event: In this report, we evaluate hydrogen as a source of low-carbon energy and its role in energy transition to a low-carbon future. To meet Paris Climate Agreement goals, many countries are increasing hydrogen's share in the energy mix. In this report, we study hydrogen and identify investment opportunities within our coverage.

Highlights:

- **Hydrogen Poised for Substantial Long-Term Growth:** (1) Unlike oil/natural gas, hydrogen doesn't emit carbon when used as an energy source, and also offers superior storage characteristics to electricity. As such, governments have identified hydrogen as an important part of the energy mix to meet 2050 Paris Climate Agreement goals, with the EU projecting that hydrogen will meet 13%-14% of its energy needs by 2050 (from under 2% currently), and Canada having a goal of hydrogen comprising 30% of its end-use energy by 2050. (2) The IEA projects hydrogen demand to grow at a modest ~2% CAGR during 2020-2030, but governments are using this decade to lower costs for consumers, and are encouraging significant investments in "green" and "blue" hydrogen, as well as the supporting infrastructure for hydrogen use in many sectors. It is forecast that technical innovations/economies of scale will lead to competitive costs for consumers by 2030, leading to 4% hydrogen demand CAGR in 2030-2040, and 8% in 2040-2050. (3) Most "pure" hydrogen today is produced from natural gas (76%), with less than 1% coming from green hydrogen, but by 2050, green hydrogen should be meeting ~50% of the hydrogen demand (natural gas with CCUS should still be ~40% of the supply base).
- **Key Investment Themes and Stock Picks Within ATB Coverage:** (1) **CCUS:** Upgrading existing "grey" hydrogen plants into "blue" hydrogen plants through CCUS is an estimated $17bn opportunity. Also, any new natural gas-based hydrogen facilities will likely have CCUS. We highlight FTI-N and KEY-T on the theme. (2) **E&C:** Significant new investment will go into building new electrolysers, benefiting E&C companies such as FTI-N, STN-T, SNC-T, WSP-T, and ARE-T. (3) **Renewables:** Green hydrogen will likely be the highest growth segment through 2050, as renewable electricity will be needed to power the electrolysers; NPI-T and CPX-T are our recommendations in the renewable space. (4) **Distribution and Transmission:** Industry is exploring opportunities to blend hydrogen with natural gas through the transmission and distribution networks, and BKR-N provides the compression systems and hydrogen powered turbines to make it possible. (5) **FCEV:** Being greenhouse gas emission free, demand for fuel cell electric vehicles is being encouraged by governments, and sales should become very material post 2030, benefitting fuel cell makers. (5) **Canadian natural gas:** Canadian natural gas will remain highly competitive in producing hydrogen with CCUS, benefiting a natural gas producer such as TOU-T.
- **Key Challenges Ahead:** Hydrogen growth targets post 2030 are highly dependent on the timing of technological innovations, realization of economies of scale, and how aggressive governments are in meeting the Paris Agreement goals.

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Executive Summary

Hydrogen 101

Hydrogen, like electricity, is an energy carrier. It is abundantly found in water (H_2O), methane gas (CH_4), and other organic material. Annual production of "pure or dedicated" hydrogen is about 70mm tonnes (T)/year globally, with the vast majority – roughly 76% – being manufactured from natural gas, with coal the second-biggest source (23%). When hydrogen is used as a source of energy, it doesn't emit carbon, but carbon can still be produced during the hydrogen manufacturing process if it is derived from natural gas or coal. Therefore, hydrogen derived from coal/natural gas is called "brown/grey" hydrogen. However, this "brown/grey" manufacturing process can be turned into "blue" if carbon capture is added to hydrogen manufacturing from natural gas/coal. On the other hand, if hydrogen is produced from the electrolysis process, there is no carbon emission, particularly when the electricity that is used in the electrolysis process comes from renewable sources. Hydrogen produced from this method is called "green" hydrogen. However, under current technologies, "green" hydrogen is significantly more expensive than "brown/grey" or "blue" hydrogen; a considerable amount of current R&D investment is going toward making "green" hydrogen less expensive.

How Good an Energy Carrier Is Hydrogen?

Hydrogen is a chemical energy carrier that makes storage and transportation easier than electricity, so unlike electricity, it can be stored for long periods of time and used when needed. Hydrogen carries more energy per unit of mass than natural gas or gasoline, which makes it attractive as a transportation fuel. However, being the lightest element, hydrogen has low energy density per unit of volume, and so larger volumes of hydrogen must be moved to meet energy demand equivalent to that of other fuels, requiring faster flowing pipelines or larger storage tanks to compensate for lower energy density. As an example, the International Energy Agency (IEA) estimates that a 3% hydrogen blend in a natural gas distribution line reduces the energy content by 2%. Hydrogen can be compressed, liquefied, or transformed into hydrogen-based fuels that have a higher energy density but each step (conversion/reconversion) adds to system inefficiencies, raising costs. Given the small size of the hydrogen molecule, it requires special handling, and to move hydrogen through the natural gas infrastructure, upgrades of materials/seals may be required, especially when moved at high pressures through transmission systems (distribution systems for residential use are typically run at lower pressures; pipeline upgrades may not be required). Hydrogen is non-toxic but it is highly flammable, with high flame velocity and a broad ignition range. Its flame is not visible to the naked eye and being colorless and odorless, leaks can be harder to detect. While the general public is used to safety considerations linked to natural gas/gasoline usage, it will need to be educated when using hydrogen.

Strong Governmental Support for Expanding Hydrogen Usage

To meet Paris Climate Agreement goals, governments around the world have realized that a clean burning source of energy such as hydrogen should be a major part of the energy mix by 2050. Estimates of the size of the hydrogen market by 2050 varies amongst the different government organizations, falling between US$2.0 trillion and US$9.0 trillion. In its strategic vision for a climate-neutral EU published in November 2018, the share of hydrogen in Europe's energy mix is projected to grow from the current <2% to 13-14% by 2050. The plan is to install at least 6GW of renewable hydrogen electrolysers in the EU by 2024 (versus <1GW currently) and 40GW of renewable hydrogen electrolysers by 2030. The EU forecasts investment of US$30-US$50bn (€24-€42bn) through 2030 in electrolysers, and about US$260-US$340bn (€220-€340bn) to scale up and directly connect 80-120GW of solar and wind energy production capacity to provide the electricity for the electrolysers. In addition, the EU forecasts investments of US$13bn (€11bn) in carbon capture and storage. Moreover, investments of US$80bn (€65bn) may be needed for hydrogen transport, distribution and storage, and hydrogen refueling stations. On December 16, 2020, the Government of Canada put forward its hydrogen strategy, which envisions hydrogen becoming 6% of the country's energy mix by 2030, and rising to 30% by 2050 (please see page 43 for more details)

Hydrogen Supply and Demand Trends Going Forward

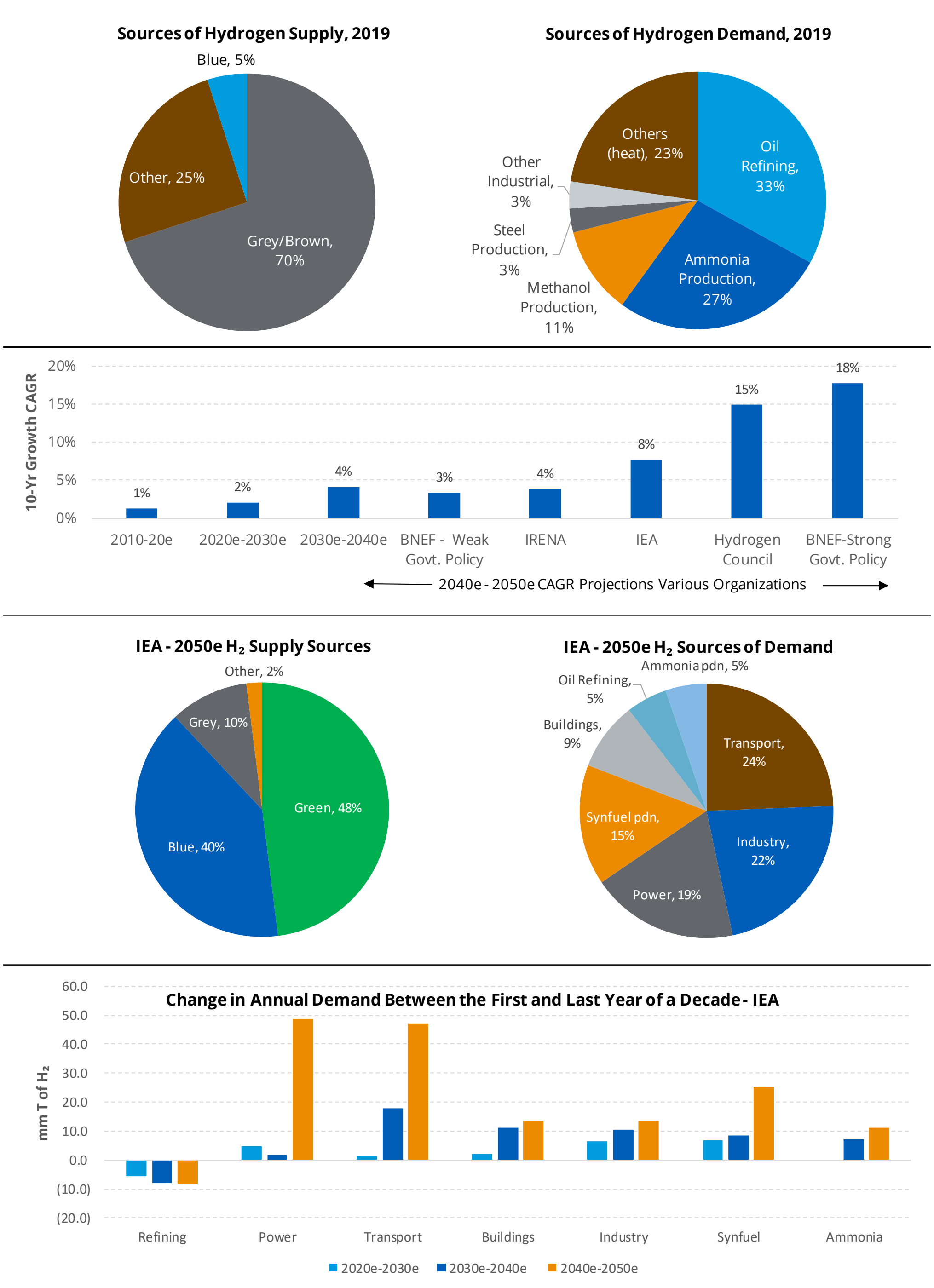


Figure 1 – Hydrogen Supply and Demand Trends Going Forward

Source: Baker Hughes, IEA, Bloomberg NEF, International Renewable Energy Agency (IRENA), Hydrogen Council, ATB Capital Markets Inc.

Hydrogen Manufacturing: Natural Gas Dominates as a Source for Hydrogen Production

About 70mm T of "pure or dedicated" hydrogen is produced annually, excluding ~45mm T of "by-product" hydrogen that is mixed with other gases and consumed. Close to 76% of dedicated hydrogen comes from natural gas and another 23% from coal. The production costs of hydrogen can vary from US$1.0-US$3.0/kg depending on the price of natural gas and coal used in the manufacturing process and whether the carbon capture, utilization, and storage (CCUS) step is included or not. The production cost of hydrogen increases to $3.0-$7.50/kg if renewable power is used in the electrolysis process. There are significant investment dollars being dedicated to lowering the cost of hydrogen production in the electrolysis process.

Key Points to Know About Hydrogen

Did You Know the Following About Hydrogen?	
Characteristics	H_2 is an energy carrier like electricity, but it is a chemical energy carrier and thus can be easily stored unlike electricity
	When burned H_2 produces no GHG gases
	Has more energy per unit of mass than natural gas or gasoline, but…
	..it has lower energy density than gasoline or natural gas, so larger volumes need to be moved to meet equivalent energy
Production	70 mmT of "dedicated H_2" is produced annually, of which 76% produced from natural gas, 23% from coal and only 1% from oil/electricity
	…additional H_2 is produced and consumed as a "by-product" hydrogen, and is used as a mixture of gases
	Producing H_2 from environmentally friendly electrolysis is most expensive, but industry is focused on lowering production costs
	To replace all current hydrogen production with electricity, 3600TWh of electricity needed, equal to current EU generation capacity
	Hydrogen is stored and delivered in compressed gas or liquid form, with 85% consumed on-site and 15% stored via trucks/pipelines
	Most current production is called "grey/brown" H_2 as it is produced from gas/coal and CO_2 is emitted in the production process
	If carbon capture, usage and storage (CCUS) added to "grey/brown" H_2 production, it is called "blue" H_2.
	H_2 produced via electrolysis produces no CO_2 and if electricity consumed in electrolysis comes from renewables, it is called "green" H_2
Demand	33% of H_2 produced currently is used in oil refining, 27% for ammonia production, 11% for methanol production, 3% for steel production
	… demand for traditional uses of H_2 should grow at GDP growth rate, but should continue to structurally decline for oil refining
	… demand growth to accelerate post 2030, as H_2 replaces traditional energy sources, and is used in transportation, power and in buildings
Storage	Compressed hydrogen (700bar pressure) has 15% of gasoline's energy density and requires 7.0x space to supply equivalent energy at refueling station
	Compressed hydrogen has higher energy density than lithium-ion battery, which can give hydrogen fuel cell powered cars/trucks greater range than battery electric vehicles
Hydrogen Distribution & Transmission	At distance <1,500km, H_2 transmission via pipeline is the cheapest option
	At distance >1,500km, shipping either as ammonia or with liquid organic hydrogen carrier (LOHCs) the cheapest
	Industry considering blending natural gas with hydrogen in traditional natural gas distribution and transmission systems
	..~3% hydrogen blend in natural gas distribution line, reduces energy content by 2%, meaning more gas will need to be burnt
	H_2 burns faster than methane, which raises risk of flames spreading, hydrogen flame not that bright, and requires new flame detectors
	H_2 blending with natural gas may require process change for industrial users, where quality of flame is important
Production Cost Comparison	Depending on the cost of natural gas, H_2 production costs can be US$1.5-US$3.0/kg for natural gas plants with CCUS
	Levy of CO_2 taxes can make H_2 with CCUS competitive with unabated fossil fuel H_2production. In the Mideast $50/T CO_2 is the threshold.
	Producing H_2 from electrolysis is getting the most R&D investments, as it is "green"
	At low gas prices, renewable electricity should be ~US$10/MWh to be cost competitive with natural gas with CCUS
	IEA doesn't expect H_2 from electrolysis to be cost competitive with H_2 produced from natural gas until about 2030
Fuel Cells	Fuel cell electric vehicles (FCEV) best suited for heavy lift and long-haul markets
	IEA estimates that 25,000 forklifts, 500 buses and 11,200 light duty FCEV (fuel cell electric vehicles) were on the road in 2018
	FCEV competitiveness dependent on cost of fuel cell stack, cost of hydrogen on board, and the cost of refueling
	IEA expects that with technological innovations and economies of scale, fuel cells would be broadly cost competitive by 2030
EU Plan for Hydrogen Investments	EU expects share of hydrogen in its energy mix increasing from 2% to 13%-15% by 2050
	EU plans to have 6GW of renewable hydrogen electrolysers in the EU by 2024 (<1GW currently) and 40GW by 2030
	EU sees investments of US$30-US$50bn in electrolysers and US$260-US$340bn in scaling up renewable electricity through 2030
	EU sees cost of retrofitting existing hydrogen plants with CCUS at US$13bn.
	Additional US$80bn of investments will be needed in hydrogen transport, distribution and storage, and hydrogen refueling stations
	End-users will need to invest in upgrades to become hydrogen ready. A small scale refueling station to cost between US$2.5-US$3.0mm.
	Steel plant requiring end-of-life hydrogen upgrade needs US$200-US$250mm capital investment.

Figure 2: Key Points to Know About Hydrogen
Source: IEA, the EU, Company Reports, ATB Capital Markets Inc.

Hydrogen Demand Growth: To Accelerate Sharply Post 2030e

Over the coming 2020e-2030e decade, demand for hydrogen is forecast to grow at the global GDP growth rate, as the key driver of growth should be industrial demand, and while demand in the power, transportation, and synthetic fuels segments is expected to increase, its impact could be offset by declining demand within the oil refining sector. The IEA projects that demand for hydrogen in the industrial sector, power sector, and synthetic fuel sector will be 6.5mm T/year, 6.9mm T/year, and 4.7mm T/year, respectively, higher by 2030e than at the beginning of the decade. Demand for hydrogen in the transportation sector will only be a modest 1.6mm T/year by the end of the decade (see Figure 1).

Post 2030, the IEA projects that demand for hydrogen will increase from a 2% CAGR to 4% CAGR in the 2030e-2040e decade, with the growth rate dependent on how quickly the cost of "green" hydrogen becomes competitive with "grey" and "blue" hydrogen, and the pace at which the cost of fuel cell electric vehicles (FCEVs) becomes competitive with internal combustion engines (ICEs) and battery electric vehicles (BEVs) (see Figure 3).

While the use of FCEVs may become more prevalent starting in 2025, the IEA projects that only by 2030 would economies of scale and technical innovations be at a level that FCEV demand starts to accelerate (see Figure 3). For example, Japan projects that its FCEVs should increase from 3,633 vehicles in 2019 to 200,000 vehicles by 2025 and to more than 800,000 vehicles by 2030. However, these figures still pale in comparison to the number of ICE vehicles on the road today, which are estimated to be more than 1 billion. The IEA expects demand for hydrogen in the transportation sector to increase from 1.6mm T/year in 2030e to 19.6mm T/year in 2040e.

Commercialization Timeline of Hydrogen Usage

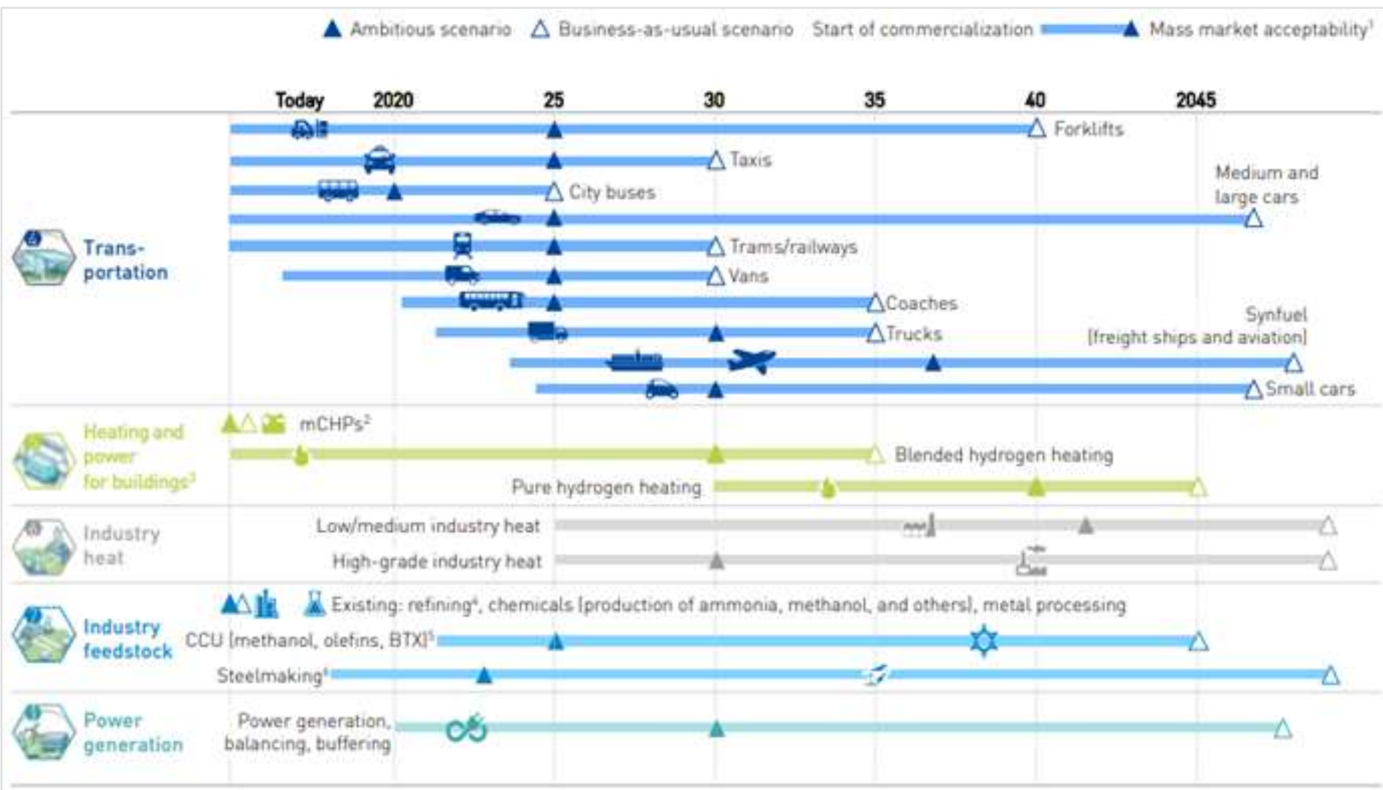


Figure 3 – Commercialization Timeline of Hydrogen Usage
Note: 1. Defined as sales >1% within segment; 2. mCHPs (micro combined heat and power) sales in EU independent of fuel type (NG or H_2); 3. Pure and blended H_2 refer to shares in total heating demand; 4. Refining includes hydrocracking, hydrotreating, and biorefinery; 5. Market share refers to the amount of production that uses hydrogen and captured carbon to replace feedstock; 6. CDA (carbon direct avoidance) process and DRI (direct reduced iron) with green H_2, iron reduction in blast furnaces, and other low-carbon steelmaking processes using H_2. BTX stands for benzene toluene xylene (hydrocarbon solvents)
Source: Hydrogen Roadmap Europe

While the transportation sector is forecast to be the biggest driver of hydrogen demand during the 2030e-2040e decade, demand for hydrogen in buildings, industry, and for synthetic fuels is expected to increase sharply too, owing to forecast gains made in the 2020e-2030e decade in lowering the cost of hydrogen production and distribution.

Post 2040, demand for hydrogen should start to accelerate even more rapidly, driven primarily by further cost reductions and from realizations of additional economies of scale in the power and transportation sectors (see Figure 1). The IEA expects hydrogen demand in the power sector to be up from 6.4mm T/year in 2040e to 55mm T/year by 2050e. Similarly, in the transportation sector, demand is forecast to increase to 66.5mm T/year in 2050e, up from 19.6mm T/year in 2040e.

However, as the world continues to shift toward low-carbon sources of energy, the IEA expects demand for hydrogen in the oil refining sector to continue to decline, falling from 38.4mm T/year in 2019, to 32.9mm T/year in 2030e, 25.1mm T/year in 2040e and 16.9mm T/year in 2050e.

For the 2040e-2050e, demand forecasts for hydrogen differ dramatically across the different organizations that are the primary source for projecting hydrogen demand. Per Bloomberg NEF, the demand CAGR for hydrogen for the 2040e-2050e decade could vary between 3% and 18%, depending on how much support hydrogen gets from governments globally. Support in the form of end market development mandates on the use of hydrogen, as well as, carbon taxes. The IRENA, IEA and the Hydrogen Council project growth CAGR of 4%, 8% and 15%, respectively, for the 2040e-2050e decade.

Assessing the Near- to Medium-Term Investment Opportunities on the Hydrogen Theme

We highlight below some near- to medium-term investment opportunities for our current coverage. We highlight stocks in our coverage that could benefit from these trends in the text below and in Figure 4.

Investment Opportunities in Carbon Capture, Utilization, and Storage

IEA and other estimates show that "blue" hydrogen should remain a major source of hydrogen production even by 2050. About 70% of "pure and mixed" hydrogen comes from "grey/brown" hydrogen. The lowest hanging fruit in reducing the carbon footprint is adding CCUS to these existing plants. Per the IEA Sustainable Development Scenario (SDS), to meet the Paris Agreement by 2050, 28 gigatons of carbon dioxide (CO_2) will need to be captured in the atmosphere, and without CCUS, the cost of Paris Agreement compliance will be about 70% greater.

By our estimates, adding CCUS to the existing "grey/brown" hydrogen production is a $17bn opportunity by 2030. Additionally, new facilities using natural gas are likely to be built, especially in areas where natural gas prices are low, such as Canada, the United States, and the Middle East. All new facilities are likely to have CCUS. Only six CCUS projects with total annual production capacity of 0.35mm T were active at the end of 2019, but the IEA estimates that more than 20 new projects have been announced for commission in the 2020s, mostly around the North Sea. More are likely to be announced in the coming years. Per the IEA, the number of CCUS projects needed to meet Paris compliant hydrogen demand for the chemicals sector by 2030 is about 450, which equals about one new project per week; for electrolyser projects to meet all chemicals demand, new projects at a rate of six to seven per week required. Clearly, this level of project start-ups is highly optimistic, though a significant increase in projects is likely. We highlight **TechnipFMC plc** as an investment on that theme. In addition to CCUS, FTI-N believes there are opportunities in the construction of electrolysers and other steam methane reforming (SMR) systems. In total, FTI-N estimates its revenue opportunity set in hydrogen at $50bn by 2030.

On the theme of carbon storage and sequestration, we note **Keyera Corp** in particular as it produces hydrogen at its Alberta EnviroFuels facility and management has noted the potential use of depleted gas wells near its asset base that could be a suitable carbon capture and sequestration option for carbon created in the hydrogen manufacturing process.

Opportunities in E&C and Provision of Renewable Energy

A number of electrolyser projects have been announced, though the base level of projects still remains low. Based on announced projects, the IEA estimates that 126 MW/year of electrolyser capacity should be operational in 2020, and that figure should increase to 1,434MW/year in 2023. The EU sees investment in the US$30-US$50bn range through 2030 in electrolysers, and about US$260-US$340bn to scale up and directly connect 80-120GW of solar and wind energy production capacity to provide the electricity for the electrolysers. These new projects will create work for E&C companies, and also boost renewable energy demand. On the E&C side, **TechnipFMC plc**, **Stantec Inc.**, **SNC-Lavalin Inc.**, **WSP Global Inc.**, and **Aecon Group Inc.** all offer leverage to the hydrogen theme. On the renewable side, **Northland Power** has identified its potential to be an early mover into green hydrogen through use of its offshore wind assets in the electrolysis process. **Capital Power Corporation** recently announced it will undergo a full repowering at its Genesee 1 & 2 facilities. We highlight that these facilities, post repowering, will offer hydrogen capacity of ~30%, which management believes it can increase at a minimal cost to 95% in the future.

Stocks Offering Hydrogen Leverage Within ATB Coverage

	Ticker	Analyst	Rating	Currency	Price Target	Remarks
CCUS for Blue Hydrogen						
TechnipFMC plc	FTI-N	WS	OP	US$	$14.50	FTI has identified $50bn H_2 opportunity set through 2030
Baker Hughes Company	BKR-N	WS	OP	US$	$24.50	BKR offers compression equipment that can be used for carbon capture
Keyera Corp.	KEY-T	NH	OP	C$	$28.00	H_2 production facilities near depleted oil/gas wells offering CO_2 storage potential
Hydrogen Transmission						
Baker Hughes Company	BHI-N	WS	OP	US$	$24.50	BKR has hydrogen powered turbines and compression equipment
Hydrogen Production						
Schlumberger Ltd.	SLB-N	WS	OP	US$	$27.00	Investing in solid oxide electrolyser technology
Enerflex Ltd.	EFX-T	TM	OP	C$	$9.00	Supplier of compression equipment required for H_2 production
Renewable Electricity						
Northland Power Inc.	NPI-T	NH	OP	C$	$45.00	Offshore wind assets to power customer electrolysers
Capital Power Corporation	CPX-T	NH	SP	C$	$36.00	Repowering coal power facilities to enable them to use natural gas/hydrogen
TransAlta Corporation	TA-T	NH	OP	C$	$11.00	Repowering one of its thermal facilities which we expect to have hydrogen capabilities
E&C Services for New Hydrogen Facilities						
TechnipFMC plc	FTI-N	WS	OP	US$	$14.50	FTI has identified $50bn H_2 opportunity set through 2030
Stantec Inc.	STN-T	CM	OP	C$	$49.00	Positioning for advisory, consulting and project delivery services of H_2 value chain
SNC-Lavalin Inc.	SNC-T	CM	OP	C$	$41.00	Part of consortium undertaking FEED study of H_2 production facility in the UK
WSP Global Inc.	WSP-T	CM	OP	C$	$125.00	Expertise in H_2 storage, distribution and production
Aecon Group Inc.	ARE-T	CM	OP	C$	$19.00	Supporting utilities in development of industrial projects and distribution networks
Gas Leveraged E&P						
Tourmaline Oil Corp.	TOU-T	PO	OP	C$	$25.00	Largest producer of natural gas in Canada

Figure 4 – Stocks Offering Hydrogen Leverage Within ATB Coverage
Source: Company Reports, ATB Capital Markets Inc.

Opportunities in Gas Transmission, Distribution, and Power

Some gas distribution companies are considering blending hydrogen with natural gas for distribution to domestic users. Since gas is supplied domestically at low pressures, and is primarily used for heat generation, minimal modifications are required to the distribution infrastructure. However, Snam in Italy has demonstrated the feasibility of blending up to 10% hydrogen in the higher-pressure gas transmission network. **Baker Hughes Company** builds equipment that can be used across the hydrogen value chain. Its compression equipment can be used in hydrogen production, transmission (including for transmission of synthetic hydrogen-based fuels), and by the users of hydrogen. Moreover, it has introduced turbines that can potentially work with 100% hydrogen and can be used for power generation. Its turbines can also be powered with methane, ammonia, and methanol, all of which have very superior long-term growth potential.

Fuel Cells

Fuel cells offer a sizeable long-term business opportunity. FCEV costs are declining, and for long haul, they are already quite competitive to BEV costs. The potential size of the FCEV market could be very large, though it may take decades to be realized. Hydrogen consumption in the transportation sector is forecast to increase from 1.6mm T/year in 2030e to 19.6mm T/year by 2040e and 66.5mm T/year by 2050e. Ballard Power Systems Inc. (BLDP-T, NR), FuelCell Energy Inc. (FCEV-N, NR), and Plug Power Inc. (PLUG-N, NR) are some of the companies engaged in fuel cells.

Canadian Natural Gas

Canada is competitively positioned as a producer of hydrogen, owing to its low-cost gas, and we highlight the country's largest gas producer **Tourmaline Oil Corp.** as a potential beneficiary of increased gas demand, as gas-sourced hydrogen demand increases. Based on data provided by the IEA and The Transition Accelerator, we estimate that Canada has the lowest cost of hydrogen production using natural gas, largely owing to the price of natural gas in Canada (see Figure 5). For Canada, the cumulative capex, opex, and natural gas consumption costs are estimated to be ~US$0.75/Kg for hydrogen in Alberta without CCUS, and about US$1.15/Kg with CCUS. These costs are about 20% lower than the Middle East and 25% lower than the United States (when CCUS is not employed). We believe Canada's cost competitiveness is relatively similar when CCUS is included. The Western Canadian Sedimentary Basin (WCSB) is a superior location for the production of hydrogen, owing to its ample supply of low-cost natural gas, and because it has depleted oil/gas fields, as well as salt caverns where hydrogen could be stored at a low cost.

Low Natural Gas Costs Make Canada Highly Competitive in Hydrogen Production

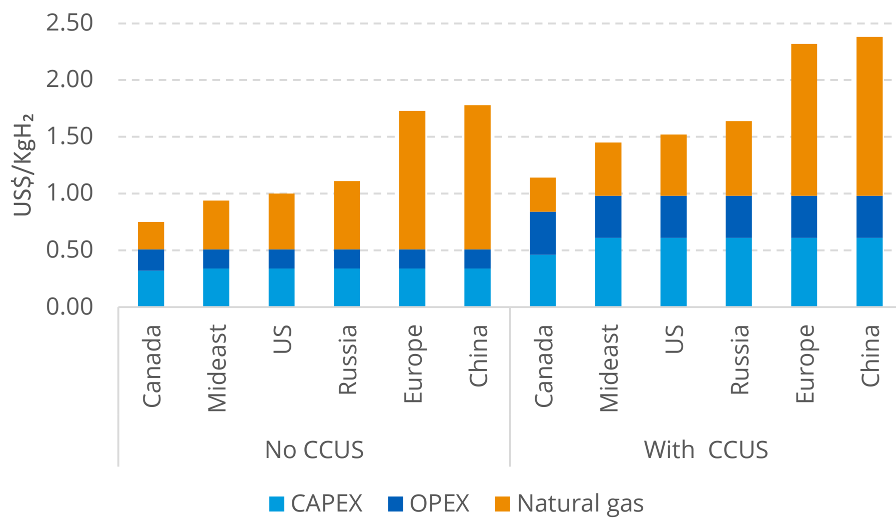


Figure 5 – Low Natural Gas Costs Make Canada Highly Competitive in Hydrogen Production
Source: IEA, The Transition Accelerator, ATB Capital Markets Inc.

Understanding Hydrogen as an Energy Carrier

The Most Abundant Element in the Universe

Hydrogen is among the most abundant elements in the universe but very scarce in free form on Earth (traces in the atmosphere). On Earth, hydrogen is usually found in compounds, for example, H_20 (water molecules) or CH_4 (methane gas), but also in other organic matter, such as plants or petroleum.

Given its abundance, the industry has often looked at hydrogen as a solution for a low-carbon future and for transition away from fossil fuels. The rationale is simple: there is no carbon in hydrogen, and when hydrogen is burned, the by-product is mainly water.

Hydrogen Is an Energy Carrier like Electricity

The IEA characterizes hydrogen as an energy carrier and not an energy source, and in that respect, it is similar to electricity. Both hydrogen and electricity can be produced from various energy sources and technologies. On their own, neither generate greenhouse gases (GHGs), particulates, sulphur oxides, or ground level ozone. However, for both hydrogen and electricity, the carbon intensity is increased if produced from fossil fuels such as natural gas, coal, or oil. This disadvantage can be overcome by changing the production source to renewables or nuclear, or equipping fossil fuel plants with CCUS.

Hydrogen Offers Better Storage and Transportation Characteristics Than Electricity

In one important respect, hydrogen is unlike electricity because as a chemical energy carrier, it is much easier to store and transport than electricity. A chemical energy carrier is composed of molecules and can be stored for long periods of time, transported (truck, pipeline, vessel, etc.), and burned to produce electricity. Hydrogen can also be combined with other elements such as carbon and nitrogen to make it easier to handle for use as feedstock in industrial uses.

Each Conversion Step Reduces System Efficiency Raising Cost of Supply

Each time an energy carrier is converted from one form of energy to another, there are system losses, which is a problem that hydrogen also faces. Per the IEA, converting electricity to hydrogen, transporting and storing it as hydrogen, and then converting it back to electricity in a fuel cell, results in the delivered energy being roughly 30% of what it was at the initial electricity input. This makes hydrogen more expensive than electricity or fossil fuel used to produce it. However, this simplified approach may not be the best way of assessing the economics of hydrogen.

First, the cost of hydrogen at the location of its use must be compared with the alternatives available at that site, and not to the cost of the natural gas used to produce it at the point of its origination. Furthermore, at the point of its use, in any economic analysis, the cost of externalities such as GHG emissions must be incorporated while assessing the cost of alternatives (the "whole value chain" approach). Since hydrogen is a clean burning fuel, it would clearly benefit from such analysis.

The IEA believes hydrogen can be used with improved efficiency in certain applications. For example, a hydrogen fuel cell in a vehicle is ~60% efficient, whereas a gasoline combustion engine is ~20% efficient (although ICE engines with 40% efficiency have been announced recently). A modern coal-fired power plant is ~45% efficient, with electricity power lines losses leading to a further ~10%+ reduction in efficiency, which potentially makes hydrogen a suitable replacement (this type of wide-scale adoption is likely even further out in the future than transportation).

Physical Properties of Hydrogen

Hydrogen carries more energy per unit of mass than natural gas or gasoline, which makes it attractive as a transportation fuel. On the other hand, hydrogen is the lightest element and has low energy density per unit of volume, and so larger volumes of hydrogen must be moved to meet energy demand equivalent to that of other fuels. As such, faster flowing pipelines or larger storage tanks are needed to compensate for the lower energy density. As an example, the energy density of hydrogen is one-third of natural gas, and per the IEA, a 3% hydrogen blend in a natural gas transmission line would reduce the energy transmitted by about 2%, meaning that end users would need to increase the volume of gas consumed to meet a given energy need.

Hydrogen can be compressed, liquefied, or transformed into hydrogen-based fuels that have a higher energy density but each step (conversion/reconversion) consumes energy.

Physical Properties of Hydrogen

Property	Hydrogen	Comparison
Density (gaseous)	0.089 kg/m^3 (0°C, 1 bar)	1/10 of natural gas
Density (liquid)	70.79 kg/m^3 (-253°C, 1 bar)	1/6 of natural gas
Boiling point	-252.76°C (1 bar)	90°C below LNG
Energy per unit of mass (LHV)	120.1 MJ/kg	3x that of gasoline
Energy density (ambient cond., LHV)	0.01 MJ/L	1/3 of natural gas
Specific energy (liquefied, LHV)	8.5 MJ/L	1/3 of LNG
Flame velocity	346 cm/s	8x methane
Ignition range	4–77% in air by volume	6x wider than methane
Autoignition temperature	585°C	220°C for gasoline
Ignition energy	0.02 MJ	1/10 of methane

Figure 6 – Physical Properties of Hydrogen
Note: cm/s = centimetre per second; kg/m3 = kilograms per cubic metre; LHV = lower heating value; MJ = megajoule; MJ/kg = megajoules per kilogram; MJ/L = megajoules per liter.
Source: IEA

Health and Safety Concerns

While the health and safety concerns of widely used energy products – gasoline, diesel, natural gas, coal, and electricity – are well known and managed by consumers, the risks associated with new energy technologies such as hydrogen are not as well known to the public at large.

Some key risks are highlighted below:

- Given the lightness and the small size of a hydrogen molecule (relative to natural gas), it requires special handling, and it can diffuse into materials, including iron and steel pipes and seals. However, there are ways in which the current natural gas infrastructure can be used for hydrogen transportation, especially for low pressure distribution.
- Hydrogen is a non-toxic gas, but is highly flammable, with high flame velocity and a broad ignition range. Its flame is not visible to the naked eye and being colorless and odorless, leaks can be harder to detect. However, hydrogen has been extensively used in industrial applications, and as such protocols are well established. There is risk that when introduced to the general public, protocols may be more complex and unfamiliar to the general population, while the general public is more familiar with the protocols for other energy carriers (including electricity).
- There are also some health and safety considerations associated with hydrogen-based fuels and feedstocks, which are familiar to the energy sector.

How Is Hydrogen Produced?

Hydrogen can be produced from fossil fuels and biomass, or from water or from a mix of both. Per the IEA, about 275mm TOE (tonnes of oil-equivalent) of energy annually is used for the production of hydrogen today, which equates to about 2% of total global primary energy demand.

Per the IEA, there is demand for about 70mm T of **dedicated or pure hydrogen** primarily for oil refining (55%) and the production of ammonia (45%) for use in the manufacturing of fertilizers (see Figure 7). This hydrogen is produced in "dedicated" facilities, where hydrogen is the primary product. Another 45mm T of hydrogen demand exists as part of a mixture of gases, such as synthesis gas, fuel, or feedstock.

Natural gas is the primary source of production of dedicated or pure hydrogen, accounting for 76% of the produced hydrogen. The IEA estimates that 205bn cubic metres of natural gas is annually (~19.8 bcf/d) (roughly 6% of total global natural gas use) used to manufacture hydrogen globally.

Coal is used more extensively for hydrogen production in China, and accounts for ~23% of global dedicated hydrogen production, using 107mm T of coal (2% of global coal use). Oil and electricity account for the remainder of the dedicated production.

Value Chain for Hydrogen

Figure 7 – Value Chain for Hydrogen
Notes: All estimates are for 2018. Other forms of pure hydrogen demand include the chemicals, metals, electronics, and glass-making industries. Other forms of demand for hydrogen mixed with other gases (e.g., carbon monoxide) include the generation of heat from steel works arising gases and by-product gases from steam crackers.
Source: IEA, ATB Capital Markets Inc.

"Color" Designation of the Hydrogen Manufacture Process

Hydrogen production is often grouped into three different categories or colors: grey/black, blue, and green.

Grey hydrogen refers to hydrogen produced from fossil fuels, namely natural gas, through the process of SMR, which emits CO_2 in the process. **Black/brown** hydrogen is generally associated with hydrogen produced from coal.

Blue hydrogen results from the same process as grey, but utilizes CCUS, whereby the resulting CO_2 from the SMR process is prevented from being released and can be stored underground or used in industrial processes. We believe that one of the biggest near-term opportunities in the hydrogen value chain is converting grey/brown hydrogen into blue through CCUS.

From a GHG perspective, **green** hydrogen is the cleanest method of hydrogen production and can result in zero emissions during the production process. Green hydrogen is produced through the electrolysis process, where hydrogen is removed from a H_2O molecule. The process consumes vast amounts of electricity, and if this electricity is produced by a renewable source, such as solar, wind, or hydroelectric, there will be minimal GHG emissions, and hence the designation "green" hydrogen.

Green hydrogen produced via electrolysis is the general approach that **Schlumberger Ltd.** is working on. **TechnipFMC plc** and several other E&Cs (see Figure 4) under ATB coverage are positioning to build green hydrogen plants when they become commercially viable. The largest increase in green hydrogen production is likely beyond 2030 when the industry expects R&D to unlock more commercial electrolysis technology. Nonetheless, a number of green projects are under construction right now, especially in Europe and Asia.

Northland Power has identified its aging offshore wind assets as potential generators for hydrogen electrolysis in the future (post-PPA), further stating that renewable fuel technologies are being evaluated as a long-term growth strategy.

Producing Hydrogen – Natural Gas Still the Primary Input for Production

SMR remains the most common method of producing hydrogen, but between 2030 and 2050, many key countries around the world are creating a fiscal environment that supports electrolysis to be a major source of hydrogen production.

Steam Methane Reforming

SMR is by far the most common method for producing hydrogen. At a high level, high-temperature steam is used to produce hydrogen from a methane source, which is most commonly natural gas.

Steam Methane Reforming – Most Common Method to Produce Hydrogen

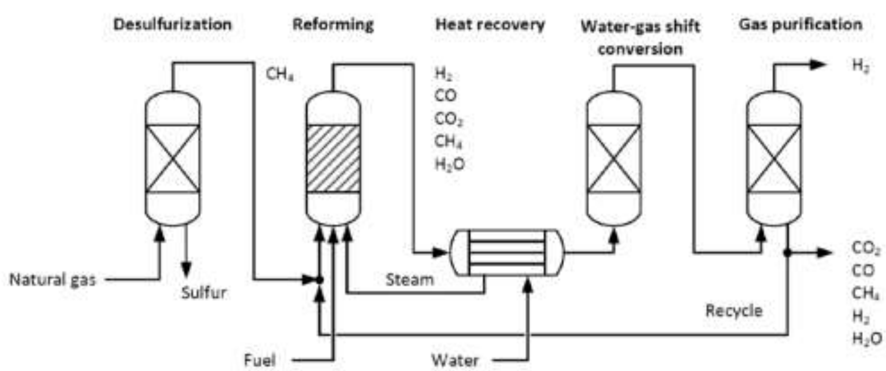


Figure 8 – Steam Methane Reforming – Most Common Method to Produce Hydrogen
Note: [Link to video on this process.]
Source: IEA

Steam Methane Reforming with Carbon Capture and Storage

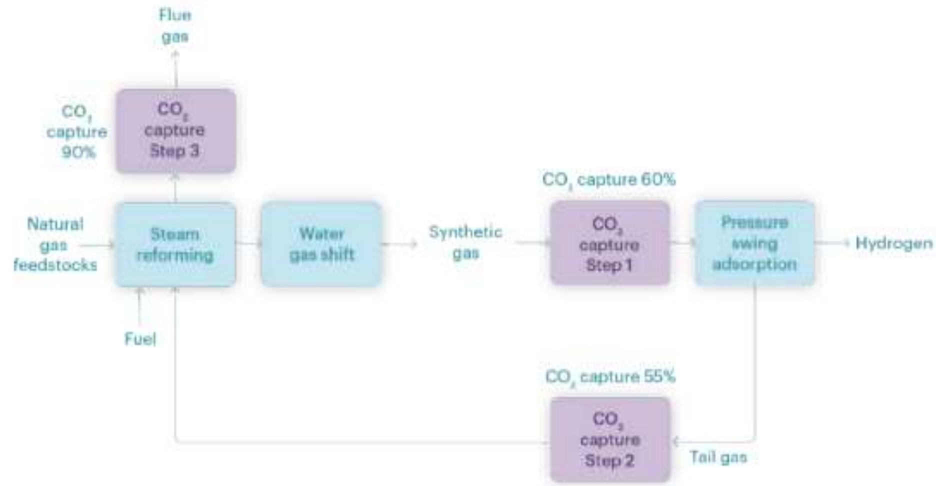


Figure 9 – Steam Methane Reforming with Carbon Capture and Storage
Source: IEA

The process involves converting CH_4 and H_2O at a high temperature to produce carbon monoxide (CO) and H_2; this is called the SMR reaction. Subsequently, in the "water-gas shift reaction," the CO produced in the previous step is combined with H_2O to produce more hydrogen and CO_2. In the final process, the "pressure-swing absorption," the gas stream (which is now hydrogen and CO_2), the CO_2, and any other impurities are removed, leaving pure hydrogen by itself. Figure 8 shows a schematic of SMR, with a link to a video of the process included as well. In Figure 9, we show the schematic of a process where an additional carbon capture step is included.

Electrolysis ("Green" or "Clean" Hydrogen Production)

Hydrogen production using electrolysis is the cleanest method of production, and is referred as "green" hydrogen. At a high level, electrolysis simply breaks down water into hydrogen and oxygen by using electricity. There are different methods of electrolysis, with the efficiency determined by the amount of electricity used to produce the hydrogen. Figure 10 provides a diagram of the general process, while Figure 11 provides a summary of the different methods of electrolysis.

Electrolysis – Promising Technology for Clean Hydrogen

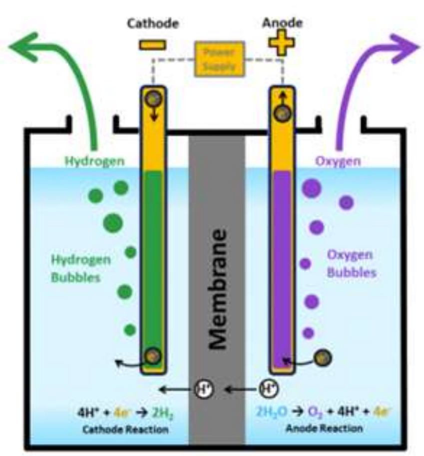


Figure 10 – Electrolysis – Promising Technology for Clean Hydrogen
Source: The US Department of Energy: Office of Energy Efficiency & Renewable Energy

Electrolysis is the method of hydrogen production that holds the most promise given that there are essentially no resulting emissions (water is the by-product of the process). But ultimately, for the economic use of electrolysis, inexpensive electricity is required, in particular, surplus renewable electricity. By contrast, if electricity generated by a natural gas power station is used for electrolysis, the overall efficiency is reduced as energy is wasted in first having to convert natural gas to electricity and then using electricity to produce hydrogen. This method of electrolysis cannot compete with SMR in terms of efficiency, as in SMR, hydrogen is directly converted from natural gas.

Types of Electrolysis – SOE Holds Promise but Still in Experimental Stage

	Temperature (°C)	Electrolyte	Plant Size		Electrical Efficiency (%)	Purity H_2 (%)	Capex ($US/KW)		Life Span (hrs)	Maturity Level
			(Nm³ H_2/h)	(kW)			Current	2030+		
Alkaline Electrolysis (AE)	60 - 80	Potassium hydroxide	0.25 - 760	1.8 - 5,300	65 - 82	99.5 - 99.9998	1,400	700 - 850	60,000 - 90,000	Commercially used for the last 100 years
Proton Exchange Membrane Electrolysis (PEM)	60 - 80	Solid state membrane	0.01 - 240	0.2 - 1,150	65 - 78	99.9 - 99.9999	1,800	900 - 1,500	20,000 - 60,000	Commercially used for medium/small applications (<300KW)
Anion Exchange Membrane Electrolysis (AEM)	60 - 80	Polymer membrane	0.1 - 1	0.7 - 4.5	N/A	99.4	N/A	N/A	N/A	Commercially available for limited applications
Solid Oxide Electrolysis (SOE)	700 - 800	Oxide ceramic	Experimental stage in laboratories		85% (lab)	N/A	5,600	1,000 - 2,800	~1,000	Experimental Stage

Figure 11 – Types of Electrolysis – SOE Holds Promise but Still in Experimental Stage
Source: Shell Hydrogen Study, IEA, ATB Capital Markets Inc.

Alkaline electrolysis (low temperature): This accounts for the vast majority of installed capacity worldwide. It has been in use since the 1920s, employed for the production of hydrogen for the fertilizer and chlorine industries. This method was in use particularly in countries with large hydropower resources (Canada, Egypt, India, Norway, and Zimbabwe), although per the IEA, almost all of these plants were decommissioned when natural gas and SMR became popular in the 1970s. Alkaline electrolysis typically has low upfront capital costs compared with the other electrolyser technologies due to the avoidance of precious materials (see Figure 11).

PEM Electrolyser (low temperature): Proton Exchange Membrane (PEM) electrolysis systems were first introduced in the 1960s. These use pure water as an electrolyte solution, and overcome some of the operational drawbacks of alkaline electrolytes. They are relatively small in size, making them attractive for dense urban areas. However, they need expensive electrode catalysts (platinum, iridium) and membrane materials. Their lifetime is also shorter than that of alkaline electrolysers. As such, their overall costs are higher than those of alkaline electrolysers and these are less widely deployed.

Solid Oxide Electrolysis (high temperature): This is a promising new electrolysis technology but is the least developed. It has not been commercialized but several companies are working on it. This is what **Schlumberger's** Genvia (part of its New Energy business) business will be employing. Solid Oxide Electrolysis (SOE) systems typically use ceramics as the electrolyte and have low material costs. They operate at high temperatures and have high electrical efficiency. Due to the system using steam for electrolysis, a heat source is needed, with nuclear power plants, solar thermal, or geothermal all capable of filling this role. Unlike alkaline and PEM electrolysers, it is possible to operate SOE systems in reverse mode as a fuel cell, that is, convert hydrogen back into electricity. This provides the system a great deal of flexibility. One main drawback of the system is the degradation of materials resulting from high operating temperatures.

Strong Growth Expected for Electrolyser Projects

The IEA estimates that 126 MW/year of electrolyser capacity should be operational in 2020, and that figure should increase to 1,434MW/year in 2023 (see Figure 12). The EU forecasts investment of US$30-US$50bn through 2030 in electrolysers, and about US$260-US$340bn to scale up and directly connect 80-120GW of solar and wind energy production capacity to provide the electricity for the electrolysers.

Global Electrolysis Capacity Becoming Operational Annually Based on Announced Projects

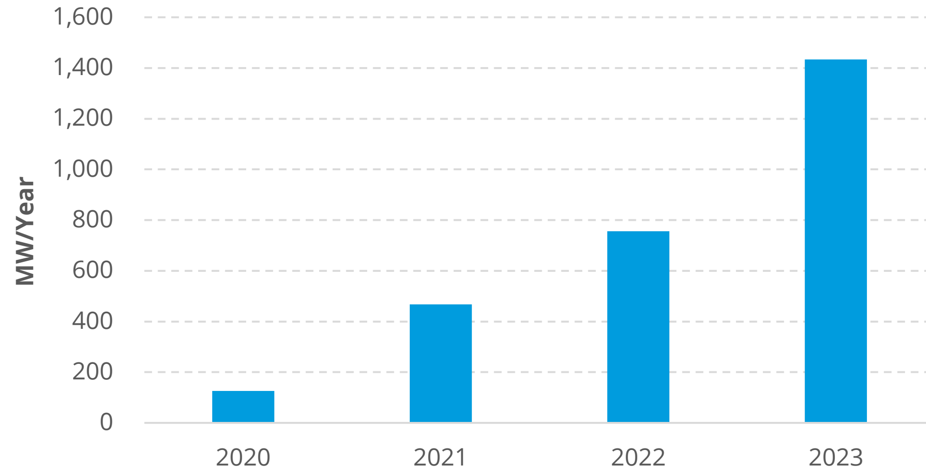


Figure 12 – Global Electrolysis Capacity Becoming Operational Annually Based on Announced Projects
Source: IEA, ATB Capital Markets Inc.

What is the Cost Structure of Hydrogen Production?

In producing hydrogen from natural gas, the cost of natural gas is the main driver for the variance in production costs across geographies. It is no surprise that regions with low natural gas prices such as Canada, the Middle East, Russia, and the United States enjoy a production cost advantage, while Europe and China, who import natural gas, have high production costs.

Capital costs for the plants increase with CCUS. The IEA estimates that in 2018, SMR with CCUS could cost about US$900-US$1,600/kWH$_2$ (per kilowatt hydrogen), while without CCUS, the cost would be US$500-US$900/kWH$_2$.

Per the IEA, adding CCUS to SMR plants can lead to a ~50% increase in capex on average and ~10% increase for fuel, while also leading to increases in OPEX as a result of CO_2 transport and storage costs. However, in some low-cost areas, the cost of hydrogen from SMR with CCUS are in the range of US$1.4-US$1.5/kgH$_2$, making it one of the lowest cost low-carbon hydrogen production methods.

Cost of Hydrogen Production Throughout the World

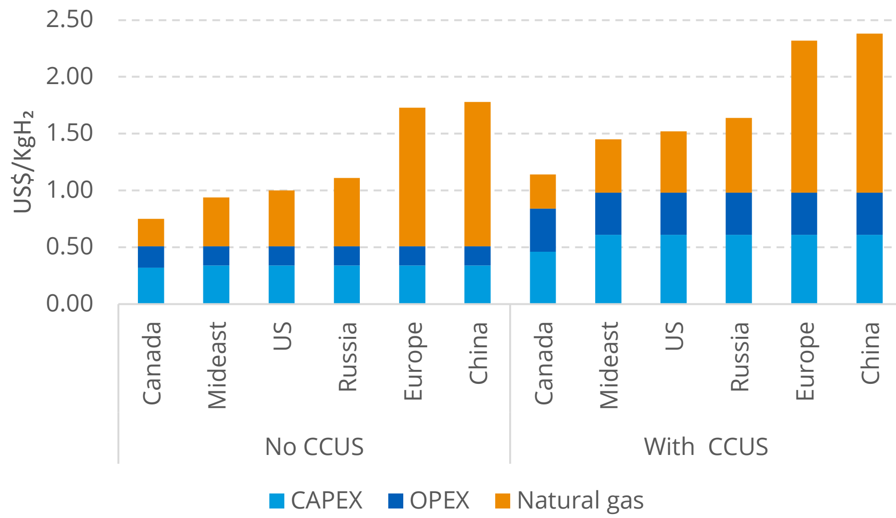


Figure 13 – Cost of Hydrogen Production Throughout the World
Source: IEA, The Transition Accelerator, ATB Capital Markets Inc.

Hydrogen Production Costs Under the Various Manufacturing Processes

The IEA's analysis and forecast show that until 2030, the cost advantage of fossil fuels in the manufacture of hydrogen will continue, even when investments into CCUS systems are incorporated into the cost base. Low-carbon hydrogen produced from CCUS or renewable electricity is in most cases more expensive than hydrogen that is generated from fossil fuels without CCUS. It is estimated that technological innovations and economies of scale may bring down the cost of electrolysis beyond 2030, making it more competitive (see Figure 15).

Hydrogen produced from natural gas typically costs around US$1.5-US$3.0/kgH$_2$, while the cost increases to US$2.5-US$6.0/kgH$_2$ when renewable electricity (solar or onshore wind) is used as an energy input. By incorporating CCUS into the hydrogen production process, capital costs go up.

Cost Ranges of Hydrogen Production by Source

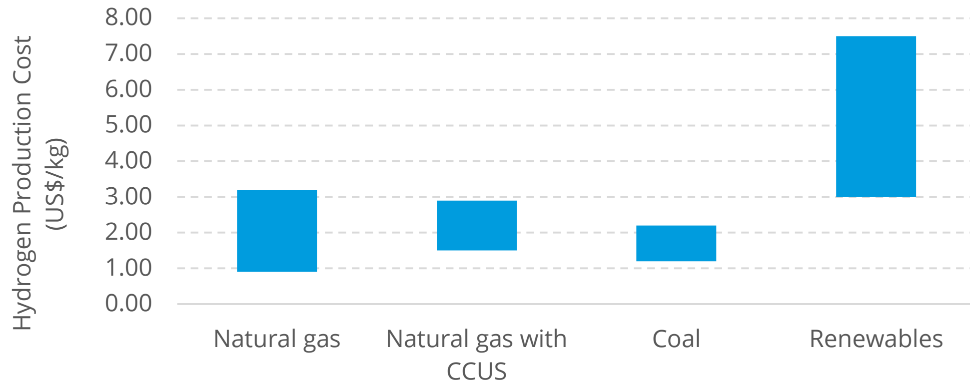
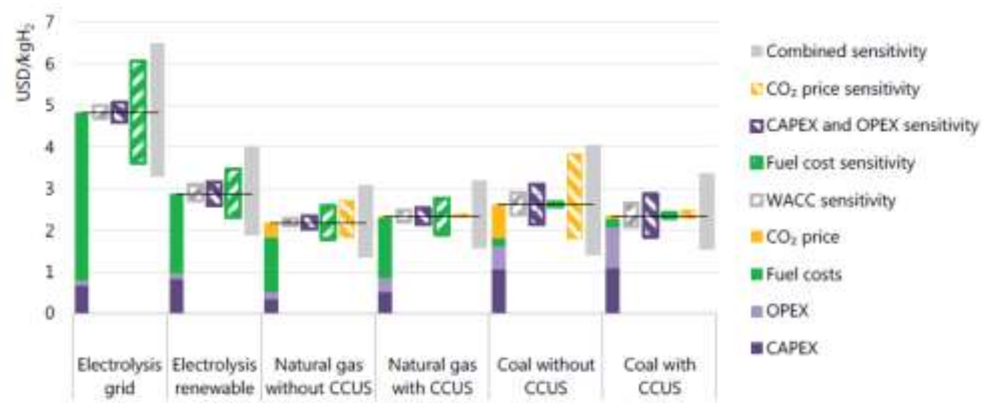


Figure 14 – Cost Ranges of Hydrogen Production by Source
Source: IEA, ATB Capital Markets Inc.

Hydrogen Production Costs for Different Technology Options, 2030



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4 000 full load hours at best locations; sensitivity analysis based on +/-30% variation in CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO_2 price of USD 40/tCO_2 to USD 0/tCO_2 and USD 100/tCO_2. More information on the underlying assumptions is available at www.iea.org/hydrogen2019

Figure 15 – Hydrogen Production Costs for Different Technology Options, 2030
Source: IEA

Blue and Green Hydrogen Can Be More Competitive with Grey Hydrogen with Carbon Taxes

In the Middle East, to make hydrogen from CCUS competitive with unabated fossil fuel hydrogen production, a CO_2 tax of around US$50/t$CO_2$ is required. Taxes per ton of CO_2 equivalent vary among the initiatives adopted by the various countries, which range from US$1 to US$139.

The Canadian government implemented a nation-wide carbon price in 2019 at about C$20/T, which increases each year by C$10/T, reaching C$50/T by 2022. The Canadian government is now proposing to increase the carbon price by C$15/T per year starting in 2023 and reach C$170/T of carbon pollution in 2030. Figure 18 shows the nominal carbon taxes in different parts of the world as of February 1, 2019.

Very few SMR plants employ CCUS, which can reduce carbon emissions by nearly 90%. The IEA estimates that less than 0.5 mmT H_2/year of SMR capacity employs CCUS, or under 1% of hydrogen produced from natural gas has CCUS facilities implemented. A total of six CCUS facilities are in operations, but an additional 20 are planned.

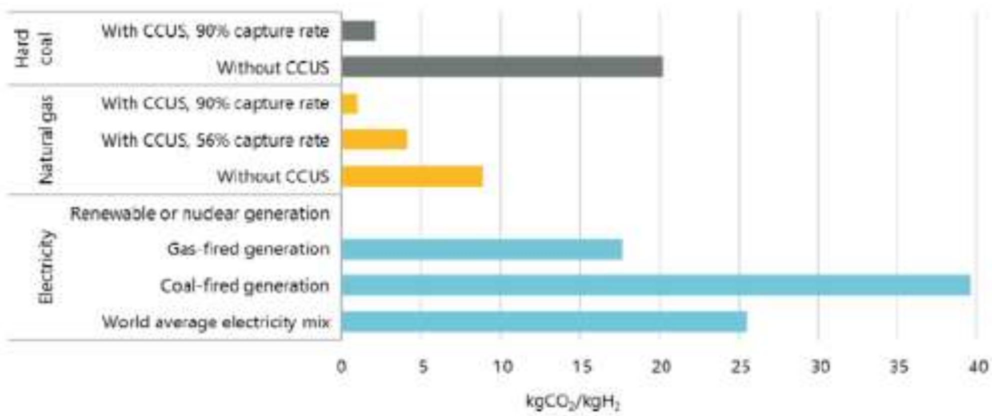
Removing carbon during the SMR production is a two-step process. The first step typically costs about US$53/T CO_2 for merchant plants (standalone plants not integrated with ammonia/methanol production) and removes about 60% of CO_2 from synthetic gas. Including the second step, carbon emissions can be lowered by 90%, but it also increases costs to around US$80/T CO_2 in merchant plants and US$90-US$115/T CO_2 in integrated ammonia/urea and methanol plants, which have more diluted CO_2 streams.

Using the autothermal reforming (ATR) method for production of hydrogen, emissions capture cost can be lower than SMR. During the ATR process, the required heat is produced within the reformer itself, which means that all CO_2 is produced inside the reactor, leading to higher CO_2 recovery rates as emissions are more concentrated than those in the SMR process. The IEA states that several studies have shown that CO_2 capture rates in excess of 90% can be achieved with the ATR process.

The competitiveness of low-carbon hydrogen produced from natural gas with CCUS or from renewable electricity mainly depends on the price of natural gas and electricity. At low gas prices, renewable electricity must reach a US$10/MWh for electrolysis to become cost competitive with natural gas with CCUS.

At a gas price of US$11/MMBtu, renewable electricity would be competitive at up to around US$30-US$45/MWh. The IEA estimates depending on local gas prices, electricity at US$10-US$40/MWh and at full load hours of around 4,000 hours are needed for water electrolysis to become cost competitive with natural gas with CCUS.

CO_2 Intensity of Hydrogen Production



Notes: Capture rate of 56% for natural gas with CCUS refers to capturing only the feedstock-related CO_2, whereas for 90% capture rate CCUS is also applied to the fuel-related CO_2 emissions; CO_2 intensities of electricity taking into account only direct CO_2 emissions at the electricity generation plant: world average 2017 = 491 gCO_2/kWh, gas-fired power generation = 336 gCO_2/kWh, coal-fired power generation = 760 gCO_2/kWh. The CO_2 intensities for hydrogen also do not include CO_2 emissions linked to the transmission and distribution of hydrogen to the end users, e.g. from grid electricity used for hydrogen compression. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Figure 16 – CO_2 Intensity of Hydrogen Production
Source: IEA

Comparison of Hydrogen Production Costs from Electricity and Natural Gas with CCUS

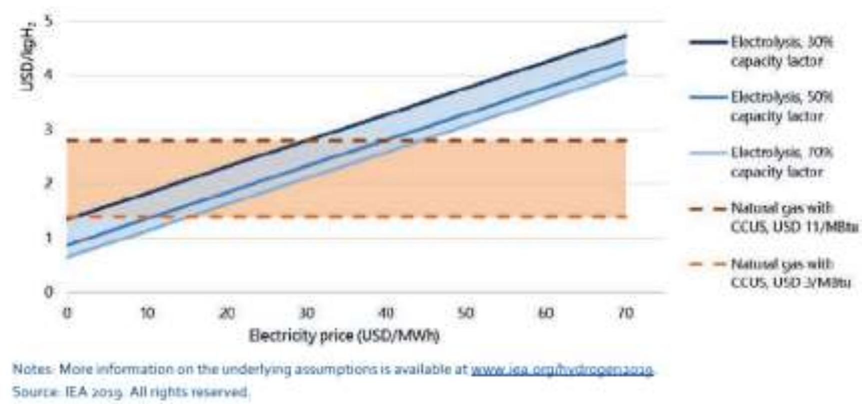


Figure 17 – Comparison of Hydrogen Production Costs from Electricity and Natural Gas with CCUS
Source: IEA

Nominal Prices Per Ton of CO_2 Emissions

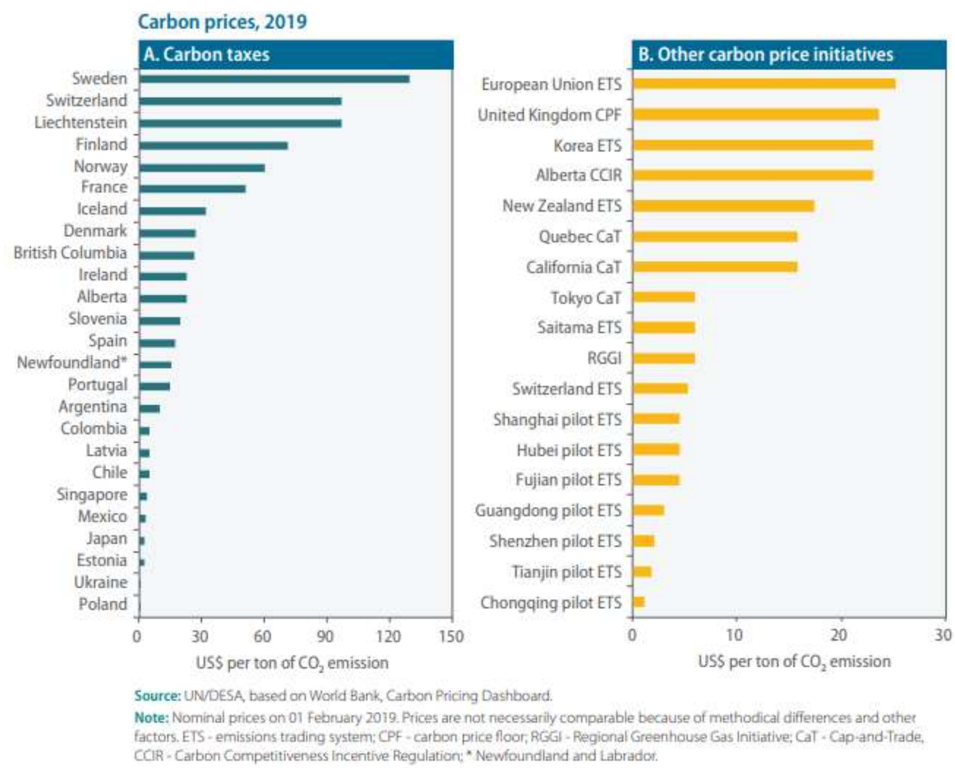


Figure 18 – Nominal Prices per Ton of CO_2 Emissions
Note: Data as of February 1, 2019. Canada implemented a C$20/T Carbon price in 2019, which increases by C$10/T each year to C$50/T by 2022. The federal government is now proposing C$15/T hikes starting 2023, reaching C$170/T by 2030.
Source: United Nations Department of Economic and Social Affairs

Canada Competitively Well Positioned for Hydrogen

Canada is one of the top 10 producers of hydrogen in the world, and is competitively well positioned as demand for hydrogen increases in the coming decades. The Government of Canada introduced its hydrogen strategy on December 16, 2020, which follows the climate plan ("A Healthy Environment and A Healthy Economy") it introduced on December 11, 2020.

In "A Healthy Environment and A Healthy Economy", the Government of Canada stated that "*Hydrogen is one of Canada's most exciting economic transformation opportunities to help businesses grow, dramatically reduce emissions in the industrial sector, and enable a new Canadian competitive advantage in a low-carbon economy. This strategy will be an ambitious framework that will cement this clean fuel as a key part of the country's path to net-zero emissions by 2050. This domestic growth will also position Canada to become a world-leading supplier of hydrogen and hydrogen-technologies".*

The hydrogen strategy announced on December 16, 2020 has the following key goals for 2050: 1) Transform Canada into one of top three global clean hydrogen producers; 2) Grow hydrogen's share in the energy mix to 30%, up from 6% in 2030; 3) Establish a supply base of low carbon intensity hydrogen with delivered prices of C$1.50/Kg to C$3.50/Kg (US$1.15/Kg to US$2.75/Kg); 4) Promote new industries enabled by a low-cost hydrogen supply network, and make hydrogen competitive for the export market; 5) Generate in excess of C$50bn in direct revenues from the hydrogen sector targeting the domestic market; and 6) Reduce carbon emissions by up to 190mm T/year.

A recent study by The Transition Accelerator, "*Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen*" – which was released in September 2020 – outlined why and how Canada could become an important global player in hydrogen production, and estimated the wholesale market potential of hydrogen for Canada at up to ~US$75bn/year (~C$100bn/year). Hydrogen already plays a big role in Canada, including in refining, production of ammonia fertilizer and other materials/chemicals, the conversion of bitumen into synthetic crude oil, and other various processes.

Hydrogen's Share in Canadian Energy Mix Could Substantially Increase by 2050

Canada was one of the countries to formally commit to net-zero CO_2 emissions by 2050, and accomplishing this goal will require significant investment in low-carbon energy and power sources, such as "blue" hydrogen. According to The Transition Accelerator, gasoline, diesel, natural gas, and other fossil fuel energy carriers – which make up ~70% of the secondary energy demand in Canada – will need to be replaced by zero-emission carriers, such as hydrogen.

The Transition Accelerator Estimates That Hydrogen Could Be the Energy Carrier for ~27% of Primary Energy Demand in Canada by 2050

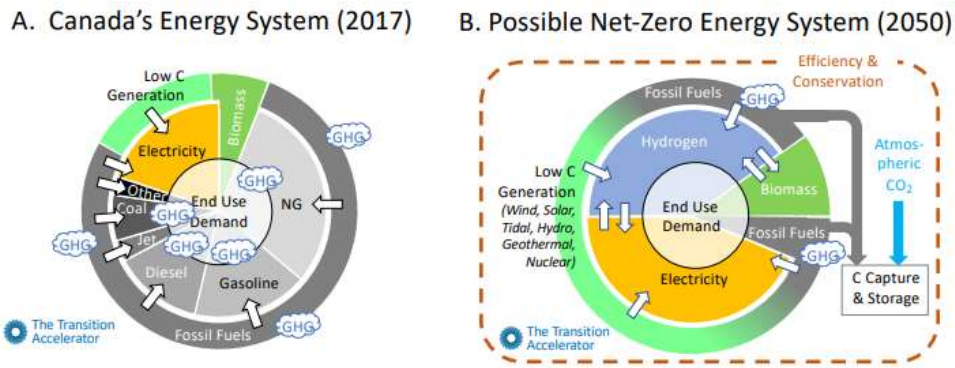


Figure 19 – The Transition Accelerator Estimates That Hydrogen Could Be the Energy Carrier for ~27% of Primary Energy Demand in Canada by 2050
Source: The Transition Accelerator

Accordingly, The Transition Accelerator projects that hydrogen would be the energy carrier for about 27% of Canada's primary energy demand by 2050 (the Government of Canada established 30% as its official goal on December 16, 2020). Canada produces about 8,200 tonnes of hydrogen per day (3mm tonnes per year), and getting to the ~27% figure of primary energy demand would require a roughly eight-fold increase to 64,000 T/day (or 23.4mm T/year), with the majority of this production likely still coming from natural gas reforming, which will need CCUS in order to meet the net-zero climate goals.

Alberta Identifies Hydrogen as a Key Growth Area

In October 2020, the province of Alberta released its Natural Gas Vision and Strategy, and highlighted as one of its goals, large-scale hydrogen production with CCUS and deployment of hydrogen in various commercial applications across the province by 2030.

It has identified export of clean hydrogen and hydrogen-derived products across Canada, North America, and globally by 2040 as a key strategic goal.

Canada's Competitive Advantage in Producing Hydrogen

Canada offers several key advantages in producing hydrogen, particularly the blue variety:

1. **Abundant and inexpensive natural gas:** In the near to medium term, the vast majority of hydrogen production will likely still come from fossil fuels, primarily natural gas. Canada – and more specifically, the WCSB – has vast reserves of natural gas, which according to the BP Statistical Review of World Energy, totaled 70.1 tcf, or ~1% of the world total. In addition, natural gas is relatively inexpensive compared with other parts of the world (and compared with OECD countries who will likely drive hydrogen initiatives), which offers another economic advantage (see Figure 20).

Canada Has a Clear Competitive Advantage with Natural Gas Prices

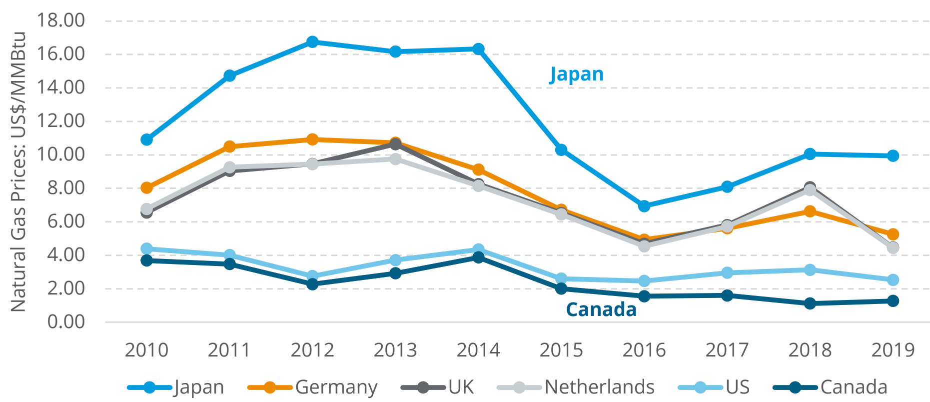


Figure 20 – Canada Has a Clear Competitive Advantage with Natural Gas Prices
Note: Japan represents LNG prices (US$/MMBtu).
Source: BP Statistical Review of World Energy, ATB Capital Markets Inc.

2. **CO_2 storage capabilities (in the context of CCUS):** Although countries and companies are now beginning to initiate "green" hydrogen projects, the vast majority of hydrogen production (and likely for the near to medium term) will likely come from fossil fuels, namely natural gas. In order to produce "blue hydrogen," the associated CO_2 will need to be CCUS. In the case of Canada (and the WCSB), if the associated CO_2 is not used for industrial purposes, an effective solution is storing the CO_2 in depleted oil and gas reservoirs. Alberta has committed $1.24bn through 2025 for two carbon capture and storage projects (the Quest project and the Alberta Carbon Trunk Line project), which will help reduce the CO_2 emissions

from the oil sands and fertilizer sectors (GHG emissions reduction of ~2.76 million tonnes each year, which is equivalent to the yearly emissions of 600,000 vehicles).

3. **Technical/industry expertise and supporting infrastructure:** Given the industrial nature of hydrogen production and the country's rich history with oil and gas production, Canada has the technical expertise, industry, and infrastructure to effectively scale its hydrogen production.

Estimated Costs of Green and Blue Hydrogen Around the World – Canada Has Among the Lowest Costs

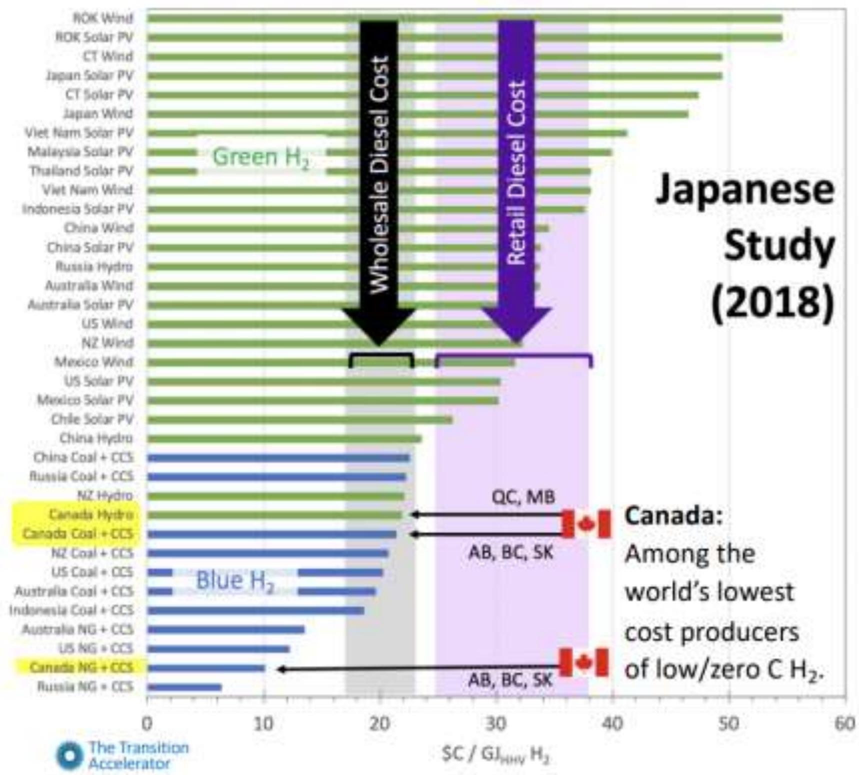


Figure 21 – Estimated Costs of Green and Blue Hydrogen Around the World – Canada Has Among the Lowest Costs
Source: The Transition Accelerator

Hydrogen Cost to Be Competitive in Canada

Fuel or Electricity Market		Wholsale Price			Retail Prices			Target H_2 Retail Price	
		Value	Units	$\$/GJ_{hhv}$	Value	Units	$\$/GJ_{hhv}$	$\$/GJ_{hhv}$	$\$/kg\ H_2$
Transportation Fuels	Low	$0.50	$/L	**$14**	$0.90	$/L	**$24**	**$25**	**$3.50**
(Gasoline, diesel, kerosene)	High	$0.90	$/L	**$24**	$1.50	$/L	**$41**	**$35**	**$5.00**
Thermo-chemical Fuels	Low	$1.00	$/GJ	**$1**	$5.00	$/GJ	**$5**	**$7**	**$1.00**
(Natural gas, coal, biomass)	High	$10.00	$/GJ	**$10**	$20.00	$/GJ	**$20**	**$20**	**$2.80**
Electricity	Low	$20.00	$/MWh	**$6**	$80.00	$/MWh	**$22**	-	-
(all sources)	High	$150.00	$/MWh	**$42**	$300.00	$/MWh	**$83**	-	-

Figure 22 – Hydrogen Cost to Be Competitive in Canada
Note: Hydrogen needs to be in the $3.50-$5.00 C$/kg range to be competitive.
Source: The Transition Accelerator.

Canada's Global Competitive Positioning in Natural Gas, Wind, and Solar

Figure 23 illustrates the economic viability of producing green hydrogen from solar and onshore wind technologies in various regions globally over the long term. Despite some regions screening better than Canada on a USD/kgH2 basis, the country has attractive hydroelectric generation (60% of power mix) and continues to develop renewable generation (wind and solar) in targeted regions that could support green hydrogen production. We also note the country's abundance of low-cost natural gas reserves that could lend support to advantaged blue hydrogen positioning.

Hydrogen Costs from Hybrid Solar PV and Onshore Wind Systems in the Long Term

Figure 23 – Hydrogen Costs from Hybrid Solar PV and Onshore Wind Systems in the Long Term
Source: IEA

Hydrogen Transmission and Distribution

To use hydrogen commercially as an energy carrier and to exploit its ability to be stored for long periods of time and to be transported across long distances, it is extremely important to ascertain the cost of hydrogen distribution and storage.

About 85% of hydrogen produced is consumed on-site where it is produced and only about 15% is transported via trucks or pipelines**.** Clearly to gain market share, hydrogen needs to move economically over longer distances.

Hydrogen Storage Options

Hydrogen is commonly stored as a gas or liquid in tanks for small-scale mobile and stationary applications, but for large-scale commercial operations, other techniques are needed.

Geological storage: Geological storage could offer a large-scale commercial solution. Salt caverns, depleted natural gas or oil reservoirs, and aquifers are all possible options for large-scale and long-term hydrogen storage. These are likely to be the lowest cost options for hydrogen storage.

Salt caverns can cost less that than US\$0.6/kgH_2 and have an efficiency of 98%. The United States has the largest salt cavern hydrogen storage system in operation, which can store 30 days of hydrogen production from a nearby steam methane reformer (~10-20 thousand T of H_2). Hydrogen can also be stored in depleted oil and gas reservoirs, which are typically larger than salt caverns, but owing to their higher permeability, they can cause contamination, which has to be removed before hydrogen can be used for fuel cells. The economic feasibility of storing hydrogen in depleted reservoirs and aquifers has not been proven as yet.

Storage tanks: Hydrogen has low energy density, nearly 15% of that of gasoline, so storing the equivalent amount of energy with compressed hydrogen (700 bar pressure) at a vehicle refueling station would require nearly 7.0x the space of a gasoline station. Nonetheless, tanks storing compressed or liquefied hydrogen have high discharge rates with efficiencies of 99%, making them appropriate for small-scale applications.

Ammonia has greater energy density, which reduces the size of tanks that would be required, but if pure hydrogen is needed as an end product, losses related to conversions/reconversions can make the process inefficient.

However, when it comes to vehicles, compressed hydrogen has higher energy density than lithium-ion batteries, and so it can create a greater range in cars or trucks than may be possible with BEVs.

Research is continuing to find ways to reduce the size of the tanks, by increasing storage pressure for use in densely populated areas.

Hydrogen Transmission and Blending

Hydrogen is expensive to transport over long distances owing to its low energy density. Blending with natural gas in the existing extensive natural gas transmission network is one low-cost way of hydrogen transmission. Other options include compression, liquefaction, or conversion into larger molecules for transportation.

Blending with natural gas for transportation: Blending hydrogen with natural gas through an existing natural gas transmission system is already happening in some countries such as France. Blending hydrogen in a low-pressure distribution system, which is typically employed for domestic use, can be accomplished without any material changes to the network (see Figure 24). However, blending hydrogen in a high-pressure natural gas transmission system may require system modification, so as to prevent leakage.

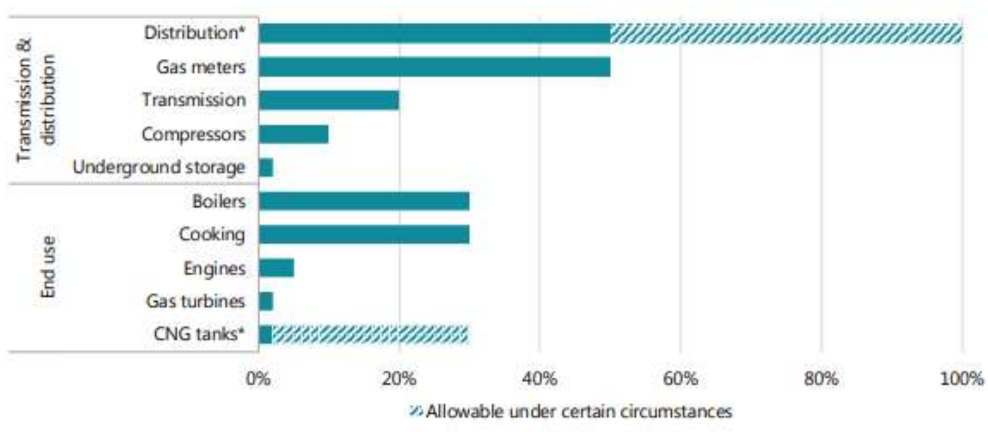
Key issues that need to be considered while blending hydrogen with natural gas are as follows.

- The energy density of hydrogen is one-third of natural gas, and per the IEA, a 3% hydrogen blend in a natural gas transmission line would reduce the energy transmitted by about 2%, meaning that end users would need to increase the volume of gas consumed to meet the same energy needs.
- Hydrogen burns faster than methane, increasing the risk of flames spreading. Also, the hydrogen flame is mostly invisible, which would necessitate a change in flame detectors.
- As the heat content and the flame quality of a hydrogen/natural gas blend is different, industrial users may need to alter their processes in some applications. For example, chemical producers may have to alter their processes, while gas turbines may have to alter their control systems and seals.
- Different systems connected to the gas transmission line will have different tolerance for hydrogen blending, and in many cases the lowest tolerance system may determine the overall hydrogen-natural gas blend ratio.

Typically, CNG tanks, turbines, and engines have the lowest tolerance to hydrogen blending as is shown in Figure 24. **Baker Hughes Company** has produced turbines that can run on hydrogen blend. On July 20, BKR-N announced that it had completed testing of the world's first "hybrid" hydrogen turbine, named NovaLT12 gas turbine. This turbine will be installed by 2021 at Snam's compressor station at Istrana, Italy. The gas turbine will compress and move hydrogen blend through Snam's transmission network of pipelines, while also use the same fuel to power itself. Seventy percent of Snam's pipelines are hydrogen ready.

Per BKR-N, by blending 10% hydrogen into the annual gas capacity transported by Snam, about 7bcm (0.7 bcf/d) of hydrogen could be introduced into the network each year. This amounts to a reduction of 5mm tons of CO_2 emissions per BKR-N.

Tolerance of Selected Existing Elements of the Natural Gas Network to Hydrogen Blend Shares by Volume



* The higher tolerance of CNG tanks is for Type IV tanks (although the tolerance for CNG tanks may be as low as 0.1% depending on the humidity of the natural gas (United Nations, 2014); the higher tolerance for distribution would require specific safety assessments.

Note: CNG = compressed natural gas.

Figure 24 – Tolerance of Selected Existing Elements of the Natural Gas Network to Hydrogen Blend Shares by Volume
Source: IEA

About 5,000km of pipelines around the world are dedicated to hydrogen transmission, which compares with 3mm km dedicated for natural gas transmission. These pipelines are mostly operated by industrial hydrogen producers. Per Royal Dutch Shell, the United States has 2,600km of hydrogen pipelines, Belgium has 600km, and Germany around 400km.

Existing natural gas pipelines could be converted to hydrogen pipelines in the future, but some modifications will need to be made. Ammonia can be transported via pipeline as well, and new pipelines for ammonia could be cheaper than those for hydrogen. About 4,830km of ammonia pipelines are present in the United States and about 2,400km of long pipeline runs from Russia to fertilizer and chemical plants in Eastern Europe.

Liquid organic hydrogen carriers (LOHCs) is another method for transporting hydrogen for long distances, as well as for storage, with transportation being similar to that of crude oil and diesel.

Shipping: Per the IEA, there are no ships that can transport pure hydrogen, although the industry is working on a solution. Hydrogen could be moved the same way as liquefied natural gas (LNG) is moved, but like LNG transportation, about 0.2% of the cargo may be consumed per day. Another method would be transporting as LOHCs, which makes crude oil or products tankers a viable option. This is the easiest way to transport but the cost of conversion and reconversion to hydrogen needs to be considered. Hydrogen could also be transported as ammonia, which typically relies on chemical and semi-refrigerated liquefied petroleum gas (LPG) tankers. These are mostly traveling from the Arabian Gulf and Trinidad and Tobago to Europe and North America.

Comparing the Cost of Various Modes of Hydrogen Transportation

Transporting hydrogen in gaseous form via pipeline is generally costlier than transporting hydrogen in liquefied form via ships as ammonia or as LOHCs, but if transported in any form other than gaseous form, the cost of conversion and reconversion has to be considered.

The IEA estimates the cost of transporting hydrogen in gaseous form via 1,500km of pipeline to be US$1 kg/$H_2$. It is cheaper to transport via pipeline as ammonia, but the cost of conversion is US$1 kg/$H_2$, which when added, makes the total cost of transmitting ammonia across 1,500 miles via pipeline equal to $1.5 kg/$H_2$. Nonetheless, the conversion cost benefits disappear when hydrogen is transmitted 2,500km, where both methods would cost roughly US$2 kg/$H_2$.

Cost Comparison of Different Modes of Hydrogen Storage and Transmission

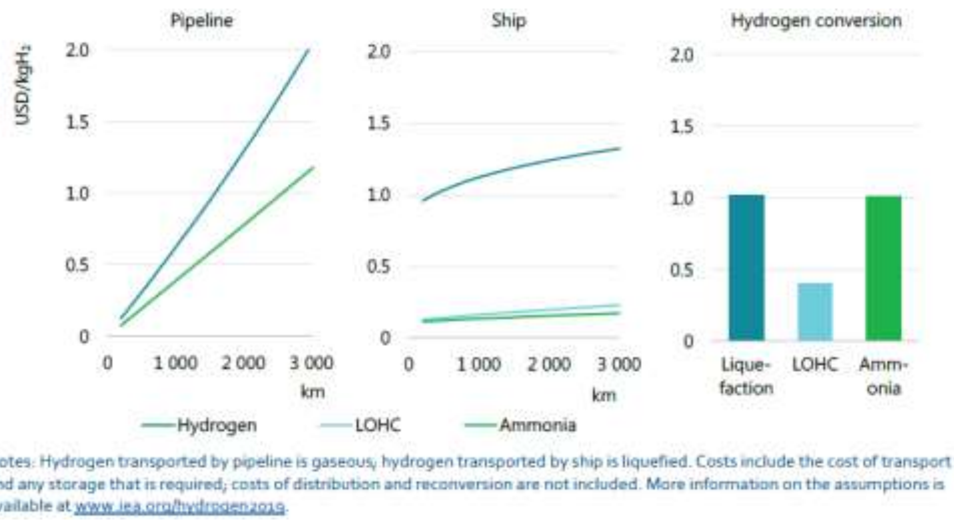


Figure 25 – Cost Comparison of Different Modes of Hydrogen Storage and Transmission
Source: IEA

In Figure 26, we highlight the IEA's cost comparison data for delivery of hydrogen for industrial sector by pipeline or by ship in 2030, using different transmission systems. Admittedly, there will be several other factors at play as well, such as the infrastructure available in the exporting and importing countries, transmission and distribution distances, etc.

Full Cost of Hydrogen Delivery to the Industrial Sector by Pipeline or by Ship in 2030 for Different Transmission Distances

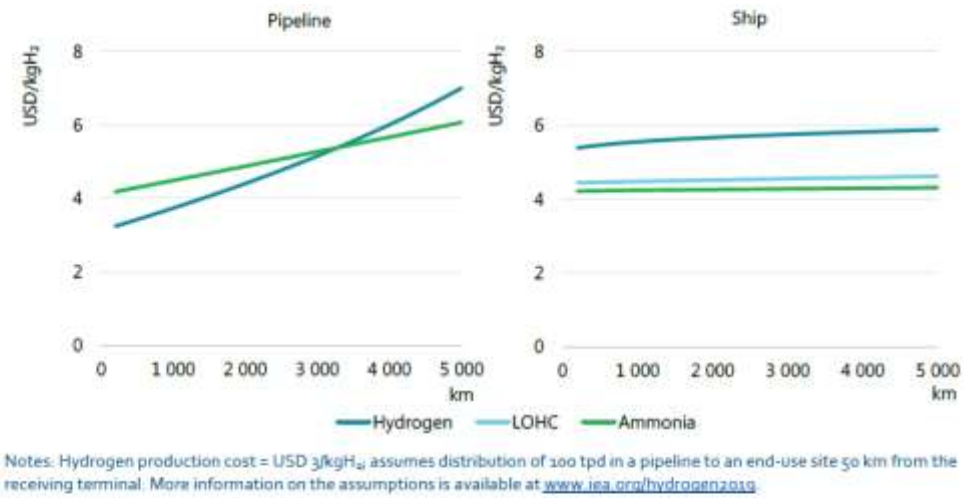


Figure 26 – Full Cost of Hydrogen Delivery to the Industrial Sector by Pipeline or by Ship in 2030 for Different Transmission Distances
Source: IEA

Comparison of Delivered Hydrogen Costs for Domestically Produced and Imported Hydrogen for Selected Trade Routes in 2030

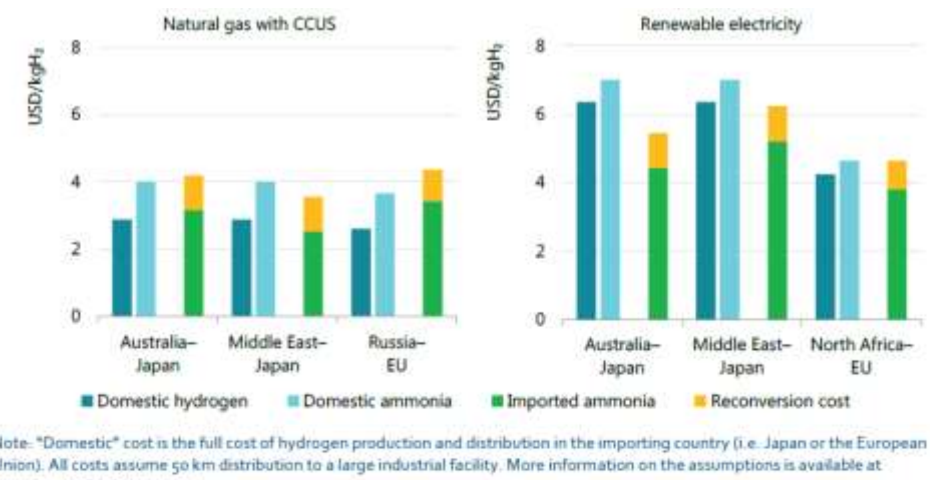


Figure 27 – Comparison of Delivered Hydrogen Costs for Domestically Produced and Imported Hydrogen for Selected Trade Routes in 2030
Source: IEA

In the case shown in Figure 26, IEA analysis shows that hydrogen gas is the cheaper option for distances less than ~3,500km for inland transmission and distribution, and beyond that distance, it is more economical to transport as ammonia. When comparing transport using pipelines and ships, transmission and distribution of hydrogen by pipeline is cheaper for distances less than 1,500km. When distance involved is more than 1,500km, LOHC and ammonia transport by ship are the cheaper options. While LOHC and ammonia have relatively similar costs, these are better than transporting liquefied hydrogen via ships.

Despite high transmission costs in some regions of the world, it may still be cheaper to import hydrogen than to use local hydrogen. The IEA estimates that for Japan's industrial sector in 2030, importing electrolytic hydrogen from Australia (around US$5.5/kg$H_2$) may be cheaper than domestic production (US$6.5/kg$H_2$).

Estimating Hydrogen Demand Going Forward

From 2020e-2030e, demand for hydrogen is forecast to grow at the global GDP growth rate, as the key driver of growth should be industrial demand, primarily from the chemical and oil refining industries, with demand for hydrogen as a transportation fuel growing over the 2025e-2030e time period, but from a very small base. Post 2030, the IEA projects that the demand for hydrogen increases from a 2% CAGR during the 2020e-2030e decade to a 4% CAGR in the 2030e-2040e decade, with the growth rate dependent on how quickly the cost of "green" hydrogen becomes competitive with "grey" and "blue" hydrogen, and the pace at which the cost of FCEVs becomes competitive with ICEs and BEVs. Demand is projected to accelerate even further in the 2040e-2050e decade, with various organizations projecting growth CAGR of 3% to 18%, depending primarily on how aggressively governments around the world target carbon emissions.

The book-ends for growth projections over the 2040e-2050e time period are provided by Bloomberg NEF, which projects 3% growth CAGR if government policies are weak with respect to decarbonization; on the other hand, should global policies be highly aggressive, demand for hydrogen could increase at an 18% CAGR. Under the more optimistic scenario, hydrogen as a replacement fuel sharply increases, and it is used more aggressively in heating/cooling of buildings, in the transportation network, and as a general source of energy (see Figure 28).

The IRENA expects a 4% growth CAGR, while the IEA projects 8%/year growth during the 2040e-2050e decade. The IEA projects hydrogen demand to increase from 70mm T in 2019 to 88mm T in 2030e, 137mm T in 2040e, and 287mm T in 2050e. The Hydrogen Council though projects 15% CAGR during the 2040e-2050e decade. These are all highly impressive growth projections.

Hydrogen Demand CAGR Projected at 2% for 2020-2030, but Accelerate Beyond

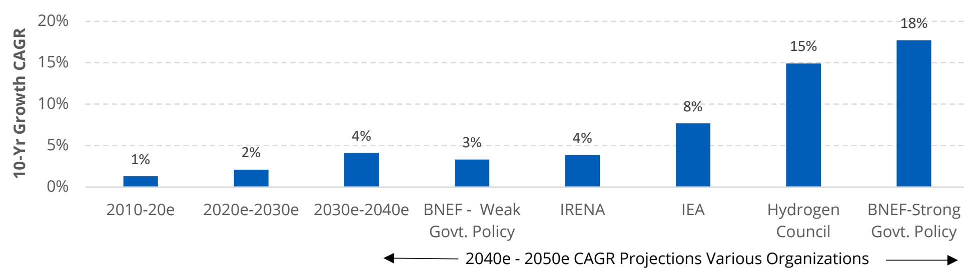


Figure 28 – Hydrogen Demand CAGR Projected at 2% for 2020-2040, but Accelerate Beyond
Source: Baker Hughes Company, IEA, Bloomberg NEF, International Renewable Energy Agency (IRENA), Hydrogen Council, ATB Capital Markets Inc.

Current State of the Hydrogen Market

The current demand for "pure" hydrogen is about 70mm tonnes, with pure meaning that it is used in applications where only small levels of additives and contaminants are tolerated. The main use of this hydrogen is in refining and ammonia production (used in the manufacture of fertilizers). An additional 45mm T of demand is for hydrogen as part of a mixture of gases, such as synthesis gas, fuel, or feedstock. A lot of this hydrogen is produced as "by-product" gas.

Thirty-three percent of hydrogen produced is used in oil refining, about 27% in ammonia production, 11% in methanol production, and about 3% for steel production via the direct reduction of iron ore. These industries are the four major consumers of hydrogen (see Figure 29).

Current Consumers of Hydrogen Demand

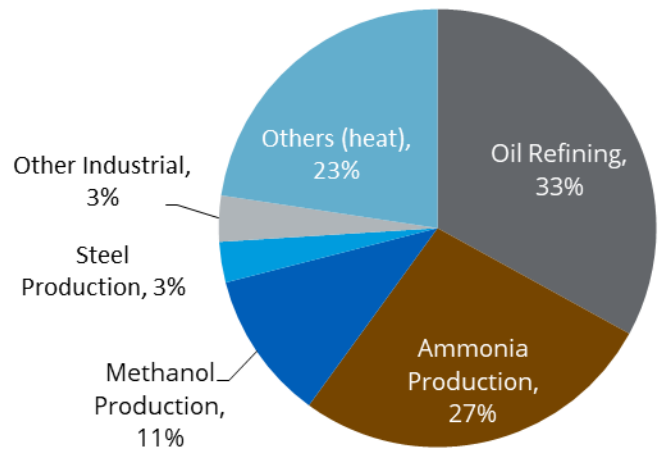


Figure 29 – Current Consumers of Hydrogen Demand
Source: IEA, ATB Capital Markets Inc.

Oil refining: Hydrogen is used primarily to remove impurities such as sulfur from crude oil (hydrotreatment) and to upgrade the heavier oils (hydrocracking). Hydrogen is also being used in small volumes in oil sands and biofuels. Hydrogen demand in the sector will directly be linked with demand for oil products. Most of the hydrogen for the sector comes from natural gas and coal, with the key opportunity for companies such as FTI-N and BKR-N being developing CCUS to reduce the carbon footprint of the hydrogen input.

Introducing CCUS adds about US$0.25-US$0.50/bbl to costs for refiners, which is above the carbon price (penalty) levels, which range between US$0 and US$0.1/bbl. This means that the refiners have an incentive to pay the carbon tax rather than invest in the capture and storage of CO_2. The IEA estimates that a $50/T CO_2 cost would make refiners economically incentivized to pursue CCUS.

Hydrogen Production Costs from Natural Gas With and Without CCUS by Region Under Different Carbon Prices, 2030

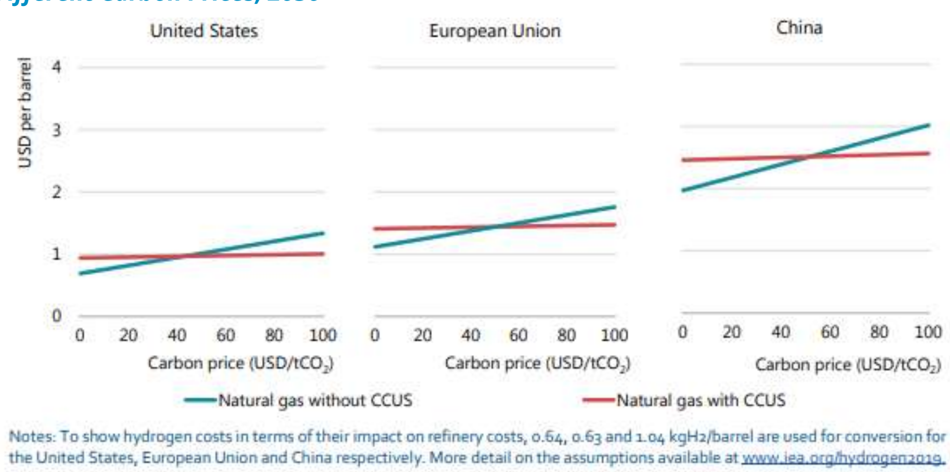


Figure 30 – Hydrogen Production Costs from Natural Gas with and Without CCUS by Region Under Different Carbon Prices, 2030
Source: IEA

Most refineries around the world use natural gas as a hydrogen source and produce hydrogen employing SMR (in China, coal is often used) but lack CCUS. We want to highlight the Pernis refinery in Rotterdam as it has invested in CCUS.

The IEA expects demand for hydrogen in oil refining to decline in the coming decades, which fits in with its view that demand for oil should start to peak at the latter part of this decade, and then decline post 2030.

IEA Expects Demand for Hydrogen in Oil Refining to Decline in the Coming Decades

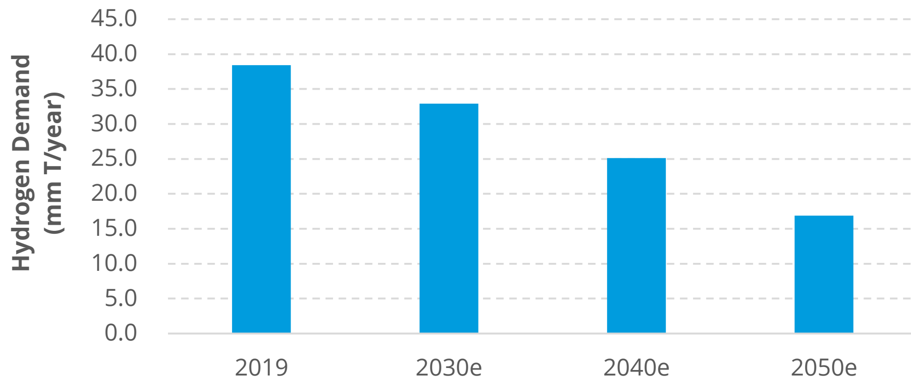


Figure 31 – IEA Expects Demand for Hydrogen in Oil Refining to Decline in the Coming Decades
Source: IEA, ATB Capital Markets Inc.

Chemical production: The chemical sector is a big user of hydrogen, with ammonia (27%) and methanol (11%) production the major users of hydrogen. Hydrogen is also used in other small-scale operations. Demand for ammonia and methanol could increase above historical rates should their use as a clean source of energy increase. The key business opportunity for the under coverage energy services companies and other E&C companies is retrofitting existing plants with CCUS to manufacture low-carbon hydrogen for ammonia and methanol production (urea and methanol will still require a source of carbon though).

More than 31mm TH_2/year of hydrogen is used as feedstock to produce ammonia, while 12mm TH_2/year is used to produce methanol. An additional 2mm TH_2/year is used to produce other products such as hydrogen peroxide mostly from hydrogen generated as a by-product within the sector.

The IEA expects demand for hydrogen for primary chemical production to increase from 44mm T/year today to 57mm T/year by 2030, with demand for ammonia increasing by 1.7%/year and for methanol by 3.6%/year.

Per the IEA, about 630mm TCO_2/year is generated by the global production of ammonia and methanol, which equates to 2.4 tonnes of CO_2 per tonne of ammonia production (the range is 1.6 to 2.7 TCO_2) and 2.2 TCO_2 per tonne of methanol (the range of 0.7 to 3.1TCO_2/T).

To meet the Paris Climate Agreement goals, if all hydrogen production is from natural gas with carbon capture, then about 450mm TCO_2 will need to be captured, or about one additional carbon capture project will be needed per week, which is an extremely aggressive target (the largest carbon capture project today is about 1 mmTCO_2/year).

On the other hand, if all the hydrogen is produced from electrolytic hydrogen, electricity needed would be around 3,200TWh/year, and 3,500-4,000 projects would be needed, given that the largest project has been about 100MW, which comes to about six to seven new projects per week, which is a highly unlikely scenario.

The manufacturing costs of ammonia and methanol can vary significantly depending on the input cost of natural gas, coal, and electricity, and then whether CCUS is employed or not in the production process. By and large, natural gas is the cheapest method of producing ammonia and methanol with full CCUS. However, in some cases where the cost of electricity is very cheap, electrolysis can be commercially viable too, though such opportunities are rare currently.

Hydrogen Projects Needed to Meet Paris-Compliant H_2 2030 Demand in Chemicals

	2018	2030
Hydrogen demand (Mt)	44	57
All H_2 Demand Met From Natural Gas with CCUS		
Natural gas consumption (bcf/d)	17	31
Carbon capture needed (mmTCO_2/yr)		450
# of Carbon capture projects required		450
Projects / week through 2030		1.0
All H_2 Demand Met From Low-Carbon Electrolytic H_2		
Electricity Demand (TWh/yr)		3,200
..% of current demand		11%
Assuming 100MW/Project, # of Projects		3,500 - 4,000
Projects/Week through 2030		6-7
Water required (bcm/year)		0.6

Figure 32 – Hydrogen Projects Needed to Meet Paris-Compliant H_2 2030 Demand in Chemicals
Source: IEA, ATB Capital Markets Inc.

Iron and steel production: Almost 7% of global demand for hydrogen is from its use in steel production during direct reduction of iron (DRI). Hydrogen is also produced as a by-product in the blast furnace, which is typically reused on site.

Use of Hydrogen in the Transportation Sector and in Buildings

The key to hydrogen's demand growth in the coming decades is for its use outside of the industrial sector, in the transportation sector, in the heating of buildings, and in the power sector.

Hydrogen as a Clean Transport Fuel

Hydrogen FCEVs can reduce local air pollution as they have zero tailpipe emissions, like BEVs. Relative to the size of the light duty vehicle market globally, a very small number of FCEVs are in use. The IEA puts the estimate at 11,200 for 2018 compared with 5.1mm BEVs on the streets in 2019 (as a comparison, the total number of vehicles on the road exceeds 1.0bn). Nonetheless, several countries around the world have set up growth targets for FCEVs, which require a strong uptick in FCEV use through 2030, albeit the figures still remain modest on an absolute level (see Figure 33).

Goals Set by Various Countries to Increase FCEV Penetration

Country	Targets
Japan	Increase from 3,633 FCEV in 2019 to 200,000 in 2025 and 811,200 in 2030
Netherlands	Grow from 241 FCEV in 2019 to 18,000 in 2023 and 300,000 in 2030
Korea	Grow to 81,000 by 2022
Canada	For zero emissions vehicles, sales target of 10% by 2025, 30% by 2030, and 100% by 2040
France	Grow to 5,200 by 2023 and 52,000 by 2028

Figure 33 – Goals Set by Various Countries to Increase FCEV Penetration
Source: IEA, ATB Capital Markets Inc.

Current Demand for Hydrogen and Derived Products in the Transport Sector

	Light Duty Vehicles Cars & vans	Heavy Duty Vehicles Trucks & Buses	Maritime	Rail	Aviation
Current Demand	11,200 vehicles in operation, mostly in California, Europe & Japan	Demonstration & niche markets; ~25,000 forklifts, 500 buses, 400 trucks, 100 vans. Several thousands buses & trucks in China	Demonstration projects for small ships and onboard power supply in larger vessels	Two hydrogen trains in Germany	Small demonstration projects and feasibility studies
Demand Outlook	Global car stock should grow; hydrogen to capture part of market	Strong growth likely; long-haul and heavy duty applications can be attractive for Hydrogen	Maritime freight activity set to grow 45% to 2030. Air pollution targets and 2050 greehhouse gas targets could promote hydrogen based fuels	Rail remains a key transport mechanism in many countries	Large storage volume and redesign would be needed for pure hydrogen, making **power-to-liquid** and biofuels more attractive for this mode
Deployment Opportunities	**Hydrogen**: Short-refuelling time; less weight for energy stored, zero tailpipe emissions. Fuel cells have lower material footprint than lithium batteries. Captive vehicle fleets can help overcome challenges of low utilization of refuelling stations; long distance and duty are attractive options.		**Hydrogen** and **ammonia** are candidates for both national action on domestic shipping and decarbonization, and IMO Greenhouse Gas Reduction Strategy, given limitations on the use of other fuels	**Hydrogen** trains can be competitive in rail freight (regional lines with low network utilization, and cross-border freight)	**Power-to-liquid**: Limited changes to status quo in distribution, operations and facilities; also maximises biomass use by boosting yield. Hydrogen: Together with batteries, can supply on-board energy supply at ports and during taxiing.
Deployment Challenges	**Hydrogen:** High fuel cost owing to low initial refueling station costs; reduction in fuel cell and storage costs needed; efficiency losses on a well-to-wheel basis. **Power-to-liquid:** Large electricity consumption and high production costs. **Ammonia:** Caustic and hazardous substance close to end users mean that use is likely to remain limited to professional operators.		**Hydrogen**: Storage cost higher than other fuels. **Hydrogen/ammonia**: cargo volume lost due to storage (lower density than current liquid fuels)	Rail is the most electrified transport mode; **hydrogen** and battery electric trains with partial line electricfication are both options to replace non electricfied operations which are substantial in many regions	**Power to liquid**: Currently 4x to 6x more expensive than kerosene, decreasing to 1.5x - 2x in the long term, potentially increasing prices and decreasing demand

Figure 34 – Current Demand for Hydrogen and Derived Products in the Transport Sector
Source: IEA, ATB Capital Markets Inc.

IEA Projects Explosive Growth for Hydrogen Use as A Transport Fuel Post 2030

There is negligible use of hydrogen as a transport fuel, but owing to incentives provided by governments around the world, the use of FCEVs should increase in this decade. While the use of FCEVs may become more prevalent starting in 2025, the IEA projects that only by 2030 would economies of scale and technical innovations be at a level that FCEV demand starts to accelerate. For example, Japan projects that its FCEVs should increase from 3,633 in 2019 to 200,000 by 2025 and to more than 800,000 by 2030. However, these figures still pale in comparison with the number of ICEs on the road today, which are estimated to be more than 1 bn. The IEA expects demand for hydrogen in the transportation sector increasing from 1.6mm T/year in 2030e to 19.6mm T/year in 2040e.

Hydrogen Use in the Transportation Sector to Become Very Material Post 2030

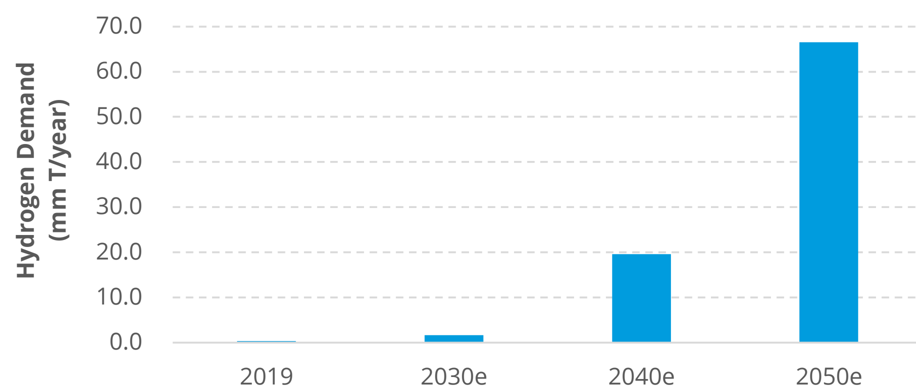


Figure 35 – Hydrogen Use in the Transportation Sector to Become Very Material Post 2030
Source: IEA, ATB Capital Markets Inc.

FCEV Best Suited for Heavy Lift and Long-Haul Markets

The study Hydrogen Roadmap Europe highlights that in the heavy lift and in long-haul markets, FCEVs could gain mass market acceptability by 2025 in an aggressive penetration scenario, but in a less optimistic scenario, they could reach mass market by 2030.

In the heavy-duty vehicle segment, the IEA estimates that about 25,000 forklifts are in service globally. In terms of buses, the IEA estimated the number plying the streets at around 500, and there are about 11 companies that manufacture fuel cell electric buses (FCEBs).

Hydrogen offers short refueling times, less weight for the energy stored, and zero tailpipe emissions. The fuel cells also have a lower footprint than lithium batteries. However, the refueling station network for hydrogen is not that well developed, and as such hydrogen is best positioned competitively for captive vehicles, such as forklifts, city buses, taxis, etc., while for small cars, BEVs still appear to be the best option (see Figure 36). We highlight the challenges and benefits in the different modes of transportation in Figure 37.

Hydrogen can also be combined with CO_2 to produce synthetic liquid fuels, which have a range of potential transport uses. Synthetic liquid fuels produced from electrolytic hydrogen are often referred to as "power-to-liquid". Synthetic fuels can be a good option for the aviation industry and for ships.

Market Readiness of Fuel Cell Electric Vehicles (FCEV)

Figure 36 – Market Readiness of Fuel Cell Electric Vehicles (FCEV)
Source: Hydrogen Roadmap Europe

Comparison of Range, Payload, and Preferred Technology

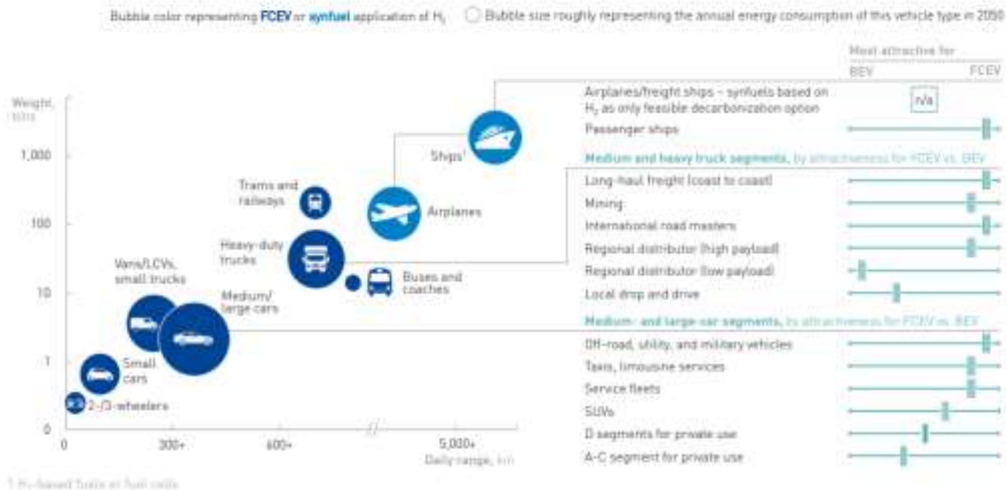


Figure 37 – Comparison of Range, Payload, and Preferred Technology
Source: Hydrogen Roadmap Europe

Understanding Cost Drivers that Affect Viability of Hydrogen in Road Transportation

Excluding the cost of hydrogen manufacture, the three components in FCEV costs are (1) the cost of fuel cell stack, (2) the cost of hydrogen stored on-board the vehicle, and (3) the cost of refueling.

Fuel Cell Cost

Fuel cell costs have been declining, and the IEA estimates the typical cost of a fuel cell at US$230/KW, which it expects can be brought down soon to US$180/KW, with further reductions quite likely. Fuel cell costs comprise the cost of the material inside a fuel cell, which can be reduced through technology, product innovation, and economies of scale.

At its Investor and Analyst Day 2020 presentation, Ballard Power highlighted that even with limited production volumes, there was a 60% reduction in FCEB prices over the past 10 years, driven primarily by technology and product innovations. The Company states that there is already total cost of ownership (TCO) parity with some battery electric buses (BEBs) in some cases (primarily in long haul), and it expects FCEVs to be less expensive than BEVs and ICEs for some applications within 10 years (see Figures 38, 39, and 40). Ballard is targeting reducing its fuel cell stack cost by 70% by 2024, through volume growth and product innovations.

Fuel Cell Competitive Positioning

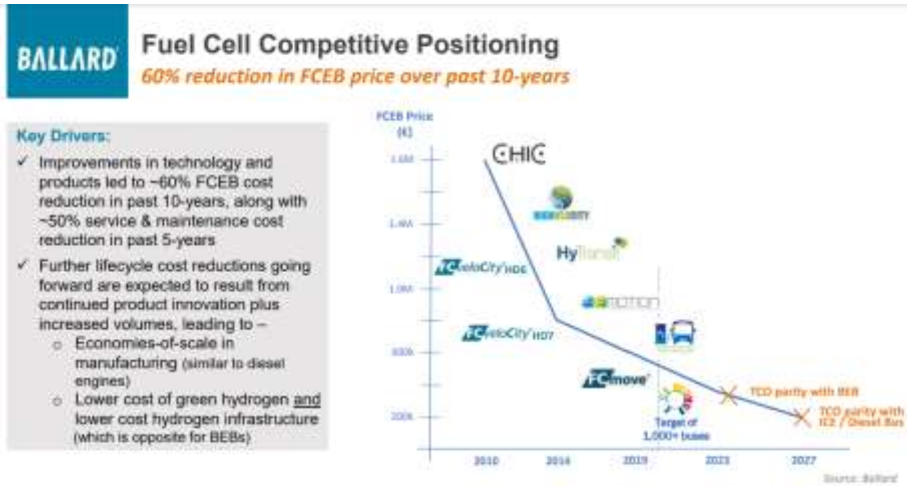


Figure 38 – Fuel Cell Competitive Positioning
Source: Ballard Power Investor and Analyst Day 2020 Presentation

On-Board Hydrogen Storage

Expensive composite materials are required for on-board storage of hydrogen, as hydrogen needs to be compressed to 350-700 bars for cars and trucks. This uses the equivalent of 6-15% of the hydrogen energy content. In 2018/2019, the IEA estimated the cost of on-board storage systems at US$23/KWh of useable hydrogen storage at a scale of 10,000 units/year, decreasing to US$14-US$18/KWh at a scale of 500,000 units/year. The U.S. DOE has an ultimate target of US$8/KWh.

Refueling Infrastructure Costs

Hydrogen refueling takes almost as little time as conventional liquid transport fuels, putting it at an advantage relative to BEVs. However, supplying the refueling stations with hydrogen has a more complicated supply chain, and requires more time and labor, relative to conventional transport fuels. There are still very few refueling stations around the world (only 48 in California and ~400 globally).

The IEA estimates that a hydrogen refueling station may cost about US$0.6-US$2.0mm when hydrogen is kept at a pressure of 700bar and US$0.15-US$1.6mm when the pressure is 350bar. The lower end of the range is for stations with a capacity of 50kgH_2/day, while the upper end is for stations with capacity of 1,300kg/H_2/day.

Ballard Expects FCEBs to Be Competitive in Europe Even Without Subsidies

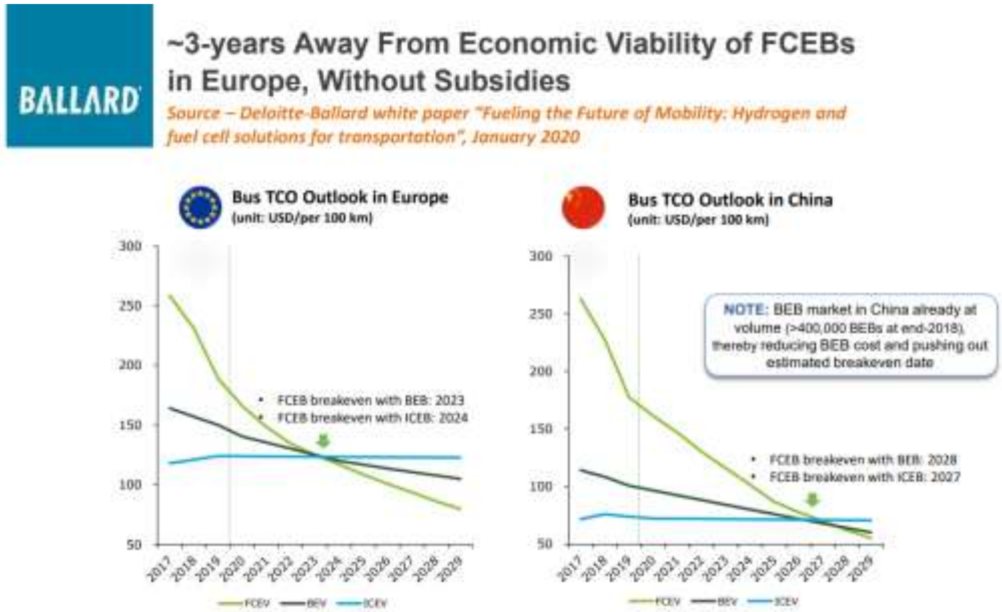


Figure 39 – Ballard Expects FCEBs to Be Competitive in Europe Even Without Subsidies
Source: Ballard Power Investor and Analyst Day 2020 Presentation

With Increased Scale, Fuel Cell Costs Could Decline Further

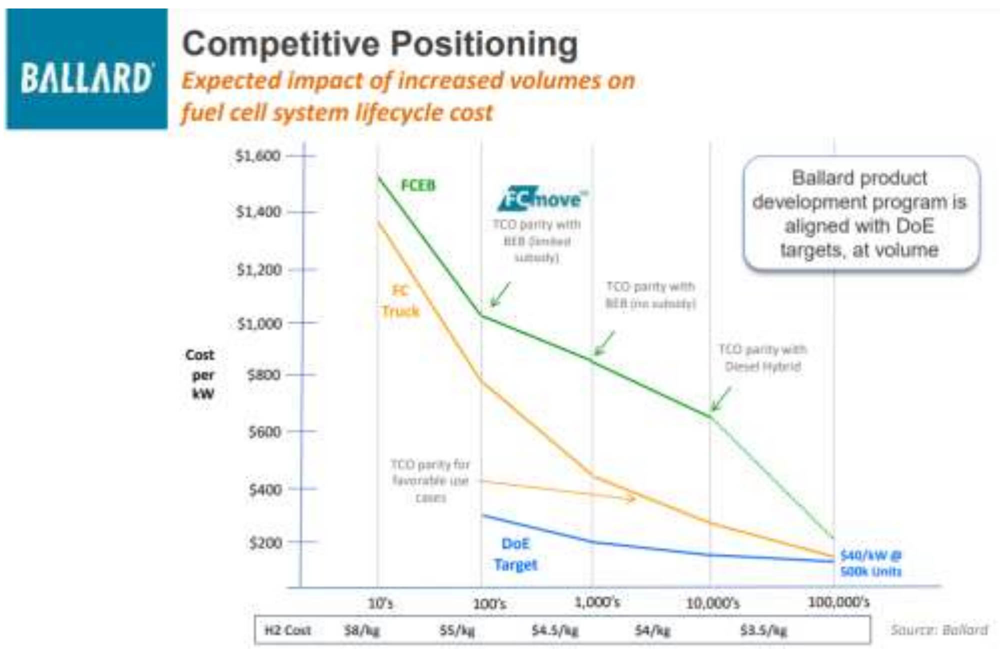


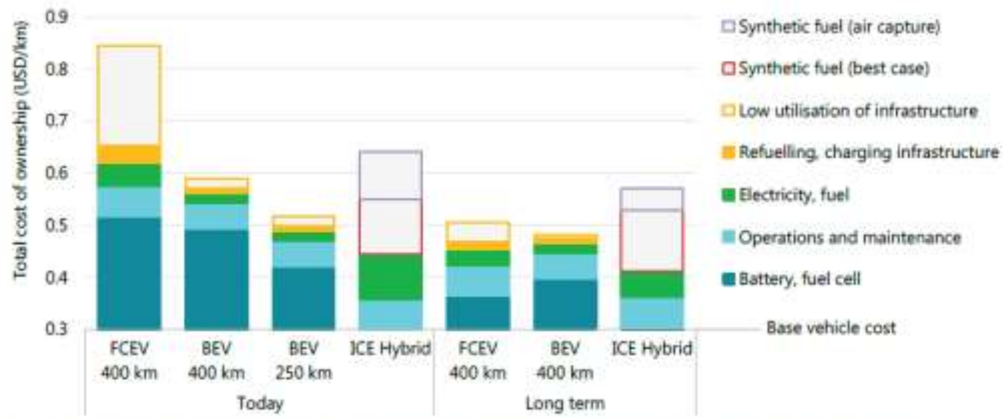
Figure 40 – With Increased Scale, Fuel Cell Costs Could Decline Further
Source: Ballard Power Investor and Analyst Day 2020 Presentation

Total Cost of Ownership Analysis

Per IEA data, a BEV today typically has a range of 250km, while a FCEVs such as the Toyota Mirai offers a range of 400km; the Hyundai Nexo is projected to be beyond the 400km range. Current FCEVs are more expensive than BEVs owing to their higher cost of fuel cells and fuel cell storage tanks, but they are designed to have a longer range, and their competitiveness improves when compared with longer range scenarios.

The IEA's view is consistent with Ballard Power, in that the total cost of ownership of a FCEV is competitive with BEV when compared with a range of about 400km, but with innovation and economies of scale, a FCEV's competitiveness could improve further in the long term.

Total Cost of Car Ownership by Powertrain, Range, and Fuel

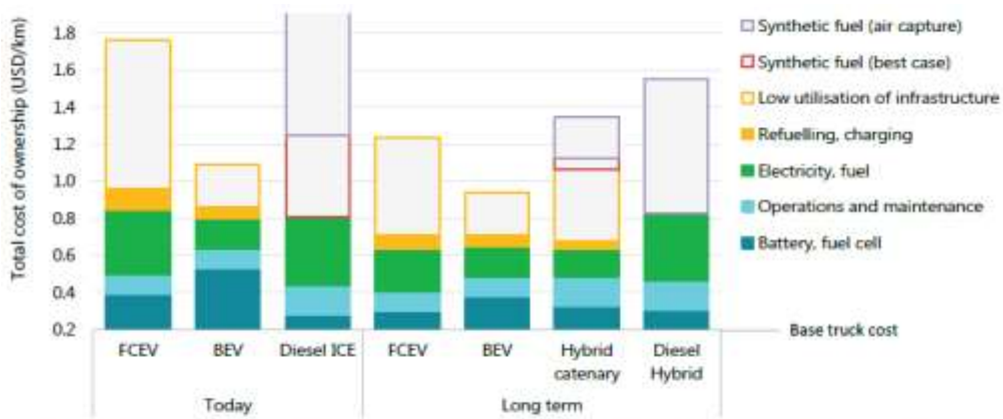


Notes: ICE = internal combustion engine. The y-axis intercept of the figure corresponds to base vehicle "glider" plus minor component costs, which are mostly invariant across powertrains. More information on the assumptions is available at www.iea.org/hydrogen2019.

Figure 41 – Total Cost of Car Ownership by Powertrain, Range, and Fuel
Source: IEA

In the heavy-duty and long-haul segment, including trucks and intercity buses, hydrogen FCEVs are more competitive, as the long range and high power of hydrogen comes into play. IEA data shows that FCEVs and BEVs are cost competitive even today in the long-haul trucking segment.

Current/Future Total Cost of Ownership in Long-Haul Trucks



Notes: The y-axis intercept of the figure corresponds to base vehicle "glider" plus minor component costs. Infrastructure covers stations, charging points and catenary lines. More information on the assumptions is available at www.iea.org/hydrogen2019.

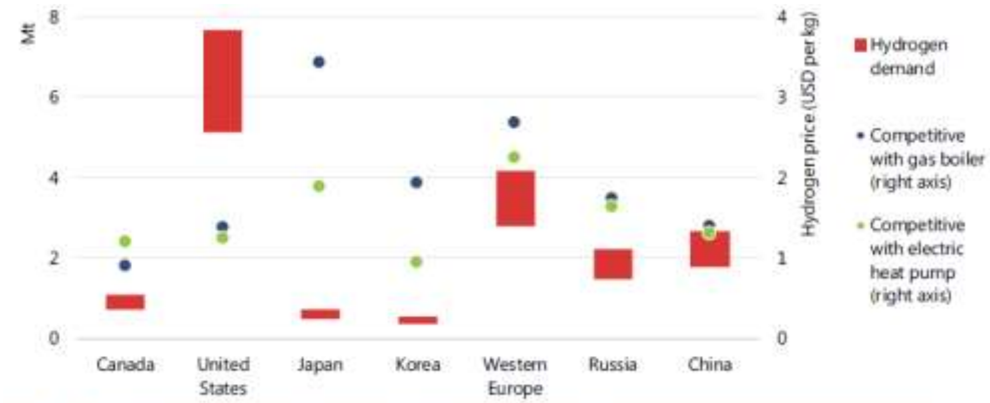
Figure 42 – Current/Future Total Cost of Ownership in Long-Haul Trucks
Source: IEA

Use of Hydrogen in Buildings for Heating

It is estimated by the IEA that the price of hydrogen delivered to consumers needs to be in the range of US$1.5-US$3.0/KgH_2 for hydrogen to compete with natural gas boilers and electric heat pumps if 100% hydrogen is to be used. Higher prices in the range of US$3.0-US$4.0/KgH_2 might still be competitive with natural gas prices in some countries or for some building types (and eventual CO_2 pricing would narrow that spread). In countries such as Canada, where gas prices are low, prices would need to be less than US$1/Kg$H_2$.

Data from The Transition Accelerator shows that the production cost for H_2 using natural gas could be around $0.75/Kg$H_2$ in Canada, but to be able to compete with natural gas for heating in buildings, the cost of distribution of hydrogen will need to be considered as well.

Potential Hydrogen Demand for Heating in Buildings and Competitive Energy Prices, 2030



Notes: Prices are average retail prices, including taxes, in USD 2017. Natural gas demand is for space heating and hot water production and includes building envelope improvements to 2030 under a Paris-compatible pathway. Competitiveness of electric heat pumps assumes a typical seasonal efficiency of the heat pump in those countries. Price competitiveness does not include capital costs of the equipment.

Figure 43 – Potential Hydrogen Demand for Heating in Buildings and Competitive Energy Prices, 2030

Source: IEA

2030 Natural Gas Demand for Heat in Buildings and Indicative Theoretical Hydrogen Demand in Selected Regions

Region	Natural gas demand (Mtoe)	Competitive price range for hydrogen (USD/kgH_2)	Indicative hydrogen demand (MtH_2)
Canada	21	0.8–1.2	0.7–1.1
United States	147	1.2–1.5	5.1–7.7
Western Europe	80	2.0–3.0	0.5–0.7
Japan	14	2.0–3.5	0.4–0.6
Korea	11	0.9–1.9	2.8–4.2
Russia	43	1.5–1.8	1.5–2.2
China	51	1.2–1.4	1.8–2.7

Notes: Natural gas demand is for space heating and hot water production and takes account of building envelope improvements under a Paris-compatible pathway. Indicative demand assumes that hydrogen production, transmission and distribution is within the competitive range shown here and does not include potential hydrogen demand for hydrogen-based fuels. Excludes natural gas use in production of commercial heat. Western Europe includes France, Germany, Italy and the United Kingdom. Indicative of direct hydrogen use in buildings. The indicative demand takes into account typical lifetimes of existing heating equipment in buildings and does not assume early retirement of equipment.

Figure 44 – 2030 Natural Gas Demand for Heat in Buildings and Indicative Theoretical Hydrogen Demand in Selected Regions

Source: IEA

Hydrogen for Power Generation and Energy Storage

Hydrogen plays a negligible role in the power sector today, accounting for less than 0.2% of electricity generation, but the IEA expects demand for hydrogen for power to increase in the coming decades, and projects that by 2030, 4.7mm T/year of hydrogen will be used for power generation, which should increase to 6.4mm T/year by 2040 and 55mm T/year by 2050.

IEA Projection of Hydrogen Demand for Electrical Power

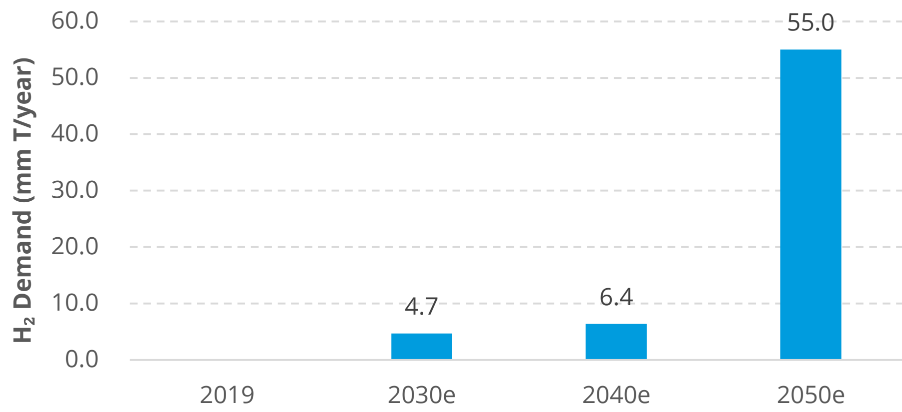


Figure 45 – IEA Projection of Hydrogen Demand for Electrical Power
Source: IEA, ATB Capital Markets Inc.

To reduce the carbon footprint of the current power plants, future power plants may look to use compressed gas, ammonia, or synthetic methane. Hydrogen could also become a long-term storage option to balance seasonal variations in electricity demand or the variations in supply of renewable energy owing to windless or sunless days. Hydrogen also offers optionality to replace diesel generators for back-up power and off-grid electricity supply.

Japan and Korea Have Mandates to Grow Hydrogen Usage in Power Production

Japan aims to reach 1GW of power capacity based on hydrogen by 2030, which equals 0.3mm T/year of H_2, but over the long term, it expects to increase hydrogen-based power capacity to 15-30GW, which equates to 15-30mm T/year of H_2 demand.

Korea's hydrogen roadmap sets a target of 1.5GW of installed fuel cell capacity in the power sector by 2022, and 15GW by 2040.

Hydrogen Could Provide Back-Up Power

For back-up power and off-grid electricity, diesel powered generators are mostly used, and fuel cells represent a possible alternative, and they could reduce local air pollution, and reduce demand for imported diesel.

The IEA estimates that in India, there are around 650,000 telecom towers, of which ~20% rely on diesel generators. They consume ~5bln litres of diesel, and emit CO_2 equaling ~5mm T/year. These could be replaced by fuel cell systems, which rely on bottled hydrogen, methanol, or ammonia as fuel.

Fuel cells can also be used to provide back-up power during outages and for off-grid electricity.

Role of Hydrogen and Hydrogen-Based Products in Power Generation

	Co-Firing Ammonia in Coal Power Plants	Flexible Power Generation	Back-Up and Off-Grid Power Supply	Long-Term & Large Scale Energy Storage
Current Role	No deployment so far; co-firing has been demonstrated in a commercial coal plant in Japan	Few commercial gas turbines using hydrogen-rich gases. 363,000 fuel cell units (1,600MW) installed	Demonstration projects for electrification of villages. Fuel cell systems in combination with storage	Three salt cavern storage sites for hydrogen in the US; another three in the UK
Demand Outlook	20% co-firing share in global coal power plant fleet could by 2030 lead to an ammonia demand of up to 670Mt ammonia or a corresponding hydrogen demand of 120 MTH_2	Assuming 1% of global gas-fired power capacity would run on hydrogen by 2030, this would result in a capacity of 25GW, generating 90 TWh of electricity and consuming 4.5 MTH_2	With increasing growth of telecommunications, also growing need for reliable power supply	As the share of variable renewable energy (VRE) increases, whose output can vary depending on ambient conditions, the need for storage would increase. In combination with long-distance trade, seasonal differences across regions in global VRE supply could be exploited.
Deployment Opportunities	Reducing the carbon impact of existing coal-fired power plants in the near term	Supporting the integration of variable renewable energy (VRE) in the power system. Some gas turbine designs already are able torun on high hydrogean shares, like turbines built by Baker Hughes	Fuel cells sytems in combination with storage as a cost-effective and less polluting alternative to diesel generators. More robust than battery systems.	Due to high energy content of hydrogen, relatively low capex cost for storage itself. Few alternative technologies for long-term and large scale storage. Conversion losses can be reduced if stored hydrogen or ammonia can be directly used in end-use applications
Deployment Challenges	CO_2 miitigation costs can be low, but rely on low-cost ammonia supply. Attention has to be paid to NOX emissions; further NOX treatment may be needed. Only a transitional measure - still significant remaining CO_2 emissions	Availability of low-cost and low-carbon hydrogen and ammonia. Competition with other flexible generation options as well as other flexibility options (e.g. demand response, storage)	Often higher initial investment needs compared with diesel generators	High conversion losses. Geological availability of salt caverns for hydrogen storage region-specific. Little experience with depleted oil and gas fields or water aquifers for hydrogen storage (e.g. contamination issues)

Figure 46 – Role of Hydrogen and Hydrogen-Based Products in Power Generation
Source: IEA, ATB Capital Markets Inc.

Hydrogen Strategies in Place around the World – Increasing Adoption and Cooperation Likely

The European Union (EU) – Hydrogen Strategy Launched in July 2020

In July 2020, the EU released its hydrogen strategy, which was largely driven by its climate neutrality goal. The focus of the EU's strategy will be renewable hydrogen (green hydrogen) as it has the biggest decarbonization potential, but will also recognize other low-carbon hydrogen production processes, such as "blue" hydrogen.

The EU strategy will consist of three phases:

1. **2020-2024:** In the first phase, the objective is to decarbonize existing hydrogen production for current uses (chemicals, industrial, manufacturing, etc.), and promote hydrogen for new applications. In this phase, the goal is to install six gigawatts of renewable hydrogen electrolysers in the EU by 2024 (there is roughly one gigawatt today), with the goal of producing up to 1mm tonnes of renewable hydrogen.
2. **2024-2030:** In the second phase, the goal is for hydrogen to become an intrinsic part of an integrated energy system, with a goal of 40+ gigawatts of renewable hydrogen electrolysers by 2030, and the production of up to 10mm tonnes of renewable hydrogen in the EU. Hydrogen use will also be gradually introduced to new sectors.
3. **2030-2050 (onward):** In the last phase, the goal is for renewable hydrogen technologies to reach maturity and be able to be deployed at large scale so that renewable hydrogen can reach all "hard-to-decarbonize" sectors.

The EU estimates that cumulative investments in renewable hydrogen in Europe could be up to US$225bn to US$600bn (€180-€470bn) by 2050, and US$4bn to US$22bn (€3-€18bn) for "blue" hydrogen. Per the EU, "*Analysts estimate that clean hydrogen could meet 24% of world energy demand by 2050, with annual sales in the range of US$800bn (€630 billion)*."

Japan – The First Country to Formally Adopt a Hydrogen Strategy

Japan was the first country to formally adopt a hydrogen strategy, which was initiated in 2017. The broad goal of Japan's hydrogen strategy is to achieve cost parity with transportation fuels (gasoline) and power generation (LNG), with the strategy covering the entire supply chain (hydrogen production to downstream markets).

One of the key reasons for Japan adopting a hydrogen strategy is due to the country's reliance on overseas fossil fuels for its primary energy supply, estimated at ~95%, as well as the shutdown of its nuclear industry following the Great East Japan Earthquake and Tsunami of 2011. In addition, per the 2015 Paris Climate Agreement, Japan will cut its GHG emissions by 26% by 2030 (2015 is the baseline), and by 80% by 2050, with hydrogen playing a key role.

Japan's strategy has 10 key points:

1. **Realizing low cost hydrogen use:** (1) Procure unused foreign energy and apply CCUS to produce "blue" hydrogen; or (2) Procure hydrogen as Japan aims to develop supply chains to procure 300k tonnes of hydrogen annually by ~2030.
2. **Developing international hydrogen supply chains:** Japan will develop energy carrier technologies to enable hydrogen transportation and storage (e.g., liquefied hydrogen).
3. **Renewable energy expansion in Japan and regional revitalization:** To expand renewable energy use, Japan will employ technologies to ensure the power supply is regular and stable,

and that surplus power from renewable sources is storable. One example is "power-to-gas" technology that stores renewable energy as hydrogen, with the goal of commercialization of this technology by 2032. Japan will also create "regional hydrogen industries" to spread adoption.

4. **Hydrogen use in power generation:** Similar to power generated from natural gas, Japan believes hydrogen power generation can play a significant role as a regulated power supply/back-up power source. Japan has a goal to make hydrogen power generation competitive with LNG power generation.
5. **Hydrogen use in mobility:** Japan aims to increase the number of fuel cell vehicles to 40k by the end of 2020, 200k by 2025, and 800k by 2030, and also has a goal to increase the number of hydrogen stations to 160 by the end of 2020 and 320 by the end of 2025.
6. **Potential hydrogen uses in industrial processes and heat utilization:** CO_2-free ("green" and "blue") hydrogen can be used as fuel for energy in areas where electrification is difficult and replace industrial-use "grey" hydrogen (from fossil fuels without CCUS).
7. **Utilizing fuel cell technologies:** Explore new markets for hydrogen fuel cells (apartments, areas in cold regions, etc.)
8. **Utilizing innovative technologies:** Government organizations will implement projects, with "green" hydrogen production being a key focus area.
9. **International expansion:** Japan will attempt to lead international standardization through international frameworks, and promote technological development and cooperation.
10. **Promoting citizen's understanding and regional cooperation:** In order to expand adoption, Japan believes it will be necessary that the understanding of hydrogen's safety and the significance of hydrogen use (vastly reduce GHG emissions) is shared among its citizens.

Canada: Targeting Raising Hydrogen's Contribution in the Energy Mix to 30% by 2050

Canada is one of the top 10 producers of hydrogen in the world, and is competitively well positioned as demand for hydrogen increases in the coming decades. On October 6, 2020, Alberta released its Natural Gas Vision and Strategy ("Getting Alberta Back to Work"), which broadly lays out a plan for the province to become a global supplier of "clean, responsibly sourced natural gas and related products, including hydrogen, petrochemicals, and recycled plastics." This was followed by Canada releasing its own formal hydrogen strategy on December 16, 2020 (see below).

Canada's Hydrogen Strategy

On December 16, 2020, Canada released its formal hydrogen strategy, "Seizing the Opportunities for Hydrogen: A Call to Action" (see here for the full report). Per the report, the strategy is "the result of three years of research and analysis, with input from 1,500 leading experts and stakeholders including workers, industry, other levels of government, Indigenous organizations, and academia."

The strategy will support the Government of Canada's recently announced climate plan, "A Healthy Environment and a Healthy Economy," and builds on hydrogen initiatives released by 23 countries across the world at the 10th Clean Energy Ministerial meeting in May 2019.

Canada's vision for 2050 has the following key goals: 1) Transform Canada into one of top three global clean hydrogen producers; 2) Grow hydrogen's share in the energy mix to 30%, up from 6% in 2030; 3) Establish a supply base of low carbon intensity hydrogen with delivered prices of C$1.50/Kg to C$3.50/Kg (US$1.15/Kg to US$2.75/Kg); 4) Promote new industries enabled by a low-cost hydrogen supply network, and make hydrogen competitive for the export market; 5) Generate in excess of

C$50bn in direct revenues from the hydrogen sector targeting the domestic market; and 6) Reduce carbon emissions by up to 190mm T/year.

Canada's strategy is designed to spur investment and partnerships, positioning the country as a global supplier of hydrogen, in a market which the Canadian government states could be C$2.5tn to C$11.7tn by 2050. The report states that blue and green hydrogen could create upwards of 350,000 jobs in Canada by 2050.

Canada's Hydrogen Opportunity

H_2 Opportunity

	2030	2050
% of Delivered Energy	6%	30%
Hydrogen Demand	4 Mt-H_2	20 Mt-H_2
GHG Emissions Abated	up to 45 Mt-CO_2e	up to 190 Mt-CO_2e

Figure 47 - Canada's Hydrogen Opportunity
Source: Hydrogen Strategy for Canada – Seizing the Opportunities for Hydrogen: A Call to Action

Alberta's Natural Gas and Strategy and Hydrogen's Role

Alberta is already a significant global producer of natural gas, with current production of roughly ~11 bcf/d (this is down from the peak of roughly 14 bcf/d in 2006, with the decrease in production largely driven by egress issues and competition from the United States).

The new Natural Gas Vision and Strategy will leverage Alberta's current strengths (ample supply, relatively low-cost production, infrastructure, technology, trained workforce, etc.), but will be oriented for the future, with a focus on areas that hold significant potential for growth and investment, with hydrogen being one of the three key new value chains (the other two are LNG and the "plastics circular economy").

Alberta will support the strategy by:

(1) Advocating for natural gas development in Canada;

(2) Pursue investment and improve its competitiveness;

(3) Enable meaningful involvement and investment from the Indigenous community;

(4) Implement best-in-class environmental frameworks and drive toward an efficient regulatory environment;

(5) Become a global leader in energy literacy; and

(6) Increase natural gas demand by advancing new, expanded, and circular pathways.

How Alberta Will Drive the New Natural Gas Vision and Strategy

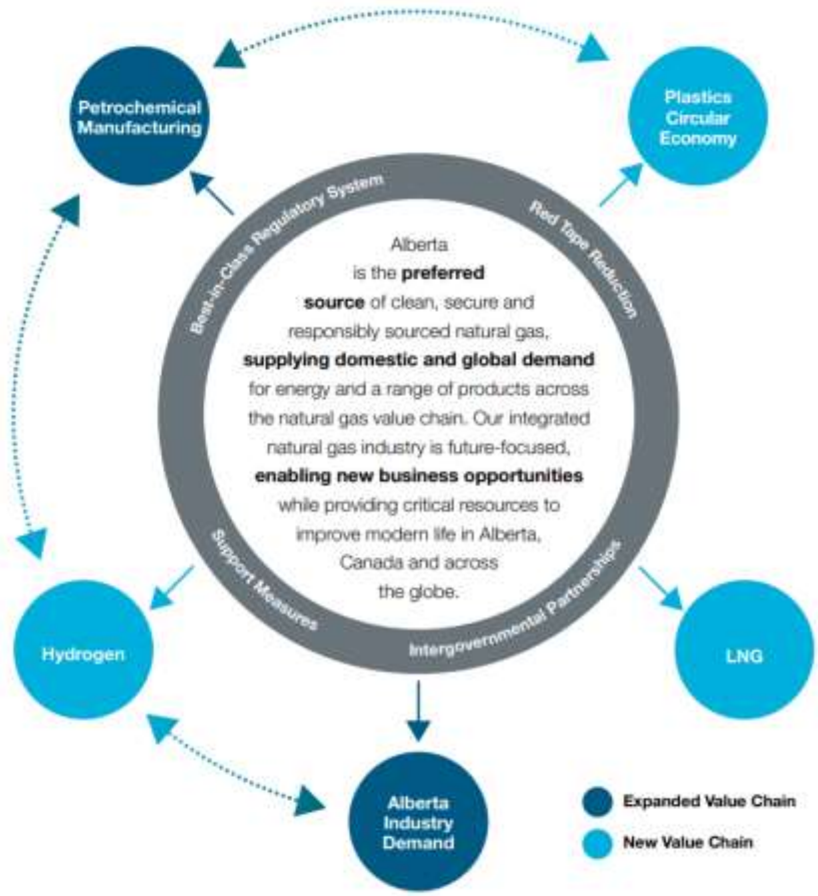


Figure 48: How Alberta Will Drive the New Natural Gas Vision and Strategy
Source: Alberta Natural Gas and Vision Strategy

Alberta's Hydrogen Goals: Large-Scale Production with CCUS by 2030 and Export of Hydrogen by 2040

Alberta has two primary goals for hydrogen:

(1) Large-scale hydrogen production with CCUS and deployment in various commercial applications across Alberta's economy by 2030.

(2) Develop the capability to export clean hydrogen and hydrogen-derived products across North America and the world by 2040.

At a high level, Alberta believes developing a hydrogen economy will unlock significant economic value for the province (and the rest of Canada), while also advancing climate goals related to GHG reduction targets per the Paris Climate Accord. Alberta is already one of the world's largest producers of hydrogen and has existing hydrogen and CO_2 sequestration infrastructure (Air Products' Heartland Hydrogen Pipeline, the Alberta Carbon Trunk Line, and the Quest Carbon Capture and Storage project). As shown in Figure 21, independent, third-party analysis suggests that Canada could end up being one of the lower cost producers of hydrogen in the world.

The Natural Gas Vision and Strategy did not specify the potential economic impact on Alberta ("more analysis is needed"), but given that hydrogen is one of the five key value chains, we believe it is likely government policy will encourage the development of hydrogen production, transport, and export capabilities.

China: "Made in China 2025 Initiative" Highlights Hydrogen

China is the global leader in hydrogen production, with estimated annual production in the range of 20-22mm T, or roughly one-third of the world's total production of "pure" hydrogen, with about 85% of the production coming from SMR, with about 62% of China's total hydrogen production coming from coal.

In 2015, the Chinese government first published its *Made in China 2025 Initiative*, which laid out a 10-year plan to revamp the country's manufacturing industry, which included hydrogen as a key technology to continue to develop. The initiative laid out goals for FCEVs with three key areas of focus: (1) domestic production of key materials/parts; (2) improved performance and competitiveness of FCEVs; and (3) infrastructure for hydrogen production and refueling stations.

In 2019, in the "Government Work Report," the Chinese government included "promoting the construction of electric vehicle charging stations and hydrogen fuel cell refueling stations," which was the first time that hydrogen was written in the "Government Work Report."

According to a September 2020 report by the Green Belt and Road Initiative Center ("Hydrogen: China's Progress and Opportunities for a Green Belt and Road Initiative"), by the end of 2019, at least 10 provincial-level governments (including Shanghai and Beijing), 21 city-level governments, and five county-level governments had released action plans dedicated to the hydrogen.

We believe China will continue to be a leader in producing hydrogen and developing supporting technologies and use cases, with FCEVs likely being one of the first wide-scale use cases. China has a goal of carbon-neutrality by 2060, and to achieve this goal, hydrogen – and more specifically, blue and green hydrogen – will likely need to play a crucial role.

Highlighting Key Companies Under ATB Coverage with Hydrogen Leverage

TechnipFMC plc (FTI-N, OP, PT US$14.50; here)

TechnipFMC plc is the hydrogen industry's global leader, with a ~35% market share, 55+ years of experience, and has provided technology on 275+ hydrogen plants that utilize SMR technology.

FTI-N estimates its opportunity set in hydrogen to be nearly $50bn by 2030, which is based on the IEA forecast of an increase in hydrogen demand from nearly 70mm tonnes in 2020 to 88mm tonnes by 2030. The opportunities are in both brownfield and greenfield projects.

We believe the largest near-term opportunity is retrofitting brownfield plants with CCUS. FTI-N is a front-runner in aiding in the production of blue hydrogen having provided reformer technology on more than 275 plants around the world. Per FTI-N, it has expertise in all aspects of CO_2 removal technology, and can provide a complete portfolio of services, which can range from feasibility studies to engineering, procurement, and construction (EPC) projects. In addition, FTI-N has already completed projects where CO_2 capture units were retrofitted on existing hydrogen plants.

One of FTI-N's key awards in the hydrogen space was a "substantial" contract ($250-$500mm) for construction of a grassroot hydrogen generation unit (HGU) for Hindustan Petroleum Corporation Ltd. (HPCL), which at the time of the award in July 2018 was India's largest HGU. FTI-N had previously executed two HGUs for HPCL. On November 30, FTI-N announced that it was starting work on a >$1bn project for a hydrocracker project in Egypt. FTI-N's work scope includes construction of a hydrogen production facility using the Company's proprietary steam reforming technology.

We believe in the near term, upgrades in energy infrastructure (more specifically petrochemicals and refining) aimed at reducing carbon emissions by utilizing CCUS will be the most likely source of actual revenue opportunity for companies such as FTI-N. For example, on September 30, FTI-N was awarded a contract to upgrade an ethylene plant (the Moerdijk petrochemicals complex) in the Netherlands for Royal Dutch Shell plc (RDSA-LN, NR). The project is an engineering, procurement, and module fabrication (EPF) contract for equipment and related services for eight ethylene furnaces, which will replace 16 older units without reducing capacity at the facility, while increasing energy efficiency and reducing GHG emissions. Per the Company, this upgrade is expected to reduce the Moerdijk plant's annual CO_2 emissions by about 10%.

Building on its experience with blue hydrogen, FTI-N is now exploring green hydrogen produced from renewable sources (wind and solar). FTI-N is developing its Deep Purple™ concept, which is a large-scale offshore storage solution for hydrogen production and distribution.

FTI-N's Green Hydrogen Partnership with McPhy

After market close on October 14, 2020, FTI-N announced that it signed a Memorandum of Understanding (MoU) with McPhy Energy SA (MCPHY-FR), pursuant to which the two companies will jointly work on technology development and project implementation for "green" hydrogen. In addition, FTI-N will also be making an equity investment in MCPHY.

The MoU establishes a collaboration framework for the manufacturing and commercialization of (1) hydrogen electrolysis production systems for large industry, renewable energy storage, and large mobility projects, and (2) hydrogen distribution systems for large mobility projects. Through the MoU, the two companies will also jointly address commercial opportunities, work on integrating their respective offerings, and work on R&D for hydrogen technology. See here for more details.

Baker Hughes Company (BKR-N, OP, PT US$24.50; here)

BKR-N is positioning for energy transition, with a focus on carbon capture, mechanical energy storage, and various parts of the hydrogen value chain.

Baker estimates that 750mm tonnes of annual CCUS capacity will be needed by 2030 to reach the IEA Sustainable Development Scenario (SDS). Just meeting the Paris Agreement by 2050 will require the capture of 28 gigatons of CO_2 in the atmosphere, and without CCUS, the cost of Paris Agreement compliance will be about 70% greater. Per the IEA, CCUS should increase from 40mm T in 2020 to 750mm T by 2030 and 2.35bn T by 2040 (see Figure 48).

The IEA Estimates CCUS to Increase from 40mm T in 2020 to 2.35bn T by 2040

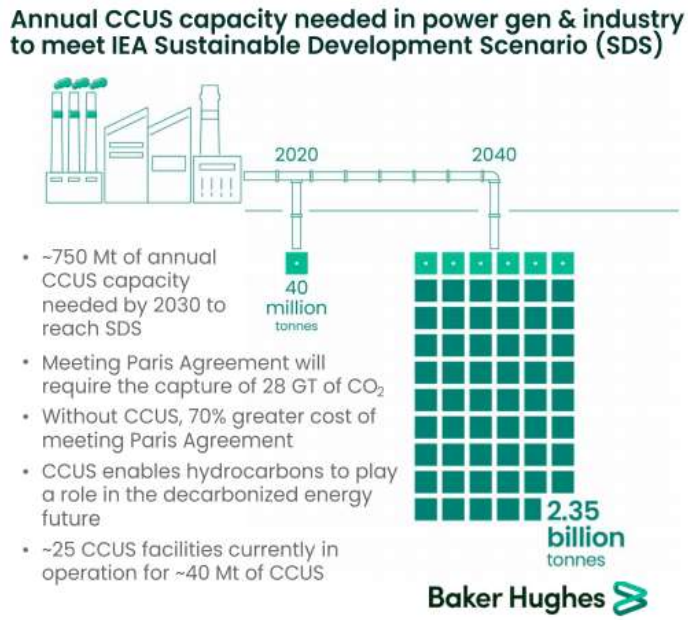


Figure 49 – IEA Estimates CCUS to Increase from 40mm T in 2020 to 2.35bn T by 2040
Source: Baker Hughes Company

On November 3, 2020, BKR-N announced that it was acquiring Compact Carbon Capture (3C), a Company that has an innovative solution for carbon capture. 3C's carbon capture technology differs from existing systems, and can provide carbon capture solutions to small- and medium-sized facilities using its proprietary rotating technology, which offers a modularized lower cost solution. The system's small footprint (75% reduction in footprint) is very well suited for brownfield applications.

BKR-N has previous experience burning a variety of fuel sources with high hydrogen content in gas turbines, and has about 70 projects worldwide that use frame and aero-derivative gas turbines.

Being a leader in compression technology, BKR-N has a long history of participation in hydrogen production, having first engaged in hydrogen production in 1962. In addition, the Company's gas turbines, which have typically been used with natural gas, can use hydrogen blended gas and NovaLT technology can run 100% on hydrogen.

Breaking Down the CCUS Process

Figure 50 – Breaking Down the CCUS Process
Source: Baker Hughes Company

On July 20, BKR-N and Snam S.p.a (SRG-MI, NR) announced that they had successfully completed testing of the world's first "hybrid" hydrogen turbine designed for gas networks; the test was conducted in Florence, Italy. The BKR-N NovaLT12 turbine would be powered by up to 10% hydrogen. Per BKR-N, the test paves the way to implement adoption of hydrogen blended with natural gas in Snam's current transmission network infrastructure, with the transmission network totalling 41k km globally. About 70% of Snam's pipelines are already built with "hydrogen-ready" pipes.

Per BKR-N, by blending 10% hydrogen into the total annual gas capacity transported by Snam, it is estimated that 7bn cubic meters of hydrogen could be introduced into the network each year, which is equivalent to the annual gas consumption of 3 million families, and represents a reduction of 5mm tons of CO_2 emissions.

BKR-N Participates in Different Parts of the Hydrogen Value Chain

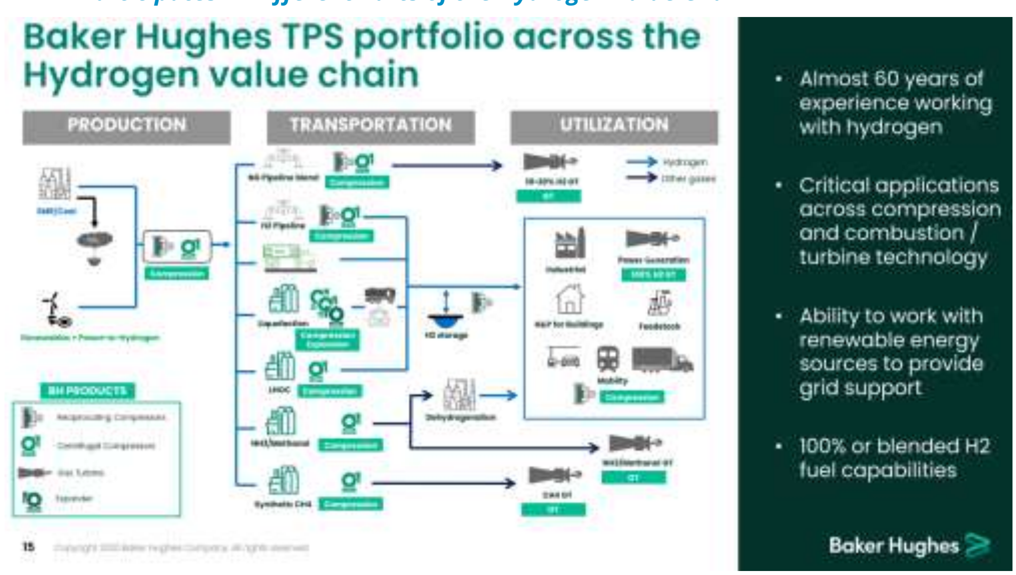


Figure 51 – BKR-N Participates in Different Parts of the Hydrogen Value Chain
Source: Baker Hughes Company

Schlumberger Ltd. (SLB-N, OP, PT US$27.00; here)

Schlumberger New Energy (SNE) is the Company's new business segment announced mid-June and we believe it could play a pivotal role in its ESG efforts. SNE was launched in early 2020 to focus on business opportunities in low-carbon or carbon-neutral energy technologies, which will expand the Company beyond oil and gas. This holds two key benefits: Diversification away from oil and gas and the potential for significant growth opportunities in the long term. SLB-N is not interested in wind and solar energy as it considers them to have become commoditized, and is seeking opportunities where it can offer a differentiated value proposition. However, SLB-N is still in the very early stages, especially with respect to gaining a foothold in the hydrogen business, and it is still unclear if its steps and ventures would lead to a commercial success.

One of SLB-N's new businesses that will be part of Schlumberger New Energy is Genvia, which is a hydrogen-producing technology venture in partnership with the French Alternative Energies and Atomic Energy Commission (CEA), as well as Vinci Construction. Per SLB-N, *"this will accelerate the development and first industrial deployment of the CEA high-temperature, reversible solid oxide electrolyser (SOE) technology.*"

SOE can potentially be a step-change in technology in the medium term as it offers a unique and efficient method to produce clean hydrogen by water electrolysis using a renewable source of electricity. The mission is to enable clean hydrogen production at a competitive price with differentiated system efficiency. Per SLB-N, low-carbon hydrogen could reach volumes greater than 10 megatons by 2035, which represents a significant growth opportunity for Genvia. Many companies are engaged in producing hydrogen via electrolysis in an economical way, and SLB-N is pursuing research in that area too.

Enerflex Ltd. (EFX-T, OP, PT C$9.00; here)

Enerflex has decades of experience as a provider of compression equipment required in hydrogen production facilities, which service the downstream oil and gas refining sector. As mass hydrogen production begins to increase, EFX-T is well positioned to benefit from increased demand for compression equipment required for blue hydrogen production. In addition, to the extent that carbon capture and storage is required for blue hydrogen production, EFX-T could benefit from increased compression demand required for underground carbon storage; an area where EFX-T has decades of experience through CO_2 floods traditionally used for enhanced oil recovery in the oilfield.

Northland Power Inc. (NPI-T, OP, PT C$45.00; here)

Pointing back to the electrolysis diagrams (Figures 11 and 12), we want to highlight the potential for offshore wind to play a major role in the production of green hydrogen, which as a reminder, is hydrogen production combining renewable power generation for electrolysis (the cleanest method of production). With global markets focused on decarbonization efforts, Northland Power has identified its potential to be an early mover into green hydrogen through use of its offshore wind assets in the electrolysis process. Not only will this extend the life of maturing assets, offshore wind assets have the potential to provide surplus renewable electricity after PPA expiration, which we expect will be low-cost, economical electricity.

Capital Power Corporation (CPX-T, SP, PT C$36.00; here); TransAlta Corporation (TA-T, OP, PT C$11.00; here)

Despite previous commentary around transitioning from coal-to-gas and operating at an economical mix over the medium term, Capital Power has recently announced it will undergo a full repowering at its Genesee 1 & 2 facilities. We highlight that these facilities, post repowering, will offer hydrogen capacity of ~30%, which management believes it can increase at minimal cost to 95% in the future. CPX-T has also taken strides toward carbon conversion as the Company continues its build-out of the

Genesee Carbon Conversion Centre (GCCC) project, a 2,500-tonne carbon nanotube facility. Turning to TA-T, the Company is less focused on its transition to hydrogen; however, management has noted it will look at repowering one of its current thermal facilities in mid-to-late 2020, which we expect would include hydrogen capabilities in line with CPX-T.

Keyera Corp. (KEY-T, OP, PT C$28.00; here)

Despite limited commentary on hydrogen from management teams in the midstream space, Keyera (KEY-T, OP, PT C$28.00) believes it is well positioned for a significant jump in hydrogen demand. While KEY-T already produces hydrogen as a by-product at its AEF facility, management has noted the potential use of depleted gas wells could be a suitable carbon capture and sequestration option for carbon created in the hydrogen manufacturing process.

In the long term, there will likely be significant opportunities for midstream players to participate in CCUS. It is a given that a significant shift to hydrogen will require pipelines and an extensive footprint for scale. However, we note that physical pipeline limitations remain for a full transition to hydrogen in the near term. On a volumetric basis, hydrogen is less energy dense than natural gas, implying that it will take more/bigger hydrogen pipelines to deliver the same amount of energy as contained in an equal volume of natural gas.

Tourmaline Oil Corp (TOU-T, OP, PT C$25.00; here)

Canada is competitively positioned as a producer of blue hydrogen, owing to its low-cost gas, and we highlight the Country's largest gas producer Tourmaline Oil Corp. (TOU-T, OP, PT C$25.00) as a potential beneficiary of increased gas demand, as gas-sourced hydrogen demand increases. The Company has conducted recent acquisitions (Modern & Jupiter Resources - 76 mboe/d) which solidify the company as a dominant gas producer in the basin and provide significant relevance on a North American scale. TOU is our top gas idea at this time, with a clear cost and structural advantage relative to peers, built on a deep asset base and infrastructure footprint and financing advantage through the Topaz (TPZ-T; NR) dropdown vehicle, and an appetite for small-and-large scale consolidation that we believe will ultimately reward shareholders by capturing future in-basin gas price upside.

Stantec Inc. (STN-T, OP, PT C$49.00; here)

Stantec is actively positioning to participate with Advisory, Consulting and Project Delivery services in the Hydrogen value chain. The Company recently released a presentation (here) which provides some background to how it sees the hydrogen supply chain and described its capabilities. Stantec is active in areas including natural gas or power delivery and water treatment, technology selection and support Electrolysers, Steam-Methane Reforming (SMR), Autothermal Reforming (ATR), Gasification units (GZN) and Carbon Capture and Storage (CCS), H_2 and CO_2 handling and storage and pipeline distribution system design, safety and integrity.

Stantec Hydrogen Overview

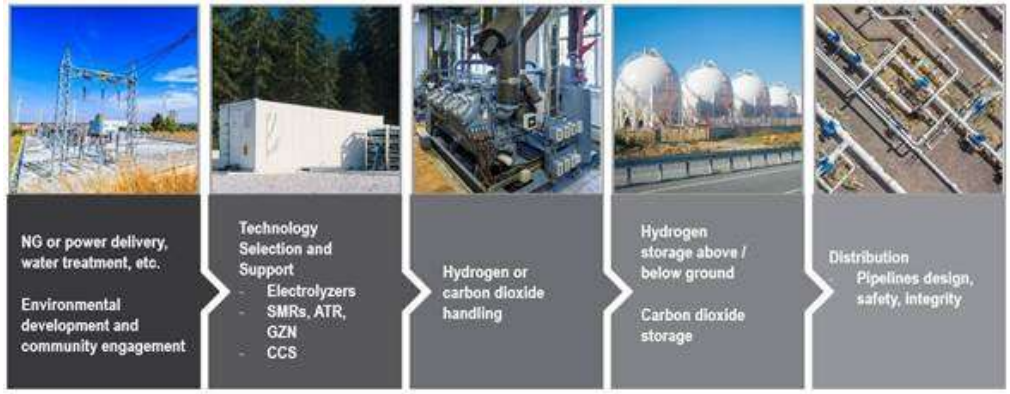


Figure 52: Stantec Hydrogen Overview
Source: Stantec Inc.

SNC-Lavalin (SNC-T, OP, PT C$41.00; here)

While not yet a material contributor to revenues, SNC is well positioned to be able to leverage its previous experience in natural gas and other process work and is a sector the Company continues to follow closely. SNC is part of a consortium undertaking FEED study for construction of a hydrogen production plant for HyNet North West in the United Kingdom leveraging its existing process capabilities.

The HyNet North West project is intended to develop a regional blue hydrogen network in the North West of England and North Wales, leveraging existing salt and gas reservoirs for CO_2 and H_2 storage, which are expected to reach the end of their economic life by 2025.

HyNet North West Overview

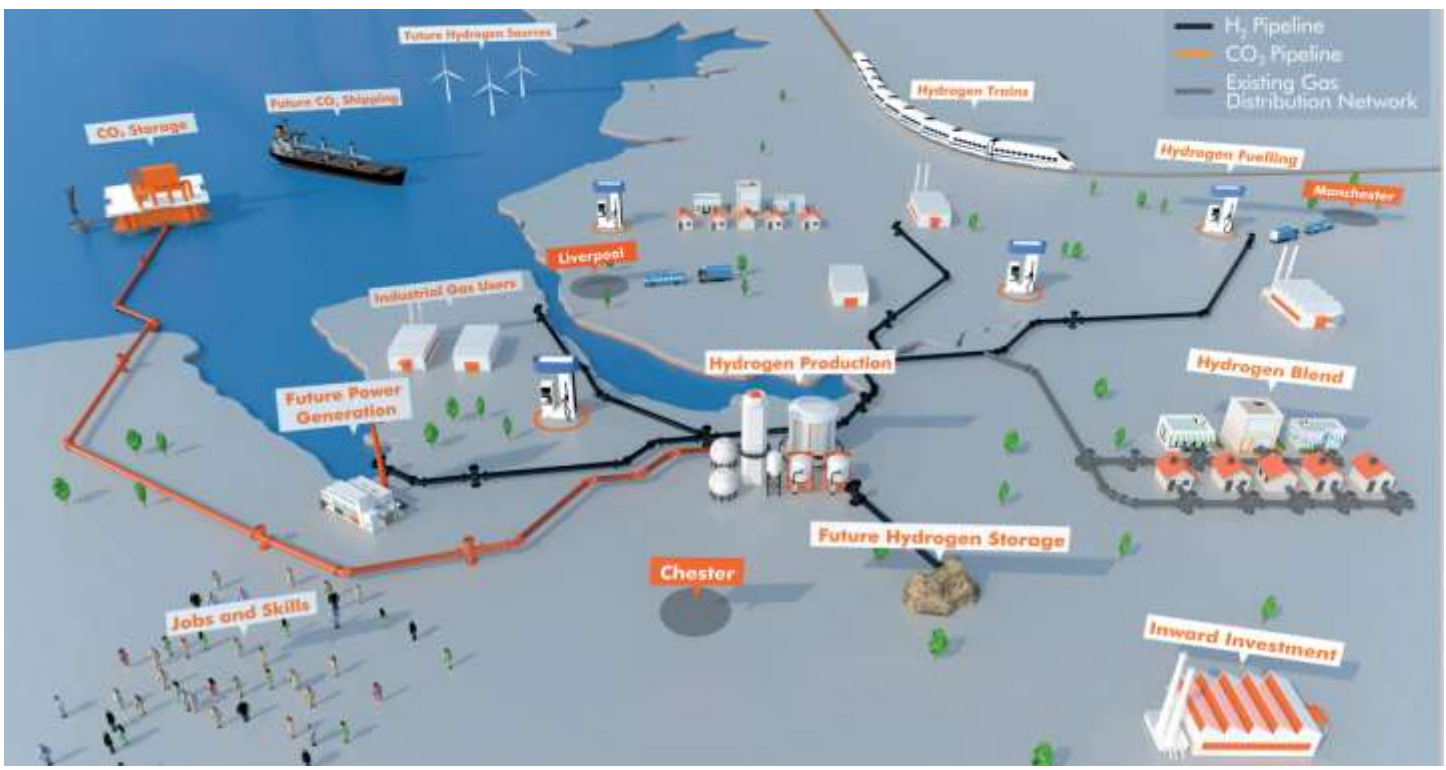


Figure 53: HyNet North West Overview
Source: HyNet North West

WSP Global Inc. (WSP-T, OP, PT C$125.00; here)

WSP has expertise in large volume underground hydrogen storage, distribution and production, leveraging its knowledge of natural gas systems. It is also active as lead planning, environmental, stakeholder and land advisory advice for HyNet North West's CO_2 pipeline and site optimisation for the Murchison Renewable Hydrogen Project (Australia). The Company was also named as the preferred supplier by the Government of South Australia (here) to develop modelling tools and a prospectus to be used to determine locations for hydrogen production and export, volume of supply, other infrastructure needs and cost of developing a commercial-scale hydrogen export industry.

Aecon Group Inc. (ARE-T, OP, PT C$19.00; here)

Aecon is Involved in supporting current utilities clients in the development of industrial projects and distribution networks performing integrity, upgrade, and new construction work. It is also looking to participate in large industrial process projects. The Company generated ~17% of trailing twelve-month revenue from its utilities segment and ~20% from its industrial business.

As an example of the type of opportunity, the Company pointed to Enbridge Inc.'s (ENB-T, NR) pilot Low-Carbon Energy Project (LCEP) in the City of Markham (here), where the Company uses excess off-peak power (mainly nuclear baseline load) to generate green hydrogen via electrolysis. The hydrogen is then blended at low levels (~2% concentration) and then delivered to ~3,600 customers with a forecast reduction in GHG emissions of 97 tCO_2e to 120 tCO_2e per year. As Aecon noted, the project requires the construction of the initial pilot plant as well as new and upgraded distribution networks and some valve and other upgrade work.

Enbridge Low-Carbon Energy Project Overview

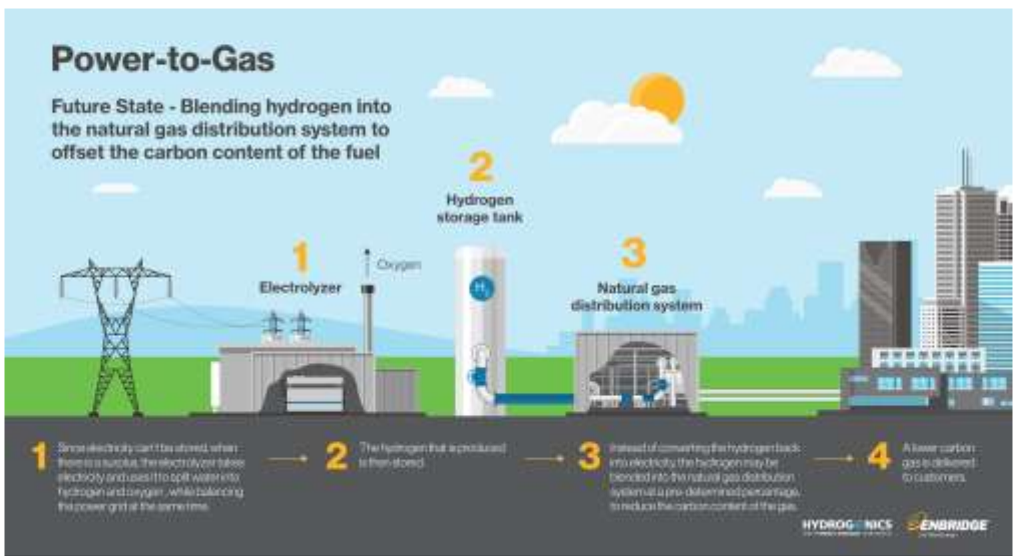


Figure 54: Enbridge Low-Carbon Energy Project Overview
Source: Enbridge Inc.

Appendix

Key Abbreviations Throughout the Report

Key Abbreviations			
ATR	autothermal reforming	HGU	hydrogen generation unit
BEV	battery electric vehicle	ICE	internal combustion engine
BTX	benzene toluene xylene (hydrocarbon solvents)	IEA	the International Energy Agency
CCUS	carbon capture, utilization, and storage	IRENA	the International Renewable Energy Agency
CDA	carbon direct avoidance	kg	kilogram
CH_4	methane gas	LHOC	liquid organic hydrogen carriers
CNG	compressed natural gas	mCHPs	micro combined heat and power
CO_2	carbon dioxide	MW	megawatt
DRI	direct reduced iron	MWh	megawatt hour
E&C	engineering and construction	PEM	proton exchange membrane (electrolysis)
EPC	engineering, procurement, and construction	PPA	power purchase agreement
EU	the European Union	SDS	sustainable development scenario
FCEV	fuel cell electric vehicle	SMR	steam methane reforming
GHG	green house gas	SOE	solid oxide electrolysis
GW	gigawatt	T	tonnes
GZN	gasification unit	TOE	tonnes oil equivalent
H_2	hydrogen	tCO_2e	tonnes CO_2 equivalent
H_20	water		

Figure 55: Key Abbreviations Throughout the Report

Source: ATB Capital Markets Inc.

ATB Capital Markets

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