New Zealand Hydrogen Scenarios and the Future of Gas

Report for the Gas Industry Company

SEPTEMBER 2022

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Definitions

BEV	Battery Electric Vehicle
BF-BOF	Blast Furnace-Basic Oxygen Furnace
Blended hydrogen	A blend of hydrogen and natural gas, with the former at 20 percent concentration by volume
CCC	Climate Change Commission
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO2e	Carbon Dioxide Equivalent
DAC	Direct Air Capture
DRI	Direct Reduced Iron
ETS	Emissions Trading Scheme
FCEV	Fuel Cell Electric Vehicles
GIC	Gas Industry Company
LCOGH	Levelised Cost of Green Hydrogen
LNG	Liquid Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LPG	Liquid Petroleum Gas
SAF	Sustainable Aviation Fuel

Executive summary

New Zealand has committed to achieve net zero emissions by 2050—this requires the energy sector to become more renewable, sustainable, and efficient. The natural gas industry is an important component of the energy sector, so it is likely to play a crucial role in ensuring that New Zealand can execute a successful energy transition.

The Gas Industry Company (GIC) co-regulates New Zealand's natural gas sector alongside the New Zealand Government. GIC is working with the Government to develop a Gas Transition Plan to decarbonize the natural gas sector.

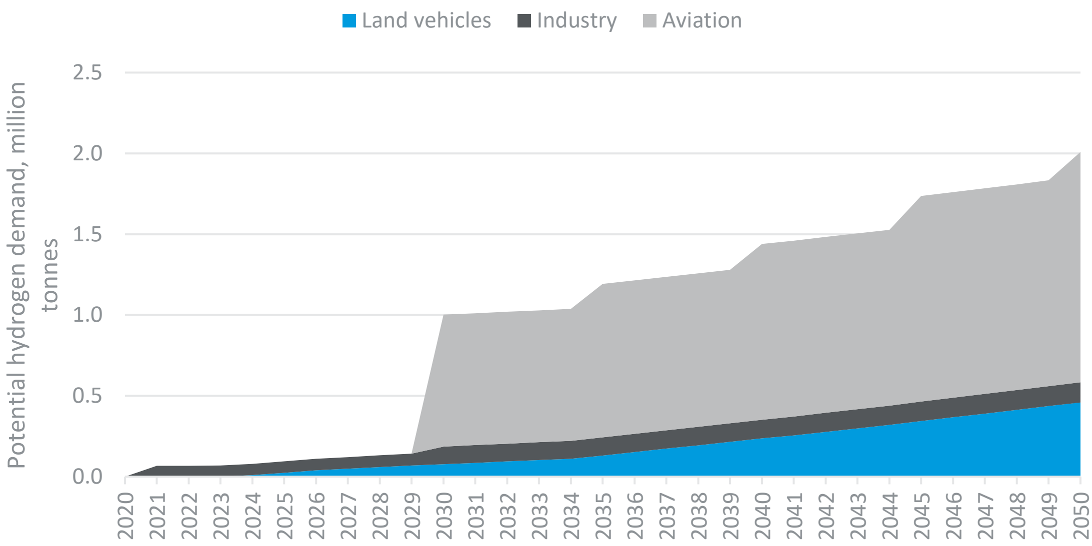
GIC wants to understand the future of hydrogen in New Zealand, how that might impact the natural gas sector, and how the sector can prepare for these impacts. Hydrogen is a promising clean energy solution with a wide range of applications that could assist with New Zealand's energy transition. GIC has engaged Castalia to provide expert economic analysis and modelling to analyse hydrogen developments, scenarios, and implications for New Zealand's natural gas sector.

Hydrogen development in New Zealand

Hydrogen could play an important role in New Zealand's energy transition, but the analysis suggests it is unlikely to involve large-scale utilisation of New Zealand's existing natural gas infrastructure. Hydrogen can help decarbonize hard-to-abate uses in New Zealand, especially heavy-duty vehicles and aviation. Potential demand for hydrogen could also come from maritime transport and energy export. Other hydrogen uses are possible, but they are less likely, or are relatively niche.

Figure 0.1 on the next page shows that under the most optimistic green hydrogen development scenario modelled, New Zealand could demand up to two million tonnes of hydrogen per year by 2050, with the bulk from hydrogen-based aviation. Hydrogen for aviation is highly uncertain, and a range of technologies, fuels or offsets could emerge as the solution to decarbonising the sector.

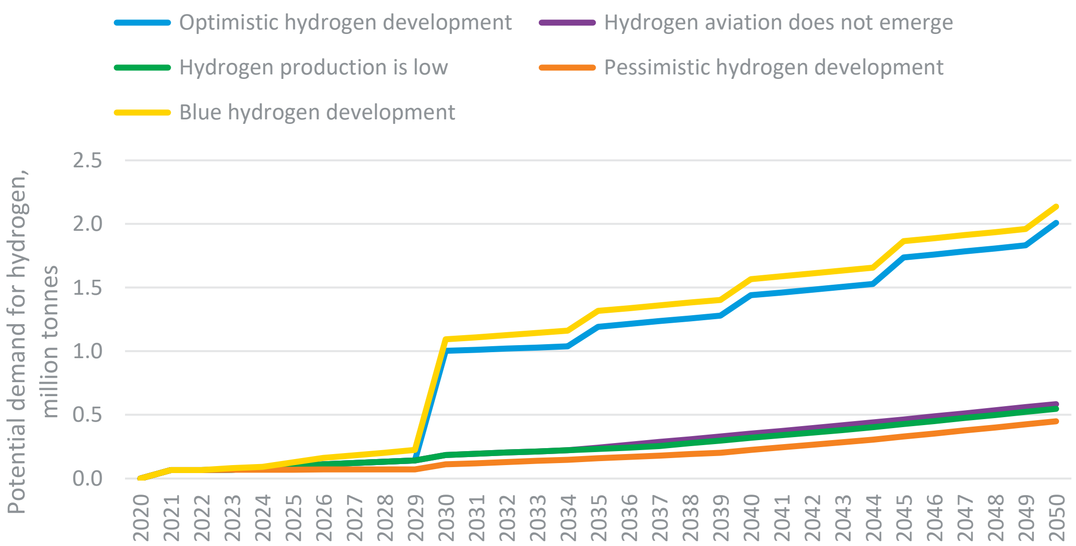
Figure 0.1: Most optimistic demand for hydrogen in New Zealand



Note: Land vehicles include heavy industrial vehicles, heavy trucks, heavy buses, and light vehicles. Industry includes fertiliser and steel production.

Figure 0.2 below shows the large differences in potential hydrogen demand in five scenarios modelled for this study. The scenarios do not predict the future, but rather are useful to understanding how hydrogen demand could impact on gas networks. For the purpose of this study, we pose the question: what if gas is phased out and hydrogen is considered as an alternative energy source for current natural gas uses?

Figure 0.2: Potential hydrogen demand in New Zealand's economy



Note: Actual demand is likely lower than potential demand for hydrogen in New Zealand. Potential demand is the upper limit for hydrogen demand in New Zealand under each hydrogen scenario

Impact of hydrogen on the natural gas sector

Despite the modelled potential demand for hydrogen, New Zealand's natural gas infrastructure is unlikely to be a viable large-scale tool for transporting hydrogen. This is because the economic operation of the existing gas network asset footprint will not align with potential hydrogen production and consumption patterns. In particular, the likely use cases for green hydrogen in New Zealand would not require green hydrogen to be produced in Taranaki, nor transmitted over large distances.

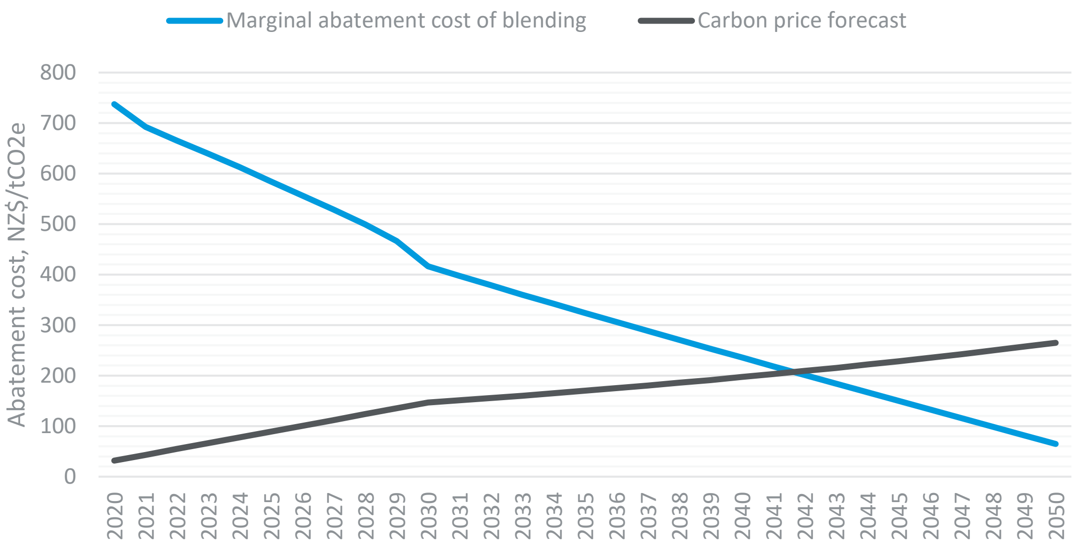
There are three main categories of natural gas infrastructure: production, transmission, and distribution. Each is likely to require different conditions to remain viable in a hydrogen-rich future:

- Production infrastructure could be viable if a full transition to blue hydrogen demands continued extraction and processing of natural gas
- Transmission infrastructure could be viable if a full transition to green or blue hydrogen demands large volumes of hydrogen produced in Taranaki and transmitted across the North Island
- Distribution infrastructure could be viable if blended hydrogen is competitive for residential and commercial consumers, or another use for the infrastructure. In this report, blended hydrogen refers to a blend of hydrogen and natural gas, with the former at 20 percent concentration by volume.

However, modelling and analysis undertaken in this study suggests that the above conditions are unlikely to eventuate:

- New Zealand could demand a large amount of green hydrogen, but the demand is likely to be located in a way that does not require production in Taranaki nor transmission across large distances
- Blue hydrogen production is only competitive with advanced CCS technologies, but CCS would also help decarbonise natural gas. Thus, New Zealand would probably continue to consume natural gas for key uses cases such as electricity generation and industrial uses, rather than use the natural gas to produce hydrogen for the same use cases
- Blended hydrogen could be financially viable for commercial and residential consumers on the distribution network. This might make hydrogen blending a viable option for partial decarbonisation. It could also make hydrogen blending (including at higher concentrations) a viable future option in case there is a technological breakthrough that lowers the cost of hydrogen or enables higher blending rates. It is important to note, however, that blended hydrogen has a high marginal abatement cost, as shown in Figure 0.3 on the next page. This means blended hydrogen is unlikely to be cost-effective at reducing emissions compared to other options.

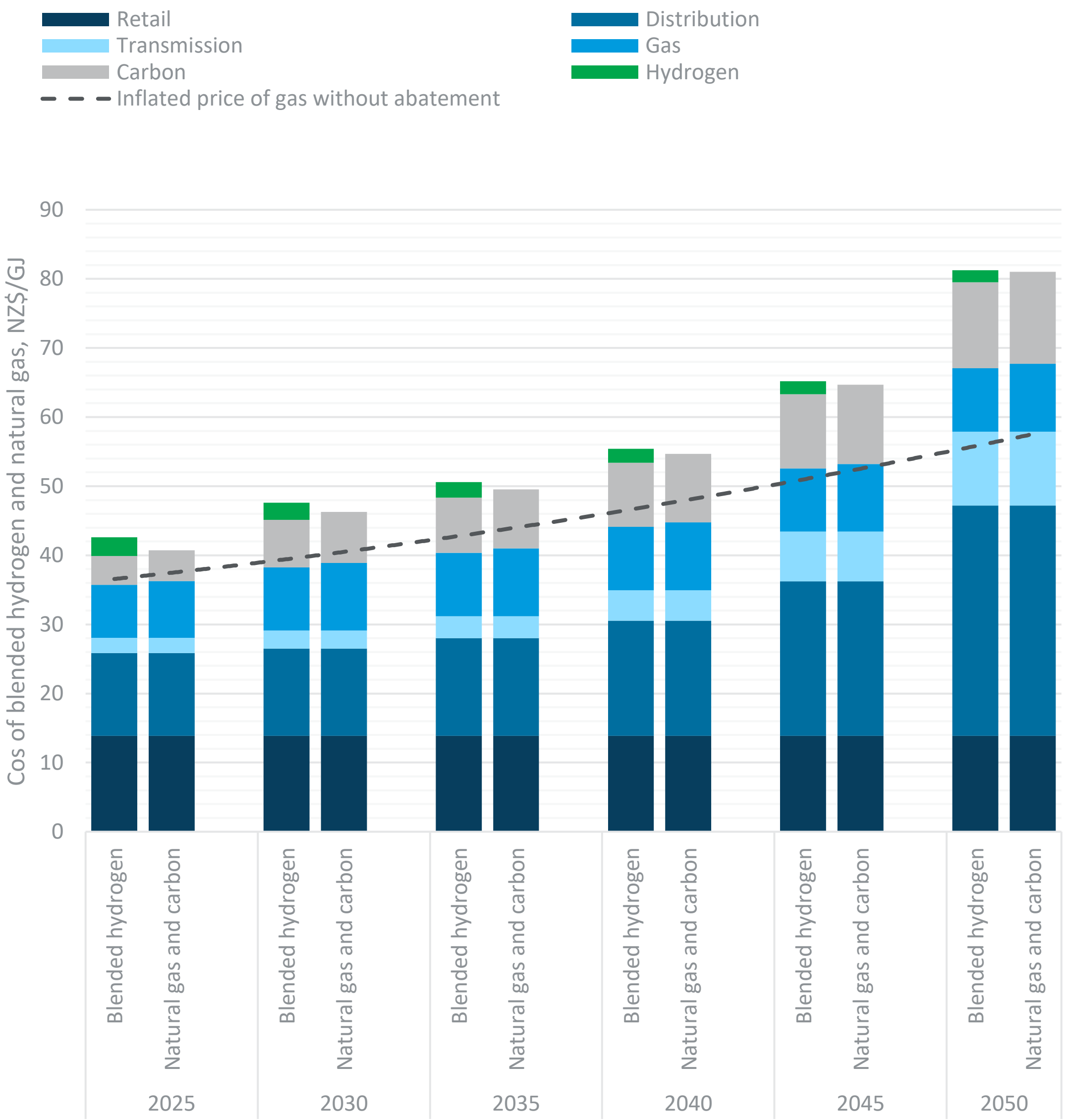
Figure 0.3: Cost effectiveness of blending in reducing emissions



Note: Carbon price forecasts are CCC headwinds scenario carbon prices. The marginal abatement cost of blending is the carbon dioxide content of natural gas displaced by green hydrogen, over the price difference between blended hydrogen and natural gas.

The cost difference between blended hydrogen and non-blended hydrogen for residential customers is displayed in Figure 0.4 on the next page. It shows that the costs associated with the production, transmission, distribution, and retail are the same for blended hydrogen and natural gas. Given the decision to abate emissions, incurring the cost of carbon is likely to be cheaper than using blended hydrogen to offset emissions until the 2040s.

Figure 0.4: Cost breakdown of blended hydrogen versus natural gas to residential consumers



Note: The inflated price of gas without abatement refers to the cost of delivered gas inflated at a rate of 2.5%p.a. from 2020 prices. It assumes zero abatement cost and keeps the retail cost constant at 2020 values.

Considering these factors, it seems that a future hydrogen economy is unlikely to involve significant reliance on the natural gas infrastructure. Hydrogen is unlikely to displace natural gas demand. Hydrogen is also unlikely to play a role in extending the lives of existing natural gas infrastructure.

Recommendations

Based on the above findings and the current, this study includes four recommendations. Natural gas industry stakeholders and energy sector policymakers should:

1. De-prioritise investment activity for the time being aimed at fully transitioning the sector to hydrogen, whether blue or green

2. Consider investment in blended hydrogen only to the extent that this:
    a. Reduces demand risk for scale hydrogen production projects in the short-term, ahead of demand emerging in the transport sector over the medium and longer-term
    b. Creates a real option for the gas sector to avoid irreversible decisions on the future of gas (like decommissioning pipelines), particularly as new information emerges on costs and viability of green hydrogen
3. Deprioritise green certificate schemes for blended hydrogen because these do not appear cost-effective, unless the cost of hydrogen decreases significantly in the short to medium-term. However, certificates may be more economic for other renewable gases
4. Investigate the technical and economic viability of blending other renewable gases in the distribution network, independently of the transmission network.

1 Introduction

This study analyses the pathways for hydrogen and their potential impacts on the natural gas sector in New Zealand. It considers the two principal forms of low-emissions hydrogen development: “blue” and “green” hydrogen.

This study focuses on hydrogen’s potential impact on New Zealand’s existing natural gas sector. It analyses the impact low-emission hydrogen could have on the natural gas sector in New Zealand by modelling a set of scenarios. For each scenario, this report describes its drivers, inhibitors, key impacts, the timing of these impacts, and the implications for the natural gas sector.

This report is structured as follows:

- Section 2 describes the current context of New Zealand’s natural gas sector
- Section 3 outlines possible future use cases for hydrogen and their potential viability in New Zealand
- Section 4 builds upon the previous sections to analyse the likely dynamics between future uses of hydrogen and the current natural gas sector
- Section 5 illustrates six hydrogen scenarios, discussing key modelling results and the impacts on the natural gas sector
- Section 6 recommends potential actions for natural gas sector participants and policymakers to prepare for the impacts of hydrogen.

2 Natural gas in New Zealand

New Zealand's natural gas sector is concentrated in the North Island. The North Island has a reticulated natural gas network. The South Island has some minor liquified petroleum gas (LPG)[1] networks. New Zealand's natural gas sector is self-contained—all gas extracted is processed, distributed, stored, and consumed domestically. No gas is directly exported via pipelines or liquified natural gas (LNG), though some is indirectly exported as methanol. New Zealand also imports and exports LPG depending on domestic supply and demand.[2] For the purposes of this study, LPG is not considered natural gas.[3]

New Zealand uses natural gas produced in Taranaki to generate electricity, provide heating, and synthesise chemicals across the North Island. The natural gas infrastructure is described in section 2.1. New Zealanders rely on natural gas because it can produce high temperatures at a relatively low cost. However, natural gas is not renewable and carries emissions. Natural gas consumption and trends are described in section 2.2.

The gas industry and government broadly expect natural gas use to decline as households, businesses, and power generation switch to low or zero emissions technologies. Natural gas production and the outlook is set out in section 2.3.

2.1 Natural gas infrastructure

New Zealand's natural gas infrastructure consists of three main components: production facilities, transmission networks, and distribution networks. The footprint of New Zealand's natural gas infrastructure reflects the existing value chain of natural gas. The natural gas value chain is organised as follows:

- Production facilities extract natural gas in Taranaki
- Transmission networks take gas from Taranaki's production facilities and transport gas at high pressures across the North Island
- Distribution networks take gas from transmission pipelines and transport gas at largely low pressures to end-users, where gas is consumed.

No import or export facilities for natural gas exist, making New Zealand an independent gas market.

2.1.1 Production and processing facilities

Natural gas production facilities extract and process natural gas from Taranaki. Around 15 natural gas fields in Taranaki supply all of New Zealand's natural gas. First Gas also owns the 18PJ Ahuroa natural gas storage facility, a depleted gas field that stores excess gas to meet peak demand.

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1 LPG, or liquified petroleum gas, is classified as oil rather than gas; however, LPG can be a substitute for natural gas, and many consumers consider LPG a type of gas

2 Genesis Energy, How the LPG market works in New Zealand, available: https://www.genesisenergy.co.nz/help/faqs/understanding-lpg-and-my-bottled-gas-bill

3 This is because LPG is not technically natural gas, does not see comparable consumption as natural gas, and does not risk leaving behind stranded assets to the same extent as natural gas (since little dedicated infrastructure exist)

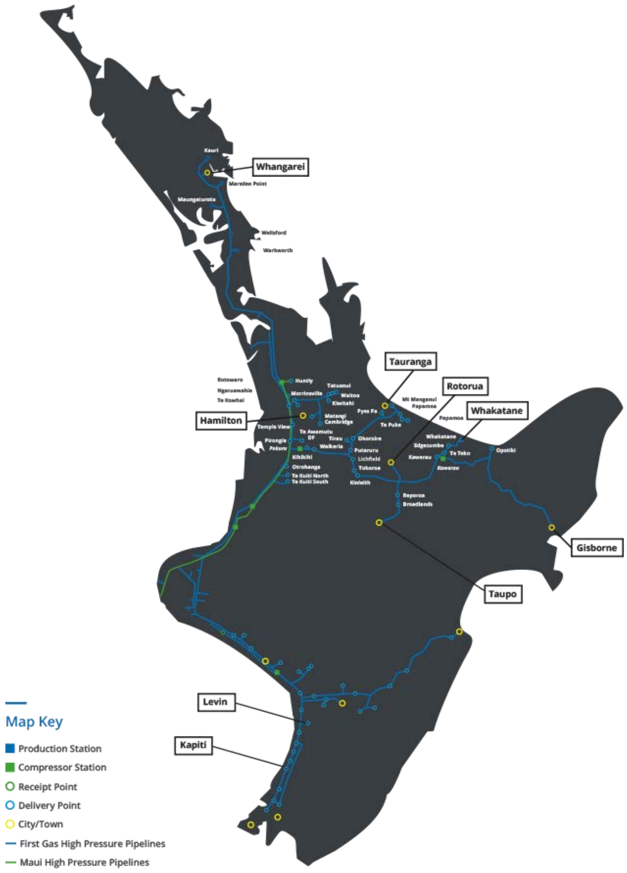
2.1.2 Transmission network

New Zealand's natural gas transmission network transports natural gas from Taranaki to 131 delivery points across the North Island.[4] First Gas operates the entire transmission network, including 2,200km of high-pressure transmission pipelines and the 300km Maui pipeline.[5]

The transmission network consists of high-pressure steel pipelines of varying wall thickness and material grades.[6] The network also includes other assets, such as compressor stations, filters, heating systems, metering, and valves.[7]

The transmission network reaches most of the North Island, stretching from Taranaki northwards to Whangarei, eastwards to Gisborne, and southwards to Wellington, as shown in Figure 2.1 below.

Figure 2.1: New Zealand natural gas transmission network



Source: First Gas

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4 First Gas, Gas Transmission Asset Management Plan, available: https://firstgas.co.nz/wp-content/uploads/Firstgas-2021-Transmission-AMP-Update.pdf

5 First Gas, Our Network, available: https://firstgas.co.nz/about-us/our-network/

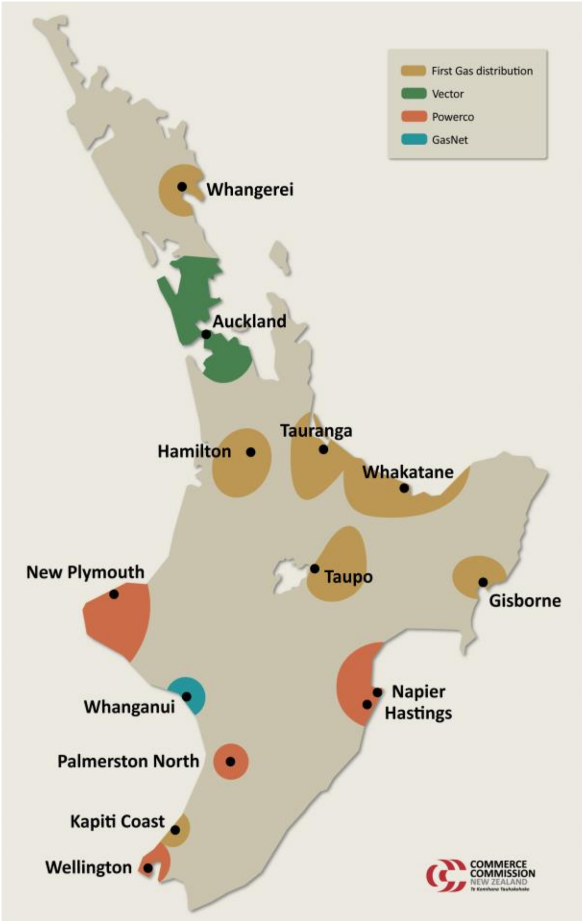
6 First Gas, Gas Transmission Asset Management Plan, available: https://firstgas.co.nz/wp-content/uploads/Firstgas-2021-Transmission-AMP-Update.pdf

7 First Gas, Gas Transmission Asset Management Plan, available: https://firstgas.co.nz/wp-content/uploads/Firstgas-2021-Transmission-AMP-Update.pdf

2.1.3 Distribution network

New Zealand's natural gas distribution network transports natural gas from the transmission network to end consumers. First Gas, Vector, PowerCo, and GasNet operate New Zealand's eleven main distribution networks, as shown in Figure 2.2 below.

Figure 2.2: New Zealand natural gas distribution network



Source: Commerce Commission

The distribution network consists of predominantly low-pressure polyethylene pipelines, but some intermediate or high-pressure steel pipelines also exist.[8] The network also includes other assets, such as regulator stations, valves, meters, and repair collars.[9]

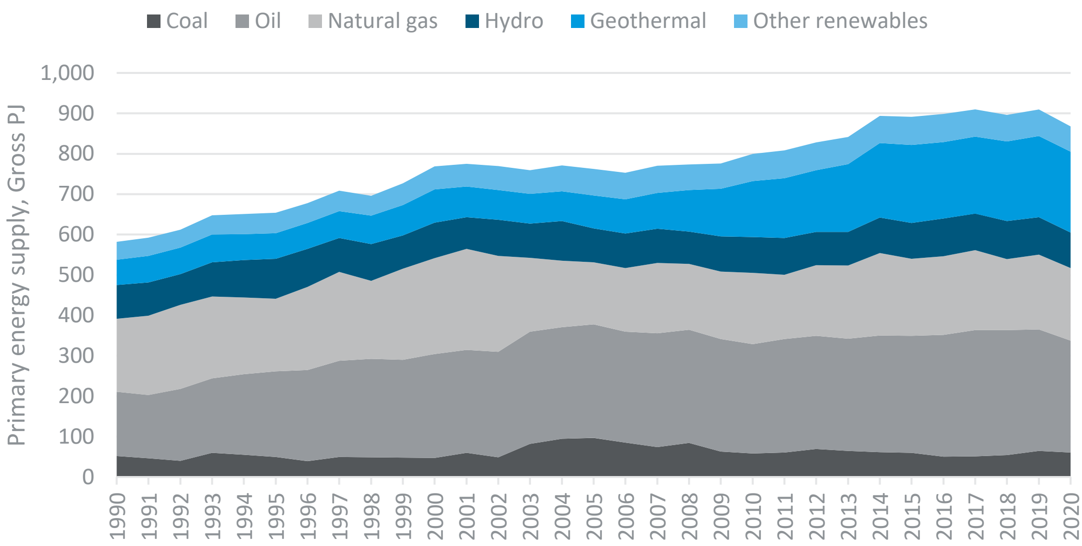
2.2 Natural gas consumption

New Zealand uses natural gas for a variety of purposes, with the majority consumed in energy and industry. Natural gas plays an important role in New Zealand's energy mix, accounting for 21 percent of total primary energy supply in 2020, as shown in Figure 2.3 on the next page.

8 Commerce Commission (2021), Gas distribution information disclosure data asset register

9 Commerce Commission (2021), Gas distribution information disclosure data asset register

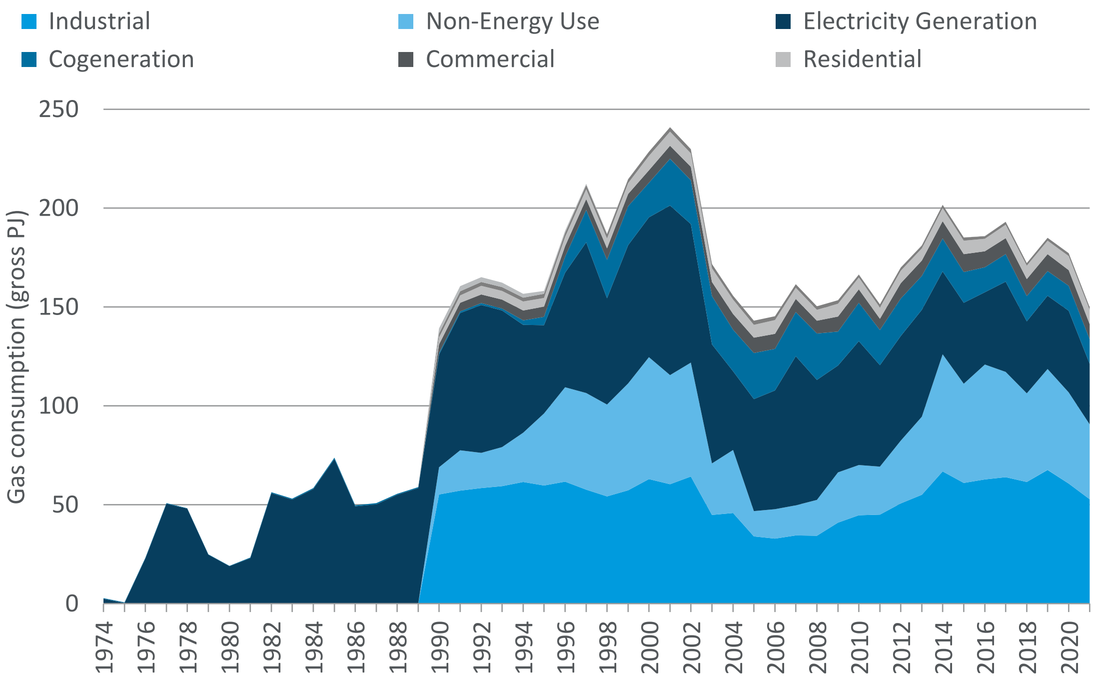
Figure 2.3: New Zealand primary energy supply by source



Note: Primary energy supply refers to energy that has not been transformed through human-engineered processes
Source: MBIE Energy in New Zealand: Energy Overview Data Tables

Natural gas is a key energy component used across multiple sectors in New Zealand. Almost 28 percent of natural gas consumed in New Zealand is used to generate electricity, while over 25 percent of natural gas has non-energy uses, as shown in Figure 2.4 below.

Figure 2.4: New Zealand natural gas consumption by sector



Source: MBIE Gas Production and Consumption Data Tables

New Zealand's natural gas consumption is highly concentrated. Methanex, the world's largest producer of methanol, has three facilities in New Zealand producing methanol from natural gas. These facilities alone would represent just under half of New Zealand's annual natural gas consumption.[10] As existing natural gas consumers wind down or switch to low-emissions technologies, natural gas demand will also decrease.[11] However, this decrease might not be gradual due to New Zealand's highly concentrated natural gas consumption pattern, which increases volatility and uncertainty for the natural gas sector.

The presence of Methanex also provides flexibility for New Zealand's natural gas sector. Due to its large scale and flexible production pattern, Methanex helps create certainty for gas sector participants.[12] The upstream sector benefits from a base level of gas supply when gas supply exceeds demand. The downstream sector benefits from Methanex reducing production and on-selling gas when gas demand exceeds supply. If Methanex exits New Zealand, the natural gas sector is likely to have reduced flexibility and confidence of supply. This could accelerate the decline in gas demand.[13]

2.3 Natural gas production

New Zealand has an independent natural gas market supplied almost entirely by domestic production, almost all of which occurs in Taranaki.[14] New Zealand's natural gas supply closely matches natural gas demand. Natural gas producers must also balance their costs—extraction and processing costs—with expected revenue—natural gas wholesale prices.

Natural gas production in New Zealand is likely to decline but remain sufficient to meet natural gas demand, according to GIC-commissioned modelling.[15] While existing gas reserves[16] are likely to deplete, contingent resources[17] could be developed to ensure security of supply. Figure 2.5 on the next page shows the projected natural gas production profile if 50 percent of reported contingent resources were developed. While contingent resources are not commercially viable now, they are likely to be developed and reclassified as reserves in the future, assuming historical gas prices hold.

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[10] Energy Resources Aotearoa (2022), Fuelling the Energy Transition: A Low Emissions Energy Future for New Zealand

[11] Concept Consulting (2021), Modelling energy costs and prices—A technical note supporting Inaia tonu neu

[12] GIC, Gas Supply and Demand, available: https://www.gasindustry.co.nz/our-work/work-programmes/gas-supply-and-demand/

[13] Commerce Commission (2022), Default price-quality paths for gas pipeline businesses from 1 October 2022: Final Reasons Paper, available: https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf

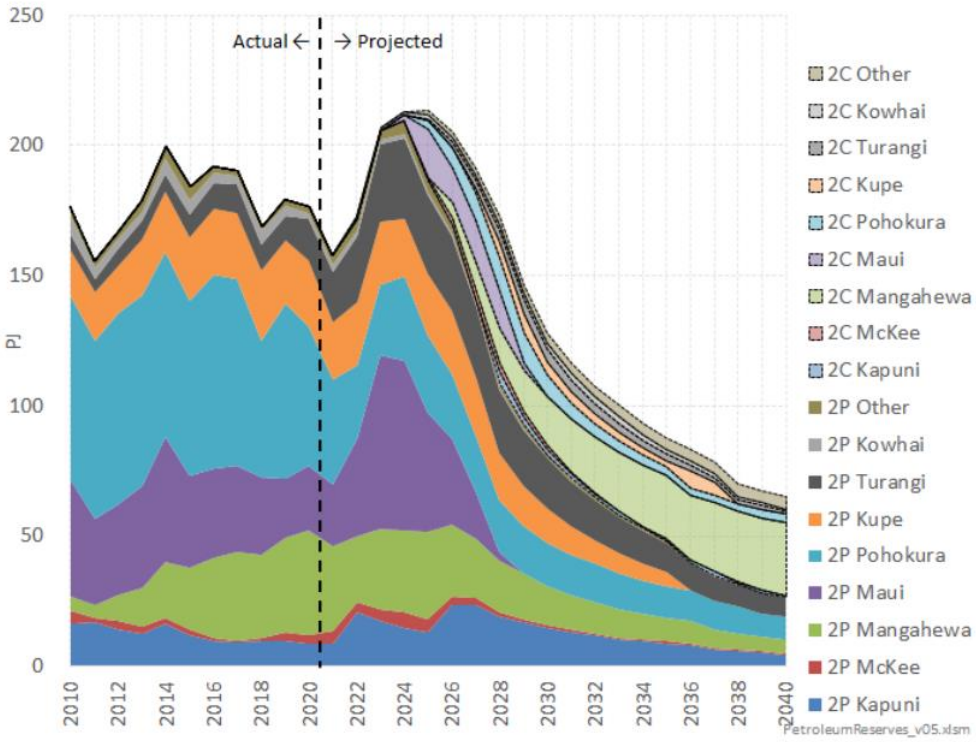
[14] MBIE, Gas Statistics, available: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/

[15] GIC, Gas Supply and Demand, available: https://www.gasindustry.co.nz/our-work/work-programmes/gas-supply-and-demand/

[16] Reserves refer to the volume of natural gas that is technically and commercially recoverable with the latest technology. 2P resources refer to those that are at least 50 percent probably, meaning that the actual gas volume is more likely to exceed estimates than not.

[17] Contingent resources refer to the volume of natural gas that is technically but not commercially recoverable with the latest technology. 2C resources refer to those that are at least 50 percent probably, meaning that the actual gas volume is more likely to exceed estimates than not.

Figure 2.5: New Zealand projected natural gas production profile

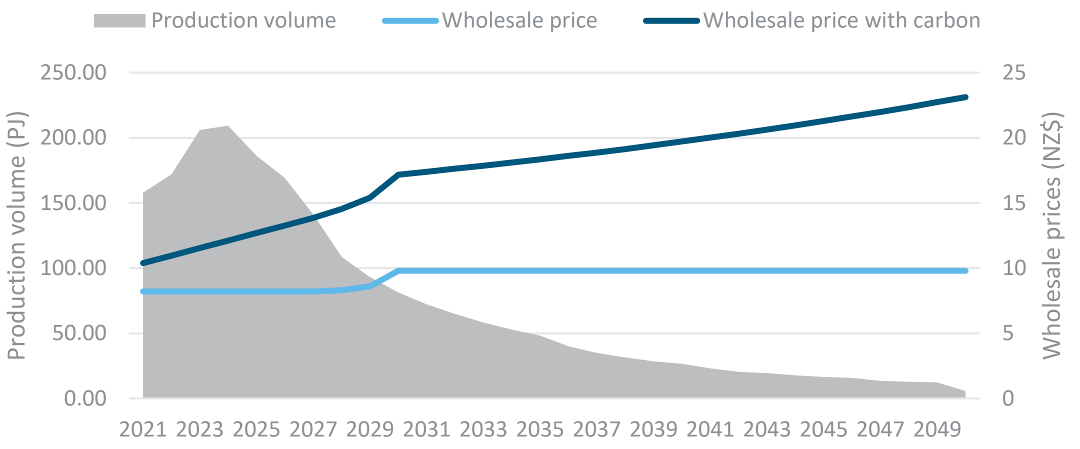


Note: The modelling assumes reserves and resources reported as of January 2021.
Source: Concept Consulting (2022) developed for GIC, Gas supply and demand projections.

Industry and government expect natural gas production to decrease over time as current users of natural gas transition to low or zero-emission alternatives.[18] Natural gas prices are also expected to remain stable because producers will likely reduce supply as natural gas demand decreases, though carbon prices charged on top are expected to increase, as shown in Figure 2.6 on the next page.

[18] Gas Infrastructure Future Working Group (2021), NZ Gas Infrastructure Future: Findings Report

Figure 2.6: New Zealand natural gas production and wholesale price forecast



Note: Wholesale prices are GST exclusive under CCC headwinds scenario.
Source: MBIE, New Zealand Energy Dashboard Gas Production Forecast; CCC, ENZ model outputs

3 Hydrogen demand in New Zealand

Hydrogen has several technologically and financially viable use cases in New Zealand that could lead to a relatively high level of hydrogen demand. Though hydrogen could have many promising uses globally, only some are likely to be viable in New Zealand:[19]

- Hydrogen is most competitive for heavy-duty transport and as a demand response tool (provided other markets exist for the hydrogen)
- Hydrogen could be economic for aviation, maritime transport, and energy export, but the technology evolution is uncertain
- Hydrogen is unlikely to be economic in New Zealand for light-duty vehicles, rail transport, fertiliser production, chemical production, steelmaking, intra-day energy storage, inter-seasonal energy storage, and heating
- Hydrogen could also have some intermediate uses in the short to medium-term to help partially abate emissions.

Table 3.1 on the next page summarises the key possible hydrogen uses cases, grouped into four categories, and their outlook in New Zealand.

Note that Sections 3.1, 3.2, and 3.3 assesses where hydrogen can be a full, or near full, decarbonisation solution. Section 3.4 further examines uses where hydrogen could contribute to partial decarbonisation.

[19] Castalia (2022), New Zealand Hydrogen Scenarios, available: https://www.mbie.govt.nz/dmsdocument/20118-new-zealand-hydrogen-scenarios-pdf

Table 3.1: Potential hydrogen uses in New Zealand

Category	High emissions use-case	Most viable solution	Other solutions	Outlook in New Zealand
Transport	Heavy-duty vehicles	Hydrogen and hydrogen derivatives	Electrification, biofuels	Likely
	Aviation	Hydrogen and hydrogen-derivatives	Electrification, biofuels	Ambiguous
	Maritime transport	Hydrogen derivatives	Electrification, biofuels	Ambiguous
	Light-duty vehicles	Electrification	Biofuels, hydrogen	Less likely
	Rail transport	Electrification	Biofuels, hydrogen	Less likely
Industry	Fertiliser production	Biomass	Hydrogen, carbon capture	Less likely
	Chemical production	Biomass	Hydrogen, carbon capture	Less likely
	Steelmaking	None	Hydrogen, electric arc furnaces, carbon capture	Less likely
	Heating	Electrification, biofuels	Hydrogen, carbon capture	Less likely
Energy	Demand response			Likely
	Energy export	Hydrogen and derivatives	None	Ambiguous
	Intra-day energy storage	Batteries	Overbuilding renewables	Less likely
	Inter-seasonal energy storage	Pumped hydro	Hydrogen and derivatives, fossil fuels with carbon capture	Less likely
Intermediate uses	Partial abatement of industry	Hydrogen	Carbon capture	Ambiguous
	Blending	Hydrogen	Carbon capture	Ambiguous

Source: Castalia analysis for MBIE, New Zealand Hydrogen Scenarios, available: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/a-vision-for-hydrogen-in-new-zealand/roadmap-for-hydrogen-in-new-zealand/

3.1 Likely hydrogen uses

New Zealand is likely to use hydrogen for heavy-duty vehicles and demand response as an effective full decarbonisation solution. This section outlines why hydrogen is suited for these likely uses, and advantages hydrogen has over competing technologies. Castalia also completed a comprehensive study of likely hydrogen use cases for MBIE in 2022.[20]

3.1.1 Heavy-duty vehicles

Hydrogen is a promising solution to lower the emissions of heavy-duty vehicles. These include heavy-duty vehicles, coach buses, and speciality vehicles, which will likely start transitioning to hydrogen in the short to medium-term.

Hydrogen is advantageous for long-distance and heavy vehicles because hydrogen fuel cell electric vehicles (FCEVs) have higher energy density, enable faster refuelling times and longer driving ranges, and are more efficient on undulating terrain.[21] Heavy-duty transport is one of the most mature uses for hydrogen, with proven technical viability and many ongoing commercial demonstration projects, both in New Zealand and overseas.[22]

The main alternatives to hydrogen are electrification and biofuels, but each has drawbacks. Electrification will require energy densities far above what batteries can achieve for large loads across long distances.[23] Battery electric vehicles (BEVs) are more suited for light vehicles over short distances. Biofuels still carry local emissions (though they can be overall net zero), are limited in supply, and could have negative land use impacts[24]. Biofuels are more suited as transition fuels due to their compatibility with existing internal combustion engines.

3.1.2 Demand response

Hydrogen production facilities are well suited for demand response because electrolysis is an interruptible process.[25] Hydrogen production can be preferentially managed around demand over less flexible activities.

3.2 Ambiguous hydrogen uses

New Zealand could use hydrogen for aviation, maritime transport, and energy export, but these uses are highly uncertain. This section outlines why hydrogen could be suitable for decarbonising these ambiguous uses and key barriers to their adoption in New Zealand.

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[20] Available at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/a-vision-for-hydrogen-in-new-zealand/roadmap-for-hydrogen-in-new-zealand/

[21] American Transportation Research Institute (2022), Understanding the CO2 Impacts of Zero-Emission Trucks, available: https://truckingresearch.org/2022/05/03/understanding-the-co2-impacts-of-zero-emission-trucks/

[22] International Council on Clean Transportation (2016), Total Cost of Ownership for Heavy Trucks in China: Battery Electric, Fuel Cell, and Diesel Trucks, available: https://theicct.org/publication/total-cost-of-ownership-for-heavy-trucks-in-china-battery-electric-fuel-cell-and-diesel-trucks/

[23] World Economic Forum (2021), Sustainable transport can't just depend on batteries. Here's why, available: https://www.weforum.org/agenda/2021/04/sustainable-transport-hydrogen-fuel-technology-batteries-volvo/

[24] Jeswani, H. K., Chilvers, A., Azapagic, A. (2020), Environmental Sustainability of Biofuels: A Review, Proc. R. Soc. A. 476:20200351., DOI: https://doi.org/10.1098/rspa.2020.0351

[25] Samani, A.E., D'Amicis, A., De Kooning, J.D., Bozalakov, D., Silva, P. and Vandevelde, L. (2020), Grid balancing with a large-scale electrolyser providing primary reserve. IET Renew. Power Gener., 14: 3070-3078. https://doi.org/10.1049/iet-rpg.2020.0453

3.2.1 Aviation

Hydrogen is a promising solution to decarbonise aviation, one of the hardest to abate use cases, in the medium to long-term.

Hydrogen-based aircrafts could replace existing jet-fuel based aircrafts because they can offer high energy density, low refuelling times, high range, and high performance in extreme environments. Hydrogen-based synthetic sustainable aviation fuels (SAFs)[26] are the most promising medium to long-term solution for long-haul flights, while hydrogen combustion engines could also be viable for short to medium-haul flights in the medium to long-term, and for long-haul flights in the very long-term.[27]

Hydrogen-based aviation is far from being technologically or commercially mature. Though aviation will likely demand hydrogen, the level of demand is uncertain because it is unclear which hydrogen technologies will prevail[28] or whether alternative technologies can establish market niches.

The main alternatives to hydrogen in aviation are electrification and biofuels, but each has drawbacks. Electric aircrafts are more mature than hydrogen-based aircrafts, but they are unlikely to be performant enough for long-haul routes. Electric aircrafts could have a niche in short-haul routes with low volumes. Biofuels could also produce SAFs, but biofuels are in short supply, and biofuel-derived SAFs are likely to become more expensive than hydrogen-derived SAFs in the long-term. Biofuels could be an important transitional aviation fuel.

3.2.2 Maritime transport

Hydrogen is potentially competitive in maritime transport, but the landscape is unclear. Hydrogen and hydrogen-based fuels can be combusted to power maritime transport.

However, electrification is a more proven technology for short-distance routes such as commuter ferries and sightseeing cruises. Hydrogen is unlikely to be directly combusted or used in hydrogen fuel cells because it is not energy-dense enough for long-distance routes.

Ammonia, methanol, and LOHCs are more likely hydrogen-based fuels because they offer better energy density for long-distance marine transport[29] Biofuels are also possible alternatives, though it could face supply constraints. Unlike aviation, the energy density demand of maritime transport is lower, so biofuels cannot be ruled out.

However, these technologies are in very early stages,[30] so any assessment is likely premature.

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[26] Synthetic SAF's are liquid fuels produced from hydrogen and captured carbon dioxide, using sustainable electricity as the principal power source. Airbus (2021), Power-to-Liquids, explained, available: https://www.airbus.com/newsroom/news/en/2021/07/Power-to-Liquids.html

[27] MIT Climate Portal (2021), Which is more likely: electric airplanes or hydrogen-powered airplanes?, available: https://climate.mit.edu/ask-mit/which-more-likely-electric-airplanes-or-hydrogen-powered-airplanes

[28] Airbus is investigating novel hydrogen combustion and hydrogen fuel cell hybrid aircrafts, while Boeing is focusing using SAFs in more conventional aircrafts. Available: https://www.wsj.com/articles/as-airbus-bets-on-hydrogen-boeing-opts-for-pragmatism-11626264000

[29] IEA (2019), The Future of Hydrogen, Chapter 5

[30] Global Maritime Forum (2021), Mapping of Zero Emissions Pilots and Demonstration Projects, available: https://www.globalmaritimeforum.org/content/2021/03/Mapping-of-Zero-Emission-Pilots-and-Demonstration-Projects-Second-edition.pdf

3.2.3 Energy export

Hydrogen is competitive for energy exports, but the level of demand from international markets is unclear. Hydrogen is the most promising zero-emissions carrier of chemical energy and could play much of the same role as fossil fuels do today.[31] Countries with high energy demand and low renewable energy production potential, such as Japan, could import hydrogen as a low-emissions fuel.[32]

Hydrogen can be transported in a variety of ways, depending on distance and volume, but if New Zealand were to export hydrogen, shipping of liquified hydrogen, ammonia, or liquid organic hydrogen carriers (LOHCs) is the most viable method.[33]

If New Zealand were to export energy through hydrogen, then two conditions must simultaneously be true:

- Cheap and excess supply of green hydrogen in New Zealand
- High demand for green hydrogen internationally

However, while both conditions are possible, neither is certain. Further, New Zealand could produce green hydrogen at an internationally competitive cost, but not necessarily at the scale needed for export. It is also unclear to what extent New Zealand is competitive relative to other potential hydrogen exporters, such as Australia.

Therefore, while the market for hydrogen exports is likely to be substantial, it is unclear what role New Zealand could play.

3.3 Less viable hydrogen uses

Hydrogen is not a viable solution for light duty vehicles, rail transport, fertiliser production, chemical production, steelmaking, intra-day energy storage, inter-seasonal energy storage, and heating, compared to competing technologies This section outlines why competing technologies are more suited for these less viable uses than hydrogen, though hydrogen could still play a limited role.

3.3.1 Light duty vehicles

Hydrogen is not competitive with electrification and biofuels for light-duty vehicles. The energy density advantages of hydrogen are less relevant for light-duty vehicles, which predominantly serve light loads, over low distances, and are regularly idle for charging.

Hydrogen could be used in hydrogen combustion engines or hydrogen fuel cells to power light-duty vehicles, but alternatives are more promising. Electrification is promising because BEVs are cheaper, more commercially advanced, and have increasingly mature supporting infrastructure. Biofuels are promising because they can be used in existing internal combustion engines, so they are a good transition fuel.

[31] IRENA (2022), Global Hydrogen Trade to Meet the 1.5C Climate Goal

[32] IRENA (2022), Geopolitics of the Energy Transformation: The Hydrogen Factor

[33] European Union Joint Research Centre (2021), Assessment of Hydrogen Delivery Options

3.3.2 Rail transport

Hydrogen is unlikely to be competitive with electrification, and potentially biofuels in rail transport.

Hydrogen could be used in hydrogen combustion engines and hydrogen fuel cells to power trains, but alternatives are more promising. Electrification is promising because it is a proven technology that is already in place for New Zealand's most trafficked rail corridors. Less trafficked corridors currently using diesel engines could potentially switch to hydrogen, but biofuels (especially biodiesel) are more promising because they can be used in existing locomotives. This favours biofuels because the capital costs of locomotives are high and existing locomotives are likely to remain in service for decades, so compatibility with existing stock can reduce the cost of switching to low emission fuels.

3.3.3 Fertiliser production

Hydrogen is unlikely to be competitive with biomass for zero-carbon fertiliser production. The fertiliser industry is currently the largest consumer of hydrogen in New Zealand, with the hydrogen sourced from natural gas at Kapuni. However, hydrogen could help produce low-emissions fertiliser for a partial abatement solution, as outlined further in 3.4.1 below.

Green hydrogen is less promising than biomass for fertiliser production. In theory, green or low-carbon hydrogen could be used to produce cleaner ammonia. That ammonia could then be used to produce fertiliser (urea). However, industrial synthesis of fertiliser (urea) requires ammonia and carbon dioxide—natural gas can provide both (grey ammonia and carbon dioxide by-product). Biomass can also provide both ammonia and carbon dioxide with lower emissions than natural gas.

Green ammonia does not provide carbon, so urea manufacturers must source carbon from elsewhere. While carbon capture and storage (CCS) could provide circular carbon,[34] the cost of CCS is uncertain, and many industries may demand circular carbon, so prices are likely to be high. Ammonium nitrate is an alternative fertiliser that does not require a carbon source, but it carries significant hazards and faces regulatory restrictions.[35]

Therefore, green hydrogen is unlikely to fully displace natural gas for fertiliser production unless the cost of CCS decreases substantially. Green hydrogen could be viable if fertiliser production is co-located with a cheap source of carbon, such as biomass combustion.

3.3.4 Chemical production

Hydrogen could be viable for chemical production, notably ammonia and methanol, but the landscape is unfavourable in the short to medium-term. The role of hydrogen in chemical production is more likely in the medium to long-term, and is likely to be dependent on advances in CCS technologies.[36]

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34 The International Energy Forum define circular carbon as carbon that is reused or recycled from materials and byproducts, such as carbon captured from hydrocarbon combustion, available: https://www.ief.org/_resources/files/news/analysis-reports/march-ief-insight-brief---the-circular-carbon-economy.pdf

35 IRENA and AEA (2022), Innovation Outlook: Renewable Ammonia

36 IRENA (2022), Green hydrogen for industry: A guide to policy making

Ammonia

Ammonia is a key chemical precursor, with 85 percent of ammonia used to produce fertiliser.[37] However, the analysis of fertiliser production in section 3.3.3 above suggests that green ammonia is ill suited for this purpose.

Ammonia is also a fuel. It has potential in maritime transport and hydrogen export. However, a range of technologies are promising in maritime transport, as outlined in section 3.2.1 above, and none are fully mature, so it's too early to make an assessment.

Ammonia could also be used to export hydrogen as energy, but it is unclear whether New Zealand can competitively export hydrogen, as outlined in section 3.2.3.

Therefore, the demand for ammonia in New Zealand is unclear, so the demand for hydrogen in green ammonia is also unclear.

Methanol

Methanol is also a key chemical precursor, with two-thirds of methanol used to produce other chemicals, such as acetic acid and formaldehyde.[38] Methanol is currently produced using fossil fuels, predominantly natural gas. Methanol is especially relevant for this study because Methanex is the largest consumer of natural gas in New Zealand, consuming around almost half of New Zealand's total natural gas supply.[39]

Methanol can also be used as a fuel or as part of a fuel blend. However, demand for e-methanol as a fuel should be attributed to the relevant mode of transport to avoid double-counting demand.

Bio-methanol and e-methanol are two low-emissions methanol production methods. Bio-methanol is produced from biomass and biogas, while e-methanol is synthesised from green hydrogen and carbon dioxide.

However, e-methanol may not be economic. Bio-methanol is cheaper now and will likely maintain this advantage in the short to medium-term.[40] Abatement through CCS could also be more economic in the short-term.

E-methanol could become competitive in the medium to long-term depending on the cost of hydrogen and circular carbon, that is, the cost of renewable electricity and CCS. However, this is uncertain.

3.3.5 Steelmaking

Hydrogen could be potentially viable for steelmaking, but the landscape is unclear.

Hydrogen could be a feedstock for steelmaking in the direct-reduced iron (DRI) process, or both a feedstock and heat source in the green hydrogen DRI process.[41] DRI is the only low

37 IRENA and AEA (2022), Innovation Outlook: Renewable Ammonia

38 IRENA and Methanol Institute (2021), Innovation Outlook: Renewable Methanol

39 Energy Resources Aotearoa (2022), Fuelling the Energy Transition: A Low Emissions Energy Future for New Zealand

40 IRENA and Methanol Institute (2021), Innovation Outlook: Renewable Methanol

41 European Union (2020), The potential of hydrogen for decarbonizing steel production: briefing paper

emissions alternative to steelmaking, but it may not be viable because the technology is relatively immature.[42]

Alternative technologies are not promising. Capturing emissions from the traditional blast furnace-basic oxygen furnace (BF-BOF) process is another approach, but CCS technology is relatively immature and costs are not likely to be competitive.

In the long term, DRI remains the most promising approach to decarbonising steelmaking since it is likely to become cheaper than BF-FOF,[43] but the outlook is uncertain. Further, demand is likely to remain relatively low in New Zealand.

3.3.6 Intra-day storage

Hydrogen is unlikely to be competitive with batteries in short-term energy storage.[44] Excess hydrogen could be stored in distributed locations to generate electricity in the future through hydrogen fuel cells. However, there is conversion loss between renewable electricity and green hydrogen,[45] so storing renewable electricity directly in batteries is more energy efficient. Battery technologies are also more mature.

3.3.7 Inter-seasonal storage

Hydrogen could be a potential long-term storage of energy, but competing technologies are currently lower-cost, and are more proven. Excess hydrogen could be stored in centralised locations to generate electricity in the future through hydrogen fuel cells. Significant changes in the cost of hydrogen production and storage would have to occur to make it an economic alternative to other long-term energy storage options. These include pumped hydro,[46] pumped heat,[47] and compressed air, which are likely more cost-effective. Though these alternatives are also not fully mature, they are further along than hydrogen.

Batteries are less viable for long-term storage because batteries must be used frequently to overcome high embedded emissions and high costs. However, long-term storage needs should be infrequent, since otherwise additional generation capacity is required.

The need for long-term storage could also be mitigated by increased deployment of diversified renewable energy. However, this is unlikely to be economic.

3.3.8 Heating

Hydrogen is unlikely to be competitive with electrification and biofuels as a complete solution for heating.[48] Hydrogen could be combusted to provide process heat for industry and

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42 Hydrogen Council (2021), Hydrogen for Net-Zero: A critical cost-competitive energy vector

43 Bloomberg (2020), Hydrogen Economy Outlook, available: https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

44 IEA (2019), The Future of Hydrogen, Chapter 5

45 Financial Times (2021), Hydrogen: the future of energy storage?, available: https://www.ft.com/content/c3526a2e-cdc5-444f-940c-0b3376f38069

46 World Energy Council (2019), Energy Storage Monitor: Latest trends in energy storage

47 T.R. Davenne, B.M. Peters, (2020), An Analysis of Pumped Thermal Energy Storage with Decoupled Thermal Stores, Front. Energy Res. DOI: https://doi.org/10.3389/fenrg.2020.00160

48 IRENA (2020), Renewable Energy Policies in a Time of Transition: Heating and Cooling

commercial purposes such as drying, cooking, and water heating. Hydrogen could also be combusted to provide environment heat for residential and commercial purposes.

However, electrification and biomass are both cheaper[49] and more mature for low and medium temperatures. Hydrogen could have niche uses in high-temperature industrial processes, but the process is immature and faces competition from electric furnaces.

Consumers might also prefer hydrogen (or other renewable gases including blends of hydrogen)because it produces a clean open flame—unlike electrification, which does not produce a flame, or biomass, which carries pollutants. Consumers are willing to pay a premium for open flame cooking and heating, as they do now for natural gas. However, the size of this premium is unclear. Box 4.1 on page 34 below addresses the trade-offs consumers are likely to make to balance their preference for open flames and their preference for lower costs.

3.4 Intermediate hydrogen uses

New Zealand could use hydrogen in the short to medium-term for partial abatement of industry and natural gas blending. While hydrogen may not fully decarbonise some uses, it can still be part of the solution. This section outlines why hydrogen could be a short to medium-term solution to decarbonising these intermediate uses and why alternative technologies are more likely to be more promising in the long-term.

3.4.1 Partial abatement of industry

Low-emissions hydrogen could abate the emissions intensity of existing industrial processes in the short to medium-term by displacing grey hydrogen.

Existing industrial processes use grey hydrogen, which creates emissions, as a feedstock. Industrial processes could switch to blue or green hydrogen to reduce their emissions. For example, Ballance's Kapuni urea plant is proposing producing green hydrogen from on-site wind turbines to feed into its ammonia-urea plant. This would reduce the carbon intensity of fertiliser production.[50] While this is not a complete decarbonisation solution, it represents part of the decarbonisation picture.

However, many existing industrial processes require other feedstock molecules that still carry emissions. For example, both urea and methanol production require carbon, currently sourced from natural gas. Using green hydrogen would require an economic source of carbon, but no clear option exists. Direct Air Capture (DAC) of carbon is immature and has likely prohibitive costs in the short to medium-term. CCS is inefficient, because it would involve capturing, transporting, and releasing carbon, whereas natural gas can achieve this in a single molecule (in addition to producing hydrogen).

Therefore, green hydrogen is unlikely to fully replace natural gas for key industrial processes, such as fertiliser production. This is because green hydrogen does not provide cheap and readily available sources of carbon. However, as the Kapuni urea plant has proposed, hydrogen can still be an effective partial decarbonisation solution under the right conditions.

49 Concept Consulting (2022), What price green gas?, prepared for Gas Infrastructure Futures Working Group

50 Hiringa, Kapuni Green Hydrogen Project, available: https://www.greenhydrogennz.com/

3.4.2 Natural gas blending

Hydrogen could help reduce emissions from natural gas by blending natural gas with green hydrogen for combustion in the short to medium-term. However, the viability of blended hydrogen is highly dependent on the cost of hydrogen. We discuss this further in Section 5.3.2.

Blended hydrogen is a potential immediate use case because it is one of the earliest opportunities for at-scale green hydrogen production. Blended hydrogen can largely be coordinated by natural gas suppliers and does not require a large amount of upfront capital investment.

However, hydrogen blends generally must consist of less than 20 percent hydrogen. Higher hydrogen concentrations are not compatible with existing appliances. Hydrogen blends above 20 percent would likely require a high level of upfront investment in repurposing transmission and distribution assets, and in hydrogen-compatible end-use appliances.[51] Further, hydrogen has lower energy per volume than natural gas, so the energy content of hydrogen is less than what its volumetric proportion would indicate. We discuss this issue in depth in Box 5.1 below.

Blended hydrogen may not be economic. Blended hydrogen will likely be more expensive than pure natural gas because hydrogen production costs and carbon prices are relatively high, whereas natural gas prices are relatively low. However, this difference may be minor. In the medium to long-term, blended hydrogen is not competitive with electrification and biofuels for most existing natural gas uses.

Therefore, blended hydrogen could be a potential way to reduce the emissions from the natural gas sector and scale up hydrogen production in the short to medium-term. However, blended hydrogen is unlikely to be sustainable in the medium to long-term because the viability of blended hydrogen is dependent on the viability of natural gas itself. Blended hydrogen should also be assessed against other decarbonisation options because it may not be the most cost-effective at abatement.

51 ACER (2021), Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing

4 Impact of hydrogen on natural gas

Hydrogen does not likely have the potential to significantly impact New Zealand's natural gas sector except for the transmission network. While there are many possible uses for hydrogen in New Zealand, only some are likely to interact with the natural gas sector. Hydrogen could theoretically be a replacement for most current natural gas use. However, hydrogen is not always competitive with other technologies, such as direct electrification and biofuels, which means this complete replacement in favour of hydrogen appliances is unlikely to be economical.

Hydrogen is most likely to be in demand for heavy vehicle transport and speciality industrial vehicles. Key uses where hydrogen is less likely to be competitive include light-duty vehicles, rail transport, fertiliser production, chemical production, steelmaking, intra-day energy storage, inter-seasonal energy storage, and heating.

Hydrogen is likely to only have an impact on the existing natural gas sector if potential hydrogen production and consumption patterns matches the current footprint of natural gas infrastructure. Hydrogen uses that do not match this footprint are unlikely to rely on hydrogen production in and transmitted from Taranaki. Therefore, hydrogen is unlikely to directly impact existing natural gas infrastructure. The most promising hydrogen uses also do not overlap heavily with natural gas uses, so hydrogen is also unlikely to impact natural gas demand directly, though some indirect effects are possible.

4.1 Hydrogen will have limited impact on gas production and processing facilities

New Zealand's natural gas production and processing facilities extract and process natural gas from gas fields to supply the transmission network. The only way hydrogen could impact the production and processing facilities is if hydrogen was blended with natural gas. This is because blended hydrogen could abate natural gas emissions and therefore prolong natural gas production.

Blended hydrogen is likely technologically viable up to 20 percent hydrogen by volume, with higher hydrogen proportions requiring significant upgrades to transmission networks, distribution networks, and end-use appliances. For the purposes of this study, blended hydrogen refers to a gas blend with 20 percent hydrogen gas by volume and 80 percent natural gas by volume.

However, blended hydrogen is only likely to be viable in New Zealand only in the short to medium-term. Unlike pure hydrogen, blended hydrogen is only a viable substitute for existing natural gas end uses. As existing consumers of natural gas wind down or switch to alternative technologies, blended hydrogen will become unviable. Transitioning from a system designed for natural gas (including blended hydrogen, biogas, and other hydrocarbon heavy gases) to one that carries pure hydrogen would impose large capital costs and coordination challenges. Yet, pure hydrogen is unlikely to be competitive for most existing natural gas use cases. Other gas blends, such as a blend of hydrogen, natural gas, and biogas, may be more viable endpoints but they are beyond the scope of this study.

Blended hydrogen might be viable in the short to medium-term to prolong the lives of existing assets while reducing the emissions intensity of natural gas. A green certification scheme can improve the viability of blended hydrogen.

Some factors could change this calculus, but they are highly unlikely. They must improve the competitiveness of blended hydrogen relative to natural gas. Factors that increase the price of natural gas, include higher carbon and natural gas prices[52] than expected , Alternatively, factors decreasing the price of hydrogen include lower electricity prices and faster hydrogen technology development than expected.

4.2 Hydrogen could be transported via the gas transmission network

New Zealand's transmission network, as it exists today, transports bulk natural gas from Taranaki to bulk end-users, including distribution networks, large industrial facilities, and power stations.

The existing distribution network benefits from volumetric economies of scale. Since the network has high capacity, additional demand (up to capacity) would only incur small increases in operating costs. Conversely, a decrease in demand would not materially change operating costs but would make cost recovery more challenging. The demand may not be linear, that is, users may tolerate a small price premium up to some tolerable threshold without significantly reducing demand.

The transmission network is likely only viable if demand does not significantly decrease. This is because as the number of customers decrease, costs per customer increases, so even more customers leave in a reinforcing cycle. This process may be abrupt because Methanex accounts for a significant portion of transmission demand. As outlined in Section 2.2, Methanex provides certainty for gas sector participants, especially large price-sensitive industrial customers served by the transmission network. Therefore, if Methanex exits New Zealand, other industrial users of gas may also decide to wind down.

4.2.1 Potential hydrogen uses in the transmission network

If the transmission network were to be repurposed for pure hydrogen, then both the supply and demand for hydrogen would also need to be in bulk volumes. If the end-uses for hydrogen were not large and concentrated enough, then it would be uneconomic to maintain existing transmission assets for this purpose.

Only the end use of hydrogen vehicle refuelling could potentially match this profile. Hydrogen is competitive for heavy-duty vehicles, but hydrogen transmission would only occur if the benefits of centralised production (or imports) in Taranaki outweigh the costs of transmission to fuelling stations.

Three hydrogen uses could potentially match this profile: industrial, chemical, and power generation (current use); inter-seasonal energy storage; and exports; However, these uses are less likely to emerge:

- Hydrogen is unlikely to be competitive with electrification and biofuels for industrial heat processes, natural gas for chemical production, and renewables for power

[52] The price of natural gas would need to rise for both domestic supply and international LNG imports, since LNG import facilities could be constructed if global natural gas prices are very low.

generation. Particularly hard-to-abate uses such as steelmaking could be an exception, but volumes are likely to be relatively small in New Zealand

- Hydrogen is not competitive with other energy storage methods for inter-seasonal energy storage
- New Zealand could export hydrogen in bulk, but that would favour centralised production in Taranaki, which would eliminate the need for transmission.

The life of the transmission network could be prolonged if blended hydrogen were viable in the distribution network. However, the transmission network itself will not necessarily be blended. This is because it is unclear whether existing industrial customers and power generation can tolerate blended hydrogen, and if so, the impact on their commercial viability.[53] Thus, key sections of the transmission network must remain non-blended in the short to medium-term.[54] Production and injection of hydrogen into distribution networks near transmission delivery points might be more attractive,[55] especially if these delivery points coincide with other demands for hydrogen, such as Wiri. Potential uses at these locations include heavy vehicle refuelling, aircraft refuelling or fuel synthesis, and heavy commercial or industrial machinery.

Some future developments could increase the viability of the transmission network. Network conversion and operating costs for hydrogen need to be low. Hydrogen FCEV adoption timelines need to be short. Domestic hydrogen production costs or international hydrogen import costs need to be low. Blended hydrogen in the distribution network needs to be viable.

4.3 Distribution network

New Zealand's natural gas distribution network, as it exists today, takes bulk natural gas from the transmission network to serve dispersed end-customers.

The existing distribution network benefits from geographic economies of scale. Since most of the network is already established, new connections would only require a small additional investment (from the street to the property). Therefore, the marginal benefit from new natural gas users exceeds the marginal cost of building a new connection. Conversely, the marginal loss in revenue from losing a customer would exceed the marginal savings from not serving them, making cost recovery more challenging.

Thus, like the transmission network, a reduction in gas use in the distribution network could induce a cycle of increasing prices, which could ultimately make the distribution network unviable. This is because as customers exit, the loss of revenue exceeds any cost savings from not serving the customer. This increases the average tariff, contributing to additional customer attrition. The demand may not be linear, that is, users may tolerate a small price premium up

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53 According to First Gas, Methanex is a "hydrogen sensitive customer." This could be because getting the right hydrogen to carbon monoxide ratio in the syngas mixture is critical for methanol synthesis efficiency. Co-firing hydrogen with natural gas in gas turbines is also in very early stages. Researchers at Stony Brook University found that co-firing could cause turbine performance decay, potential engine power shortages, and increased nitrous pollutions. Therefore, more technical analysis is needed to investigate whether industrial and power customers can tolerate blended gas. Study available at: https://doi.org/10.3390/en15103582

54 First Gas, New Zealand Hydrogen Pipeline Feasibility Study

55 Hydrogen injection points must be close to natural gas supply where they can mix before entering the network. Otherwise, different parts of the network will see different concentrations of hydrogen and natural gas.

to some tolerable threshold, because they prefer gas, or have high switching costs. Beyond this threshold however, users can no longer tolerate the premium and will begin to wind down operations or transition to alternative technologies.

4.3.1 Potential hydrogen uses in the distribution network

Hydrogen could be efficiently distributed via the current natural gas distribution network if the end uses for hydrogen approximately matched the profile of dispersed natural gas consumption. For the complete repurposing of the natural gas network to pure hydrogen to have a similar level of economic viability, the end-uses of hydrogen need to be geographically located in a way similar to the existing geographic location of natural gas uses in the distribution network. That is, the volume of hydrogen demanded need to be dispersed, not concentrated.

Maintaining a pure hydrogen distribution network of the same size and scale as the current natural gas network would be uneconomic if the end uses did not match a similar profile of current natural gas consumption. This is because the network costs (operation and maintenance) need to be spread over the users. In contrast, a blended hydrogen distribution network would serve the same uses as natural gas—commercial and residential heating. Therefore, the network costs are spread over users in a similar way to the existing natural gas network.

Only two theoretical hydrogen uses could match the footprint of the current natural gas network: commercial and residential heating, and hydrogen vehicle refuelling. However, neither is likely to be viable.

Refuelling vehicles will probably not require use of the gas distribution network

Heavy vehicles are mobile and will refuel at a relatively small number of refuelling stations. Heavy-duty vehicles, such as trucks, buses, and speciality vehicles, are more likely to require a small amount of large capacity fuelling stations. This is because they are likely to be based at hubs, such as ports, depots, and factories. Since FCEVs have high range, heavy-duty vehicles can refuel at their bases.

Heavy-duty vehicles do not need dispersed fuelling stations. Light vehicles need dispersed fuelling stations because light vehicles are likely to be based across geographically dispersed households and businesses. However, hydrogen is competitive for heavy-duty vehicles but not competitive for light vehicles. Most commentary concedes that light BEVs are more energy efficient and economic than light FCEVs. Therefore, unless a technological breakthrough occurs that makes light FCEVs more economic (thus requiring a dispersed fuelling network), it is unlikely that the locations of hydrogen demand for vehicles will match the footprint of the distribution network.

If hydrogen for aviation becomes viable, then consumption will be at large storage facilities at a small number of airports. In some isolated cases, there may be uses for existing gas distribution assets, for example, taking hydrogen from a storage site to an airport via a portion of the gas distribution network.

Hydrogen use for heating is unlikely to be economically viable, so will not require use of the distribution network

Pure hydrogen is unlikely to be used as an energy source for commercial or residential heating to the same extent as natural gas is currently used. Pure hydrogen is not competitive with electrification or biofuels in heating, especially the low and intermediate heating most relevant for the commercial and residential customers that make up the bulk of distribution network demand.

A strong consumer preference for clean open flames could change this calculus, as outlined in Box 4.1 below. However, this need is likely to be serviced by bottled gas rather than the distribution network.

Box 4.1: Consumer preference for natural gas and renewable gases

Many residential and commercial consumers prefer open flames for heating and cooking. However, this does not necessarily imply that all of those consumers would switch to hydrogen to meet their energy needs.

Hydrogen can fulfil consumers' preferences because it produces a clean open flame. Open flames are desirable for cooking because they provide immediate heat and interact with a wide variety of cooking implements. Competing technologies such as biogas produce a flame, but it is not clean; electrification is clean, but does not produce a flame. Gas-based water heaters also provide more reliable hot water than electric water heaters.

New Zealand consumers have an existing revealed preference for gas because they are cooking and heating with gas despite electrification alternatives often being cheaper. Households and businesses are especially attached to gas for cooking, even though electrified induction hobs have some cost and performance advantages.[56]

However, hydrogen is estimated to be 2.4 times as expensive as electrification for commercial space heating and 1.9 times as expensive for residential water heating.[57] This is because hydrogen is more expensive than electricity, and hydrogen appliances are less efficient than electric appliances.

It is unlikely that a sufficient critical mass of consumers will transition to hydrogen to justify the network infrastructure costs of operating and maintaining a North Island network. A majority of consumers are likely to prefer direct electrification options. Consumers that switch to hydrogen must be willing to stomach a price premium, lock themselves to purchasing hydrogen-compatible appliances, and commit to paying for hydrogen over time. Therefore, consumers using hydrogen may be more likely to be serviced by delivery of bottled hydrogen (similar to the delivery of bottled LPG), rather than receiving delivery of the gas through the existing distribution network.

Blended hydrogen for commercial and residential heating could be viable in the distribution network in the short to medium-term to assist the energy transition. A green certification scheme could close the viability gap for blended hydrogen, as outlined in Box 4.2 on the next page.

56 In a 2022 report of consumer preferences for qualities of gas versus electric induction in cooking, the New York Times notes that compared to gas, induction is faster, more efficient, safer, more comfortable to use, and offers more precise control. These advantages are likely to also hold over hydrogen-based stove tops. Induction stove tops are more expensive than gas stove tops now, though prices are likely to fall. Available: https://www.nytimes.com/2022/03/11/dining/induction-cooking.html

57 Concept Consulting (2022), What price green gas? Prepared for Gas Infrastructure Futures Working Group

Box 4.2: Blended hydrogen and green certification schemes

Hydrogen can help reduce the emissions intensity of natural gas when it is blended into the network. Blended hydrogen with up to 20 percent hydrogen by volume is likely to be compatible with existing natural gas infrastructure and heating uses, without the need to upgrade the network or replace or upgrade appliances. Producers, distributers, and consumers of natural gas may find blended hydrogen attractive because it can prolong the lives of existing assets while reducing emissions.

A green certification scheme for blended hydrogen could improve the viability of blended hydrogen and kickstart investment into New Zealand's hydrogen sector. Certified Energy, the operator and administrator of the New Zealand Energy Certificate System, is investigating a green certification scheme for renewable gas, including blended hydrogen.

Under this scheme, gas users could purchase a certificate to support New Zealand's energy transition and demonstrate their support for renewable energy. Proceeds from the scheme will close the viability gap between blended hydrogen and natural gas, which will enable blended hydrogen through entire distribution networks. Though all gas users would consume and enjoy the benefits of blended hydrogen, only certificate holders will be able to claim that they have paid for and consumed blended hydrogen during the relevant period. Though certification would come at a cost, certificate-holders could generate goodwill so that the overall economic impact is positive.

However, while a green certificate scheme for blended hydrogen could have net positive impact, it is unclear whether it is the best option. Section 5.3.2 below demonstrates that blended hydrogen may not the most economic abatement solution due to the high cost of green hydrogen. The natural gas industry could have more cost-effective alternatives, such as a green certificate scheme for biogas.

Therefore, green certification schemes for blended hydrogen could prolong the lives of natural gas infrastructure, but only if the cost of hydrogen decreases more than expected over the short to medium-term.

Source: Certified Energy, available: https://www.certifiedenergy.co.nz/renewable-gas

Therefore, it is unlikely that hydrogen would prolong the life of the natural gas distribution network, though blended hydrogen could be viable in the short to medium-term as part of New Zealand's energy transition.

4.3.2 The distribution network could be viable separately from the transmission network

New Zealand's natural gas distribution network could remain viable for longer than the transmission network. However, the mechanics to implement this separation is complex and will require additional analysis. There are technical and economic considerations to consider.

The pathway for the distribution network will not necessarily mirror that of the transmission network. It is important to consider the distribution network separately from the transmission network because they have different characteristics. Overall, these characteristics are likely to improve the viability of the distribution network relative to the transmission network during the energy transition. Table 4.1 on the next page outlines some of these differences and their relative impacts on the distribution network.

Table 4.1: Distinct characteristics of the transmission and distribution networks

Characteristic	Distribution network	Transmission network	Relative impact on the distribution network
Total demand for gas	Lower	Higher	More likely to tolerate changes in the upstream gas sector
Customer base type	Mostly commercial and residential	Mostly industrial	Distribution network customer base more likely to continue using gas despite premium over electrification
Customer base concentration	Relatively dispersed across households and businesses	Relatively concentrated in key industrial users	Distribution network customer base less likely to be negatively impacted by decision of individual customers
Average customer size	Smaller	Larger	Distribution customers more likely to experience an orderly transition. Market discontinuities less likely
Compatibility with hydrogen	Likely compatible	Likely incompatible, with potentially high upgrade costs	Distribution network can be adapted to renewable gases at lower cost and could remain viable for longer

The distribution network may be able to transport natural gas (or blended of natural gas) in an economic way without the transmission network. Though the transmission network is currently the most cost-effective way to deliver natural gas from production sites in Taranaki to the distribution network, this need not be the case, especially if transmission tariffs increase, as outlined in Section 4.2.

Alternative transmission options may still be economic even if the transmission network no longer carries natural gas. For example, existing reticulated LPG networks in the South Island rely on trucked LPG delivered to LPG storage facilities.[58] These networks have remained viable despite their relatively small scales and the increased cost of trucking and storing LPG. LNG terminals could also supply natural gas to distribution networks located near major ports, as is done internationally. If the gas sector pursues other renewable gases such as biogas, then the production of renewable gases may be local, avoiding the need for transmission. The viability of the distribution network may vary by location, so more detailed technical and economic analysis is needed to reach a sound conclusion.

[58] For example, Genesis operates two reticulated LPG networks in Dunedin and near Christchurch totaling almost 70km.

5 Hydrogen scenarios

In this section, we illustrate relevant hydrogen scenarios in New Zealand, focusing on those that directly impact the natural gas industry, and discuss modelled scenario results.

The modelling of hydrogen scenarios and analysis of results suggest that hydrogen is unlikely to have a significant(?) impact on New Zealand's natural gas industry because:

- The level of predicted hydrogen demand is likely low compared to existing gas throughput
- The geographic distribution of predicted hydrogen demand does not favour transmission
- The marginal abatement cost of hydrogen is high in the short to medium-term.

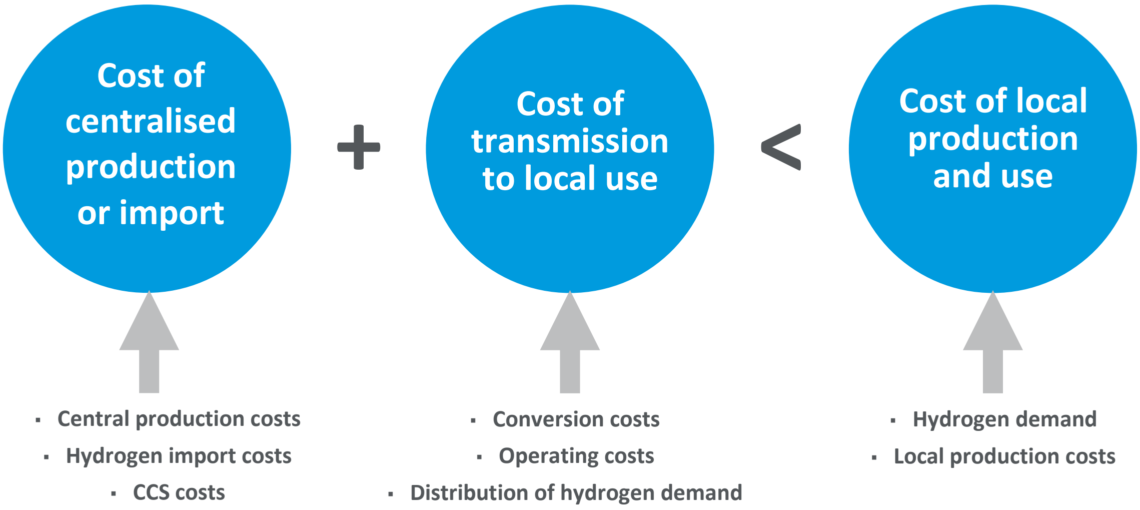
As outlined in section 4, though many promising hydrogen uses exist, only a subset is relevant for New Zealand's natural gas sector. These apply to the transmission network in the long-term, and the distribution network in the short to medium-term. Hydrogen for heavy-duty vehicles and aviation are the key uses that could impact New Zealand's natural gas sector by providing an opportunity to repurpose the transmission network.

Therefore, the viability of existing natural gas transmission assets will depend on factors falling under three categories:

- Hydrogen uptake, including the timeline and scale of heavy-duty vehicles in the short to medium-term, and that of aviation in the medium to long-term
- Hydrogen production, including the benefits of at-scale centralised production of green hydrogen, blue hydrogen production costs, and international hydrogen import costs
- Hydrogen transport, including the costs of inter-regional transmission and intra-regional distribution.

Repurposing transmission pipelines for hydrogen transmission could be viable if for a given level and distribution of hydrogen demand, the cost of centralised production and transmission exceeds that of local production, as shown in the Figure 5.1 on the next page.

Figure 5.1: Necessary condition for hydrogen transmission viability



5.1 Hydrogen scenarios overview

Hydrogen scenarios can illustrate the dynamics of potential hydrogen demand. These scenarios can help reveal potential interactions between hydrogen and New Zealand's natural gas infrastructure.

These scenarios are not necessarily the most likely but will together provide insight on possible outcomes. The scenarios also point to potential enabling factors for New Zealand's natural gas infrastructure to be repurposed for hydrogen.

This study modelled six hydrogen scenarios in total, including:

- Four full transition scenarios, assuming the transmission network would transport pure green hydrogen in the medium to long-term
- One blue hydrogen scenario, assuming the transmission network would transport pure blue hydrogen in the medium to long-term
- One blended hydrogen scenario, assuming the transmission network would not transport hydrogen, but that the distribution network can transport blended hydrogen in the short to medium-term.

Table 5.1 on the next page summarises the key differences between the six hydrogen scenarios, with full modelling parameters provided in Appendix A: Modelling assumptions.

Table 5.1: Overview of hydrogen scenarios

Scenario type	Code	Name	Aviation demand	Policy support	Carbon price	Electrolyser advancement	Diesel price
Full transition	A	Optimistic hydrogen development	Yes	High	High	High	High
	B	Hydrogen aviation does not emerge	No	High	High	High	High
	C	Hydrogen production is low	No	High	High	Low	High
	D	Pessimistic hydrogen development	No	Low	Low	Low	Low
Blue hydrogen	E	Blue hydrogen development	Yes	High	High	Not applicable	High
Blended hydrogen	F	Blending for abatement	No	Medium	High	Medium	Low

Note: Shading indicates factors that are likely to increase potential hydrogen demand

5.1.1 Full transition scenarios

Full transition scenarios inform the viability of New Zealand's natural gas transmission network in the medium to long-term. Under full transition scenarios, existing demand for natural gas is assumed to disappear in the transmission and distribution networks over time as natural gas consumers wind down or switch to alternatives. Some residual natural gas demand might still exist, but they would not use existing networks. Transmission network demand stems from new uses of hydrogen. This study models four full transition scenarios to illustrate the range of possible outcomes for a hypothetical transmission network carrying pure hydrogen.

Scenario A: Optimistic hydrogen development

The optimistic hydrogen development scenario tests the most optimistic case for hydrogen in New Zealand and its impacts on New Zealand's natural gas infrastructure. This scenario assumes high hydrogen demand across key sectors, high policy support for hydrogen, high carbon prices, high technological advancements, and high diesel prices.

Scenario B: Hydrogen aviation does not emerge

The hydrogen aviation setback scenario tests whether a lack of demand for hydrogen in aviation would significantly impact the effect of hydrogen on New Zealand's natural gas infrastructure. This scenario has the same underlying assumptions as the optimistic hydrogen scenario but excludes all hydrogen demand from aviation.

Scenario C: Hydrogen production is low

The hydrogen production setback scenario tests the impact of lower-than-expected hydrogen production technological advancement on the potential demand for hydrogen in New Zealand, and the resulting impact on New Zealand's natural gas infrastructure. This scenario assumes high hydrogen demand across key sectors, high policy support for hydrogen, high carbon prices, low technological advancements, and high diesel prices.

Scenario D: Pessimistic hydrogen development

This hydrogen development scenario tests a pessimistic case for hydrogen in New Zealand, and its impacts on New Zealand's natural gas infrastructure. This scenario assumes low levels of hydrogen development across key sectors, low policy support for hydrogen, low carbon prices, slow technological advancements, and low diesel prices.

5.1.2 Blue hydrogen scenario

The blue hydrogen scenario is similar to full transition scenarios but uses blue hydrogen instead of green hydrogen. This study models one blue hydrogen scenario to investigate potential differences in potential hydrogen demand between blue and green hydrogen, and the resulting impact on the transmission infrastructure, if any.

Scenario E: Blue hydrogen development

The blue hydrogen development scenario tests whether the dynamics of blue hydrogen differs from that of green hydrogen. This scenario takes an optimistic view of blue hydrogen, assuming low additional CCS costs of US$0.5 per kg,[59] and escalating costs over time.[60] This scenario also assumes high policy support, high carbon prices, and high diesel prices.

5.1.3 Blended hydrogen scenario

The blended hydrogen scenario informs the viability of New Zealand's natural gas distribution network in the short to medium-term. The potential demand for hydrogen is assumed to stem from existing natural gas uses, because hydrogen can abate the emissions of natural gas through blending. This study models one blended hydrogen scenario to investigate the viability of providing blended hydrogen to commercial and residential consumers in the short to medium-term.

Scenario F: Blending for abatement

The blending for abatement scenario tests the viability of blended hydrogen in the short to medium term within the distribution network. Since blended hydrogen is not a necessary step towards full transition, it does not create additional option value.[61] Therefore, blended hydrogen should be both financially viable and cost-effective in terms of abatement.

This study assumes relatively low levels of policy support because blending is likely to occur in the short to medium-term when the level of policy support is likely uncertain.[62] This scenario is relatively optimistic in that it assumes relatively high natural gas demand in the future under CCC's current policy reference path.

Unless otherwise stated, blended hydrogen refers to gas with 80 percent natural gas by volume and 20 percent hydrogen by volume.

59 IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5C Climate Goal

60 This is due to carbon prices. Blue hydrogen is likely not zero-emissions because CCS cannot capture all emissions. The extraction of natural gas also creates additional upstream emissions.

61 Blended hydrogen does not create additional option value upon the status quo, because it neither opens nor closes future options relative to the status quo. Blended hydrogen does represent additional option value upon a hypothetical decommissioning of natural gas infrastructure.

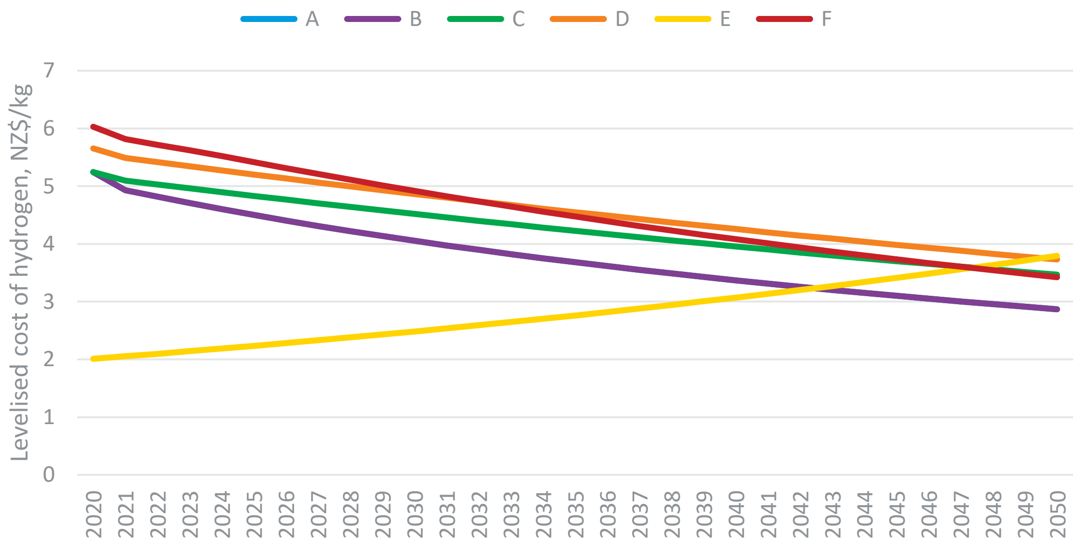
62 Modelled results in Section 5.2 below show that policy support can help bring forward demand but has limited effects on creating demand. Thus, the level of policy support is unlikely to be pivotal for the viability of blended hydrogen. It is also possible that high policy demand will channel hydrogen to other uses (such as heavy FCEVs), which could reduce the viability of blended hydrogen if hydrogen supply is limited.

5.2 Key modelling results

All modelled scenarios show growing demand for hydrogen over time as the lifetime costs of using hydrogen technologies become more competitive.

The levelised cost of green hydrogen (LCOGH) produced in New Zealand is modelled to decrease by around a third between now and 2050. This decrease is driven by likely advances in hydrogen production technologies, lower renewable electricity prices, and increasing returns to scale. Figure 5.2 below illustrates the levelised cost of hydrogen produced in New Zealand under each hydrogen scenario. By 2050, green hydrogen is modelled to cost between NZ$2.87 per kg and NZ$3.73 per kg.

Figure 5.2: Lowest levelised cost of hydrogen produced in New Zealand

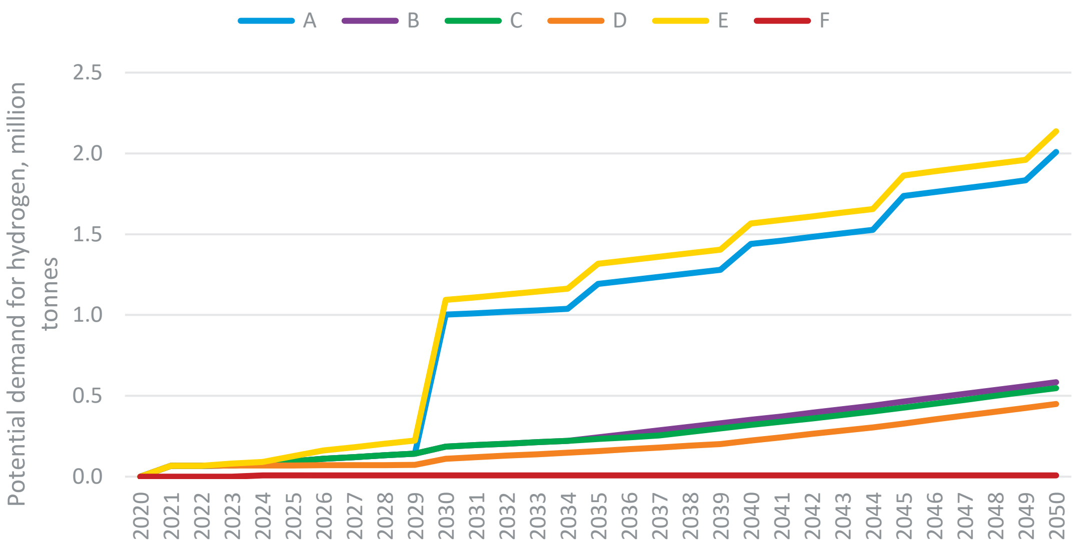


Note: Levelised cost of hydrogen under scenarios A, B, C, D, and F are modelled results. The cost of blue hydrogen under scenario E is exogenously assumed. Actual cost of hydrogen production may be higher, especially at smaller scales.

The demand for hydrogen in New Zealand depends on the lifetime costs of hydrogen-enabled technologies versus that of alternative technologies. At a given point in time, consumers will choose the technology that is the cheapest to own and operate, including capital costs (such as the cost of hydrogen fuel cell vehicles) and operating costs (such as the cost of hydrogen fuel).

Under the defined hydrogen scenarios, modelling shows that as hydrogen technologies decrease in costs over time, they become competitive and widely adopted for uses in transport and industry. Figure 5.3 on the next page illustrates the potential demand for hydrogen in New Zealand under each scenario. Potential demand is not projected demand. Potential demand represents the maximum demand for hydrogen in New Zealand, assuming modelled LCOGH, no supply constraints, and no other inhibitors (such as lacking infrastructure).

Figure 5.3: Potential hydrogen demand in New Zealand's economy



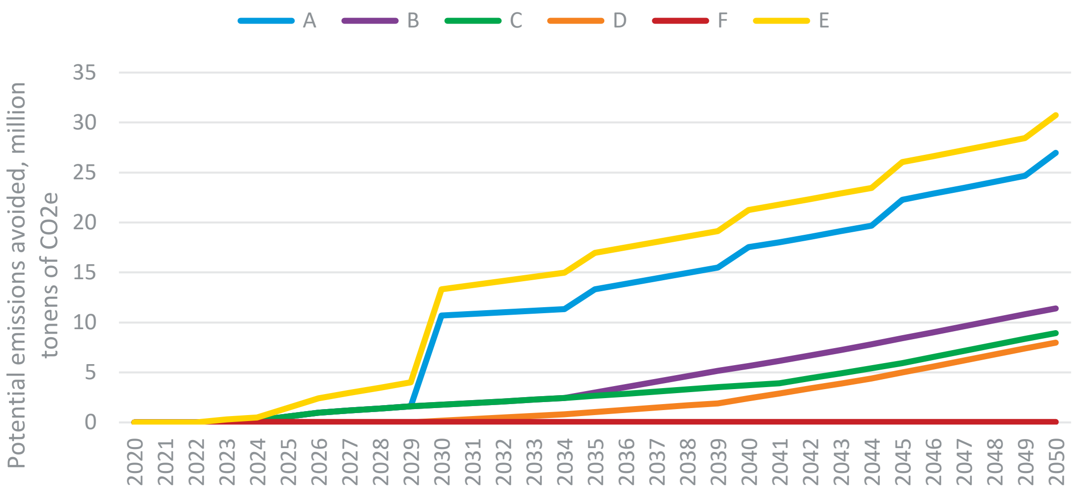
Note: Actual demand is likely lower than potential demand for hydrogen in New Zealand. Potential demand is the upper limit for hydrogen demand in New Zealand under each hydrogen scenario The step changes seen in scenario A and E represent discrete jumps in aviation demand. These jumps represent, with a high level of uncertainty, the adoption of new hydrogen-based aircrafts. This process is not gradual because airlines are likely to introduce/phase out aircraft models at once to minimise the costs of operating diverse fleets.

Technological development and policy levers have a relatively small impact on potential hydrogen demand. The differences between scenarios B, C, and D are minor. By 2050, potential hydrogen demand under scenario B is only 30 percent higher than that of scenario D, but 71 percent lower than that of scenario A. This suggests increased rates of technological development and stronger policy support could bring forward potential demand but would not be pivotal to the viability of hydrogen technologies in the medium to long-term. Therefore, these factors may not have a large impact on the viability of hydrogen transmission.

The abatement potential of hydrogen parallels the potential demand in each scenario, as shown in Figure 5.4 on the next page. For reference, New Zealand's 2019 greenhouse gas gross emissions totalled 82.3 million tonnes of CO2e.[63]

[63] Ministry for the Environment (2021), Latest annual inventory of greenhouse gases in New Zealand released 13 April 2021, available: https://environment.govt.nz/news/latest-annual-inventory-of-greenhouse-gases-in-new-zealand-released-13-april-2021/

Figure 5.4: Potential emissions avoided in New Zealand's economy attributable to hydrogen



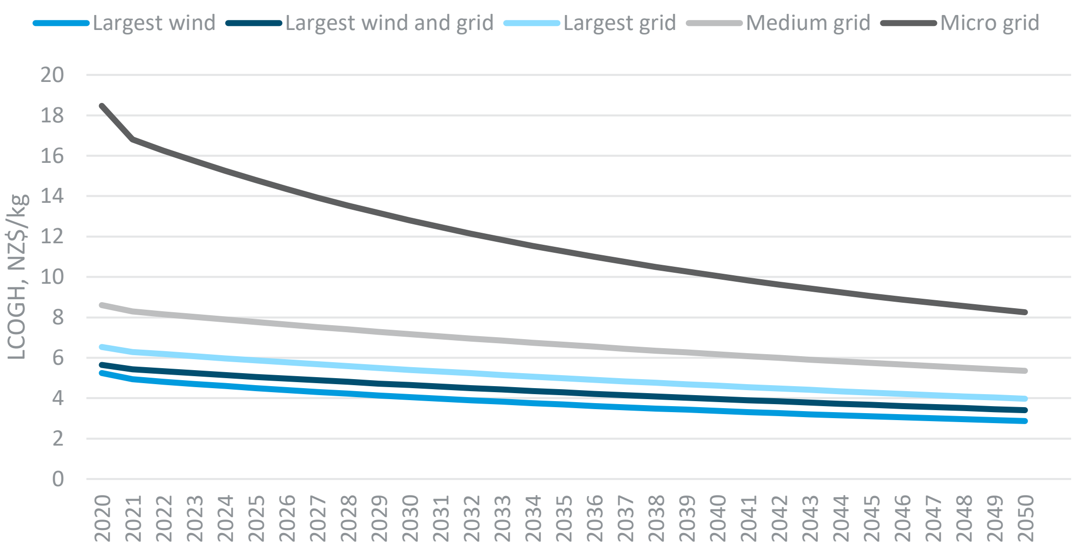
Note: Potential emissions avoided in industry are excluded because while hydrogen can help decarbonize chemical production and steelmaking, total decarbonization of industry requires carbon feedstock to also come from low or zero emission sources.

The variance between scenarios for emissions avoided is higher than that of potential hydrogen demand. This is because uses with greater abatement potential (such as heavy vehicles) are more sensitive to changes in LCOGH than uses with less abatement potential (such as industry).

Green hydrogen production benefits from economies of scale

Modelling of the levelised cost of green hydrogen shows that producing green hydrogen at scale is advantageous, as shown in Figure 5.5 below.

Figure 5.5: Economies of scale in green hydrogen production



Note: Assuming scenario A parameters. The largest plants can produce 120,440 kg of hydrogen per day, medium plants 4,010 kg/day, and micro plants 4 kg/day.

Economies of scale in hydrogen production favour centralised production hydrogen, which can then be transported to end-use locations. Repurposed natural gas pipelines could be a competitive hydrogen transport option.

However, the extent to which New Zealand's existing natural gas transmission and distribution infrastructure can fulfil this role depends on two unlikely conditions:

- Potential hydrogen demand centres must not be clustered in a way that can justify large-scale hydrogen production on-site or nearby
- The transmission network must be able to service a large proportion of potential hydrogen demand centres at low costs.

Analysis in the section below and in section 0 suggests that neither condition is likely to be true in New Zealand.

Actual transmission network hydrogen throughput is likely to be lower than modelled

The actual gas transmission network throughput of hydrogen will only contain the uses that cannot sustain on-site hydrogen production and that are situated closely to the existing gas transmission network. These uses, outlined in Section 4.2.1, can benefit from large savings in LCOGH from economies of scale, while paying a relatively small transmission cost. If a hydrogen use is likely to demand high hydrogen volumes and is geographically concentrated, then it can benefit from both low LCOGH and low transport costs by producing hydrogen at a large scale on-site.

The modelled potential hydrogen demand also applies to the whole of New Zealand, so demand located in the South Island, or far away from the existing gas transmission network, cannot benefit from hydrogen transmission.

Table 5.2 below breaks down the potential demand for hydrogen into its end use components, showing that the transmission network may not be competitive with on-site production for many uses where large-scale on-site hydrogen production is possible.

Table 5.2: Assessment of the likelihood of transmission for potential hydrogen demand components

Modelled hydrogen uses	Relevant Scenarios	Viability of large-scale on-site production	Likely transmission demand compared to total in use case	Comments
Heavy industrial vehicles	A, B, C, D, E	Medium	Medium	▪ Some industrial sites could justify large-scale production, especially in combination with other uses. These include major ports, inland ports, and other very large distribution hubs ▪ Other industrial sites cannot justify large-scale production and will likely rely on hydrogen produced elsewhere.
Heavy truck	A, B, C, D, E	Low	High	▪ Truck depots are relatively small and spread across multiple sites ▪ Most truck depots are not large enough to justify large-scale production on-site and will likely rely on hydrogen produced elsewhere.
Heavy bus	A, B, C, D, E	Low	High	▪ Heavy bus depots and fuelling stations are spread across urban areas ▪ Most bus depots and fuelling stations are not large enough to justify large-scale production on-site and will likely rely on hydrogen produced elsewhere.
Light vehicles	A, B, C, D, E	Low	High	▪ Depots for specialised light vehicle fleets are not large enough to justify large-scale production on-site and will likely rely on hydrogen produced elsewhere or be co-located with other demand centres.
Aviation	A, E	High	Low	▪ Airports are potentially some of the largest hydrogen demand centres ▪ Major airports are large enough to justify large-scale production on-site and could even supply excess hydrogen to nearby sites.
Fertilisers	A, B, C, D, E	High	Low	▪ Fertiliser plants are centralised because they also benefit from economies of scale ▪ Most fertiliser plants are large enough to justify large-scale production on-site, especially if they are clustered in industrial areas.
Steel	A, B, C, D, E	High	Low	▪ Most steelmaking facilities are large enough to justify large-scale production on-site because steelmaking can use hydrogen both as a feedstock and as a heat source.

5.3 Impacts on the natural gas industry

Modelled results suggest that hydrogen is unlikely to impact the natural gas industry. This is because the volume and distribution of hydrogen or blended hydrogen transported is unlikely to align with the footprint of New Zealand's existing natural gas infrastructure.

The demand for hydrogen will probably affect New Zealand's natural gas industry in two ways:

- Medium to long-term demand for transporting hydrogen gas could extend the life of New Zealand's natural gas transmission infrastructure, through repurposing the existing transmission network for pure hydrogen
- Short to medium-term demand for the abatement of natural gas emissions could extend the life of New Zealand's natural gas distribution infrastructure, through transporting blended hydrogen

The actual amount of hydrogen transported in the transmission network is likely much lower than what modelled results would initially indicate, because the actual demand for hydrogen is almost certain to be less than the potential demand and may not require transmission of hydrogen from Taranaki.

Unless otherwise stated, the analysis in this section is on an energy basis because consumers care about meeting their energy needs, not the volume or mass of gas delivered. Box 5.1 below highlights why this distinction is key.

Box 5.1: Energy content of hydrogen and blended hydrogen

Hydrogen has lower volumetric density and higher gravimetric density than natural gas. For a given amount of energy, hydrogen (and blended hydrogen) has higher volume and lower mass. This does not hurt hydrogen's energy delivery capacity since hydrogen is also capable of a higher flow velocity compared to natural gas.

Accounting for the energy density difference between hydrogen and natural gas is important. For blended hydrogen, hydrogen makes up 20 percent of its volume, but only 6.5 percent of its energy content. That means that by volume, blended hydrogen has only 86.5 percent of the energy content of natural gas. For the same reason, blended hydrogen achieves only a 6.5 percent reduction in emissions compared to natural gas, much less than what its hydrogen proportion by volume might indicate.

5.3.1 Full transition

New Zealand's natural gas infrastructure is unlikely to be viable under full transition scenarios because there is not likely to be sufficient demand to justify the costs of upgrading the transmission network for pure hydrogen.

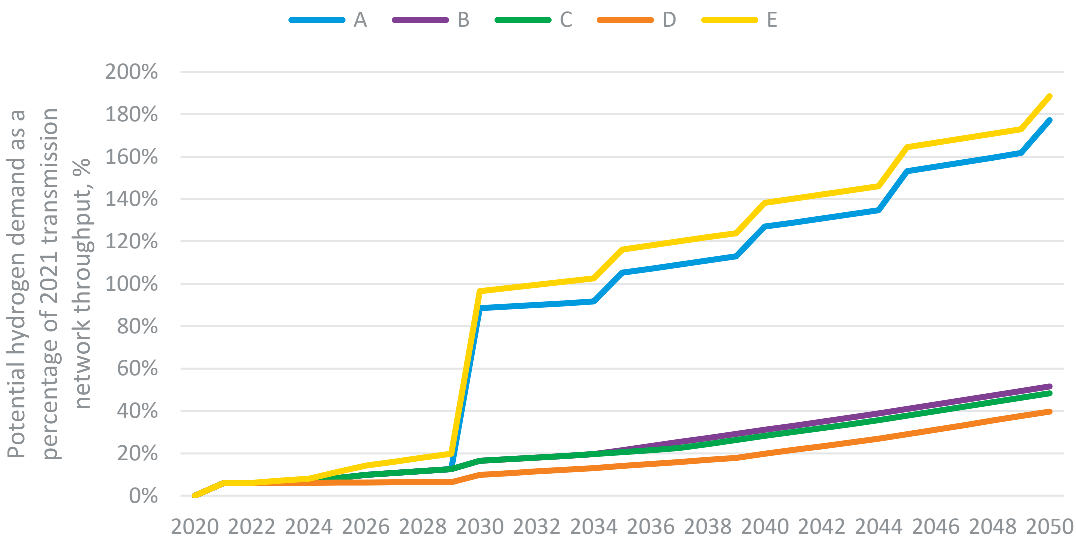
Less optimistic transition scenarios are unlikely to drive sufficient hydrogen volumes. By 2050, scenarios B, C, and D would see potential hydrogen demand equivalent to 52 percent, 48 percent, and 40 percent of current natural gas throughput in the transmission network, respectively, though any actual hydrogen throughput is likely to be lower

Optimistic transition scenarios could drive sufficient hydrogen volumes, but that does not imply the viability of the transmission network. By 2050, scenarios A and E would see potential hydrogen demand equivalent to 177 percent and 190 percent of current natural gas throughput in the transmission network, respectively. However, the demand for hydrogen from aviation is unlikely to utilise the transmission network.

Hydrogen demand is likely to be insufficient for transmission network viability without aviation demand

Modelling suggests that in the absence of hydrogen-based aviation, no full transition scenario would be able to sustain comparable levels of gas to what is seen today. This is illustrated in Figure 5.6 below, where scenarios A and E include aviation, whereas other scenarios do not.

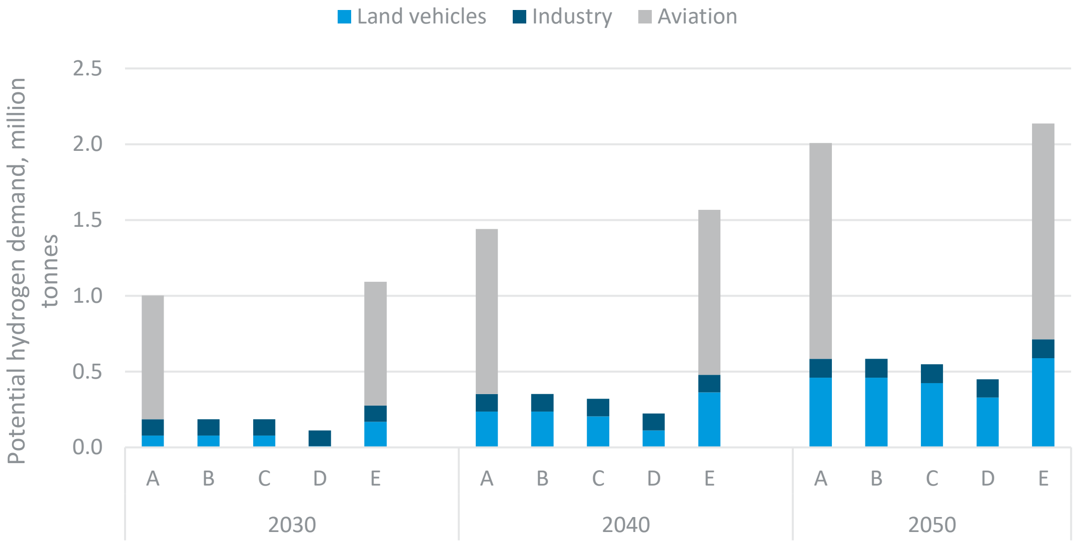
Figure 5.6: Potential hydrogen demand as a proportion of current transmission throughput



Note: This figure shows the potential pure hydrogen demand under each scenario as a proportion of 2020 transmission network throughput by energy content.

Aviation is a pivotal hydrogen use. The potential demand for hydrogen in aviation would exceed that of all other uses combined, as shown in Figure 5.7 on the next page.

Figure 5.7: Drivers of potential hydrogen demand under full transition scenarios by total demand



Note: Land vehicles include heavy industrial vehicles, heavy trucks, heavy buses, and light vehicles. Industry includes fertiliser and steel production.

Aviation demand for hydrogen could be high, but is unlikely to align with the existing transmission network footprint

Aviation could play a pivotal role in building high levels of hydrogen demand, but its effect on the transmission network is highly uncertain. The demand for hydrogen in aviation is the least clear of all uses because hydrogen-based aircraft technology is immature (although developing rapidly). While hydrogen-based aviation could increase total potential hydrogen demand, it is not guaranteed to increase the demand for hydrogen transmission.

Transporting hydrogen in the transmission network is attractive when large-scale green hydrogen production in Taranaki achieves economies of scale benefits that outweigh the cost of transmission to sites where economies of scale are not possible. However, it is unlikely that Taranaki is the only location where large-scale production would be least-cost, even including the cost of transporting the hydrogen to the point of use.

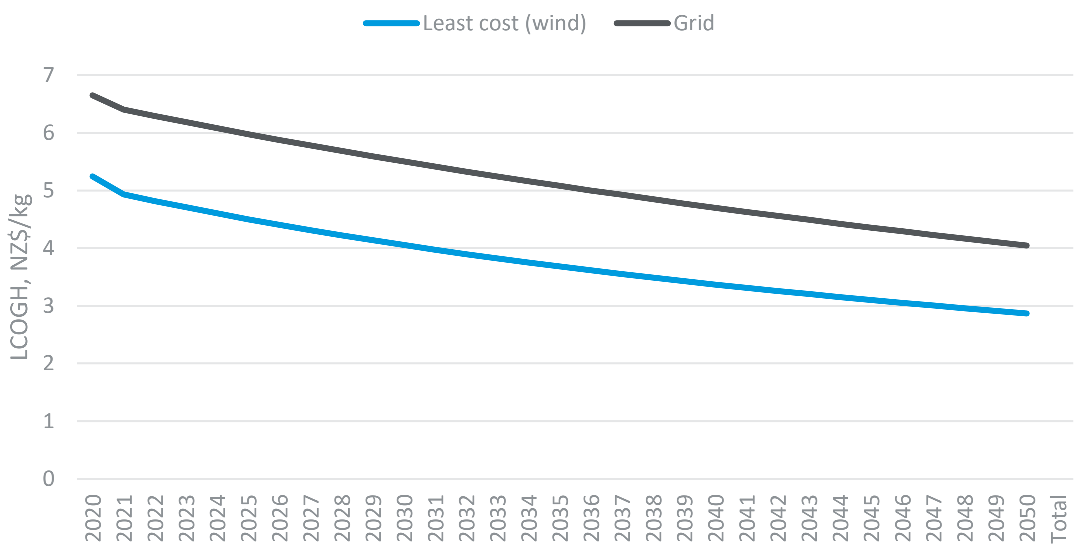
This scale advantage is important for FCEVs, but less important for aviation. This is because FCEV refuelling stations are unlikely to justify large-scale production, whereas hydrogen-based aircraft refuelling stations could. Aviation consumes more hydrogen and has higher geographic concentration of demand, which makes large-scale on-site production possible. Hydrogen FCEVs could rely on the transmission network because the combined cost of large-scale centralised production in Taranaki and transmission costs of refuelling stations could be smaller than small-scale production on-site at refuelling stations. However, aviation would demand such high levels of hydrogen that on-site production at or near airports would also benefit from economies of scale, without incurring additional transmission costs.

Further, in 2018,[64] only 65 percent of domestic flights and 82 percent of international flights by passenger number departed from or arrived at a North Island airport,[65] further reducing the potential hydrogen demand serviceable by the transmission network.

Aviation could even undermine the viability of the transmission network for FCEVs, because airports could become green hydrogen production hubs with aviation to anchor demand. Excess hydrogen produced at airports could be distributed to nearby FCEV refuelling stations at a lower cost than that of hydrogen produced in Taranaki

The competitiveness of airports as green hydrogen production hubs depends on the price of grid electricity, since airports are not good sites for wind power. Figure 5.8 below illustrates that green hydrogen production using electricity from the grid is between NZ$1.18 and $1.48 more expensive than using electricity from direct wind. Airports would be competitive as hydrogen production hubs if the production cost premium from using grid electricity on-site at the airport is less than the cost of transmitting (wind-based) green hydrogen via the pipelines from, say, Taranaki.

Figure 5.8: Cost of hydrogen production using direct wind versus grid electricity in urban area



Note: Assumes scenario A parameters, with all plants at the largest efficient scale. The levelised cost of electricity from wind is NZ$0.07/KWh, and the levelised cost of electricity from the grid (including generation, distribution, and transmission prices) is NZ$0.11/KWh.

Blue hydrogen production and transmission/distribution in the gas network may not be economic

The competitiveness of blue hydrogen depends on low CCS costs. Blue hydrogen is produced from natural gas but relies on the carbon dioxide emissions inherent in the production process to be captured and stored.

[64] This study analyses 2018 aviation data to avoid potential distortions from the COVID-19 pandemic and travel restrictions

[65] Castalia analysis of Ministry of Transport data, available: https://www.transport.govt.nz/statistics-and-insights/air-and-sea-transport/sheet/air-passengers

If CCS costs are low, the natural gas industry and natural gas users would have a range of options to reduce carbon emissions. These include CCS at the point of natural gas consumption (for example, at Methanex's plant, at Ballance Kapuni, at a Combined Cycle Gas Turbine (CCGT) generation plant, or at a milk powder drying plant). Such options may be lower cost than using natural gas to produce blue hydrogen as an energy source or feedstock.

The blue hydrogen development scenario is also a full transition scenario, so the implications of blue hydrogen on the natural gas industry are likely to be similar to that of scenario A. This means that even the most optimistic hydrogen development scenario would be unlikely to sustain sufficient demand for hydrogen in the existing gas transmission network

However, the lower cost of blue hydrogen now induces a relatively small increase in potential hydrogen demand, as shown in Figure 5.3 above. This is because the capital costs of hydrogen technologies remain high in the short to medium-term, so the lifetime costs of using hydrogen technologies are not highly competitive regardless of hydrogen production costs. Blue hydrogen costs around a third of green hydrogen now, but prices would be near parity by the 2040s,[66] as shown in Figure 5.2 above.

Further, the low cost of blue hydrogen is dependent on low CCS costs, but this would also improve the economic viability of natural gas itself, which in turn reduces the demand for blue hydrogen. If CCS were to become viable at locations of natural gas consumption, then natural gas demand would probably continue in the following uses:

- Large chemical processes, such as Methanex, fertiliser plants, and steelmaking, could continue to consume natural gas if these firms could perform CCS on-site[67]
- Large heating processes, such as dairy, paper, and metal products, could also burn natural gas and perform carbon capture on-site[68] and potentially also storage
- Electricity generation through high-efficiency CCGT plants or via Allam-Fedvedt cycle generation (such as the proposed 8 Rivers, LLC's Project Pouakai). This would impact New Zealand's energy resilience by using natural gas with CCS as a lower-emissions firming option, as the share of variable renewable generation in New Zealand's electrical grid increases.

Together, these uses could sustain New Zealand's natural gas network, as illustrated in Figure 2.4 above, without resorting to hydrogen at all. Therefore, if CCS costs are low, it is not clear that the natural gas industry would benefit from transitioning to green or blue hydrogen.

Full transition scenarios will likely require large upfront investments

Repurposing New Zealand's natural gas infrastructure for pure hydrogen will likely incur high capital costs for the transmission network to handle pure hydrogen efficiently and safely. Different parts of the natural gas infrastructure will require different upgrade costs to handle pure hydrogen:

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66 IRENA states that: "an aggressive electrolyser deployment pathway can make green hydrogen cheaper than any low-carbon alternative before 2040." Source: IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5C Climate Goal, available: https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction

67 This is especially attractive because many chemical processes require carbon molecules that might otherwise be difficult to source in a low-emissions way

68 Smaller heating processes are likely to continue to be electrified, because small-scale CCS is likely to be more expensive unless the cost of direct air capture of carbon dioxide significantly reduces in costs

- Production and processing facilities are unlikely to be upgraded, with the possible exceptions of retrofitted CCS for blue hydrogen production, or for hydrogen storage
- The transmission network could require large upgrades because it is unclear whether existing high pressure steel transmission pipelines are compatible with hydrogen due to embrittlement[69]
- The distribution network will likely require minor upgrades because existing polyethylene pipelines are compatible with hydrogen.[70]

The median cost of upgrading[71] the transmission network is approximately NZ$1.95 billion, as shown in Table 5.3 below. The likely costs of upgrading pipelines in the transmission network can be found by multiplying the length of the network to be upgraded, with the European Hydrogen Backbone initiative estimates of repurposing costs per kilometre.[72]

Table 5.3: Transmission network upgrade cost estimates for compatibility with pure hydrogen

Estimates	Total upgrade cost	Annual recovery needed	Tariff increase per GJ
High	$2,337,674,970	$152,069,112	$1.03
Medium	$1,948,062,475	$126,724,260	$0.86
Low	$1,168,837,485	$76,034,556	$0.52
Very low	$331,837,485	$21,586,505	$0.15

Notes: Annual recovery needed assumes 5 percent per annum discounted over 30 years. Tariff increase per GJ is based on 2021 transmission network energy throughput and will increase if network throughput decreases. The high, medium, and lows estimates assume that the entire network requires upgrades at varying upgrade costs. The very low estimate assumes that only parts of the transmission network made up of high-grade steel require upgrades.
Source: Castalia analysis, using transmission network data from the Commerce Commission and First Gas, and network upgrade cost estimates from the European Hydrogen Backbone initiative

Cost recovery of assets is only feasible when there is sufficient demand for hydrogen to be transported in the transmission network. For network owners to recover the capital expenditure associated with network upgrades, they must increase the tariffs charged to consumers. Two conditions must be true to ensure that tariffs remain affordable:

69 A high level of uncertainty remains around the compatibility of low grade steel (API X52 and lower) with hydrogen. In principle, low grade steel is less vulnerable to embrittlement than high grade steel because the former is more ductile and thus less likely to fracture. Over two-thirds of New Zealand's transmission network is composed of low strength steel pipelines. If these pipelines do not require upgrading, then the upgrade cost of the transmission network could be lower. However, it is unclear whether low strength steel is safe for hydrogen gas transmission. For example, data collated by Sandia National Laboratory show that high pressure hydrogen gas induces similar fatigue crack growth rates across a range of steel grades. Source: US Department of Energy (2019), available: https://www.osti.gov/servlets/purl/1646101

70 Polyethylene pipelines make up most of the distribution network, though limited steel pipelines exist. The distribution network is also less prone to embrittlement because it operates at lower pressures compared to those in the transmission network.

71 Our estimates of network upgrades include the cost of pipeline upgrades only. Other asset upgrades, such as compressor stations, are also necessary. However, this study excludes these assets from estimates because they are due for renewal, independent of any decisions to upgrade the transmission network for pure hydrogen. Source: First Gas (2021), New Zealand Hydrogen Pipeline Feasibility Technical Report

72 European Hydrogen Backbone (2021), Extending the European Hydrogen Backbone: A European Hydrogen Infrastructure Vision Covering 21 Countries, available: https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf

- The total demand for hydrogen should be high
- The distribution of hydrogen production demand should be such that hydrogen would go through the transmission network.

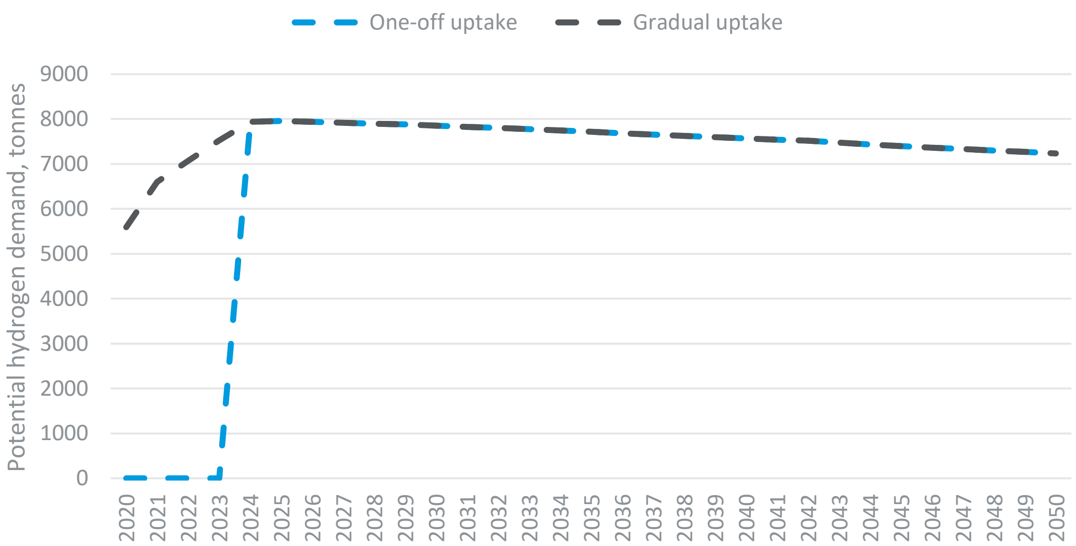
If the demand for hydrogen transported through the transmission network is insufficient, then the unit tariff must increase for asset recovery. This would likely lead to a decreased customers and even higher tariffs, as discussed in section 4.

5.3.2 Blended hydrogen

Modelling suggests that blended hydrogen financially viable but is likely not cost-effective at reducing emissions. Blended hydrogen could become close to financially viable soon as LCOGH decreases and carbon price increases, assuming consumers can tolerate a minor increase in gas prices.

For illustrative purposes, modelling assumes that consumers can tolerate a five percent premium for blended hydrogen over natural gas. If this is true, blended hydrogen could be financially viable now, as shown in Figure 5.9 below.

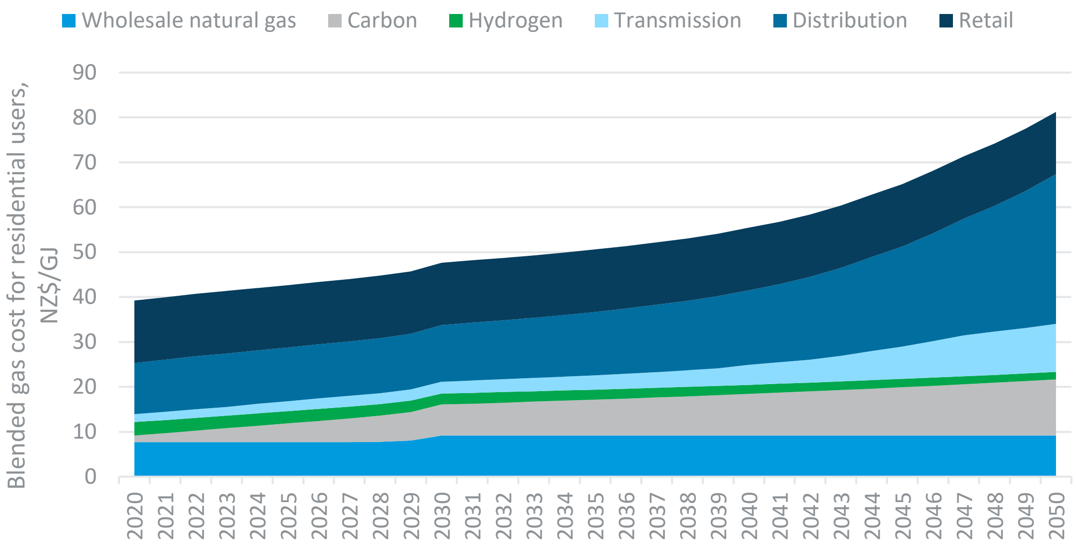
Figure 5.9: Potential hydrogen demand for blending in the distribution network



Note: Assuming maximum hydrogen blending of 20 percent by volume and tolerable price premium of blended over non-blended gas of 5 percent. One-off uptake assumes a constant blending ratio, with blending starting when premiums fall under the threshold, while gradual uptake varies the blending ratio to keep premiums under the threshold.

The price premium of blended hydrogen over natural gas is smaller than that between green hydrogen and natural gas. This is because the premium of blended hydrogen over natural gas is relatively low from the perspective of end consumers once the cost of carbon, transmission, distribution, and retail are included. Figure 5.10 on the next page breaks down the cost components of blended hydrogen for residential end consumers.

Figure 5.10: Price components of blended hydrogen for residential consumers



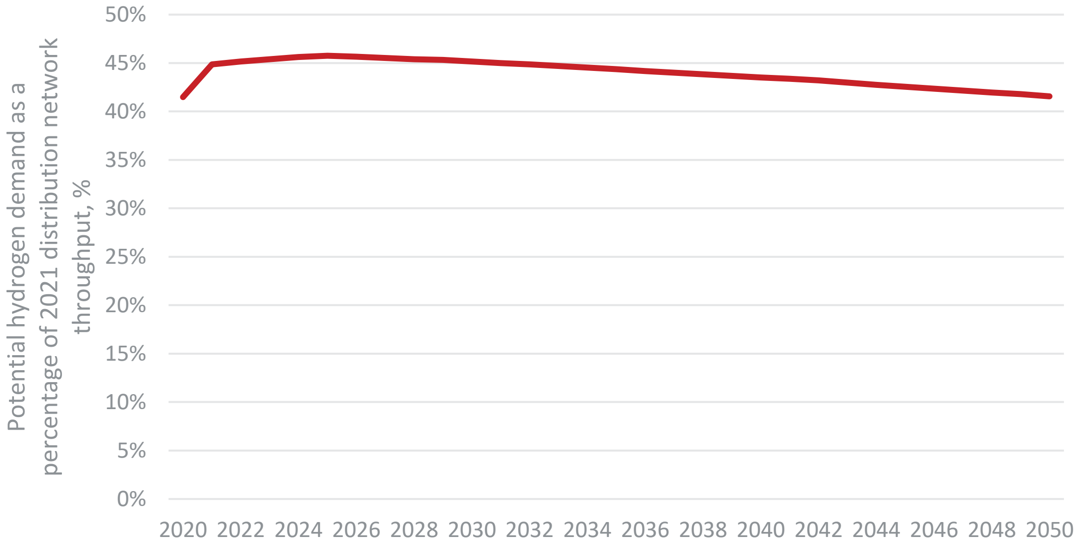
Note: Wholesale, carbon, transmission, distribution, and retail forecasts are under CCC headwind scenario.

However, while the relative premium of blended hydrogen over natural gas most likely decreases over time, the absolute retail cost of blended hydrogen is projected to double between now and 2050. This is because blended hydrogen is almost certain to create lower throughput in the distribution network than non-blended natural gas, so the average price increases. Blended hydrogen likely has a lower throughput because:

- Blended hydrogen in the distribution network is only viable for commercial and residential heating
- Commercial and residential heating is likely to transition to greater electrification.

Under these assumptions, the demand for blended hydrogen would peak around 2025 at 15,920 TJ and decrease afterwards, as shown in Figure 5.11 on the next page. Therefore, the unit costs of transmission and distribution would increase over time, assuming that maintenance and asset recovery needs stay at existing levels.

Figure 5.11: Potential blended hydrogen demand as a proportion of current distribution network throughput



Note: Potential blended hydrogen demand is the sum of residential and commercial demand under the CCC headwinds scenario

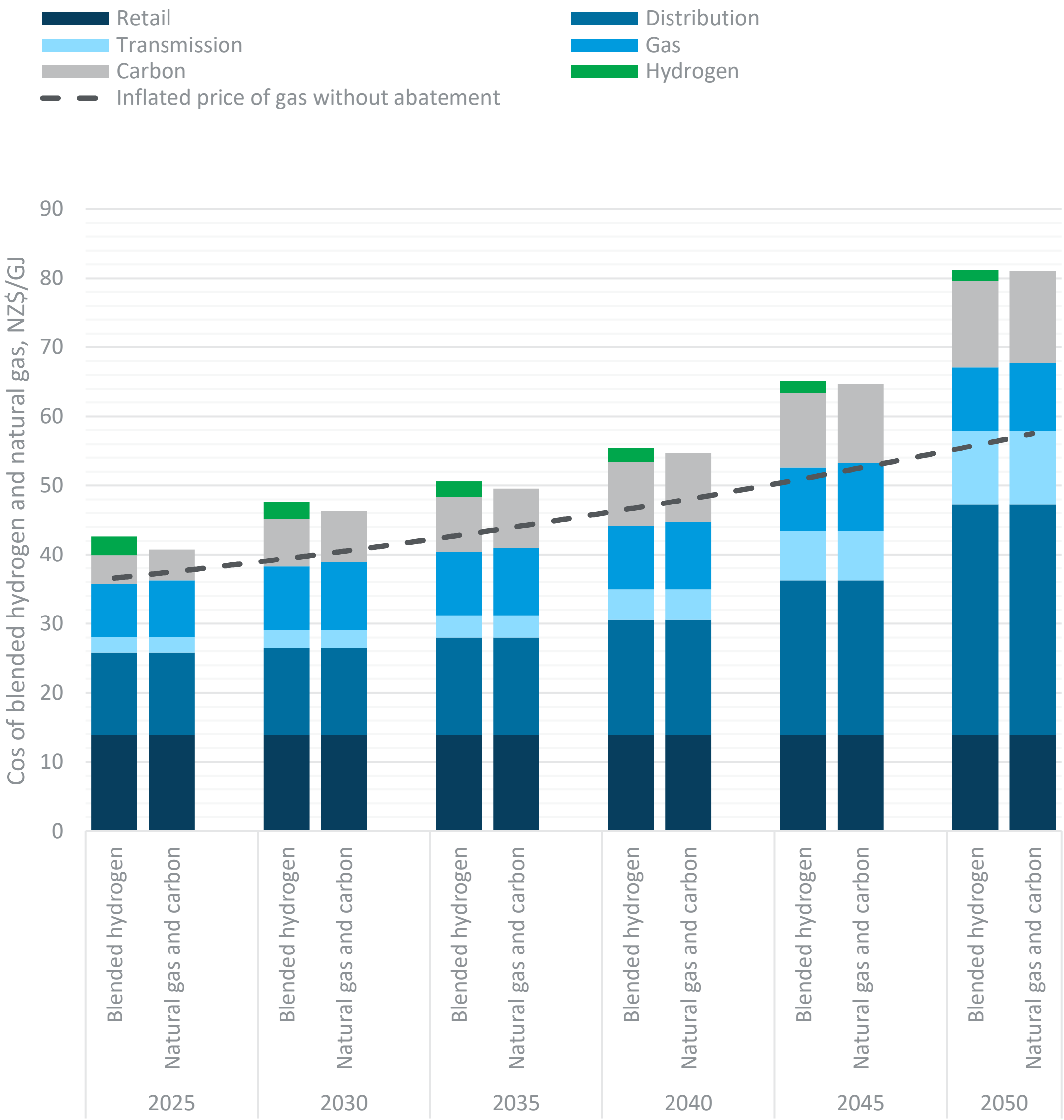
Blended hydrogen could still be viable. While consumers would likely switch to more affordable alternatives over time, many consumers could be willing to pay the modelled premium for natural gas, at least in the short to medium-term.

However, while blended hydrogen is potentially viable, it also appears suboptimal because it is a relatively expensive way of reducing emissions. Figure 5.12 on the next page breaks down the cost components of blended hydrogen and natural gas delivered to residential end users. For reference, it also includes a cost stack of the inflated price of natural gas without abatement, with wholesale gas, transmission, and distribution costs inflated at a rate of 2.5 percent per annum from 2020 prices.[73] It shows that the costs associated with producing, transmitting, distributing, and retailing natural gas are likely similar for blended hydrogen and natural gas. The price premium for blended hydrogen over natural gas results from the abatement method used. Blended hydrogen abates emissions through a combination of reduced emissions from the green hydrogen (blended at 20 percent by volume) and the cost of carbon for the 80 percent by volume natural gas.[74] The natural gas-only stack abates emissions entirely through an associated cost of carbon. The modelled results show that, given the decision to abate emissions, incurring the cost of carbon is likely to be cheaper than using blended hydrogen to offset emissions until around the 2040s. This holds true up to a carbon cost of 580, 415, and 325 New Zealand dollars per tonne of CO2 equivalent by 2025, 2030, and 2035 respectively.

[73] This reference scenario could be interpreted as a hypothetical scenario where the energy transition does not take place. Gas consumption remains largely similar to what exists today, and there is no need to abate emissions.

[74] This translates to a 6.5 percent reduction in total emissions attributable to green hydrogen. This is due to the lower volumetric energy density of hydrogen compared to natural gas, as explained in Box 5.1.

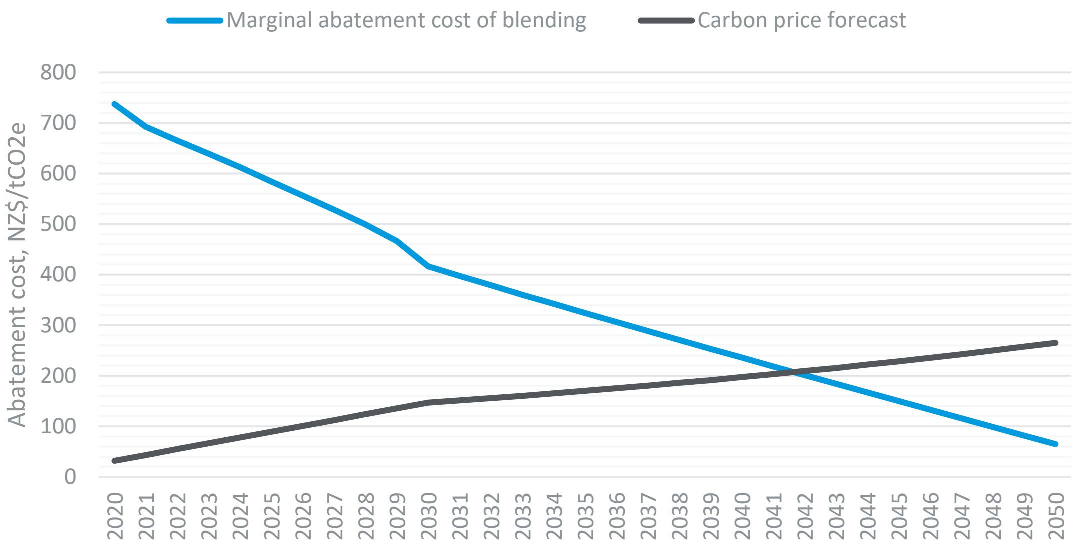
Figure 5.12: Cost breakdown of blended hydrogen versus natural gas to residential consumers



Note: The inflated price of gas without abatement refers to the cost of delivered gas inflated at a rate of 2.5%p.a. from 2020 prices. It assumes zero abatement cost and keeps the retail cost constant at 2020 values.

The marginal abatement cost of blended hydrogen is likely to be high, so it is not cost effective at reducing emissions compared to purchasing ETS units until the 2040s, as shown in Figure 5.13 on the next page. The high levelised cost of hydrogen is the dominant driver behind the high marginal abatement cost of blended hydrogen. Costs associated with transmission, distribution, or retail, do not influence the marginal abatement cost because these costs are assumed to be equivalent for blended hydrogen and natural gas.

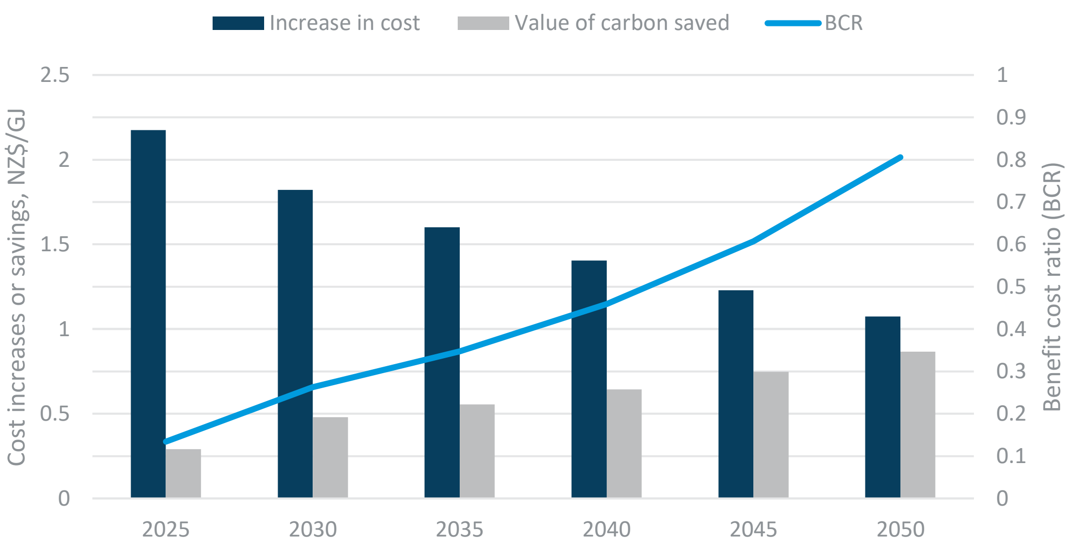
Figure 5.13: Cost effectiveness of blended hydrogen in reducing emissions



Note: Carbon price forecasts are CCC headwinds scenario carbon prices. The marginal abatement cost of blending is the price difference between blended hydrogen and natural gas over the carbon dioxide content of natural gas displaced by green hydrogen.

Figure 5.14 below further demonstrates that investment into blended hydrogen is not likely to yield positive returns in the short to medium-term. Every additional dollar spent on blended hydrogen will likely return less than a dollar's worth of emissions reductions, as measured in forecasted carbon prices.

Figure 5.14: Benefits and costs of blended hydrogen



Notes: The benefit cost ratio (BCR) is the value of carbon emissions avoided, divided by the increase in price of blended hydrogen compared to natural gas.

Therefore, while blended hydrogen is commercially viable, it is unlikely to be economically optimal due to the opportunity cost of not pursuing more effective abatement methods. For example, by 2030, every additional dollar spent on blended hydrogen would likely reduce 2.4kg of carbon emissions. In contrast, the Ministry for the Environment estimates that by 2030, every additional dollar spent on electrifying existing commercial and residential space heaters could reduce 8kg and 4kg of carbon emissions respectively.[75]

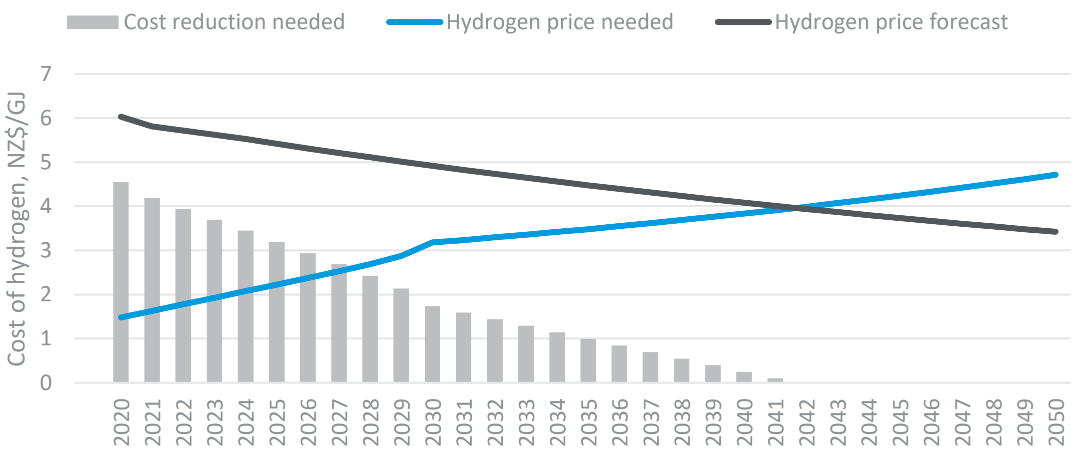
The high marginal abatement cost of blended hydrogen also casts doubt on the willingness of businesses to partake in green certification schemes. Businesses are likely to prefer alternative green initiatives that are more cost-effective, or simply purchasing ETS units and taking them off the market.

However, it is possible that blended hydrogen could become more cost-effective than expected in the future. The natural gas sector could explore blended hydrogen before cost reductions occur if this provided a valuable option to retain the gas network infrastructure in the event hydrogen costs fell significantly in future.

Unexpected increases in the carbon price or decreases in the cost of green hydrogen could also change the economic viability of blended hydrogen. If carbon prices rise more than expected, this increases the value of carbon saved, which could make blended hydrogen more cost effective. As Figure 5.13 above shows, by 2030, blended hydrogen could be cost-competitive if carbon prices exceed NZ$400 per tonne of carbon dioxide equivalent.

If the cost of producing green hydrogen falls more than expected, this decreases the cost of abatement. By 2030, blended hydrogen could be cost-competitive if the cost of green hydrogen is 35 percent less than what is forecasted under this scenario, or NZ$3.18 per kg rather than NZ$4.92 per kg. Figure 5.15 below shows how much reduction in the cost of green hydrogen is needed for blended hydrogen to become cost-effective at abatement.

Figure 5.15: Cost reduction in green hydrogen needed for blended hydrogen to be cost-effective



Note: The hydrogen price forecast assumes parameters consistent with the blending scenario (scenario F).

75 Ministry for the Environment (2020), Marginal abatement cost curves analysis for New Zealand, available: https://environment.govt.nz/assets/Publications/Files/marginal-abatement-cost-curves-analysis_0.pdf

6 Recommendations

Hydrogen is not likely to have a significant impact on New Zealand's natural gas sector. This is because potential hydrogen demand is not likely to be aligned with the current footprint of natural gas infrastructure.

Therefore, this study recommends that natural gas industry stakeholders and energy sector policymakers should:

1. De-prioritise investment activity for the time being aimed at fully transitioning the sector to hydrogen, whether blue or green
2. Consider investment in blended hydrogen only to the extent that this:
    a. Reduces demand risk for scale hydrogen production projects in the short-term, ahead of demand emerging in the transport sector over the medium and longer-term
    a. Creates a real option for the gas sector to avoid irreversible decisions on the future of gas (like decommissioning pipelines), particularly as new information emerges on costs and viability of green hydrogen
3. Deprioritise green certificate schemes for blended hydrogen because these do not appear cost-effective, unless the cost of hydrogen decreases significantly in the short to medium-term. However, certificates may be more economic for other renewable gases
4. Investigate the technical and economic viability of blending other renewable gases in the distribution network, independently of the transmission network

This study finds that hydrogen is unlikely to have an impact on the natural gas sector. Therefore, this study can only rule out less promising approaches, not recommend promising interventions or policies for the natural gas sector. While this study draws from the latest available information as of July 2022, hydrogen technologies are rapidly evolving, so unexpected developments could change the conclusions of this study.

6.1 Full transition to hydrogen should be deprioritised

New Zealand's natural gas sector should not prioritise investment into fully transitioning to hydrogen because this is unlikely to prolong the lives of existing natural gas infrastructure.

The business case for repurposing existing natural gas infrastructure for hydrogen depends on the viability of repurposing the transmission network (section 4.2). However, repurposing the transmission network is unlikely to be viable (section 0), because the potential hydrogen demand in New Zealand is unlikely to:

- Command sufficient volumes to justify the cost of repurposing
- Be located near existing gas transmission infrastructure so that lower costs of hydrogen transport are achieved.

Stakeholders should reassess the case for a full transition as more information becomes available, especially when evaluating the option value of preserving network assets against decommissioning them. The decision could hinge on unexpected developments in hydrogen technologies, such as:

- Novel hydrogen uses that considerably increase potential hydrogen demand
- Highly efficient large electrolysers that justify centralised production in Taranaki.

6.2 Network investment for blue hydrogen is unlikely to be justified

New Zealand's natural gas sector should not prioritise investment in blue hydrogen, because transitioning to hydrogen would be unnecessary if blue hydrogen were viable. The competitiveness of blue hydrogen depends on low CCS and natural gas costs, but these factors also favour continued natural gas use, by reducing the carbon footprint and cost of natural gas consumption (section 5.3.2).

However, this conclusion assumes that CCS is viable at the site of natural gas consumption. If CCS were only viable at the site of blue hydrogen production and not natural gas consumption, an unlikely outcome, then stakeholders should reassess the case for blue hydrogen.

6.3 Network investment for blended hydrogen may be justified but only to reduce hydrogen offtake risk

New Zealand's natural gas sector should carefully consider any investment in blended hydrogen (or green certificate schemes for blended hydrogen). While blended hydrogen is financially viable, it is not likely to be cost-effective at reducing emissions.[76]

However, blended hydrogen could provide two routes to lower emissions:

- Blending hydrogen might reduce demand risk for scale hydrogen production projects in the short-term, ahead of demand emerging in the transport sector over the medium and longer-term. As demand for hydrogen increasing in other sectors, the blending ratio would reduce
- Blending hydrogen may create a real option for the gas sector to avoid irreversible decisions on the future of gas (like decommissioning pipelines), particularly as new information emerges on costs and viability of green hydrogen

The business case for blended hydrogen depends on the viability of the distribution network (section 4.3). Distributing blended hydrogen is likely to be financially viable, assuming end consumers are willing to accept a small increase in their gas bills (section 5.3.2). Blended hydrogen is financially attractive because it reduces the emissions of the natural gas industry at a minor cost of end customers.

However, blended hydrogen is unlikely to be economically attractive because:

- Blended hydrogen is not cost-effective—the marginal abatement cost of blended hydrogen will likely be higher than the carbon price until the 2040s[77]

[76] This conclusion assumes that the natural gas sector can trade carbon credits with other sectors to reach net targets. If upcoming policy requires the sector to reach absolute targets without offsets, then blended hydrogen may be more attractive. However, it must still be compared against other renewable gases, which is out of scope for this study. As of August 2022, we are not aware of any finalised emissions targets for the gas sector.

[77] It is unlikely, but possible, that blended hydrogen would become cost competitive. This will inquire unexpected increases in the carbon price or decreases in the cost of green hydrogen. We outline the necessary conditions in Section 5.3.2.

- Clear alternatives to blended hydrogen exist—electrification is viable for consumers of blended hydrogen, likely at a lower cost.

A green certificate scheme for blended hydrogen is unlikely to have an impact on the viability of blended hydrogen, because the scheme would use the proceeds from selling certificates to bridge the viability gap of blending. However, neither part is likely:

- Businesses are unlikely to buy green certificates since the marginal abatement cost of blended hydrogen is high, and cheaper abatement methods are available
- Consumers are likely to tolerate the price premium of blended hydrogen, so the viability gap may not exist.

However, blended hydrogen could help kickstart green hydrogen production in New Zealand, because unlike other hydrogen uses, blended hydrogen is viable now. Blended hydrogen can bridge the offtake risk for hydrogen producers by guaranteeing a base level of hydrogen demand.

Blended hydrogen could potentially reduce total emissions in the long-term even if it is not the least-cost abatement option now. This is because blended hydrogen could bring forward scale production of hydrogen before heavy vehicles and other uses exist to justify scale production. Therefore, blended hydrogen could help resolve the “chicken and egg problem” that often slows the adoption of innovative technologies, reducing emissions in the long-term even if cheaper abatement options exist now. Industry stakeholders and policymakers could jointly explore policy tools and financial instruments that can leverage the blended hydrogen opportunity to de-risk green hydrogen production in New Zealand.

Finally, blended hydrogen creates a possible option for repurposing pipelines and infrastructure, in case green hydrogen production becomes considerably cheaper or technological development means appliance conversion costs fall. In the event of irreversible decisions about the future of the gas network, the real option value should be taken into account.

6.4 Other renewable gases could improve the viability of the distribution network

New Zealand’s natural gas sector should investigate the technical and economic viability of blending other renewable gases in the distribution network (independently of the transmission network). This study finds that blended hydrogen is unlikely a cost-effective GHG abatement method, however, other renewable gases could be more promising.

Analysis in Section 4.3.2 shows that the distribution network might be a viable gas transportation option even if the transmission network no longer carries natural gas. This is because:

- The distribution network has several characteristics that are likely to extend its life relative to the transmission network
- Non-pipeline transmission methods may be able to supply natural gas at an economic cost for blending
- Some renewable gases, such as biogas, may not require transmission from a centralised production location.

Blending renewable gases in the distribution network could help the gas sector meet its emissions reduction goals. If industrial consumers of natural gas reduce consumption (or cease operations) the load on the transmission network would be significantly lower. This would also considerably reduce the total emissions of the gas sector, as shown in Figure 2.4 above. Depending on the gas sector’s emissions targets,[78] continuing to supply commercial and residential gas customers may not require significant further decarbonisation efforts. Under such a scenario, only a limited volume of renewable gases would be required to meet the gas sector’s emissions targets. This resolves a key disadvantage of biogas—its limited supply.

Since this possibility would require more detailed assessments of renewable gases other than hydrogen, it is outside the scope of this study. However, this study recommends that the gas sector explore whether other renewable gases can help decarbonise the distribution network, notably those that can be produced and consumed locally. Further investigation into alternative transmission options, such as trucking or LNG terminals, could also provide insight into the viability of blending without relying on the transmission network.

[78] As of August 2022, we are not aware of any finalised emissions targets for the gas sector. This recommendation may change depending on the setup of targets, which are likely to be developed in the upcoming Gas Transition Plan.

Appendix A: Modelling assumptions

Table 0.1: Hydrogen scenario inputs

Label	Aviation demand included	Policy support	Electrolyser capital cost escalation	Carbon price	Diesel price	Natural gas price	Sectoral demand
A	Yes	High	-6.70%	CCC headwinds	20% escalation	3% escalation	Historic trends
B	No	High	-6.70%	CCC headwinds	20% escalation	3% escalation	Historic trends
C	No	High	-1.38%	CCC headwinds	20% escalation	3% escalation	Historic trends
D	No	Low	-1.38%	CCC current policy reference	3% escalation	3% escalation	Historic trends
E	No	High	Not applicable	CCC headwinds	20% escalation	3% escalation	Historic trends
F	Yes	Base	-3.40%	CCC headwinds	3% escalation	CCC forecast	CCC current policy reference

Note: -6.70% capital cost escalation halves electrolyser prices in ten years (in line with the most optimistic IRENA forecasts), -3.40% in 20 years, and -1.38% in 50 years. Historic trends extrapolate sectoral demand between 2000 and 2019 forward. High policy support includes 30% diesel tariff increases and 45% hydrogen plant cost subsidisation; medium policy support includes 20% diesel tariff increases and 35% hydrogen plant cost subsidisation; low policy support refers to 10% diesel tariff increases and 25% hydrogen plant cost subsidisation; base policy support has no diesel tariff increase or hydrogen plant cost subsidisation.

Table 0.2: Key model choices

Parameter	Value	Source
Blended gas hydrogen content by volume	20%	Industry consensus
Natural gas transmission, distribution, and retail costs	Forecasts to 2050	Climate Change Commission (2021), Technical modelling assumptions in energy and transport sectors
Carbon price	Forecasts to 2050	Climate Change Commission (2021), Technical modelling assumptions in energy and transport sectors
Natural gas wholesale prices	Forecasts to 2050	Climate Change Commission (2021), Technical modelling assumptions in energy and transport sectors
Natural gas demand by sector	Forecasts to 2050	Climate Change Commission (2021), Scenarios dataset for the Commission's 2021 Final Advice
Blue hydrogen cost forecasts	US$1.5/kg in 2021, increasing by 2.14% per annum	IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5C Climate Goal

Table 0.3: Key model parameters

Parameter	Value	Source
Hydrogen gravimetric energy density	130 GJ/t	J. Ramage (1983), Energy: A Guidebook. Oxford University Press
Hydrogen volumetric energy density	10.8 MJ/m^3	Arup (2016), Five minute guide: Hydrogen
Natural gas volumetric energy density	38.85 MJ/m^3	Parliament of Australia (1998), Natural Gas: Energy for the New Millennium, Research Paper 5 1998-99, Science, Technology, and Resources Group
Carbon dioxide equivalent of nitrous oxide	298	Intergovernmental Panel on Climate Change (2007), Fourth Assessment Report
Natural gas emissions density	0.0496 GJ/tCO2e	US Environment Protection Agency, Greenhouse Gases Equivalencies Calculator References
Jet fuels emission density	0.09 gCO2e/MJ	International Civil Aviation Organisation (2019), Carbon Offsetting and Reduction Scheme for International Aviation, Annex 16 Volume IV
Diesel carbon dioxide emissions intensity	1.30 kg/km	Carbon Independent, https://www.carbonindependent.org/20.html
Diesel nitrous oxide emissions intensity	3.69 g/km	US Bureau of Transportation Statistics, Estimated Average Vehicle Emissions Rate per Vehicle
Transmission network gas throughput in 2021	147351254 GJ	Commerce Commission, Gas Distribution Information Disclosure
Distribution network gas throughput in 2021	34792986 GJ	Commerce Commission, Gas Distribution Information Disclosure
Weighted average transmission pipeline diameter in 2021	2408 mm	Commerce Commission, Gas Transmission Information Disclosure
Transmission system length in 2021	2513.629 km	Commerce Commission, Gas Transmission Information Disclosure
Pipeline upgrade cost	0.3–0.6 million euros/km	European Hydrogen Backbone (2021), Extending the European Hydrogen Backbone: A European Hydrogen Infrastructure Vision Covering 21 Countries
Infrastructure discount rate	5.0% p.a.	The Treasury, Discount Rates for Economic Analyses

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